entergy

December 19, 2022

<u>**By Hand Delivery**</u>

Mr. Brandon Frey
Louisiana Public Service Commission
Galvez Building, 12th Floor
602 North Fifth Street
Baton Rouge, LA 70802

Re: **Re:** ***In Re:*** **Application of Entergy Louisiana, LLC for Approval of the Entergy Future Ready Resilience Plane (Phase I) (LPSC Docket No. U-_______)**

Dear Mr. Frey:

I have enclosed, on behalf of Entergy Louisiana, LLC ("ELL" or "Company"), the original and three copies of a Non-Confidential Public Version of the Company's Application for Approval of the Entergy Future Ready Resilience Plan (Phase I), along with the Direct Testimony and Exhibits of Phillip R. May, Sean Meredith, Alyssa Maurice-Anderson, Charles W. Long, Jason D. De Stigter, Todd A. Shipman, and Jay A. Lewis. Please retain the original and two copies for your files and return a date-stamped copy to our by-hand courier.

I have also enclosed five copies of the Confidential Version of the referenced filing, which is being provided under seal pursuant to the provisions of the LPSC General Order dated August 31, 1992, and Rules 12.1 and 26 of the Commission's Rules of Practice and Procedure. The confidential materials included in the filing consist of competitively sensitive market information or sensitive infrastructure information, the disclosure of which may create an artificial target for suppliers/vendors or create physical security risks. For this reason, this material is confidential and commercially sensitive. The disclosure of the information contained herein would subject not only the Company, but also its customers, to a substantial risk of harm. Accordingly, it is critical that this information remain confidential.

Please retain the appropriately marked Confidential Version for your files and return a date-stamped copy our by-hand courier. The three additional confidential copies are for the Administrative Law Judge, Staff Attorney, and Research Attorney. Additional copies of the Confidential Version of this filing will be provided to the appropriate representatives of the Louisiana Public Service Commission Staff and made available to intervenors once a suitable Confidentiality Agreement has been executed by the parties.

If you have any questions, please do not hesitate to call me. Thank you for your courtesy and assistance with this matter.

Respectfully submitted,

Lawrence J. Hand, Jr.

LJH/kll
Enclosures

cc: LPSC Commissioners (Public version only by email)
Phillip R. May
Mark D. Kleehammer

BEFORE THE

LOUISIANA PUBLIC SERVICE COMMISSION

***IN RE*: APPLICATION OF ENTERGY LOUISIANA, LLC FOR APPROVAL OF THE ENTERGY FUTURE READY RESILIENCE PLAN (PHASE I)**	))))	**DOCKET NO. U- _______**

APPLICATION OF ENTERGY LOUISIANA, LLC FOR
APPROVAL OF THE ENTERGY FUTURE READY RESILIENCE PLAN (PHASE I)

Pursuant to the Rules of Practice and Procedure of the Louisiana Public Service Commission ("LPSC" or the "Commission"), Entergy Louisiana, LLC ("ELL" or the "Company") respectfully submits its Application for Approval of the Entergy Future Ready Resilience Plan (Phase I) (the "Application").

In particular, with this Application, ELL requests that the Commission approve, and issue a public interest finding regarding, the Entergy Future Ready Resilience Plan (the "Resilience Plan"),[1] which is the Company's proposed course of action to improve the resilience of its electric system through accelerated infrastructure hardening and vegetation management.[2] As further described herein, the relief sought by the Company in this Application, as supported by the accompanying witness testimony and exhibits thereto, is necessary and essential to foster a more resilient and reliable system that can better withstand extreme events, avoid or mitigate customer outages from such events, and facilitate faster restoration of service after such events.

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[1] Company witness Jay Lewis discusses the specific Commission orders that may be relevant to the Commission's consideration of the Company's request in this proceeding.

[2] Alternatively, the Company requests that the Commission determine the level of resilience investment that the Commission believes serves the public interest.

I. OVERVIEW OF RELIEF SOUGHT BY THE APPLICATION

As discussed by Company witness Phillip R. May and others, ELL's Application addresses directly the significant risks faced by communities in the Gulf Coast region and the Company's plan to improve its electric system to help customers meet the challenges and opportunities of tomorrow. In particular, following Hurricane Ida, and in the light of the back-to-back years of historically severe weather affecting the areas served by the Company and the other Entergy Operating Companies ("EOCs),[3] including both major hurricanes and severe winter storms, the EOCs consulted their own internal subject matter experts and stakeholders, evaluated the practices of other utilities across the country, and undertook a holistic analysis of the opportunities available for creating a more resilient system. As that process evolved, the Company engaged an outside industry consultant, 1898 & Co., to assist with identifying potential hardening projects and estimating the costs and benefits of those projects. The result of those comprehensive and customer focused efforts – which have been aimed at understanding the risks faced and identifying cost-effective and achievable projects to build a more resilient electric system – is the Company's Resilience Plan. As discussed in the witness testimony supporting the Application, the Resilience Plan is reasonably expected to reduce the cost of restoring the electric grid after major storms as well as reduce the number and duration of outages associated with those events. The implementation of the Resilience Plan will thus result in a substantially improved risk profile for the ELL grid, and that improvement is vital to the communities served by the Company and, in turn, to the economy of Louisiana.

The Company is proposing to implement the Resilience Plan over the 10-year period from 2024 to 2033. In this docket, the Company seeks specific approval of Phase I of the

[3] The five EOCs include Entergy Arkansas, LLC; ELL; Entergy Mississippi, LLC; Entergy New Orleans, LLC; and Entergy Texas, Inc.

Resilience Plan, which includes approximately $5.0 billion in projects proposed to be implemented in the first five years (2024 to 2028) ("Phase I").

The Company also is seeking approval in its Application of a new rider for ELL, the Resilience Plan Cost Recovery Rider (the "Resilience Plan Rider" or "Rider"), to permit timely recovery of the Resilience Plan's revenue requirement as ELL completes the plan's resilience improvements and customers begin receiving the benefits of those improvements. Undertaking the level and pace of spending in the proposed Resilience Plan and recovering the resulting costs via existing ratemaking mechanisms would place ELL's financial condition at great risk and expose ELL to adverse action from the credit rating agencies and, in turn, its customers to higher costs. The proposed Rider would improve ELL's cash flow and place ELL in a much better position to execute the Resilience Plan and maintain ELL's financial condition for the benefit of customers.

Finally, the Company's Application requests certain accounting and ratemaking treatments related to the Resilience Plan and approval of the Company's proposed monitoring plan for the resilience investments.

II. THE COMPANY

ELL is a limited liability company duly authorized and qualified to do and doing business in the State of Louisiana, created and organized for the purposes, among others, of generating, transmitting, distributing, and selling electricity for power, lighting, heating, and other such uses; and ELL is engaged in the business thereof in fifty-eight (58) of the sixty-four (64) parishes of the State of Louisiana. ELL provides electric service to approximately 1.1 million customers.

A significant portion of ELL's service area in Louisiana is comprised of communities that are regularly exposed to extreme weather and flooding, and, as such, ELL has been working to make its system more resilient since the significant storms that impacted Louisiana in the early

2000s. The experience with Hurricane Ida in 2021, as well as the challenges of the record setting 2020 Atlantic hurricane season, demonstrate the necessity of those improvements. In the intervening years, ELL, like the overall electric utility industry in the United States, has invested considerable capital to replace and upgrade aging infrastructure. In particular, ELL has modernized its power plants, adding both cleaner and more efficient energy sources in order to provide its customers with reliable, safe, and low-cost energy. ELL has also invested significantly in its transmission grid to expand for growth and to comply with federal reliability requirements. And, for its distribution system, ELL has implemented grid modernization and system-hardening improvements. In particular, grid modernization is being enabled by new technology and developed in response to increasing customer expectations for reliability enhancements that require a more modern, responsive, and resilient grid to minimize the frequency and duration of outages.

III. THE RESILIENCE PLAN

Although the Company has successfully invested in resilience for years, the increasing threat of extreme weather events and the transition to a more electrified economy have necessitated a review of the timeline on which the Company must continue to make those investments to position our communities to be ready for future weather events. Because major storm events are occurring more frequently and with more intensity, it is very likely that the Company will incur costs, one way or another, to improve the resilience of the electric system. That is, either it will incur these costs as part of a comprehensive, accelerated plan to improve resilience, or it will incur these and additional costs in the aftermath of a major storm or weather event (1) without achieving the same level of resilience and (2) in the face of obstacles and challenges that make it difficult to perform work as efficiently and with the level of management oversight and coordination that is possible if the work is performed during blue sky conditions.

Therefore, in line with input received from stakeholders and as the next step in the Company's ongoing efforts to provide customers with safe, reliable, affordable, and sustainable service, the Company has developed a proposed course of action specifically designed to improve overall electric system resilience through accelerated infrastructure hardening and vegetation management. The projects and the associated investment proposed in the Company's Resilience Plan represent investment that goes beyond what the Company had already planned in its capital budgets prior to Hurricane Ida. Furthermore, these investments do not fall into the same category as the Company's day-to-day reliability programs. Instead, these projects represent a careful, studied approach to enable the Company to accelerate investment, where appropriate, to address the frequency and intensity of storms that pose an increasing threat to the electric system.

Specifically, the Resilience Plan has four interconnected components:

- *First*, the Company proposes to complete approximately 9,600 identified distribution and transmission hardening projects, which will harden more than 269,000 structures over more than 11,000 line miles over the course of the 10-year period from 2024 to 2033 (the "Comprehensive Hardening Plan") at a cost of approximately \$9 billion (nominal).[4] Phase I of the Resilience Plan includes the first five years of the Comprehensive Hardening Plan and is estimated at \$4.6 billion.

[4] The specific projects contained in the Comprehensive Hardening Plan are attached to the testimony of Company witness Sean Meredith as Highly Sensitive Protected Materials ("HSPM") Exhibit SM-2. Although the Company's proposed plan sets forth the Company's best efforts to identify the scope and timing of the selected projects, the precise work performed (as well as the timing of when that work will be performed) will be subject to continual refinement as the Company implements its Resilience Plan.

- *Second*, the Company proposes to construct 44 dead-end structures for the Company's 500 kV transmission lines, which form the high voltage backbone of the transmission system. This will improve the resilience of these lines by helping prevent and/or limit cascading damage to transmission structures. The additional cost for these dead-end structure projects is included in Phase I of the Resilience Plan and is estimated to be $88 million.
- *Third*, the Company is proposing a number of projects aimed specifically at increasing the resilience of the Company's telecommunications systems, which play an integral part in the Company's efforts to respond to and recover from disruptions caused by major weather events. The projects included in Phase I of the Resilience Plant are estimated to cost approximately $100 million (approximately $97.2 million in capital spending and $2.8 million in incremental operation and maintenance costs).
- *Fourth*, the Company is proposing resilience-based enhancements to its current vegetation management programs to accelerate trim cycles and to implement additional program elements. These enhancements on the Company's distribution and transmission systems will cost approximately $172 million in Phase I of the Resilience Plan.

In addition, while not presently a part of the Resilience Plan, the Company has identified a number of non-wire alternatives ("NWAs"), or microgrids, that are able to provide a local source of power that can swiftly restore power to a substation, to the feeders that are connected to a substation, or to certain critical loads in the Company's distribution system. Specifically, the Company has identified ten NWAs across the state for consideration, which NWAs are possible alternatives to certain transmission hardening projects identified in the Comprehensive Hardening Plan. While these NWAs would not prevent damage during a weather event, they are expected to enable the electric system to restore electric service rapidly when damages and outages do occur.

IV. COST RECOVERY AND REQUESTED ACCOUNTING AND RATEMAKING TREATMENTS

Absent the sort of commitment to and substantial investment in resilience measures included in the Resilience Plan, the Gulf Coast will be insufficiently prepared to address the future risks posed by extreme weather events, which are becoming more frequent, severe, unpredictable, and costly, and are disproportionately impacting the Gulf Coast region. But the level of investment contemplated in the Resilience Plan is substantial, and undertaking the proposed Resilience Plan with cost recovery via the currently existing ELL ratemaking mechanisms would compromise ELL's credit metrics and cash flow and thus expose ELL to adverse action from the credit rating agencies and its customers to higher costs. Therefore, ELL is proposing that the revenue requirement associated with the Resilience Plan be recovered through a new contemporaneous recovery mechanism – the Resilience Plan Rider – the specifics of which are discussed by Company witness Alyssa Maurice-Anderson in her testimony. In short, the proposed Rider would accomplish contemporaneous recovery of Resilience Plan costs through a forward-looking rate that would also include a true-up after a prudence review.

In addition, the Company also intends to request a waiver from the Federal Energy Regulatory Commission ("FERC") to allow ELL to capitalize conductor handling costs incurred through the Resilience Plan, which treatment would benefit customers by lowering the Resilience Plan's immediate bill effects. ELL requests that the Commission express support or non-opposition to the contemplated FERC waiver request.

The Company also requests authorization to create a regulatory asset for the remaining net book value associated with assets that must be retired and replaced as part of the Resilience Plan. ELL would include the regulatory asset in rate base and amortize such retired plant costs at a rate consistent with the associated depreciation expense currently reflected in rates. With this approved ratemaking treatment, customers would not see an incremental increase in rates associated with ELL's recovery of assets prudently retired in connection with the Resilience Plan.

V. <u>CUSTOMER BENEFITS</u>

The Company expects that the investment contemplated in the Resilience Plan will produce significant customer benefits by, among other things, (1) lowering future post-storm restoration costs and (2) decreasing the number of customers impacted and the duration of the overall outage after major weather events. Specifically, if implemented, the Company's Comprehensive Hardening Plan, which is a large component of the Resilience Plan, is reasonably projected to produce a reduction in storm restoration costs of approximately 50 percent over the next fifty years. Moreover, the projects identified in the Comprehensive Hardening Plan are reasonably projected to produce a decrease in the projected customer minutes interrupted after a major storm (*i.e.*, shortening the period during which customers are without electricity) by approximately 55 percent over the next fifty years. The Company's proposed vegetation management enhancements included in the Resilience Plan also complement the accelerated storm hardening of transmission and distribution assets by helping to decrease the number of times that the Company's storm-hardened assets will be tested by vegetation during and after a major storm. These enhancements therefore are likewise expected to increase overall system resilience and reduce the number and duration of outages following a major storm.

A third anticipated benefit of implementing the Company's Resilience Plan is that blue sky resilience work can be more carefully planned, executed, and overseen as compared to reactive, post-storm restoration work where the Company is working as quickly and safely as possible to restore power, often in highly unattractive conditions and with tens of thousands of contract workers laboring simultaneously across a vast area impacted by a major storm.

For all of these reasons, the extensive hardening and resilience work included in the Resilience Plan will benefit not only the Company, the Company's customers, and the communities that the Company serves, but also customers of other Louisiana utilities served by the Company's transmission system in terms of fewer and shorter transmission outages as a result of storms and other major weather events.

VI. PROJECT MANAGEMENT AND CONTRACTING APPROACH

Given the magnitude of the Resilience Plan and the Company's existing organizational framework for construction and project management, the Company plans to work with qualified contractors ("Alliance Partners") that will be retained in addition to the Company's management team. Specifically, the Company plans to use a competitive bidding process among the identified Alliance Partners to select contractors to perform various aspects of the work and, if needed, the Company will qualify additional partners to add capacity and execution capabilities.

The Alliance Partners will be heavily relied upon for project execution and support; however, these Alliance Partners will not be utilized exclusively to execute the Resilience Plan, as the Company also plans to leverage existing contract partners and strategies. Additionally, the Company will maintain appropriate project controls in the areas of project safety, cost, and schedule. The Company will also employ the necessary administrative and technical resources to ensure that project design, quality, and material deliverables are achieved in accordance with the Company's specifications.

The Company is using Alliance Partners because the Company has determined that this approach is the best method for controlling costs and to consistently and reliably execute the large portfolio of projects contained in the Resilience Plan. As discussed by Company witness Mr. Meredith, after considering a number of different contracting strategies, including an "EPC" model, baseload contractors, and strategic sourcing, the alliance model emerged as the preferred contracting strategy for the Resilience Plan. As the Company executes the Resilience Plan, the Company will continue to evaluate the best contracting structure with Alliance Partners to cost effectively execute the plan.

VII. MONITORING PLAN

To keep the Commission informed on the progress and costs of the Resilience Plan, the Company is proposing to file progress reports every six months beginning August 15, 2024. As discussed by Mr. Meredith in his testimony, the reports generally will provide information regarding the preceding two quarters and will address subjects such as project completion status, projects schedule, material business issues, and additional matters intended to keep the Commission informed on the progress of the Resilience Plan. For example, the report filed on August 15, 2024, will discuss projects completed and developments in the execution of the plan for the period of January 1, 2024, through June 30, 2024; and the report filed on February 15, 2025, will discuss projects completed and developments in the execution of the plan for the period of July 1, 2024, through December 31, 2024. Near the end of Phase I, the Company will evaluate the impact of its efforts and make a recommendation about completing the portfolio of resilience projects in Phase II of the Resilience Plan.[5]

[5] Phase II of the Resilience Plan is projected to include approximately $4.6 billion in infrastructure resilience and storm hardening projects.

VIII. SUMMARY OF WITNESSES SUPPORTING THE APPLICATION

Attached to this Application are the testimonies of seven witnesses of the Company:

- Phillip R. May – President and Chief Executive Officer of ELL. Mr. May provides an overview of the Company's Application as well as the Resilience Plan, including why the Company has developed that plan. He also describes the Company's historical investment in its generation, transmission, distribution systems; the Company's current and future plans to continue to modernize and harden its infrastructure for the benefit of its customers; and the significant and emerging circumstances supporting the necessity for accelerating the pace of certain hardening investment as contemplated in the Resilience Plan. He also introduces the Company's other witnesses in this proceeding.
- Sean Meredith – Vice President, System Resilience. Mr. Meredith presents ELL's Resilience Plan and provides details regarding the proposed projects under that plan. He also summarizes the estimated costs and benefits of implementing the plan, provides support for the conclusion that the investments included in the Resilience Plan are in the public interest and should be made, and summarizes the Company's proposed monitoring plan.
- Alyssa Maurice-Anderson – Director, Regulatory Filings and Policy, for ESL. Ms. Maurice-Anderson's testimony supports the Company's request in its Application in this proceeding seeking approval of the Resilience Plan Rider to permit more timely recovery of the Resilience Plan's revenue requirement as ELL completes the plan's resilience improvements and customers begin receiving the benefits of those improvements. Ms. Maurice-Anderson also explains that the need for the Resilience Plan is supported by ELL's expectation that it will have limited securitization capacity to finance future storm-

related restoration costs in the near term and that financing future restoration costs would likely occur at a less favorable cost to customers. Her testimony also supports the requested ratemaking treatment related to transmission and distribution assets that must be retired and replaced with new assets pursuant to the Resilience Plan and discusses an accounting waiver that ELL intends to request at the FERC, which will mitigate the near term bill effect on customers.

- Charles W. Long – Vice President of Power Delivery Operations for ESL. Mr. Long discusses the Power Delivery Organization that is responsible for planning, operating, and maintaining ELL's transmission and distribution systems, as well as the Capital Projects Organization that designs and constructs ELL's transmission and distribution systems. These two organizations will work with ELL to execute the Comprehensive Hardening Plan and bring resilience benefits to ELL and its customers. He also discusses the ongoing process of the Company's reliability work on its distribution and transmission systems and provides an overview of those systems and operations. He then discusses the Company's proposed changes to vegetation management programs and spending. Finally, he discusses the need for the Comprehensive Hardening Plan and the benefits that a comprehensive resilience effort can provide.
- Jason D. De Stigter – Director, 1898 & Co. Mr. De Stigter summarizes the results and methodology used to develop the Comprehensive Hardening Plan, including a description of how the assessment was performed and why it was performed in that way. He also describes the major elements of the Storm Resilience Model, which include a Major Storms Event Database, Storm Impact Model, Resilience Benefit Module, and Investment Optimization & Project Prioritization. He also reviews historical major storm

events that have impacted ELL's service area, describes the datasets used in the Storm Impact Model and how they were used to model system impacts due to storms events, and explains how to understand the resilience benefit results. Finally, he describes the calculations and results of the Storm Resilience Model.

- Todd A. Shipman – Principal, Utility Credit Consultancy LLC. Mr. Shipman explains what credit ratings are, the importance of utility credit ratings to regulators, and the analytical framework used for determining utility credit ratings. He also provides information regarding the overall utility industry's financial outlook from a ratings perspective. He then summarizes ELL's current credit ratings and outlook, and, in that context, he opines on how Moody's Investor Service and S&P Global Ratings may react to ELL's proposed Resilience Plan and Resilience Plan Rider.
- Jay A. Lewis – Principal, ASD@Work, LLC. Mr. Lewis discusses a number of Commission orders that may be implicated by the Company's request regarding the Resilience Plan and provides context for how the Company's proposal may be considered. Additionally, he discusses the public interest standard that has been historically used at the LPSC and how that standard should be applied in the context of an accelerated resilience program like the Resilience Plan that has both traditional benefits and nontraditional benefits. He further discusses the periodic reporting required by the Business Combination order and the proposed monitoring plan for the resilience investments. He then summarizes the regulatory requests being made by ELL.

IX. SERVICE OF NOTICE AND PLEADINGS

The Company requests that notices, correspondence, and other communications concerning this Application be directed to the following persons:

Mark D. Kleehammer
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bfenasc@entergy.com

ELL requests that the foregoing persons be placed on the Official Service List for this proceeding, and respectfully requests that the Commission permit the designation of more than one person to be placed on the Official Service List for service in this proceeding.

X. REQUEST FOR CONFIDENTIAL TREATMENT

Portions of the Company's evidence supporting this Application contain information considered by the Company to be proprietary and confidential. Disclosure of certain of this information may expose the Company and its customers to an unreasonable risk of harm. Therefore, in the light of the commercially sensitive nature of such information, the Company has submitted two versions of each of the affected documents, one marked "Non-Confidential Redacted Version" and the other marked "Confidential Version." In anticipation of the execution of a suitable confidentiality agreement in this docket, the Confidential Versions bear the designation "Highly Sensitive Protected Materials" or words of similar import. Although the confidential information and documents included with this Application may be reviewed by appropriate representatives of the LPSC Staff and intervenors pursuant to the terms and conditions of a suitable confidentiality agreement once such an agreement has been executed in this Docket, this confidential information also is being provided pursuant to, and shall be exempt from public disclosure pursuant to, the Commission's General Order dated August 31, 1992 and Rule 12.1 of the Rules of Practice and Procedure of the Commission.

XI. PRAYER FOR RELIEF

WHEREFORE, for the foregoing reasons, Entergy Louisiana, LLC respectfully requests that, after due and lawful proceedings are held, its Application be approved. In particular, the Company requests that the Commission:

1. Approve Phase I of the Resilience Plan as prudent and in the public interest subject to an ongoing obligation of ELL to prudently manage the Resilience Plan;
2. Deem the prudently incurred costs under the Resilience Plan to be eligible for cost recovery via the rate mechanisms proposed by the Company;
3. Approve the Resilience Plan Cost Recovery Rider to permit timely recovery of the Resilience Plan's revenue requirement and to provide for true-up reporting, prudence review and dispute resolution procedures;
4. Approve the creation of a regulatory asset for addressing recovery of (and on, if applicable) the remaining net book value of assets that are replaced through the Resilience Plan, at the level currently reflected in ELL's rates;
5. Approve the Company's proposed monitoring plan;
6. Acknowledge that ELL will be requesting Federal Energy Regulatory Commission approval to capitalize certain conductor handling expenses that would otherwise be treated as expenses, and express support or non-opposition to the contemplated FERC waiver request;
7. Publish notice of this proceeding in the Commission's Official Bulletin and establish a twenty-five (25)-day period for interventions in this proceeding;
8. Provide for appropriate protection for any confidential information to be produced in this proceeding;

9. Direct that notice of all matters in these proceedings be sent to Mark D. Kleehammer, Lawrence J. Hand, Jr., and Brett P. Fenasci as representatives of Entergy Louisiana, LLC; and

10. Grant all other relief that the law and the nature of the case may permit or require.

Respectfully submitted,

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ATTORNEYS FOR
ENTERGY LOUISIANA, LLC

BEFORE THE

LOUISIANA PUBLIC SERVICE COMMISSION

***IN RE*: APPLICATION OF ENTERGY LOUISIANA, LLC FOR APPROVAL OF THE ENTERGY FUTURE READY RESILIENCE PLAN (PHASE I)**	**))))**	**DOCKET NO. U- _______**

DIRECT TESTIMONY

OF

PHILLIP R. MAY

ON BEHALF OF

ENTERGY LOUISIANA, LLC

DECEMBER 2022

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EXHIBIT LIST

I. QUALIFICATIONS AND PURPOSE OF TESTIMONY

Q1. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND OCCUPATION.

A. My name is Phillip R. May. I am President and Chief Executive Officer ("CEO") of Entergy Louisiana, LLC ("ELL" or the "Company").[1] My business addresses are 4809 Jefferson Highway, Jefferson, Louisiana 70121, and 446 North Boulevard, Baton Rouge, Louisiana 70802.

Q2. ON WHOSE BEHALF ARE YOU SUBMITTING THIS DIRECT TESTIMONY?

A. I am submitting this Direct Testimony on behalf of ELL.

Q3. PLEASE DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

A. I have a Bachelor of Science degree in Electrical Engineering from the University of Southwestern Louisiana, now called the University of Louisiana at Lafayette, and a Master of Business Administration from the University of New Orleans. I also completed the Wharton School's Mergers and Acquisitions program.

I have worked for subsidiaries of Entergy Corporation for over 36 years. I joined Louisiana Power & Light Company (now known as ELL) in 1986 as an Engineer in the Rates and Regulatory Affairs Department. I was responsible for developing cost of

[1] On October 1, 2015, pursuant to Louisiana Public Service Commission ("LPSC" or "Commission") Order No. U-33244-A, Energy Gulf States Louisiana, L.L.C. ("Legacy EGSL") and Entergy Louisiana, LLC ("Legacy ELL") combined substantially all of their respective assets and liabilities into a single operating company, Entergy Louisiana Power, LLC, which subsequently changed its name to Entergy Louisiana, LLC ("Business Combination"). Upon consummation of the Business Combination, ELL became the public utility that is subject to LPSC regulation and now stands in the shoes of Legacy EGSL and Legacy ELL in pending Commission dockets.

service studies to support Legacy ELL's retail and wholesale rates. I also planned and directed numerous engineering studies and special projects. In 1993, I joined the Entergy/Gulf States Utilities Merger Team as a Senior Engineer. Following that assignment, I joined Entergy Services, Inc.'s[2] Financial Planning Department and was responsible for financial planning for Entergy Gulf States, Inc. (a predecessor-in-interest to Entergy Texas, Inc., and Legacy EGSL) as well as for Legacy ELL. In 1994, I was promoted to Senior Lead Analyst in Wholesale Transactions. In that role, I worked directly with large customers to meet their wholesale power requirements. In 1995, I was promoted to Manager of Strategic Planning. The members of my group served as internal consultants to various business units. I was later promoted to the Director of Utility Transition and Development. I was responsible for analytical and strategic analysis of the regulated utilities' transition to competition efforts. In 2000, I assumed the role of Vice President, Regulatory Services. In that position, I was responsible for providing technical and analytical support to all of the EOCs to enable them to satisfy their regulatory obligations. My department consisted of: System Regulatory Planning & Support, Regulatory Strategy, Regulatory Projects, and Integrated Energy Management. In February 2013, I became the President and CEO of Legacy ELL and Legacy EGSL. Legacy ELL and Legacy EGSL consummated their Business Combination in October 2015, and I continue to serve as President and CEO of the combined entity, ELL.

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[2] Entergy Services, LLC ("ESL"), formerly Entergy Services, Inc., is a service company to the five Entergy Operating Companies ("EOCs"), which are Entergy Arkansas, LLC; ELL; Entergy Mississippi, LLC; Entergy New Orleans, LLC ("ENO"); and Entergy Texas, Inc.

As my background and current duties indicate, in addition to my other areas of formal education and experience, I have particular experience with analyzing how industry trends, strategic initiatives, policy choices, and financial planning affect the Company's ability to provide safe, efficient, and reliable service at reasonable rates.

Q4. HAVE YOU PREVIOUSLY TESTIFIED IN ANY REGULATORY PROCEEDINGS?

A. Yes. A listing of the cases in which I have previously testified is attached hereto as Exhibit PRM-1.

Q5. WHAT ARE YOUR CURRENT DUTIES?

A. As President and CEO of ELL, I have executive responsibility for the Company, including financial responsibility for the business and assets that are used to serve customers, which include generation, transmission, and distribution assets. In addition, my responsibilities include oversight of the field management of the Company's gas distribution system, customer service, economic development, regulatory affairs, public affairs, and the financial performance of ELL.

Q6. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to provide an overview of the Company's Application for Approval of the Entergy Future Ready Resilience Plan (Phase I) (the "Application"). ELL's Application addresses directly the significant risks faced by communities in the Gulf Coast region and the Company's plan to improve its electric system to help customers meet the challenges and opportunities of tomorrow. The nature and harmful impacts of those risks on ELL's customers and the Louisiana communities we serve are all too familiar in the wake of recent major hurricanes that have struck Louisiana and elsewhere along the Gulf Coast. Effectively addressing those risks will require a combined and coordinated effort among all stakeholders. For its part, the Company has invested in resilience for years; however, the increasing threat of extreme weather events and the transition to a more electrified economy have necessitated a review of the timeline on which the Company must continue to make those investments to position our communities to be ready for future weather events. That review has been comprehensive and customer focused, and the result is the Entergy Future Ready Resilience Plan (the "Resilience Plan"), which, as I and other Company witnesses explain, is reasonably expected to reduce the cost of restoring the electric grid after major storms as well as reduce the number and duration of outages associated with those events. The implementation of the Resilience Plan will thus result in a substantially improved risk profile for the ELL grid, and that improvement is vital to the communities that we serve and, in turn, to the economy of Louisiana.

To summarize my testimony, I introduce the Company's Resilience Plan, which seeks to improve the resilience of ELL's electric system through accelerated infrastructure hardening and vegetation management. I begin with further discussion of why the Company has developed its Resilience Plan. Next, I describe the Company's historical investment in its generation, transmission, and distribution systems; the Company's current and future plans to continue to modernize and harden its infrastructure for the benefit of its customers; and the significant and emerging circumstances supporting the necessity for accelerating the pace of certain hardening investments as contemplated in the Resilience Plan. I also introduce the Company's other witnesses in this proceeding.

II. ACCELERATED RESILIENCE IS NEEDED TO ADDRESS THE INCREASING FREQUENCY AND SEVERITY OF EXTREME WEATHER EVENTS AND THEIR IMPACT ON THE GULF COAST REGION

Q7. PLEASE DESCRIBE FURTHER THE COMPANY'S APPLICATION AND THE RESILIENCE PLAN ADDRESSED THEREIN.

A. Through its Application, the Company provides notice to the Commission that it has developed a proposed course of action specifically designed to improve overall electric system resilience through accelerated infrastructure hardening and vegetation management. The Company is proposing to implement the Resilience Plan over the ten-year period from 2024 to 2033. As described in more detail by Company witness Sean Meredith, in this docket, the Company seeks specific approval of Phase I of the Resilience Plan, which includes approximately $5.0 billion in projects proposed to be implemented in the first five years.[3]

As explained by Mr. Meredith, following Hurricane Ida, and in the light of the back-to-back years of historically severe weather affecting the areas served by the EOCs (including both major hurricanes and severe winter storms), the EOCs consulted their own internal subject matter experts and stakeholders, evaluated the practices of other utilities across the country, and undertook a holistic analysis of the opportunities available for creating a more resilient system. As that process evolved, the Company

[3] Phase II of the Resilience Plan is projected to include approximately $4.6 billion in infrastructure resiliency and storm hardening projects.

engaged an outside industry consultant, 1898 & Co., which provides strategic asset planning services and has experience in developing similar resilience plans, to assist with identifying potential projects and estimating the costs and benefits of those projects. The Resilience Plan is the result of a company-wide effort to better understand the risks faced and to identify cost-effective and achievable projects to build a more resilient electric system.

Specifically, and as Mr. Meredith discusses, the Resilience Plan has four interconnected components:

- First, the Company proposes to complete approximately 9,600 identified distribution and transmission hardening projects, which will harden more than 269,000 structures over more than 11,000 line miles over the course of the ten-year period from 2024 to 2033 (the "Comprehensive Hardening Plan").[3] The Comprehensive Hardening Plan will cost approximately $9 billion (nominal). Those projects are generally grouped into seven programs: (i) Distribution Feeder Hardening (Rebuild); (ii) Distribution Feeder Undergrounding; (iii) Lateral Hardening (Rebuild); (iv) Lateral Undergrounding; (v) Transmission Rebuild; (vi) Substation Control House Remediation; and (vii) Substation Storm Surge Mitigation.[4] The specific projects contained in the Comprehensive Hardening Plan are attached to Mr. Meredith's testimony as Highly Sensitive Protected Materials ("HSPM") Exhibit SM-2.

[4] Although the Company's proposed plan sets forth the Company's best efforts to identify the scope and timing of the selected projects, the precise work performed (as well as the timing of when that work will be performed) will be subject to continual refinement as the Company implements its Resilience Plan.

- Second, the Company proposes to construct 44 dead-end structures for the Company's 500 kV transmission lines, which form the high voltage backbone of the transmission system; this will improve the resilience of these lines by helping prevent and/or limit cascading damage to transmission structures. The additional cost for these dead-end structure projects is estimated to be $88 million.
- Third, the Company is proposing a number of projects aimed specifically at increasing the resilience of the Company's telecommunications systems, which play an integral part in the Company's efforts to respond to and recover from disruptions caused by major weather events. These projects will involve approximately $108 million in capital spending and $12 million in incremental operation and maintenance costs.
- Fourth, the Company is proposing enhancements to its current vegetation management programs to accelerate trim cycles and to implement additional program elements. Specifically, on the distribution system, the Company is proposing to (i) reduce its trim cycle to five years; (ii) implement mid-cycle herbicide treatments; (iii) implement a backbone "skylining" project; (iv) implement additional programs to target poor performing species of trees and danger trees (including work performed outside the right of way ("OROW")); and (v) increase reactive trimming efforts. On the transmission system, the Company is proposing to increase its OROW work and implement air-saw trimming of vegetation along transmission lines. Together, these enhancements will cost approximately $369 million over the next ten years.

Q8. IS THE COMPANY OFFERING ANY OTHER POTENTIAL PROJECTS FOR CONSIDERATION WITH THIS FILING?

A. Yes. While not presently a part of the Resilience Plan, the Company has identified a number of non-wire alternatives ("NWAs"), or microgrids, that are able to provide a local source of power that can swiftly restore power to a substation, to the feeders that are connected to a substation, or to certain critical loads in the Company's distribution system. Specifically, as discussed by Mr. Meredith, the Company has identified ten NWAs across the state for consideration, which NWAs are possible alternatives to certain transmission hardening projects identified in the Comprehensive Hardening Plan. While these NWAs would not prevent damage during a weather event, they are expected to enable the electric system to restore electric service rapidly when damages and outages do occur.

Q9. IS THE COMPANY REQUESTING APPROVAL OF THE ENTIRE RESILIENCE PLAN AT THIS TIME?

A. No. As I mentioned earlier, at this time, the Company is requesting approval for Phase I of the Resilience Plan, which includes approximately $5.0 billion in projects proposed to be implemented in the first five years (2024-2028). Specifically, Phase I includes the first five years of (1) the Comprehensive Hardening Plan ($4.6 Billion), (2) the dead-end structure projects ($88 million), (3) the telecommunications improvements ($100 million), and (4) the vegetation management enhancements ($172 million).

Q10. ARE THERE CIRCUMSTANCES THAT COULD CHANGE THE SCOPE OF THE RESILIENCE PLAN?

A. Yes. First and foremost, ELL's plan is subject to approval by the Commission, and the Company acknowledges that the Commission may determine that the public interest is served by the Company pursuing resilience projects that differ, at least in part, from those proposed by the Company. Second, as Mr. Meredith discusses, the scope of the plan is subject to change as the Company moves into detailed planning, engineering, and execution. For example, the Company may identify NWAs that are reasonable alternatives to some of the proposed wires projects. Finally, the Company acknowledges that the Commission is evaluating the potential for statewide resilience standards in Docket No. R-36227. Any rule adopted by the Commission in that docket may require that the Company either adjust its Resilience Plan to comply with that rule or seek a waiver from the Commission for any non-conforming aspects.

Q11. WHAT DO YOU MEAN WHEN YOU SAY THAT THE RESILIENCE PLAN IS DESIGNED TO IMPROVE SYSTEM RESILIENCE?

A. In this context, resilience is the ability to prepare for, adapt to, and recover from non-normal weather events, such as hurricanes, floods, winter storms, wildfires, tornadoes, and other major disruptions. By comparison, system reliability focuses on the availability of power to customers under normal operating conditions, which include day-to-day operational challenges such as thunderstorms. Although resilience and reliability are complementary from the customers' perspective, the projects being proposed as part of the Resilience Plan were selected specifically to help improve resilience as compared to a focus on system reliability.

For electric utility systems, resilience relative to severe weather events has at least three critical dimensions: (1) hardening, which involves building or improving a system in ways that will make it better able to withstand the impacts caused by severe weather events; (2) modernization, which includes adapting the system to reflect or incorporate newer technologies that can improve the system's ability to withstand non-normal weather events, including self–healing networks, smart sensors, fault-detection technology, and microgrids; and (3) recovery, which includes incorporating customer-sited generation and back-up options, as well as designing resources to assist with recovery after a major weather event. Although such efforts should be expected to have positive impacts on the day-to-day operations of the utility system under normal conditions (*i.e.*, reliability), projects designed to improve resilience are focused particularly on preparing the electric system to withstand and recover from severe, non-normal weather events.

Q12. PLEASE ELABORATE ON THE RELATIONSHIP BETWEEN RESILIENCE AND RELIABILITY.

A. Although, as I just indicated, resilience efforts may avoid interruptions that are measured by traditional reliability indices, defining a precise relationship between resilience and reliability is challenging. That said, while reliability focuses on the availability of power to customers, resilience takes a broader view of the grid and looks for ways to avoid, mitigate, survive, and/or recover from the effects of disruptive events.

Q13. WILL YOU SUMMARIZE THE REASONS WHY THE COMPANY HAS DEVELOPED ITS RESILIENCE PLAN?

A. Certainly. First and foremost, the Company takes seriously its responsibility to provide customers with safe, reliable, affordable, and sustainable service, and the Company's Resilience Plan is the next step in the Company's ongoing efforts toward that goal. As I discuss in greater detail below, the combination of several significant and emerging circumstances has made it necessary for ELL and its stakeholders to carefully evaluate and consider accelerating the pace of hardening investment. Notably, as the number and intensity of major hurricanes and other significant weather events prevalent in ELL's service area increase, and as ELL's customers depend more than ever on electricity to power their lives and businesses, the need for a more resilient and reliable system that can better withstand extreme events, avoid or mitigate customer outages from such events, and facilitate faster restoration of service after such events is critical. The Company stands ready to work with the Commission and stakeholders to determine the appropriate timing and pace of resilience investments.

Q14. MUST MORE BE DONE TO ADDRESS THE RESILIENCE OF THE GULF COAST REGION BEYOND WHAT THE COMPANY IS PROPOSING IN ITS RESILIENCE PLAN?

A. Yes. Improving resilience in Louisiana will involve more than just strengthening the electric grid. Investing to become more resilient is necessary to protect people and assets, allow for enhanced economic activity, and preserve the economic competitiveness of our region. In this way, improving resilience in Louisiana will require an unprecedented, combined, and coordinated effort to address such issues as the adequacy and enforcement of building code standards, urban planning, elevation requirements, water management, and coastal restoration, among other things. Stakeholders must work together to build a portfolio of economically sensible approaches for addressing risks and building a resilient Gulf Coast.

Q15. CAN YOU PROVIDE AN EXAMPLE OF HOW COORDINATED EFFORTS BY STAKEHOLDERS CAN IMPROVE RESILIENCE?

A. Yes. Grand Isle, Louisiana was one of the communities hardest hit by Hurricane Ida in 2021. Almost every structure on the island was damaged, and hundreds were destroyed completely. It was observed, however, that many structures that were built in the decade before Hurricane Ida in conformity with new building code standards (that were adopted by government officials after Hurricane Katrina) survived with only minimal damage.[5]

Hurricane Ida caused catastrophic damage to ELL's system that serves Grand Isle, and ELL rebuilt the impacted system with resilience in mind so that it now is rated to withstand winds of up to 150 mph. In addition to ELL's resilience investment, the Army Corps of Engineers is undertaking a $122 million project to repair Grand Isle's levees, rock jetties, and other storm defenses. As property owners likewise restore and rebuild, it is critical that those owners and government officials continue to not only update and

[5] Nick Reiher and Tara Lukasik, *Hurricanes Underscore what is Needed for Building Resilience,* Building Safety Journal (May 11, 2022), *available at* https://www.iccsafe.org/building-safety-journal/bsj-perspectives/if-you-want-to-build-resilient-use-the-i-codes/.

further strengthen building standards in Louisiana, but also to comply with and enforce those standards so that the resilience benefits associated with construction that prioritizes disaster-resilient design actually can be realized.[6] Simply put, having electricity available via enhanced resilience when there are no facilities able to use it is not a worthwhile goal.

Q16. WHY ARE SUCH COORDINATED MEASURES NECESSARY AT THIS TIME?

A. Absent the sort of commitment to and substantial investment in resilience measures that I mention above, the Gulf Coast will be insufficiently prepared to address the future risks posed by extreme weather events, which are becoming more frequent, severe, unpredictable, and costly, and are disproportionately impacting the Gulf Coast region.

At the same time, ongoing coastal erosion and land loss is exacerbating the Louisiana coast's exposure to climate risk through the destruction of natural coastal defenses (such as coastal marshes, wetlands, and barrier islands), as shown in Figure 1 below.

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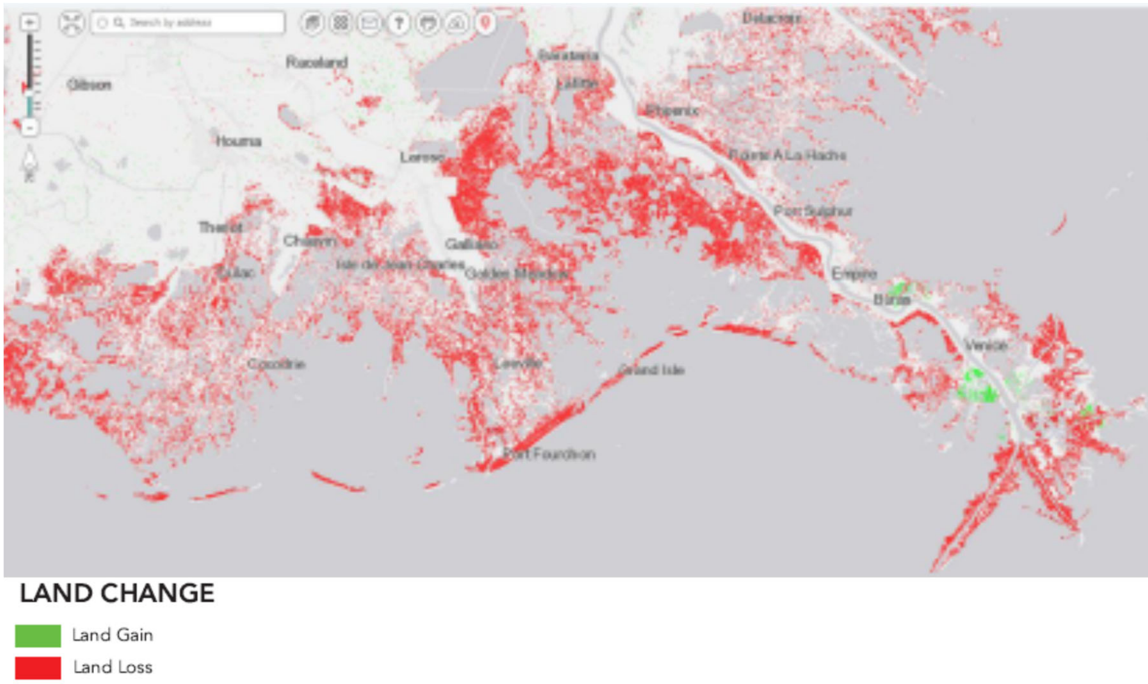
[6] FEMA also recently announced a national initiative to modernize building codes so that communities can be more resilient following extreme weather events. *FACT SHEET: Biden-Harris Administration Launches Initiative to Modernize Building Codes, Improve Climate Resilience, and Reduce Energy Costs*, The White House (June 1, 2022) *available at* https://www.whitehouse.gov/briefing-room/statements-releases/2022/06/01/fact-sheet-biden-harris-administration-launches-initiative-to-modernize-building-codes-improve-climate-resilience-and-reduce-energy-costs/.

Figure 1: Potential Land Loss and Gain over the Next 30 Years[7]



The loss of these natural defenses means coastal communities are exposed to greater risks from extreme weather events.

Q17. CAN YOU ELABORATE ON THE TYPES OF RISKS TO WHICH YOU ARE REFERRING?

A. Yes. Extreme weather events create significant risks across a broad spectrum of issues, as shown in Figure 2 below.

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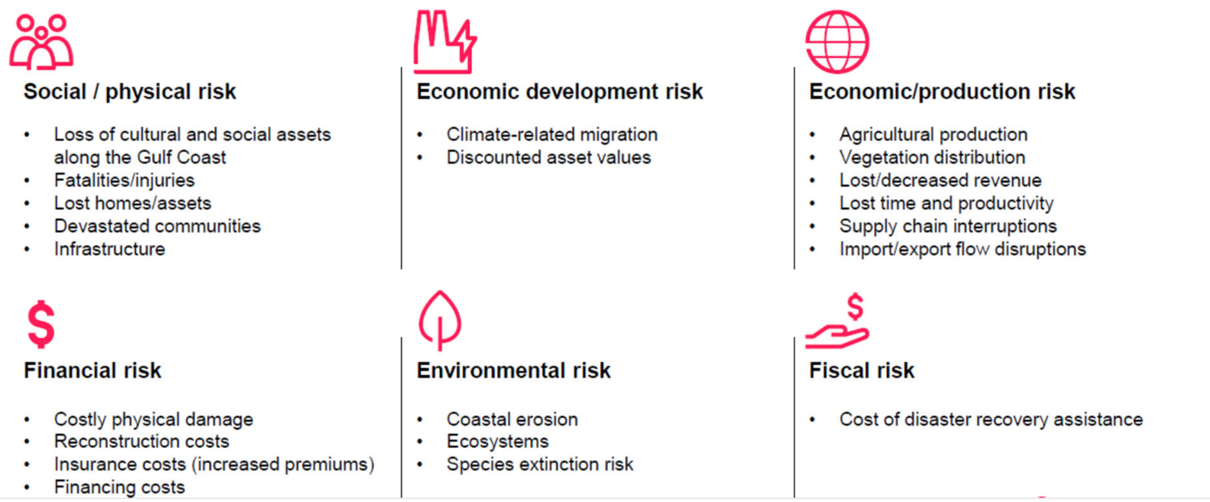
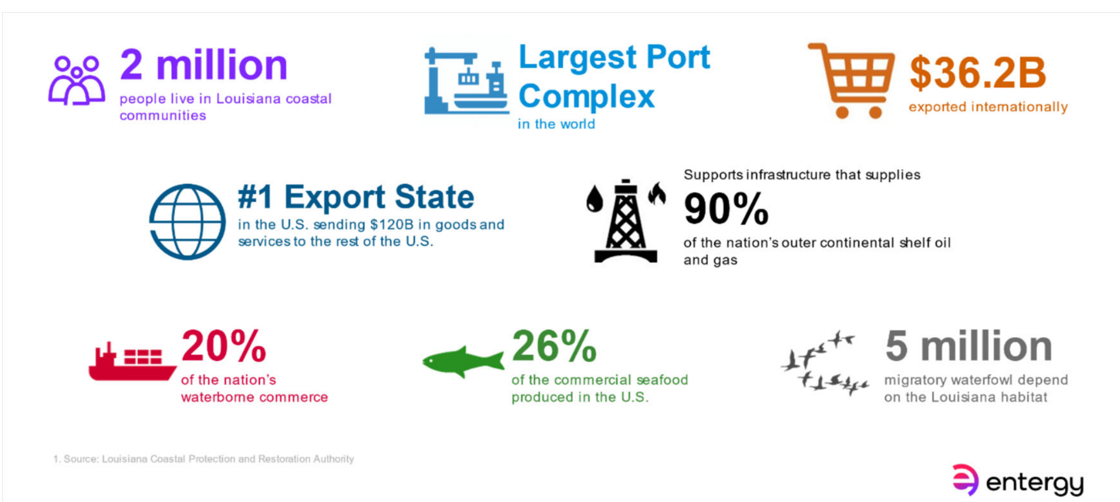
[7] Coastal Protection and Restoration Authority; map shows expected land loss under high scenario if Louisiana's coastal master plan is not implemented. Coastal Protection and Restoration Authority, *Louisiana's Comprehensive Master Plan for a Sustainable Coast,* State of Louisiana (June 2, 2017) *available at* http://coastal.la.gov/wp-content/uploads/2017/04/2017-Coastal-Master-Plan_Web-Single-Page_CFinal-with-Effective-Date-06092017.pdf.

Figure 2: Significant Risks Created by Severe Weather Events



Failure to address these risks will have serious and costly implications considering that a resilient Gulf Coast is vital to the economic livelihood of our region's future. In addition, Louisiana's risk exposure has national and international implications, as shown in Figure 3 below.

Figure 3: Risk Exposure of Louisiana has National and International Implications



The Company remains open to collaborating on these issues with state and local officials, and all stakeholders, as part of a community approach to resilience.

III. ELL'S INVESTMENT IN ITS SYSTEM

Q18. WILL YOU DESCRIBE GENERALLY THE COMPANY'S HISTORICAL INVESTMENT IN ITS SYSTEM?

A. Yes. ELL has been working to make its system more resilient since the significant storms that impacted Louisiana in the early 2000s, and the experience with Hurricane Ida in 2021, as well as the challenges of the record-setting 2020 Atlantic hurricane season, demonstrate the necessity of those improvements. In the intervening years, ELL, like the overall electric utility industry in the United States, has invested considerable capital to replace and upgrade aging infrastructure.

In particular, ELL has modernized its power plants, adding both cleaner and more efficient energy sources in order to provide our customers with reliable, safe, and low-cost energy. ELL has also invested significantly in its transmission grid to expand for growth and to comply with federal reliability requirements. And, for its distribution system, ELL has implemented grid modernization and system-hardening improvements. In particular, grid modernization is being enabled by new technology and developed in response to increasing customer expectations for reliability enhancements that require a more modern, responsive, and resilient grid to minimize the frequency and duration of outages. Table 1 details the amounts that the Company has invested in its generation, transmission, and distribution systems for the period 2013-2022.

Table 1: ELL Capital Closings (2013-2022*)

	Capital Closings (Values in $B)
Generation	$5.7**
Transmission	$3.4**
Distribution	$2.3***

* Includes actuals through October 2022 for generation, transmission, and distribution.
** Excludes certain amounts related to major storm damage, including, more recently, amounts addressed through securitization financing in LPSC Docket Nos. U-35991 and U-36350.
*** Excludes amounts related to storm damage and Advanced Metering System ("AMS") investments.

As Table 1 shows, over the last decade, the Company has invested considerable capital aimed at enhancing grid reliability and resilience. As I and other Company witnesses discuss, a combination of factors (including the increased frequency and severity of storms and the resulting impacts to customers) now supports an accelerated approach to improving resilience to the benefit of all stakeholders.

Q19. WHAT CONSIDERATIONS ARE INVOLVED IN DETERMINING THE APPROPRIATE LEVEL OF INVESTMENT IN THE COMPANY'S SYSTEM?

A. The Company's investment in its system must be balanced with the need to maintain affordable customer bills. Indeed, in LPSC Docket No. U-35565, the Commission Staff did not support a cost recovery mechanism necessary to reasonably support the level of distribution spending proposed by ELL, reflecting the Commission's longstanding concern with customer bill impacts. A settlement reflecting a mechanism that did not support the higher level of distribution spending proposed by the Company was reached and approved by the Commission. Mindful of and sharing the Commission's concern, ELL has over the years prudently planned its system to withstand reasonably-expected risks while managing the resulting costs and customer bill impacts. Moreover, and although there have certainly been exceptions over time, with respect to distribution assets specifically, the electric utility industry traditionally has not replaced or reconfigured such assets until they fail. This approach has been considered cost-effective for customers and further reflects the balance that utilities must strike between reliability and cost. But the industry is evolving and modifying that approach through the use of new technology and modernization efforts that respond to increasing customer expectations for reliability enhancements aimed at preventing outages altogether (as opposed to reactive measures designed to minimize customers impacted by, and shorten the recovery time associated with, an outage). This approach requires not only a more modern and responsive grid, but also a more resilient one.

Any investment in the Company's system also must recognize that serving our customers reliably requires ongoing investment in many areas of our business (*e.g.*, generation, distribution, transmission, and innovation/technology). The ability to withstand and recover quickly from major storms in particular requires transmission, generation, and distribution facilities that are robust and working in tandem to get power into the homes and businesses in our communities.

With that said, hardening investment is a trade-off that involves spending more now to avoid damage, costs, and outages should a major event strike (with the added benefit of providing better reliability and service quality to customers during more routine storms or events). But complete insulation from risk is not feasible, and while substantial protection can be had at a substantial cost, if resulting customer bills are unaffordable, then ELL has not met its obligation to provide reliable service at the lowest reasonable cost.

Q20. WILL YOU DESCRIBE IN MORE DETAIL THE COMPANY'S EFFORTS TO MODERNIZE ITS GENERATION PORTFOLIO?

A. Yes. Ninemile Unit 6 ("Ninemile 6"), a highly-efficient combined-cycle gas turbine ("CCGT") that commenced commercial operation in 2014, was a significant step in the Company's long-term plan to modernize its generation fleet. In 2016, the Company, along with other EOCs, acquired the 1,980-megawatt ("MW") (summer rating) Union Power Station ("UPS"), a highly-efficient, natural gas-fired generating facility consisting of four CCGTs located near El Dorado, Arkansas. (The Company also had previously acquired other modern gas-fired combustion turbine-based generation including Perryville Power Station ("Perryville"), Ouachita Power Plant Unit 3 ("Ouachita 3"), Calcasieu Generation Facility ("Calcasieu"), and Acadia Energy Center Power Block 2 ("AECPB2").) The J. Wayne Leonard Power Station ("JWLPS") followed in 2019, followed by the Lake Charles Power Station ("LCPS") in 2020. CCGT units like Ninemile 6, UPS, Perryville, Ouachita 3, AECPB2, JWLPS, and LCPS supply reliable, clean energy to customers and have helped to transform the Company's portfolio to cleaner, more efficient generation intended to improve system reliability, reduce environmental impacts, and produce substantial customer savings over the long term.[8]

[8] Ninemile 6 and JWLPS played critical roles in quickly restoring power to the greater New Orleans and surrounding areas following Hurricane Ida in 2021.

The Company also acquired in 2020 the Washington Parish Energy Center ("WPEC") – with its two modern, combustion turbines that are designed to start and ramp up quickly to meet customers' immediate energy needs – to provide ELL with needed peaking and reserve generating capacity. The addition of WPEC provided a modern, cost-effective, low-carbon and reliable source of power to the Company's grid.

The Company also has sought to grow its green power-generating portfolio by procuring 475 megawatts of solar power, in addition to the 50 MW of solar the Company purchases through the Capital Region Solar Plant in West Baton Rouge[9] and various hydroelectric and other renewable resources. These new solar facilities are expected to begin delivering power to customers in 2024.[10]

Q21. HAS THE COMPANY'S HISTORICAL INVESTMENT IN GENERATION ALSO SUPPORTED THE RESILIENCE OF THE ELECTRIC SYSTEM FOLLOWING STORMS AND OTHER MAJOR WEATHER EVENTS?

A. Yes. Generation investment is a critical part of resilience. Typical restoration protocols after major weather events call for rebuilding damaged transmission structures first, powering up the grid, and then building out the distribution system. But when the transmission system is severely damaged, the availability of local generation is essential to providing timely restoration of power to the region after a major weather event.

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[9] The Capital Region Solar Plant began delivering power to the grid in October 2020.

[10] *See,* Order Number U-36190 (October 14, 2022), *In re: Application for Certification and Approval of the 2021 Solar Portfolio, Rider Geaux Green Option, Cost Recover and Related Relief, Docket No. U-36190.*

For example, in 2020, Hurricane Laura resulted in southwest Louisiana's complete isolation from the bulk electric system, with all nine transmission lines into that region rendered out of service. Due to the extensive damage to the transmission system surrounding LCPS and Calcasieu, these plants were not able to draw from external power to resume operations. After the first transmission source was energized to the area providing limited capacity, ELL was able to return LCPS and Calcasieu to service, paving the way for providing significant amounts of power to communities impacted by Hurricane Laura in Sulphur and Lake Charles.

Similarly, after Hurricane Ida in 2021, the greater New Orleans area was completely isolated from the bulk electric system, with all eight transmission lines into that region rendered out of service. After the first transmission tie line into the Jefferson/Orleans area was reconnected, Ninemile 6 and the New Orleans Power Station ("NOPS")[11] were utilized in tandem, building load and restoring power to the region.

Q22. PLEASE DESCRIBE IN MORE DETAIL THE COMPANY'S RECENT INVESTMENT IN AND IMPROVEMENT OF ITS TRANSMISSION SYSTEM.

A. As is discussed by Company witness Charles Long, transmission capital investment can be divided into a few primary categories: (1) projects that ensure the transmission system meets North American Electric Reliability Corporation ("NERC") standards for bulk electric system reliability through new lines, substations, and equipment upgrades; (2) projects that improve reliability through replacement of aging equipment; (3) projects

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[11] NOPS is owned and operated by ENO.

that go beyond basic NERC reliability to enhance the reliability of critical infrastructure or improve customer experiences; (4) projects needed to interconnect new facilities such as new generators or new customers; and (5) projects that build new facilities to reduce congestion on the system to ensure customers have access to the lowest cost power. As I mentioned above, for the period 2013 through October 2022, and with the Commission's support, the Company invested approximately $3.4 billion in its transmission system (not including costs associated with Hurricanes Laura, Delta, and Zeta, Winter Storm Uri, and Hurricane Ida). The need for this level of investment was driven by many factors, including reliability planning, load growth, infrastructure maintenance and reliability needs, economic transmission investments (*i.e.*, investments that produce cost savings to customers), and generation interconnection projects.

Q23. CAN YOU PROVIDE SPECIFIC EXAMPLES OF RECENT TRANSMISSION INVESTMENT THAT HAVE IMPROVED THE RESILIENCE OF THE SYSTEM AND ITS ABILITY TO RELIABLY SERVE CUSTOMERS?

A. Yes. In 2018, the Company completed three resilience projects, including one of the largest single transmission projects in company history, the Lake Charles Transmission Project. It included construction of two new substations, expansion of two others, and adding approximately 25 miles of high-voltage transmission lines to move power more efficiently into southwest Louisiana, which investment totaled approximately $191.6 million. Also in 2018, the Company completed (1) the Oakville – Alliance transmission project that included the rebuilding and expansion of the Oakville substation to construct a 230 kV transmission path between one of ELL's substations in Jefferson Parish and a substation in Plaquemines Parish (an investment of approximately $55.0 million), and (2) the Bayou Vista – Terrebonne 230 kV transmission line that was built on structures designed to withstand winds of up to 150 mph (an investment of approximately $76.8 million).[12]

In 2021, we strengthened the electric system in Grand Isle and Port Fourchon to make it more resilient, with crews installing class-one utility poles with extra hardened footings for critical power lines in the area. These structures are designed to withstand 150 mph winds.

And earlier this year, the Company completed, among other projects, (1) a $100 million project across Ouachita Parish that positioned the region for economic growth and increased the resilience and reliability of the electric system in north Louisiana,[13] and (2) an $86 million transmission system upgrade in Lafourche Parish.[14]

Q24. WHAT IS THE STATUS OF ELL'S INVESTMENT IN ITS DISTRIBUTION SYSTEM?

A. As discussed in greater detail by Mr. Long, ELL has ramped up the pace and level of its distribution investment in recent years and plans to continue making significant investments to modernize and improve the reliability and resilience of the distribution grid. On average, the Company invested approximately $267 million annually in capital

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12 The Bayou Vista – Terrebonne 230 kV transmission line took a direct hit from Hurricane Ida's winds and sustained only minimal damage.

13 As part of this project, new transmission equipment was installed, and portions of the existing, local transmission system were upgraded.

14 As part of this project, roughly seven miles of power lines were upgraded and approximately 80 steel structures were replaced with infrastructure built to withstand winds of up to 150 mph.

spending (non-storm) for its distribution system for the five-year period of 2017 through 2021, with distribution line plant closings increasing from $177 million in 2017 to $377 million in 2021.[15] And another $346 million has been invested in the Company's distribution system during the period January through October 2022. This investment has been part of the Company's overall effort to meet customers' expectations and transform our business as technology and the industry evolve, while maintaining reasonable rates.

These improvements to the distribution system are time-consuming and capital-intensive due to the large amount of equipment involved and the broad geographic footprint of ELL's system, which includes over 32,000 miles of distribution lines in Louisiana. Yet these improvements, and the resulting benefits to all customers from a more modern electric grid, will be particularly visible and meaningful to the Company's distribution-level customers who depend on ELL to keep their homes and businesses running.

Q25. CAN YOU PROVIDE SPECIFIC EXAMPLES OF RECENT INVESTMENT IN THE COMPANY'S DISTRIBUTION SYSTEM?

A. Yes. As discussed in more detail by Mr. Long, the Company has recently constructed new substations and distribution circuits in Calcasieu Parish (an investment of approximately $23.8 million), Ouachita Parish (an investment of approximately $18.8 million), and Lafourche Parish (an investment of approximately $23.6 million) as part of its commitment to increasing the resilience of the electric system and providing

[15] Distribution capital additions for 2017-2021 exclude amounts related to storm damage and Advanced Metering System ("AMS") investments.

customers with reliable power. In his testimony, Mr. Long also provides examples of the storm hardening strategies and investments that have been implemented by the Company in recent years.

IV. OVERVIEW OF THE COMPANY'S RESILIENCE PLAN

Q26. WHAT IS THE RESILIENCE PLAN INTENDED TO ACCOMPLISH?

A. The Company's Resilience Plan is intended to serve as a guide for the Company's efforts to accelerate the resilience of its electric system through a comprehensive set of cost-effective hardening projects and enhanced vegetation management activities. The projects being proposed as part of the Resilience Plan were selected and evaluated for their ability to aid the Company's efforts to avoid, mitigate, survive, and/or recover from the effects of disruptive weather events. As summarized above, and as discussed more fully by Mr. Meredith, the Company is proposing to harden certain distribution and transmission assets to standards designed to better withstand the extreme conditions caused by severe weather events. The Company also is proposing to construct additional transmission structures to limit cascading failures that can occur during such major storm events. While such projects should be expected to have positive impacts on the day-to-day operations of the Company's utility system under normal conditions by further protecting against and mitigating outages, they are focused more particularly on preparing the electric system to withstand and recover from severe, non-normal weather events. Moreover, the Resilience Plan approaches resilience in a holistic fashion, addressing each of the three critical dimensions of resilience relative to severe weather events that I mentioned previously, namely, hardening, modernization, and recovery.

It is important to understand, however, that the projects presented in the Company's Resilience Plan are not intended to strengthen every line, pole, or piece of equipment on the Company's system. Such a plan would be cost-prohibitive, and, as discussed above, the Company and the Commission must always balance service improvements with customer affordability. Nevertheless, it is clear that a substantial investment in infrastructure is needed, and that investment is expected to pay dividends for customers in the long-run, producing significant customer benefits by lowering post-storm restoration costs and reducing customer minutes interrupted ("CMI").

With that understanding in mind, it is important to point out that the projects and the associated investment proposed in the Company's Resilience Plan represent investment that goes beyond what we had already planned in our capital budgets prior to Hurricane Ida. Furthermore, these investments do not fall into the same category as the Company's day-to-day reliability programs. Instead, these projects represent a careful, studied approach to enable the Company to accelerate investment, where appropriate, to address the frequency and intensity of storms that pose an increasing threat to the electric system for the reasons that I discuss in greater detail below.

Q27. WHY DOES THE COMPANY BELIEVE THAT IT IS NECESSARY TO CONSIDER ACCELERATING THE PACE OF HARDENING INVESTMENT?

A. While the efforts and investments (described above) that have been undertaken to date by ELL with the Commission's support were reasonable, it has become evident that ELL and its stakeholders must carefully evaluate and consider accelerating the pace of hardening investment due to several emerging and significant changes, including, but not limited to:

- Increased storm severity and frequency and the related national economic challenges arising from such storms,
- Increased customer dependency on electricity and demand for resilience,
- Technological innovation,
- Potential restrictions on access to capital,
- Prospects for federal funding, and
- Benefits to communities and the economy of avoided power outages.

Q28. WILL YOU FIRST DESCRIBE HOW THE INCREASING THREAT OF SEVERE WEATHER SUPPORTS THE IMPLEMENTATION OF THE COMPANY'S RESILIENCE PLAN?

A. Yes. Recent experience with hurricanes, winter storms, and other severe storm activity requires action to address the increasing intensity, frequency, and cost of extreme weather events. Between 2005 and 2017, no hurricanes higher than a Category 2 struck the United States. Since 2017, however, eight major hurricanes have made landfall in the contiguous United States or Puerto Rico: Harvey (2017), Irma (2017), Maria (2017), Michael (2018), Laura (2020), Zeta (2020), Ida (2021), and Ian (2022). In the past two years alone, the U.S. experienced a record-setting number of billion-dollar weather and climate disasters (22 events in 2020), with another 20 separate billion-dollar events impacting the nation in 2021.[16] In broader context, the total cost of U.S. billion-dollar disasters over the last 5 years (2017-2021) is $742.1 billion, with a 5-year annual cost average of $148.4 billion.[17]

In Louisiana, recent storms such as Hurricanes Laura, Delta, Zeta, and Ida have shown that extreme weather events are impacting our state with increased frequency and severity, resulting in greater costs and disruptions to ELL, its customers, and Louisiana itself. Some of these major storms have moved slowly after landfall or brought more precipitation than prior storms, further increasing the potential for devastation and damage.

Q29. PLEASE DESCRIBE FURTHER HURRICANES LAURA, DELTA, ZETA, AND IDA AND THE DAMAGE THAT THEY INFLICTED ON THE COMPANY'S SYSTEM.

A. As depicted in Figure 4, Hurricanes Laura, Delta, Zeta, and Ida impacted the state of Louisiana during back-to-back historic storm seasons in 2020 and 2021.

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16 Adam Smith, *2021 U.S. Billion-Dollar Weather and Climate Disasters in Historical Context,* National Oceanic and Atmospheric Administration (January 24, 2022), *available at* https://www.climate.gov/news-features/blogs/beyond-data/2021-us-billion-dollar-weather-and-climate-disasters-historical?itid=lk_inline_enhanced-template. These costs exclude Hurricane Ian costs.

17 *Id.*

Figure 4

As shown in Table 2, these storms caused substantial, and in the case of Hurricanes Laura and Ida, catastrophic damage to ELL's distribution system. Table 3 sets forth the impact of those storms on ELL's transmission system.

Table 2: Distribution Facilities Damaged or Destroyed

Hurricane	Poles	Transformers	Spans of Wire	Cross-Arms
Laura	12,453	4,264	27,166	9,263
Delta	969	356	2,407	793
Zeta	2,424	481	1,593	655
Ida	25,595[18]	5,617	34,932	21,270

18 The number of distribution poles that were damaged or destroyed by Hurricane Ida was double that of Hurricane Laura, and more than Hurricanes Katrina (2005), Ike (2008), Delta (2020), and Zeta (2020) combined.

Table 3: Transmission Damage

Hurricane	Transmission Structures Damaged or Destroyed	Substations Damaged and/or Impacted	Lines Out of Service
Laura	1,822	188	152
Delta	171	142	116
Zeta	199	24	32
Ida	530	91	190

Q30. ARE THE SEVERE WEATHER EVENTS THAT RECENTLY HAVE IMPACTED THE COMPANY'S SERVICE AREA LIMITED TO HURRICANES?

A. No. In February 2021, back-to-back winter storms referred to as Winter Storm Uri brought freezing rain and ice to Louisiana. The first storm hit on February 15, 2021, and heavily impacted the Livingston Parish, Tangipahoa Parish, and Greater Baton Rouge areas. On February 17, the second storm heavily impacted central and north Louisiana. Ice accumulation damaged vegetation, causing sagged or downed trees, limbs, and power lines, which, in turn, caused significant damage to ELL's distribution equipment and facilities, including 260 distribution poles, 158 transformers, and 1,863 spans of wire. In addition, twenty-five transmission lines in ELL's service area experienced outages during Winter Storm Uri.

Some communities we serve have also endured devastating tornadic activity this year. Louisiana experienced multiple tornadoes within an 8-day period in March 2022. A powerful tornado caused significant damage in the Arabi community of St. Bernard Parish on the evening of March 22, 2022. The tornado sprung from a storm system blamed for earlier tornadoes in Texas. It also spawned a tornado that touched down in the Lacombe area of St. Tammany Parish. According to the National Weather Service, the Arabi damage was caused by a tornado of at least EF-3 strength, meaning it had winds of 158 to 206 mph, while the Lacombe-area twister was an EF-1, with winds as strong as 90 mph. Southeast Louisiana again saw severe storms move through during the evening of March 30, 2022. Several storms triggered tornado warnings, and there were two reports of tornadoes touching down on the Northshore of Lake Pontchartrain in St. Tammany Parish.

Most recently, a line of powerful storms and tornadoes tore through North Louisiana on December 13, 2022. Several tornadoes reportedly touched down in the community of Keithville in Caddo Parish and the town of Farmerville in Union Parish, leaving devastating destruction in their wake. On December 14, 2022, this same storm system spawned tornadoes that caused damage in or near Marrero and Gretna in Jefferson Parish, and once again in Arabi, in St. Bernard Parish. As it worked its way from west to east, this same line of storms spawned more than 40 reported tornadoes across four states, including 21 tornadoes in Louisiana.

In short, the increasingly frequent threat of severe weather poses a serious risk to ELL's service area, and the Company and its customers need to be prepared to address the impacts of such severe weather events.

Q31. WILL YOU PROVIDE MORE DETAILS ABOUT THE IMPACTS OF SEVERE STORMS ON THE COMPANY, ITS CUSTOMERS, AND THE COMMUNITIES IT SERVES?

A. Yes. The following table reflects the outages experienced by the Company's customers and the costs that the Company (through its predecessor entities) incurred following Hurricanes Katrina, Rita, Gustav, Ike, Isaac, Laura, Delta, Zeta, and Ida.

Table 4

Hurricane	Year(s) of Storm	Customer Outages (approximate)	Time Between Landfall and Date of Restoration[19]	Costs Incurred ($M)[20]
Katrina and Rita	2005	1,007,000[21]	11 days (Legacy EGSL); 25 days (Legacy ELL) 21 days (Legacy EGSL); 5 days (Legacy ELL)	Legacy ELL: 545 Legacy EGSL: 187 **Total: 732**[22]
Gustav and Ike	2008	862,000[23]	19 days 11 days	Legacy ELL: 394 Legacy EGSL: 234 **Total: 628**[24]

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19 Reflects the restoration of power to customers who were able to safely accept service (*i.e.*, customers who did not require reconstruction of their personal property).

20 The costs indicated in the table are those costs that the Company incurred and the Commission, after thorough investigation and extensive regulatory proceedings, deemed prudent and properly recoverable following Hurricanes Katrina, Rita, Gustav, Ike, Isaac, Laura, Delta, and Zeta. The Company's application for recovery of costs related to Hurricane Ida is still pending.

21 Approximately 598,000 outages are associated with Hurricane Katrina, and 409,000 with Hurricane Rita.

22 *See,* Order No. U-29203-B (August 21, 2007), *In re: Joint Application of Entergy Gulf States, Inc. and Entergy Louisiana, Inc. for Interim and Permanent Recovery in Rates of Costs Related to Hurricanes Katrina and Rita, Docket No. U-29203, Id.* at p. 16.

23 Approximately 721,000 outages are associated with Hurricane Gustav, and 141,000 with Hurricane Ike.

24 *See,* Order No. U-30981 (April 30, 2010), *In re: Joint Application of Entergy Gulf States Louisiana, L.L.C. and Entergy Louisiana, LLC for Recovery in Rates of Costs Related to Hurricanes Gustav and Ike, Docket No. U-30981, Id.* at p. 7.

Hurricane	**Year(s) of Storm**	**Customer Outages (approximate)**	**Time Between Landfall and Date of Restoration**[19]	**Costs Incurred ($M)**[20]
Isaac	2012	580,000	7 days	Legacy ELL: 224.3 Legacy EGSL: 66.5 **Total: 290.8**[25]
Laura, Delta, and Zeta	2020	1,355,000[26]	35 days 8 days 15 days	Total**:** **2,007.3**[27]
Ida	2021	697,000	29 days	Total: **2,543.3**[28]

In addition, the Commission authorized ELL to recover $49.6 million in costs associated with ELL's response to Winter Storm Uri in 2021,[29] which knocked out power to approximately 228,000 ELL customers.[30] Although not quantified above, the harmful non-bill impacts and disruption to customers and communities from major storm events (such as deaths from extreme weather or other accidents, water/sewer system outages, health care disruptions, lost business inventory costs, evacuation inconvenience and

[25] *See,* Order No. U-32764 (June 18, 2014), *In re: Joint Application for Recovery in Rates of Costs Related to Hurricane Isaac, Determination of Appropriate Storm Reserve Escrow Amounts and Related Relief, Docket No. U-37264, Id.* at p.57. *See,* Order No. U-32764-A (June 18, 2014), *In re: Joint Application for Recovery in Rates of Costs Related to Hurricane Isaac, Determination of Appropriate Storm Reserve Escrow Amounts and Related Relief, Docket U-32764, Id.* at p.57.

[26] Approximately 436,000 outages are associated with Hurricane Laura, 616,000 with Hurricane Delta, and 303,000 with Hurricane Zeta.

[27] *See,* Order Number U-35991-A (March 3, 2022), *In re: Application for Recovery in Rates of Costs Related to Hurricanes Laura, Delta, Zeta and Winter Storm Uri and for Related Relief, Docket No. U-35991, Id.* at p. 28

[28] *See,* Application (April 29, 2022), *In re: Application of Entergy Louisiana, LLC for Recovery in Rates of Costs Related to Hurricane Ida and for Related Relief, Docket No. U-36350, Id.* at p. 9. The Company also requested approval for recovery of $58.7 million in carrying costs.

[29] *Id.*

[30] Customers who were affected by the first storm, which hit on February 15, 2021, including those that lost power days after the storm had passed due to limbs falling after the fact and other scenarios, were restored by February 20. Most customers affected by the second storm, which hit on February 17, 2021, were restored by February 22, with isolated cases in the hardest-hit areas restored on February 23.

costs, industrial outages, and school and business closings, gas and gasoline price increases, and supply chain disruptions) cannot be overlooked.

Likewise, as I mentioned above, the impact to the national and regional economies of severe weather events in ELL's service area is a vital consideration because ELL serves a large number of industries that are essential to those economies. The refineries, petroleum import and storage facilities, and natural gas gathering and processing facilities served by ELL are essential to the national energy supply, and if service to these customers is interrupted for an extended time, it will affect energy supply and prices nationally, as occurred in the aftermath of Hurricanes Katrina, Rita, and Laura. The industrial corridor also has three of the largest ports in the U.S., including the world's largest bulk cargo port.

As Table 4 and the above discussion make clear, despite the hardening that the Company has been undertaking for years now, the increased frequency and severity of storms (and the resulting costs and customer hardships) warrant consideration of an accelerated approach to hardening and improving resilience to the benefit of all stakeholders.

Q32. DOES FLORIDA'S RECENT EXPERIENCE WITH HURRICANE IAN HAVE ANY BEARING ON THE COMPANY'S APPROACH TO RESILIENCE?

A. I believe that it does, considering that Hurricane Ian was the latest example of the increasingly frequent and intense storms affecting the Gulf Coast. Hurricane Ian made landfall on September 28, 2022, as a strong Category 4 Hurricane with maximum sustained winds of 155 mph, tying the record for the fifth-strongest hurricane on record to strike the United States.

More to the point, Hurricane Ian underscored the potential value of undertaking the sort of resilience plan that the Company is proposing. After the 2004-2005 Atlantic Hurricane Seasons, the Florida Public Service Commission enacted rules requiring electric utilities to develop storm protection plans. In 2019, the Florida legislature codified the requirement for utilities to develop and implement storm protection plans with the objective of reducing restoration costs and outage times caused by extreme weather, and, under the statute, utilities are allowed to recover costs for approved plans through a charge separate and apart from base rates. While the transmission and distribution systems of electric utilities in Florida suffered outages and sustained damage in the wake of Hurricane Ian's destructive winds and storm surge, it appears that the storm protection investments of the affected utilities had a favorable impact on system resilience and the pace of those utilities' restoration efforts.

Q33. DOES THE RESILIENCE OF THE COMPANY'S ELECTRIC SYSTEM HAVE ANY BEARING ON THE COMPANY'S ABILITY TO ACCESS CAPITAL ON REASONABLE TERMS?

A. It does. As the Company continues to position itself to provide safe, reliable, and cost-effective service well into the future, ELL faces several challenges to maintaining the financial health required to make necessary investments in a manner that maximizes benefits and minimizes costs to the Company and our customers. As discussed by Company witness Todd Shipman, Moody's Investor Service ("Moody's") last reviewed its "Baa1" issuer rating on ELL in August 2022 and detailed its credit opinion in October 2022. It left unchanged the negative outlook that was imposed in 2021 after Hurricane Ida. A main driver of Moody's opinion of ELL's credit quality are the environmental risks associated with its concentration in a storm-prone service area.

Similarly, S&P Global Ratings' ("S&P") issuer rating on the Company as of August 2022 is "BBB+," a rating that reflects a downgrade from last year out of the "A" category after Hurricane Ida. S&P's opinion of ELL's credit quality is also concentrated on storm risk, namely, the Company's exposure to severe hurricanes and storms in its service area.

It follows that lenders and investors are insisting upon greater levels of resilience and are increasingly weighing climate risk in their decisions regarding whether to provide capital. ELL's ability to continue to access capital on reasonable terms depends upon taking steps to reduce risk and increase resilience to major storm events. Failure to take such steps would unfavorably distinguish ELL from its peers and competitors for capital, and would put at risk ELL's ability to continue to access capital on reasonable terms – potentially increasing costs to customers and reducing bill headroom for needed investments.

Q34. CAN YOU PROVIDE MORE DETAIL ABOUT HOW RECENT STORM EVENTS, INCLUDING HURRICANE IDA, WILL IMPACT ELL'S ABILITY TO FINANCE VIA SECURITIZATION STORM COSTS RESULTING FROM FUTURE STORMS?

A. Yes. As discussed in more detail by Company witness Alyssa Maurice-Anderson, ELL intends to rely on Act 55[31] securitization financing to recover all of its Hurricane Ida costs. Assuming Commission approval of ELL's requested storm costs, the Company estimates that after the issuance of securitized bonds to finance the recovery of its remaining Hurricane Ida costs, it will have $4.7 billion of securitization bond principal outstanding at year-end 2023.[32] For the reasons explained by Ms. Maurice-Anderson, ELL very likely would have limited capacity to use securitization debt to finance any additional storm costs for a number of years.

Therefore, the Commission's traditional practice of using securitization as a low-cost means to finance storm restoration costs likely will be unavailable in the near term. And if ELL, in the near term, sustains widespread storm damage with a scope and cost comparable to that experienced with Hurricane Ida, the Commission and ELL will be in "uncharted territory." In that event, ELL would have to propose and the Commission, consistent with applicable law, would have to consider authorizing a new financing method for restoration costs that would likely be much less favorable to customers than securitization, especially the Act 55 financings that have been used by ELL to further

[31] In 2007, the Louisiana Legislature enacted Part VIII of Chapter 9 of Title 45, entitled the "Louisiana Utilities Restoration Corporation Act," which is often referred to as "Act 55." In 2021, the Louisiana Legislature supplemented Act 55 through Act No. 293 of the Louisiana Regular Session of 2021, La. R.S. §§ 45:1331-1343.

[32] Ms. Maurice-Anderson discusses in her testimony the steps taken by the Company to recover the storm restoration costs resulting from prior storms impacting ELL's service area, including Hurricane Ida and Winter Storm Uri in 2021, as well as Hurricanes Laura, Delta, and Zeta in 2020.

lower costs for customers. For this reason, the Resilience Plan is necessary not only to reduce ELL's business risk by decreasing future restoration costs, but also to mitigate risk and uncertainty for customers.[33]

Q35. HOW DOES INCREASED CUSTOMER DEPENDENCE ON ELECTRICTY SUPPORT THE NEED TO ACCELERATE THE SORT OF INVESTMENT AT ISSUE IN THE RESILIENCE PLAN?

A. Our society depends on electricity to power homes and businesses and to support critical services and infrastructure such as government, military, police, fire, health care, water/sewage/drainage, natural gas, food, and communications systems and services. Due to a variety of trends, customers' dependence upon the electric grid is increasing, which, in turn, is increasing demands and expectations for a resilient system. With today's reliance on technology and communication, the challenges customers face from power outages are more significant than was the case in prior decades. Additionally, the impact of outages is only expected to increase over the next decade due to the increasing electrification of technology and industrial processes, including the use of electric vehicles and other sustainability efforts, creating new, potentially significant risks from prolonged outages. Moreover, the increasing frequency of challenges posed by severe

[33] As explained by Ms. Maurice-Anderson and Mr. Shipman, in order for ELL to undertake the accelerated investment contemplated in the Resilience Plan in addition to its existing capital program without putting ELL and customers at risk, a new contemporaneous recovery mechanism is likewise necessary. Specifically, ELL is proposing that the revenue requirement associated with the Resilience Plan be recovered initially through a new rider, the Resilience Plan Cost Recovery Rider.

weather is causing outmigration, deterring new businesses and business growth, and causing economic harm to the communities that ELL serves.

Q36. PLEASE ELABORATE ON HOW TECHNOLOGY AND CUSTOMER EXPECTATIONS RELATE TO THE EVOLUTION OF THE ELECTRIC UTILITY INDUSTRY.

A. Technological advancements are changing the way electricity can be supplied, distributed, and consumed. Supply alternatives such as utility-scale solar photovoltaic ("PV") are becoming increasingly viable options for serving customers under the appropriate circumstances. Customers increasingly are also generating their own energy through Distributed Energy Resources ("DER"), such as residential-scale solar PV systems, and interconnecting those DERs to the electric distribution grid. Customers expect that the electric distribution grid will accommodate and facilitate their adoption of these and other technologies, like electric vehicles. Technological advancements have also changed customer expectations regarding how they interact with their service providers and how they manage the services that are provided. Technological advancements have also led to increasing energy efficiency and reductions in usage per customer, particularly in the residential and small commercial customer classes. Added to these advancements is the wealth of knowledge and services that are available to consumers via the internet, and, over the past several years, there has been a significant increase in customers' expectations that they be able to access information and manage services via mobile devices like smart phones and tablets.

Accordingly, as an electricity generator and provider, the Company understands that it plays a key role in the areas and neighborhoods that it serves because the electric system contributes substantially to withstanding and recovering from disruptive events. In other words, the accelerated pace of hardening investments contemplated in the Resilience Plan is designed precisely to mitigate these sorts of risks and, importantly, is responsive to the stated desires of the Company's customers, communities, and stakeholders.

Q37. HAS COVID-19 ALSO AFFECTED CUSTOMER EXPECTATIONS FOR THE DISTRIBUTION SYSTEM?

A. Yes, I believe so. Even before COVID-19, reliance on the electric system by businesses and households had expanded over the past decade as e-commerce and related payment by credit-card transactions displaced traditional retail sales. As COVID-19 brought stay-at-home orders and other measures for reducing the spread of the virus, e-commerce spending accelerated, with many consumers relying on online shopping for the first time. As the e-commerce industry continues its growth, customer expectations for reliable electric service in their homes and businesses will likewise increase for this additional reason. Likewise, when COVID-19 struck, numerous employers instructed their employees to work remotely to mitigate the spread of the virus. Some employers, in the wake of that experience, have adopted more flexible work policies that allow workers to work remotely some or all of the time. And even workers who generally commute to their employer's place of business each day now, in many cases, need and expect to be able to work remotely from time to time if they wish to do so. These emerging trends in work practices have increased customers' dependence upon electricity, which is essential to most remote work activities.

Q38. YOU MENTIONED CUSTOMER EXPECTATIONS AND RELIANCE ON TECHNOLOGY. DOES THE AVAILABILITY OF EMERGING TECHNOLOGY ALSO SUPPORT ACCELERATING THE PACE OF HARDENING INVESTMENT?

A. Yes. As a result of technological innovation, new options and strategies to achieve system resilience are more available and more cost effective than was the case in past decades. Utilities are also assessing NWAs (including those that could function as microgrids), which may become more feasible and achieve greater cost competitiveness.

Q39. WHAT IS A MICROGRID?

A. Although there are various definitions of what constitutes a "microgrid," generally speaking, a microgrid consists of localized, distribution-scale resources or storage (or both) integrated by a controller that can island the targeted load and continue serving customers within this microgrid in response to an outage event or, in certain instances, can respond to market conditions and enhance reliability during times of peak usage. In other words, microgrids, or NWAs generally, are able to provide a local source of power that can swiftly restore power to a substation, to the feeders that are connected to a substation, or to certain critical loads on the Company's distribution system.

Today, most microgrids are associated with providing enhanced resilience to a single entity (*e.g.*, a hospital or campus that has the capability to be islanded and stay in operation during an outage). However, there are instances in the United States of microgrids that serve a broader area involving multiple electricity consumers.[34] One obvious benefit to constructing a microgrid that serves a broader area (*i.e.*, an entire substation, feeder, or lateral), as opposed to a single customer, is that the wider coverage brings incremental resilience to more customers who are contributing to its costs. But whether a microgrid is suitable for a broader area and a particular resilience application depends on a variety of factors, including the availability of suitable land and right of way access to natural gas sources or pipelines (in the case of a gas-powered microgrid), and the specific goals of the resilience solution.

Q40. PLEASE DESCRIBE THE NON-WIRE ALTERNATIVES THAT THE COMPANY IS OFFERING FOR CONSIDERATION WITH ITS FILING.

A. In developing the portfolio of projects proposed in this filing, the Company has identified a number of potential investments in several new generation alternatives (*i.e.*, NWAs), that could function as microgrids. As Mr. Meredith explains, ELL performed a planning-level evaluation of microgrids and has identified ten microgrid projects for consideration, subject to further development and discussion, that could serve as alternatives to certain transmission projects in the Comprehensive Hardening Plan. These NWAs, which consist of dispatchable natural-gas generator microgrids, were the most cost effective and practical solutions to providing a storm-resilient generation source following a major

[34] An example is the Commonwealth Edison Company's Bronzeville Community Microgrid project in Chicago, Illinois, which involves a utility-owned and operated microgrid serving approximately 7 MW of load and more than 1,000 retail electricity customers; includes multiple forms of power generation, energy storage, and sophisticated controls; and is capable of linking to the separate Illinois Institute of Technology's campus microgrid. *See* https://microgridknowledge.com/bronzeville-microgrid-cluster-lessons-comed/.

storm considering the costs to construct the microgrids and the ability of the microgrid to reliably provide power following a major weather event. As Mr. Meredith describes, the proposed microgrid projects would provide a decentralized and local source of generation for a defined area following a major storm.

As the Commission and parties consider the microgrid projects identified by the Company, it is important to understand that the use of microgrids as a tool and a strategy to enhance resilience is novel and therefore involves inherent risk that should be evaluated before proceeding with these options.

Q41. ARE THERE ANY OTHER CONSIDERATIONS THAT THE COMMISSION SHOULD BE AWARE OF IN CONNECTION WITH THE COMPANY'S RESILIENCE PLAN?

A. Yes. Approximately 31,000 poles that are targeted for upgrade or hardening under the Resilience Plan are poles currently owned by other entities to which the Company has certain equipment and facilities attached pursuant to a joint use agreement. In connection with the specific resilience projects in question, the Company will work with joint-use counterparties to address upgrade and cost issues in a reasonable manner.

Q42. HAS THE COMPANY PURSUED FEDERAL FUNDING TO HELP ADDRESS THE COSTS ASSOCIATED WITH HARDENING INVESTMENTS IN ITS SERVICE AREA?

A. Yes. The Company has raised with state and federal agencies the need for increased resilience investment grants that will enable additional hardening investment while also addressing bill impacts to customers.

For example, earlier this year, the Company, in coordination with The Governor's Office of Homeland Security and Emergency Preparedness and together with ENO, submitted eight grant applications to the Federal Emergency Management Agency ("FEMA") requesting funding for projects to enhance the resilience of the electric grid through FEMA's Building Resilient Infrastructure and Communities ("BRIC") Program. Although those efforts ultimately were not successful, the Company also will be applying for future FEMA grants to help defray the cost to customers of the proposed investments included in the Resilience Plan. At this time, the Company is planning to partner with Parish and local communities to submit joint applications for the next round of funding.

Q43. CAN YOU PROVIDE DETAILS ABOUT ANY OTHER FUTURE GRANTS FOR WHICH THE COMPANY INTENDS TO APPLY?

A. Yes. The Company intends to apply for federal funds made available that may provide resilience benefits for ELL and its customers and that align with the Company's resilience goals in the State of Louisiana. For example, ELL has been monitoring the release of Infrastructure Investment and Jobs Act ("IIJA") funding opportunities from the Department of Energy ("DOE") relative to resilience, including, but not limited to, the

DOE's Grid Resilience and Innovative Partnership ("GRIP") Program, which is geared toward supporting comprehensive and regional resilience strategies aimed at preventing outages and enhancing the resilience of the electric grid, deploying technologies to enhance grid flexibility, and demonstrating innovative approaches to power sector infrastructure resilience and reliability.[35] ELL intends to apply for the programs under GRIP for which the Company is eligible to apply directly and is also prepared to work with the State of Louisiana and units of local government that are eligible to apply to the remaining programs in order to support projects that provide the most resilience benefits to Louisiana customers.

The Company has also been working to access funds through the Community Development Block Grant disaster recovery ("CDBG-DR") program approved by Congress in September 2022 in a continuing resolution/emergency supplemental bill to, among other things, address disaster needs from 2021. For the first time in more than a decade, the bill includes language allowing utilities such as ELL to be eligible for CDBG-DR funding to address the reconstruction of infrastructure damaged by Hurricane Ida and to provide customer bill relief, but how such funds made available to Louisiana will be allocated is at the discretion of the Governor.

In sum, ELL is continuing to monitor and evaluate these and other funding opportunities as they are released by the federal government and is planning to pursue

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[35] The United States Department of Energy, *Request for Information on Grid Resilience and Innovation Partnerships Program,* The Federal Register (September 9, 2022), *available at* https://www.federalregister.gov/documents/2022/09/07/2022-19308/request-for-information-on-grid-resilience-and-innovation-partnerships-program. GRIP includes three resiliency programs: grid resilience grants, smart grid grants, and the grid innovation program.

those that are aligned with the Company's resilience goals. Any such grant proceeds received by ELL would be for the benefit of customers, as opposed to the Company.

Q44. ARE THERE ANY ADDITIONAL EFFORTS SUPPORTED BY THE COMPANY RELATING TO FEDERAL FUNDING OPPORTUNITIES FOR RESILIENCE INVESTMENT?

A. Yes. The Company also has been engaged in ongoing discussions with local, state, and federal entities, together with the Louisiana Public Service Commission, to seek out funding opportunities for investments intended to modernize its infrastructure for the benefit of its customers such as those available to electric cooperatives through the Stafford Act (42 U.S.C. 5172, *et seq.*). Traditionally, when an electric cooperative's service territory is included in a Presidentially-declared disaster area, FEMA reimburses a co-op at least 75 percent of the allowed costs of replacing damaged and destroyed co-op facilities.[36] Investor-owned utilities historically have not had access to such federal relief even though their customers are similarly affected by these disasters and pay federal income taxes. As noted by the Commission in LPSC Resolution No. 01-2021, *In re: Resolution directed to Louisiana's Congressional Delegation to take any necessary action to ensure federal disaster relief be made available to all Louisiana electric utilities*

[36] For Hurricanes Laura and Ida, FEMA's normal cost-share rate of 75 percent was raised to 90 percent.

FEMA, *FEMA Cost Share Adjustment Grants Louisiana more Funds for Public Assistance in Hurricane Laura Recovery,* The Federal Emergency Management Agency (March 23, 2021), *available at* https://www.fema.gov/press-release/20210323/fema-cost-share-adjustment-grants-louisiana-more-funds-public-assistance

FEMA, *FEMA Announces 90/10 Cost Share Adjustment,* The Federal Emergency Management Agency (March 18, 2022), *available at* https://www.fema.gov/press-release/20220318/fema-announces-9010-cost-share-adjustment *affected by the 2020 and 2021 storms, and ultimately the ratepayers and citizens of Louisiana*, an expansion of Stafford Act relief to allow all electric utilities to cover all or part of storm-related losses would mitigate not only the impact on the citizens of Louisiana, but also on some of the nation's critical infrastructure industries that are located in the state.

Q45. CAN YOU PROVIDE MORE DETAILS ON THE CUSTOMER BENEFITS THAT THE COMPANY ANTICIPATES FROM THE ACCELERATED INVESTMENTS INCLUDED IN THE RESILIENCE PLAN?

A. Yes. As I noted above, the Company expects that the investment contemplated in the Resilience Plan will produce significant customer benefits by, among other things, lowering post-storm restoration costs and reducing CMI. Specifically, as discussed by Company witnesses Jason De Stigter and Mr. Meredith, if implemented, the Comprehensive Hardening Plan is estimated to decrease future restoration costs following storms by approximately $2.9 billion to $4.2 billion and to decrease the total number of CMI following major events by 60.1 billion to 87.6 billion minutes over the next fifty years depending on the frequency of storms. For the projects completed during Phase I of the Resilience Plan, the Company estimates that those projects will decrease future restoration costs following major weather events by approximately $2.1 billion and lead to a reduction in total CMI following major events of 34.31 billion minutes over the next fifty years assuming an above average frequency of storms.

Company witnesses Mr. Long and Mr. Meredith provide more details on the anticipated benefits of implementing the Company's Resilience Plan in their testimony.

V. INTRODUCTION OF OTHER WITNESSES

Q46. WHO ARE THE OTHER ELL WITNESSES SUBMITTING TESTIMONY IN THIS PROCEEDING?

A. The other witnesses filing testimony in support of ELL's Application include:

- Sean Meredith – Vice President, System Resilience. Mr. Meredith presents ELL's Resilience Plan and provides details regarding the proposed projects under that plan. He also summarizes the estimated costs and benefits of implementing this plan, provides support for the conclusion that the investments included in the Resilience Plan are in the public interest and should be made, and summarizes the Company's proposed monitoring plan.
- Alyssa Maurice-Anderson – Director, Regulatory Filings and Policy, for ESL. Ms. Maurice-Anderson's testimony supports the Company's request in its Application in this proceeding seeking approval of a new rider for ELL, the Resilience Plan Cost Recovery Rider, to permit more timely recovery of the Resilience Plan's revenue requirement as ELL completes the plan's resilience improvements and customers begin receiving the benefits of those improvements. Ms. Maurice-Anderson also explains that the need for the Resilience Plan is supported by ELL's expectation that it will have limited securitization capacity to finance future storm-related restoration costs in the near term and that financing future restoration costs would likely occur at a less favorable cost to customers. Her testimony also supports the requested ratemaking treatment related to transmission and distribution assets that must be retired and replaced with new assets pursuant to the Resilience Plan and discusses an

accounting waiver that ELL intends to request at the Federal Energy Regulatory Commission, which will mitigate the near-term bill effect on customers.

- Charles Long – Vice President of Power Delivery Operations for ESL. Mr. Long discusses the Power Delivery Organization that is responsible for planning, operating, and maintaining ELL's transmission and distribution systems, as well as the Capital Projects Organization that designs and constructs ELL's transmission and distribution system. These two organizations will work with ELL to execute the Comprehensive Hardening Plan and bring resilience benefits to ELL and its customers. He also discusses the ongoing process of the Company's reliability work on its distribution and transmission systems and provides an overview of those systems and operations. He then discusses the Company's proposed changes to vegetation management programs and spending. Finally, he discusses the need for the Comprehensive Hardening Plan and the benefits that a comprehensive resilience effort can provide.
- Jason De Stigter – Director, 1898 & Co. Mr. De Stigter summarizes the results and methodology used to develop the Comprehensive Hardening Plan, including a description of how the assessment was performed and why it was performed in that way. He also describes the major elements of the Storm Resilience Model, which include a Major Storms Event Database, Storm Impact Model, Resilience Benefit Module, and Investment Optimization & Project Prioritization. He also reviews historical major storm events that have impacted ELL's service area, describes the datasets used in the Storm Impact Model and how they were used to model system impacts due to storms events, and explains how to understand the resilience benefit

results. Finally, he describes the calculations and results of the Storm Resilience Model.

- Todd Shipman – Principal, Utility Credit Consultancy LLC. Mr. Shipman explains what credit ratings are, the importance of utility credit ratings to regulators, and the analytical framework used for determining utility credit ratings. He also provides information regarding the overall utility industry's financial outlook from a ratings perspective. He then summarizes ELL's current credit ratings and outlook, and, in that context, he opines on how Moody's and S&P may react to ELL's proposed Resilience Plan and Resilience Plan Cost Recovery Rider.
- Jay Lewis – Principal, ASD@Work, LLC. Mr. Lewis discusses a number of Commission orders that may be implicated by the Company's request regarding the Resilience Plan and provides context for how the Company's proposal may be considered. Additionally, he discusses the public interest standard that has been historically used at the LPSC and how that standard should be applied in the context of an accelerated resilience program like the Resilience Plan that has both traditional benefits and non-traditional benefits. He further discusses the periodic reporting required by the Business Combination order and the proposed monitoring plan for the resilience investments. He then summarizes the regulatory request being made by ELL.

VI. CONCLUSION

Q47. PLEASE SUMMARIZE WHY THE COMPANY IS PROPOSING ITS RESILIENCE PLAN.

A. The time is ripe for undertaking the enhanced resilience efforts included in the Resilience Plan. Fundamentally, spending on hardening involves a balance between risk and cost, with the two being inversely proportional. While there are tradeoffs between accelerating investment and managing customer bill impacts, the increasing harm resulting from prolonged outages, the increasing frequency and cost of storm restoration, and the declining cost of new technologies that promote resilience demonstrate that the Resilience Plan is in the public interest and now is an appropriate time to pursue accelerated infrastructure hardening and vegetation management.

Designing and constructing electrical infrastructure strong enough to withstand storms that are striking with increased intensity and frequency is an important decision that must include input from customers, regulators, and government policymakers. Constructing stronger poles, towers and electric infrastructure requires substantial investments, and we must ensure that all aspects of reliability, affordability, and sustainability are considered. We look forward to working with the Commission to determine the appropriate timing and pace of the proposed resilience investments by ELL as well as providing input on a statewide resilience plan being considered in Docket No. R-36227.

Q48. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, at this time.

AFFIDAVIT

STATE OF LOUISIANA

PARISH OF JEFFERSON

NOW BEFORE ME, the undersigned authority, personally came and appeared, **PHILLIP R. MAY**, who after being duly sworn by me, did depose and say:

That the above and foregoing is his sworn testimony in this proceeding and that he knows the contents thereof, that the same are true as stated, except as to matters and things, if any, stated on information and belief, and that as to those matters and things, he verily believes them to be true.

Phillip R. May

Phillip R. May

SWORN TO AND SUBSCRIBED BEFORE ME
THIS 15 DAY OF DECEMBER, 2022

NOTARY PUBLIC

My commission expires: at death

Lawrence J. Hand Jr.
Bar 23770 / Notary 52176
Notary Public in and for the
State of Louisiana.
My Commission is for Life.

BEFORE THE

LOUISIANA PUBLIC SERVICE COMMISSION

***IN RE*: APPLICATION OF ENTERGY**	**)**	
LOUISIANA, LLC FOR APPROVAL	**)**	**DOCKET NO. U- _______**
OF THE ENTERGY FUTURE READY	**)**	
RESILIENCE PLAN (PHASE I)	**)**	

EXHIBIT PRM-1

DECEMBER 2022

Listing of Previous Testimony Filed by Phillip R. May

DATE	TYPE	SUBJECT MATTER	REGULATORY BODY	DOCKET NO.
05/31/2000	Direct	UCOS & ECOM	PUCT	22356
08/28/2000	Supplemental Direct	UCOS & ECOM	PUCT	22356
03/30/2001	Rebuttal	UCOS & ECOM	PUCT	22356
05/15/2001	Settlement	Stranded Costs	LPSC	U-22092
05/15/2001	Settlement	Stranded Costs	LPSC	U-20925
06/25/2001	Direct	Qualified Power Region	PUCT	24309
06/29/2001	Direct	Transition to Competition Costs	APSC	01-041-U
07/02/2001	Direct	Price to Beat	PUCT	24336
09/25/2001	Rebuttal	Price to Beat	PUCT	24336
05/08/2002	Supplemental	Price to Beat	PUCT	24336
07/12/2002	Supplemental Rebuttal	Price to Beat	PUCT	24336
03/01/2004	Supplemental	Business Separation Plan	LPSC	U-21453 (Sub. B)
08/25/2004	Direct	2004 Rate Case	PUCT	30123
05/17/2005	Direct	Formula Rate Plan & Generation Performance Based Resource Plan	Council of the City of N.O. (“Council”)	UD-01-04 & UD-03-01
07/05/2005	Direct	Capacity Rider	PUCT	31315
08/15/2005	Direct	TTC	PUCT	31544
10/05/2005	Rebuttal	Capacity Rider	PUCT	31315
02/10/2006	Rebuttal	TTC	PUCT	31544
04/26/2006	Direct	Jurisdictional Separation Plan	LPSC	U-21453 (Sub. J)
05/14/2007	Rebuttal	TTC Plan	PUCT	33687
09/26/2007	Direct	2007 Rate Case	PUCT	34800
05/02/2008	Rebuttal	2007 Rate Case	PUCT	34800
12/12/2008	Answering	Spindletop	FERC	EL08-51-002
01/09/2009	Direct	Bandwidth	FERC	ER08-1056-002
02/03/2009	Cross Answering	Spindletop	FERC	ER08-51-002
09/18/2009	Direct	PCRF	PUCT	37482
10/09/2009	Direct	Bandwidth	FERC	ER09-1224-001
12/21/2009	Direct	2009 Rate Case	PUCT	37744
09/01/2010	Direct	ICT	LPSC	S-31509
09/20/2010	Direct	ICT	Council	undocketed
10/12/2010	Answering	Depreciation Complaint	FERC	EL10-55-001
10/25/2010	Cross Answering	Depreciation Complaint	FERC	EL10-55-001
02/23/2011	Rebuttal	Depreciation Complaint	FERC	EL10-55-001
7/22/2011	Direct	MSS-4 Repricing	Council	UD-11-02
11/28/2011	Direct	2011 Rate Case	PUCT	39896
1/26/2012	Supplemental Direct	CGS	PUCT	38951
4/13/2012	Rebuttal	2011 Rate Case	PUCT	39896
4/24/2012	Supplemental Rebuttal	CGS	PUCT	38951
4/30/2012	Direct	MISO Change of Control	PUCT	40346
9/5/2012	Direct	ITC Transaction	LPSC	U-32538
9/12/2012	Direct	ITC Transaction	Council	UD-12-01
2/15/2013	Direct	EGSL 2013 Rate Case	LPSC	U-32707
2/15/2013	Direct	ELL 2013 Rate Case	LPSC	U-32708
3/28/2013	Direct	ELL Algiers 2013 Rate Case	Council	UD-13-01
4/9/2013	Direct	ELL EGSL Hurricane Isaac Storm Recovery	LPSC	U-32674

DATE	TYPE	SUBJECT MATTER	REGULATORY BODY	DOCKET NO.
5/21/2013	Rebuttal	ITC Transaction	LPSC	U-32538
5/29/2013	Errata-Rebuttal	ITC Transaction	LPSC	U-32538
2/18/2014	Rebuttal	ELL Algiers 2013 Rate Case	Council	UD-13-01
4/04/2014	Rejoinder	ELL Algiers 2013 Rate Case	Council	UD-13-01
9/30/2014	Direct	ELL/EGSL Business Combination	LPSC	U-33244
11/06/2014	Direct	ELL/EGSL Business Combination	Council	UD-14-03
1/13/2015	Direct	EGSL Union Power Station	LPSC	U-33510
5/1/2015	Rebuttal	ELL/EGSL Business Combination	LPSC	U-33244
6/5/2015	Direct	Ninemile 6 Prudence Review	LPSC	U-33633
7/13/2015	Settlement	ELL/EGSL Business Combination	LPSC	U-33244
8/25/2015	Direct	St. Charles Power Station	LPSC	U-33770
3/11/2016	Rebuttal	St. Charles Power Station	LPSC	U-33770
11/2/2016	Direct	Lake Charles Power Station	LPSC	U-34283
11/15/2016	Direct	Oxy PPA Amendment	LPSC	U-34303
11/22/2016	Direct	Advanced Metering System	LPSC	U-34320
2/23/2017	Direct	Carville PPA	LPSC	U-34401
4/21/2017	Direct	MISO Renewal	LPSC	U-34447
4/24/2017	Rebuttal	Lake Charles Power Station	LPSC	U-34283
5/23/2017	Direct	Washington Parish Energy Center	LPSC	U-34472
8/21/2017	Direct	2016 FRP Extension	LPSC	U-34631
5/29/2020	Direct	ELL FRP Extension	LPSC	U-35565
6/24/2020	Direct	J. Wayne Leonard Power Station Prudence Review	LPSC	U-35581
10/14/2020	Direct	ELL Laura Interim Financing	LPSC	U-35762
4/30/2021	Direct	ELL Storm Recovery Filing	LPSC	U-35991
9/8/2021	Direct	1803 Application	LPSC	U-35927
9/22/2021	Direct	ELL Ida Interim Financing	LPSC	U-36154
9/30/2021	Direct	ELL Storm Recovery Filing (3rd Supp. App.)	LPSC	U-35991
11/9/2021	Direct	ELL Solar Portfolio and Green Tariff	LPSC	U-36190
12/8/2021	Direct	ELL Lake Charles Prudence Review	LPSC	U-36222
1/31/2022	Direct	JDEC NextEra Joint Application	LPSC	U-36135
2/14/2022	Direct	DEMCO NextEra Joint Application	LPSC	U-36133
4/29/2022	Direct	ELL Ida Storm Recovery Filing	LPSC	U-36350

BEFORE THE

LOUISIANA PUBLIC SERVICE COMMISSION

***IN RE*: APPLICATION OF ENTERGY LOUISIANA, LLC FOR APPROVAL OF THE ENTERGY FUTURE READY RESILIENCE PLAN (PHASE I)**	**))))**	**DOCKET NO. U- _______**

DIRECT TESTIMONY

OF

SEAN MEREDITH

ON BEHALF OF

ENTERGY LOUISIANA, LLC

DECEMBER 2022

TABLE OF CONTENTS

EXHIBIT LIST

I. INTRODUCTION AND PURPOSE

Q1. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND OCCUPATION.

A. My name is Sean Meredith. My business address is 2107 Research Forest Dr., Suite 300, The Woodlands, TX 77380. I am employed by Entergy Services, LLC ("ESL")[1] as Vice President, System Resilience.

Q2. ON WHOSE BEHALF ARE YOU SUBMITTING THIS DIRECT TESTIMONY?

A. I am submitting this Direct Testimony on behalf of Entergy Louisiana, LLC ("ELL" or the "Company").

Q3. PLEASE DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

A. I have a Bachelor of Science degree in Systems Engineering from the United States Naval Academy, and I completed the Naval Nuclear Propulsion Program. I served in the United States Navy as a submarine officer aboard three fast attack submarines over a ten-year period. In my last assignment, aboard the USS Hartford, I served as the Engineer Officer responsible for the operation, maintenance, and repair of the nuclear reactor plant and all support systems, as well as training and qualifying all sailors in the engineering department.

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[1] ESL is a service company to the five Entergy Operating Companies ("EOCs"), which are Entergy Arkansas, LLC; Entergy Louisiana, LLC; Entergy Mississippi, LLC; Entergy New Orleans, LLC; and Entergy Texas, Inc.

In 2014, I joined Entergy's nuclear organization as a supervisor of the Instrumentation and Controls department at the James A. FitzPatrick Nuclear Power Plant in Scriba, New York, where I was responsible for the maintenance and repair of various systems in the plant. In 2016, I joined Entergy's transmission organization as a senior program manager and became the Training Manager for transmission in the spring of 2017. In that capacity, I led a team that established and executed a Journeyman Training Program for all craft journeymen and transitioned the apprenticeship training programs to utilize a new training facility. In 2018, I became the director of operations for the Transmission Control Center North with responsibilities for the EOCs' transmission operations that included bulk power operations, generation coordination with the Midcontinent Independent System Operator, Inc. ("MISO"), and outage management. From April 2020 to October 2021, I served as Vice President, Power Plant Operations, where I was responsible for the safe, compliant, and reliable operation of the EOCs' non-nuclear generation fleet, including the strategic planning for all generation assets across the EOCs' service areas. Finally, in October 2021, I assumed my current role as Vice President, System Resilience.

Q4. PLEASE DESCRIBE YOUR CURRENT JOB RESPONSIBILITIES.

A. As the Vice President, System Resilience, I am responsible for the strategic leadership and oversight of the EOCs' efforts related to resilience. I am responsible for leading the development of the Company's strategic initiatives and goals to achieve excellence in resilience project performance and drive continued project efficiency around the execution of resilience projects. As part of that effort, I help ensure that the Company's standards incorporate resilience aspects and are properly included in all new generation, transmission, and distribution projects. Moreover, I provide leadership, direction, and oversight to a geographically dispersed organization of technical professionals, field leadership, and contract personnel, ensuring that internal and external resources are available to meet the projected workload. I work collaboratively with senior leadership and key stakeholders to accomplish strategic imperatives and deliver on desired outcomes of the Company's resilience-based programs.

Q5. HAVE YOU PREVIOUSLY PROVIDED TESTIMONY BEFORE A REGULATORY COMMISSION?

A. Yes. A list of my prior testimony is attached as Exhibit SM-1.

Q6. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony presents the Entergy Future Ready Resilience Plan (the "Resilience Plan") and provides details regarding the proposed projects under that plan. I also summarize the estimated costs and benefits of implementing the Resilience Plan, and I provide support for the conclusion that these investments are in the public interest and should be made.

II. RESILIENCE PLAN

Q7. WHAT IS THE RESILIENCE PLAN?

A. The Resilience Plan is the Company's proposed course of action to improve overall electric system resilience through an accelerated infrastructure hardening and vegetation management effort. The Company is proposing to implement the plan over the 10-year period from 2024 to 2033 in two five-year phases. The Resilience Plan is the result of a holistic review of the Company's assets and vulnerabilities in the light of the changing circumstances illustrated by the extreme weather events of recent years. That comprehensive review was used to determine a broad set of transmission, distribution, and generation resources that should be targeted for hardening.

In this docket, the Company seeks specific approval of Phase I of the Resilience Plan, which includes projects estimated to cost approximately $5.0 billion.[2] If fully implemented, the Resilience Plan is estimated to decrease future restoration costs following storms by approximately $2.9 billion to $4.2 billion and to decrease the total number of customer minutes interrupted ("CMI") following major events by 60.1 billion to 87.6 billion minutes over the next fifty years depending on the frequency of storms. For the projects completed during Phase I of the Resilience Plan, the Company estimates that those projects will decrease future restoration costs following major weather events by approximately $2.1 billion and lead to a reduction in total CMI following major events of 34.31 billion minutes over the next fifty years assuming an above average frequency of storms.

Q8. PLEASE DESCRIBE THE COMPONENTS OF THE RESILIENCE PLAN.

A. The Resilience Plan has four interconnected components.

First, the Company proposes to complete approximately 9,600 identified distribution and transmission hardening projects, which will harden more than 269,000

[2] Phase II of the Resilience Plan is projected to include approximately $4.6 billion in infrastructure resiliency and storm hardening projects.

structures over more than 11,000 line miles over the course of the ten-year period from 2024 to 2033 (the "Comprehensive Hardening Plan").[3] The Comprehensive Hardening Plan will cost approximately $9 billion (nominal). Those projects are generally grouped into seven programs: (i) Distribution Feeder Hardening (Rebuild); (ii) Distribution Feeder Undergrounding; (iii) Lateral Hardening (Rebuild); (iv) Lateral Undergrounding; (v) Transmission Rebuild; (vi) Substation Control House Remediation; and (vii) Substation Storm Surge Mitigation. I discuss the scope of those programs later in my testimony. The specific projects contained in the Comprehensive Hardening Plan are attached to my testimony as Highly Sensitive Protected Materials ("HSPM") Exhibit SM-2. While the Company's proposed plan sets forth the Company's best efforts to identify the scope and timing of the selected projects, the precise work performed (as well as the timing of when that work will be performed) will be subject to continual refinement as the Company implements its Resilience Plan.

Second, the Company proposes to construct 44 dead-end structures for the Company's 500 kV transmissions lines, which form the high voltage backbone of the transmission system; this will improve the resilience of these lines by helping prevent and/or limit cascading damage to transmissions structures. The additional cost for these dead-end structure projects is estimated to be $88 million.

Third, the Company is proposing a number of projects aimed specifically at increasing the resilience of the Company's telecommunication systems, which play an integral part in the Company's efforts to respond to and recover from disruptions caused

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[3] With respect to the Comprehensive Hardening Plan, the term "project" refers to a set of assets for hardening.

by major weather events. Such projects include upgrading select serial-based Remote Terminal Units ("RTUs") to Internet Protocol ("IP") based RTUs and undergrounding nearly 198 miles of All-Dielectric Self-Supporting ("ADSS") fiber cable. These projects will involve approximately $108 million in capital spending and $12 million in incremental operation and maintenance costs.

Fourth, the Company is proposing enhancements to its current vegetation management programs to accelerate trim cycles and to implement additional program elements. Specifically, on the distribution system, the Company is proposing to (i) reduce its trim cycle to five years; (ii) implement mid-cycle herbicide treatments; (iii) implement a backbone "skylining" project; (iv) implement additional programs to target poor performing species of trees and danger trees (including work performed outside the right of way ("OROW")); and (v) increase reactive trimming efforts. On the transmission system, the Company is proposing to increase its OROW work and implement air-saw trimming of vegetation along transmission lines. Together, these enhancements will cost approximately $369 million over the next ten years.

Q9. IS THE COMPANY OFFERING ANY OTHER POTENTIAL PROJECTS FOR THE COMMISSION'S CONSIDERATION WITH THIS FILING?

A. Yes. The Company has identified ten non-wire alternatives ("NWAs"), or microgrids, for consideration as part of this filing. To be clear, these NWAs are not a part of Phase I of the Resilience Plan. Rather, these ten NWAs are possible alternatives to certain transmission hardening projects identified in the Comprehensive Hardening Plan. NWAs are able to provide a local source of power that can swiftly restore service to a substation, to the feeders that are connected to a substation, or to certain critical loads on the Company's distribution system. While these NWAs would not prevent damage during a weather event, they are expected to enable the electric system to rapidly restore service when damages and outages do occur. Together, these ten NWAs would cost approximately $1.03 billion.

Q10. IS THE COMPANY REQUESTING APPROVAL OF THE ENTIRE RESILIENCE PLAN AT THIS TIME?

A. No. As I mentioned earlier, at this time, the Company is currently requesting approval for Phase I of the Resilience Plan, which includes approximately $5.0 billion in projects proposed to be implemented in the first five years. Phase I includes the first five years (2024-2028) of the Comprehensive Hardening Plan ($4.6 billion), the dead-end structure projects ($88 million), the telecommunication improvements ($100 million), and the vegetation management enhancements ($172 million).

Q11. WAS THE COMPANY'S HOLISTIC REVIEW OF ITS ASSETS IN CONNECTION WITH THE RESILIENCE PLAN LIMITED TO COASTAL AREAS OF ITS SERVICE AREA?

A. No. The Company's evaluation of potential projects for inclusion in the Resilience Plan considered all of the Company's service area. That said, certain considerations such as proximity to the coast or location within specific wind loading zones did factor into planning the order of certain resilience activities.

Q12. DOES THE PLAN BEING PROPOSED HERE CONTAIN THE ONLY RESILIENCE PROJECTS BEING CONSIDERED BY THE COMPANY?

A. No. Creating a resilient system involves a continual process of identifying opportunities and evaluating options to improve and adapt the electric system's ability to withstand and/or recover from major weather events. As part of those efforts to identify additional areas to improve system resilience, the Company is continuing to assess options that have not been included in the Resilience Plan at this time. For example, the Company is studying possible solutions to harden certain transmission towers, such as the Little Gypsy to Waterford Towers. The Company is not proposing to move forward with these solutions as part of the Resilience Plan at this time because additional analysis is needed to identify the most effective way to implement the potential projects at the lowest reasonable cost to the Company's customers.

III. IMPROVING SYSTEM RESILIENCE

Q13. WHAT DO YOU MEAN WHEN YOU SAY THAT THE RESILIENCE PLAN IS DESIGNED TO IMPROVE SYSTEM RESILIENCE?

A. In this context, resilience is the ability to prepare for, adapt to, and recover from non-normal events, such as hurricanes, floods, winter storms, and other major weather disruptions. By comparison, system reliability focuses on the availability of power to customers under normal operating conditions, which include day-to-day operational challenges such as thunderstorms.[4] Although resilience and reliability are complementary from the customers' perspective, the projects being proposed as part of the Resilience Plan were selected specifically to help improve resilience as compared to a focus on system reliability.

For electric utility systems, resilience relative to severe weather events has at least three critical dimensions: (1) hardening, which involves building or improving a system in ways that will make it better able to withstand the impacts caused by severe weather events; (2) modernization, which includes adapting the system to reflect or incorporate newer technologies that can improve the system's ability to withstand non-normal events, including self–healing networks, smart sensors, fault-detection technology, and microgrids; and (3) recovery, which includes incorporating customer-sited generation and back-up options and designing resources to assist with recovery after a major weather event.

The projects that are being proposed as part of the Resilience Plan were selected and evaluated for their ability to aid the Company's efforts to avoid, mitigate, withstand, and/or recover from the effects of major disruptive weather events. For example, as discussed more fully below, the Company is proposing to harden certain distribution and transmission assets to standards designed to better withstand the extreme conditions caused by severe weather events. The Company is also proposing to construct additional transmission structures to limit the outages potentially caused by such major disruptive

[4] I note that this view of resilience is consistent with the explanation provided in the Resilience Investment and Benefit Report prepared by 1898 & Co. and attached as an exhibit to the direct testimony of Company witness Jason De Stigter.

events. While such projects should be expected to have positive impacts on the day-to-day operations of the Company's utility system under normal conditions by further protecting against and mitigating outages, they are focused more particularly on preparing the electric system to withstand and recover from severe, non-normal weather events. Moreover, the Resilience Plan approaches resiliency in a holistic fashion, addressing each of the critical dimensions that I mentioned: hardening, modernization, and recovery.

Q14. WHY IS THE COMPANY PRESENTING ITS RESILIENCE PLAN AT THIS TIME?

A. As discussed more fully in Company witness Phillip May's direct testimony, because the frequency and intensity of major storm events have increased, and because customers' dependence upon the electric grid has increased, which, in turn, has raised demands and expectations for a resilient system, it is critical that the Company's system be more resilient and reliable such that it can withstand conditions caused by severe weather events, avoiding and mitigating customer outages and enabling faster, less costly restorations. Over the last six years, hurricanes have become more frequent and intense,[5] bringing greater costs and disruptions to ELL and its customers. And, as seen in the chart below, we are currently in a period of unmatched frequency of Category 4 to Category 5 storms.

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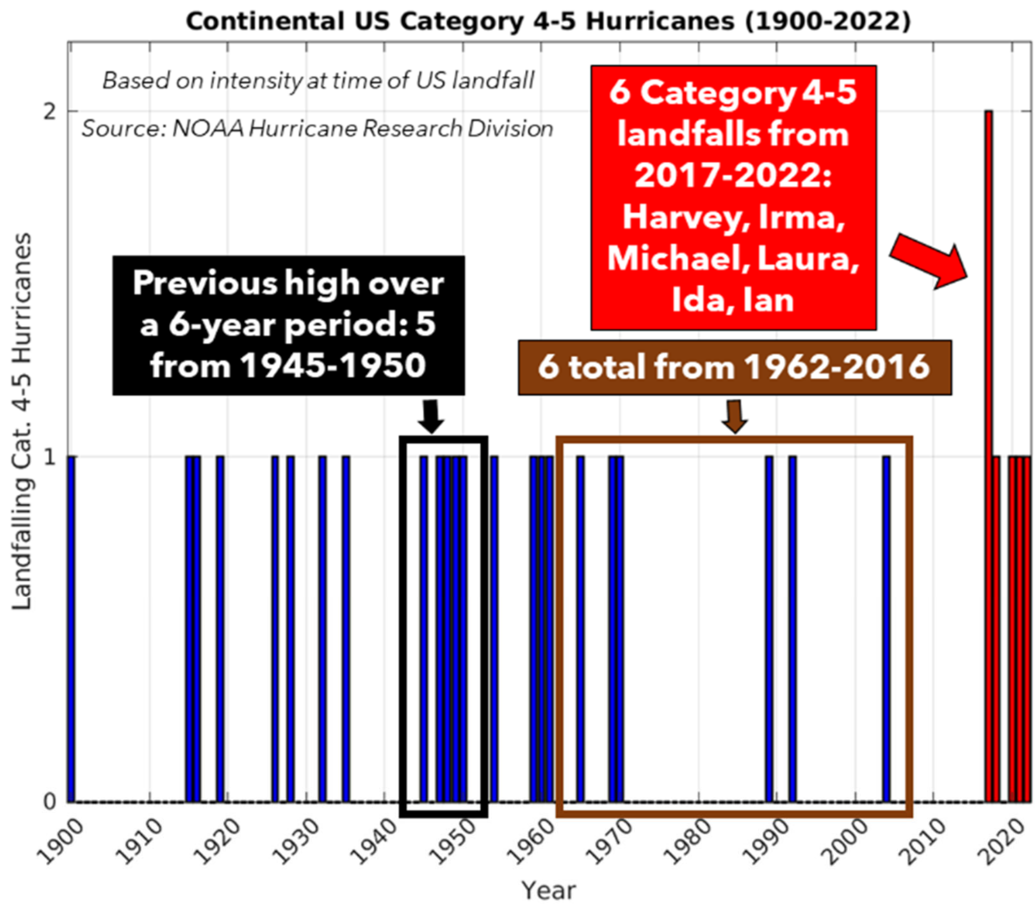
[5] Since 2017, eight major hurricanes (Category 3 or higher) have made landfall in the contiguous United States or Puerto Rico: Harvey (2017), Irma (2017), Maria (2017), Michael (2018), Laura (2020), Zeta (2020), Ida (2021), and Ian (2022).

Figure 1[6]



These major storms pose an increasing threat to the electric system, which has reinforced the need to invest, and to evaluate ways to accelerate that investment where appropriate, to address the increased frequency and intensity of storms. The Resilience Plan is part of the Company's response to that threat, and the Resilience Plan is expected to reduce the cost of restoring the electric grid after major storms as well as reduce the number and duration of outages associated with those events.

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[6] Jake Carstens, Ph.D. (@JakeCarstens) (Sep. 28, 202, 2:03 PM), https://twitter.com/jakecarstens/status/1575199465157591040.

Q15. DOES FLORIDA'S RECENT EXPERIENCE WITH HURRICANE IAN HAVE ANY BEARING ON THE COMPANY'S APPROACH TO RESILIENCE?

A. Yes, I believe it does. As an initial matter, Hurricane Ian was the latest example of the increasingly frequent and intense storms affecting the Gulf Coast. Hurricane Ian made landfall on September 28, 2022, as a strong Category 4 Hurricane with maximum sustained winds of 155 mph, tying the record for the fifth-strongest hurricane on record to strike the United States and putting it on par with Hurricanes Laura (2020) and Ida (2021). And, as with Hurricanes Laura and Ida, Hurricane Ian caused widespread power outages.

Hurricane Ian underscored the potential value of undertaking the sort of resilience plan that the Company is proposing. After the 2004-2005 Atlantic Hurricane Seasons, the Florida Public Service Commission enacted rules requiring electric utilities to develop storm protection plans. In 2019, the Florida legislature codified the requirement for utilities to develop and implement storm protection plans with the objective of reducing restoration costs and outage times caused by extreme weather, and, under the statute, utilities are allowed to recover costs for approved plans through a charge separate and apart from base rates. Although the transmission and distribution systems of electric utilities in Florida suffered outages and sustained damage caused by Hurricane Ian, it appears that the storm protection investments of the affected utilities had a favorable impact on system resilience and the pace of restoration efforts.

Q16. HOW DID THE COMPANY DEVELOP THE RESILIENCE PLAN?

A. Following Hurricane Ida, and in the light of the back-to-back years of severe weather affecting the areas served by the EOCs in forms of both hurricanes and winter storms, the EOCs consulted their own internal subject matter experts and stakeholders, evaluated the practices of other utilities across the country, and undertook a holistic analysis of the opportunities available for creating a more resilient system. As that process evolved, the Company engaged an outside industry consultant, 1898 & Co., which provides strategic asset planning services and has experience in developing similar resilience plans, to assist with identifying potential projects and estimating the costs and benefits of those projects. The Resilience Plan is the result of a company-wide effort to understand the risks faced and to identify cost-effective and achievable projects to build a more resilient electric system.

Q17. WHY IS THE COMPANY PROPOSING TO UNDERTAKE THESE PROJECTS ON AN ACCELERATED BASIS RATHER THAN OVER TIME, AS EXISTING FACILITIES COMPLETE THEIR USEFUL LIVES?

A. As Mr. May discusses in his direct testimony, the Company's customers have increased their reliance on electricity, and the 2020 and 2021 Atlantic hurricane seasons and lessons from the COVID-19 pandemic support accelerated resilience. To explain, the Company takes seriously its responsibility to provide customers with safe and reliable service at the lowest reasonable cost. To strike a reasonable balance between reliability and cost, electric utilities traditionally have not replaced or reconfigured distribution assets until they fail. This approach has been considered cost-effective for customers and reflects the balance that I mentioned between reliability and cost. In recent years, however, ELL and the industry have evolved and modified that approach by deploying new technology and preventive elements. And, as some customers work from home, increase their reliance on e-commerce, purchase electric vehicles, and electrify industrial processes, it becomes more urgent that the electric system is resilient in the face of major disruptions such as hurricanes.

That said, the Company recognizes that the total cost of the proposed projects in the Resilience Plan is significant, and customers' bills will reflect the cost of those efforts. However, as demonstrated by the analysis the Company presents in this proceeding, taking proactive steps to improve system resilience across the Company's distribution, transmission, and generation assets can reduce customer outage time and restoration costs compared with the traditional approach to repairing assets after a major weather event.

Q18. WHAT BENEFITS DOES THE COMPANY EXPECT TO ACHIEVE BY IMPLEMENTING THE RESILIENCE PLAN?

A. There are generally three sets of benefits that can be achieved in undertaking a resilience effort like the Company is proposing. *First*, as discussed more fully in Company witness Charles Long's direct testimony, "blue-sky" work on the system can be more carefully and efficiently planned, executed, and overseen as compared to the reactive post-storm environment when the Company is working as quickly and safely as possible to restore power on a mass scale. *Second*, as I discuss later in my testimony, the "blue-sky" work can typically be executed at a reduced cost as compared to post-storm restoration work.

Third, and finally, the Company believes that undertaking this work will result in fewer and shorter outages experienced by its customers during and following major weather events. I discuss how these benefits were analyzed later in my testimony.

Q19. ARE THERE OTHER BENEFITS THAT THE PROPOSED RESILIENCE PROJECTS PROVIDE TO CUSTOMERS?

A. Yes. Undertaking the Resilience Plan is expected to provide positive benefits for customers by reducing the number and duration of outages following major storm events. Moreover, although the focus of the Resilience Plan is protection against major storm events, taking an accelerated approach to resilience projects allows customers to enjoy the enhanced reliability benefits of these projects sooner than if the resilience projects were delayed until after individual assets fail or reach the end of their useful lives.[7] While this benefit is incidental, it is not insignificant, particularly considering customers' ever-increasing reliance upon electricity as discussed in more detail by Mr. May.

Q20. CAN THIS APPROACH HELP FACILITATE NON-TRADITIONAL AND NEWER TECHNOLOGIES THAT AID RESILIENCE?

A. Yes. Non-traditional NWAs that can aid overall system resilience can be more cost effective if the work to install those projects is undertaken proactively. Take, for

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[7] The Company believes that the Resilience Plan, which includes projects focused on hardening large sections of the Company's distribution system with new equipment constructed to current standards, should improve system reliability (reflected in System Average Interruption Frequency Index ("SAIFI") and System Average Interruption Data Index ("SAIDI") scores) over the long run. Nonetheless, a resilience effort of this size may at times increase the Company's SAIFI and SAIDI scores as a result of planned outages occurring while the Company completes the projects in a safe manner.

example, the installation of distributed generation designed to operate during emergency events. Deploying those generators to critical customers (*e.g.*, water and sewer utilities) after a storm is typically very costly and often afflicted with delays due to the challenging logistics that exist in the immediate aftermath of a major storm event. Deploying those assets proactively would be more cost effective, avoid delays in availability caused by storm events, and would deliver benefits to customers and communities during outages both following and outside of major events.

Q21. WILL THE RESILIENCE PLAN COMPLETELY ELIMINATE OR AVOID RESTORATION COSTS AND OUTAGES CAUSED BY EXTREME WEATHER EVENTS?

A. No. It is critical to understand that no amount of investment can make an electric system completely resistant to the impacts of extreme weather events. As such, the Resilience Plan will not completely eliminate power outages caused by severe storms or the need for future storm cost recovery or securitization proceedings following major storms. Moreover, the estimated reductions in restoration costs and outage times expected from the Resilience Plan are directly affected by how frequently ELL's service area is impacted by extreme weather events and where those impacts are felt. And no one can predict with absolute certainty how frequently such events will occur or where precisely they will strike.

Additionally, the success of the Resilience Plan and the benefits estimated to result from implementing the Resilience Plan are dependent to a certain extent on what other community stakeholders do. A truly resilient electric system requires more than just strengthening the electric grid. It must coincide with overall efforts to build more resilient communities, which involve considerations of the adequacy and enforcement of building code standards, urban planning, elevation requirements, water management, and coastal restoration, among other things.

Nonetheless, the expectation is that the proposed Resilience Plan will increase the resilience of ELL's electric system and, ultimately, will lower the costs and impacts of extreme weather events, in addition to helping further improve grid reliability and overall service quality for customers, resulting in fewer outages and disruptions for ELL's customers.

Q22. IS THE RESILIENCE PLAN EXPECTED TO BENEFIT CUSTOMERS SERVED BY OTHER LOUISIANA UTILITIES?

A. Yes. While those benefits are not captured in the report prepared by 1898 & Co., it stands to reason that ELL's Resilience Plan will benefit customers of other utilities served by ELL's transmission system in terms of fewer and shorter transmission outages as a result of storms.

IV. COMPREHENSIVE HARDENING PLAN

Q23. PLEASE GIVE AN OVERVIEW OF THE COMPREHENSIVE HARDENING PLAN.

A. As noted above, the Comprehensive Hardening Plan involves significant incremental spending in hardening the Company's distribution and transmission assets to address the potential impacts caused by increasingly severe weather events. In collaboration with 1898 & Co., the Company utilized a resilience-based planning approach to identify hardening projects and prioritize investment in ELL's transmission and distribution assets through the Storm Resilience Model. The proposed projects identified through that process will cost approximately $9 billion in nominal terms (or $7.7 billion in 2022 dollars).

Q24. PLEASE EXPLAIN THE METHODOLOGY USED TO IDENTIFY THE PROPOSED PROJECTS FOR INCLUSION IN THE COMPREHENSIVE HARDENING PLAN.

A. The Storm Resilience Model, or "SRM," was the methodology used by the Company in collaboration with 1898 & Co. to assist in identifying the projects for inclusion in the Comprehensive Hardening Plan. Using a four-step process, the SRM employs a data-driven decision-making methodology utilizing robust and sophisticated algorithms to evaluate the assets on ELL's system and calculate resilience costs and estimated benefits of hardening those assets in terms of CMI and avoided future storm restoration costs. The ultimate purpose of the SRM is to identify and prioritize projects that would have the highest benefits to customers. It would be infeasible, logistically and financially, to address the risk arising from every single asset on the ELL electric system. The SRM thus serves to identify and prioritize which set of assets the hardening of which would deliver the most benefits in terms of avoided customer outage minutes and avoided future storm restoration costs for the money spent. In this way, the SRM facilitates the prudent and efficient use of finite resources to achieve the most significant reduction of risk that can be achieved through reasonable diligence. This methodology is described in more detail in the direct testimony and exhibits of Mr. De Stigter, a consultant with 1898 & Co. who helped in developing the Comprehensive Hardening Plan.

Q25. WHAT ASSETS DID THE SRM EVALUATE?

A. As discussed more fully by Mr. De Stigter in his direct testimony and the report prepared by 1898 & Co., the SRM is comprehensive and evaluated nearly all of ELL's transmission and distribution systems. The SRM also evaluated a number of the Company's substations. Table 1, below, shows the asset types and counts included in the SRM.

Table 1

Asset Type	Count
Distribution Circuits	1,249
Feeder Poles	345,740
Lateral Poles	550,513
Feeder OH Primary	12,156 miles
Lateral OH Primary	15,274 miles
Transmission Circuits	888
Wood Poles	19,816
Steel / Concrete / Lattice Structures	30,508
Conductor	5,580 miles
Substations	249

Q26. HOW WERE THE POTENTIAL HARDENING PROJECTS IDENTIFIED?

A. The potential hardening projects were identified based on a combination of data driven assessments, operational knowledge of the system, and historical performance of ELL's system during major storm events. As I mentioned earlier, a "project" refers to a collection of assets identified for hardening and evaluated by the SRM under the different program alternatives, which I discuss later. The approach to identifying hardening projects employs asset management principles utilizing a bottom-up approach starting with the system assets. The following describes the approach to identifying hardening candidate assets and grouping them into projects.

- **Distribution Projects:** For distribution projects, assets were grouped by their most immediate upstream protection device, which was either a breaker, recloser, sectionalizer, auto transfer switch, vacuum fault interrupter, or a fuse. This approach focuses on reducing customer outages. The objective is to harden each asset that could fail and result in a customer outage. Since only one asset needs to fail downstream of a protection device to cause a customer outage, failure to harden all the necessary assets still leaves vulnerable components that could potentially fail in a storm and result in an outage. Rolling assets into "projects" at the protection device level allows for hardening of all vulnerable components in the circuit and for capturing the full benefit for customers, including avoidance or mitigation of an outage.

  When evaluating project types for distribution circuit projects – laterals (assets grouped by a fuse protection device) and feeders (assets grouped by a breaker or recloser protection device) – the Company considered both rebuilding to a storm resilient overhead design standard and undergrounding, where possible. Overhead hardening rebuilds are generally lower cost than undergrounding projects, but they may provide fewer resilience benefits than undergrounding. The SRM Model balances this tradeoff for every project zone across ELL's service area where both options are technically feasible (undergrounding in wetlands and in certain dense urban settings is typically not feasible). Assets identified for inclusion in these projects include older wood poles and those designed to a previous wind rating, as well as copper conductors.

Distribution assets were evaluated under multiple criteria to determine whether they are hardening candidates. Distribution structures were evaluated based on height, class, transformer count, and other attachments to calculate a percentage of maximum loading. For distribution conductor, the asset was included in a project as a hardening candidate if either of the conductor's adjacent poles was selected as a hardening candidate. Additionally, small conductor, such as copper, was included as a hardening candidate since it is at risk of failing in high wind events.

- **Transmission Projects:** At the transmission circuit level, poles identified for hardening will be replaced with higher wind rated structures and materials. Transmission structures were grouped at the transmission line or circuit level into projects. A transmission asset was deemed to be a hardening candidate if the structure's wind rating did not meet or exceed a minimum wind hardening standard for that geographic region.[8]

[8] I note that the wind hardening standards used to identify transmission structures as potential hardening candidates are not identical to the Company's current standards for transmission assets. In completing its analysis, 1898 & Co. used a combined wind-loading map for both transmission and distribution assets that reflects a minimum required level of wind loading for both distribution and transmission assets. Although those minimum standards reflect the extreme wind loading requirements of NESC 250C, which I discuss more fully below, the EOCs have subsequently adopted more stringent standards for the transmission system in some Louisiana parishes. Accordingly, in some instances, 1898 & Co. evaluated the proposed transmission projects using a lower standard than is currently required under the Company's Extreme Wind Guidelines for transmission assets; however, in completing transmission rebuild projects, the Company will harden all transmission assets to its current standards

- **Substation Projects:** ELL's control houses were identified as a particular risk due to some roofs not being designed to withstand winds that exceed certain speeds. If the roof is broken or ripped off during a storm, rainfall resulting in substantial water inside the control house will damage much of the substation protection equipment, rendering it out of service. The Company provided a list of control houses and known current wind ratings. In turn, control houses with non-hardened ratings were added as potential projects. A detailed storm surge modeling using the Sea, Land, and Overland Surges from Hurricanes ("SLOSH") model was performed. Substations with any potential flooding risk were considered as candidate projects. Those substations that are located behind a levee are not considered to be at risk of storm surge.

Q27. WHAT PROGRAM ALTERNATIVES WERE CONSIDERED IN THE SRM?

A. As part of the SRM, the Company grouped the potential projects into seven different program alternatives: Distribution Feeder Hardening (Rebuild); Distribution Feeder Undergrounding; Lateral Hardening (Rebuild); Lateral Undergrounding; Transmission Rebuild; Substation Control House Remediation; and Substation Storm Surge Mitigation. Table 2 shows the number of potential hardening projects contained in each program.

(*e.g.,* a potential transmission project may have been evaluated under the assumption it would be hardened to 140 mph; however, if approved, that project will be hardened to 150 mph).

Table 2

Program	Project Count
Distribution Feeder Hardening (Rebuild)	5,858
Distribution Feeder Undergrounding	5,858
Lateral Hardening (Rebuild)	78,174
Lateral Undergrounding	78,174
Transmission Rebuild	888
Substation Control House Remediation	53
Substation Storm Surge Mitigation	212
Total	169,217

Q28. PLEASE EXPLAIN WHAT THE DIFFERENT PROGRAM ALTERNATIVES ENTAIL.

A. The projects included in the Distribution Feeder Hardening (Rebuild), Lateral Hardening (Rebuild), and Transmission Rebuild involve the evaluation of the identified projects (*i.e.,* the set of grouped assets) to determine the level of work needed to harden the assets contained in those projects (*i.e.,* bring those assets up to the current design standards for distribution and transmission assets). As I discuss below, the Company's distribution and transmission design standards have recently been revised in the light of the severe weather conditions experienced in recent years. If the Comprehensive Harding Plan is approved, the Company will thoroughly design and plan the work needed to bring each distribution or transmission asset in the selected projects up to the Company's updated standards and then perform the work as needed to rebuild or replace those assets. As I discuss below, the Company will keep the Commission advised of any material changes between the projected and actual costs of a project.

As might be expected, the Distribution Feeder Undergrounding and the Lateral Undergrounding programs involve the undergrounding of overhead lines. As discussed more fully in Mr. Long's testimony, it is worth noting that the cost of undergrounding overhead distribution and lateral segments can be higher than the cost of rebuilding or hardening those same segments. The relocation of long-established overhead electric facilities to underground can prove challenging, or in some cases infeasible, primarily due to the increased ground area required for underground equipment, which further increases the cost of such projects. While undergrounding the entirety of ELL's distribution or lateral segments would not be cost effective, selective undergrounding of certain lateral segments, as shown below, is expected to produce more benefits as compared to rebuilding or replacing those segments.

The Substation Control House Remediation involves the hardening of identified substations by bringing the roofs of those facilities up to identified wind standards, and the Substation Storm Surge Mitigation involves undertaking identified work such as constructing flood walls at specific substations to protect against storm surge caused by severe weather. If approved, the Company will more thoroughly scope out the work needed to be performed at the identified substations.

Q29. YOU MENTIONED THAT THE COMPANY'S TRANSMISSION AND DISTRIBUTION DESIGN STANDARDS ARE REFLECTED IN THESE PROGRAM ALTERNATIVES. PLEASE EXPLAIN.

A. As I mentioned, the "hardening" program alternatives involve the evaluation and potential rebuilding or replacement of assets to bring those assets up to the Company's current distribution and transmission standards as opposed to the applicable standards when the assets were initially constructed. It is important to again note that those standards were reevaluated recently as part of the Company's overall approach to addressing the resilience of the electric grid following back-to-back years with major hurricanes.

More specifically, the EOCs revised their wind design criteria for distribution and transmission structures. This revision recognizes that customers and communities are demanding a more resilient grid as they build back stronger, and the increased standards discussed further below reflect what researchers and Gulf Coast residents have learned about the challenges that communities on or near the coast are facing and may face in the future. For example, hurricanes appear to be more frequently undergoing "rapid intensification," which refers generally to at least a 35 mph increase in intensity over a 24-hour period before landfall, as seen with Hurricanes Ian (2022), Ida (2021), Grace (2021), Laura (2020), Michael (2018), and Harvey (2017). In such instances, communities have less time to prepare for major weather and secure property, which, as a result, can lead to wind-blown objects interfering with the EOCs' distribution and transmission assets. Furthermore, as seen during Hurricane Ida, the "brown ocean effect," which refers to a storm's maintaining hurricane strength as it moves over swamps and marshland saturated with warm waters that fuel the storm, may explain why hurricanes are damaging property well inland. Thus, communities beyond the immediate coast have experienced, and must prepare for, hurricane-force conditions. For example, Hurricane Laura in 2020 maintained major hurricane status through Cameron, Calcasieu, and southern Beauregard Parishes and maintained hurricane strength until just before it crossed I-20 near Shreveport. The changes to the EOCs' wind loading criteria will help prepare the communities served by the EOCs for future challenges.

Q30. CAN YOU EXPLAIN HOW THE COMPANY REVISED ITS WIND LOADING CRITERIA?

A. Yes. Before addressing the EOCs' process for the recent revisions, it is important to understand the foundation from which the EOCs were working. The EOCs have always designed their distribution and transmissions systems to meet or exceed the requirements of the National Electric Safety Code ("NESC"). Section 25 of the NESC provides the loading requirements to be applied to transmission and distribution facilities. Rule 250A provides the general loading requirements. Rules 250B, 250C, and 250D address, respectively, specific structure loading requirements for (i) combined ice and wind loading by geographical loading districts; (ii) extreme wind loading requirements; and (iii) extreme ice loading with concurrent winds. The extreme wind and extreme ice loading requirements of NESC 250C and 250D apply to structures or support facilities that exceed 18 meters (60 feet) above ground or water, in recognition that wind speed increases with increasing height above the ground.

It also is important to recognize the purpose of the NESC when considering the EOCs' decision to exceed the NESC safety requirements within its design specifications. The purpose of the NESC, as defined in Rule 010, is "the practical safeguarding of persons and utility facilities during the installation, operation, and maintenance of electric supply and communication facilities, under specified conditions." It contains the basic provisions, under specified conditions, that are necessary for safeguarding of the public, utility workers, and utility facilities. "In essence, the rules of the NESC give the basic requirements of construction that are necessary for safety." *See,* Comments to NESC 010-2017. However, the NESC does not prohibit or limit the EOCs' ability to consider other factors beyond safety and practicality and establish standards in excess of the requirements of the NESC. Accordingly, in addition to developing distribution design specifications that meet the NESC safety requirements, the EOCs have also considered many other factors in their design specifications, including customer and community requirements, costs of increased design specifications, as well as system reliability, repairability, and resilience.

After considering EOC and community experiences during the 2020 and 2021 Atlantic Hurricane Seasons, the balance of these factors supported revision to the EOCs' wind loading guidelines that generally exceed the extreme wind loading requirements of Rule 250C. The EOCs' assessment of design opportunities that may mitigate the effects of major hurricanes like Hurricanes Laura and Ida and make the grid more resilient included the following: (i) reviewing wind data from recent hurricanes;[9] (ii) exploring extreme wind guidelines similar to NESC 250C for distribution lines;[10] (iii) evaluating design specifications and best practices from similarly-situated electric utilities; (iv) reviewing the technical impacts of increased wind guidelines on distribution structure design; (v) considering other actions that may reduce structure loading during extreme wind events; and (vi) evaluating other actions that may reduce exposure to wind damage.

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[9] Hurricane Laura and Hurricane Ida both made landfall as strong Category 4 hurricanes with sustained winds speeds of 150 mph. During Hurricane Ida, an instantaneous peak wind gust of 172 mph was clocked by instruments on a ship in Port Fourchon, Louisiana, and a peak gust of 110 mph was recorded north of Lake Pontchartrain in Mandeville, Louisiana. Hurricane Ida did not downgrade to Category 3 (which has sustained winds up to 129 mph) until its eyewall was near Houma, Louisiana.

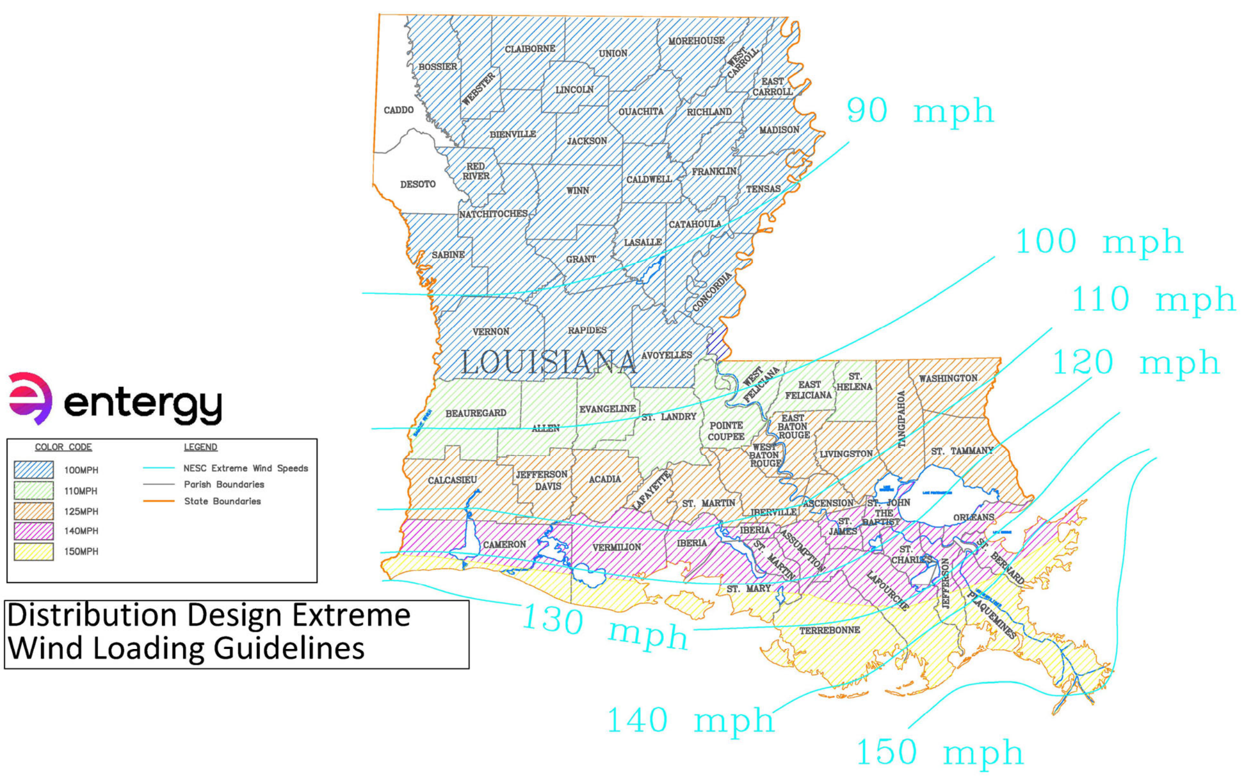
[10] Prior to the development of the EOCs' current extreme wind guidelines, the EOCs generally have designed distribution structures less than 18 meters (60 feet) above ground or water to meet or exceed the requirements of NESC 250B, which, again, provides the general combined ice and wind loading requirements to account for weather conditions in defined geographical loading districts. In the light of the EOCs' experience with Hurricanes Laura and Ida, the EOCs have developed increased design standards for their distribution structures reflective of the extreme wind loading requirements of Rule 250C.

Based on this assessment, the EOCs determined that it was technically feasible to improve the resilience of their structures using a stronger wind design to mitigate major storm impacts to the distribution system. Similar increases in the design standards were made for transmission assets. In evaluating design standards, the EOCs balanced the need for the transmission and distribution systems to withstand the extreme conditions increasingly experienced during major events with their duty to provide customers with safe and reliable service at the lowest reasonable cost. These considerations led the EOCs ultimately to adopt wind loading standards for transmission assets that are higher in some areas than the standards in those same areas for distribution assets. The EOCs believe that these increased standards will benefit customers in the long run. Designing to these higher wind loading standards should result in stronger structures that are more capable of withstanding greater weather impacts, resulting in decreased restoration costs as well as fewer and shorter outages following major events.

Q31. PLEASE DESCRIBE THE NEW WIND LOADING STANDARDS FOR DISTRIBUTION.

A. Some brief additional background is helpful to describing the revised wind loading standards for distribution assets. As mentioned above, the EOCs have always designed their distribution lines to meet or exceed the applicable NESC standards. And, over the years, the EOCs have adopted additional design practices to harden distribution assets to prepare for severe weather. For example, the EOCs have installed storm guying on distribution feeders located in open marshy terrain immediately adjacent to the coast. After Hurricanes Katrina and Rita, the EOCs studied several potential hardening strategies with respect to distribution assets. Based on that analysis, the EOCs adopted additional practices, including using only Class 3 (or larger) poles for three-phase feeder construction for distribution lines located immediately adjacent to the coast and using steel distribution poles for new interstate crossings along major hurricane evacuation routes. Since 2018, after additional analysis, the EOCs have used Class 1 poles for feeder poles south of Interstate 10, where feasible, and nothing smaller than Class 3 poles for all primary applications. At this time, as discussed above and shown in Figure 2 and in the attached Exhibit SM-3, the EOCs have issued new design standards that are based on the extreme wind loading requirements of NESC 250C.

Figure 2
<u>Wind Loading Guidelines for Distribution Lines</u>



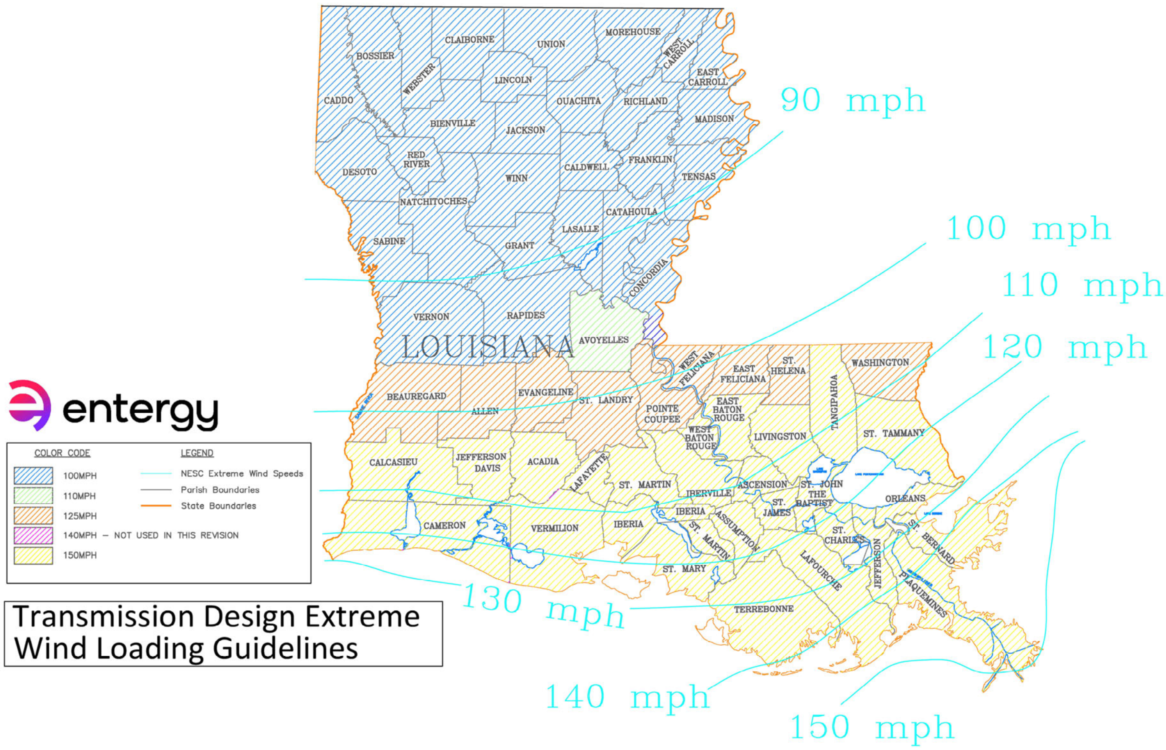
As indicated in Figure 2 and in the attached Exhibit SM-3, distribution assets and structures in portions of the following Parishes will be designed to the 150-mph extreme wind loading requirements: Cameron, Vermilion, Iberia, St. Mary, Terrebonne, Lafourche, Jefferson, Plaquemines, and St. Bernard. A 140-mph wind zone will be applied in portions of the following Parishes: Cameron, Vermilion, Iberia, St. Mary, St. Martin, Assumption, St. James, St. John the Baptist, St. Charles, Jefferson, Plaquemines, Orleans, and St. Bernard. Distribution assets and structures in the following Parishes (or portions of those Parishes) will be designed to the 125-mph extreme wind loading requirements: Calcasieu, Jefferson Davis, Acadia, Lafayette, St. Martin, Iberville, West Baton Rouge, East Baton Rouge, Ascension, Livingston, Tangipahoa, Washington, and St. Tammany. A 110-mph wind zone will be applied to the following Parishes (or portions of those Parishes): Beauregard, Allen, Evangeline, St. Landry, Pointe Coupee, West Feliciana, East Feliciana, and St. Helena. All other Parishes will be in a 100-mph wind zone.

Q32. PLEASE DESCRIBE THE CURRENT WIND LOADING STANDARDS FOR TRANSMISSION AND HOW THEY COMPARE TO PRIOR STANDARDS.

A. As with the distribution standards, some additional background is helpful to understanding the current wind loading standards for transmission. In the mid-1990s, when the EOCs' design standards were consolidated after Entergy Corporation's merger with Gulf States Utilities Company ("GSU"), the 140-mph wind loading requirements in the coastal zone (previously developed by Louisiana Power and Light in response to Hurricane Betsy and before the NESC introduced extreme wind loading requirements) were extended west to encompass coastal parishes and counties previously served by GSU. With increased extreme wind requirements in the 2002 NESC code, the EOCs created a 150-mph zone for the southern portions of the five most southeastern Louisiana parishes (Terrebonne, Lafourche, Jefferson, Plaquemines, and St. Bernard). The 140-mph zone was extended north to include the entirety of any county or parish that is crossed by Interstate 10. In the EOCs' recent revision shown in Figure 3 below, the 140-mph coastal zone was raised to 150 mph, and existing 125-mph zones in Texas and Eastern Louisiana were connected by a new 125-mph zone through central Louisiana. Specifically, all Parishes/Counties previously designed for 140 mph extreme wind loading, as well as Tangipahoa and Livingston Parishes, will now be designed for 150 mph. Additionally, the eight parishes south of the Mississippi/Louisiana border that were previously designed for 110 mph will now be designed for 125 mph.

Figure 3 below and the attached Exhibit SM-4 shows the EOCs' revised minimum wind loading guidelines for transmission assets and further shows that those standards meet or exceed the NESC extreme wind loading requirements.

Figure 3
<u>Wind Loading Guidelines for Transmission Lines</u>



As indicated in Figure 3 and the attached exhibit SM-4, transmission structures and assets in the following Parishes will be designed to the 150-mph extreme wind loading requirements: Calcasieu, Cameron, Jefferson Davis, Vermilion, Acadia, Lafayette, St. Martin, Iberia, St. Mary, Iberville, West Baton Rouge, East Baton Rouge, Ascension, Assumption, Terrebonne, St. James, Lafourche, Livingston, Tangipahoa, St. James, St. John the Baptist, St. Charles, Jefferson, Orleans, Plaquemines, St. Bernard, and St. Tammany. Additionally, the 125-mph wind zone will be applied to the following Parishes: Beauregard, Allen, Evangeline, St. Landry, Pointe Coupee, West Feliciana, East Feliciana, St. Helena, and Washington. A 110-mph wind zone will be applied to the Parish of Avoyelles. All other Parishes will be in a 100-mph wind zone.

Q33. HOW WILL THE COMPANY IMPLEMENT THESE STANDARDS AS PART OF THE COMPREHENSIVE HARDENING PLAN?

A. As discussed above, as part of the Company's Comprehensive Hardening Plan, the Company proposes to evaluate and replace or rebuild the identified distribution and transmission assets as part of the "Hardening" and "Rebuild" program alternatives. The wind zones for a particular area drive the design and construction of new transmission and distribution assets. In other words, going forward, the Company will design new structures using the revised wind zones to help determine the wind forces that are exerted on structures. These designs account for the wind forces that may impact these structures as well as the wind forces that may impact the supported facilities or equipment attached to those structures, including the pole, transformers, conductors, and other components.

The Company will use multiple design and materials combinations to meet the applicable wind loading standards. The design of a structure is rooted in the loading requirements for that particular structure, which requirements drive the components and materials that are used. Accordingly, each distribution and transmission asset or structure is designed for the specific wind zone and its location using a number of design choices, including, but not limited to, the class of pole, the material used for the pole or other attachment (*e.g.*, composite or concrete poles or fiberglass cross arms), and the configuration of cross arms or insulators. Additionally, to help meet the wind loading requirements, other supporting applications such as storm guying may be used.

Q34. TURNING BACK TO THE METHODOLOGY USED TO DEVELOP THE COMPREHENSIVE HARDENING PLAN, YOU STATED THAT THE SRM USED A FOUR-STEP PROCESS. CAN YOU GIVE AN OVERVIEW OF THAT PROCESS?

A. Yes. *First,* the SRM starts with a universe of major storm events that could impact ELL's service area, called the "Major Storm Event Database," from which 49 unique storm types were identified. *Second*, a "Storm Impact Model" estimates the restoration costs and durations of outages following each of the 49 storm types under (i) the current condition of the Company's assets and (ii) the assumed conditions of those assets if hardened pursuant to the proposed program alternatives. The Storm Impact Model compares the restoration costs and the duration of outages from both sets of circumstances to determine a "benefit" for completing each project. *Third*, a "Resilience Benefit Module" employs stochastic modeling to determine a weighted benefit for each project over the next fifty years. And *fourth*, an investment optimization and project prioritization process is employed to determine an overall project list that is the most cost-beneficial for the Company and its customers. I discuss each step in more detail below, and this process is discussed more fully in Mr. De Stigter's direct testimony as well as in the Resilience Investment and Benefits Report prepared by 1898 & Co that is attached as an exhibit to Mr. De Stigter's testimony.

Q35. YOU ALSO MENTIONED THAT THE SRM EMPLOYS A "DATA-DRIVEN" METHODOLOGY. WHAT CORE DATA SETS WERE USED IN THE SRM?

A. As discussed by Mr. De Stigter, the SRM uses a number of data sets composed of Company information, including (i) the Company's Geographic Information System

("GIS"), which provides a list of the Company's assets and how they are connected; (ii) the Company's Outage Management System, which provides detailed outage information cause codes for the Company's protection devices over the last 22 years; (iii) customer type data; (iv) a vegetation density algorithm, which was used for identifying and prioritizing resilience investment for the circuit assets; (v) wind loading designs of the Company's distribution and transmission structures; (vi) the actual or estimated age and condition of each wood pole, metal structure, overhead primary, and transmission conductor; (vii) accessibility data for the Company's assets (*i.e.*, whether the asset is available via roadside access versus deep within rights-of-way); and (viii) terrain data.

The SRM also utilizes specific data sets to understand the impacts to substations and transmission assets. *First,* with respect to substations, a detailed analysis of the impacts of storm surge is performed using the SLOSH model to evaluate the potential failure of ELL's substations as a result of storm surge and associated flooding.[11] The SLOSH model results are overlaid with the location of ELL's substations to determine which substations have a risk of flooding depending on the hurricane category. *Second*, due to the complex interconnected nature of the transmission system, 1898 & Co. and the Company developed a transmission outage framework based on historical performance of the transmission system in major storm events and the known redundancies of the transmission system. This framework outlines the customer impact if a given line or a

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[11] The SLOSH models perform simulations to estimate surge heights above ground elevation for various storm types. The simulations are based on historical, hypothetical, and predicted hurricanes. The model uses a set of physics equations applied to the specific location shoreline, incorporating the unique bay and river configurations, water depths, bridges, roads, levees, and other physical features to establish surge height. These results are simulated several thousand times to develop the Maximum of the Maximum Envelope of Water, the worst-case scenario for each storm category.

combination of lines fails. Seven specific scenarios were modeled to capture the potentially catastrophic risk to the transmission system that major storms can cause.

Q36. DOES ANY OTHER WITNESS DISCUSS THE SRM?

A. Yes, as I have mentioned, Mr. De Stigter discusses the SRM and the analysis conducted by 1898 & Co. in more detail in his testimony and in the report prepared by 1898 & Co., which is attached to Mr. De Stigter's testimony. However, I have attempted to describe the SRM at a high level in my testimony to address certain points helpful to understanding how projects were selected for the Comprehensive Hardening Plan and how the costs and estimated benefits of those projects were determined.

A. <u>Major Storm Event Database</u>

Q37. PLEASE BRIEFLY EXPLAIN THE MAJOR STORM EVENT DATABASE AND HOW IT WAS USED IN THE SRM.

A. The Major Storm Event Database utilizes information drawn from the National Oceanic and Atmospheric Administration ("NOAA") database of major storm events, available information on the impact of major storms to other utilities, and the Company's experience with storms and storm recovery. The "universe" of information comprising the Major Storm Event Database included information regarding the major storms that have impacted ELL's service area over the last 170 years. This historical information was used to identify 49 unique storm types based on varying combinations of storm category, storm distance, and storm side (*i.e.*, weak side or strong side). Additionally, the future storm probabilities were developed for each of the different types of storms. Finally, for each storm type, the Major Storm Event Database also contained information regarding the potential impacts of the storm type, expressed in terms of the duration of outages, system percentage impacted, and storm costs.

Q38. DOES THE MAJOR STORM EVENT DATABASE INCORPORATE ANY ASSUMPTIONS ABOUT THE FREQUENCY OR INTENSITY OF FUTURE STORMS?

A. Yes, the SRM accounts for the increasing storm frequency and intensity seen in recent years in developing the future probabilities of each of the future storm types. The model uses the last thirty periods of 100 years (*i.e.,* 1922-2021, 1921-2020, 1920-2019, etc.) to predict the likelihood of future storms. If the thirty periods of 100 years were equally weighted, storms occurring during the middle years of the study period would more strongly influence future storm probabilities because they are captured in more of the individual 100-year periods the model uses. To correct for this effect and account for the increasing storm severity and restoration costs experienced in more recent storm seasons, the model weights the most recent years more heavily.

B. <u>Storm Impact Model</u>

Q39. PLEASE EXPLAIN THE STORM IMPACT MODEL FURTHER.

A. The Storm Impact Model identifies, from a weighted perspective, the particular laterals, feeders, transmission lines, access sites, and substations that are damaged to the point of requiring repair and/or replacement for each type of storm in the Major Storm Event Database. The Storm Impact Model also estimates the restoration costs associated with the sub-system failures and calculates the impact to customers in terms of CMI. Finally, the Storm Impact Model models each storm event for both the "Status Quo" and "Hardened" scenario. The Hardened scenario assumes that the assets that make up each project have been hardened in accordance with the program alternatives I discussed above. The Storm Impact Model then calculates the resilience benefit of each hardening project from a reduced restoration cost, CMI, and monetized CMI perspective.

Q40. HOW DOES THE STORM IMPACT MODEL IDENTIFY THE ASSETS THAT ARE LIKELY TO FAIL DURING MAJOR STORM EVENTS?

A. The Storm Impact Model identifies the portions of the system that are likely to be damaged to the point of needing repair and/or replacement by modeling the elements that cause failures in the Company's assets. To do so, the "Likelihood of Failure," as modeled in the Storm Impact Model, assumes that a storm has impacted a project (*i.e.* a set of assets) and caused an outage. The model does not choose specific structures or assets for failure, but rather assigns a weighted likelihood of failure in every storm for every project. The likelihood of that project failing, among all the possible projects, is based on the collective attributes of the assets (poles, structures, wires, control houses, etc.) inside that project. The calculation of the Likelihood of Failure score for a project is based on a vegetation rating, an age and condition rating, and a wind zone rating for each asset inside each project. The vegetation rating factor is based on the vegetation density around the conductor. The higher the vegetation density, the greater the probability of failure. The age and condition rating utilizes expected remaining life curves with the asset's "effective" age, determined using condition data. The less remaining life an asset has, the higher the probability of failure. The wind zone rating is based on the actual wind rating of the asset as compared to the wind zone that the asset is located within; the larger the differential between the wind rating of the asset and the wind zone in which it sits, the greater the probability of failure.

Q41. HOW DOES THE STORM IMPACT MODEL DETERMINE THE COST OF RESTORATION FOLLOWING EACH STORM EVENT?

A. The Storm Impact Model calculates the restoration costs for every asset (including poles, overheard primary, transmission structures, transmission conductors, power transformers, and breakers) required to rebuild the system to provide service. The costs were based on estimated replacement costs plus storm restoration cost multipliers.

Furthermore, the storm impact model uses this cost information and the Likelihood of Failure to determine which projects will incur costs, as well as the extent of those costs, as a result of a given type of storm. This produces a Status Quo restoration cost to represent a world without the project being hardened. The hardened restoration cost of a project is calculated by taking the Status Quo restoration cost and reducing it based on an improved strength and reduced likelihood of failure due to hardening. As mentioned, the restoration cost benefit is calculated as the difference between Status Quo restoration cost and Hardened restoration cost.

Q42. PLEASE EXPLAIN WHAT YOU MEAN WHEN YOU SAY THAT RESTORATION COSTS WERE BASED ON STORM RESTORATION COST MULTIPLIERS.

A. As I mentioned above, and as discussed more fully in Mr. Long's direct testimony, replacing assets following major weather events is much costlier than replacing assets during "blue-sky" hours through planned replacement. This is true for restoration work performed by the Company's crews as well as restoration work performed by mutual assistance, non-Entergy crews. Accordingly, to approximate the additional cost it would take to repair or rebuild assets that were damaged during a major weather event, the Company and 1898 & Co. worked collaboratively to develop cost multipliers based on prior storm experiences, the expected inventory constraints, and the expected mix of Company and non-Company crews needed for the various asset types and storms.

Based on that collaborative analysis, the cost multipliers used to determine restoration costs were developed. With respect to the Company's crews, it was determined that the costs to restore infrastructure following storm events can be 1.5 to 2.0 times higher than infrastructure replacements during "blue-sky" rebuilds as a result of factors such as overtime fees, inefficiencies, and rework risks. For major weather events, the Company relies on mutual assistance to restore the system with non-Company crews from across the nation. Given costs and challenges associated with the per-diems, overtime rules, mobilization and demobilization, and managing outside resources, the costs of restoration work performed by those workers can be even higher.

Q43. HOW DOES THE MODEL ESTIMATE THE CUSTOMER MINUTES INTERRUPTED FOR EACH STORM EVENT?

A. The Storm Impact Model calculates the CMI by assets/project for each storm scenario. Since projects are organized by protection device, the customer counts and customer types are known for each asset in the Storm Impact Model. The time it will take to restore each protection device, or project, is calculated based on the expected storm duration and the hierarchy of restoration activities. This restoration time is then multiplied by the known customer count to calculate the total CMI.

Q44. YOU MENTIONED THAT A RESILIENCE BENEFIT WAS CALCULATED FOR EACH PROJECT BY MAJOR STORM EVENT. PLEASE EXPLAIN HOW THAT RESILIENCE BENEFIT WAS CALCULATED.

A. The resilience benefit for each project is determined by calculating the difference between the Status Quo and the Hardened Scenarios. Accordingly, the restoration cost benefit is calculated as the difference between Status Quo restoration cost and Hardened restoration cost. Similarly, the CMI benefit is calculated as the difference between the Status Quo CMI and Hardened CMI. These benefits are discussed more fully in the Resilience Investment and Benefits Report attached to Mr. De Stigter's testimony.

Q45. IS IT IMPORTANT TO CONSIDER BOTH RESTORATION COSTS AND CMI IN EVALUATING THE RESILIENCE BENEFIT?

A. Yes. Determining the value and potential benefits of any storm hardening effort is a complex task, and it requires more than a simple objective evaluation of the possibly avoided restoration costs. As I mentioned earlier and as discussed in Mr. May's testimony, the communities served by the Company are increasingly dependent on electricity and expect a more resilient system. It follows, therefore, that the qualitative benefits of any resilience effort (*i.e.*, the benefits to customers that come from having an electric system that is better able to withstand and timely recover from major weather events) must also be considered. Company Witness Jay Lewis further discusses the value of these benefits from the customer's perspective. As such, it is important to consider both the avoided restoration costs and the reduced CMI in determining the potential benefits of the proposed hardening projects.

Q46. WHY WERE CMI BENEFITS MONETIZED?

A. The CMI benefits were monetized for project prioritization purposes. The Storm Impact Model calculates each hardening project's CMI and restoration cost reduction for each storm scenario. In order to prioritize projects, a single prioritization metric is needed. Since CMI is in minutes and restoration costs are in dollars, the SRM monetizes CMI. The monetized CMI benefit is combined with the calculated restoration cost benefit for each project to calculate a total resilience benefit in dollars.

Q47. HOW WERE CMI BENEFITS MONETIZED?

A. CMI benefits were monetized using the U.S. Department of Energy's ("DOE") Interruption Cost Estimate ("ICE") Calculator.[12] This tool provides information that can

[12] This tool is designed for electric reliability planners at utilities, government organizations, or other entities that are interested in estimating interruption costs, typically for shorter duration outages, and/or benefits associated

be used to provide a rough approximation of the value placed on outages by electric customers, also known as the "Value of Service." The values in the tool are differentiated by customer type: residential, small commercial/industrial, and large commercial/industrial. For the SRM, 1898 & Co. used the DOE's ICE Calculator and extrapolated from it to account for the longer outage durations associated with storm outages. These estimates for outage cost for each customer are multiplied by the specific customer count and expected duration for each storm for each project to calculate the monetized CMI at the project level.

Q48. ARE THERE ANY LIMITATIONS ON USING THE U.S. DEPARTMENT OF ENERGY'S ICE CALCULATOR?

A. Yes. The DOE's ICE Calculator does not consider the all the factors that would be necessary to assess the causes and impacts of an outage to customers in specific circumstances, particularly during longer outages. Again, for project prioritization purposes, the SRM uses an extrapolation of the DOE's ICE Calculator to evaluate the societal impacts to customers on a general basis. But there is no industry standard method for valuing the costs of outages to a particular customer, and the value of an outage to any particular customer would be based on many individualized factors. Moreover, outages for a particular customer could depend on factors beyond the control of a utility (*e.g.,* damage to a customer's home or business). Accordingly, the Company's

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with reliability or resilience improvements in the United States. The DOE's ICE Calculator was funded by the Office of Electricity Delivery and Energy Reliability at the DOE. The DOE's ICE Calculator incudes the cost of an outage for different types of customers. Lawrence Berkeley National Laboratory & Nextant, Inc., ICE Calculator, U.S. Department of Energy's Office of Electricity, *available at* https://icecalculator.com/home.

use of the DOE's Ice Calculator to help prioritize projects within the Comprehensive Hardening Plan is not an endorsement of the DOE's Ice Calculator's ability to calculate accurately or effectively the economic impact of a particular outage on any particular customer.

C. Resilience Benefit Module

Q49. PLEASE EXPLAIN THE RESILIENCE BENEFIT MODULE.

A. The Resilience Benefit Module uses the benefit calculated from the Storm Impact Model and the estimated project costs to estimate the net benefits for each project over the next fifty years. To be clear, the benefits of these storm hardening projects are highly dependent on the frequency, intensity, and location of future major storm events. For this reason, stochastic modeling, or a Monte Carlo Simulation, is used to randomly trigger the types of storm events from the Major Storm Event Database that may impact the Company's service area over the next 50 years at various levels of storm frequency. Each project's CMI, monetized CMI, and restoration costs were calculated for the 49 storm types for each event triggered in the Monte Carlo Simulation for both the Status Quo and Hardened Scenarios over the 50-year time horizon. As mentioned above, the difference between the Status Quo and Hardened Scenarios is the benefit for that project for that storm event. The sum of the benefits for all 49 storm types for each iteration of the simulation equals the total benefits for the project. The CMI, monetized CMI, and restoration benefits are then weighted by the probability of the 49 storm types to calculate the weighted benefit. To calculate the net benefits, the project costs are determined.

Q50. WHAT ECONOMIC ASSUMPTIONS ARE MADE IN THE RESILIENCE BENEFIT MODULE?

A. The resilience net benefit calculation performed as part of the Resilience Benefit Module includes the following economic assumptions:

- 50-year time horizon – most of the hardening infrastructure will have an average service life of 50 or more years;
- 2.5 percent escalation rate; and
- 7.5 percent discount rate.

Q51. HOW WERE PROJECT COSTS DETERMINED FOR EACH OF THE PROPOSED HARDENING PROJECTS?

A. Project costs were estimated for the projects considered in the SRM. Some of the estimated project costs were provided by the Company, while others were estimated using the data within the SRM to estimate the scope of the project, including asset counts and line miles, that was then multiplied by unit cost estimates developed collaboratively by the Company and 1898 & Co. to calculate the project costs. As discussed more fully above, the Distribution Feeder Hardening (Rebuild) and Lateral Hardening (Rebuild) projects consist of replacing or rebuilding structures within a protection zone that do not meet the Company's current design standards, including replacing copper wire. The costs for distribution hardening rebuild projects are the aggregate costs for all of the structures and wire that are hardening candidates. Project costs generally were developed using the following steps:

1. A base cost per structure was determined;

2. The base cost was increased to account for multi-phase conductor requirements or foundation needs for higher wind rating areas;

3. Next, a conductor cost was added for each span of wire that will need to be replaced in the project;

4. Additional costs were added based on the number and size of transformers in the project, including labor and materials costs; and

5. Cost estimates for projects are further adjusted based on factors such as: amount of nearby vegetation based on tree canopy density; ability to access the equipment from the road; known terrain based on U.S. Fish & Wildlife Service Seamless Wetland data (marsh land); and population density.

Additionally, Transmission Rebuild projects consist of replacing structures within a substation-to-substation segment that do not meet the current wind rating for the area. These structures are hardening candidates. Generally, structure replacements on transmission will result in a steel mono-pole installation, and project costs are built to reflect this assumption. River crossing projects or other extenuating circumstances may result in adjusted project costs, but the transmission costs generally were developed using the following steps:

1. A base cost per mono-pole steel structure that includes insulators and attachments was determined;

2. The structure cost was increased to account for multi-circuit requirements or foundation needs for higher wind rating areas;

3. Next, a conductor cost per structure was added to account for reconductoring needs;

4. Cost estimates for projects are further adjusted based on factors such as: number of nearby trees based on tree canopy density; ability to access the equipment from the road (versus deep in the right-of-way); known terrain based on U.S. Fish & Wildlife Service Seamless Wetland data (marsh land); and population density.

With respect to the Distribution Feeder Undergrounding and Lateral Undergrounding projects, the Company's GIS data was used to determine the length of overhead conductor to be converted to underground for each project, and additional GIS analysis determined the population density. These factors were used to develop the cost per mile rate in rural, suburban, and urban areas.

The costs for the Substation Control House Remediation and the Substation Storm Surge Mitigation programs are dependent on a number of different factors. For the remediation factors, the costs are influenced by the condition of the roof, vintage, and its size. For the storm surge mitigation projects, the costs to mitigate the effects of storm surge for each substation can vary widely depending on the mitigation method employed. The Company developed generally conservative base costs for these projects that it and 1898 & Co. used in the SRM.

Finally, to be clear, these cost estimates for all of the projects within the Comprehensive Hardening Plan are based only on a high-level scoping of the projects. If the Comprehensive Hardening Plan is approved, these hardening candidates will be more fully evaluated to determine what assets in the identified projects need to be rebuilt or replaced, and the final costs for any particular project may need to be adjusted accordingly. As I discuss more fully below, the Company will keep the Commission informed regarding these adjustments.

Q52. WHAT ARE THE SPECIFIC OUTPUTS OF THE RESILIENCE BENEFIT MODULE?

A. The Resilience Benefit Module estimates the following for each project:

- CMI 50-Year Benefit;

- Restoration Cost 50-Year NPV Benefit (*i.e.,* avoided restoration costs);
- 50-Year NPV gross Benefit (monetized CMI benefit + restoration cost benefit); and
- 50 Year NPV net Benefit ([monetized CMI benefit + restoration cost benefit] – project costs).

D. Investment Optimization and Project Prioritization

Q53. PLEASE PROVIDE AN OVERVIEW OF THE PROJECT PRIORITIZATION AND INVESTMENT OPTIMIZATION PROCESS.

A. As part of the SRM, an optimized investment and project prioritization list is determined based on the highest ratio of resilience benefit to cost. Specifically, the model prioritizes each project using a benefit cost ratio based on the sum of the restoration cost benefit and monetized CMI benefit divided by the project cost. This calculation is performed for the range of potential benefit values to create the overall resilience benefit cost ratio. Using the benefit cost ratio as a guide, the Storm Resilience Model performs an investment optimization simulation to identify the point of diminishing returns for hardening investments for the 10-year period. Prioritizing and optimizing projects in this way is intended to ensure that the overall investment level is appropriate, and customers get the most cost-effective solutions, *i.e.*, "biggest bang for the buck."

Q54. IS THE COMPANY PROPOSING TO COMPLETE EVERY PROJECT WITH A POSITIVE BENEFIT COST RATIO?

A. No, the Company is not proposing to complete every project with a positive benefit cost ratio, much less proposing to harden every asset in the Company's distribution and transmission systems. While additional projects could be completed that would provide value to customers, the Company has considered other factors, including the potential bill impact to customers and supply chain limitations, to determine a final proposed investment level that the Company believes is achievable and will improve the resilience of the system. As discussed in Mr. May's testimony, however, the Company looks forward to working collaboratively with the Commission to determine the level of investment that best serves the public interest.

Q55. HOW WERE THE HARDENING PROJECTS PRIORITIZED IN THE SRM?

A. Because all projects in the SRM were evaluated on a consistent basis, they can all be ranked against each other and compared. The SRM ranks all the projects based on their benefit cost ratio using the life cycle 50-year PV gross benefit value. The ranking is performed for an average storm future, a high storm future, an extreme storm future, as well as an additional weighted value (based on the average, high, and extreme storm futures). Performing prioritization for the four benefit cost ratios (*i.e.* the average, high, extreme, and weighted) is important since each project has a different slope in its benefits from an average storm future to an extreme storm future. For example, many of the lateral rebuild projects have the same benefit in an average storm future as they do in an extreme storm future. Alternatively, many of the transmission asset hardening projects are minorly beneficial in an average storm future but have significant benefits in a high storm future and even more in an extreme storm future. To account for these differences and an expectation of an above average storm future, the Company and 1898 & Co. settled on using the weighted value for the base prioritization metric.

Q56. DID THE COMPANY HAVE FINAL CONTROL OVER THE LIST OF PROPOSED PROJECTS?

A. Yes. While the investment optimization and project prioritization performed as part of the SRM served as a useful guide, the Company applied its own operational experience and judgment in determining which projects to propose as part of the Comprehensive Hardening Plan and how those projects ultimately should be scheduled.

E. Overview of Proposed Projects and Estimated Benefits

Q57. WHAT PROJECTS WERE IDENTIFIED FOR INCLUSION IN THE COMPREHENSIVE HARDENING PLAN AS A RESULT OF THE SRM?

A. Based on the results of the Storm Resilience Model, the Company proposes to undertake roughly 9,569 hardening projects across its transmission and distribution systems and 41 projects at substations across its service area. These projects are listed in the attached HSPM Exhibit SM-2. Furthermore, based on the project costs, which were determined as explained above, the Company estimates that the cost of performing these projects over the next ten years will be approximately $9 billion.[13] Distribution Feeder Hardening

[13] The projects proposed and the years in which costs are expected to be incurred are based on the results of the investment optimization and prioritization process discussed above. While the Company's proposed plan sets

(Rebuild) accounts for 48 percent of the total cost of the Comprehensive Hardening Plan; Lateral Hardening (Rebuild) accounts for 27 percent; Transmission Rebuild accounts for 18 percent; Lateral Undergrounding accounts for 5 percent; and, Distribution Feeder Undergrounding, Substation Control House Remediation, and Substation Storm Surge Mitigation account for the final 2 percent.

More specifically, of the 5,806 project candidates evaluated for the Distribution Feeder Hardening (Rebuild) and Distribution Feeder Undergrounding, the SRM identified 2,250 hardening projects and 7 overhead to underground projects that provide benefits and fall within the optimized budget, at an estimated nominal cost of $4.22 billion and $39.40 million, respectively. Additionally, of the 77,745 project candidates evaluated for the Lateral Hardening (Rebuild) and the Lateral Undergrounding, the SRM identified 6,384 rebuild projects and 723 overhead to underground projects that provide benefits and fall within the optimized budget, at an estimated nominal cost of $2.45 billion and $432.66 million, respectively.

The SRM also identified 205 transmission rebuild projects that provide benefits and fall within the optimized budget, at an estimated nominal cost of $1.54 billion. For example, one project is on the Raceland to Coteau 230 kV line, which involves strengthening or replacing 127 structures along approximately 12 line-miles. That project is expected to cost approximately $50.47 million.

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forth the Company's best efforts to identify the scope, cost, and timing of these projects, the precise work performed will be subject to continual refinement as the Company implements the plan following approval. As I discuss below, the Company will keep the LPSC informed of material changes.

Finally, the SRM identified 25 projects for the Substation Control House Remediation program and 16 projects for the Substation Storm Surge Mitigation that provide benefits and fall within the optimized budget, at estimated nominal costs of $12.20 million and $160.10 million, respectively.

Q58. DO YOU HAVE ANY OBSERVATIONS ON THE NUMBER OF UNDERGROUNDING PROJECTS SELECTED FOR INCLUSION IN THE COMPREHENSIVE HARDENING PLAN?

A. Yes. As I noted above, and as discussed more completely by Mr. Long, the cost of converting existing overhead distribution lines to underground is significant, and the potential resilience benefits considered by the SRM (*i.e.*, the potential reduction in restoration costs and avoided CMI following major events) did not justify the selection of many undergrounding projects. In other words, generally speaking, the increased cost of undergrounding existing overhead distribution lines was typically higher than the benefits that undergrounding those segments would provide.

To be sure, the Company is recommending undergrounding projects where the resilience benefits as evaluated by the SRM support undertaking those costs. This targeted approach (as compared to a complete undergrounding of the Company's existing overhead distribution system) is consistent with the Company's historical undergrounding strategy as well as the Commission Staff's previously-expressed position that "a state-wide mandate for underground retrofit should not be enacted[.]"[14]

Finally, I note that prioritizing the undergrounding of existing distribution lines to a level above that indicated in the SRM could have limited the Comprehensive Hardening Plan's impact on overall system resilience. Given the increased costs of undergrounding, the amount of rebuild hardening projects that could be selected would decrease as more undergrounding projects are selected (barring a drastic budget increase). By selecting only those undergrounding projects that were supported by the resilience benefits, the Company was able to incorporate more rebuild hardening projects in the Comprehensive Hardening Plan, thereby hardening larger portions of the overall distribution system and providing the direct benefits of a resilient system to more customers.

Q59. WHAT ARE THE ESTIMATED BENEFITS OF COMPLETING THOSE PROJECTS?

A. The completion of the hardening projects contained in the Comprehensive Hardening Plan is expected to benefit ELL's customers by creating distribution and transmission systems that are more resilient in the face of increasingly severe weather. While no amount of investment or hardening will completely eliminate outages or restoration costs caused by future storms, the identified projects are expected to decrease storm restoration costs, the number of customers impacted by outages from future storms, and the overall duration of outages over the next 50 years. Based on the SRM, the identified projects are

[14] *See,* Staff's Report (January 28, 2009), *In re: Identification and Evaluation of Potential Methods to Decrease the Vulnerability of Electric Utility Distribution Infrastructure in Response to Severe Weather Events, Docket No. R-30821*

reasonably projected to produce a reduction in storm restoration costs of approximately 50 percent. In relation to the plan's capital spending, the amount of the restoration costs savings (expressed in 2022 dollars), ranges from 37 to 54 percent of the total plan cost (in 2022 dollars) depending on future storm frequency and impacts. In other words, the avoided restoration cost benefits alone pay for approximately 37 to 54 percent of the cost of the identified projects. Moreover, the identified projects are reasonably projected to produce a decrease in the projected customer minutes interrupted after a major storm by approximately 55 percent over the next 50 years.

More specifically, based on the SRM, assuming each hardening project is performed, which together total approximately $9 billion in costs, the model projects that the Company and customers will see benefits of approximately $2.9 billion to $4.2 billion in avoided restoration costs and 60.1 billion to 87.55 billion minutes in avoided CMI following major weather events over the next fifty years depending on the frequency of storms.

These estimated benefits are discussed more fully in the direct testimony of Mr. De Stigter and in the Resilience Investment and Benefits Report prepared by 1898 & Co and attached to Mr. De Stigter's testimony.

V. ADDITIONAL RESILIENCE PROJECTS

Q60. IN ADDITION TO THE COMPREHENSIVE HARDENING PLAN, IS THE COMPANY PROPOSING OTHER PROJECTS?

A. Yes. As I mentioned previously, there are three other program components that are a part of the Company's Resilience Plan. Specifically, those programs include the dead-end structure projects, the telecommunications hardening projects, and resilience-based enhancements to the Company's vegetation management practices. Additionally, while not presently a part of the Resilience Plan, the Company has identified ten NWAs for consideration.

Q61. WHY WERE THESE OTHER PROJECTS NOT INCLUDED AS PART OF THE COMPREHENSIVE HARDENING PLAN?

A. The Comprehensive Hardening Plan was designed and evaluated with a particular focus on hardening identified, existing distribution and transmission assets as well as substations. The proposed hardening projects establish a necessary, resilient foundation for improving overall system resilience. However, as I discussed above, the Company's evaluation of how to improve system resilience was holistic and identified other opportunities for improvement. These additional programs and proposals were identified by the Company as achievable, potentially cost-effective avenues for adding needed resilience to the Company's electric system.

A. Dead-End Structure Projects

Q62. PLEASE DESCRIBE THE DEAD-END STRUCTURE PROJECTS.

A. In addition to the Comprehensive Hardening Plan and the transmission projects included therein, the Company has identified six 500 kV transmission lines on which the Company proposes to install 44 additional dead-end structures. These six lines were selected to shore up the resilience of the transmission interconnections along the Gulf Coast Region from the Louisiana load centers (Baton Rouge and New Orleans) across the Atchafalaya basin into Texas. These structures will help improve the ability of these transmission lines to withstand the effects of major weather events by limiting cascading damage to transmission structures.

Q63. HOW DO DEAD-END STRUCTURES IMPROVE RESILIENCE?

A. Dead-end structures within a transmission line, an example of which is pictured below, add support to the line by mitigating the destructive force of a downed conductor through the use of horizontal strain insulators at the end of the conductor segments that meet at a structure, with the conductors connected by a jumper between the two segments. Because of this design, dead-end structures are helpful tools to prevent cascading failures. Cascading failures occur when one structure collapses and, thereafter, increases the forces/strain on the adjacent or subsequent structures, giving rise to multiple tower-structure collapses. Dead-end structures act as break points to help prevent additional tower-structure collapses. Accordingly, transmission lines with the strategic placement of dead-end structures are more resilient because they are better protected against cascading failures that can result from severe weather.

Figure 4
Dead End Structures

Q64. WHAT IS THE ESTIMATED COST OF THOSE PROJECTS?

A. The total estimated cost for completing the dead-end structure projects is $88 million. As I mentioned above, the Company has identified six transmissions lines on which to place these structures, spanning approximately 176 line miles. The breakdown of those costs by the particular transmission lines is set forth in the attached HSPM Exhibit SM-5.

Q65. WHAT IS THE TIME FRAME FOR COMPLETING THOSE PROJECTS?

A. These projects are expected to be completed within Phase I of the Resilience Plan, *i.e.*, within the first five years.

B. Telecommunications Projects

Q66. PLEASE DESCRIBE THE TELECOMMUNICATIONS PORTION OF THE RESILIENCE PLAN.

A. The Company is proposing two sets of telecommunications projects. *First,* the Company performed an evaluation of serial-based RTUs to select for potential upgrade to IP-based RTUs, which can take advantage of multiple routing paths as compared to serial-based RTUs that rely on primary and secondary communication paths. These evaluations occurred at select facilities, with priority being given to nuclear facilities and their off-site voltage paths; substations listed in the Entergy Disaster Recovery Plan; black-start resources; generators key to hurricane response; and substations in South Louisiana that are important for the Company's hurricane response. Based on that analysis, the Company identified RTUs in ELL's service area for upgrade. These upgraded RTUs require an initial capital investment, an ongoing capital hardware refresh program, and incremental O&M support costs. *Second*, the Company is proposing to replace 198 miles of overhead ADSS fiber on distribution lines over a five-year period with underground fiber cable.

Q67. HOW DO THESE INVESTMENTS IN THE COMPANY'S TELECOMMUNICATIONS ASSETS IMPROVE RESILIENCE?

A. The Company uses its telecommunications system to convey asset status and provide remote control of those assets from a control center. Field data is gathered by an RTU and transmitted to the supervisory control and data acquisition ("SCADA") systems located at control centers through combined uses of fiber optic cable and transport electronics, microwave communications systems, and connections provided by third-party communications companies. Control center operators can remotely control breakers and switches through these same devices. RTUs also convey information that allows an operator to determine where a fault has occurred so that field crews can be dispatched efficiently to the fault location for quick recovery. Without this field information, adapting to and recovering from disruptions can be more challenging. During extreme weather events that cover a wide area, the Company uses the functionality of the RTUs and their communication paths, but those communication paths are vulnerable to the same effects of extreme weather as transmission and distribution systems, which can delay power restoration. These risks are expected to be mitigated by upgrading to IP-based RTUs, which allow for the use of multiple communication paths in times of need. Additionally, undergrounding ADSS fiber will improve overall resilience by ensuring that these lines of communications are better able to withstand the conditions created by major weather events. As such, hardening of the Company's telecommunication assets is an integral part of the Company's plan to improve resilience.

Q68. WHAT ARE THE ESTIMATED COSTS OF THOSE PROJECTS?

A. These projects will involve approximately $108 million in capital spending and $12 million in incremental operation and maintenance costs. The portion of projects to be completed in Phase I will involve approximately $97.2 million in capital spending and $2.8 million in incremental operation and maintenance costs.

Q69. WHAT IS THE TIME FRAME FOR COMPLETING THOSE PROJECTS?

A. The proposed upgrading of the selected serial-based RTUs to IP-based RTUs and the undergrounding of ADSS fiber cable is expected to be completed in Phase I. The required hardware refresh program for RTUs is expected to be completed in Phase II.

C. Vegetation Management

Q70. PLEASE DISCUSS THE COMPANY'S PROPOSED FUNDING INCREASE FOR VEGETATION MANAGEMENT AND RIGHT OF WAY MANAGEMENT.

A. The Company is proposing an enhancement of its current vegetation management program to accelerate trim cycles and to implement additional program elements. Specifically, on the distribution system, the Company is proposing to (i) reduce its trim cycle to five years; (ii) implement mid-cycle herbicide treatments; (iii) implement a backbone "skylining" project; (iv) implement additional programs to target poor performing species of trees and hazard trees (including work performed OROW); and (v) increase reactive trimming efforts. On the transmission system, the Company is proposing to increase its OROW work and implement air-saw trimming of vegetation along transmission lines.

Q71. IS THE PROPOSED VEGETATION MANAGEMENT PLAN BEING OFFERED BECAUSE THE COMPANY'S CURRENT VEGETATION MANAGEMENT PRACTICES ARE INADEQUATE?

A. No. The Company's current vegetation management practices are reasonable and help the Company provide its customers with safe, reliable power at the lowest reasonable cost. The programs and enhancements to current practices that are being proposed in this filing were identified as opportunities to further improve system resilience in the face of major weather events rather than address any inadequacies or gaps in the Company's current practices.

Q72. CAN YOU PROVIDE MORE DETAIL ABOUT THE RESILIENCE-FOCUSED VEGETATION MANAGEMENT PRACTICES THE COMPANY IS PROPOSING?

A. Yes. On the distribution system, the Company is proposing a number of resilience-focused efforts. *First*, the Company is proposing an increase in its current funding of its cycle-trim program by $17.63 million over the next ten years ($8.27 million during Phase I) to reduce the trim cycle to a five-year cycle, or approximately 5,600 miles annually. The Company will also incrementally increase its reactive-trim budget by $21.6 million over the next ten years ($13.2 million during Phase I).

Second, the Company is proposing to double its current herbicide budget to allow for mid-cycle herbicide applications. This herbicide program is a staple of the Company's preventative maintenance program and helps control vegetation that grows on the ground of the Company's right-of-way along distribution lines. It is the Company's expectation that these mid-cycle applications will improve resilience by improving visibility of, access to, and safety along distribution lines. The Company estimates that this effort will cost $12.2 million over the next ten years ($6.1 million during Phase I).

Third, the Company is proposing to "skyline" approximately twenty percent of its backbone trunk line miles (*i.e.,* the main circuits that run from a substation to a fault-isolating device) in Louisiana each year. "Skylining" refers to the removal of all overhanging limbs above identified areas on our feeder circuits. In many cases, the removal of skyline limbs requires advanced coordination with and approval by the affected landowner. The Company estimates that it will take approximately five years to complete the backbone skyline project. After the Company has completed the backbone skyline project, the Company will continue to perform maintenance required to maintain the skylining on the backbone trunk line miles. The Company will then move to skylining additional critical devices and other areas with repeated outages. The Company estimates that this skylining effort and follow-up maintenance will cost approximately $82.47 million over the next ten years ($38.22. million during Phase I).

Fourth, the Company is proposing to increase funding to remove hazard trees and poor performing species of trees. Annually, the Company identifies between 10,000 and 20,000 hazard trees for removal, but can only remove twenty-five to fifty percent of identified hazard trees each year based on current funding levels.[15] The Company expects that by increasing its funding to remove hazard trees, the Company will be able to remove nearly all identified hazard trees, thereby reducing the potential for damage caused by these trees during major weather events. Additionally, the Company is proposing to engage in a program targeting the removal of poor performing species of trees. For example, the Company believes that removing water oak trees, which are prone to rot and dieback, from urban areas with high customer counts will help improve system resilience. Trees located in urban areas have a shorter lifespan due to the stress associated

[15] Hazard trees are dead and diseased trees outside of a utility's right-of-way that have the potential to fall into utility lines or structures.

with pollution, restricted root zones, and poor and compacted soil. Those trees are more susceptible to damage during severe weather as a result of deteriorating tree health and root systems. In the Company's view, eliminating those threats before major storms will improve the overall resilience of the system. The Company is proposing to increase funding for these activities by $85.77 million over the next ten years ($40.19 million during Phase I).

Finally, in order to effectively perform this additional work, the Company proposes an additional $17.7 million over ten years ($8.2 million during Phase I) in overhead funding and to hire additional contract foresters, who will be utilized to oversee crews on the proposed projects, negotiate removals with landowners, and carry out other necessary tasks to implement these projects.

On the transmission system, the Company is proposing: (1) an additional $85.84 million to perform an OROW and Reclamation Project, which involves clearing vegetation both within and outside the ROW, over the next ten years ($37.71 million during Phase I); and (2) an additional $46.22 million in funding for use of an air-saw to trim approximately 300 miles of transmission line within the ROW annually over the next ten years ($20.31 million during Phase I). Currently, the Company maintains the ROW on an individual span-by-span basis guided by routine inspections of the system. These additional programs will allow the Company to expand those efforts to proactively maintain the full ROW along transmission lines. This proactive, cycle-based effort along transmission lines would improve resilience by clearing away vegetation both inside the ROW and OROW that could interfere with transmission lines during a major storm or otherwise inhibit the pace of restoration efforts.

D. Non-Wire Alternatives

Q73. PLEASE DESCRIBE THE NON-WIRE ALTERNATIVES THE COMPANY IS OFFERING FOR CONSIDERATION.

A. In addition to the foregoing components, the Company has identified a number of potential investments in new generation options (*i.e.*, non-wire solutions) that could function as microgrids. The Company understands that there is interest in exploring the potential for microgrids in Louisiana, and ELL believes that any resilience-focused plan should consider the use of microgrid generation resources. To that end, ELL has performed a planning-level analysis and has identified projects herein for the Commission's consideration, subject to further development and discussion, that could serve as alternatives to certain transmission projects in the Comprehensive Hardening Plan. The full list of proposed microgrids is attached hereto as HSPM Exhibit SM-6. The following NWAs identified in HSPM Exhibit SM-6 were identified in coordination with the transmission and distribution hardening effort and were selected on the basis of providing a resilient source of power to critical loads that are served on distribution feeders connected to substations in the Company's service area. The proposed microgrids would provide a decentralized and local source of generation for a defined area following a major storm.

To be clear, at this time, the Company has completed only a planning-level evaluation of microgrids to enhance resilience and is presenting these various microgrid options for consideration and discussion. As the Commission and parties consider such alternatives, it is important to understand that the use of microgrids as a tool and a strategy to enhance resilience is novel. Because of its novelty, deploying this technology as a resilience tool involves inherent risk, and it will be important to evaluate the technology carefully before proceeding.

Q74. WHAT IS A MICROGRID?

A. Although there are various definitions of what constitutes a "microgrid," generally speaking, a microgrid consists of localized, distribution-scale resources and/or storage integrated by a controller that can island the targeted load and continue serving customers in response to an outage event or, in certain instances, can respond to market conditions and enhance reliability during times of peak usage. In other words, microgrids, or NWAs, are able to provide a local source of power that can swiftly restore power to a substation, to the feeders that are connected to a substation, or to certain critical loads on the Company's distribution system.

Today, most microgrids are associated with providing enhanced resilience to a single entity (*e.g.*, a hospital or a campus that has the capability to be islanded and stay in operation during an outage). However, as is discussed by Mr. May, there are also instances in the United States of microgrids that serve a broader area involving multiple electricity consumers. One obvious benefit to constructing a microgrid that serves a broader area (*i.e.*, an entire substation, feeder, or lateral), as opposed to a single customer, is that the wider coverage brings incremental resilience to more customers who are contributing to its costs. But whether a microgrid is suitable for a broader area and a particular resilience application depends on a variety of factors, including the availability of suitable land and right of way, access to natural gas sources or pipelines, and the specific goals of the resilience solution.

Q75. HOW DO MICROGRIDS OR NWAS HELP IMPROVE RESILIENCE?

A. As I mentioned previously, system resilience is the ability to prepare for, adapt to, and recover from non-normal events. While these solutions do not prevent damage during a weather event, microgrids and other NWAs can improve resilience by helping modernize the Company's system and providing an alternative source to rapidly recover and help restore electric service when outages occur during major events. The distributed and de-centralized nature of the NWAs, especially when incorporated into the Company's larger resilience plan, allows for an alternative, localized means of restoring power quickly after a disruptive event if the transmission or/and distribution systems are damaged and not immediately available.

However, in considering the value NWAs could bring to improving system resilience, it is important to remember that the microgrid, the communication and switching devices, and the local source of power must all be capable of surviving major storms or other disruptive events such that they are capable of operating immediately and safely after that event. Furthermore, the distribution system connecting the various parts of the microgrid together, including the local power source and the customers served by the microgrid, also must be hardened such that it is capable of surviving the disruptive weather event. Accordingly, hardening the identified distribution and transmission assets as part of the Comprehensive Hardening Plan plays a critical role in implementing any NWAs, and, in order to take full advantage of these newer technologies, any investment in those technologies must be made hand-in-hand with an investment in hardening the Company's distribution and transmission systems. In this way, the proposed investments in hardening distribution and transmission assets further benefit ELL's customers by establishing a necessary, resilient framework and foundation for new and emerging technologies.

Q76. WHAT NWAS DID THE COMPANY CONSIDER?

A. The Company considered a variety of NWAs, or microgrids, in developing the set of NWAS presented in this filing. The different microgrid options considered by the Company include: dispatchable natural-gas generator microgrids; bulk energy storage system ("BESS") anchored microgrids; hybrid natural-gas generator and BESS-anchored microgrids; and microgrids anchored by photovoltaic panels coupled with a BESS. The Company also considered the role of decentralized and distributed energy resources. Ultimately, the Company determined that dispatchable natural-gas generators were the most cost effective and practical solutions to providing a storm-resilient generation source following a major storm considering the costs to construct the microgrids and the ability of the microgrids to provide power reliably following a major weather event.

Q77. PLEASE PROVIDE AN EXAMPLE OF ONE OF THE NWAS THAT THE COMPANY IS OFFERING FOR CONSIDERATION.

A. One NWA that the Company is evaluating is the Kentwood Microgrid. This microgrid would provide a storm hardened local power source to serve all of the approximately 2,600 customers served by distribution feeders connected to the Kentwood 115 kV substation, including about 30 industrial customers, about 70 governmental customers, about 300 commercial customers, and about 2,200 residential customers. This resilience microgrid project involves the installation of a 17.5 MW natural gas fired generator to provide power to customers served by this substation, should the power source from the transmission system to the substation be disrupted. In addition to the generator, the microgrid would require a microgrid controller that would allow the microgrid to operate autonomously. So long as the natural gas supply can be maintained after a significant outage event, the microgrid is designed to provide power to the microgrid for the full duration of the outage. Under normal "blue-sky" conditions, the Kentwood Microgrid's generator is designed to participate in the wholesale energy, capacity, and ancillary services markets, thus benefiting all customers.

Q78. DO THE NWAS COST LESS THAN THE TRANSMISSION HARDENING PROJECTS THEY WOULD REPLACE?

A. No. While the transmission solutions may be more cost effective than the proposed microgrids, the Company believes that the microgrids, as decentralized sources of local power generation, may provide resilience benefits that are different from (and potentially more desirable than) those provided by the transmission solutions. To that end, the Company looks forward to working with the Commission and the parties to further evaluate these (and any other) microgrid options, consider their potential resilience benefits, and determine what solutions should be pursued in ELL's overall resilience strategy.

VI. PROJECT MANAGEMENT AND CONTRACTING APPROACH

Q79. HOW WILL THE COMPANY MANAGE THE RESILIENCE PLAN?

A. Given the magnitude of the Resilience Plan and the Company's existing organizational framework for construction and project management in the Capital Projects organization, the Company plans to work with qualified contractors ("Alliance Partners") that will be retained in addition to the Company's management team. The Alliance Partners will be heavily relied upon for project execution and support; however, these Alliance Partners will not be utilized exclusively to execute the Resilience Plan, as the Company also plans to leverage existing contract partners and internal resources. Additionally, the Company will maintain appropriate project controls in the areas of project safety, cost, and schedule. The Company will also employ the necessary administrative and technical resources to ensure that project design, quality, and material deliverables are met in accordance with the Company's specifications.

The project management approach will follow the Company's Project Delivery System ("PDS") Policy, Standards and Guidelines in support of driving consistency and certainty in project delivery outcomes. The PDS provides a framework to ensure the Company's business units consistently and effectively develop and implement capital projects. The PDS establishes a Stage Gate Process ("SGP") approach as a single and comprehensive framework for project development, planning, and execution. The SGP provides a roadmap of key deliverables and decisions that need to be sequentially completed to promote consistent, reliable, and high-quality project outcomes. Additionally, the SGP prescribes a continuous systematic evaluation of the project organization, scope, and maturity of project management deliverables that helps ensure projects are executed successfully. This occurs through a series of independent Gate Reviews/Assessment and Approvals.

Q80. WHY IS THE COMPANY USING ALLIANCE PARTNERS?

A. The Company is using Alliance Partners because the Company has determined that this approach is the best method for controlling costs and to consistently and reliably execute the large portfolio of projects contained in the Resilience Plan. After considering a number of different contracting strategies, including an "EPC" model, baseload contractors, and strategic sourcing, the alliance model emerged as the preferred contracting strategy for the Resilience Plan for a number of reasons. Leveraging existing framework structures with existing Alliance Partners provides the Company with early contractor engagement, allows the Company to secure constrained resources earlier, and helps the Company realize economies of scale in implementing a major undertaking such as the Resilience Plan. The efficiencies that can be realized using Alliance Partners help to reduce overall project costs. Using an alliance model will also allow the Company to streamline governance and oversight of the Alliance Partners executing the Resilience Plan through aligned key performance indicators ("KPI"). Additionally, the Company expects that using an alliance model will allow the Company to structure its agreements with Alliance Partners to capture cost efficiencies realized through continued engagement and lessons learned. As the Company executes the Resilience Plan, the Company will continue to evaluate the best contracting structure with Alliance Partners to cost effectively execute the plan.

Moreover, the Company currently engages a number of key contracting partners to execute a number of transmission, distribution, and generation projects, and these partners have capabilities to execute work across all/most of these areas. As the Company works to identify Alliance Partners for the Resilience Plan through a competitive bidding process, the Company also will evaluate the capabilities of any possible partners across the broader portfolio of the Company's projects. The Company would then be able to structure the Alliance Partnerships with execution/contracting flexibility to ensure that the right contract structure is utilized to execute the projects with the most effective partner not only within the Resilience Plan, but also across the entire portfolio of Company projects and programs.

Q81. HOW WILL THE COMPANY SELECT ALLIANCE PARTNERS FOR THE RESILIENCE PLAN?

A. As I just mentioned, the Company plans to use a best value evaluation through a competitive bidding process among the identified Alliance Partners to perform the work and, if needed, the Company will qualify additional partners to add capacity and execution capabilities. Let me explain. Using the list of hardening projects generated through the Company's work with 1898 & Co. and the additional resilience projects identified by the Company, the Company will develop a bid package to take to market. The Company will then evaluate bids, considering such factors as capacity to support regional portfolios; ramp-up and execution plans; safety and oversight programs; engineering and construction capabilities; commercial rates; efficiency gains and continuous improvement programs; subcontracting plans; and sustainability considerations. Upon completion of the sourcing effort, the Company expects to make award recommendations that will allow the Company and its Alliance Partners to support executing regional portfolios of work through long-term alliance agreements.

Q82. HAS THE COMPANY FINALIZED THE TERMS OF ITS ALLIANCE PARTNERSHIP AGREEMENTS AT THIS TIME?

A. No, the Company has not finalized the terms of the Alliance Partnerships for the Resilience Plan, and the final Alliance Partners for the Resilience Plan have not yet been identified.

VII. RISK MANAGEMENT, MITIGATION, AND OTHER CONSIDERATIONS

Q83. IS IT IMPORTANT TO HAVE PLANS IN PLACE TO MANAGE AND MITIGATE THE POTENTIAL RISKS ASSOCIATED WITH THE RESILIENCE PLAN?

A. Yes. The Resilience Plan represents a substantial investment, and it needs to be well managed. Good management includes proper consideration of the risks that can be reasonably foreseen and the development of a plan to reasonably manage and mitigate those risks. Good project management should not seek to eliminate all potential risks irrespective of the costs to do so, but instead should reasonably manage those risks considering the probability of occurrence, potential magnitude of impact, and cost to mitigate.

Q84. WHAT ARE SOME OF THE KEY RISKS TO IMPLEMENTING THE RESILIENCE PLAN AND HOW ARE THOSE RISKS BEING MANAGED?

A. There are a number of risks associated with an undertaking as large as the Resilience Plan. Key risks include acquiring and managing adequate labor resources; ensuring an adequate supply of materials and managing lead time to acquire those materials; the potential for wage inflation to affect estimated costs; and potential delays to project scoping and execution. The Company will actively manage these key risks, as well as other risks that emerge, through its oversight of the work being completed by its Alliance Partners through its project management system and PDS, which I discuss above.

Q85. YOU MENTIONED THAT HAVING AN ADEQUATE SUPPLY OF MATERIALS IS A RISK TO IMPLEMENTING THE RESILIENCE PLAN. WHAT IS THE COMPANY'S STRATEGY FOR SOURCING MATERIALS TO USE TO COMPLETE THE RESILIENCE PLAN?

A. To address this risk, the Company is currently engaged in strategic discussions with an existing third-party material integrator who is deeply experienced in large-scale project materials acquisition and logistics in the utility industry. By using a third-party material integrator, the Company expects to operate more cost-effectively on a program of this scale and be able to: (a) isolate the project materials for directly-planned projects; (b) assure visibility into near- and long-term availability of materials; (c) isolate the project costs from ongoing operations; (d) allow for simpler ramp up and ramp down of infrastructure required for project activities; and (e) minimize potential disruptions. The company will also continue to evaluate the materials markets through the life of the Resilience Plan to ensure that the risk is managed appropriately.

Q86. ARE THERE ANY OTHER AREAS THAT THE COMPANY IS EVALUATING AS IT DEVELOPS THE RESILIENCE PLAN?

A. Yes. As noted by Mr. May in his direct testimony, a portion of the distribution projects included in the Comprehensive Hardening Plan include poles that are owned by other entities, and the Company is evaluating options to manage the costs of hardening its assets on those joint-use poles.

Q87. HAS THE COMPANY SUBMITTED ANY PERMIT APPLICATIONS FOR THE PROJECTS PROPOSED IN THE RESILIENCE PLAN?

A. No. The Company has not reached a final determination of which governmental bodies other than the Commission will have regulatory and/or permitting oversight over the different components of the Resilience Plan. However, the Company will comply will all permitting or regulatory oversight requirements in implementing each project.

Q88. WILL THE RESILIENCE PLAN NEED REVISION AND REFINEMENT AS IT IS IMPLEMENTED?

A. Yes, as I discussed above, although the Company's proposed plan sets forth the Company's best efforts to identify the scope, cost, and timing of the selected projects, the precise work performed (as well as the cost and timing of when that work will be performed) will be subject to continual refinement as the Company implements its Resilience Plan.

VIII. MONITORING AND COST CONTROL

Q89. IS THE COMPANY PROPOSING A MONITORING PLAN AS PART OF ITS RESILIENCE PLAN?

A. Yes. In working with its Alliance Partners to implement the Resilience Plan, the Company will track the progress of each proposed project and its costs as part of its project management. The Company will utilize its project management process-controls reporting that accompanies all project executions to track both assets installed and the costs of each project.

To keep the LPSC informed on the overall progress of the Resilience Plan, the Company is proposing to file progress reports every six months beginning August 15, 2024. The reports generally will provide information regarding the preceding two calendar quarters. For example, the report filed on August 15, 2024, will discuss projects completed, as well as developments in the execution of the plan for the period of January 1, 2024, through June 30, 2024; the report filed on February 15, 2025, will discuss projects completed, as well as developments in the execution of the plan for the period of July 1, 2024, through December 31, 2024. Those reports will address:

- Project Completion Status – identifying the projects completed during the reporting period;

- Project Schedule – providing general information about the projects scheduled for work during the next reporting period (e.g., program and region information) and an explanation for any material scheduling changes from previously-filed reports;

- Business Issues – identifying any material business issues as they relate to the Resilience Plan, including any material business disputes with Alliance Partners, force majeure issues, labor problems or disputes, and any issues associated with local governments or the local communities; and

- Additional Matters – providing a summary highlighting progress on the Resilience Plan, significant changes to the plan, and other notable developments, including, to the extent not provided elsewhere, information regarding any material variances to the schedule and/or scope of projects under the Resilience Plan.

Furthermore, cost monitoring will occur as part of the Resilience Plan Cost Recovery Rider procedures. As part of the true-up reporting and prudence review portion of the rider filing, the Company would include a report comparing the actual Resilience Plan Revenue Requirement to the projected Resilience Plan Revenue Requirement, along with explanations on material variance.

Q90. WHAT HAPPENS IF DISRUPTIVE EVENTS, SUCH AS ANOTHER PANDEMIC OR A SERIES OF STORMS, HAVE A MATERIAL EFFECT ON THE RESILIENCE PLAN'S COSTS OR PROGRESS?

A. Unanticipated delays and unforeseen circumstances are a part of any project, particularly with an undertaking as large as the proposed Resilience Plan. The Company will work to address any issues that might arise and, as I mentioned above, refine or revise the Resilience Plan as necessary given the realities of the situation. Furthermore, the Company will keep the Commission advised of material changes to the Resilience Plan and its progress and the causes of any material changes.

IX. CONCLUSION

Q91. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, at this time.

AFFIDAVIT

STATE OF TEXAS

COUNTY OF MONTGOMERY

NOW BEFORE ME, the undersigned authority, personally came and appeared, **SEAN MEREDITH**, who after being duly sworn by me, did depose and say:

That the above and foregoing is his sworn testimony in this proceeding and that he knows the contents thereof, that the same are true as stated, except as to matters and things, if any, stated on information and belief, and that as to those matters and things, he verily believes them to be true.

S Meredith

Sean Meredith

SWORN TO AND SUBSCRIBED BEFORE ME
THIS 15 DAY OF DECEMBER, 2022

Carol Tompkins

NOTARY PUBLIC

My commission expires: February 01, 2025

NOTARY PUBLIC STATE OF TEXAS

CAROL TOMPKINS
My Notary ID # 130989368
Expires February 1, 2025

BEFORE THE

LOUISIANA PUBLIC SERVICE COMMISSION

***IN RE*: APPLICATION OF ENTERGY**	**)**	
LOUISIANA, LLC FOR APPROVAL	**)**	**DOCKET NO. U- _______**
OF THE ENTERGY FUTURE READY	**)**	
RESILIENCE PLAN (PHASE I)	**)**	

EXHIBIT SM-1

DECEMBER 2022

Listing of Previous Testimony Filed by Sean Meredith

DATE	TYPE	SUBJECT MATTER	REGULATORY BODY	DOCKET NO.
04/30/2021	Direct	ELL Storm Recovery Filing	LPSC	U-35991
07/23/2021	Supplemental	ELL Storm Recovery Filing	LPSC	U-35991

BEFORE THE

LOUISIANA PUBLIC SERVICE COMMISSION

***IN RE*: APPLICATION OF ENTERGY LOUISIANA, LLC FOR APPROVAL OF THE ENTERGY FUTURE READY RESILIENCE PLAN (PHASE I)**	**))))**	**DOCKET NO. U- _______**

EXHIBIT SM-2

HIGHLY SENSITIVE
PROTECTED MATERIAL

INTENTIONALLY OMITTED

DECEMBER 2022

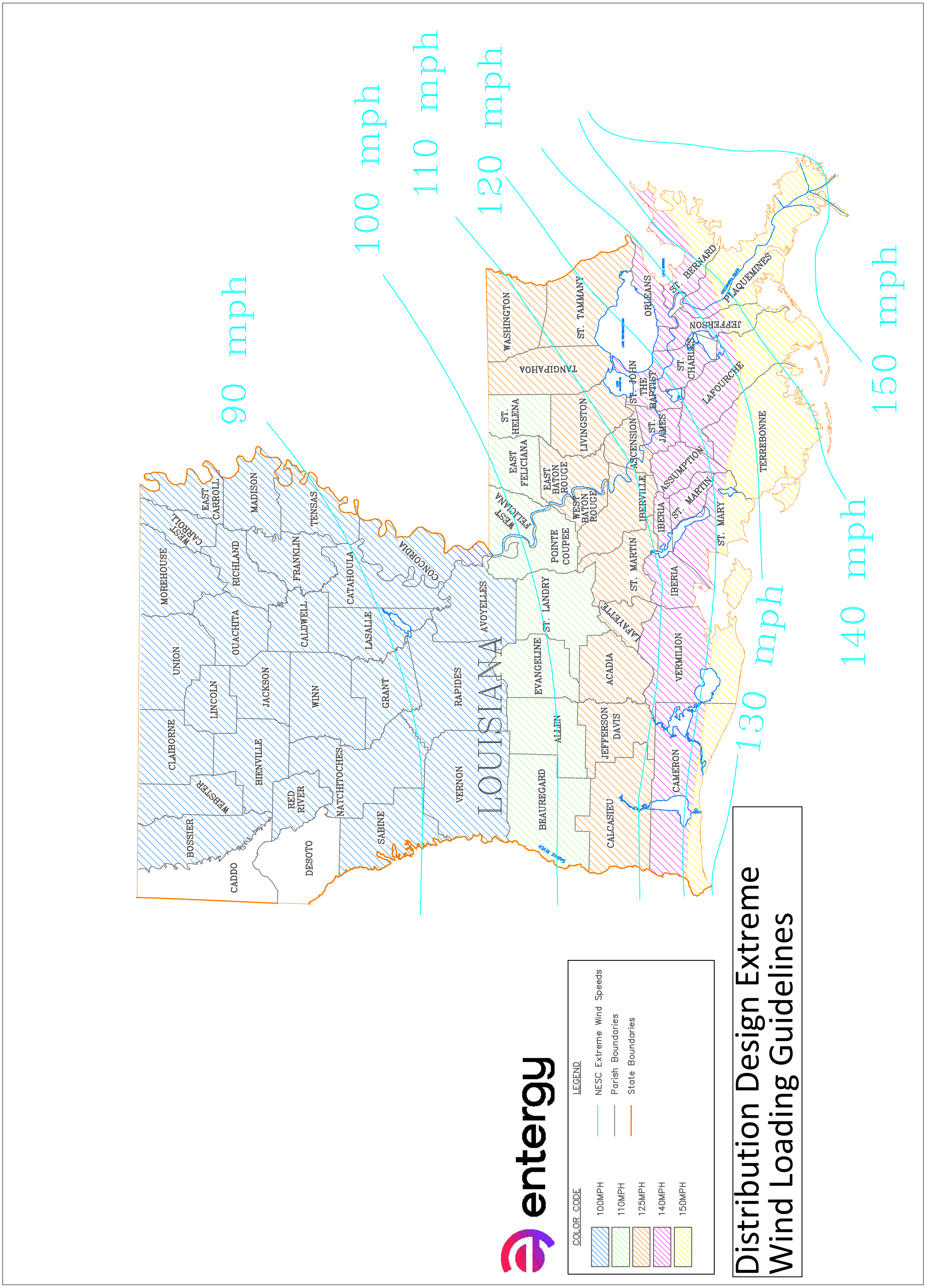
BEFORE THE

LOUISIANA PUBLIC SERVICE COMMISSION

***IN RE*: APPLICATION OF ENTERGY LOUISIANA, LLC FOR APPROVAL OF THE ENTERGY FUTURE READY RESILIENCE PLAN (PHASE I)**	**))))**	**DOCKET NO. U- _______**

EXHIBIT SM-3

DECEMBER 2022


Distribution Design Extreme Wind Loading Guidelines
entergy
COLOR CODE
100MPH
110MPH
125MPH
140MPH
150MPH
LEGEND
NESC Extreme Wind Speeds
Parish Boundaries
State Boundaries
90 mph
100 mph
110 mph
120 mph
130 mph
140 mph
150 mph
LOUISIANA
CADDO
BOSSIER
WEBSTER
CLAIBORNE
UNION
MOREHOUSE
WEST CARROLL
EAST CARROLL
LINCOLN
OUACHITA
RICHLAND
MADISON
BIENVILLE
JACKSON
CALDWELL
FRANKLIN
TENSAS
DESOTO
RED RIVER
WINN
LASALLE
CATAHOULA
CONCORDIA
NATCHITOCHES
SABINE
GRANT
RAPIDES
AVOYELLES
VERNON
BEAUREGARD
ALLEN
EVANGELINE
ST. LANDRY
POINTE COUPEE
WEST FELICIANA
EAST FELICIANA
ST. HELENA
WASHINGTON
TANGIPAHOA
ST. TAMMANY
LIVINGSTON
EAST BATON ROUGE
WEST BATON ROUGE
IBERVILLE
ASCENSION
ST. JAMES
ST. JOHN THE BAPTIST
ST. CHARLES
ORLEANS
ST. BERNARD
PLAQUEMINES
JEFFERSON
LAFOURCHE
TERREBONNE
ASSUMPTION
ST. MARTIN
IBERIA
ST. MARY
LAFAYETTE
ACADIA
VERMILION
JEFFERSON DAVIS
CALCASIEU
CAMERON

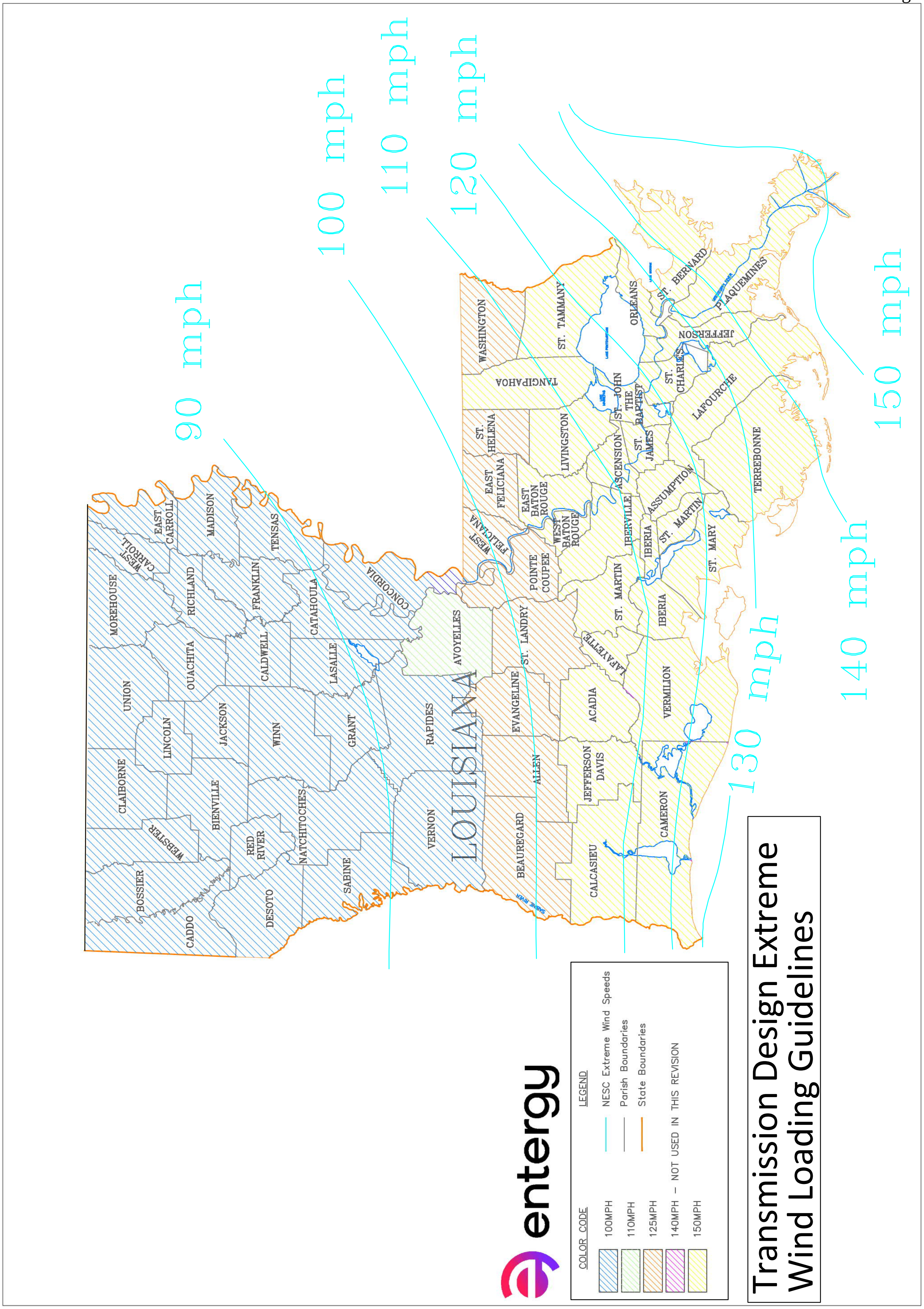
BEFORE THE

LOUISIANA PUBLIC SERVICE COMMISSION

***IN RE*: APPLICATION OF ENTERGY LOUISIANA, LLC FOR APPROVAL OF THE ENTERGY FUTURE READY RESILIENCE PLAN (PHASE I)**	**))))**	**DOCKET NO. U- _______**

EXHIBIT SM-4

DECEMBER 2022



Transmission Design Extreme Wind Loading Guidelines

BEFORE THE

LOUISIANA PUBLIC SERVICE COMMISSION

***IN RE*: APPLICATION OF ENTERGY LOUISIANA, LLC FOR APPROVAL OF THE ENTERGY FUTURE READY RESILIENCE PLAN (PHASE I)**	**))))**	**DOCKET NO. U- _______**

EXHIBIT SM-5

HIGHLY SENSITIVE
PROTECTED MATERIAL

INTENTIONALLY OMITTED

DECEMBER 2022

BEFORE THE

LOUISIANA PUBLIC SERVICE COMMISSION

***IN RE*: APPLICATION OF ENTERGY LOUISIANA, LLC FOR APPROVAL OF THE ENTERGY FUTURE READY RESILIENCE PLAN (PHASE I)**	**))))**	**DOCKET NO. U- _______**

EXHIBIT SM-6

HIGHLY SENSITIVE
PROTECTED MATERIAL

INTENTIONALLY OMITTED

DECEMBER 2022

BEFORE THE

LOUISIANA PUBLIC SERVICE COMMISSION

IN RE: **APPLICATION OF ENTERGY LOUISIANA, LLC FOR APPROVAL OF THE ENTERGY FUTURE READY RESILIENCE PLAN (PHASE I)**	**))))**	**DOCKET NO. U-_____**

DIRECT TESTIMONY

OF

ALYSSA MAURICE-ANDERSON

ON BEHALF OF

ENTERGY LOUISIANA, LLC

DECEMBER 2022

TABLE OF CONTENTS

EXHIBITS

I. INTRODUCTION AND BACKGROUND

Q1. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Alyssa Maurice-Anderson. I am employed by Entergy Services, LLC ("ESL")[1] as the Director, Regulatory Filings and Policy. My business address is 639 Loyola Avenue, New Orleans, Louisiana 70113.

Q2. ON WHOSE BEHALF ARE YOU TESTIFYING?

A. I am testifying before the Louisiana Public Service Commission (the "LPSC" or "Commission") on behalf of Entergy Louisiana, LLC ("ELL" or the "Company").[2]

Q3. PLEASE DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

A. I hold a Master's in Business Administration (concentration in Finance) from Tulane University's Freeman School of Business (2011), a Juris Doctor from Loyola University New Orleans School of Law (2002) and a Bachelor of General Studies from the University of New Orleans (1998). I joined the ESL Legal Department in 2001 and until August 2020, I held varying levels of responsibility supporting regulatory litigation matters. Most notably, beginning in 2008, my practice focused on leading rate matters

[1] ESL is a service company to the five Entergy Operating Companies ("EOCs"), which are Entergy Arkansas, LLC ("EAL"), Entergy Louisiana, LLC, Entergy Mississippi, LLC ("EML"), Entergy Texas, Inc., and Entergy New Orleans, LLC ("ENO").

[2] On October 1, 2015, pursuant to Commission Order No. U-33244-A, Entergy Gulf States Louisiana, L.L.C. ("Legacy EGSL") and Entergy Louisiana, LLC ("Legacy ELL") combined substantially all of their respective assets and liabilities into a single operating company, Entergy Louisiana Power, LLC, which subsequently changed its name to Entergy Louisiana, LLC ("ELL"). Upon consummation of the Business Combination, ELL became the public utility that is subject to LPSC regulation and now stands in the shoes of Legacy EGSL and Legacy ELL in pending Commission dockets.

filed by regulated subsidiaries of Entergy Corporation -- first for ENO, then for Legacy ELL and Legacy EGSL, and then for both ENO and ELL. My responsibilities included providing legal advice and developing legal strategies necessary to file applications/requests on behalf of the referenced operating companies, manage, and obtain approval of rate making treatments that resulted in rates that were just and reasonable to customers and the investor-owned utility, as well as various related duties, such as issuing probability assessments, drafting, and reviewing inserts to disclosure documents, *etc*. The rate making treatments for which the companies sought approvals (and which I supported) sometimes were made as stand-alone proceedings, *e.g.*, rate case or Formula Rate Plan ("FRP") proceedings or in connection with major strategic initiatives, such as joining the Midcontinent Independent System Operator, Inc., business separations, resource additions, *etc*.

In 2020, I transitioned from the legal department to ENO as Director, Regulatory Operations (Affairs), reporting directly to the President and Chief Executive Officer of ENO. As Director, Regulatory Operations, I contributed to the development of regulatory strategy, appeared on behalf of ENO before its regulator, the Council of the City of New Orleans, and interfaced with customers at public meetings. Additionally, with the support of several analysts and ESL's Regulatory Services organization, I was responsible for the coordination and/or submission of retail regulatory filings on behalf of ENO. In May 2021, I returned to ESL and since then have worked as Director, Regulatory Filings and Policy.

In my current role, I oversee the department that assists in coordination and execution of activities necessary to meet certain regulatory filing requirements applicable to the EOCs as providers of utility service. Those activities include extracting per book data and/or preparing *pro formas* to that data for use in the various regulatory filings submitted by and on behalf of the EOCs and System Energy Resources, Inc., as well as providing financial analytics that support certain strategic initiatives that require regulatory approvals. The deliverables resulting from this technical support take the form of revenue requirement and cost of service analysis, responses to internal and external data requests for financial information and explanation of policies used in regulatory proceedings. I am also responsible for providing testimony on certain policy issues and/or rate making treatments, including the types that are the subject of these regulatory proceedings.

Q4. HAVE YOU PREVIOUSLY TESTIFIED BEFORE ANY REGULATORY BODIES?

A. Yes. I have submitted pre-filed testimony to the LPSC and the Public Utility Commission of Texas. A list of my previously filed testimony is attached hereto as Exhibit AMA-1. I have also appeared as regulatory counsel on behalf of ELL and ENO before the LPSC and the Council of the City of New Orleans, respectively.

II. PURPOSE OF TESTIMONY

Q5. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My direct testimony supports the Company's Application requesting approval for Phase I of the Entergy Future Ready Resilience Plan ("Resilience Plan"), which includes approximately $5.0 billion in projects proposed to be implemented in the first five years (2024-2028), and the Resilience Plan Cost Recovery Rider ("Resilience Plan Rider"). As discussed by Company witness Phillip May, the Resilience Plan is a multi-year plan of capital projects and other elements intended to enhance the resiliency of ELL's transmission and distribution infrastructure by reducing future restoration costs and storm outage times.

The Resilience Plan is necessary because ELL is likely to have more limited alternatives for financing restoration costs at a reasonable cost and, as discussed by Mr. May, customer reliance on utility service has evolved to a level that requires an even greater level of reliability, even following major storms. If, in the near term, ELL sustains widespread storm damage with a scope and cost comparable to that experienced with Hurricane Ida, the Commission and ELL will be in "uncharted territory" from a financial perspective. In that event, ELL would have to propose and, consistent with applicable law, the Commission would have to consider authorizing a new financing method for major storm restoration costs that would likely be much less favorable to customers than securitization. To mitigate this risk for customers and for reasons explained by other ELL witnesses, ELL plans to take accelerated steps to make the physical assets that comprise its power delivery system more storm resilient to reduce future storm restoration costs.

The pace at which system upgrades and investments are made is typically guided by a variety of considerations, including not only the needs of the system, but also the potential effects of such spending on customer bills and the financial health and stability of the company (which necessarily considers other important priorities that compete for capital, *e.g.*, addressing potential shortfalls in generation capacity needed to serve customer requirements over time, or transmission projects required by applicable government regulations). Taking comprehensive steps to upgrade the power delivery system in an accelerated manner, assuming the resulting costs are recovered via the currently existing ELL ratemaking mechanisms, would compromise ELL's cash flow and corresponding credit metrics. This could adversely affect ELL's credit rating and thus introduce an increase in costs for customers that could be avoided, as discussed by Company witness Todd Shipman.

ELL's existing capital program already is sizable, and ELL can only execute that program and keep capital costs low for customers because of the contemporaneous recovery mechanisms that the Commission has added to ELL's Formula Rate Plan ("FRP"). I explain why a new contemporaneous recovery mechanism is likewise necessary for ELL to undertake the proposed Resilience Plan (described by Company witness Sean Meredith) in addition to its existing capital program without putting ELL and customers at risk. Accordingly, ELL is proposing that the revenue requirement associated with the Resilience Plan be recovered through the Resilience Plan Rider that I present later in my testimony and accompanying exhibit.

In addition, my direct testimony supports the requested ratemaking treatment related to transmission and distribution assets that must be retired and replaced with new assets pursuant to the Resilience Plan and discusses an accounting waiver ELL intends to request at the Federal Energy Regulatory Commission ("FERC"), which will mitigate the near term bill effect on customers.

Specifically, ELL requests authorization to create a regulatory asset for the remaining net book value associated with assets that must be retired and replaced with new assets as part of the Resilience Plan. ELL would include the regulatory asset in rate base and amortize such retired plant costs at a rate consistent with the associated depreciation expense currently reflected in rates. With this approved ratemaking treatment, customers would not see an incremental increase in rates associated with ELL's recovery of assets prudently retired in connection with the Resilience Plan.

III. NEED FOR AN ACCELERATED RESILIENCE PLAN

Q6. HAS THE COMMISSION CONSISTENTLY AUTHORIZED SECURITIZATION FINANCING AS THE METHOD FOR ELL TO RECOVER STORM RESTORATION COSTS SINCE THE LEGISLATION PROVIDING THAT ALTERNATIVE BECAME AVAILABLE?

A. Yes. In 2005, Louisiana utilities, including Legacy ELL and Legacy EGSL, experienced what, until then, had been unprecedented storm-related damage from Hurricanes Katrina and Rita. In response, in 2006, the Louisiana Legislature enacted Part V-B of Chapter 9 of Title 45, entitled the "Louisiana Electric Utility Storm Recovery Securitization Act," which is often referred to as "Act 64." Then, in 2007, the Louisiana Legislature enacted Part VIII of Chapter 9 of Title 45, entitled the "Louisiana Utilities Restoration Corporation Act," which is often referred to as "Act 55."[3] The purpose of these Acts is to enable the Commission to authorize the use of low-cost securitization financing for utility system storm restoration and for contributions to financially strengthen and stabilize utilities after storms in order to minimize costs charged to customers. The Commission

[3] The Louisiana Legislature supplemented Act 55 in 2021 through Act 293.

has approved all of ELL's requests to utilize Louisiana Act 55 securitization financing to recover system restoration costs.[4]

Q7. PLEASE SUMMARIZE THE STORM SECURITIZATIONS ELL AND ITS PREDECESSORS HAVE USED PRIOR TO 2022.

A. See the following table.

Table 1
Summary of Act 55 Securitizations Prior to 2022

Associated Storms	Issuance Year	Tenor (Years)	Principal Outstanding at End of Issuance Year ($ millions)
Katrina/Rita	2008	10	966.1
Gustav/Ike	2010	12	713.0
Isaac	2014	12	314.9

Q8. ALL THREE OF THESE BOND ISSUANCES HAVE BEEN OUTSTANDING IN THE SAME YEAR. WHAT IS THE GREATEST AMOUNT OF BOND PRINCIPAL THAT HAS BEEN OUTSTANDING AT ONE TIME PRIOR TO 2022?

A. The greatest amount of bond principal that has been outstanding at year-end was $1.5 billion in 2010. The outstanding bond principal remained above $1.0 billion through year-end 2015.

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4 Act 55 defines "system restoration costs" to include "those prudent incremental costs incurred or to be incurred by a utility in undertaking a system restoration activity, including associated carrying costs," as well as "the costs to fund and finance any storm damage reserves." La. R.S. 45:1312(19).

Q9. PLEASE BRIEFLY DESCRIBE THE STORM ACTIVITY ELL EXPERIENCED IN 2020 AND 2021.

A. In August 2020 and October 2020, and as is further discussed by Mr. May, Hurricane Laura, Hurricane Delta, and Hurricane Zeta caused significant damage to portions of ELL's service area. In February 2021, two winter storms (collectively, Winter Storm Uri) brought freezing rain and ice to Louisiana, which caused damage to ELL's transmission and distribution systems. In August 2021, Hurricane Ida caused extensive damage to ELL's distribution and, to a lesser extent, transmission systems resulting in widespread power outages. I sometimes refer to the system restoration costs resulting from this series of storms as "Post-2019" system restoration costs.

Q10. HOW DOES ELL PLAN TO RECOVER THE POST-2019 SYSTEM RESTORATION COSTS?

A. The recovery process has multiple steps and includes short-term conventional financing, but ELL ultimately intends to rely on Act 55 securitization financing to recover all of its Post-2019 system restoration costs. The first step involved the issuance of shorter term mortgage bonds to provide interim financing for restoration costs associated with Hurricane Laura, Hurricane Delta, Hurricane Zeta, and Winter Storm Uri, and in November 2020, ELL issued $1.1 billion of 0.62% Series mortgage bonds due November 2023. The first step also involved the withdrawal of $257 million of previously funded storm reserves. In October 2021, ELL issued $1.0 billion of shorter-term mortgage bonds to provide interim financing at a reduced cost for Hurricane Ida restoration costs.[5]

The second step involved the issuance of securitized 15-year bonds in the aggregate principal amount of $3.2 billion. From the issuance of these bonds and the subsequent transfer of funds, ELL (1) received $1.8 billion of system restoration costs from Hurricane Laura, Hurricane Delta, Hurricane Zeta, and Winter Storm Uri; (2) funded a $290 million cash storm reserve; (3) funded a $1.0 billion reserve to partially pay for Hurricane Ida restoration costs pending further regulatory proceedings regarding that storm; and (4) received $96 million for carrying costs and bond issuance costs. ELL proposed the $1.0 billion reserve to partially pay for Hurricane Ida restoration costs to take advantage of the historically low interest rates available at that time and thus save customers money.[6]

The third step will involve issuance of securitized bonds to finance the recovery of the remaining Hurricane Ida restoration costs. Assuming LPSC approval of ELL's requested system restoration costs, ELL estimates that securitized bonds with an aggregate principal amount of approximately $1.6 billion will be issued for the second Ida securitization ("2023 Ida Securitization"). ELL has recommended a 15-year tenor for these bonds, but the exact tenor and other terms are unknown at this point.

[5] LPSC Order No. U-36154, dated November 22, 2021, at 1.

[6] LPSC Order No. U-35991 (Amended), dated March 11, 2022, at 12.

Q11. HOW MUCH SECURITIZATION BOND PRINCIPAL DOES ELL EXPECT WILL BE OUTSTANDING AFTER THE 2023 IDA SECURITIZATION?

A. ELL estimates that there will be $4.7 billion of securitization bond principal outstanding at year-end 2023. Assuming the 2023 Ida Securitization has a 15-year tenor, ELL further estimates that the outstanding bond principal would remain above $2.0 billion through year-end 2032 and above $1.0 billion through year-end 2034. Attached to my testimony as Exhibit AMA-2 is a schedule that reflects actual and estimated securitization bond principal outstanding at year-end 2008 through 2037.

Q12. ARE YOU CONCERNED ABOUT POTENTIAL REPERCUSSIONS FROM THE 2023 IDA SECURITIZATION RELATIVE TO FUTURE STORMS?

A. Yes. Once the 2023 Ida Securitization is complete, ELL very likely would have limited capacity to use securitization debt to finance any additional storm restoration costs for a number of years. This creates a need to take aggressive steps to reduce future storm damage through accelerated projects such as those proposed in the Resilience Plan, in addition to the other reasons supporting the need for the Resilience Plan discussed by other Company witnesses.

Q13. WHY IS ELL CONCERNED ABOUT ITS SECURITIZATION CAPACITY?

A. ELL is concerned about its securitization capacity because of the proportion of a typical residential bill that will be dedicated to servicing securitization debt after the 2023 Ida Securitization. That proportion, which I refer to as "Securitization Burden," will be greater after the 2023 Ida Securitization than the Securitization Burden of any other U.S. utility collecting securitization charges.

The goal of securitization is to obtain a bond issuance that achieves a 'AAA' rating so that the cost to the customer of such debt, which is set by the competitive debt markets, is minimized. Further, per the terms of the previous securitization Financing Orders, the Louisiana Utilities Restoration Corporation ("LURC") may not cause the issuance of additional bonds if such issuance causes any of the then-current ratings of any outstanding issuances to be suspended, withdrawn, or downgraded. ELL understands that the credit rating agencies consider two key criteria when rating a bond issue tied to a specific electric customer rider revenue stream: (i) the strength of the underlying legislation and financing order, and (ii) the Securitization Burden. The Securitization Burden calculation considers all outstanding securitization charges. Also, the credit rating agencies analyze the Securitization Burden, which changes in response to actual sales and sales projections,[7] using various stress assumptions (*e.g.*, consumption decline of up to 50%, no sales for the summer months, top ten customer default). The credit rating agencies have not stated what Securitization Burden would be too high to achieve a 'AAA' rating.

ELL estimates that the 2023 Ida Securitization, assuming a 15-year tenor, would increase ELL's Securitization Burden to a range between 11%-12%. Depending on the stress case used, ELL's Securitization Burden could rise even more. No comparable 'AAA' securitization issuances exist in which the utility's Securitization Burden has

[7] ELL's current securitization rider rates adjust semiannually to changes in sales.

reached this range; therefore, the rating of the 2023 Ida Securitization as currently proposed is uncertain. The Company is currently considering how to address this uncertainty. Considering these developments, ELL likely has limited securitization capacity to finance future storm restoration costs for a number of years. Therefore, a need for an accelerated storm resiliency plan exists.

Q14. ARE THERE ANY OTHER POTENTIAL REPERCUSSIONS FROM THE 2023 IDA SECURITIZATION ABOUT WHICH YOU ARE CONCERNED?

A. Yes, but I do not think the repercussions are well understood at this time. Although I expect that ELL will be reimbursed for its restoration costs and the temporary financing will be retired, a significant cash amount collected from ELL customers will be going directly to service bonds held by securitization debt investors for a long time (*i.e.*, those revenues become an obligation that must be remitted to the LURC). Stated in another manner, the securitization related revenue is unavailable to ELL to repay other outstanding debt and/or to address emergent operational issues. As such, existing first mortgage bond investors experience increased risk as securitized debt investment increases. Likewise, the equity owner is at increased risk to maintain sufficient cash flow to fund operations.

IV. ELL'S PROJECTED FINANCIAL CONDITION DURING THE RESILIENCE PLAN WITHOUT THE REQUESTED RIDER

Q15. WHAT WOULD HAPPEN TO ELL'S FINANCIAL CONDITION IF IT UNDERTOOK THE RESILIENCE PLAN WITHOUT A NEW RIDER TO RECOVER THE PLAN'S COSTS?

A. As I mentioned earlier in my testimony, undertaking the proposed Resilience Plan assuming the resulting costs are recovered via the currently existing ELL ratemaking mechanisms would compromise ELL's credit metrics and cash flow and thus expose ELL to adverse action from the credit rating agencies and its customers to higher costs. For these reasons, to undertake the level and pace of spending in the proposed Resilience Plan and recover the resulting costs via existing ratemaking mechanisms would place ELL's financial condition at great risk and may not be feasible.

I present an indicative financial model ("Financial Model"), which I describe below, supporting my opinion. The Financial Model uses simplifying assumptions to compare cash flow results under existing mechanisms and the new proposed rider. The Financial Model shows that ELL's most important credit metric, funds from operations ("FFO") to debt, would experience significant downward pressure over the first five years of the Resilience Plan's construction phase assuming ELL must rely upon only the current ratemaking mechanisms to recover the resulting costs. The Financial Model is attached to my testimony as Exhibit AMA-3.

Q16. PLEASE FURTHER DESCRIBE THE FINANCIAL MODEL PRESENTED ON EXHIBIT AMA-3.

A. The Financial Model projects the cash flows that would occur during the construction phase of the Resilience Plan[8] assuming the current ratemaking mechanisms, *i.e.*, the Formula Rate Plan ("FRP") with the Transmission Recovery Mechanism ("TRM") and the Distribution Recovery Mechanism ("DRM"),[9] were in effect and applied to the Resilience Plan's revenue requirement. The Financial Model then uses the cash flows to calculate the projected degradation to ELL's FFO to debt cash flow ratio for the first five years of the Resiliency Plan's construction phase, 2024 through 2028. For the reasons I address later, the Financial Model does not attempt to project cash flows for the remainder of ELL's operations.

Q17. WHY DOES THE FINANCIAL MODEL FOCUS ON CASH FLOW TO DEBT RATIO?

A. As discussed by Company witness Todd Shipman in his Direct Testimony, the FFO to Debt ratio and cash flow from operations before changes in working capital ("CFO pre-WC") to debt have become the preferred credit metric of utility credit analysts. These ratios measure the degree of financial risk (the lower the percentage, the higher the risk)

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8 The Financial Model is conservative as it incorporates approximately $4.6 billion in investment associated with the Comprehensive Hardening Plan and does not include any of the projects for dead-end structures, communication network upgrades or vegetation management, although the Company proposes to recover these categories of costs through the Resilience Rider.

9 ELL's current Rider FRP as approved by the LPSC in Order U-35565 authorizes certain levels of distribution and transmission plant closings to be recovered dollar for dollar (*i.e.*, "outside of the band") through the DRM and TRM, respectively.

experienced by a company by comparing its cash flow to the level of debt the company requires to sustain its operating and capital investment activities. As explained by Mr. Shipman, this is often perceived as the most rigorous measure of creditworthiness since improvements in the measure require growing cash flow from operations at a faster pace than adding new debt and increasing risk.

Q18. IS IT NECESSARY THAT THE FINANCIAL MODEL ATTEMPT TO PROJECT CASH FLOWS FOR THE REMAINDER OF ELL'S OPERATIONS?

A. No. It is not necessary because the Resilience Plan would not affect the remainder of ELL's operations. The Resilience Plan, which involves accelerated capital projects to produce near term benefits to customers, would be incremental to ELL's ongoing capital program.

Additionally, the Financial Model does not include cash flow projections for the remainder of ELL's operations because such projections for the remainder of ELL's operations would require many complex assumptions, which ELL has not developed or has not fully developed, such as those related to the book minimum tax created by the Infrastructure Investment and Jobs Act. Moreover, the further out in time a projection extends, the more tenuous the assumptions and resulting projections. For example, ELL has an expectation of future sales and load growth as industrial customers seek to have more of their processes powered with electricity, but future sales and load growth from industrial customers are uncertain as to timing and amount. Accordingly, in ELL's planning processes, that sales and load growth is risk-adjusted to reflect the inherent uncertainty regarding whether that load growth will materialize. Likewise, ELL has not fully developed forecasts of what it will cost to serve this new load.

More importantly, however, significant uses of cash are likely from the remainder of ELL's operations. Putting aside the Resilience Plan, ELL's existing capital program requires sizable amounts of cash. This capital program will drive debt issuances just like the Resilience Plan. Thus, it is very difficult to have confidence that the significant downward pressure on ELL's FFO to Debt Ratio from the Resilience Plan, which would be virtually certain assuming Commission approval of the Plan, will be mitigated by the upward pressure on ELL's FFO to Debt Ratio and CFO pre-WC to Debt Ratio attributable to increased industrial sales, which are uncertain and offset in part by debt issuances from ELL's existing capital program.

Q19. WHAT ELEMENTS IN THE FINANCIAL MODEL ARE USED TO CALCULATE THE CASH FLOW TO DEBT RATIOS?

A. The Financial Model calculates cash flow using two elements: (1) "Incremental Revenue" from rate changes due to the Resilience Plan projects and (2) Interest Expense from the Debt supporting the Resilience Plan projects. The Financial Model calculates Debt by assuming that approximately 50.5% of Resilience Plan Capital Expenditures are funded with new debt issuances. The Resilience Plan Capital Expenditures for the first five years of the Plan are set forth in the table below.[10]

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[10] These expenditure amounts assume that conductor handling costs are capitalized as discussed *infra*.

Table 2 2024-2028 Projected Resilience Plan Capital Expenditures by Function ($ millions)			
Year	**Transmission**	**Distribution**	**Total**
2024	29.4	334.6	364.0
2025	127.1	739.9	867.0
2026	312.3	906.9	1,219.2
2027	298.6	636.8	935.4
2028	334.3	877.0	1,211.3
Total	1,101.8	3,495.2	4,596.9

Q20. WHAT ARE THE ASSUMPTIONS RELATED TO INCREMENTAL REVENUE?

A. The Financial Model assumes that Incremental Revenue results from FRP Rate Adjustments under the current FRP as Resilience Plan projects are included in rates. The Financial Model assumes that the transmission projects in the Resilience Plan are placed in service semiannually in April and August and that the transmission annual depreciation rate is 2%. The Financial Model further assumes timely recovery of the Resilience Plan transmission project costs in large part through the TRM.

The Financial Model assumes that the Resilience Plan's distribution projects are placed in service quarterly in March, June, September, and December and that the distribution annual depreciation rate is 3%. The Financial Model further assumes regulatory lag on the recovery of the Resilience Plan's distribution project costs because the DRM cap is consumed by distribution projects unrelated to the Resilience Plan.

Q21. WHAT ARE THE ASSUMPTIONS ASSOCIATED WITH INTEREST PAYMENTS?

A. The Financial Model assumes that the interest paid on debt supporting the Resilience Plan projects is based on an assumed cost of debt of 5.2%, which is the assumed cost used in ELL's financial planning processes. Debt issuances are assumed to occur midyear for purposes of calculating interest paid in the year of issuance.

Q22. WHAT ARE THE ASSUMPTIONS REGARDING INCOME TAXES?

A. The Financial Model assumes that ELL continues to have a net operating loss through year-end 2028. Accordingly, in the Financial Model, ELL is assumed not to be making income tax payments, and ELL is assumed not to be including liberalized depreciation accumulated deferred taxes in rate base when calculating revenue from rate changes driven by the Resilience Plan projects.

Q23. WHAT ARE THE CASH FLOW TO DEBT RATIOS FOR THE FIRST FIVE YEARS OF THE RESILIENCE PLAN?

A. The cash flow to debt ratios from the Financial Model show that the cost recovery of the Resilience Plan revenue requirement through the existing FRP would put significant strain on ELL's financial condition and based on the rating agencies' established criteria, would create concern for them. As shown below, the cash flow to debt ratios start negative and increase slowly as the FRP's current provisions slowly incorporate the Resilience Plan revenue requirement into ELL's rates.

Table 3
Cash Flow to Debt Ratio for the Resilience Plan
Assuming Recovery Through Existing FRP
for the Years Ended December 31, 2024 through 2028

	2024	**2025**	**2026**	**2027**	**2028**
CF to Debt – FRP Recovery	-2.4%	-2.1%	-0.3%	3.3%	6.6%

S&P Global has stated that ELL's FFO to Debt Ratio should be 13% or above to maintain ELL's credit rating, and Moody's Investor Service has stated that ELL's CFO pre-WC to Debt Ratio should be 18% or above to maintain ELL's credit rating. The cash flow to debt ratios from the Financial Model show that, assuming all else unchanged, the cost recovery of the Resilience Plan revenue requirement through the existing FRP would not support ELL meeting those thresholds and would put significant downward pressure on ELL's overall FFO to Debt Ratio and CFO pre-WC to Debt Ratio. Therefore, the above results from the Financial Model support the need for ELL to have a cost recovery mechanism other than the current FRP to address the financial pressures of the Resilience Plan.

V. RESILIENCE PLAN RIDER

Q24. PLEASE PROVIDE AN OVERVIEW OF THE RESILIENCE PLAN RIDER.

A. The proposed Resilience Plan Cost Recovery Rider ("Resilience Plan Rider" or "Rider"), which is attached to my testimony as Exhibit AMA-4, would accomplish contemporaneous recovery of Resilience Plan costs through a forward-looking rate that would also include a true-up after a prudence review. ELL would make the Rider Filing using a forecasted basis twice each year, and the Rider's procedures would provide the Commission ample time to review the investments and expenses to be made in the next six-month period and determine the prudence of actual investments and expenses from a previous six-month period. ELL would calculate the Rider rates based on a percentage of base revenue.

Q25. PLEASE EXPLAIN THE SCHEDULE FOR RIDER FILINGS.

A. ELL would file the Rider on or before January 10 and July 10 of each year. Rider rates from the January filing would become effective the following March. Similarly, Rider rates from the July filing would become effective the following September. Each filing would include a calculation of the Resilience Revenue Requirement and supporting workpapers regarding ELL's resiliency costs incurred over the upcoming six months. The January calculation of the Resilience Revenue Requirement would capture costs to be incurred over the period March through the end of August. The July calculation of the Resilience Revenue Requirement would capture costs to be incurred over the period September through the end of February of the following year.

Beginning with the third Rider Filing, ELL would include the true-up of a previous Resilience Revenue Requirement and supporting workpapers. With a January Rider Filing, the true-up would cover the previous six-month period ended in August. With a July Rider Filing, the true-up would cover the previous six-month period ended in March.

Q26. WHAT COSTS WILL BE RECOVERED THROUGH THE RIDER?

A. The Rider would recover depreciation expense and a return on the transmission and distribution resilience projects, including dead-end and telecommunications projects, described by Mr. Meredith in his testimony. The Rider also would recover vegetation management expenses to be incurred by ELL in excess of the amount included in rates and other resilience-related expenses that may become necessary in the future. The proposed vegetation management programs and costs are described by Company witnesses Mr. Sean Meredith and Mr. Charles Long. ELL would include the above costs in its calculation of the Resilience Revenue Requirement, which would be a forward-looking revenue requirement. As stated above, the Company would true-up the Resilience Revenue Requirement with carrying costs.

Q27. HOW WOULD THE RESILIENCE REVENUE REQUIREMENT BE CALCULATED?

A. ELL would calculate the Resilience Revenue Requirement based on (1) the resilience projects (a) in service but not recovered through another method and (b) projected to enter service in the upcoming six-month period and (2) the expenses projected to be incurred in the upcoming six-month period. The return on rate base would be based on the weighted average cost of capital reflected in ELL's most recent FRP filing multiplied by the beginning-ending average resilience investment for the upcoming six-month period. Depreciation expense would be calculated based on a 3% annual depreciation rate for distribution investments and a 2% annual depreciation rate for transmission investments multiplied by the beginning-ending average gross resiliency investment for the upcoming six-month period. ELL would use these rates for ease of calculating a revenue requirement for the Rider only; these rates are not intended to change the applicable LPSC-approved depreciation rates. To support the revenue requirement, ELL would supply workpapers identifying each resilience project and its actual or expected in-service date and any expenses.

Q28. HOW WOULD THE RESILIENCE REVENUE REQUIREMENT BE ALLOCATED AMONG THE RATE CLASSES?

A. Considering, among other potential factors, that the investments and elements recovered through the Rider serve, in significant part, to reduce future storm-related restoration costs, ELL proposes to use the same allocation approach as that recently approved by the Commission for the allocation of system restoration costs in LPSC Order No. U-35991. ELL would functionalize the Resilience Revenue Requirement into transmission and distribution components.

The functionalized revenue requirements would be allocated among rate classes based on each rate class's share of base revenue from the most recent calendar year. As approved by the above Order, transmission voltage customers would be assigned 33% of the distribution revenue requirement and their 12 coincident peak ("12 CP") share of the transmission revenue requirement. The costs assigned to transmission voltage customers would then be divided by the amount that transmission voltage customers would have been assigned if costs were based solely on their proportion of base revenue for the applicable period. The resulting percentage would be applied to the total combined revenue requirements for the period, and the resulting allocation would be used to determine an equal percentage factor, expressed as a percentage of applicable base revenue, applying to all retail customers. The remainder of the total combined revenue requirements, or the revenue requirement that is not assigned to transmission voltage retail customers, shall be used to determine an additional equal percentage factor, expressed as a percentage of applicable base revenues, that applies to distribution voltage customers.

Q29. HOW WOULD THE RIDER RATES BE CALCULATED?

A. The Rider rates for each class would be calculated as a percentage of base revenue based on the most recently filed FRP or most recent calendar year's base revenue.

Q30. HOW MUCH TIME WOULD BE AVAILABLE TO THE STAFF TO REVIEW THE CALCULATION OF THE RESILIENCE REVENUE REQUIREMENT AND THE RIDER RATES?

A. The Staff and other parties would have thirty days to review the calculation of the Resiliency Revenue Requirement and the proposed Rider rates and identify any corrections or other disputed issues to ELL. If ELL and the other parties are able to resolve all or a portion of the disputed issues, then revised Rider rates incorporating the resolved issues would become effective in the applicable month. If disputed issues remain, rates would be implemented subject to refund until such time as the Commission would resolve those disputed issues through a hearing. The dispute resolution provisions of the Rider are substantially similar to those in the FRP.

Q31. PLEASE DESCRIBE THE TRUE-UP OF THE RESILIENCE REVENUE REQUIREMENT AND PRUDENCE REVIEW.

A. Beginning with the third Rider Filing, such Filing would include a true-up calculation of a previous Resilience Revenue Requirement using actual accounting data. For example, the January filing would include a calculation of a true-up of the Resilience Revenue Requirement for the period from March through August of the previous year. The July filing would include a calculation of a true-up of the Resilience Revenue Requirement for the period from September of the previous year through February of the current year. The Company would then implement the true-up in the following Rider Filing. For example, the July 2025 Rider Filing would include a true-up of the Resilience Revenue Requirement for the period September 2024 through February 2025, and such true-up would be reflected in Rider rates effective March 2026 through August 2026.

Q32. WHAT IS THE BASIS FOR THE TIMING OF THE TRUE-UP IN RIDER RATES?

A. ELL expects that the Commission will want to provide ample time for review of the prudence of the costs subject to the true-up. The Rider provides ninety days to review the projects closed to plant in service and any expenses incurred during the six-month true-up period and identify any disputed issues, including any expenditures challenged as being imprudently incurred. To facilitate this review, the Company would provide an exhibit listing all projects included in the previous Resilience Revenue Requirement and all projects that entered service during the true-up period. The exhibit would show the variances for each project and provide a brief description of the cause of any material variances. For expenses other than those associated with the projects that entered service (*e.g.*, depreciation expense), the Company would provide the accounting data for that expense.

If ELL and the other parties are able to resolve all or a portion of the disputed issues, then a revised true-up incorporating the resolved issues would be included in Rider rates in the applicable month. If disputed issues remain, then the true-up would take effect in rates subject to refund until such time as the Commission would resolve those disputed issues through a hearing. Again, the dispute resolution provisions regarding the true-up are substantially similar to those in the FRP.

VI. ELL'S FINANCIAL CONDITION WITH THE PROPOSED RIDER

Q33. WHAT EFFECT WOULD THE RIDER HAVE ON ELL'S FINANCIAL CONDITION?

A. As shown in the table below, ELL's cash flow would improve, and the FFO to Debt Ratio for the Resilience Plan would not have such a negative effect on the overall FFO to Debt Ratio. Such improvement would put ELL in a much better position to meet the financial thresholds applied by the credit ratings agencies.

Table 4
Cash Flow to Debt Ratio for the Resilience Plan
Comparing Recovery Through Existing FRP and
Recovery Through Rider
for the Years Ended December 31, 2024 through 2028

	2024	2025	2026	2027	2028
CF to Debt – FRP Recovery	-2.4%	-2.1%	-0.3%	3.3%	6.6%
CF to Debt – Rider Recovery	6.1%	8.6%	10.8%	13.5%	14.3%

Q34. DID ELL CHANGE ANY ASSUMPTIONS IN THE FINANCIAL MODEL BECAUSE OF THE PROPOSED RIDER?

A. The only change made to the Financial Model was to change the cost recovery mechanism from the existing FRP to the proposed Rider, as described above. The effect of that change was to provide for more timely recovery of the Resilience Plan projects than that afforded by the existing FRP. The effect is most pronounced with respect to resilience distribution projects because they experienced significant regulatory lag and they are the majority of the Resilience Plan's investment.

Q35. WHAT ARE THE ESTIMATED FACTORS RESULTING FROM THE NEW RIDER ASSUMING THE RIDER IS APPROVED AS REQUESTED?

A. Please see Table 5 for the resulting distribution and transmission factors that would result from the proposed Resilience Rider for Phase 1 of the Resilience Plan.

Table 5
Distribution and Transmission Factors under Resilience Rider for the Years Ended December 31, 2024 through 2028

	2024	2025	2026	2027	2028
Distribution Rate	3.26%	7.46%	14.82%	22.98%	30.94%
Transmission Rate	1.72%	3.28%	6.52%	10.88%	15.53%

VII. REQUESTED RATEMAKING TREATMENT FOR RETIREMENTS OF EXISTING PLANT RESULTING FROM THE RESILIENCE PLAN

Q36. PLEASE DESCRIBE THE COMPANY'S REQUEST CONCERNING UNRECOVERED PLANT COSTS.

A. ELL requests authorization to create a regulatory asset for the remaining net book value associated with assets that must be retired and replaced with new assets as part of the Resilience Plan. ELL would include the regulatory asset in rate base and amortize such retired plant costs at a rate consistent with the associated depreciation expense currently reflected in rates. With this ratemaking treatment, customers would not see an incremental increase in rates while ELL recovers its prudently incurred costs, all else being equal.

Q37. WHY SHOULD THE COMMISSION ALLOW THE REGULATORY ASSET TO BE INCLUDED IN RATE BASE?

A. Allowing ELL to include the regulatory asset in rate base will not have any effect on customers' rates relative to current rates. The net book value of these assets is already reflected in ELL's rate base and, therefore, its rates. Additionally, the prudent retirement of these assets to advance resilience objectives should not change ELL's recovery of the return on these assets.

Q38. IS THIS REQUEST SUBSTANTIALLY SIMILAR TO THE REQUEST MADE REGARDING THE METERS RETIRED AS A RESULT OF THE ADVANCED METERING SYSTEM PROJECT?

A. Yes.[11]

Q39. PLEASE DESCRIBE THE WAIVER THAT THE COMPANY INTENDS TO REQUEST FROM THE FERC.

A. Conductor handling costs are the costs associated with transferring existing conductor and other fixtures to new poles during pole replacements. ELL's conductor handling costs would increase as a result of the Resilience Plan. Under the FERC Uniform System of Accounts ("USOA"), ELL must record these costs as expenses in the year in which the work was performed. ELL intends to seek a waiver from the FERC authorizing ELL to

[11] *See* LPSC Order No. U-34320, *In Re: Application of Entergy Louisiana, LLC for Approval to Implement a Permanent Advanced Metering System and Request for Cost Recovery and Related Relief*, dated August 25, 2017.

capitalize conductor handling costs incurred in conjunction with Resilience Plan capital projects over the period January 1, 2024 through December 31, 2033.

Q40. HOW WOULD CAPITALIZATION BENEFIT CUSTOMERS?

A. Capitalization benefits customers by allowing conductor handling costs incurred in one year to be depreciated and be recovered from customers over a longer period to reduce immediate bill impacts to customers. Given these customer benefits, ELL requests that the LPSC, in addition to approving the Resilience Plan, acknowledge the contemplated FERC waiver request regarding conductor handling expenses by expressing support or non-opposition.

Q41. HAVE OTHER ELECTRIC UTILITIES OBTAINED SIMILAR WAIVERS FOR CONDUCTOR HANDLING COSTS?

A. Yes. The FERC granted Florida Power & Light Company, Gulf Power Company, and Duke Energy Florida, LLC limited duration accounting authorizations allowing capitalization of conductor handling costs.[12]

[12] *See Florida Power & Light Co.*, Letter Order, Docket No, AC18-23 (Jan. 31, 2018); *Gulf Power Co.*, Letter Order, Docket No, AC20-131 (July 30, 2020); *Duke Energy Florida, LLC*, Letter Order, Docket No, AC21-141 (July 29, 2021).

VIII. CONCLUSION

Q42. WHAT ARE THE MAIN POINTS IN YOUR TESTIMONY THAT THE COMMISSION SHOULD TAKE NOTE OF?

A. The main points made in my testimony are as follows. First, after the 2023 Ida Securitization, ELL expects to have limited securitization capacity to finance future storm restoration and thus, in the near term, financing future storm restoration costs likely would occur at a less favorable cost to customers than that of securitization. This development, among other reasons discussed by Company witnesses, supports the need for Phase I of the Resilience Plan.

Second, recovering the Resilience Plan's projected costs through ELL's existing ratemaking mechanisms would compromise ELL's credit metrics and cash flow, which could adversely affect ELL's credit rating and thus introduce an increase in costs for customers that could be avoided through constructive ratemaking, as discussed by Mr. Shipman. Thus, the proposed Resilience Plan Rider, which provides contemporaneous cost recovery consistent with other extraordinary storm related costs, is necessary to help ELL maintain its credit metrics and overall financial health.

Third, the Commission should authorize ELL's proposed approach for recovering the remaining net book value of assets that must be retired and replaced with new assets as part of the Resilience Plan because such approach allows the recovery of prudently incurred costs to continue without an incremental increase in rates and is otherwise consistent with the objectives of ELL's request for constructive ratemaking.

Q43. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, at this time.

AFFIDAVIT

STATE OF LOUISIANA

PARISH OF ORLEANS

NOW BEFORE ME, the undersigned authority, personally came and appeared, **ALYSSA MAURICE-ANDERSON**, who after being duly sworn by me, did depose and say:

That the above and foregoing is his sworn testimony in this proceeding and that he knows the contents thereof, that the same are true as stated, except as to matters and things, if any, stated on information and belief, and that as to those matters and things, he verily believes them to be true.

Alyssa Maurice-Anderson
Alyssa Maurice-Anderson

SWORN TO AND SUBSCRIBED BEFORE ME
THIS 14th DAY OF DECEMBER, 2022

Sean D Moore
NOTARY PUBLIC

My commission expires: upon death

Sean D. Moore-La. Bar No. 20303
Notary Public for the State of Louisiana
My commission expires upon death

BEFORE THE

LOUISIANA PUBLIC SERVICE COMMISSION

***IN RE*: APPLICATION OF ENTERGY LOUISIANA, LLC FOR APPROVAL OF THE ENTERGY FUTURE READY RESILIENCE PLAN (PHASE I)**	**))))**	**DOCKET NO. U- _______**

EXHIBIT AMA-1

DECEMBER 2022

List of Testimony Presending Before Utility Regulatory Bodies
by Alyssa Maurice-Anderson

Item No.	Date	Testimony	Docket No.	Jurisdiction	Type	Subject Matter
1	June 2022	Application of Entergy Louisiana, LLC, for Approval of the 2021 Solar Portfolio, the Geaux Green Option, Cost Recovery and Related Relief , Rebuttal Testimony	U-36190	Louisiana Public Service Commission	Rebuttal	Ratemaking
2	June 2022	In Re: Application of Entergy Louisiana, LLC for Recovery in Rates of Costs Related to Hurricane Ida and Related Relief, Direct Testimony Re Financing Application	U-36350	Louisiana Public Service Commission	Direct	Securitization, Ratemaking
3	June 2022	In Re: Application of Entergy Louisiana, LLC for Recovery in Rates of Costs Related to Hurricane Ida and Related Relief, Direct Testimony Re Ancillary Application	U-36350	Louisiana Public Service Commission	Direct	Securitization, Ratemaking
4	July 2022	Application of Entergy Texas, Inc. for Authority to Change Rates	53719	Public Utility Commission of Texas	Direct	Decomm Escalation Rate, Reg Services Affiliate Costs
5	June 2022	In Re: Application of Entergy Louisiana, LLC for Recovery in Rates of Costs Related to Hurricane Ida and Related Relief, Direct Testimony Re Financing Application	U-36350	Louisiana Public Service Commission	Settlement	Securitization, Ratemaking

BEFORE THE

LOUISIANA PUBLIC SERVICE COMMISSION

***IN RE*: APPLICATION OF ENTERGY LOUISIANA, LLC FOR APPROVAL OF THE ENTERGY FUTURE READY RESILIENCE PLAN (PHASE I)**	**))))**	**DOCKET NO. U- _______**

EXHIBIT AMA-2

DECEMBER 2022

Outstanding balance as of:	2008/EGSL	2008/ELI	2010/EGSL	2010/ELI	2014/EGSL	2014/ELI	2022/ELL	2023/ELL (Ida) *ESTIMATED*	**Storm Securitization Balance**
12/31/2008	278,400,000.00	687,700,000.00	-	-	-	-	-	-	966,100,000.00
12/31/2009	263,063,423.00	650,781,130.00	-	-	-	-	-	-	913,844,553.00
12/31/2010	239,647,685.00	592,778,302.00	244,100,000.00	468,900,000.00	-	-	-	-	1,545,425,987.00
12/31/2011	215,051,113.00	532,017,590.00	226,969,223.91	436,714,317.97	-	-	-	-	1,410,752,244.88
12/31/2012	189,228,676.00	468,383,019.00	208,576,244.23	401,411,419.59	-	-	-	-	1,267,599,358.82
12/31/2013	162,103,390.00	401,000,058.00	189,899,996.90	365,705,118.94	-	-	-	-	1,118,708,563.84
12/31/2014	133,429,277.00	329,732,510.00	170,925,135.39	329,500,942.72	71,000,000.00	243,850,000.00	-	-	1,278,437,865.11
12/31/2015	103,042,045.00	254,275,018.00	151,653,979.77	292,485,071.93	67,769,906.66	231,524,204.79	-	-	1,100,750,226.15
12/31/2016	70,843,265.00	174,440,329.00	132,030,818.31	254,564,340.14	62,446,267.35	212,810,373.87	-	-	907,135,393.67
12/31/2017	36,562,352.00	89,860,263.00	111,837,963.30	215,671,854.17	56,968,384.74	193,787,837.58	-	-	704,688,654.79
12/31/2018	-	-	91,018,708.79	175,498,139.66	51,333,549.35	174,446,119.05	-	-	492,296,516.85
12/31/2019	-	-	69,528,287.40	133,967,169.70	45,535,714.77	154,783,539.66	-	-	403,814,711.53
12/31/2020	-	-	47,223,003.90	90,991,047.79	39,571,659.15	134,726,848.50	-	-	312,512,559.34
12/31/2021	-	-	24,058,429.46	46,366,037.21	33,435,366.97	114,037,671.26	-	-	217,897,504.90
12/31/2022	-	-	-	-	27,122,657.52	92,671,774.45	3,193,505,000.00	-	3,313,299,431.97
12/31/2023	-	-	-	-	20,627,955.22	70,608,799.57	3,039,208,410.42	1,621,825,000.00	4,752,270,165.21
12/31/2024	-	-	-	-	13,946,307.85	47,824,667.33	2,873,518,444.25	1,539,825,000.00	4,475,114,419.43
12/31/2025	-	-	-	-	7,072,133.46	24,296,720.11	2,701,784,653.96	1,453,825,000.00	4,186,978,507.53
12/31/2026	-	-	-	-	-	-	2,523,786,580.75	1,363,825,000.00	3,887,611,580.75
12/31/2027	-	-	-	-	-	-	2,339,258,459.67	1,268,825,000.00	3,608,083,459.67
12/31/2028	-	-	-	-	-	-	2,147,219,543.76	1,169,825,000.00	3,317,044,543.76
12/31/2029	-	-	-	-	-	-	1,947,138,129.15	1,065,825,000.00	3,012,963,129.15
12/31/2030	-	-	-	-	-	-	1,738,677,399.81	955,825,000.00	2,694,502,399.81
12/31/2031	-	-	-	-	-	-	1,521,439,812.82	839,825,000.00	2,361,264,812.82
12/31/2032	-	-	-	-	-	-	1,294,841,742.85	717,825,000.00	2,012,666,742.85
12/31/2033	-	-	-	-	-	-	1,058,453,074.86	589,825,000.00	1,648,278,074.86
12/31/2034	-	-	-	-	-	-	811,784,323.64	453,825,000.00	1,265,609,323.64
12/31/2035	-	-	-	-	-	-	554,013,414.37	310,825,000.00	864,838,414.37
12/31/2036	-	-	-	-	-	-	284,578,206.32	159,825,000.00	444,403,206.32
12/31/2037	-	-	-	-	-	-	-	-	-
12/31/2038	-	-	-	-	-	-	-	-	-

BEFORE THE

LOUISIANA PUBLIC SERVICE COMMISSION

***IN RE*: APPLICATION OF ENTERGY LOUISIANA, LLC FOR APPROVAL OF THE ENTERGY FUTURE READY RESILIENCE PLAN (PHASE I)**	**))))**	**DOCKET NO. U- _______**

EXHIBIT AMA-3

DECEMBER 2022

	2024	2025	2026	2027	2028
Without Rider					
Resilience Investment					
Transmission	29,425,038	127,126,886	312,319,535	298,582,177	334,298,134
Distribution	334,609,448	739,914,824	906,896,826	636,781,947	876,959,531
Total	364,034,486	867,041,710	1,219,216,361	935,364,125	1,211,257,664
Cumulative	364,034,486	1,231,076,196	2,450,292,557	3,385,656,682	4,596,914,346
Plant-in-Service					
Transmission	14,712,519	78,275,962	219,723,210	305,450,856	316,440,155
Distribution	250,957,086	638,588,480	865,151,326	704,310,667	816,915,135
Total	265,669,605	716,864,442	1,084,874,536	1,009,761,523	1,133,355,290
Cumulative	265,669,605	982,534,047	2,067,408,583	3,077,170,107	4,210,525,397
Book Depreciation					
Transmission	147,125	1,077,010	4,057,002	9,308,742	15,527,652
Distribution	3,764,356	17,107,540	39,663,637	63,205,567	86,023,954
Total	3,911,481	18,184,550	43,720,639	72,514,309	101,551,606
Cumulative	3,911,481	22,096,031	65,816,670	138,330,979	239,882,585
Net Investment	360,123,005	1,208,980,165	2,384,475,888	3,247,325,703	4,357,031,761
Rate Base					
TRM	66,031,362	235,541,818	504,858,630	804,181,003	1,078,100,559
DRM	-	-	-	-	-
Inside Band	123,596,365	557,933,200	1,281,417,515	2,014,713,909	2,700,712,050
Total	189,627,727	793,475,018	1,786,276,145	2,818,894,913	3,778,812,609
Incremental Revenue - Resilience	293,075	7,613,314	44,064,477	128,507,164	246,224,945
Cumulative Debt Issuance	182,186,228	611,623,065	1,206,306,351	1,642,822,073	2,204,222,368
Interest Expense	4,736,842	20,639,042	47,266,165	74,077,339	100,023,155
Incremental Pre-tax Income	(8,355,249)	(31,210,278)	(46,922,326)	(18,084,485)	44,650,183
Incremental Tax Expense	2,250,068	8,404,928	12,636,182	4,870,152	(12,024,294)
Incremental Earnings - Resilience	(6,105,180)	(22,805,350)	(34,286,144)	(13,214,333)	32,625,889
Net Cash Impact					
Revenue	293,075	7,613,314	44,064,477	128,507,164	246,224,945
Int Expense	(4,736,842)	(20,639,042)	(47,266,165)	(74,077,339)	(100,023,155)
Operating Cash flow	(4,443,767)	(13,025,728)	(3,201,687)	54,429,825	146,201,789
Debt Issuance	182,186,228	429,436,837	594,683,286	436,515,722	561,400,295
Capex	(364,034,486)	(867,041,710)	(1,219,216,361)	(935,364,125)	(1,211,257,664)
Net Cashflow - Resilience	(186,292,025)	(450,630,601)	(627,734,763)	(444,418,578)	(503,655,580)
OCF:Debt					
Operating Cash Flow	(4,443,767)	(13,025,728)	(3,201,687)	54,429,825	146,201,789
Debt	182,186,228	611,623,065	1,206,306,351	1,642,822,073	2,204,222,368
OCF:Debt Ratio	-2.4%	-2.1%	-0.3%	3.3%	6.6%

	2024	2025	2026	2027	2028
With Resilience Rider					
Resilience Investment					
Transmission	29,425,038	127,126,886	312,319,535	298,582,177	334,298,134
Distribution	334,609,448	739,914,824	906,896,826	636,781,947	876,959,531
Total	364,034,486	867,041,710	1,219,216,361	935,364,125	1,211,257,664
Cumulative	364,034,486	1,231,076,196	2,450,292,557	3,385,656,682	4,596,914,346
Plant-in-Service					
Transmission	14,712,519	78,275,962	219,723,210	305,450,856	316,440,155
Distribution	250,957,086	638,588,480	865,151,326	704,310,667	816,915,135
Total	265,669,605	716,864,442	1,084,874,536	1,009,761,523	1,133,355,290
Cumulative	265,669,605	982,534,047	2,067,408,583	3,077,170,107	4,210,525,397
Book Depreciation					
Transmission	147,125	1,077,010	4,057,002	9,308,742	15,527,652
Distribution	3,764,356	17,107,540	39,663,637	63,205,567	86,023,954
Total	3,911,481	18,184,550	43,720,639	72,514,309	101,551,606
Cumulative	3,911,481	22,096,031	65,816,670	138,330,979	239,882,585
Net Investment	360,123,005	1,208,980,165	2,384,475,888	3,247,325,703	4,357,031,761
Rate Base					
Resilience Rider	130,879,062	611,098,070	1,481,014,965	2,470,215,521	3,454,740,970
Inside Band	-	-	-	-	-
Total	130,879,062	611,098,070	1,481,014,965	2,470,215,521	3,454,740,970
Incremental Revenue - Resilience	15,762,042	73,516,966	177,820,450	296,182,162	414,364,188
Cumulative Debt Issuance	182,186,228	611,623,065	1,206,306,351	1,642,822,073	2,204,222,368
Interest Expense	4,736,842	20,639,042	47,266,165	74,077,339	100,023,155
Incremental Pre-tax Income	7,113,719	34,693,374	86,833,647	149,590,513	212,789,426
Incremental Tax Expense	(1,915,724)	(9,342,926)	(23,384,301)	(40,284,725)	(57,304,192)
Incremental Earnings - Resilience	5,197,994	25,350,449	63,449,346	109,305,788	155,485,233
Net Cash Impact					
Revenue	15,762,042	73,516,966	177,820,450	296,182,162	414,364,188
Int Expense	(4,736,842)	(20,639,042)	(47,266,165)	(74,077,339)	(100,023,155)
Operating Cash Flow	11,025,200	52,877,924	130,554,286	222,104,823	314,341,032
Debt Issuance	182,186,228	429,436,837	594,683,286	436,515,722	561,400,295
Capex	(364,034,486)	(867,041,710)	(1,219,216,361)	(935,364,125)	(1,211,257,664)
Net Cashflow - Resilience	(170,823,058)	(384,726,948)	(493,978,790)	(276,743,580)	(335,516,337)
OCF:Debt w/ Resilience					
Operating Cash Flow	11,025,200	52,877,924	130,554,286	222,104,823	314,341,032
Debt	182,186,228	611,623,065	1,206,306,351	1,642,822,073	2,204,222,368
OCF:Debt Ratio	6.1%	8.6%	10.8%	13.5%	14.3%

	2024	2025	2026	2027	2028
Variance					
Revenue - Base Recovery	293,075	7,613,314	44,064,477	128,507,164	246,224,945
Revenue - Resilience Recovery	15,762,042	73,516,966	177,820,450	296,182,162	414,364,188
Difference	15,468,967	65,903,652	133,755,973	167,674,998	168,139,243
Net Operating Cashflow - Base Recovery	(4,443,767)	(13,025,728)	(3,201,687)	54,429,825	146,201,789
Net Operating Cashflow - Resilience Recovery	11,025,200	52,877,924	130,554,286	222,104,823	314,341,032
Difference	15,468,967	65,903,652	133,755,973	167,674,998	168,139,243
OCF:Debt - Base Recovery	-2.4%	-2.1%	-0.3%	3.3%	6.6%
OCF:Debt - Resilience Recovery	6.1%	8.6%	10.8%	13.5%	14.3%
Difference	8.5%	10.8%	11.1%	10.2%	7.6%

BEFORE THE

LOUISIANA PUBLIC SERVICE COMMISSION

***IN RE*: APPLICATION OF ENTERGY LOUISIANA, LLC FOR APPROVAL OF THE ENTERGY FUTURE READY RESILIENCE PLAN (PHASE I)**	**))))**	**DOCKET NO. U- _______**

EXHIBIT AMA-4

DECEMBER 2022

RESILIENCE PLAN COST RECOVERY RIDER

I. PURPOSE AND APPLICABILITY

The purpose of the Resilience Plan Cost Recovery Rider ("Rider") is to establish the Rider Rate by which Entergy Louisiana, LLC ("ELL" or the "Company") will recover the costs associated with the Entergy Future Ready Resilience Plan ("Resilience Plan") for long-term grid resilience subject to the Louisiana Public Service Commission's ("LPSC's" or "Commission") oversight.

Note: Generally, unless otherwise specified herein, capitalized terms used throughout this document are as defined in the Company's Terms and Conditions.

II. NET MONTHLY BILL

The Net Monthly Bill or Monthly Bill calculated pursuant to each applicable retail rate schedule* and/or rider schedule* on file with the LPSC will be adjusted monthly by the appropriate percentage of applicable Base Rate Revenues, before application of the monthly fuel adjustment.

III. SEMI-ANNUAL FILINGS FOR RIDER RATE REDETERMINATION

A. GENERAL

For the Term of this Rider, ELL shall make Semi-Annual Filings with the Commission on or before the dates specified below of each calendar year providing the basis for Rider Rates to be effective in accordance with the schedule below.

1. Defined Terms
    a. Eligible Resilience Plan Costs - Those Resilience Expenses and Resilience Investments authorized for recovery through this Rider by the Commission in Docket # [U-XXXX].
    b. Resilience Expenses - those vegetation management expenses or other expenses to be incurred pursuant to the Company's Resilience Plan that are not being recovered through ELL's base rates or Formula Rate Plan.
    c. Resilience Investment – those Transmission and Distribution and other investments associated with the Company's Resilience Plan that are not being recovered through ELL's base rates or Formula Rate Plan and that are expected to be placed in service during the rate effective period associated with each Semi-Annual Filing.
    d. Resilience Plan Revenue Requirement – the calculated revenue requirement of Eligible Resilience Plan Costs
    e. True-up Amount –comparison of the actual Resilience Plan Revenue Requirement to the projected Resilience Plan Revenue Requirement for the rate effective period that has most recently concluded, along with explanations on material variances.
    f. True-up Report - calculates a True-Up Amount, until such time that the costs have been realigned to base rates, that shall be included in the following Semi-Annual Filing's proposed redetermined Rider Rates, with carrying charges calculated based on the weighted average cost of capital in effect as determined by the most recent rate filing.

RESILIENCE PLAN COST RECOVERY RIDER

3. Rider Rates shall initially recover the projected revenue requirement associated with Eligible Resilience Plan Costs, as defined above. When and where applicable, the Rider shall recover or return a True-Up Amount based on a comparison of projected to actualized Resilience Plan Revenue Requirements. Such filing shall include workpapers sufficient to document fully the calculations of the redetermined Rider Rates. The Commission Staff ("Staff") and all intervenors ("Intervenors") in Docket U-___ shall receive a copy of each Semi-Annual Filing at the time it is filed with the Commission.

Date of Filing	Rate Effective Period
January 10	Mar through August of Filing Yr
July 10	Sept of Filing Yr through Feb. of subsequent year

B. RESILIENCE REVENUE REQUIREMENT REDETERMINATION PROCEDURE

Each Semi-Annual Filing shall provide the Resilience Plan Revenue Requirement for projects that are expected to be placed into service during the rate-effective period corresponding with each Semi-Annual Filing. The projected Resilience Plan Revenue Requirement shall also include the costs associated with Resilience Investments previously placed into service to the extent that their costs are not recovered through another mechanism. The Semi-Annual Filing shall provide a complete list of Eligible Resilience Plan Costs that are expected to be incurred and projects placed in service or expected to be placed into service during the rate-effective period corresponding with each Semi-Annual Filing.

The Staff and Intervenors shall have 30 (thirty) days to ensure that the Resilience Revenue Requirement and Rider Rates comply with the requirements of this Rider. If any of the Parties should detect any error(s) in the application of the principles and procedures contained in this Rider or identify issues with any resilience expenses and investments, such error(s), data, or issues ("Disputed Items") shall be formally communicated in writing to the other Parties by the fortieth day after the Semi-Annual Filing. Each such Disputed Item shall include, if available, documentation of the proposed correction. The Company shall then have 10 (ten) days to review any proposed corrections or identified issues in response to the Disputed Items, to work with the other Parties to resolve any Disputed Items and to file a revised Attachment A containing Rider Rates reflecting all corrections upon which the Parties agree. The Company shall provide the other Parties with appropriate workpapers supporting any revisions made to the Rider Rates initially filed.

Except where there are unresolved Disputed Items, which shall be addressed in accordance with the provisions of Section III.C below, the Rider Rates initially filed or such corrected Rider Rates shall become effective for bills rendered on and after the first billing cycle for the month of March or September, as described above. Those Rider Rates shall then remain in effect until changed pursuant to the provisions of this Rider.

RESILIENCE PLAN COST RECOVERY RIDER

C. TRUE-UP REPORT AND PRUDENCE REVIEW

Beginning with the third Semi-Annual Filing, ELL shall also include a report of the True-Up Amount. For example, the Company's January filing will include a comparison of actual and projected Resilience Plan Revenue Requirements for the period from March through August and the Company's July filing will include a comparison of actual and projected Resilience Plan Revenue Requirements for the period from September through February. The January True-Up Report shall contain the True-Up Amount to be returned to or recovered from customers effective the first billing cycle of the following September. The July True-Up Report shall contain a True-Up Amount to be returned to or recovered from customers effective the first billing cycle of the following March.

The Staff and Intervenors shall have ninety days to ensure that the True-Up Amount complies with the requirements of this Rider and to review the prudence of any expenses or investments included therein. If any of the Parties should detect any error(s) in the True-Up Amount or identify issues as to the prudence of any expense or investment, such error(s), data, or issues and pertinent amounts shall be formally communicated in writing to the other Parties by the ninetieth day after the filing. Each such indicated Dispute shall include, if available, documentation of the proposed correction or prudence issue and the calculation of each amount in Dispute. The Company shall then have sixty days to review any proposed corrections or identified issues, to work with the other Parties to resolve any Disputes and to file a revised True-Up Amount reflecting all corrections upon which the Parties agree. The Company shall provide the other Parties with appropriate workpapers supporting any revisions made to the True-Up Amount initially filed.

Except where there are Unresolved Disputes, which shall be addressed in accordance with the provisions of Section III.D below, the True-Up Amount initially filed or such corrected True-Up Amount shall become effective for bills rendered on and after the first billing cycle for the month of March or September, as described above. Those True-Up Amount shall then remain in effect until changed pursuant to the provisions of this Rider.

D. DISPUTED ISSUES HEARING

In the event there are unresolved Disputed Items regarding any Evaluation Report, the Parties shall work together in good faith to resolve such Disputed Item(s). If the Parties are unable to resolve the disputes or reasonably believe they will be unable to resolve the disputes by the end of the periods provided for in Section III.B and III.C above, the remaining Disputed Items shall be submitted to the Commission for resolution.

If the Commission's final ruling on any Disputed Items requires changes in the current Rider Rates, including any True-Up Amounts initially implemented pursuant to the above provisions, the Company shall file a revised Attachment A containing such further modified Rate Adjustments within fifteen (15) days after receiving the Commission's order resolving the Disputes. The Company shall provide a copy of the filing to the other Parties together with appropriate supporting documentation. Such modified Rider Rates shall then be implemented with the next applicable monthly billing cycle after filing and shall remain in effect until superseded by Rider Rates established in accordance with the provisions of this Rider.

RESILIENCE PLAN COST RECOVERY RIDER

Within sixty (60) days after receipt of the Commission's final ruling on any Disputes, the Company shall determine the amount to be refunded or surcharged to customers, if any, together with interest at the legal rate of interest in effect at the time of the Filing. Such refund/surcharge amount shall be effective as an input to the next regular True-up Amount. Such refund/surcharge amount shall be applied to customers' bills in the manner prescribed by the Commission.

IV. RATE DETERMINATION

A. RIDER RATES

i. Resilience Revenue Requirement

The Resilience Revenue Requirement shall be redetermined semi-annually as set forth in Attachment A to this Rider. The Resilience Revenue Requirement shall be comprised of functionalized Transmission and Distribution revenue requirements. For the purposes of calculating the revenue requirements, an annual depreciation rate of 3% shall be used for all Distribution Resilience Investments and an annual depreciation rate of 2% shall be used for all Transmission Resilience Investments.

ii. Allocation of the Functionalized Revenue Requirements

The functionalized revenue requirements shall be allocated among rate classes based on each rate class's share of base revenue from the most recent calendar year. Transmission voltage customers shall be assigned 33% of the Distribution revenue requirement and the 12 coincident peak ("12 CP") share of the Transmission revenue requirement. The costs assigned to Transmission voltage customers shall then be divided by the amount that Transmission voltage customers would have been assigned if costs were based solely on their proportion of base revenue for the applicable period. The resulting percentage shall be applied to the total combined revenue requirements for the period and the resulting allocation shall be used to determine an equal percentage factor, expressed as a percentage of applicable base revenue, that applies to all retail customers. The remainder of the total combined revenue requirements, or the revenue requirement that is not assigned to transmission voltage retail customers, shall be used to determine an additional equal percentage factor, expressed as a percentage of applicable base revenues, that applies to distribution voltage customers. This allocation methodology is set forth in Attachment A to this Rider.

B. REVENUE ANNUALIZATION AND REALIGNMENT OF RESILIENCE REVENUE REQUIREMENT

During the Term of this Rider, and for as long as the Company remains subject to an FRP, the Resilience Revenue Requirement and associated present rate revenue shall be realigned and annualized into the FRP Evaluation Report and taken into account within the bandwidth calculation of the applicable FRP, when it is practical to do so.

If at any point during the Term of this Rider the Company no longer remains subject to an FRP, ELL shall continue to make Semi-Annual update filings pursuant to Section III subject to the limitation in Section V below.

RESILIENCE PLAN COST RECOVERY RIDER

V. TERM

This Rider shall remain in effect from the date of implementation unless otherwise modified on terms mutually agreeable to the Company and other parties or terminated by a future order.

If this Rider is terminated by a future order of the Commission, the Rider Rates then in effect shall continue to be applied until the Commission approves an alternative mechanism by which the Company can recover the costs reflected in the then-current Rider Rate or until such costs can be realigned to base rates (or the FRP, as applicable). At that time, any cumulative over-recovery or under-recovery resulting from application of the then-current Rider Rate, inclusive of carrying costs at the pre-tax weighted average cost of capital, shall be applied to customer billings over the twelve (12) month billing period beginning on the first billing cycle of the second month following the termination of the Rider in a manner prescribed by the Commission.

Attachment A
Effective:

ENTERGY LOUISIANA, LLC
RESILIENCE PLAN COST RECOVERY RIDER
ELECTRIC
FOR THE SIX MONTHS ENDED XX
RATE ADJUSTMENTS

The following Rider Rates are applicable under the regular terms and conditions of the Company to all Customers served under any retail electric Rate Schedule and/or Rider schedule except as noted below*. The Rider Rate applicable to a specific Customer shall be determined by either the base rate schedule(s) applicable to the customer's geographic location (*i.e.*, Legacy ELL Service Area or Legacy EGSL Service area) or, where applicable, the base rate schedule(s) elected by the Customer.

Voltage Level	Rate
Transmission*	%
Distribution*	%

*Excluded Schedules: AFC-L, AFC-G, AFC, AMSOO, ASPS-G, B-L, CM-G, Contract Minimums, CS-L, CS-L Rider 1, DTK, EAC, EAPS-L, EAPS-G, EECR-PE, EECR-QS-L, EECR-QS-G, EECS-L, EEIS-G, EER-L, EER-G, EEDBP, EIO, EIS-G, EIS-I-G, ERDRS-G, FCA (3,4,5,6), Facilities Charges, FA, FR-1-G, FSCII-ELL, FSCIII-ELL, FSCII-EGSL, FSCIII-EGSL, FSCIV-ELL, FSPP, FT, GPO, IES, Incremental Load under LCOP, LIS-L Rider 2, LQF-PO-G, LVGPO, MS, MVDR, MVER-L, MVER-G, NFRPCEA-L, NFRPCEA-G, OBP, PPS-1-L, QFSS-L, RCL, REP, RPCEA-L, RPCEA-G, RRD-V-G, RRD-VI-G, SCO-L, SCO-G, SCOII-L, SCOII-G, SCOIII-L, SCOIII-G, SCOIV-ELL, SLGO-L, SLGR-L, SMQ-G, SQF-L, SQF-G, SSTS-G, UODG, and applicable Special Contracted Rates.

Entergy Louisiana, LLC
Resilience Plan Cost Recovery Rider
Transmission & Distribution Allocations
Electric
For the Six Months Ended XX

			Transmission & Distribution		
No.	Rate Class [1]	Applicable Base Revenue [2]	Allocation	Revenue Requirement	Billing Factor
(a)	(b)	(c)	(d)	(e)	(h)
1	Residential		#DIV/0!	#DIV/0!	#DIV/0!
2	SGS		#DIV/0!	#DIV/0!	#DIV/0!
3	LGS		#DIV/0!	#DIV/0!	#DIV/0!
4	ECS		#DIV/0!	#DIV/0!	#DIV/0!
5	EECS		#DIV/0!	#DIV/0!	#DIV/0!
6	EIS		#DIV/0!	#DIV/0!	#DIV/0!
7	LIPS		#DIV/0!	#DIV/0!	#DIV/0!
8	LIS & LPS		#DIV/0!	#DIV/0!	#DIV/0!
9	LLHLFPS & HLFS		#DIV/0!	#DIV/0!	#DIV/0!
10	Lighting		#DIV/0!	#DIV/0!	#DIV/0!
11	Municipal Water Pumping Service		#DIV/0!	#DIV/0!	#DIV/0!
12	QFSS	$ -	#DIV/0!	#DIV/0!	#DIV/0!
13	Special Contracted Rates	$ -	#DIV/0!	#DIV/0!	#DIV/0!
14	Total	$ -	#DIV/0!	#DIV/0!	#DIV/0!
15	Resilience Revenue Requirement (T&D)			#DIV/0!	

Line			**Distribution Only**			
No.	Rate Class [1]	Applicable Base Revenue [3]	Allocation	Revenue Requirement	Billing Factor	TOTAL
(a)	(b)	(c)	(d)	(e)	(g) / (c) = (h)	(i)
16	Residential		#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!
17	SGS		#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!
18	LGS		#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!
19	ECS		#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!
20	EECS		#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!
21	EIS		#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!
22	LIPS		#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!
23	LIS		#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!
24	LLHLFPS		#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!
25	Lighting		#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!
26	Municipal Water Pumping Service		#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!
27	QFSS	$ -	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!
28	Special Contracted Rates	$ -	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!
29	Total	$ -	#DIV/0!	#DIV/0!	#DIV/0!	
30	Resilience Revenue Requirement (D Only)			#DIV/0!		

31	Distribution Revenue Requirement		$ -
32	Transmission Revenue Requirement		$ -
33	Combined T&D Revenue Requirement		$ -
34	Percent Applicable Revenue from T-level Customers		#DIV/0!
35	Transmission Voltage Allocation	Line 33 * Line 34	#DIV/0!
36	Distribution Revenue Requirement		$ -
37	Percentage Assignment to Transmission		
38	Distribution Revenue Requirement to be Shared	Line 36 * Line 37	$ -
39	T-level Customers Percent of 12CP [4]		
40	Distribution Revenue Requirement Allocated to Transmission	Line 34 * Line 48	#DIV/0!
41	Transmission Revenue Requirement Allocated to Transmission	Line 32 * Line 39	$ -
42	Total Allocated to Transmission		#DIV/0!
43	Transmission & Distribution Revenue Requirement	Line 42 / Line 35	#DIV/0!
44	Combined T&D Revenue Requirement Allocation to T-level Customers & D-level Customers	Line 33 * Line 43	#DIV/0!
45	Portion Allocated to D-level Customers Only	Line 33 - Line 44	#DIV/0!

Notes:

[1] Excluding Schedules AFC, AFC-L, AFC-G, AMSOO, DTK, EAC, EECR-PE, EECR-QS-G, EECR-QS-L, EER-G, EER-L, ERDRS-G, FA, FR-1-G, FRP, FSCII-EGSL, FSCII-ELL, FSCIII-EGSL, FSCIII-ELL, FSPP, FT, LQF-PO-G, MS, MVER-G, MVER-L, NFRPCEA-G, NFRPCEA-L, PPS-L, RCL, REP, RPCEA-G, RPCEA-L, RRD-V-G, RRD-VI-G, SCO-G, SCO-L, SCOII-G, SCOII-L, SCOIII-G, SCOIII-L, SLGO-L, SLGR-L, SQF-G, and SQF-L

[2] Applicable Base Revenues from ELL's most recent Formula Rate Plan filing if subject to an FRP, or from most recent calendar year

[3] Applicable Base Revenues from Distribution voltage customers only

[4] Transmission Voltage 12CP allocation as determined by ELL Cost of Service Study

Entergy Louisiana, LLC
Resilience Plan Cost Recovery Rider
Revenue Requirement - Transmission
Electric
For the Six Months Ended XX

		Beginning Balance	Ending Balance	B/E Average
1	Transmission Plant in Service (1)	-		-
2	Accumulated Depreciation (2)	-	-	-
3	Rate Base	-	-	-
4	Benchmark Return on Rate Base (3)			-
5	Depreciation Expense			-
6	Total			-
7	Vegetation Management Expenses			
8	Other Resilience Expenses			-
9	Total Transmisison Resilience Expenses			-
10	True-Up w Carrying Charges (4)			
11	Revenue Related Expense Factor (5)			
12	Retail Allocation Revenue Factor (5)			
13	Transmission Revenue Requirement			-

(1) Ending Balance from prior filing subject to true up + WP1 Line 4
(2) Per Rider Schedule FRRCR Section IV.B.i annual depreciation rate for Transmission closings shall be 2%
(3) Line 3 * WP6
(4) WP3
(5) From most recently filed Formula Rate Plan Filing

Entergy Louisiana, LLC
Resilience Plan Cost Recovery Rider
Revenue Requirement - Distribution
Electric
For the Six Months Ended XX

		Beginning Balance	Ending Balance	B/E Average
1	Distribution Plant in Service (1)	-		-
2	Accumulated Depreciation (2)	-	-	-
3	Rate Base	-	-	-
4	Benchmark Return on Rate Base (3)			-
5	Depreciation Expense			-
6	Total			-
7	Vegetation Management Expenses			
8	Other Resilience Expenses			-
9	Total Distribution Resilience Expenses			-
10	True-Up w Carrying Charges (4)			
11	Revenue Related Expense Factor (5)			
12	Retail Allocation Revenue Factor (5)			
13	Distribution Revenue Requirement			-

(1) Ending Balance from prior filing subject to true up + WP1 Line 9
(2) Per Rider Schedule FRRCR Section IV.B.i annual depreciation rate for Distribution closings shall be 3%
(3) Line 3 * WP5
(4) WP2
(5) From most recently filed Formula Rate Plan Filing

BEFORE THE

LOUISIANA PUBLIC SERVICE COMMISSION

***IN RE*: APPLICATION OF ENTERGY LOUISIANA, LLC FOR APPROVAL OF THE ENTERGY FUTURE READY RESILIENCE PLAN (PHASE I)**	**))))**	**DOCKET NO. U- _______**

DIRECT TESTIMONY

OF

CHARLES W. LONG

ON BEHALF OF

ENTERGY LOUISIANA, LLC

DECEMBER 2022

TABLE OF CONTENTS

EXHIBITS

I. INTRODUCTION

A. Qualifications

Q1. PLEASE STATE YOUR NAME AND CURRENT BUSINESS ADDRESS.

A. My name is Charles W. Long. My business address is 6540 Watkins Drive, Jackson, Mississippi 39213.

Q2. ON WHOSE BEHALF ARE YOU FILING THIS DIRECT TESTIMONY?

A. I am testifying before the Louisiana Public Service Commission ("Commission" or "LPSC") on behalf of Entergy Louisiana, LLC ("ELL" or the "Company") in support of the proposed resilience projects that will benefit ELL's customers and communities.

Q3. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by Entergy Services, LLC ("ESL")[1] as Vice President of Power Delivery Operations.

Q4. PLEASE DESCRIBE YOUR EDUCATION AND BUSINESS EXPERIENCE.

A. In 1991, I graduated from the University of Alabama in Tuscaloosa with a Bachelor of Science degree in Electrical Engineering. I began my professional career in 1992 with Louisiana Power & Light Company (now ELL) as a system protection engineer,

[1] ESL is a service company to the five Entergy Operating Companies ("EOCs"), which are Entergy Arkansas, LLC ("EAL"), ELL, Entergy Mississippi, LLC ("EML"), Entergy New Orleans, LLC ("ENO"), and Entergy Texas, Inc. ("ETI").

remaining in that capacity until 1996. In 1996, I moved into transmission operations planning within Entergy Services, Inc. (the predecessor of ESL), where I worked until 2000. In 2000, I became the substation supervisor in Baton Rouge, Louisiana, for the former Entergy Gulf States Louisiana, L.L.C. ("Legacy EGSL").[2] In 2006, I assumed the role of Manager, Transmission Planning with planning responsibility for transmission facilities for EAL and EML.

In April 2012, I was promoted to Director, Transmission Planning, where I oversaw the development of proposals for the expansion of, and improvements to, the transmission systems of the EOCs, including those of ELL. Specifically, my responsibilities included providing leadership and guidance to a staff of managers and engineers engaged in all aspects of long-term transmission planning, including the development of projects and plans designed to (1) ensure that the transmission systems of the EOCs remain in compliance with North American Electric Reliability Corporation ("NERC") reliability standards governing transmission planning, as well as local planning criteria, and (2) deliver energy to the customers of ELL and the other EOCs at the lowest reasonable cost.

In June of 2019, I was promoted to Vice President, Transmission Planning & Strategy, where I oversaw the development of the transmission capital investment plans and options for the EOCs. In August of 2021, I was promoted to Acting Vice

[2] On October 1, 2015, pursuant to Commission Order No. U-33244-A, Legacy EGSL and the former Entergy Louisiana, LLC ("Legacy ELL") combined substantially all of their respective assets and liabilities into a single operating company, Entergy Louisiana Power, LLC, which subsequently changed its name to Entergy Louisiana, LLC ("Business Combination"). Upon consummation of the Business Combination, ELL became the public utility that is subject to Commission regulation and now stands in the shoes of Legacy EGSL and Legacy ELL in pending Commission dockets.

President, Transmission, where I led the Transmission business unit which planned, designed, constructed, operated, and maintained the transmission assets of the EOCs.

In May of 2021, I assumed my current position as Vice President of Power Delivery Operations within the Power Delivery Organization, which is a new organization within ESL. I describe the Power Delivery Organization later in my testimony. The Power Delivery Operations group that I lead is responsible for the safe and reliable operation of the EOCs' respective transmission and distribution electrical systems. As the leader of that group, I further ensure that my organization's operations processes, practices, and procedures conform to NERC, Federal Energy Regulatory Commission ("FERC") and Southeastern Electric Reliability Corporation ("SERC") regulations and that future plans to improve the reliability performance and resilience of the systems include the operational experiences my teams collect. I am a registered professional engineer in the state of Louisiana and have over thirty years of experience in system planning, operations, and maintenance. My work experiences include significant involvement in the planning for and recovery from the impacts of hurricanes, ice storms and other major weather beginning with Hurricane Andrew in 1992, and most recently with Hurricane Ida. A list of my prior testimony is attached as Exhibit CWL-1.

B. <u>Purpose of Testimony</u>

Q5. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My direct testimony supports the Company's Application in this proceeding seeking approval of the Entergy Future Ready Resilience Plan ("Resilience Plan"). That plan represents the next evolution in satisfying ELL's obligation to serve and meet customers' expectations. The goal of the Resilience Plan is to enhance the resilience of ELL's transmission and distribution ("T&D") infrastructure in a defined period so that future storm restorations can occur more expeditiously and efficiently, resulting in (1) customers experiencing shorter service interruptions and (2) the reduction of storm restoration costs. In fact, Company witness Jason De Stigter notes in his direct testimony that ELL's Comprehensive Hardening Plan, which is a large component of the Resilience Plan, is reasonably projected to produce a reduction in storm restoration costs of approximately 50 percent. Moreover, the projects identified in the Comprehensive Hardening Plan are reasonably projected to produce a decrease in the projected customer minutes interrupted ("CMI") after a major storm by approximately 55 percent over the next 50 years. Those cost and customer outage reductions would be transformative.

ELL's storm experience, especially with recent, major hurricanes, indicates that the Commission should consider accelerating resilience efforts, and the Comprehensive Hardening Plan is different from what ELL previously has done to enhance the reliability and resilience of its T&D infrastructure. Maintaining and enhancing the reliability of T&D infrastructure is an ongoing process for ELL, and the Company enhances resilience by implementing new engineering design standards as it performs its reliability work. Enhancing resilience in the course of reliability work, however, will not provide resilience to as many customers in as timely a manner as proactive, continuous resilience work. That being said, and as is noted by Company witness Sean Meredith in his direct testimony, Resilience Plan projects should improve system reliability over the long run. In the past, ELL has undertaken some resilience efforts during storm restoration, but those efforts were targeted and more narrowly-focused than the plan presented here. Moreover, as I discuss below and as Mr. Meredith discusses in his direct testimony, addressing resilience during storm restoration involves significant obstacles and challenges and is not as efficient as proactive resilience work. The Resilience Plan also includes a requested increase in vegetation management spending, which should complement ELL's proposed hardening efforts. Accordingly, the Commission should approve the Resilience Plan, with an appropriate cost-recovery mechanism, so that ELL can begin the Resilience Plan's initial phase and deliver comprehensive resilience benefits to customers.

Q6. HOW IS YOUR TESTIMONY STRUCTURED?

A. In Section II, I discuss the Power Delivery Organization, which is responsible for planning, operating, and maintaining ELL's transmission and distribution systems, as well as the Capital Projects Organization, which designs and constructs ELL's transmission and distribution system. Those two organizations will work with ELL to execute the Comprehensive Hardening Plan and bring resilience benefits to ELL and its customers. In Section III, I discuss the ongoing process of the Company's reliability work on its distribution and transmission systems, which includes an overview of those systems and operations. In Section IV, I address ELL's proposed changes to vegetation management programs and spending. Finally, in Section V, I discuss the need for the Comprehensive Hardening Plan and the benefits that a comprehensive resilience effort can provide.

II. THE POWER DELIVERY ORGANIZATION

Q7. YOU PREVIOUSLY EXPLAINED THAT THE POWER DELIVERY ORGANIZATION IS A NEW GROUP WITHIN ESL. PLEASE ELABORATE.

A. The Power Delivery Organization was formed in May 2022, and it essentially resulted from the combination of what had been ESL's separate distribution and transmission organizations. Those organizations were combined for a number of reasons, including: (1) to enhance coordination between the transmission, distribution, and capital projects teams in order to deliver service to our customers; (2) to improve the resilience and reliability of our transmission and distribution systems, and to achieve our customer-centricity goals; (3) to improve our ability to manage electrification, renewables, and resilience by centralizing certain functions in project delivery; (4) to improve safety performance; and (5) to improve the overall customer experience by more effectively executing planned and unplanned work.

Q8. WHO IS THE LEADER OF THE POWER DELIVERY ORGANIZATION?

A. Elaina Ball is the Senior Vice President, Power Delivery, and I report to Ms. Ball.

Q9. PLEASE DESCRIBE THE POWER DELIVERY ORGANIZATION.

A. The Power Delivery Organization is responsible for planning, operating and maintaining ELL's transmission and distribution systems that provide power and energy to homes, businesses, and governmental entities within the Louisiana communities that ELL serves. Power Delivery also is responsible for setting and maintaining the engineering standards to be applied to the transmission and distribution systems, while also designing and constructing smaller projects, such as projects necessary to interconnect new customers and to replace failed equipment. Larger projects and programs involving more complex project management and engineering techniques are executed by the Capital Projects organization, subject to the standards set by the Power Delivery Engineering group. I discuss both the Capital Projects organization and the Power Delivery Engineering group below. A significant majority of the proposed Comprehensive Hardening Plan's resilience work will therefore be executed by the Capital Projects organization and contractors that the organization retains. Accordingly, the Capital Projects organization and the Power Delivery Organization will work with ELL to execute the Comprehensive Hardening Plan and bring resilience benefits to ELL and its customers.

Q10. HOW IS THE POWER DELIVERY ORGANIZATION ORGANIZED?

A. The Power Delivery Organization contains the following groups: (1) Power Delivery Engineering; (2) Project and Portfolio Development; (3) Power Delivery Services; (4) Storm Operations; and (5) Power Delivery Operations, which is the group that I lead.

Q11. WHAT ARE THE RESPONSIBILITIES OF THE POWER DELIVERY ENGINEERING GROUP?

A. The Power Delivery Engineering group assures that there are appropriate transmission and distribution engineering and construction standards and processes throughout the Power Delivery and Capital Projects organizations. The group sets the standard of work for all engineers in the Power Delivery and Capital Projects organizations. The standards set and maintained by the Power Delivery Engineering group meet or exceed all National Electrical Safety Code ("NESC")[3] standards and are in accordance with other recognized industry standards. In the case of the Comprehensive Hardening Plan, and as is discussed in greater detail in Mr. Meredith's direct testimony, the Company has established more stringent wind loading design standards that incorporate the recent operating experiences from major storms including Hurricanes Laura and Ida, which were particularly devastating and catastrophic storms that impacted the communities that ELL serves. These new wind loading design standards will result in more resilient facilities. The pace at which facilities designed to these new standards will replace legacy facilities designed to prior standards is the subject of the Comprehensive Hardening Plan.

Q12. WHAT ARE THE RESPONSIBILITIES OF THE PROJECT AND PORTFOLIO DEVELOPMENT GROUP?

A. The Project and Portfolio Development group develops and prioritizes the portfolio of projects necessary to serve our customers reliably, including new facilities, the renewal and replacement of aging or poorly performing assets, the construction of facilities to support or enable economic growth, and the development of projects to address a range of other needs. This group is also charged with developing the

[3] The Institute of Electrical and Electronics Engineers ("IEEE") defines the NESC as follows: "Published exclusively by IEEE and updated every five years to keep the Code up-to-date with changes in the industry and technology, the National Electrical Safety Code® (NESC®) sets the ground rules and guidelines for practical safeguarding of utility workers and the public during the installation, operation, and maintenance of electric supply, communication lines and associated equipment." https://standards.ieee.org/products-programs/nesc/.

strategies around maintaining and replacing assets and the overall design of the transmission and distribution systems.

Q13. WHAT ARE THE RESPONSIBILITIES OF THE POWER DELIVERY SERVICES GROUP?

A. The Power Delivery Services group supports my group, along with the Capital Project's project delivery organization, by centralizing certain functions such as safety, vegetation management, fleet management, field metering, environmental services, and right-of-way. This group also implements best practices to provide these services across the EOCs' transmission and distribution systems during the construction of new facilities as well as the renewal of and maintenance of these facilities.

Q14. WHAT ARE THE RESPONSIBILITIES OF THE STORM OPERATIONS GROUP?

A. The Storm Operations group supports storm-related operations, such as planning for major storm events and implementing strategies to respond to them, while continuously monitoring and updating storm safety and performance metrics. This group, along with ESL and EOC employees who are involved in storm restoration, participate in the restoration strategy group, which is activated during severe weather such as widespread severe thunderstorms and hurricanes.

Q15. WHAT ARE THE RESPONSIBILITIES OF THE POWER DELIVERY OPERATIONS GROUP THAT YOU LEAD?

A. The Power Delivery Operations Group oversees the day-to-day operations of the transmission and distribution systems that deliver energy from generation resources to the customers served by each of the EOCs, including ELL. The Power Delivery Operations team is responsible for a number of activities, including: constructing facilities to interconnect new customers, responding to and restoring outages, operating and monitoring the performance of the transmission and distribution systems, repairing and maintaining transmission and distribution assets and facilities, and an array of support functions such as engineering services for small, *ad hoc* projects.

The electric grid consists of electric transmission and distribution systems that bring energy from generating facilities to ELL's customers. The Power Delivery Operations group monitors the transmission and distribution system loads and voltage levels, along with other characteristics, to ensure there is adequate capacity to meet customer needs and that the quality of the energy delivered meets customer expectations. In addition, the group handles routine and emergency switching needed to maintain a continuous supply of electricity to customers and to address customer interruptions as safely and quickly as reasonably possible.

The electric transmission and distribution systems require regular inspection and maintenance to preserve their integrity and ability to provide reliable service to customers. These maintenance activities are both preventative and reactive, as discussed later in my testimony. Preventative maintenance includes equipment inspections and introducing new maintenance practices to enhance the overall operation and reliability of the electric system, whereas reactive repairs and upkeep are required when service is interrupted due to strong winds, lightning, or other types of damage. Maintenance activities also include routine vegetation management along rights-of-way ("ROWs"). Should these inspections, monitoring by the control centers, or system events identify facilities not performing correctly, jobs are planned to upgrade or replace those facilities.

Moreover, to accommodate customer growth, ELL must continually add to or upgrade its distribution facilities. These additions, both major and minor, require constructing distribution line extensions or increasing the capacity of existing distribution facilities. Construction also includes clearing new ROWs of vegetation. The construction of new or enhanced distribution lines is part of ELL's goal to provide safe and reliable service at the lowest reasonable cost to all current and prospective customers.

The Power Delivery Operations organization utilizes over 1,200 employees across ESL and ELL, including line workers; engineers; engineering associates; substation mechanics; technicians; operators; region, line, and construction supervisors; drafters; storekeepers; administrative assistants; and various others, as well as hundreds of contract resources. These employees and contractors provide support for ELL in the areas of engineering, design, operations, accounting, customer service, and other miscellaneous areas and perform these activities for the five ELL regions identified later in my testimony. Coordination between these employees, at both a centralized and localized level, allows for synergies between the various teams in the performance of their duties.

III. THE ONGOING PROCESS OF T&D RELIABILITY AND AN OVERVIEW OF THE COMPANY'S T&D SYSTEMS AND OPERATIONS

A. The Distinction Between Reliability and Resilience

Q16. BEFORE DISCUSSING RELIABILITY, PLEASE EXPLAIN WHAT YOU MEAN BY THE TERM "RESILIENCE" SO THAT A DISTINCTION BETWEEN THE TWO CONCEPTS CAN BE UNDERSTOOD.

A. As discussed by Company witness Phillip R. May, resilience is the ability to prepare for, adapt to, and recover from non-normal weather events, such as hurricanes, floods, winter storms, wildfires, tornadoes, and other major disruptions. By comparison, system reliability focuses on the availability of power to customers under normal operating conditions, which include day-to-day operational challenges such as thunderstorms. Although resilience and reliability are complementary from the customers' perspective, the projects being proposed as part of the Resilience Plan were selected specifically to help improve resilience as compared to a focus on system reliability.

For electric utility systems, resilience relative to severe weather events has at least three critical dimensions: (1) hardening, which involves building or improving a system in ways that will make it better able to withstand the impacts caused by severe weather events; (2) modernization, which includes adapting the system to reflect or incorporate newer technologies that can improve the system's ability to withstand non-normal weather events, including self–healing networks, smart sensors, fault-detection technology, and microgrids; and (3) recovery, which includes incorporating customer-sited generation and back-up options and designing resources to assist with recovery after a major weather event. While such efforts should be expected to have positive impacts on the day-to-day operations of the utility system under normal conditions (*i.e.*, reliability), projects designed to improve resilience are focused particularly on preparing the electric system to withstand and recover from severe, non-normal weather events.

Q17. PLEASE ELABORATE ON THE RELATIONSHIP BETWEEN RESILIENCE AND RELIABILITY.

A. As discussed by Mr. May, and although, as I just indicated, resilience efforts may avoid interruptions that are measured by traditional reliability indices, defining a precise relationship between resilience and reliability is challenging. That said, while reliability focuses on the availability of power to customers, resilience takes a broader view of the grid and looks for ways to avoid, mitigate, survive, and/or recover from the effects of disruptive events.

Q18. IS THE APPROACH TO RELIABILITY THE SAME FOR DISTRIBUTION AS FOR TRANSMISSION?

A. In many respects, the approach is the same. For both functions, ensuring reliability entails planning for the expected needs of the system, now and in the future, as well as identifying the causes of outages and targeting activities to prevent their recurrence, or reduce their impact. The primary differences in the approach to reliability for each function are based on the different general designs of each system. The transmission system is generally a looped system, meaning that every point where energy is delivered from the transmission system has at least two sources. Thus, the reliability experienced by customers from the transmission system is good if one of the sources is highly reliable even if the other source is less reliable. In contrast, the majority of the distribution system is radially fed, meaning that in most cases, each customer is dependent on a single source, and thus the reliability that customers experience is based on the reliability of that single source.

From an overall system perspective, the transmission system interconnects generators and other systems together, and thus the reliability of the entire electric system can be impacted by transmission reliability issues. The reliability of the transmission system is not only important to ensure the quality of the service provided to an individual customer, but also to ensure the reliability of the entire Eastern Interconnection.[4] Transmission system reliability challenges are less frequent than those affecting the distribution system, but they can be enormously impactful, as seen from the widespread blackouts that have been experienced in the Northeast in 2003,[5] in the West in 2011,[6] and in Texas in 2021 during Winter Storm Uri.[7] In

[4] The Eastern Interconnection reaches from Central Canada eastward to the Atlantic coast (excluding Québec), south to Florida and west to the foot of the Rockies (excluding most of Texas). All of the electric utilities in the Eastern Interconnection are electrically tied together during normal system conditions and operate at a synchronized frequency operating at an average of 60Hz.

[5] States in the Midwest and Northeast United States, along with Ontario, Canada, faced a blackout on August 14, 2003. The states affected alongside the Canadian province of Ontario were Ohio, Michigan, Pennsylvania, New York, Vermont, Massachusetts, Connecticut, and New Jersey. The blackout started shortly after 4:00p EST, with some areas not being restored for four days.

contrast, distribution system reliability challenges are more frequent, but also tend to be very localized as compared to transmission. Thus, the solutions identified for addressing transmission reliability challenges may differ from the solutions best suited for distribution. Nonetheless, the fundamentals of identifying the existing or potential future causes of outages and improving the systems so that they are less likely to be impacted by those causes through improved component designs, system designs, or operational practices are the same.

In any event, and as will be discussed below, ELL has maintained its distribution and transmission assets to support reliable operations while keeping rates affordable. ELL's asset management programs that support reliability, however, will not transform ELL's transmission assets like the proposed Resilience Plan would. An overview of the Company's distribution and transmission systems and operations will put the Company's proposed Resilience Plan's resilience projects into further context.

U.S.-Canada Power System Outage Task Force, *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations,* United States Department of Energy (April 2004), *available at* https://www.energy.gov/sites/prod/files/oeprod/DocumentsandMedia/BlackoutFinal-Web.pdf.

[6] On September 8, 2011, a blackout occurred, affecting states in the Pacific Southwest, along with parts of Mexico. The states affected alongside areas in Mexico contained parts of Arizona, Southern California, and Baja, California. The blackouts began during the afternoon, with some areas not being restored for up to 12 hours, due to an 11-minute system disturbance.

Staff, *Arizona-Southern California Outages on September 8, 2011,* The Federal Agency Regulatory Commission and the North American Electric Reliability Corporation (April 2012), *available at* https://www.nerc.com/pa/rrm/ea/September%202011%20Southwest%20Blackout%20Event%20Document%20L/AZOutage_Report_01MAY12.pdf,

[7] On February 15, 2021, over 4 million customers throughout the State of Texas lost power, with many of the outages occurring through the following day.

The Earth Observatory, *Extreme Winter Weather Causes U.S. Blackouts,* National Aeronautics and Space Administration (February 16, 2021), *available at* https://earthobservatory.nasa.gov/images/147941/extreme-winter-weather-causes-us-blackouts.

B. ELL's Distribution System and Operations

1. Evolution and Status of ELL's Distribution System

Q19. PLEASE DESCRIBE ELL'S DISTRIBUTION SYSTEM AND THE GENERAL FUNCTION IT SERVES.

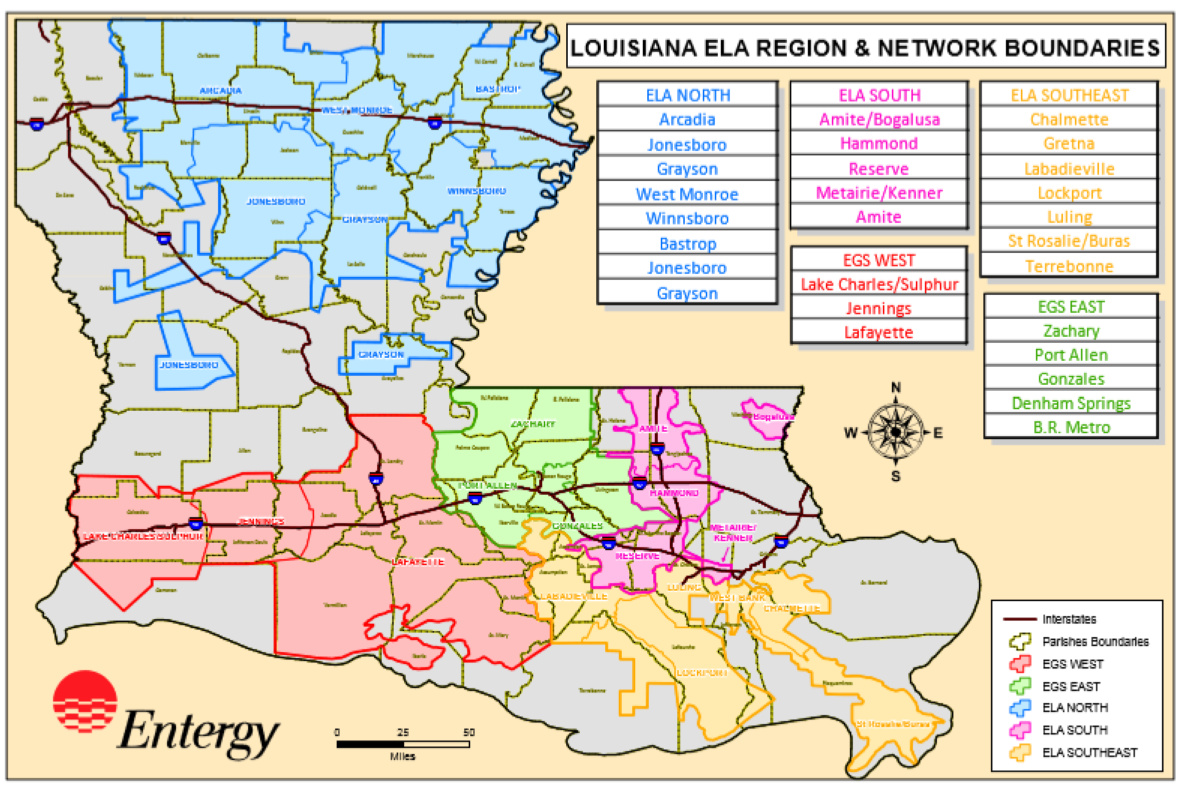
A. The distribution system is the infrastructure that ultimately delivers electric power to most of ELL's customers. ELL's distribution system begins at the substations, where power is transformed from transmission-level voltage into distribution-level voltage, a voltage level suitable for delivering power directly to residential, and certain commercial, governmental, and industrial customers.[8] ELL's electric distribution system is the portion of the electric grid operating at voltage levels below 69,000 kilovolts (69 "kV"). The predominant operating voltages of the Company's distribution circuits are 13.2 kV, 13.8 kV, and 34.5 kV (nominal, phase-to-phase). ELL's distribution system serves nearly 1.1 million customers. There are approximately 500 ELL substations that supply power to over 32,000 distribution circuit miles, of which approximately 28,000 are overhead circuit miles, and approximately 4,000 are underground circuit miles.

The Power Delivery Organization operates local Service Centers throughout the areas served by ELL. These local service centers and the distribution facilities supported by them are divided among five larger geographic operating regions consisting of 28 networks. Their respective geographical boundaries are depicted in the map in Figure 1.

[8] Some of ELL's largest commercial, governmental, and industrial customers are connected directly to the Company's transmission system.

Figure 1

Map of ELL's Geographical Regions



Q20. WHAT IS THE STATUS OF ELL'S DISTRIBUTION SYSTEM?

A. ELL has ramped up the pace and level of its distribution investment in recent years and plans to continue making significant investments to modernize and improve the reliability and resilience of the distribution grid. On average, the Company invested approximately $267 million annually in capital spending for its distribution system for the five-year period of 2017 through 2021, with distribution line plant closing increasing from $177 million in 2017 to $377 million in 2021.[9]

Like many of its utility peers, ELL has an aging distribution system that is now in a period of significant modernization as it evolves to address changes in customer expectations and grid technologies, opportunities to maximize the benefits of the Company's investment in AMS,[10] and the increasing frequency and severity of named storms and other extreme weather events, as evidenced in the past two Atlantic hurricane seasons and in the recent tornadoes that have impacted Louisiana as described by Mr. May.

As I discuss further below, ELL's distribution plan combines system hardening and grid modernization efforts with traditional reliability and infrastructure programs with an objective to improve the overall service quality provided to customers. This distribution plan involves a coordinated effort to undertake replacement and hardening of aging distribution infrastructure and deploy devices that enable functionalities associated with a modernized grid.

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[9] Distribution capital additions for 2017-2021 exclude amounts related to storm damage and Advanced Metering System ("AMS") investments.

[10] The Commission approved ELL's AMS in LPSC Order No. U-34320. *See,* Order No. U-34320 (August 25, 2017), *In re: Application of Entergy Louisiana, LLC for Approval to Implement a Permanent Advanced Metering System and Request for Cost Recovery and Related Relief, Docket No. U-34320.*

Q21. CONCERNING SERVICE QUALITY, HAS ELL TRADITIONALLY PROVIDED RELIABLE SERVICE TO ITS CUSTOMERS?

A. Yes. ELL has a long track record of providing reliable service to its customers. In its General Order of April 30, 1998, issued in Docket No. U-22389, the Commission set minimum distribution reliability performance standards that were phased-in over a period of seven years to reach the current metrics: an annual System Average Interruption Frequency Index ("SAIFI")[11] score of 2.28 and an annual System Average Interruption Duration Index ("SAIDI")[12] score of 2.87 hours, or 172.2 minutes. In the two decades since that order was issued, ELL has consistently exceeded the LPSC's minimum performance levels. ELL's SAIFI score was significantly lower (and therefore better) than the LPSC's minimum performance level in each year. Although there were exceptions in 2018 and 2019, years when ELL's SAIDI score was not within the Commission's performance target have been very rare, and the Company's SAIDI scores for 2020 and 2021 were within the Commission's performance target.[13] Furthermore, the 2018 and 2019 SAIDI scores

[11] SAIFI is used to measure the number of outages or interruptions per customer per year. Most electric utilities use this measurement as a tool to assess the reliability of their electrical system, excluding major outage events that cause interruptions to a significant portion of their customer base. SAIFI is calculated by adding up the number of customers experiencing a sustained outage longer than 5 minutes during the reporting period and then dividing it by the average annual number of electric customers.

[12] SAIDI measures the number of outage minutes per customer per year. Most utilities also use this measurement when reviewing the reliability of their electrical system, excluding outage events that cause interruptions to a significant portion of their customer base due to extreme weather or unusual events. SAIDI is calculated by adding up the outage minutes of all the customers that have been without power during a sustained outage longer than 5 minutes and then dividing by the average annual number of electric customers.

[13] The highest contributing outage categories to both frequency and duration of customer interruptions in 2018 and 2019 were consistent with historical interruption patterns, including primary conductor equipment failure, the presence of vegetation from outside of ELL's rights-of-way ("OROW") falling onto the Company's distribution lines, lightning, and vehicle incidents.

reflected the implementation of updated safety practices for lineman and distribution workers, which required more planned outages to be taken, and there were fewer events in those years that met the Major Event exclusion of the Commission's General Order.[14] That absence of events qualifying for the Major Event exclusion certainly illustrates that 2018 and 2019 did not have the sort of Atlantic hurricane season that we experienced in 2020 and again in 2021, but ongoing efforts to modernize the grid also minimize the impact of outages by decreasing the number of affected customers. So, although ELL continues to provide reliable service as measured by the Commission's established requirements, SAIFI and SAIDI scores should not be viewed in isolation from the challenges that ELL faces in providing reliable service or the industry transformation that is underway to modernize the distribution grid.

Q22. WHAT DO YOU MEAN BY THE TERM GRID MODERNIZATION?

A. Grid modernization refers to upgrading and redesigning distribution infrastructure while also adding new technologies and intelligent devices (*i.e.*, devices equipped with communicative capabilities) that can facilitate safe multidirectional energy flows, automate operations, enable remote control operation, increase operational efficiency, reduce outage frequency and duration, improve quality of service, increase reliability and resilience, expand options for and enhance communications with

[14] *See,* General Order (April 30, 1998), *In re: Ensuring Reliable Electric Service* §2 ("Major Event: A catastrophic event that exceeds the design limits of the electric power system, such as an extreme storm. These events shall include situations where there is a loss of service to 10% or more of the customers in a region, and where full restoration of all affected customers requires more than 24 hours from the beginning of the event.").

customers, and improve storm and outage response restoration times. Grid modernization is a fundamental change to the way electric utilities evaluate, invest in, operate, and maintain the distribution system, while monitoring and responding to the rapid pace of technological innovations and evolution of customer needs and expectations. This change involves adopting a more customer-centric strategy for designing and maintaining the distribution grid – one which seeks to minimize interruptions experienced by customers regardless of fluctuating conditions on the distribution system.

The technology and infrastructure components that comprise a modernized grid can be thought of in three broad categories: Smart Grid Infrastructure, Smart Grid Technology, and Advanced Distribution Planning.

The first category, Smart Grid Infrastructure, includes assets capable of supporting increased bidirectional power flow and which facilitate optimization of distributed energy resources ("DERs") like solar power photovoltaic and battery storage systems. Examples of Smart Grid Infrastructure assets include conductors with increased load-carrying capacity, electronic reclosers to sense and isolate issues, and smart tie switches allowing alternate energy paths.

The second category, Smart Grid Technology, represents the specialized sensors, collectors, and associated software systems that collect, analyze, and deliver information for real-time decision-making and automation. Examples of technologies in this category include: (i) Smart Grid Sensors: small communication nodes that serve as detection stations in a sensor network, which enable the remote monitoring of equipment such as transformers and power lines; (ii) Distribution Automation ("DA") Enabled Devices: distribution grid devices, such as reclosers, regulators, and capacitors, that are equipped with smart controls that enable the devices to communicate with utility software solutions and perform real-time sensing and reconfiguration of the distribution system; and (iii) Data Analytics Software: computer programs that use data from smart devices to identify portions of the distribution system reporting abnormal conditions and enable proactive engineering analyses to prevent outages in these areas by replacing equipment before it fails.

The third category, Advanced Distribution Planning, represents a transition from peak-based analysis of the system in order to leverage additional data captured from AMS and DA to perform more robust analysis during multiple time periods and under differing load conditions to ensure infrastructure upgrade projects meet future load scenarios.

Q23. PLEASE ELABORATE ON HOW THIS MORE CUSTOMER-CENTRIC STRATEGY MARKS A FUNDAMENTAL CHANGE FROM THE INDUSTRY'S TRADITIONAL APPROACH TO DISTRIBUTION ASSET MANAGEMENT.

A. Although there have certainly been exceptions over time, the electric utility industry traditionally has not replaced or reconfigured distribution assets until they reached end of life. This approach has been considered cost-effective for customers and reflects the balance that utilities must strike between reliability and cost. As I indicated above, however, the industry is evolving and modifying that approach by deploying new technology and preventative elements. In fact, ELL, like the electric utility industry in general, is in a cycle of increased capital expenditures to replace or upgrade aging distribution infrastructure to improve reliability and keep pace with, among other things, evolving technology and expanding regulatory and safety requirements. This new approach is being enabled by new technology and developed in response to increasing customer expectations for reliability enhancements aimed at preventing outages altogether (as opposed to reactive measures designed to minimize customers impacted by, and shorten the recovery time associated with, an outage). This approach requires a more modern, responsive, and resilient grid.

Q24. CAN YOU PROVIDE ANY EXAMPLES OF THE TYPES OF PROJECTS THAT ELL HAS RECENTLY UNDERTAKEN TO IMPROVE ITS DISTRIBUTION SYSTEM?

A. Yes. ELL recently constructed new substations and distribution circuits in Calcasieu, Ouachita, and Lafourche Parishes that increase the resilience of its system. In Calcasieu Parish, the Company recently invested approximately $23.8 million to construct the new Goos Ferry substation and install more than 3 miles of new distribution circuits that provide electricity from the substation to area homes and businesses in the Gillis, Moss Bluff, and North and East Lake Charles areas.

In Ouachita Parish, the Company recently constructed a new Cotton substation and installed nearly 10 miles of new distribution circuits to serve customers south of West Monroe. In addition to the Cotton substation's two transformers, several reclosers were installed to incorporate automation and create Self-Healing Networks, the details and benefits of which I describe later in my testimony. In total, the Company invested approximately $18.8 million on the Cotton substation project.

In Lafourche Parish, the Company recently invested approximately $23.6 million to construct the new Chackbay substation, including additional transformer capacity through installation of new distribution circuits. These new circuits create electrical tie points with the adjacent substations to form a mutually-supported substation group, creating operational flexibility along with provisions for an alternate source of electricity for area customers previously served in a radial configuration.

The Cotton, Goos Ferry, and Chackbay substations are designed for expandability to accommodate additional transformation and circuits as the electrical system continues to grow.

Q25. PLEASE ELABORATE ON THE COMPANY'S EFFORTS TO MAINTAIN AND IMPROVE ITS DISTRIBUTION SYSTEM.

A. ELL currently implements several programs to improve reliability and maintain infrastructure. As I noted above, many of these efforts are reactive, meaning that the actions taken are in response to devices that have failed and/or outages that have occurred, while others are preventative, meaning that the actions taken are an attempt to prevent devices from failing and/or outages from occurring. Together, these programs helped to mitigate the effects of Hurricane Ida on the Company's infrastructure, and I describe them briefly below. In fact, grid investments implemented by the EOCs avoided an estimated 24,321 customer interruptions during Hurricane Ida as a result of new reclosers and Self-Healing Networks.

<u>FOCUS Program</u>[15] – Targeted inspection based on repeated, prioritized outages. The program identifies devices (*e.g.*, breakers, reclosers, line fuses, and sectionalizers) where reliability has been adversely affected. A list of FOCUS devices is then created, prioritized by customer interruptions, and areas behind the devices are then selected to have work performed during the calendar year. The intent of the FOCUS Program is to improve the reliability performance of the selected FOCUS-identified devices; it is not a full feeder inspection. Remediation plans include replacing damaged equipment; installing animal guards and/or protective covers to mitigate outages caused by animals; shielding, installing, or relocating lightning arrestors; and addressing target vegetation issues. The FOCUS Program also addresses ELL's worst-performing distribution circuits and devices, as identified annually in accordance with Commission orders in Docket Nos. U-22389 and U-33244. The Company's FOCUS Program has led to reliability improvements. For example, using a three-year, rolling average of customer interruptions on circuits and devices that have undergone FOCUS improvements, customer interruptions have decreased. Specifically, for all FOCUS projects undertaken by ELL from 2011 through 2018, if one takes the rolling average of customer interruptions during the three-year period preceding each FOCUS project, and if one compares that to the rolling average of customer interruptions during the three-year period following each

[15] "FOCUS" stands for "Find the device, Observe the condition, Collect the damages, Understand the value, Succeed with the results."

FOCUS project, customer interruptions on those devices and circuits have been reduced, in the aggregate, by 44 percent. Moreover, our more recent FOCUS work is showing similar trends for "customer interruption" reductions, but more time is needed to determine whether those trends will continue or reach a point of diminishing returns.

Strategic Reliability Plan – Multi-part program using device reliability performance to prioritize general reliability improvement projects that focus on decreasing customer interruptions and outage durations. Programs that are part of the Strategic Reliability Plan (implemented in 2021) include:

- Repeat Devices – Projects driven by repeated historical outages that may not qualify for other reliability programs. Designed to be a quick-reacting trigger for reliability improvement work for customers that see an above-average number of outages.
- Outage Follow Up – Reliability projects driven by large Customer Interruption ("CI")[16]/Customer Minutes ("CM")[17] outages (>500 CI and >50,000 CM).
- Network Identified – General reliability work that is not triggered by device performance but is based on addressing point-specific reliability concerns before they turn into customer interruptions.
- 5 Percent Worst Performing – Reliability projects driven by an annual look-back at ELL's 5 percent poorest-performing feeders. The poorest-performing devices

16 Customer Interruption is defined as the number of customers experiencing the outage.

17 Customer Minutes is defined as the duration of the outage in minutes multiplied by the number of customers experiencing the outage.

on those feeders are slated for work unless previously identified as part of another program.

Distribution Automation Program – Includes identification and implementation of Self-Healing Networks (also known as automatic load transfer systems). Self-Healing Networks include a compilation of devices such as reclosers, switchgear, switches, and a network of communication devices used to automatically reconfigure the source of power after isolating an outage so that all other unaffected customers in the surrounding area are restored to improve customers' quality of service. Since 2019, ELL has installed 265 reclosers as part of the Distribution Automation Program. These reclosers have produced 63,467 avoided customer interruptions for the twelve months ending September 30, 2022. While we will need to monitor customer interruptions to determine whether these reductions will be sustained over time, these figures are an early indication that the Distribution Automation Program is producing benefits.

Sectionalization Program – Involves the placement of sectionalizing devices (pole top switches, reclosers, etc.) to improve restoration times for customers. This program is designed to fast-track installation of a DA communications system to reap the benefits of increased sectionalization in advance of full grid modernization in an area.

Feeder Level Investment Plan ("FLIP") – Identifies and addresses all reliability concerns on a complete feeder route based on historical performance and other factors.[18] It should be noted that, to date, 18 FLIP projects have been completed for ELL, with most projects having in-service dates on or after December 2021. If one compares the rolling average of customer interruptions during the two-years preceding the completion of each FLIP project to the monthly average of customer interruptions after each completion date, there is a reduction of 15,945 customer interruptions annually across the portfolio of 18 feeders, which is an approximate 51 percent reduction in customer interruptions. While we will need to monitor customer interruptions to determine whether these reductions will be sustained over time, these figures are an early indication that the FLIP work is producing benefits.

Pole Program – Consists of a visual inspection of the pole and, where appropriate, excavation or reinforcement. ELL maintains a cyclical pole inspection program that uses an outside vendor to inspect a portion of ELL's poles each year. The recommended program actions depend on the findings of the inspection and the age of the pole. Poles judged to be sound receive no further action. Those identified as needing additional attention are either treated in the field or reinforced, depending on the condition of the pole. Those that are deemed beyond treatment or reinforcement are prioritized for replacement. The Pole Program inspects approximately 10 percent of the distribution pole assets on a yearly basis. The 2022 program year is year 4 of the first ten-year cycle, which will end in 2028, at which time the program will begin the second ten-year cycle and will repeat thereafter. After the first ten-year cycle is

[18] The FLIP replaced the Company's Backbone Program in 2021. The Backbone Program was a proactive infrastructure program designed to inspect and address the portion of selected circuits from the substation breaker up to and including the first protective device that has the responsibility of isolating the remainder of the circuit.

completed in 2028, and as the second ten-year cycle proceeds, the Company expects that pole rejection rates will decrease by approximately 60 percent, as compared to the rejection rates found during the first ten-year cycle.

Equipment Maintenance Program – Includes annual inspections on reclosers, switch cabinets, capacitor banks, and voltage regulators to ensure operational performance. Inspections can result in either replacement or repair of the equipment.

Underground Residential Distribution ("URD")/Cable Program – Involves the splicing or replacement of failed primary URD cable. Replacement of failed URD cable is performed in lieu of splicing when possible to prevent future outages.

Vegetation Management Program – Consists primarily of a cycle-based proactive element, but the program also includes reactive, customer-driven, and selective herbicide components. The proactive trim cycles are examined annually and are determined by several factors, including growth rates, type and density of side and floor vegetation, vegetation-related outage information, and time since last maintenance. Identified circuits or areas are maintained using a combination of both conventional side trimming and herbicides depending on the specific application. The reactive component of the program consists of investigating potential problem areas that are identified by Company personnel and/or stakeholders and determining a remedial course of action when the potential problem involves the Company's facilities. For example, ELL seeks to address through this reactive component reports of damaged, dying, diseased, decayed, leaning, or otherwise compromised trees located outside its ROWs[19] that might endanger the Company's conductors and structures, particularly during storm events. Because those efforts seek to remove trees from private property, they require negotiations with OROW property owners. The remedial work itself involved with removing such danger trees can be considered preventative because it may avoid future damage to the distribution system (and the associated cost of repair). Table 1 below shows the number of ELL customer interruptions caused by vegetation over the past five years:

Table 1

Year	Number of ELL Customer Interruptions Caused by Vegetation
2017	265,372
2018	307,050
2019	274,486
2020	209,127
2021	173,316

As the table indicates, ELL has seen a reduction in vegetation-caused customer interruptions in 2020 and 2021. Those interruptions, however, can be caused by a number of factors, including vegetation-management funding levels, major storms that blow down trees, and weather patterns.

[19] Vegetation located outside of ELL's ROWs is referred to herein as "OROW" vegetation.

Q26. PLEASE ELABORATE ON THE STANDARDS AND PRACTICES THAT APPLY TO ELL'S VEGETATION MANAGEMENT PROGRAM.

A. There are several standards and practices that ELL observes and follows in its vegetation management program.[20] The Company and its vegetation contractors follow applicable guidelines established by the Occupational Safety and Health Administration and industry-accepted standards, including (1) American National Standards Institute ("ANSI") A300 – Tree, Shrub, and Other Woody Plant Maintenance – Standard Practices (Pruning); and (2) ANSI Z133 – Pruning, Repairing, Maintaining, Removing Trees, and Cutting Brush – Safety Requirements. All utilities in Louisiana must also perform their vegetation work in accordance with the Louisiana Department of Agriculture and Forestry's Horticulture Commission Law (La. Rev. Stat. §§ 3:3801-3816) and the Horticulture Commission's Rules and Regulations. In addition, all work plans must comply with the Entergy Transmission and Utility Operations Safe Work Rules Manual.

The target distribution pruning cycle is determined for each individual circuit based on its own unique characteristics (*i.e.*, last cycle pruning, actual clearances achieved from conductor, tree growth rates, percentage of fast-growing tree species, side/floor vegetation, etc.) and historical reliability information. Target pruning cycles can range from two (2) to eight (8) years. Urban circuits, where trimming rights are often more restrictive, are on a more frequent schedule due to the more

[20] The Company filed its current vegetation management plan ("Entergy's Line Clearing Program Overview for 2021") with the Commission on September 30, 2022, pursuant to the Commission's General Order.

limited clearance that the Company is able to achieve. Unless a previous trim point allowed for greater clearance (which ELL would maintain), the Company generally trims to provide minimum below and side clearance of six (6) to fifteen (15) feet between a tree and a primary conductor and twenty (20) feet between an overhanging limb and a primary conductor. The minimum general clearance depends on the rate of tree growth (slow or fast) and location (*i.e.*, smaller ROW widths in predominantly urban areas and larger ROW widths in rural areas).

From time to time, as required, the Company will initiate a focused effort to address areas where the cycle-maintenance vegetation program may not adequately address reliability needs. For example, in early 2021, the Company inspected and identified work on several circuits that had a high number of vegetation-related outages in 2020 (including circuits located in areas that ultimately would be impacted by Hurricane Ida later in 2021). Vegetation-related work (beyond routine tree trimming) was identified and completed prior to the 2021 hurricane season on these circuits in order to improve overall reliability. As a result of this work, we saw a 75 percent reduction in customer interruptions and a 43 percent reduction in outages on those circuits from 2020 to 2021. We also performed additional danger tree removals and skyline trimming on certain targeted devices beginning in May 2021 and continued that work until Hurricane Ida made impact.

In its May 2020 filing in Commission Docket No. U-35565, noting that the increased investment that ELL was making in its distribution system would provide additional opportunities to identify and address danger trees as more work is done to modernize the grid, the Company set forth a proposal to coordinate with grid upgrades over the next few years, the removal of OROW vegetation hazards. Furthermore, in its report filed on December 3, 2021, in Docket No. U-35565, ELL advised the Commission that for the 6-month period ending November 30, 2021, the Company removed a total of 2,933 trees outside of its ROWs with the consent of property owners or pursuant to a contractual right to do so. In the light of its experience during the 2020 and 2021 Atlantic hurricane seasons, ELL expects that coordinating removal of OROW danger trees with future infrastructure upgrades can help prepare the distribution system for future storms and improve system resilience, and the Resilience Plan thus includes such coordination and tree removal work as part of the proposed projects for which it provides.

2. Storm Hardening of the Distribution System and New Engineering Standards

Q27. CONSIDERING LOUISIANA'S SUSCEPTIBILITY TO HURRICANES, HAS THE COMPANY TAKEN STEPS TO REDUCE THE VULNERABILITY OF ITS DISTRIBUTION INFRASTRUCTURE TO STORMS?

A. Yes. In addition to the Company's traditional reliability and infrastructure improvement programs that I discussed previously, storm hardening strategies and investments implemented after Hurricanes Katrina, Rita, Gustav, Ike, and Isaac proved successful during Hurricanes Laura, Delta, and Zeta in 2020 and once again during Hurricane Ida in 2021. As I will discuss further below, ELL has made changes over time to its construction methods in the coastal areas including:

- Targeting coastal lines with severe or repeat damage for scheduled rebuilds to hardened design levels (double guys and larger class poles).

- Using only Class 1 poles for three-phase distribution feeder construction for selected circuits (*e.g.*, feeders immediately adjacent to the coast).

Also, ELL's recent experience with hurricanes reinforced its historical decision to follow two practices:

- ELL has always designed its distribution lines to meet or exceed the requirements of the NESC. Structures for distribution applications utilize pressure-treated wood poles or tubular steel poles. All structures are designed at installation to meet or exceed the wind requirements of the NESC.
- For years, ELL has installed storm guying on distribution feeders located in open marshy terrain immediately adjacent to the coast except where not practical due to ROW considerations or where not required due to soil conditions. Storm guying refers to the practice of installing down guys and anchors on each side of a pole, perpendicular to the direction of the conductors. The purpose of storm guying is to help strengthen the line of poles against winds blowing laterally against the conductors. Distribution lines located in open marshy coastal terrain are especially prone to being blown over during tropical storms and hurricanes due to (1) proximity to the coast and the associated higher winds during storms, (2) the general lack of tree protection from the winds, and (3) the softness of the ground itself.

Beyond the coast, ELL has historically gone beyond NESC requirements by hardening structures to withstand strong winds that accompany hurricanes long after landfall. Additional actions, designs, or practices have included the following:

- Replacing support circuits crossing interstate highways with steel or concrete structures instead of wood as well as burying certain interstate crossings;
- Using steel distribution poles for new interstate crossings along major hurricane evacuation routes;[21]
- In substations in coastal areas, raising water-sensitive equipment several feet above the flood levels that have been experienced in recent years due to storm surge or erosion;
- Designing new substations so that water-sensitive equipment will be above those same flood levels; and
- Hardening existing service centers and building new ones to withstand winds up to 145 mph.

In addition, new facilities, rebuilt facilities, and, to the extent possible, facilities restored after any storm have been constructed and/or upgraded to meet then-current design standards, except in rare instances where performing the upgrades would result in extreme service disruptions or prohibitive costs.

In October 2018, the Entergy Distribution Design Basis Department released a new pole philosophy:

- Only Class 1 poles are to be used for feeder poles in the zone along the coast. For this application, a feeder pole is any pole in that part of the circuit protected by a substation breaker or any pole with three phases of primary that

[21] The purpose of using steel poles for this application is to eliminate the possibility of weakened poles due to future rot at the ground line for these new crossing poles.

has the ability to tie with any other three-phase line from another circuit, when needed.

- Nothing smaller[22] than Class 3 poles should be used for all primary applications.

Finally, Mr. Meredith describes in his testimony the Company's recent adoption of revised wind loading guidelines for transmission and distribution assets. From my perspective, the revised guidelines will allow the Company to improve the resilience of its system.

Q28. HAS THE COMPANY CONSIDERED THE BURIAL OF ITS OVERHEAD DISTRIBUTION LINES AS A MEANS TO FURTHER DECREASE THE VULNERABILITY OF ITS DISTRIBUTION SYSTEM TO HURRICANES AND OTHER SEVERE WEATHER EVENTS?

A. Yes. After Hurricane Gustav in 2008, the Commission opened a rulemaking docket (R-30821) to explore the potential costs and benefits of investments to decrease the vulnerability of electric utility infrastructure to severe weather events. In response to certain questions posed by the Commission regarding the potential hardening of distribution facilities through undergrounding, the Company noted that there would be considerable expense to placing overhead electric distribution facilities underground. Recovery of this expense would have a significant effect on customer bills. Moreover, burying lines does not fully mitigate the exposure of electric systems

[22] "Smaller" in this sense characterizes strength. A Class 1 pole is stronger than a Class 3 pole. The standard sets out that the minimum strength for all primary applications must be Class 3 strength.

to storms and may adversely affect reliability by increasing the duration of outages. In particular, storm damage to source transmission lines and substation facilities will cause outages to the distribution lines fed from these systems even though the distribution facilities may be completely intact. Also, underground distribution facilities still can be damaged by flooding, storm surge, and heavy equipment used to remove storm debris, in addition to damage from trees uprooted during storm events.

Among the many conclusions reached by the LPSC Staff in their report was the following:

> Different weather events create advantage for underground distribution systems versus overhead and vice versa. Clearly, it would not be prudent to install underground distribution systems in areas that are prone to flooding since underground distribution systems are susceptible to damage by flooding. The fact that different terrains and areas present advantages for underground versus overhead distribution systems supports providing utilities with the flexibility to plan their systems in a manner that best meets the needs and environmental factors present. In addition, it supports the idea that a state-wide mandate for underground retrofit should not be enacted by the Commission. Moreover, for the same reasons, a mandate for utilities to implement underground distribution systems on a prospective basis for new construction should not be required either.[23]

Because underground facilities are typically multiple times the cost of overhead, the Company would not recommend wholesale conversion of overhead to underground. We must balance the benefits of investment in hardening with the need to ensure that electricity remains affordable for our customers. However, installing underground

[23] *See* Staff Report (January 28, 2009), *In re: Identification and Evaluation of Potential Methods to Decrease the Vulnerability of Electric Utility Distribution Infrastructure in Response to Severe Weather Events, Docket No. R*-30821.

facilities will be pursued if determined to be cost-effective for strategic hardening initiatives, such as with the interstate crossings I mentioned previously as well as a recently-completed reliability project involving the burial of two primary feeders across Bayou Lafourche in Lockport, Louisiana. Additionally, following Hurricane Ida, the Company completed a $52.5 million underground project in Grand Isle, which involved burying 12.5 miles of three-phase distribution line in connection with rebuilding and strengthening the distribution system in that community.

Moreover, Messrs. Meredith and De Stigter discuss the inclusion of certain undergrounding projects as projects to be evaluated for potential inclusion in of the Comprehensive Hardening Plan. The 1898 report that Mr. De Stigter sponsors provides a methodology to guide the Company's decision-making process regarding when an undergrounding project should be pursued as part of the Comprehensive Hardening Plan. It should be noted that it would not be cost-beneficial to convert all potential overhead Comprehensive Hardening Plan projects into underground projects. The cost of only constructing underground Comprehensive Hardening Plan projects would be prohibitive. A goal of the Comprehensive Hardening Plan is to mitigate risk in a cost-effective manner, and if the Company were to invest all dollars into underground work, far fewer resilience projects could be pursued (barring a drastic budget increase), which would unreasonably leave a larger number of ELL customers exposed to storm risk.

Q29. HAS THE COMPANY EVALUATED OTHER POTENTIAL ACTIVITIES OR PROJECTS THAT MAY FURTHER REDUCE THE VULNERABILITY OF THE COMPANY'S INFRASTRUCTURE TO THE DAMAGING EFFECTS OF STORMS?

A. Yes. In fact, the purpose of the Company's Application in this docket is to obtain Commission approval for ELL to execute its plan to conduct extensive hardening and resilience work that will reduce the vulnerability of the Company's infrastructure to storms. That work will benefit not only the Company, but also the Company's customers and the communities that the Company serves, as well as other utilities served by ELL's transmission system. Mr. Meredith describes the Company's plan in detail, and I generally discuss and support that plan later in my testimony.

That being said, evaluating the costs and benefits of potential hardening activities is an ongoing process for the Company, and the Commission recently opened a general rulemaking docket to look at statewide hardening and resilience. Within the past decade, ELL also has targeted approximately 25 critical substations in Louisiana for additional storm hardening. The Company has built structures to elevate critical equipment at existing substations with a potential for flooding, constructed levees around substation equipment to protect infrastructure from flooding, and designed many new substations to sit above the 100-year flood plain, raised the site, or, when possible, located the site out of the flood plain. In one unique case, ELL designed and built a portable control house. This mobile unit can be removed and transported to higher ground if a storm surge is expected.

By way of further example, after Hurricane Katrina, the Company's service center in Chalmette was elevated to provide protection from storm surge inundation during severe weather events. The Chalmette service center sustained no major damage during Hurricane Ida, and the Company was able to utilize the building as a home base for planning and execution of our storm restoration. In addition, we also had two Customer Service Managers in place, and customers were able to visit the service center in person after the storm to inquire about their accounts and expected restoration times.

C. <u>ELL's Transmission System & Operations</u>

Q30. PLEASE PROVIDE A GENERAL DESCRIPTION OF THE ENTERGY TRANSMISSION SYSTEMS.

A. The EOCs' transmission systems span portions of five states (Arkansas, Louisiana, Mississippi, Texas, and Missouri) and are comprised of approximately 16,100 circuit miles of transmission lines and approximately 1,500 substations. Employees based at various locations throughout the service area plan, design, construct, operate, and maintain the transmission systems.

Q31. WHAT GENERAL FUNCTIONS DO THE EOCS' TRANSMISSION SYSTEMS PERFORM?

A. The EOCs' transmission systems move high-voltage, bulk electric power produced by market participants within the Midcontinent Independent System Operator, Inc. Regional Transmission Organization and neighboring regions across an interconnected system of transmission lines and substations to distribution points for delivery to retail customers of the EOCs, as well as to wholesale customers such as municipalities and cooperatives, or to points of delivery into other transmission systems. The transmission systems also deliver power directly to large commercial and industrial retail customers of the EOCs. These customers include refineries, chemical plants, oil and gas processing facilities, pumping stations, and large manufacturing sites vital to the region and nation.

Q32. WHO OWNS THE TRANSMISSION ASSETS IN THE SYSTEM?

A. The EOCs own the transmission system assets located in their respective service areas, as well as other assets (such as computer systems) that support the operations of the transmission systems.

Q33. PLEASE DESCRIBE ELL'S TRANSMISSION SYSTEM SPECIFICALLY.

A. The ELL transmission system is comprised of over 5,000 circuit miles of transmission lines and approximately 500 substations operating at voltages of 500 kV, 345 kV, 230 kV, 138 kV, 115 kV, and 69 kV. The ELL transmission system is interconnected with the transmission systems of EAL, ENO, EML, ETI, Lafayette Utilities System, Louisiana Generating LLC, Cleco Power LLC ("Cleco"), Louisiana Electric Power Authority, Mississippi Power Company, and Southwestern Electric Power Company.

Q34. WHY IS ELL'S TRANSMISSION SYSTEM INTERCONNECTED WITH OTHER TRANSMISSION SYSTEMS?

A. ELL's transmission system is interconnected with other transmission systems primarily to promote system reliability. The interconnection of transmission systems also provides access to other power suppliers, some of which may provide more economic sources of power than what is available on-system.

Q35. HOW IS THE ENTERGY TRANSMISSION SYSTEM PLANNED, DESIGNED, CONSTRUCTED, OPERATED AND MAINTAINED?

A. The transmission systems of all EOCs, including ELL's, are planned, designed, constructed, and operated to function as a single integrated transmission system within the broader Eastern Interconnection. The Power Delivery organization is responsible for the planning, operation, and maintenance of those systems. These broad activities include operating the facilities in the field that move energy to customers, monitoring the performance of the transmission systems, responding to outages, performing preventive maintenance on facilities to keep them in working order, managing vegetation, environmental services, and executing small projects. The Capital Projects organization designs and constructs the transmission systems. These broad services include engineering the transmission lines and substations used to deliver energy as well as the project management services to ensure projects are delivered efficiently and on time. The roles and responsibilities of both ELL and ESL personnel are designed to avoid duplication.

Q36. PLEASE DESCRIBE THE COMPANY'S RECENT INVESTMENT IN AND IMPROVEMENT OF ITS TRANSMISSION SYSTEM.

A. Transmission capital investment can be divided into a few primary categories: (1) projects that ensure the transmission system meets NERC standards for bulk electric system reliability through new lines, substations, and equipment upgrades; (2) projects that improve reliability through replacement of aging equipment; (3) projects that go beyond basic NERC reliability to enhance the reliability of critical infrastructure or improve customer experiences; (4) projects needed to interconnect new facilities such as new generators or new customers; and (5) projects that build new facilities to reduce congestion on the system to ensure customers have access to the lowest cost power. For the period 2013 through October 2022, the Company invested approximately $3.4 billion in its transmission system. Note that the totals in Table 2 below do not include certain costs associated with major storms that have impacted the Company's service area, including, more recently, costs that have been addressed through securitization financing in LPSC Docket No. U-35991 (Hurricanes Laura, Delta, and Zeta, and Winter Storm Uri in 2020) and LPSC Docket No. U-36350 (Hurricane Ida in 2021).

Table 2

ELL Transmission Capital Closings (Non-Major Storm)

Values in $M

2013	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022***	**Total**
168.3	198.1	188.3	288.6	291.8	490.8	449.4	521.9	377.3	416.3	3,391.0

* Includes actuals through October 2022.

The need for this level of investment was driven by many factors, including reliability planning, load growth, infrastructure maintenance and reliability needs, economic transmission investments (*i.e.*, investments that produce cost savings to customers), and generation interconnection projects. Examples of the type of work recently performed to promote the reliability and resilience of the Company's transmission system include:

- Updating and replacing certain older "legacy" lattice and wooden structures with steel mono-pole or multi-pole framings;
- Maintaining or exceeding NESC wind speed design standards, with most coastal areas being designed to withstand 140-150 mph winds; and
- Installing 30-to-60-foot steel caisson foundations for new transmission structures located in coastal areas.

Q37. CAN YOU PROVIDE SPECIFIC EXAMPLES OF TRANSMISSION PROJECTS RECENTLY COMPLETED BY THE COMPANY?

A. Yes. The Company recently completed a transmission system upgrade in Lafourche Parish in south Louisiana that is designed to improve resilience and reliability of the local power grid for customers in the Bayou region. The Company's transmission lines were upgraded and approximately 80 steel structures between Cut Off and Golden Meadow were replaced with infrastructure built to withstand winds of up to 150 mph. In particular, new infrastructure was placed into steel caissons to create strong foundations.

Another example is the West Monroe Reliability Improvement Project that spans across Ouachita Parish and positions the region for economic growth and increased resilience and reliability. New transmission equipment was installed and portions of the existing, local transmission system were upgraded. Major components of the project include:

- Upgrading 4 transmission lines to 230kV,
- Construction of a new 3-mile 230kV transmission line, and
- Upgrading or expanding 5 substations.

This work made the electric system in the area more interconnected with higher capacity, which will help the Company deliver power now and into the future by way of clean generating resources like solar, for example. Also, while the project enhances service reliability, it can also help import lower-cost power to keep the region attractive to existing or new customers, including those turning to electrification to reach sustainability goals, and is an important step in the Company's modernization of the electric system in north Louisiana.

Another recently-completed project is the Waterford – Vacherie 230 kV line upgrade. This project, located in southeast Louisiana, involved upgrading the Waterford – Vacherie 230 kV line to a higher rating to address future load growth and reliability needs.

As I noted above, ELL has also made significant investments in its transmission system during the past several years utilizing modern design standards. The Company evaluates hardening strategies from a customer perspective, weighing the benefits of fewer and shorter outages against the increased costs of hardening the system, which our customers ultimately must bear. Maximizing resilience on every aspect of the grid is not cost-effective for customers. In other words, ELL continually searches for ways to improve the resilience of its transmission system while also managing and balancing the resulting effects on the rates that are paid by customers. Furthermore, all of the Company's transmission facilities are designed and constructed to meet or exceed the applicable design standards at the time of construction.

Q38. CAN YOU EXPLAIN WHAT YOU MEAN BY APPLICABLE DESIGN STANDARDS?

A. Yes. Referring specifically to the transmission system in southeast Louisiana that was impacted during Hurricane Ida, that system was designed under different sets of standards. Older structures, for example those installed prior to 1997 when the various standards were unified, were designed to either the Louisiana Power & Light ("LP&L") or the New Orleans Public Service Inc. ("NOPSI") standards that were in effect at the time of construction, which have been grandfathered into ELL's system. These standards were developed under earlier versions of the NESC, and, therefore, structures built under each set of standards were designed to withstand different wind loadings. Transmission facilities designed and constructed more recently utilized the unified Entergy Design Standard implemented in 1997.

In any event, the unified Entergy Design Standard required all transmission lines built or substantially upgraded in southeast Louisiana to be designed for at least 110 mph, with the majority being designed for 125 mph or 140 mph winds. Older transmission lines located in south Louisiana that were designed and constructed before the development of the unified Entergy Design Standard were based on legacy LP&L or NOPSI design standards. All lines, regardless of vintage, meet or exceed the NESC requirements in effect at the time of their construction. As Mr. Meredith discusses in his direct testimony, the Entergy Design Standard was recently replaced by revised wind loading guidelines for transmission lines.

Q39. PLEASE DESCRIBE THE COMPANY'S MAINTENANCE PROGRAMS AND PRACTICES APPLICABLE TO ITS TRANSMISSION SYSTEM.

A. The Company utilizes several types of inspections for its transmission line structures, including routine aerial patrols leveraging both helicopters and Unmanned Aerial System ("UAS") technology, wood pole groundline treatment and inspection, climbing inspection (for wood poles), and comprehensive aerial inspection (for concrete and steel poles). Climbing and comprehensive aerial inspections are triggered by the performance of the lines and through conditions found during routine aerial patrols, outage patrols, and groundline inspections. As it relates to the Company's preparation for storms, the Company typically completes at least one cycle of transmission aerial inspections prior to June of each year.

The Company flags corrective maintenance items identified through inspections that are then prioritized for remediation into the following categories:

- Priority 1 – emergency work to begin within 0-24 hours from the time work is identified;

- Priority 2 – urgent work to begin within 14 days from the time work is identified;
- Priority 3 (High) – work identified to be planned, scheduled, and work to begin within 90 days from the time work is identified;
- Priority 3 (Medium) – work identified to be planned, scheduled, and work to begin in the next calendar year; and
- Priority 3 (Low) – work identified to be planned, scheduled, and bundled with other work.

Q40. PLEASE DESCRIBE THE COMPANY'S VEGETATION PROGRAMS AND PRACTICES APPLICABLE TO ITS TRANSMISSION SYSTEM.

A. To keep ROWs in proper condition, the Company typically performs at least two aerial patrols of all transmission lines each year to inspect the ROWs and identify any areas requiring corrective maintenance. Vegetation is maintained in a manner that keeps it clear from growing into the transmission lines and causing associated electrical interruptions based on proximity. A combination of traditional trimming and herbicides are used to maintain the ROWs, and the Company implements an inspection program to identify and remove trees located outside of the Company's ROWs that may endanger the conductor zone. Through that inspection program, the Company works to proactively mitigate high risk trees outside of our ROWs with customer permission; however, obtaining customer consent to trim beyond our ROWs can, at times, pose a challenge.

IV. THE COMPANY'S PROPOSED INCREASE IN VEGETATION MANAGEMENT EXPENDITURES SHOULD PROVIDE BENEFITS THAT COMPLEMENT THE COMPANY'S RESILIENCE EFFORTS

Q41. PLEASE DESCRIBE THE COMPANY'S PROPOSED SPENDING INCREASE FOR VEGETATION MANAGEMENT AND RIGHT OF WAY MANAGEMENT.

A. As described more fully in Mr. Meredith's testimony, the Company is proposing enhancements to its current vegetation management programs to accelerate trim cycles and to implement additional program elements. Specifically, on the distribution system, the Company is proposing to (i) reduce its trim cycle to five years; (ii) implement mid-cycle herbicide treatments; (iii) implement a backbone "skylining" project; [24] (iv) implement additional programs to target poor performing species of trees and danger trees (including work performed OROW); and (v) increase reactive trimming efforts. On the transmission system, the Company is proposing to increase its OROW work and implement air-saw trimming of vegetation along transmission lines.

Q42. ARE THESE ENHANCEMENTS BEING PROPOSED BECAUSE THE COMPANY'S CURRENT VEGETATION MANAGEMENT PRACTICES ARE INADEQUATE?

A. No. The Company's current vegetation management practices, which I describe above, are reasonable and help the Company provide its customers with safe, reliable power at the lowest reasonable cost. The programs and enhancement to current

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[24] "Skylining" refers to the removal of all overhanging limbs above identified areas on an electric line.

practices that are being proposed in this filing were identified as opportunities based on the Company's experience with prior storms to further improve system resilience in the face of major weather events rather than to address any inadequacies or gaps in the Company's current practices.

Q43. CAN ANY INSIGHTS BE DRAWN FROM THE COMPANY'S EXPERIENCE WITH PRIOR STORMS THAT SUGGEST THE PROPOSED ENHANCEMENTS WILL HELP IMPROVE SYSTEM RESILIENCE?

A. Yes. The Company's experience with prior storms has demonstrated that OROW trees can be significant contributing factors to damage to the Company's facilities during major storms. For example, the Company's damage assessment after Hurricane Ida did not indicate that the Company had inadequate vegetation management in its distribution or transmission line ROWs, but rather revealed that the storm brought significant vegetation-related damage to ELL's facilities from downed trees that came from outside of the Company's ROWs. Under major storm force winds, uprooted trees and the loss of large structural limbs cause the most substantial vegetation-related damage to the overhead distribution system. In the light of its experience during the 2020 and 2021 Atlantic Hurricane Seasons, ELL expects that coordinating removal of OROW danger trees with future infrastructure upgrades can help prepare the distribution system for future storms and improve system resilience.

Q44. WHAT ARE THE ANTICIPATED BENEFITS OF THE COMPANY'S VEGETATION MANAGEMENT PROPOSAL?

A. The vegetation management enhancements that the Company is proposing under the Resilience Plan are expected to increase overall system resilience. For example, the Company is proposing to implement a backbone skylining project over five years, performing skylining on approximately twenty percent of the Company's backbone distribution lines annually. By removing all overhanging limbs from these distribution lines, the Company expects to reduce the outages and damage these limbs could cause during major storms. Similarly, the Company is proposing to identify species of trees that have historically caused major damage (*i.e.,* Water Oak trees in urban areas with high customer counts) and target those trees for removal. By removing these trees before they fail during a major event, the Company can mitigate threats from expected sources of storm damage. As a result, the Company expects that these efforts should reduce the number and duration of outages following a major storm.

Q45. HOW DOES THE COMPANY'S VEGETATION MANAGEMENT PROPOSAL COMPLEMENT THE COMPANY'S OTHER PROPOSALS, INCLUDING THE PROPOSED STORM HARDENING?

A. The proposed vegetation management enhancements work hand-in-hand with the Company's overall resilience plan to address the multifaceted threats posed by a major storm. Specifically, as discussed by Mr. Meredith, the Company's overall plan is the result of a holistic review of the Company's assets and vulnerabilities in the light of the changing circumstances illustrated by the extreme weather events of recent years. From that review, the Company identified the overarching portfolio of projects that comprise the Resilience Plan. A large portion of that Resilience Plan is designed to accelerate storm hardening of transmission and distribution assets so that the *assets* themselves (and, in turn, the entire distribution and transmission systems) can better withstand and better recover from the conditions caused by extreme weather events, including interference from vegetation. The vegetation management portion of the Company's proposal is a logical complement to the Company's hardening efforts by addressing some of the potential *causes of outages* themselves. While the Company cannot control all of the conditions caused by major storms (such as extreme winds and flooding), the Company can take steps to limit the potential for vegetation to cause damage during major events by taking proactive actions, including "skylining" a large portion of its distribution lines, working to remove danger trees, and removing other identified "problem species" of trees. Similarly, the use of an air-saw to further assist transmission line trimming can help reduce the threat of damage posed by vegetation near the Company's transmission lines, including in generally inaccessible areas. In this way, the vegetation work complements the hardening effort by helping to decrease the number of times that the Company's storm-hardened assets will be tested by vegetation during and after a major storm.

V. THE NEED FOR THE COMPREHENSIVE HARDENING PLAN AND THE BENEFITS THAT THE PLAN WILL PROVIDE

Q46. DOES ELL'S STORM EXPERIENCE INDICATE THAT THE COMMISSION SHOULD CONSIDER WHETHER ELL SHOULD UNDERTAKE THE COMPREHENSIVE HARDENING PLAN OR SOME MEANINGFUL AND COMPREHENSIVE INITIATIVE TO ACCELERATE RESILIENCE FOR THE BENEFIT OF CUSTOMERS?

A. Yes. As is discussed by Company witness Phillip R. May, over the last few years, hurricanes, winter storms, and other severe storm activity has created significant concerns about the increasing intensity, frequency, and cost of extreme weather events. Beginning with Katrina and Rita and most recently with Laura and Ida – both Category 4 hurricanes hitting in back-to-back years – the Company and its customers and communities have incurred billions of dollars in storm-related restoration and outage costs, with power sometimes being out for extended periods of time before it could be restored. It is evident that an accelerated approach to hardening/resilience is appropriate, and it is time for the Company, in collaboration with the Commission, to embark upon a program to proactively address the risks that the electric system is exposed to by these increasingly intense weather events. Because major storm events are occurring more frequently and with more intensity, it is very likely that the Company will incur costs, one way or another, to improve the resilience of the electric system. That is, either it will incur these costs as part of a comprehensive, accelerated plan to improve resilience, or it will incur these and additional costs after major events strike without achieving the same level of resilience. However, as

Company witness Sean Meredith discusses in more detail in his direct testimony and as I discuss below, there are obstacles and challenges in the aftermath of a major storm event that make it difficult to perform work as efficiently and with the level of management oversight and coordination that is possible if the work is performed proactively.

The purpose of the Comprehensive Hardening Plan is to improve resilience more efficiently by directing our efforts with careful controls and strategically-planned design as opposed to performing work urgently, over a compressed timeframe, and under the exigent circumstances that exist after a major storm event – when the focus and priority must necessarily be to repair facilities and restore service as quickly and safely as possible. By implementing the Comprehensive Hardening Plan, the Company can construct more resilient facilities such that damages after major events are less severe and easier and quicker to recover from. If the Company does not more aggressively plan and construct these facilities to more storm resilient standards, it will likely pay more to repair them during future crises arising from major storm events like we have experienced over the past few years. In fact, Mr. De Stigter notes in his direct testimony that the projects contained in ELL's Comprehensive Hardening Plan are reasonably projected to produce a reduction in storm restoration costs of approximately 50 percent. Moreover, the projects identified in the Comprehensive Hardening Plan are reasonably projected to produce a decrease in the projected CMI after a major storm by approximately 55 percent over the next 50 years. Those cost and customer outage reductions would be transformative. I endorse the Comprehensive Hardening Plan that Messrs. Meredith and De Stigter describe in their direct testimony, and I generally discuss below the benefits that the Comprehensive Hardening Plan will provide.

Q47. HOW ARE ELL'S PAST AND PRESENT RELIABILITY EFFORTS DIFFERENT FROM THE COMPANY'S PROPOSED COMPREHENSIVE HARDENING PLAN'S RESILIENCE ACTIONS?

A. Reliability improvements can reduce certain customer interruptions and their duration, but they do not produce the above-discussed, post-storm cost savings and outage reductions resulting from resilience work. Although resilience work and reliability work may look the same and involve the same activities, such as replacing a utility pole, the analyses and drivers supporting that work are very different. For example, reliability may be diminished on a distribution circuit due to a poorly-performing device such as a recloser (a device that temporarily turns off power to allow the system to return to normal and then restores power automatically). A poorly performing recloser may fail to open a circuit causing upstream devices to operate instead, interrupting more customers than necessary. It may also open inadvertently thus interrupting customers unnecessarily. A project born from a strategy to improve reliability would likely include replacing the recloser, and potentially the pole it was mounted on, if inspection of the pole determines that the pole is not up to standards. The new recloser would improve the reliability in that area. By comparison, a resilience-focused strategy would identify degraded poles, as well as otherwise-functioning poles that did not meet current standards, and target them for replacement. If the poles include devices that need replacement, such as the faulty recloser in this example, they would be replaced when the poles were replaced. In instances where equipment has not reached the end of its life, but was not designed to meet the more stringent wind loading design standards that Mr. Meredith discusses, the Company will likely replace that equipment to meet the new standards if that equipment poses a material risk to the recovery after an event. In all, the approach the Company proposes would result in improved reliability, but also in a more resilient system due to the pole upgrades. The reliability approach would result in nearly the same reliability performance during thunderstorms, or mild weather incidents, as the resilience approach. However, the resilience approach would yield the additional benefits of being more capable of withstanding extreme events.

Q48. WILL ELL'S PROPOSED PLAN TO IMPROVE RESILIENCE DETRACT FROM ITS COMMITMENTS TO PROGRAMS DESIGNED TO IMPROVE RELIABILITY?

A. No. In fact, the Comprehensive Hardening Plan will coexist with and complement ELL's programs targeted to improve reliability. First, the facilities identified as highly valuable for resilience upgrades overlap significantly with facilities targeted for reliability improvements in the future. For example, the FLIP identified several feeders that would see improved reliability if the entire feeder were upgraded to new standards to address aging facilities such as crossarms and poles, as well as the equipment operating on the feeder, such as reclosers and regulators. In fact, 90 percent of the feeders identified in the FLIP program are identified in the Comprehensive Hardening Plan as valuable from a resilience perspective. Similarly, ELL's programs to replace poles involve inspecting poles and then either extending the life of them through treatment or replacing them when treatment will not maintain adequate strength. The Comprehensive Hardening Plan includes the replacement of lower strength poles with poles meeting the new extreme wind guidelines. The Comprehensive Hardening Plan introduces a new facet into how ELL's transmission and distribution systems are planned, designed, and constructed. Projects that were and will be developed to improve reliability will be designed to withstand higher wind loading, thus improving resilience. Projects identified as highly valuable from a resilience perspective for facilities with high levels of reliability already will be prioritized and evaluated based on their resilience benefits alone, and thus lower in priority than projects with immediate reliability and longer-term resilience benefits. Similarly, a project to improve reliability located on facilities that are already designed to be resilient would slot behind a project that had reliability and resilience attributes. It is important to understand that the Comprehensive Hardening Plan and the programs already underway will be prioritized based on reliability and resilience attributes. While there are certainly needs to enhance the resilience of ELL's electric system, improvements in reliability are also needed. Thus, projects will continue to be developed that provide the highest value to ELL's customers. The Comprehensive Hardening Plan will introduce projects that have resilience benefits that will complement the programs historically developed to improve reliability. Thus, the Comprehensive Hardening Plan will not detract from reliability efforts.

Q49. WHAT ARE THE BENEFITS OF PERFORMING RESILIENCE WORK IN THE CONTEXT OF A RESILIENCE EFFORT SUCH AS THE COMPREHENSIVE HARDENING PLAN?

A. Generally speaking, there are two categories of benefits that arise by virtue of the Company performing "blue sky"[25] resilience work as compared to performing reactive, post-storm restoration work. The first category of benefits relates to the fact that "blue sky" restoration work can be more carefully planned, executed and overseen as compared to reactive, post-storm restoration work where the Company is working as quickly and safely as possible to restore power, often in highly unattractive conditions that I will discuss later in my testimony. Moreover, to expedite restoration of outages, some components of post-storm restoration work must be performed by third-party contractors and mutual-assistance resources that are not necessarily as familiar with the Company's system, standards, operating procedures, and safety rules. The Company educates those third-party workers about those matters, and the Company incurs additional costs to ensure the efficiency and quality of the work performed in the immediate aftermath of a major storm, often by tens of thousands of contract workers. Those costs can be minimized and/or avoided when the Company executes comparable work in "blue sky" conditions when the work can be planned and executed without the urgency that accompanies widespread outages.

25 "Blue sky" work means work that is planned and performed under normal weather conditions.

The second category of benefits relates to cost. Specifically, and as is discussed in the direct testimony of Company witnesses Mr. Meredith and Mr. De Stigter, "blue sky" work can typically be executed at a reduced cost as compared to post-storm restoration work.

Q50. PLEASE DISCUSS THE FIRST CATEGORY OF BENEFITS.

A. As noted above, "blue sky" restoration work can be more carefully planned, executed and overseen as compared to reactive, post-storm restoration work. Specifically, in "blue sky" conditions, the Company can more methodically and efficiently identify, plan and execute projects, as compared to the hectic, post-storm restoration environment when the Company is working as quickly and safely as possible to restore power, often in highly unattractive conditions and with tens of thousands of contract workers laboring simultaneously across a vast area impacted by a major storm.

Q51. CAN YOU ELABORATE ON THE HIGHLY UNATTRACTIVE CONDITIONS THAT CAN EXIST IN THE AFTERMATH OF A STORM?

A. Yes. After a major storm, there are often significant obstacles that the Company encounters that hinder and complicate the restoration work. For example, hurricane-caused obstacles include the delay in deploying resources that may result if a major storm maintains hurricane strength into inland areas of our service area; obstacles to mobility such as trees and debris across roadways as well as flooded roadways;[26] trees and debris across or blocking access to ROWs; saturated ground from rains preventing truck access; trees and debris cluttering work sites; flooding along the coastal areas; domestic livestock and wildlife (alive and dead) displaced by hurricane or storm surge impeding access to roads, ROWs, and work sites; and storm surge damage to infrastructure such as roads and bridges.

Other obstacles relate to the accessibility of our infrastructure. These obstacles would exist even without the devastation of a hurricane, but they can be exacerbated by hurricane debris. An example of this was the difficulty after Hurricane Ida to make repairs to facilities located in rear lots, alleys, or off-road. In those cases, truck access was often not available or was blocked by customer buildings and debris. This type of construction required that most work be done by carrying specialized equipment and materials to the rights-of-way and manually reconstructing the facilities without the assistance of trucks for digging holes, erecting poles, and lifting workers and equipment into position on the poles. Even under normal operating conditions, these types of facilities are more difficult and time-consuming to restore, but the time and cost of repairing these facilities increases due to post-storm conditions.

[26] For example, in Hurricane Ida, Interstate 10 between New Orleans and Baton Rouge was temporarily closed because of flooding, with water reported to be 4 feet deep in one location.

Q52. ARE THERE ANY OTHER CHALLENGES FACED BY THE COMPANY DURING POST-STORM RESTORATION?

A. There are. Another significant challenge after a storm is providing support to the workforce necessary that restores power to ELL's service area, often in the extreme heat and humidity experienced in southeast Louisiana during the summer and early fall. The main example is the significant operational challenge involved in managing and maintaining logistical support for thousands of workers from outside the local area. The provision of lodging, meals, ice, laundry, parking, fuel, and other resources required to support this effort present unique challenges. For example, at the Distribution-level, over 24,000 workers responded to Hurricane Ida in Louisiana. Restoration workers came from 41 states to assist in the restoration efforts following Hurricane Ida. This includes mutual-assistance and off-system resources that were acquired through our memberships and contracts with the Southeast Electric Exchange ("SEE"), the Edison Electric Institute ("EEI"), the Midwest Regional Mutual Assistance Group, Regional Equipment Sharing for Transmission Outage Restoration ("RESTORE"),[27] and the Texas Regional Mutual Assistance Group. While the help of these resources is always needed and greatly appreciated, it is more difficult to plan and execute work in difficult, post-storm conditions with all of the above-discussed logistical issues that complicate storm restoration. Simply put, there are fewer distractions when performing work in "blue sky" conditions.

[27] RESTORE is sponsored by the North American Transmission Forum ("NATF"). NATF members include investor-owned, state-authorized, municipal, cooperative, U.S. federal, and Canadian provincial utilities. The NATF promotes excellence in the reliability and resiliency of the electric transmission system.

Q53. CAN YOU PLEASE PROVIDE MORE INFORMATION ON THE MUTUAL-ASSISTANCE AND OTHER THIRD-PARTY RESOURCES WHO ASSIST WITH STORM RESTORATION?

A. Yes. With respect to mutual-assistance resources, Entergy is a party to mutual-assistance agreements, and for safe, timely, and efficient restoration from major storms, our industry depends on off-system mutual assistance resources to support restoration efforts. Over the years, Entergy has assisted many other electric utilities by sending support to aid in their restoration efforts. Mutual-aid support typically consists primarily of line crews supplied from other utilities. Other third-party resources can include (1) damage assessment contractors; (2) line contractors; (3) vegetation contractors; (4) logistics contractors that provide support to staging areas such as mass housing, catering, and other logistics coordination and procurement; (5) investment recovery contractors who assist in the recovery and disposal of damaged equipment and debris; (6) fuel suppliers; (7) trucking and equipment contractors that move equipment, material and supplies; (8) security services; and (9) transportation contractors that repair/replace damaged tires and dead batteries, and perform other minor vehicle repairs.

Q54. ARE THESE THIRD-PARTY RESOURCES NECESSARILY AS FAMILIAR WITH THE COMPANY'S SYSTEM, STANDARDS, OPERATING PROCEDURES AND SAFETY RULES?

A. No. These third-party contractors and mutual-assistance resources are not necessarily as familiar with the Company's system, standards, operating procedures, and safety rules as the Company's own employees. While the Company makes every reasonable effort to ensure that those workers are adequately trained and educated on those standards, procedures, and rules, and while the Company actively manages and oversees the work of those third parties to ensure adherence, it is more reasonably practicable and effective for the Company to ensure the efficiency and quality of the work in "blue sky" conditions when the Company's employees and base load contract partners are performing the work. This is particularly true given the scope and scale of post-storm work that is performed in far-from-ideal conditions. By contrast, "blue sky" work can be conducted more methodically, and over a longer period time, than can post-storm restoration work. For all of the above reasons, as compared to post-storm restoration work, resilience work that is performed in "blue sky" conditions can be more efficiently managed, and the quality of that "blue sky" work can be obtained on a less-costly basis.

Q55. CAN YOU PLEASE DISCUSS THE SECOND CATEGORY OF BENEFITS OF "BLUE SKY" RESTORATION WORK, AS COMPARED TO POST-STORM RESTORATION WORK?

A. Yes. Comparatively speaking, as is discussed in the direct testimony of Mr. Meredith, "blue sky" work can typically be executed at a reduced cost as compared to post-storm restoration work. Specifically, after a major storm, there are often hundreds of thousands of customers without power. The Company understands the importance of quickly and safely restoring service to protect the health and safety of its customers, including essential state and local emergency facilities. It is also critical to restore service to key facilities that have a significant impact on the regional and national economies. To restore service as safely and quickly as possible, ELL will often use every available resource to the maximum extent, which includes long hours by every worker and expedited delivery of materials from every source reasonably available.

Q56. HOW DOES THE NEED TO QUICKLY RESTORE SERVICE AFFECT COSTS?

A. Restoring power in a prompt manner after a major storm requires the Company to incur significant costs over and above the costs of its normal operations. The additional or incremental costs often incurred to restore service after a major storm event, and not generally incurred for "blue sky" work, include items such as:

Additional Crews – With extensive damage to vegetation and to the Company's distribution and transmission facilities, the Company often must significantly supplement its existing workforce to clear debris, assess damage to facilities, and repair those facilities simultaneously so that service can be restored. As I discuss above, to complete a prompt restoration, the Company will engage mutual-assistance utility partners and third-party line/vegetation contractors.

Overtime/Premium Pay – Instead of working typical 40-hour weekly work shifts, employees and contractors can work significantly more hours and incur substantial overtime. For example, after Hurricane Ida, employees and contractors worked up to 112-hour weekly work shifts (16 hours per day, 7 days per week) to restore service as quickly and safely as possible. ELL was therefore required to pay overtime labor rates to these workers. A 112-hour weekly work shift is nearly three weeks of work compressed into a single week. In addition, some of the contractors we engage require a single premium rate for storm restoration that is applied to all hours. This practice is becoming more common for storm response crews, and it is generally one and one-half to two times the normal straight-time rate.

Lodging – When personnel and crews are brought into the Company's service area, the cost of this temporary work force includes not only labor costs, but also the expense of housing and other related costs to support the crews.

Meals – In addition to lodging, all of the restoration personnel have to be fed, often when restaurants are not open due to the effects of the storm.

Increased Materials Prices – Due to the ongoing pandemic, some essential materials were in high demand after the storms experienced in 2020 and 2021. As the demand became greater for the materials, ELL had to engage supply vendors that it had not normally used to supplement its established vendors. In those instances where ELL had to acquire materials from any vendor with which it did not have a pre-existing contract, prices for materials were compared to prices of similar materials that ELL typically secures under contract and further weighed against ELL's experience and the exigent circumstances.

Fuel – After a storm, the Company needs to acquire significant amounts of fuel to support restoration efforts. For example, after Hurricane Ida, ELL acquired 3,071,338 gallons of fuel.

Q57. HOW ELSE CAN THE POST-STORM ENVIRONMENT INCREASE COSTS?

A. The Company exercises diligence to source services and materials at the lowest reasonable cost. However, given the urgent demand for timely service restoration after a storm, in such circumstances the Company sometimes is required to pay more for services and materials than it would for work performed in the normal course of business. The priorities of service restoration, protecting public health and welfare, preserving strategic energy supplies, and supporting emergency responders can take precedence over obtaining potential cost reductions. That being said, the Company has years of experience in emergency restoration procurement, and, as a highly-skilled purchaser of these services and materials for its facilities, the Company is very familiar with the costs of the products and services of the vendors with which it is working. Accordingly, while post-storm costs can increase, the Company is in a position to ensure that the prices and terms under which it purchases services and materials are fair and reasonable under the extreme circumstances. There may be instances in which the Company might have to pay higher prices than it would have in a non-emergency situation; however, the Company's processes and experience ensure that the prices and costs it does pay are reasonable under the circumstances.

Nonetheless, for the reasons I discuss above, "blue sky" work can typically be executed at a reduced cost as compared to reactive, post-storm restoration work.

Q58. BASED ON YOUR EXPERIENCE WITH STORMS, CAN YOU PROVIDE SOME SPECIFIC EXAMPLES OF TYPES OF BENEFITS THE COMPREHENSIVE HARDENING PLAN WILL BRING?

A. Building a more resilient transmission and distribution system will allow the Company to more quickly and efficiently restore power to the communities it serves after major events and will improve the reliability of these systems. Major events such as hurricanes can inflict damages to these systems that require thousands of resources and hundreds of millions of dollars in replacement materials. The largest costs are associated with replacing transmission structures and distribution poles that have been destroyed. While damages to minor materials such as insulators, shield wires, conductors, etc. may still occur after resilience investments are made, repairing these types of damages takes much less time and much fewer resources. We have recent real-world examples of how resilient designs and construction techniques can result in quicker and more efficient restorations.

Just prior to the landfall of Hurricane Laura, a new transmission project, the Lake Charles Transmission Project ("LCTP") was completed. The LCTP was constructed to support industrial expansion in the Lake Charles industrial area and was designed and constructed to the modern standards being proposed by the Comprehensive Hardening Plan. The eye of Hurricane Laura passed directly over this new transmission facility with winds estimated to exceed 125mph when it impacted the LCTP. All structures constructed on the LCTP survived with only minimal damages. Within a day or two, the LCTP portion of the transmission system in Lake Charles was ready to move energy. This provided a path to begin the restoration, and the LCTP proved to be integral to the restoration. Once less resilient interconnecting facilities were repaired, the LCTP was used to interconnect Lake Charles to undamaged parts of the system to the west of Lake Charles. The LCTP was the only undamaged transmission line in the immediate area. Had more facilities in the Lake Charles area been hardened in the same manner as the LCTP, the "first lights" in the Lake Charles area would have likely occurred in less than five days, as opposed to the thirteen days experienced after Laura.

A similar example of the benefits of resilient designs occurred after Hurricane Ida in the Port Fourchon area. In recent years, the transmission system had been hardened into the Fourchon area with only one section remaining that was not built to the modern, more resilient design. All sections constructed to the more resilient design survived, with the exception of two structures (less than 2 percent of the line) that were impacted by what is believed to be a barge that had broken free from its mooring and collided with the transmission structure. There were damages to minor facilities, primarily insulators impacted by flying debris, but the structures were upright and undamaged, which resulted in restoration timelines being reduced from months to days.

VI. CONCLUSION

Q59. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, at this time.

AFFIDAVIT

STATE OF MISSISSIPPI

COUNTY OF HINDS

NOW BEFORE ME, the undersigned authority, personally came and appeared, **CHARLES W. LONG**, who after being duly sworn by me, did depose and say:

That the above and foregoing is sworn testimony in this proceeding and that knows the contents thereof, that the same are true as stated, except as to matters and things, if any, stated on information and belief, and that as to those matters and things, verily believes them to be true.

Charles W. Long

SWORN TO AND SUBSCRIBED BEFORE ME
THIS 14th DAY OF DECEMBER, 2022

Brittney King

NOTARY PUBLIC

My commission expires: June 14, 2026

STATE OF MISSISSIPPI
NOTARY PUBLIC
ID # 124361
BRITTNEY B. KING
Commission Expires
June 14, 2026
MADISON COUNTY

BEFORE THE

LOUISIANA PUBLIC SERVICE COMMISSION

***IN RE*: APPLICATION OF ENTERGY LOUISIANA, LLC FOR APPROVAL OF THE ENTERGY FUTURE READY RESILIENCE PLAN (PHASE I)**	**))))**	**DOCKET NO. U- _______**

EXHIBIT CWL-1

DECEMBER 2022

Charles Long's Prior Testimonies
(Updated 12/15/2022)

1. DOCKET NO. 43958 – Testimony on behalf of Entergy Texas, Inc. at the Public Utility Service Commission of Texas
   - Application of Entergy Texas, Inc. For Approval Of An Amendment To Certificate Of Convenience And Necessity And For Public Interest Determination For Purchase Of Unit 1, Union Power Station
2. DOCKET NO. 46416 – Testimony on behalf of Entergy Texas, Inc. at the Public Utility Service Commission of Texas
   - Application Of Entergy Texas, Inc. For A Certificate Of Convenience And Necessity To Construct Montgomery County Power Station
3. DOCKET NO. 51997 – Testimony on behalf of Entergy Texas, Inc. at the Public Utility Service Commission of Texas
   - Application Of Entergy Texas, Inc. For Determination of System Restoration Costs
4. DOCKET NO. 09-084-U – Testimony on behalf of Entergy Arkansas, Inc. at the Arkansas Public Service Commission
   - Direct (September 2009)
   - Supplemental Direct (March 2010)
   - Sur-Reply (April 2010)
   - Application of Entergy Arkansas, Inc for Revenue to Recover a Retail Revenue Deficiency (rate case)
5. DOCKET NO. 09-127-U – Testimony on behalf of Entergy Arkansas, Inc. at the Arkansas Public Service Commission
   - Direct (December 2009)
   - Application of Entergy Arkansas, Inc. For A Certificate of Convenience and Necessity to Construct Cabot Substation
6. DOCKET NO. 09-110-U – Testimony on behalf of Entergy Arkansas, Inc. at the Arkansas Public Service Commission
   - Direct (October 2009)
   - Application of Entergy Arkansas, Inc. for A Certificate of Convenience and Necessity to Construct Osage Grandview Switching Station
7. DOCKET NO. 10-011-U – Testimony on behalf of Entergy Arkansas, Inc. at the Arkansas Public Service Commission
   - Supplemental (October 2013)
   - In The Matter Of A Show Cause Order Directed To Entergy Arkansas, Inc. Regarding Its Continued Membership In The Current Entergy System Agreement, Or Any Successor Agreement Thereto, And Regarding The Future Operation And Control Of Its Transmission Assets
8. DOCKET NO. 10-050-U – Testimony on behalf of Entergy Arkansas, Inc. at the Arkansas Public Service Commission
   - Direct (June 2010)
   - Application of Entergy Arkansas, Inc. for A Certificate of Convenience and Necessity to Construct Transmission Line and Associated Facilities in Lonoke, Pulaski and Faulkner Counties

9. DOCKET NO. U-33244 – Testimony on behalf of Entergy Louisiana, LLC. at the Louisiana Public Service Commission
    - Joint Application of Entergy Louisiana, LLC and Entergy Gulf States, L.L.C. for Approval of Business Combination, for Related Relief, and for an Interim Order Regarding the Companies' 2014 Test Year Formula Rate Plan Filings
10. DOCKET NO. U-33770 – Testimony on behalf of Entergy Louisiana, LLC at the Louisiana Public Service Commission
    - Ex Parte: Joint Application Of Entergy Louisiana, LLC, Entergy Gulf States Louisiana, L.L.C., And Entergy Louisiana Power, LLC For Approval To Construct St. Charles Power Station, And For Cost Recovery
11. DOCKET NO. U-34283 – Testimony on behalf of Entergy Louisiana, LLC. at the Louisiana Public Service Commission
    - Application Of Entergy Louisiana, LLC For Approval To Construct Lake Charles Power Station, And For Cost Recovery
12. DOCKET NO. U-34631 – Testimony on behalf of Entergy Louisiana, LLC. at the Louisiana Public Service Commission
    - Entergy Louisiana, LLC, Ex Parte. Application Of Entergy Louisiana, LLC For Extension And Modification Of Formula Rate Plan
13. DOCKET NO. U-34472 – Testimony on behalf of Entergy Louisiana, LLC. at the Louisiana Public Service Commission
    - Application Of Entergy Louisiana, LLC For Approval To Acquire Washington Parish Energy Center And For Cost Recovery
14. DOCKET NO. 2010-UA-171 – Testimony on behalf of Entergy Mississippi, LLC at the Mississippi Public Service Commission
    - Direct Testimony (April 2010)
    - Entergy Mississippi, Inc. Petition for A Certificate of Convenience and Necessity foe Transmission Line and Related Facilities and Rights-of-Way in Holmes and Attala Counties
15. DOCKET NO. 2014-UN-132 – Testimony on behalf of Entergy Mississippi, LLC at the Mississippi Public Service Commission
    - Notice Of Intent Of Entergy Mississippi, Inc. To Modernize Rates To Support Economic Development, Power Procurement, And Continued Investment
16. DOCKET NO. UD-14-02 – Testimony on behalf of Entergy New Orleans, LLC. at the Council of the City of New Orleans
    - Application Of Entergy Louisiana, LLC For Approval Of Business Combination, And For Related Relief
17. DOCKET NO. UD-16-02 – Testimony on behalf of Entergy New Orleans, LLC. at the Council of the City of New Orleans
    - Application Of Entergy New Orleans, Inc. For Approval To Construct New Orleans Power Station And Request For Cost Recovery And Timely Relief

BEFORE THE

LOUISIANA PUBLIC SERVICE COMMISSION

***IN RE*: APPLICATION OF ENTERGY LOUISIANA, LLC FOR APPROVAL OF THE ENTERGY FUTURE READY RESILIENCE PLAN (PHASE I)**	**))))**	**DOCKET NO. U- _______**

DIRECT TESTIMONY

OF

JASON D. DE STIGTER

ON BEHALF OF

ENTERGY LOUISIANA, LLC

DECEMBER 2022

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EXHIBITS

I. INTRODUCTION

Q1. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Jason De Stigter, and my business address is 9400 Ward Parkway, Kansas City, Missouri 64114.

Q2. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by 1898 & Co. as a Director, and I lead the Utility Investment Planning team as part of our Utility Consulting Practice. 1898 & Co. was established as the consulting and technology consulting division of Burns & McDonnell Engineering Company, Inc. ("Burns & McDonnell") in 2019. 1898 & Co. is a nationwide network of nearly 400 consulting professionals serving the Manufacturing & Industrial, Oil & Gas, Power Generation, Transmission & Distribution ("T&D"), Transportation, and Water industries.

Burns & McDonnell has been in business since 1898, serving multiple industries, including the electric power industry. Burns & McDonnell is a family of companies made up of more than 10,000 engineers, architects, construction professionals, scientists, consultants, and entrepreneurs with more than 40 offices across the country and throughout the world.

Q3. PLEASE DESCRIBE BRIEFLY YOUR EDUCATIONAL BACKGROUND AND CERTIFICATIONS.

A. I received a Bachelor of Science degree in Engineering and a Bachelor's in Business Administration from Dordt College, now called Dordt University. I am a registered Professional Engineer in the State of Kansas. My full resume is included as Exhibit JDD-1.

Q4. PLEASE DESCRIBE BRIEFLY YOUR PROFESSIONAL EXPERIENCE.

A. I am a professional engineer with 15 years of experience providing consulting services to electric utilities. Through my work at 1898 & Co. and Burns & McDonnell, I have extensive experience in asset management, capital planning and optimization, risk and resilience assessments and analysis, asset failure analysis, and business case development for utility clients. I have been involved in numerous studies modeling risk for utility industry clients, which have included risk and economic analysis engagements for several multi-billion-dollar capital projects and large utility systems. In my role as a Director, I have worked on and overseen risk and resilience analysis consulting studies on a variety of electric power transmission and distribution assets, including developing complex and innovative risk and resilience analysis models. My primary responsibilities are business development and project delivery within the Utility Consulting Practice, with a focus on developing risk and resilience-based business cases for large capital projects/programs.

Prior to joining 1898 & Co. and Burns & McDonnell, I served as a Principal Consultant at Black & Veatch, inside their Asset Management Practice, where I also performed risk and resilience studies.

Q5. HAVE YOU PREVIOUSLY PROVIDED TESTIMONY BEFORE A REGULATORY BODY?

A. Yes. A list of my prior testimony is included in Exhibit JDD-1.

Q6. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY IN THIS PROCEEDING?

A. Entergy Louisiana, LLC ("ELL" or the "Company") engaged 1898 & Co. to assist with identifying potential projects to include in the Company's Comprehensive Hardening Plan to improve system resilience and estimating the costs and benefits of those projects. My testimony introduces, summarizes, and incorporates by reference, the Resilience Investment and Benefits Report, which is attached hereto as Exhibit JDD-2, that was developed as part of that effort.

Q7. WHAT WAS THE EXTENT OF YOUR INVOLVEMENT?

A. I served as the 1898 & Co. project director and worked directly with personnel representing ELL involved in the resilience-based planning approach as part of the development of the Comprehensive Hardening Plan. I was directly involved in the development of the Storm Resilience Model (the methodology used to identify projects, along with calculating potential costs and benefits), the assessment and results. I was also the primary author of the attached Resilience Investment and Benefits Report.

Q8. BRIEFLY OUTLINE THE STORM RESILIENCE INVESTMENT PLAN DESCRIBED IN THE ATTACHED RESILIENCE INVESTMENT AND BENEFITS REPORT.

A. As shown in the attached Resilience Investment and Benefits Report, the overall plan includes approximately $9 billion of hardening investments across seven investment programs. The feeder hardening rebuilds make up most of the total, accounting for 48 percent of the total investment. Lateral hardening is next, with 28 percent. Transmission hardening follows with 17 percent. Lateral undergrounding makes up 5 percent, while feeder undergrounding, substation control house remediation, and substation storm surge mitigation make up the final 2 percent.

Q9. BRIEFLY, WHAT ARE THE EXPECTED BENEFITS THAT ARE SHOWN IN THE ATTACHED RESILIENCE INVESTMENT AND BENEFITS REPORT?

A. As shown in the attached Resilience Investment and Benefits Report, the storm hardening projects identified in the report are expected to (1) decrease storm restoration costs after major weather events; and (2) decrease the customers impacted and the duration of the overall outage after major weather events. First, the identified projects are reasonably projected to produce a reduction in storm restoration costs of approximately 50 percent. In relation to the plan's capital investment, the amount of the restoration costs savings (expressed in 2022 dollars), ranges from 37 to 54 percent of the total plan cost (in 2022 dollars) depending on future storm frequency and impacts. In other words, the avoided restoration cost benefits alone pay for approximately 37 to 54 percent of the investment plan. Second, the identified projects are reasonably projected to produce a decrease in the projected customer minutes interrupted after a major storm by approximately 55 percent over the next 50 years. This decrease includes eliminating outages, reducing the number of customers interrupted, and decreasing the length of the outage time.

II. RESILIENCE-BASED PLANNING OVERVIEW

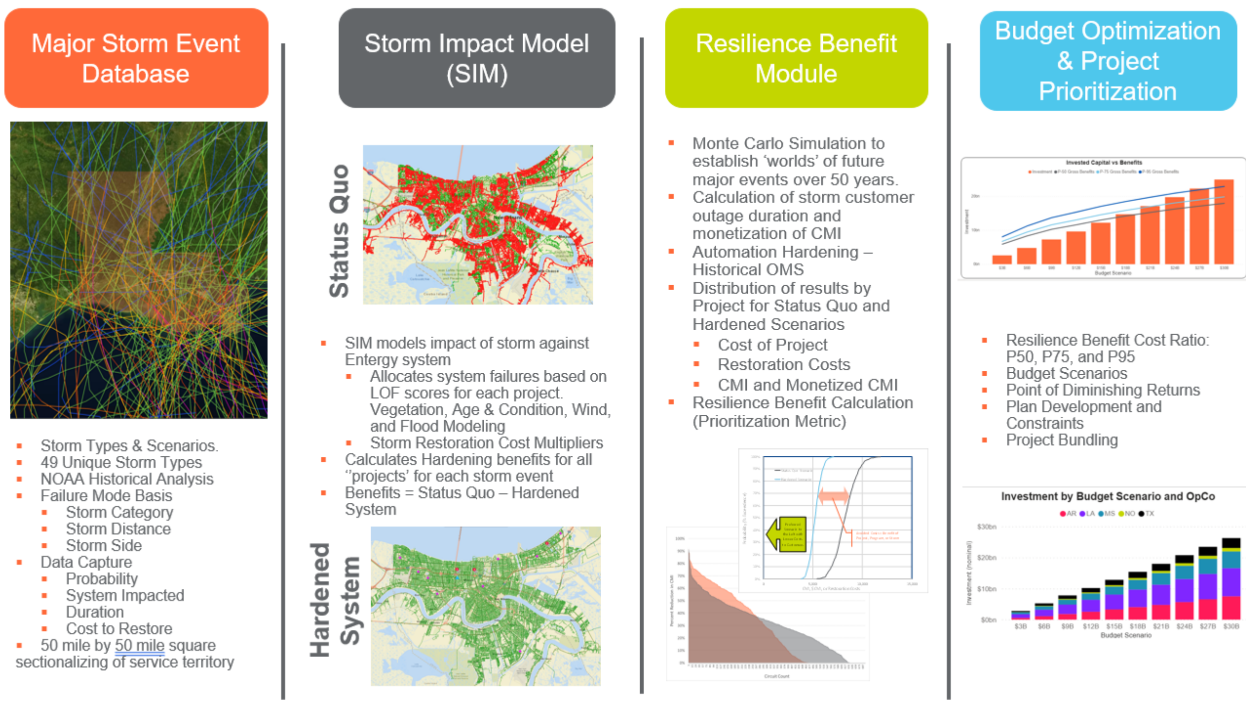
Q10. PLEASE DESCRIBE THE ANALYSIS 1898 & CO. CONDUCTED FOR THE COMPANY.

A. 1898 & Co. utilized a resilience-based planning approach to identify hardening projects and to assist the Company in prioritizing investments in the Company's transmission and distribution systems utilizing a Storm Resilience Model ("SRM"). The SRM consistently models the benefits of all potential hardening projects for an "apples to apples" comparison across the systems. The resilience-based planning approach calculates the benefit of storm hardening projects from a customer perspective. This approach consistently calculates the resilience benefit at the asset, project, and program level. The results of the SRM are:

1. A decrease in storm restoration costs after major weather events; and
2. A decrease in the customers impacted, and the duration of the overall outage, calculated as customer minutes interrupted ("CMI") after major weather events.

The SRM employs a data-driven, decision-making methodology utilizing robust and sophisticated algorithms to calculate the resilience benefits. Figure 1 provides an overview of the SRM used to calculate the project benefits and prioritize projects.

Figure 1: Storm Resilience Model Overview



The Major Storm Events Database contains storm probability distributions, along with the range of sub-system impacts for 49 different storm types. The 49 different storm types are based on the range of storm categories, storm distance from the infrastructure, and the side of the storm impacting the infrastructure. The database organizes the Company's service area into 31 different 50-mile by 50-mile system sections to provide the granularity of the impact of the 49 storm types against the infrastructure. The database includes probabilities and impacts for all 49 different storm types for each of the 31 system sections.

Each storm type for each system section is then modeled within the Storm Impact Model to identify which parts of the system are most likely to fail in the event of each type of storm. The Likelihood of Failure ("LOF") is based on the vegetation density around each conductor asset, the difference between the wind loading of the asset as compared to the Company's current wind loading standard, and the age and condition of the asset. The Resilience Model is comprehensive in that it evaluates nearly all of the Company's transmission and distribution systems. The Storm Impact Model also estimates the restoration costs and CMI for each of the potential hardening projects for each storm type. For purposes of the report, the term "project" refers to a collection of assets. Assets are typically organized from a customer impact perspective. The Storm Impact Model calculates the benefit in decreased restoration costs and CMI if that project is hardened per ELL's hardening standards. The CMI benefit is monetized using the Department of Energy's ("DOE") Interruption Cost Estimator ("ICE") for project prioritization purposes.

The benefits of storm hardening projects are highly dependent on the frequency, intensity, and location of future major storm events over the next 50 years. Each storm type has a range of potential probabilities and consequences. For this reason, the Resilience Benefit Calculation utilizes stochastic modeling, also known as a Monte Carlo simulation, to randomly select a thousand future worlds of major storm events to calculate the range of both "Status Quo" and Hardened restoration costs and CMI for each project. The probability of each storm scenario is multiplied by the benefits calculated for each project (*i.e.* the difference between the calculated values for the Status Quo and Hardened scenarios) from the Storm Impact Model to provide a resilience-weighted benefit for each project in dollars.

The Project Scheduling and Investment Optimization model prioritizes the projects based on the highest resilience benefit/cost ratio factoring in execution and investment-level constraints. It also performs the Investment Optimization over a range of budget levels to identify the point of diminishing returns. The model prioritizes each project based on the sum of the restoration cost benefit and monetized CMI benefit divided by the project cost. This is done for the range of potential benefit values to create the resilience benefit cost ratio. The model also incorporates technical and operational constraints in scheduling the projects applicable to ELL and its service area, such as contractor capacity, logistics, and limits on materials. Using the Resilience Benefit Calculation and Project Scheduling and Investment Optimization model, the SRM calculates the net benefit in terms of reduced restoration costs and CMI for the 10-year investment profile.

This resilience-based prioritization facilitates the identification of the critical hardening projects that provide the most benefit. Prioritizing and optimizing investments in the system helps provide confidence that the overall investment level is appropriate and that customers get the "biggest bang for the buck."

Q11. WHY IS THIS APPROACH TO HARDENING PROJECT IDENTIFICATION IMPORTANT?

A. This approach to hardening project identification is important for several reasons.

1. The approach is comprehensive and evaluates nearly all of the assets on the Company's transmission and distribution systems. By considering and

evaluating those systems on a consistent basis, the results of the hardening plan provide confidence that portions of the Company's transmission and distribution assets are not overlooked for potential resilience benefit.

2. By breaking down the entire distribution system by protection zone, the resilience-based planning approach is foundationally customer centric. Each protection zone has a known number of customers and type of customers such as residential, small or large commercial and industrial, priority customers, and National Critical Infrastructure customers. The objective is to harden each asset that has a higher risk of failing, which would result in a customer outage. Since only one asset needs to fail downstream of a protection device to cause a customer outage in that zone, failure to harden all the necessary assets still leaves vulnerable components that could potentially fail in a storm. Rolling assets into projects at the protection device level allows for hardening of all vulnerable components in the project zone and for capturing the full benefit for customers.

3. The granularity at the asset and project levels allows the Company to invest in portions of the system that provide the most value to customers from both a restoration cost reduction and avoided CMI perspective. For example, a circuit may have 10 laterals that come off a feeder, and the SRM may determine that only 3 out of the 10 should be hardened. Without this granularity, a suboptimal or inefficient level of investment could

occur. The adopted approach provides confidence that the overall plan is investing in parts of the system that provide the most value for customers.

4. The approach balances the use of robust data sets along with the Company's experience with storm events to develop storm hardening projects. Data-only approaches may provide decisions that don't match reality, while experience-based solutions can reflect bias. The approach balances the two to better identify types of hardening projects.

Q12. WHY IS IT ADVANTAGEOUS TO MODEL STORM HARDENING PROJECT BENEFITS USING THIS RESILIENCE-BASED PLANNING APPROACH AND THE SRM?

A. The SRM was designed for the purpose of calculating storm hardening project benefits in terms of reduced restoration costs and customer minutes interrupted to build a plan with an appropriate level of investment that provides the most benefit for customers. It was appropriate to model storm hardening projects using the resilience-based planning approach for the following reasons:

1. The benefits of hardening projects are wholly dependent on the number, type, and overall impact of future storms to impact the region served by the Company. Different storms have dramatically different impacts to ELL's transmission and distribution systems. For this reason, the resilience-based planning approach includes the "universe" of potential major events that could impact ELL over the next 50 years.

2. Major events cause assets to fail, and assets collectively serve customers. Moreover, it only takes one asset failure to cause customer outages. The cost to restore the failed assets is dependent on the extent of the damage and resources used to fix the system. The duration to restore affected customers is dependent on the extent of the asset damage and the extent of the damage on the rest of the system. It may only take 4 hours to fix the failed equipment, but customers could be without service for 4 days if crews are busy fixing other parts of the system for 3 days and 20 hours. All of this is dependent on the type of storm to impact the system. Modeling this series of events for the entire system at the asset and project level for both a "Status Quo" and "Hardened" scenarios is needed to accurately model hardening project benefits. Therefore, the resilience-based planning approach includes the Storm Impact Model to calculate the phases of asset and project resilience for each of the 49 storm events for both scenarios. The core data and calculations of the Storm Impact Model to develop the phases of resilience for every asset, project, program, and plan are discussed in further detail in the attached report.

3. The output of the Storms Impact Model is the resilience benefit of each project for each of the 49 storm types. The life-cycle resilience benefit for each hardening project is dependent on the probability of each storm and the mix of storm events to occur over the life of the hardening projects. A project's resilience value comes from mitigating outages and associated restoration costs not just for one storm event, but from several over the

life-cycle of the assets. A future "world" of major storm events could include a higher frequency of Category 1 storms with average level impact and a low frequency of tropical storms with higher impacts. Alternatively, it could include a low frequency of Category 1 type storms with high impact and a high frequency of tropical storms with lower impacts. The number of storm combination scenarios is significant given there are 49 unique types of storm events that could impact grid infrastructure. To model this range of combinations, the Storm Restoration Model employs stochastic modeling, or Monte Carlo Simulation, to randomly select from the 49 storm events for each of the 31 system sections to create a future "world" of the unique storm events that could hit ELL's service area. The Monte Carlo Simulation creates a 1,000-future storm "world." From this, the life-cycle resilience benefit of each hardening project can be calculated. This is done in the Resilience Benefit Module, which is discussed in more detail in the attached report.

4. To answer the questions of how much hardening investment is prudent and where that investment should be made, it was necessary to include an Investment Optimization and Scheduling Model within the SRM. The Investment Optimization algorithm develops the project plan and associated benefits over a range of investment levels to identify a point of diminishing returns where additional investment provides very little return. The Project Scheduling component uses the preferred budget level and develops an executable plan by prioritizing projects that provide the

most benefit while balancing ELL's technical constraints, such as contractor capacity, logistics, and materials limits.

Q13. WHAT ARE THE KEY TAKE-AWAYS FROM HOW THE RESILIENCE-BASED PLANNING ASSESSMENT WAS PERFORMED?

A. The follow are the key take-aways from how the resilience-based planning assessment was performed in the SRM:

- **Customer- and Asset-Centric**: The model is foundationally customer- and asset-centric in how it "thinks" with the alignment of assets to protection devices and protection devices to customer information (number, type, and priority). Further, the focus of investment to hardening all asset vulnerabilities that serve customers shows that the SRM identifies hardening projects that provide the most benefit to customers.
- **Comprehensive**: The comprehensive nature of the assessment is a best practice. By considering and evaluating nearly the entire T&D system, the results of the hardening plan provide confidence that portions of the ELL system are not overlooked for potential resilience benefit.
- **Consistency**: The model calculates benefits consistently for all projects. The model carefully normalizes for more accurate benefits comparison between asset types. For example, the model can compare a substation hardening project to a lateral undergrounding project. This is a significant achievement allowing the assessment to perform project prioritization across the entire asset base for a range of budget scenarios. Without this

capability, the assessment would not have been able to identify a point of diminishing returns, balance restoration and CMI benefits, and calculate benefits on the same basis for the entire plan.

- **Rooted in Cause of Failure**: The SRM is rooted in the causes of asset and system failure from two perspectives. First, the Major Storms Event Database outlines the range of storm stressors and the high-level impact to the system. Second, the detailed data streams and algorithms within the Storm Impact Model are aligned with how assets fail – mainly vegetation density, asset age, wind design differential, and flood modeling. With this basis, hardening investment identification and prioritization provide a robust assessment to focus investment on the portions of the system that are more likely to fail in a major storm.
- **Drives Prudency**: The assessment and modeling approach drives prudency for the Comprehensive Hardening Plan on two main levels. First, the granularity of potential hardening projects, nearly 170,000, allows the Company to invest in the portions of the system that provide the most value to customers. Without this granularity, there is risk that parts of the system "ride the coat-tails" of needed investment causing inefficient allocation of limited capital resources. Second, the Investment Optimization allows for the identification of the point of diminishing returns so that suboptimal or inefficient levels of investment in storm hardening are less likely.

Q14. WHAT CONCLUSIONS CAN BE MADE FROM THE RESULTS OF THE RESILIENCE ANALYSIS?

A. The following contain the conclusions of ELL's Comprehensive Hardening Plan evaluated within the SRM:

- The overall investment level of approximately $9 billion for ELL's Comprehensive Hardening Plan provides significant benefits for customers, is reasonable, and provides customers with optimal benefits given execution constraints. The Investment Optimization analysis shows that the overall investment level is below the point of diminishing returns (*i.e.,* below the point at which an incremental dollar spent produces benefits of less than a dollar in return), showing over-investment is not occurring. In fact, more investment could be made to decrease the impact to customers if execution constraints did not exist.
- ELL's Comprehensive Hardening Plan is reasonably projected to produce a reduction in storm restoration costs of approximately 50 percent. In relation to the plan's capital investment, the amount of the restoration costs savings (expressed in 2022 dollars), ranges from 37 to 54 percent of the total plan cost (in 2022 dollars) depending on future storm frequency and impacts. In other words, the avoided restoration cost benefits alone pay for approximately 37 to 54 percent of the investment plan.
- The projected customer minutes interrupted decrease by approximately 55 percent over the next 50 years. This decrease includes eliminating outages, reducing the number of customers interrupted, and decreasing the length of the outage time.
- Subject to assumptions outlined in the report regarding the monetization of avoided CMI, the investment plan provides Resilience Benefit Cost Ratios in the 3.0 to 4.3 range, showing significant benefits to customers.

- The Company's mix of hardening investments strikes a balance between investment in the substations and transmission system targeted mainly at increasing resilience for the high impact / low probability events and investment in the distribution system, which increases resilience for all ranges of event types.
- The plan will benefit all of the Company's customers as well as other utilities served by ELL's transmission system. The avoided storm restoration costs are shared by all customers. Additionally, customers will experience fewer storm outages from both direct and indirect factors. Direct benefits are realized by those customers whose infrastructure directly upstream was hardened. Indirect benefits are realized by all customers since storm restoration crews will be able to rebuild the system quicker because less infrastructure will fail.
- The hardening investment benefits are conservative. First, the benefits outlined above are only direct benefits of investments to specific investments in the grid and do not factor in the indirect benefits from lower overall storm restoration durations, such as the indirect benefits realized by customers from the ability of storm restoration crews to rebuild the system quicker as a result of the investments. Second, the investments will also provide "blue sky" benefits from decreased outages that occur during non-major storm days. Third, the evaluation did not take into account other utilities served by the Entergy Louisiana transmission system who would reasonably benefit from the transmission hardening investments. These additional benefit streams are not factored into the evaluation.

III. CONCLUSION

Q15. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, at this time.

AFFIDAVIT

STATE OF MISSOURI

COUNTY OF JACKSON

NOW BEFORE ME, the undersigned authority, personally came and appeared, **JASON D. DE STIGTER**, who after being duly sworn by me, did depose and say:

That the above and foregoing is his sworn testimony in this proceeding and that he knows the contents thereof, that the same are true as stated, except as to matters and things, if any, stated on information and belief, and that as to those matters and things, he verily believes them to be true.

Jason D. De Stigter

SWORN TO AND SUBSCRIBED BEFORE ME
THIS 15 DAY OF DECEMBER, 2022

NOTARY PUBLIC

My commission expires: 4/8/23

BELINDA STEVENSON
Notary Public - Notary Seal
STATE OF MISSOURI
Jackson County
My Commission Expires April 8, 2023
Commission # 15634636

BEFORE THE

LOUISIANA PUBLIC SERVICE COMMISSION

***IN RE*: APPLICATION OF ENTERGY LOUISIANA, LLC FOR APPROVAL OF THE ENTERGY FUTURE READY RESILIENCE PLAN (PHASE I)**	**))))**	**DOCKET NO. U- _______**

EXHIBIT JDD-1

DECEMBER 2022

Jason De Stigter, PE

Director - Utility Investment Planning

Education

B.S. / Engineering

B.A. / Business Administration

Registrations

- Professional Engineer (KS)

6 years with 1898 & Co.

15 years of experience

Visit my LinkedIn profile.

Jason leads the Utility Investment Planning business line at 1898 & Co., part of Burns & McDonnell. In this role, Jason is responsible for business development, marketing, staff training and development, solution and product development, and overall project delivery within the business line. The Utility Investment Planning business line supports electric utilities in developing long-term investment plans and portfolios to meet one or all of the following objectives: 1) aging infrastructure, 2) reliability, 3) resilience or system hardening, and 4) electrification and distributed energy resources (DERs). The business line owns solutions and tools around each of offerings to produce data-driven decisions. Jason is the main architect and solution developer of the data-driven analytic solutions for each of the four offerings inside 1898 & Co.'s AssetLens Analytics Engine.

Jason has 15 years of extensive experience in performing business case evaluation on a variety of project types helping utility clients with difficult investment decisions. Jason also has a deep financial and economic analysis background and specializes in business case evaluation and risk assessment and management for utility client. Jason has extensive experience modeling risk for utility industry clients. His modeling experience includes developing complex and innovative risk analysis models using industry leading risk analysis software tools employing Monte Carlo simulation, decision trees, and Optimization algorithms. His experience includes performing risk and economic analysis engagements for several multi-billion-dollar capital projects and large utility systems for aging infrastructure, system resilience, reliability and distribution automation, and electrification. Jason also serves as expert witness for many of these engagements supporting the full regulatory process.

TESTIMONY/REGULATORY FILING EXPERIENCE

Utility Company	Regulatory Agency	Docket No. | Year	Subject
Tampa Electric Company (TEC)	Florida Public Service Commission	20220048-EI | 2022 Direct Testimony (412-485) Filing/Sponsoring Report (141-222) Oral Testimony Provided	2022 – 2031 Storm Protection Plan (SPP)
Oklahoma Gas and Electric Company (OG&E)	Oklahoma Corporation Commission	202100164 | 2022 Direct Testimony (1-45) Filing/Sponsoring Report (46-181) Rebuttal Testimony Not in Public Domain	Grid Enhancement Business Case for 2020 & 2021 Investment
Tampa Electric Company (TEC)	Florida Public Service Commission	20200067-EI | 2020 Direct Testimony (549-623) Filing/Sponsoring Report (100-180) Rebuttal Testimony (72-105)	2020 – 2029 Storm Protection Plan (SPP)
Indianapolis Power & Light Company (now AES Indiana)	Indiana Utility Regulatory Commission	45264 | 2019 Direct Testimony Filing/Sponsoring Report Rebuttal Testimony Oral Testimony Provided	Indianapolis Power & Light Company Transmission Distribution Storage System Improvement Charge (TDSIC) Plan

Additionally, Jason testified in front of the State of Alaska Senate and House Resource committees on project economics and challenges of the AKLNG project.

PROJECT EXPERIENCE

Long-term Portfolio Development / Confidential Client

Midwest / 2022-Current

Project director for developing the portfolio of investment projects for a Midwest Investor Owned Utility. Jason is leading the effort to identify and justify investments in transmission, substation, and distribution systems over the next 5 years. The evaluation leveraged 1898 & Co.'s AssetLens Analytics Engine, an asset investment planning tool to evaluate the life-cycle benefits of replacing Transmission and Distribution (T&D) infrastructure and deploying smart devices across the distribution system. The analysis leveraged utility datasets (GIS, OMS, distribution circuit models, asset management systems, condition records, customer counts and profiles) inside the engine's aging infrastructure and reliability analytics. The project included data cleansing, organizing, linking, and transformation and configuration of the holistic risk framework across poles, conductor spans, line transformers, breakers, power transformers, relays, and other assets classes. Jason will serve as the expert witness and sponsor the technical report.

Grid Investment Plan Benefits Assessment / Confidential IOU

Midwest / 2022 - Current

Project director for development of the benefits assessment for a $2.6 billion grid investment plan. The plan includes investments in distribution circuit upgrades, distribution automation, substation rebuilds, capacity rebuilds, and low voltage conversions to improve reliability and resilience, manage long-term costs, modernize for the future, and decrease risk. The engagement include mapping investments to the underlying asset infrastructure, calculating the benefits using the AssetLens Analytics Engine analytics models, and developing the business case for over 6,000 different investment activities across 6 programs. The analysis and results are formalized within a technical report that will be submitted within the public record.

Grid Enhancement Investment Plan Benefits Assessment / Oklahoma Gas & Electric

Oklahoma / 2021-2022

Project director for development of the benefits assessment for OG&E's 2020 and 2021 Grid Enhancement Plan. The plan includes investments in distribution circuit upgrades, distribution automation, and substation rebuilds totaling nearly $250 million. Jason organized the business case framework including the linkage of investments to benefits approaches and calculating the life-cycle benefits in terms of decreased customer outages and avoided restoration costs. Jason also served as the expert witness for the benefits assessment and has provided direct testimony sponsoring the technical report, supported interrogatories and data requests, and provided rebuttal testimony. OG&E settled the case in June 2022.

2022-2031 Storm Protection Plan Resilience Assessment / Tampa Electric Company

Florida / 2021-2022

Project director for supporting the development of TEC's 2022-2031 10-year Storm Protection Plans for its transmission and distribution system in accordance with Florida Statute 366.96. This project is an update to the original 2020-2029 10-Yr Storm Protection Plan. The project utilized 1898 & Co.'s Storm Resilience Model to develop and prioritize projects on a cost benefit perspective. The model employed data-driven analyses and robust algorithms to calculate the resilience benefit of over 20,000 storm hardening projects in terms of the range of reduced restoration costs and customer minutes interrupted (CMI). The Storm Resilience Model models nearly 100 storm events and estimates which parts of the system will fail in each storm event. The model evaluates each project before and after hardening. The model further utilizes Stochastic Model to simulate storm events and calculate resilience benefits. Finally, the model performs budget optimization to identify ideal investment levels and prioritize projects. The 1898 & Co. resilience benefit assessment report and Jason written testimony were included in the filing. Jason supported the regulatory process to include responding to data requests and interrogatories. Jason is scheduled to testifying at the hearings in Tallahassee in early August 2022.

Long-term Portfolio Development / Public Service New Mexico

New Mexico / 2021-Current

Project director for developing the portfolio of investment projects for Public Service New Mexico (PNM). Jason led the effort to identify and justify investments in PNM's transmission, substation, and distribution systems over the next 20 years. The evaluation leveraged 1898 & Co.'s AssetLens Analytics Engine, an asset investment planning tool to evaluate the life-cycle benefits of replacing Transmission and Distribution (T&D) infrastructure and deploying smart devices across the distribution system. The analysis leveraged PNM datasets (GIS, OMS, distribution circuit models, asset management systems, condition records, customer counts and profiles) inside the engine's aging infrastructure and reliability analytics. The project included data cleansing, organizing, linking, and transformation and configuration of the holistic risk framework across poles, conductor spans, line transformers, breakers, power transformers, relays, and other assets classes. The evaluation organized all PNM's assets into over 20,000 projects. The risk framework allowed for the calculation of benefit in financial terms across each of the 20,000 projects from, specifically the mitigated reactive and restoration costs and the monetization of customer outages. Finally, the project included budget optimization to identify the point of diminishing returns to provide valuable management insights into the level of needed investment in the system over the next 20 years. The overall investment level is confidential. PNM is currently executing the projects that resulted from the evaluation and moving their overall investment levels to manage system risk.

2020-2029 Storm Protection Plan Resilience Assessment / Tampa Electric Company

Florida / 2019-2020

Project director for supporting the development of TEC's 2020-2029 10-year Storm Protection Plans for its transmission and distribution system in accordance with Florida Statute 366.96. The projects utilized 1898 & Co.'s Storm Resilience Model to develop and prioritize projects on a cost benefit perspective. The model employed data-driven analyses and robust algorithms to calculate the resilience benefit of over 20,000 storm hardening projects in terms of the range of reduced restoration costs and customer minutes interrupted (CMI). The Storm Resilience Model models nearly 100 storm events and estimates which parts of the system will fail in each storm event. The model evaluates each project before and after hardening. The model further utilizes Stochastic Model to simulate storm events and calculate resilience benefits. Finally, the model performs budget optimization to identify ideal investment levels and prioritize projects. Tampa Electric Company $1.5 billion 10-year plan was approved in September 2020. The 1898 & Co. resilience benefit assessment report and Jason written testimony were included in the filing. Jason supported the regulatory process to include responding to data requests and interrogatories. He also provided rebuttal testimony. Tampa Electric settled with the interveners.

Grid Investment Business Case / Confidential IOU

Southeast / 2021

Project director for development of a business case for all grid investment planned projects over the next 10 years. Business case evaluated both mitigated life-cycle reactive and restoration costs and monetization of customer outages. Investments included traditional rebuilds for reliability and resilience purposes, distribution automation, communications, and deployment of new technologies. The business case was used for internal executive management approvals.

Distribution Investment Plan Development with AssetLens / Evergy

Missouri and Kansas / 2019-Current

Project director for configuration and implementation of AssetLens for Evergy's distribution system across multiple states and jurisdictions. AssetLens is an asset investment planning software developed by 1898 & Co. to 1) automate project identification in T&D systems using typical utility data set and 2) provide business justification for all projects in life-cycle NPV benefit terms. The software ingests a range of datasets to include GIS, OMS, distribution circuit models, asset management systems, condition records, customer counts and profiles and performs the necessary cleansing, transformation, and linking. Jason led the effort to configure the risk framework analytics that estimate the risk adjusted life-cycle costs and customer impact for all T&D asset classes including poles, pole tops, primary conductor spans, primary underground sections, secondary cable, line transformers, manholes, conduit, splices in manholes, network assets and more. The analytics employ a risk-based methodology across a range of failure types (various probabilities and consequences) to calculate the annual risk costs for a Status Quo and Investment scenario. Life-cycle risk costs include a range of reactive and restoration costs and the monetization of customer outages. The evaluation organized assets into over 100,000 potential projects and scheduled investments to maximize benefit given budget, schedule, and other technical constraints. The overall investment level is confidential. AssetLens visualizes the project plan geospatially providing specific assets for replacement with the business case results for each project. Evergy's distribution engineering teams has been using AssetLens to develop work orders and executive the project plan. It was also used to support their regulatory filing to the Missouri commission.

Distribution Automation Plan Development / Confidential IOU

Central Midwest / 2021-Current

Project director for development of a distribution automation investment plan for the next 5 years. The project involved using GIS and outage records to circuits that would provide the most benefit from the deployment of reclosers. The effort included estimating the number of devices for each circuit and placement of devices for the first few years of the plan. The business case results include the estimated decrease in customer outages and monetization of the outages for an investment business case. The utility is currently developing work orders for 2022 projects.

Overhead and Underground Business Case Development / Confidential IOU

Upper Midwest / 2021-Current

Project director for development of a business case comparing overhead rebuilds to a new modern standards or undergrounding. The business case was performed from a life-cycle cost perspective and impact to customers over a range of events to include extreme weather. The business case evaluated a range of areas of the system to include urban, rural, and suburban. The result of the evaluation may be used for responding to regulators requests.

Long-term Investment Plan Development / Confidential IOU

Midwest / 2021

Project director for identification and justification of distribution circuit and substation investments for a long-term investment plan. The evaluation utilized the AssetLens Analytics Engine to evaluate a range of investment options across the grid, establish 'ideal' investment levels, and provide direction to the 'ideal' split of investment across the system.

The utility utilized the study to help develop their long-term investment plan for executive management approval and regulatory strategy.

Distribution Automation Business Case Pilot / Confidential IOU

Midwest / 2021

Project director for a pilot study on distribution automation project identification and justification. The evaluation performed 8760 modeling to understand system overloading constraints to performing automated load transfer schemes. The constraints analysis was utilized in the business case assessment to understand the percentage of time the scheme could operate and provide benefits to customers and if there was a business case to make other grid investments to unlock potential overloading constraints.

Distribution Reliability Investment Plan Development with AssetLens / Confidential IOU

Midwest / 2020-Current

Project director for development of a 10-year distribution investment plan focused on improving overall system reliability and delivery of AssetLens. The data and analytics-based planning approach included the cleansing, organizing, transformation, and linking of GIS, OMS, distribution circuit models, customer data, and condition information. The planning analytics included evaluation of the benefits and costs of rebuilding each protection zone, over 40,000, across they system. Benefit profiles included the mitigated reactive and restoration costs and decreased customer outages monetized using the DOE ICE Calculator. The project also included budget optimization to identify the long-term need for investment. The overall investment level is confidential. The client's distribution engineering team is currently utilizing the AssetLens solution to build work orders from the projects identified. The client is also moving toward the more 'ideal' long-term investment levels to manage system risk.

Long Term Electric Transmission and Distribution Capital Plan / Indianapolis Power & Light

Indiana / 2017-2019

Project manager for developing IPL's asset risk model. The asset risk model includes transmission circuit, substation, and distribution circuit assets. The asset risk model was used to identify and prioritize asset replacements for nearly $750 million of the $1.2 billion filing. Jason developed an innovative approach for modeling distribution circuit risk down to the span level. For the risk model, Jason developed an integrated and holistic probability and consequence of failure framework to evaluate any asset consistently. The approach has allowed IPL to prioritize investment across transmission and distribution and substations and circuits. The analysis included using Burns & McDonnell's proprietary capital optimization algorithm to group assets into projects and prioritize projects to maximize risk reduction benefit. Burns & McDonnell prepared two reports that are part of IPL's public record filing. Jason also provided written (direct and rebuttal) and oral testimony. The entire plan (100%) was approved in February of 2020.

Grid Modernization Engineering Study / Entergy

Louisiana/Mississippi/Arkansas/Texas / 2016–2019

Entergy is embarking on a new approach to electric distribution planning, design and engineering to meet the future needs of its customers. The new approach includes developing modernize electric distribution equipment, engineering and design, and construction standards to drive value throughout the supply chain from material purchasing, inventory, system design, and construction. Additionally, the grid modernization approach leverages a modern holistic distribution asset and capital planning process with associated tools (DNV GL's Synergy) to facilitate efficient and robust performance and risk assessment of Entergy's electric distribution system. The approach identifies the portfolio of issues facing a family or cluster of distribution feeders and then develops the ideal portfolio of projects to address to improve feeder performance, cost, and risk.

Project manager for the business case evaluation and capital project prioritization aspects of Grid Modernization Engineering Study for Entergy. For the portfolio of projects, Jason developed a robust business case methodology that calculates risk reduction benefits, reliability improvement, and operational efficiency (i.e. fewer truck rolls) to justify each capital investment.

Entergy intends to use the results of the engineering study to propose a list of grid modernization project to consider for regulatory approval and funding. Additionally, these projects and the holistic planning approach will be the first step in an evolutionary change to build Entergy's grid of the future, ready for the next generation of consumers and system performance.

69 kV Wood Pole Replacement Program Evaluation / Salt River Project (SRP)

Phoenix, Arizona / 2017–2018

Project manager for evaluation of the 'ideal' level of 69 kV wood pole replacement SRP should execute each year. The effort includes development of an asset risk model, including risk framework, and various replacement strategies that maximize risk reduction while also maintaining overall budget levels. The final outcome will include the risk mitigated for the whole portfolio over 30 years for a range of budget levels to identify an 'ideal' overall investment rate.

PRIOR EXPERIENCE

Capital and Operations & Maintenance (O&M) Budget Prioritization / Tulsa Metropolitan Utility Authority (TMUA) Utility Enterprise Initiative

Tulsa, Oklahoma / 2013-2016

Project manager for the Capital Prioritization and Optimization task of TMUA's Asset Management implementation initiative, Utility Enterprise Initiative. He used a 'Project Prioritization and Optimization' solution for several water and wastewater projects as part annual cycle phased approach (executed three of four phases). Jason was responsible for leading workshops with engineering and maintenance staff, developing business case approaches for each water/wastewater project, performing Monte Carlo and optimization simulations, and developing strategies for the Utility's capital improvement plan (CIP) during a period of tight budget constraints to minimize rate increases. TMUA was working toward codifying the process and tool into their own annual budget and rates process. As such, Jason was responsible for developing users guide documentation and holding training on the process and tool for TMUA.

2017 Executive Asset Management Plan Alternatives Evaluation / Washington Suburban Sanitation Commission (WSSC)

Laurel, Maryland / 2015

Project manager for alternatives evaluation to support WSSC in the development of their 2017 Enterprise Asset Management Plan Business Case. Effort included developing forecasted 30-year capital plans optimizing on level of service, risk and cost. WSSC utilized the results of the evaluation to develop long term forecasts of capital improvements for communication to decision make Capital Prioritization Pilot Project / Salt River Project (SRP)

Project Prioritization / Salt River Project

Arizona / 2013-2014

Subject matter expert for this pilot study for SRP to prioritize and optimize several electrical generation, transmission and distribution planned investments. Allowed SRP management the opportunity to further develop and improve upon their current budget processes and to consider adopting the solution enterprise-wide. Jason's responsibilities included developing business case approaches for several of the pilot study projects and supporting workshops.

Long Term Electric Transmission and Distribution Capital Plan / Duke Energy

Indiana / 2014-2015

Subject matter expert and manager for development of a risk-based electric T&D capital plan that included Duke's long-term electric transmission and distribution (T&D) investments. This work provided evidence of how Duke's investments in its system provided risk reduction benefits and focused spending on high risk assets. As a capital prioritization and risk subject matter expert, he also developed capital plan profiles and resulting risk reduction solutions which were key to showing the value of the 7-year capital plan.

Long Term Electric Transmission and Distribution Capital Plan / Northern Indiana Public Service Company (NIPSCO)

Indiana / 2013-2014

Subject matter expert for development of a long-term $1 billion plus capital plan for NIPSCO's electric T&D infrastructure. A system risk model was developed to analyze and score asset risk across the T&D system for NIPSCO. The model highlighted the risk reduction benefits achieved through NIPSCO's long-term asset replacement program, which is focused on addressing high-risk assets that are nearing the end of their useful life.

Capital Prioritization System Master Plan / Hetch Hetchy Water and Power

California / 2009, 2011, 2012

Primary consultant for this system master plan, developing the analysis and prioritization of recommended capital and O&M projects for the Hetch Hetchy power, transmission and civil asset system. The process utilized a risk-based approach to economically schedule investments to maximize risk reduction given a certain budget constraint. The Hetch Hetchy Reservoir system lies within the scenic Yosemite National Park and provides electricity and water storage for the San Francisco Public Utility Commission.

Capital Project Prioritization with Risk Assessment / Colorado Springs Utilities

Colorado Springs, Colorado / 2008

Primary analyst on an innovative capital project prioritization process for Colorado Springs Utilities' Raw Water System. The engagement applied the Strategic Value Creation process to quantify the physical and financial parameters of capital and O&M projects identified for the utility's raw water system. A wide variety of projects and risk were then prioritized to develop the system capital improvement plan while considering utility risk tolerance, budget constraints and other planning criteria. Monte Carlo simulations were used to quantify the physical and financial parameters of each individual project, and the projects are evaluated and ranked using a consistent and transparent approach.

Jason was responsible for performing the Monte Carlo analysis, understanding the risks of each CAPITAL and O&M project, and prioritizing the projects to reduce the overall risk to the client.

Alaska Liquefied Natural Gas (AKLNG) Economic and Risk Analysis / State of Alaska Departments of Natural Resources and Revenue

Alaska / 2013-2016

Project manager responsible for economic and risk analysis for the AKLNG project on behalf of the State. In this role, Jason developed analysis to explore various project questions and negotiating position to better understand the perspective of each project sponsor and the best position for the State. He routinely developed materials to present to the commissioners of the departments or Natural Resources and Revenue, the State of Alaska legislature, negotiating teams, and the governor's office. On a few occasions, Jason has testified to the state of Alaska legislature of the economics and risks associated with the AKLNG project.

Deep Tunnel Sewerage System (DTSS) Phase 2 Resiliency Assessment / Singapore Public Utilities Board (PUB)

Singapore / 2014-2015

Subject matter expert for an alternative's resiliency assessment of several deep tunnel sewerage systems alternatives for Singapore PUB. In his role for this engagement, Jason created an innovated approach to evaluating the resiliency of several tunneling alternatives including total risk weighted level of service and cost over the asset's life cycle. The assessment identified several key risks impacting each alternative then quantifying the likelihood and the level of service and cost impacts of each risk. Employing Monte Carlo simulation, the risk cost and discount to level of service scores were calculated to develop a range of potential benefit cost ratios for each alternative. Singapore PUB utilized the process and results to identify a preferred alternative and move forward with key design decisions.

Kirkwood Penstock Risk Evaluation / Hetch Hetchy Water and Power

California / 2014

Project manager for a risk assessment of HHWP's critical Kirkwood Penstock which over 80% of San Francisco Bay's water supply moves through. The risk assessment following guidelines set out by the United States Bureau of Reclamation including a failure modes and effects analysis applying a qualitative scoring-based approach to evaluate the likelihood and consequence of failure for each failure mode. HHWP utilized the results of the evaluation to prioritize investment needs to ensure reliability of this critical asset.

Business Case Evaluation and Risk Analysis / Hampton Roads Sanitation District (HRSD, Wastewater Utility)

Virginia / 2011-2012

Business case evaluation and lead risk consultant for this long-term evaluation of the business case and associated risk of alternative wastewater system master plans. Working with Hampton Roads' senior management team, Jason evaluated the economics and risk of alternative strategic long-term wastewater system expansion plans related to biosolids management, which involved hundreds of millions of dollars in capital and O&M expenditures. This developed a long-term strategy that is now being used to optimize short- and long-term implementation plans for HRSD's wastewater system.

Conveyance Alternative Risk Assessment / Metropolitan Water District

California / 2010

Primary consultant for this engagement which analyzed several water conveyance options for the California State Department of Water Resources. This analysis was focused on capital cost and schedule risk of different multi-billion-dollar canal and tunnel conveyance alternatives. Jason was the risk specialist for the Environmental team for the risk assessment workshop. Utility decision-makers utilized the results to more fully understand the risk inherent in each alternative to decide on a preferred alternative.

Integrated Water Power Plant Economic and Regulatory Assessment / Public Authority for Electricity and Water of Oman

Oman, Middle East / 2009-2010

Primary analyst for the economic and regulatory (tariff) modeling of a new, highly efficient integrated water & power plant. Jason's responsibilities included performing economic and tariff modeling of several different desalination and power plant alternatives and presenting final results to the Chairman of the Public Authority for Electricity and Water of Oman.

AGIA Economic and Risk Modeling / State of Alaska Department of Natural Resources (DNR)

Alaska / 2009-2010

Primary analyst for this economic and risk modeling assignment for the State of Alaska DNR. Analysis included modeling and evaluation of different natural gas pipeline project risk factors, as well as risk mitigation measures the state has within its control. The results of the analysis assisted the State of Alaska in negotiations with other pipeline stakeholders.

Black & Veatch's Energy Market Perspective Emissions Modeling

Overland Park, Kansas / 2012-2013

As part of Black & Veatch's annual release of its Energy Market Perspective, Jason developed a fundamental economic model to calculate emissions prices based on the EPA's Cross State Air Pollution Rule.

Commercial Modeling and Analysis / Alaska Gasline Development Corporation (AGDC)

Anchorage, Alaska / 2010-2011

Lead consultant for ongoing commercial and tariff modeling for AGDC's analysis of in-state pipeline alternatives. This modeling included sensitivity and scenario analysis, midstream tariff modeling, and stakeholder cash flow analysis.

Black & Veatch's Energy Market Perspective

Overland Park, Kansas / 2009-2011

The Energy Market Perspective developed by Black & Veatch uses an integrated market modeling approach to develop price forecasts for energy and natural gas prices. The modeling team, which included Jason, developed forecasts for CO2 taxes, energy demand and peak demand, generation retirements, generation expansion, renewables buildout and transmission expansion. Using these forecasts, the integrated market model used an interactive process of a production cost model for electric prices and a fundamental market model for natural gas prices.

Jason's principal responsibilities included developing forecasts, running and understanding the production cost model for a large region in the United States, and drawing conclusions for the region. The main forecasts Jason developed included energy and peak demand, generation retirements, generation expansion, and transmission expansion. Furthermore, Jason was responsible for developing the final report for the regional perspective.

Alaska Gasline Inducement Act (AGIA) Net Present Value (NPV) and Risk Analysis / State of Alaska Departments of Natural Resources and Revenue

Alaska / 2007-2008

In 2007, the state of Alaska passed the Alaska Gasline Inducement Act (AGIA). This act created a framework for the State to issue a license to build a 1,400 mile pipeline to transport natural gas from the North Slope of Alaska to either the North American market or elsewhere.

Uncertainty for a project of this size (over $30 billion) is understandably significant. In order to quantify this significant uncertainty, risk analysis was performed explicitly with the NPV model to evaluate the level of project risk to the various stakeholders due to various assumptions such as commodity prices, capital cost escalation, project schedule uncertainty, and reserve risk.

Jason performed economic, risk and financial analysis for several different stakeholders for the proposed projects and several sensitivities and alternative scenarios. Jason's main responsibilities included model development/creation, Monte Carlo risk modeling, and understanding risk for each stakeholder. He also performed financial analysis, data validation, and report and presentation support.

Socioeconomic Analysis, Riverbend Unit 3 and Fermi Unit 3 Nuclear Licensing Project / Entergy and Detroit Edison

Louisiana and Michigan / 2007-2008

Senior analyst served as an economist for a detailed socioeconomic analysis associated with the construction and operating license application (COLA) process for Entergy and Detroit Edison. He was responsible for developing population distributions; population projections; demographic characteristics to include age, sex, race and income; transient population distributions; and community characteristics for the surrounding area. Jason was also responsible for writing and reviewing significant portions of the COLA

Market and Economic Analysis / Termobarranquilla

Colombia, South America / 2007-2008

As a senior analyst, Jason provided market analysis, economic analysis and a discounted cash flow model to evaluate the worth of the Termobarranquilla power plant after an energy market restructuring in Colombia. He was responsible for developing an energy market model, economic dispatch model, discounted cash flow model and writing the report.

Taylor Energy Center Need for Power Application / Various Clients

Florida / 2006

Jason performed production costing, economic analysis and other support to facilitate the completion and filing of the Taylor Energy Center (TEC) Need for Power Application (NFP). The NFP provided a determination of the most cost-effective capacity addition to satisfy forecasted capacity requirements for the four separate utilities participating in the project while maintaining consistency with the Florida Public Service Commission statutory requirements. The analysis considered self-build and purchase-power alternatives.

Portfolio of Wind Farms and Coal Fired Plants / Sembcorp Industries Pte Ltd.

China / 2011

Lead consultant to Sembcorp Industries Pte (buy-side), in support of their potential acquisition of an equity position in a Chinese investment company (confidential). This engagement required due diligence site visits and technical and commercial review of a wind portfolio and coal fired generation plant in Shanxi Province, Hebei Province, and Inner Mongolia Autonomous.

Water and Wastewater Utility Independent Engineer's Report / Confidential Client

2011

Primary consultant assisted and prepared an independent engineer's report for a confidential client seeking to divest its portfolio of water and wastewater utilities. The report provided an overview of the systems, the major sources of supplies, rates, and environmental and regulatory issues. Major facilities were evaluated to document the condition of specific utilities. A final report was prepared and delivered to the client for use in its divestment proceedings.

Combined Cycle Due Diligence / Confidential Client

California / 2011

Jason was involved with the technical due diligence of 1,000 megawatt (MW) combined-cycle power plant in the state of California. Jason was responsible for reviewing maintenance and performance reports on plant equipment and safety along with O&M and energy management agreements. Jason also developed the corresponding report sections that summarized the results of the analysis.

Engineer's Report / Philadelphia Gas Works (PGW)

Philadelphia, Pennsylvania / 2010-2011

Lead consultant on the engineer's reports developed for PGW's last two revenue bond issues for $165 million and $150 million, respectively. Proceeds from the bond issues funded needed capital improvements to PGW's distribution system and LNG facilities. The engineer's report summarized the findings of a study of PGW's facilities, management, operations, gas supply, rates and marketing, and customer service, and assessed the financial feasibility of the bond issue.

E.ON US Portfolio Due Diligence, Various Coal, Gas and Hydroelectric Power Plants / E.ON

Kentucky, United States / 2010

Jason performed technical due diligence for the potential sales of approximately 9,500 MW coal, gas and hydroelectric generating assets in the state of Kentucky. Jason was responsible for reviewing maintenance and performance reports on plant equipment and safety along with O&M and energy management agreements. Jason also developed the corresponding report sections that summarized the results of the analysis.

Technical Due Diligence / Con Edison Development, Inc.

2007

Jason performed a technical due diligence assessment of certain power generation facilities in the northeast United States. He was responsible for developing power plant performance sections of the assessment and reviewing O&M, power purchase, maintenance, gas supply, oil supply, electrical interconnection and water supply agreements.

PUBLICATIONS AND PRESENTATIONS

- *Asset Management: A Framework for Maximized Value*, published and featured in Burns & McDonnel's quarterly BenchMark article in 2020. (Video and quoted)
- How IPL Created an Optimized Capital Plan to manage risk across the entire T&D system, published and presented at the 2020 DistribuTECH conference. (Co-Author)
- How IPL solved the challenges of modeling linear assets in their asset risk model by leveraging GIS, published and presented at the 2020 DistribuTECH conference. (Co-Author)
- Capital Planning for Grid Modernization, Building the Grid of Tomorrow, 2018 EUCI course presenter. (Co-presenter)
- *Changing the Way the Grid's Future is Planned*, published Burns & McDonnell white paper in 2017. (Co-Author)
- Monetizing Risk Helps Tulsa Optimize Capital Investments, published in the July 2016 Journal American Water Works Associate (JAWWA). (Co-Author)
- Monte Carlo Simulations Take The Chance Out Of Investment Decisions, published in the April 2016 Breaking Energy. (Co-Author)
- Monetizing Risk – Capital Investment Prioritization and Optimization for Tulsa Metropolitan Utility Authority, published at the 2016 Utility Management Conference. (Co-Author)
- Priorities: Getting the Most From Your Capital Improvement Plan, published in the May 2015 Florida Water Resources Journal. (Author)
- Monetizing Risk – A Capital Investment Prioritization and Optimization Model, presented and published at the 2015 Texas Water Conference. (Co-Author/Presenter)
- How to Get More Reliability Bang from Your Capital Spending Buck, presented and published at the 2014 Florida Water Resources Conference. (Co-Author/Presenter)
- Triple Bottom Line and Monte Carlo Simulation: Business Case Evaluation Methodologies and Testing Sensitivities: Understanding Economic Models and Uncertainty in Results, presented at the 2013 WEFTEC conference workshop titled "WERF Barriers to Biogas Workshop: Learn to Use the Right Economic Methodologies to Evaluate Cost-Saving Projects". (Presenter)
- The Challenge of Regulatory Compliance and Multiple Facility Upgrades – A Progressive System Approach, presented and published at the 2012 WEFTEC conference proceedings. (Co-Author)
- Asset Management and Maintenance Strategies – Balancing Costs and Risk, poster presentation and published at Hydrovision 2011 conference. (Co-Author)

BEFORE THE

LOUISIANA PUBLIC SERVICE COMMISSION

***IN RE*: APPLICATION OF ENTERGY**	**)**	
LOUISIANA, LLC FOR APPROVAL	**)**	**DOCKET NO. U- _______**
OF THE ENTERGY FUTURE READY	**)**	
RESILIENCE PLAN (PHASE I)	**)**	

EXHIBIT JDD-2

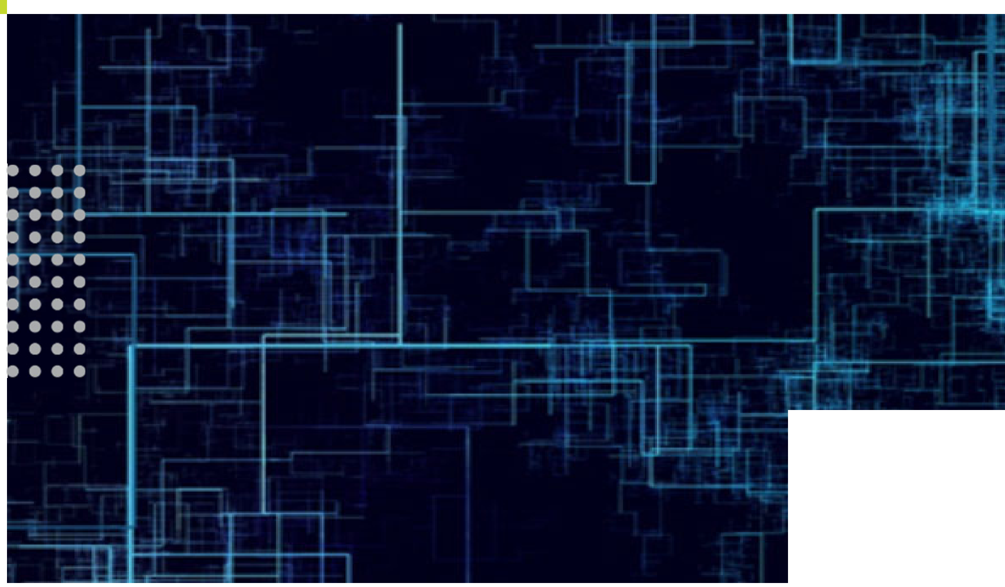
DECEMBER 2022

Resilience Investment and Benefits Report

Entergy Louisiana, LLC

Entergy Louisiana, LLC Comprehensive Hardening Plan
Project No. 142412

Revision 1
12/15/2022



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LIST OF ABBREVIATIONS

Abbreviation	**Term/Phrase/Name**
ANL	Argonne National Laboratory
Burns & McDonnell	Burns & McDonnell Engineering Company, Inc.
C&I	Commercial & Industrial
CMI	Customer Minutes Interrupted
DOE	Department of Energy
GIS	Geographic Information System
ICE	Interruption Cost Estimator
IEEE	Institute of Electrical and Electronics Engineers
LOF	Likelihood of Failure
MED	Major Event Day
NIAC	National Infrastructure Advisory Council
NOAA	National Oceanic and Atmospheric Administration
OMS	Outage Management System
PNNL	Pacific Northwest National Laboratory
POF	Probability of Failure
PV	Present Value
ROW	Right-of-Way
SIM	Storm Impact Model
SLOSH	Sea, Land, and Overland Surges from Hurricanes
T&D	Transmission and Distribution

1.0 EXECUTIVE SUMMARY

1898 & Co, the advisory and technology consulting arm of Burns & McDonnell, was engaged on behalf of Entergy Louisiana, LLC ("Entergy Louisiana" or "ELL") to assist with the development of a plan to strategically accelerate investment in storm resilience for the period 2024-2034 ("Comprehensive Hardening Plan"). In collaboration, Entergy Louisiana and 1898 & Co. utilized a resilience-based planning approach to identify hardening projects and to prioritize investments in the Transmission and Distribution ("T&D") system utilizing a Storm Resilience Model. The Storm Resilience Model evaluates each hardening project's ability to reduce the magnitude and/or duration of disruptive storm events. Key objectives for the Storm Resilience Model are:

1. Calculate the customer benefit of hardening projects through reduced utility restoration costs and impacts to customers
2. Prioritize hardening projects with the highest resilience benefit per dollar invested into the system
3. Establish an overall investment level and mix that maximizes customer benefits while working within labor and material technical execution constraints provided by Entergy Louisiana.

The Storm Resilience Model employs a data-driven decision-making methodology utilizing robust and sophisticated algorithms to calculate the resilience benefit of hardening projects in terms of the range of reduced restoration costs and Customer Minutes Interrupted ("CMI"). Resilience-based prioritization facilitates the identification of the hardening projects that provide the most benefit. Prioritizing and optimizing investments in the system helps provide confidence that the overall investment level is appropriate and that customers will get the most value for the level of investment.

This report outlines project prioritization and benefits calculations for the following Entergy Louisiana storm hardening programs:

- Distribution Feeder Hardening (Rebuild)
- Distribution Feeder Undergrounding
- Lateral Hardening (Rebuild)
- Lateral Undergrounding
- Transmission Rebuild
- Substation Control House Remediation

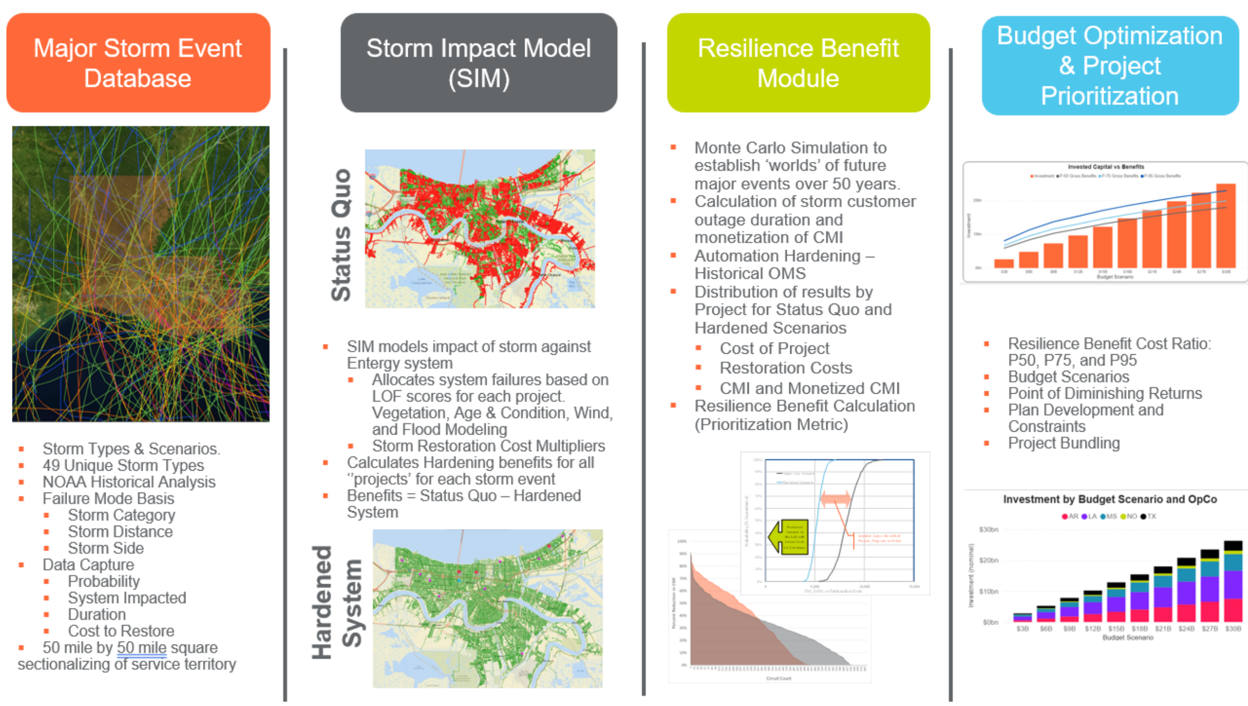
- Substation Storm Surge Mitigation

1.1 Resilience Based Planning Approach

Figure 1-1 provides an overview of the Storm Resilience Model. The model employs a resilience-based planning approach to calculate the benefits of reducing storm restoration costs and CMI. Each of the different components are reviewed in further detail in Sections 2.0 through 7.0.

The Major Storm Events Database contains storm probability distributions, and the range of impacts for 49 different storm types. The 49 different storm types are based on the range of storm categories, storm distance from the infrastructure, and the side of the storm impacting the infrastructure. The database organizes the Entergy Louisiana service area into 31 different 50-mile by 50-mile system sections to provide the granularity of the impact of the 49 storm types against the infrastructure. The database includes probabilities and impacts for all 49 different storm types for each of the 31 system sections.

Figure 1-1: Storm Resilience Model Overview



Each storm type for each system section is then modeled within the Storm Impact Model to identify which parts of the system are most likely to fail in the event of each type of storm. The Likelihood of Failure ("LOF") is based on the vegetation density around each conductor asset, the differential in the current wind loading of the asset vs the applicable hardened wind loading standard, and the age of the asset base. The Resilience Model is comprehensive in that it evaluates nearly all of Entergy Louisiana's T&D systems. Table 1-1 provides an overview of the potential project count for each of the programs.

Table 1-1: Potential Hardening Projects Evaluated

Program	Project Count
Distribution Feeder Hardening (Rebuild)	**5,858**
Distribution Feeder Undergrounding	**5,858**
Lateral Hardening (Rebuild)	**78,174**
Lateral Undergrounding	**78,174**
Transmission Rebuild	**888**
Substation Control House Remediation	**53**
Substation Storm Surge Mitigation	**212**
Total	**169,217**

The Storm Impact Model also estimates the restoration costs and CMI for each of the projects in Table 1-1 above for each storm type. For purposes of this report, the term "project" refers to a collection of assets. Assets are typically organized from a customer impact perspective, see Section 2.2. Finally, the Storm Impact Model calculates the benefit in decreased restoration costs and CMI if that project is hardened per Entergy Louisiana's hardening standards. The CMI benefit is monetized using the Department of Energy's ("DOE") Interruption Cost Estimator ("ICE") for project prioritization purposes.

The Resilience Benefit Calculation utilizes stochastic modeling, also known as a Monte Carlo simulation, to select a storm probability for each of the 49 storm types for each of the system sections for 1,000 iterations. This produces 1,000 different future storm worlds and the expected range of benefit values depending on the different probabilities and impact ranges to the Entergy Louisiana system. The probability of each storm scenario is multiplied by the benefits calculated for each project from the Storm Impact Model to provide a resilience-weighted benefit for each project in dollars.

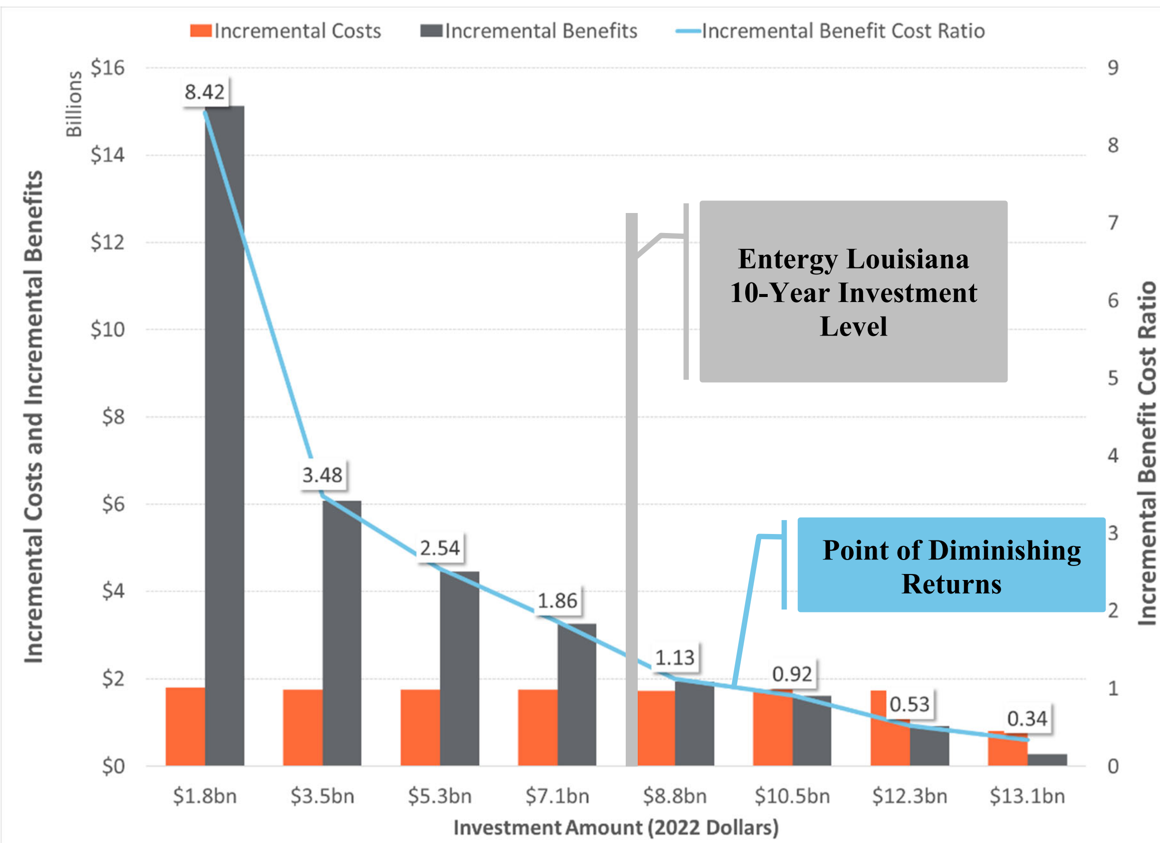
The Project Scheduling and Investment Optimization model prioritizes the projects based on the highest resilience benefit cost ratio factoring in execution constraints. It also performs an investment optimization over a range of budget levels to identify the point of diminishing returns.

The model prioritizes each project based on the sum of the restoration cost benefit and monetized CMI benefit divided by the project cost. This is done for the range of potential benefit values to create the resilience benefit cost ratio. The model also incorporates expected technical and operational constraints in scheduling the projects applicable to Entergy Louisiana and its service area, such as contractor capacity, logistics, and materials limits. Using the Resilience Benefit Calculation and Project Scheduling and Investment Optimization model, the Storm Resilience Model calculates the net benefit in terms of reduced restoration costs and CMI for the 10-year investment profile.

1.2 Investment Optimization and Plan Summary

Entergy Louisiana and 1898 & Co. utilized a resilience-based planning approach to understand the 'point of diminishing' returns and identify and prioritize resilience investment in the T&D systems. It would cost approximately $22 billion (2022 dollars) to harden all Entergy Louisiana infrastructure. Given the total level of potential investment, the Investment Optimization analysis was performed in approximately $1.8 billion increments ($1.8B in 2022 dollars is approximately $2.0 billion in nominal terms when escalated) up to $13.1 billion (in 2022 dollars). Figure 1-2 shows the results of the Investment Optimization analysis comparing the incremental costs to the incremental benefits at each investment level.

Figure 1-2 Investment Optimization Results



The figure shows the that the point of diminishing returns occurs at an investment level of approximately $9.4 billion in 2022 dollars (linearly interpolating between an $8.8b and $10.5b scenario);

when that level of investment is exceeded, the incremental costs begin to exceed the incremental benefits. Approximately $7.6 billion (in 2022 dollars) or $8.8 billion (nominal dollars) is Entergy Louisiana's recommended investment level based on technical constraints where the incremental benefit cost ratio is approximately 1.5. Section 7.1 shows the benefit cost ratio for the overall investment level. While additional investments could be made that would provide value to customers, technical execution constraints due to labor and materials availability affects the overall investment level, not the business justification.

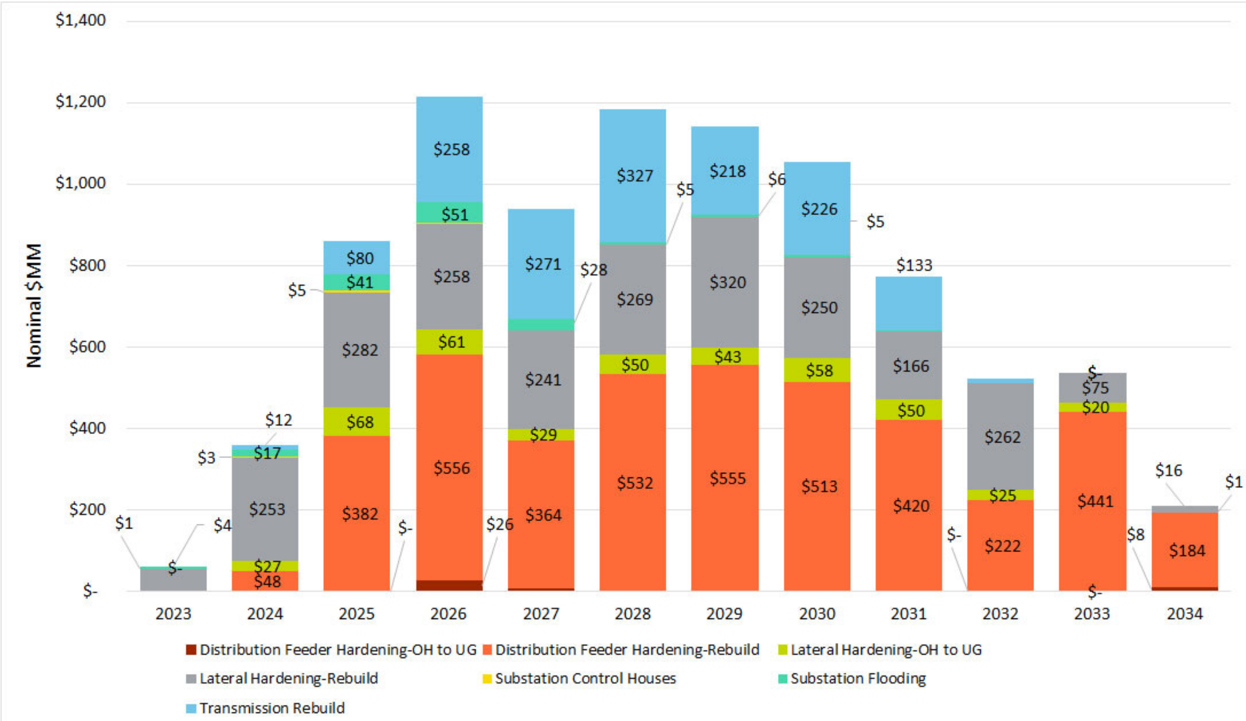
Resilience-based planning establishes an overall investment level with the following principles:

1. Fundamentally mitigating the impact of major disruptions to system stakeholders, for storm resilience events that includes maximizing the decrease in restoration costs and customer outages.
2. Investing in infrastructure upgrades that provide customer benefits that outweigh their costs.
3. Establishing a portfolio of projects, and the resulting funding level, which is executable given labor, materials, and other constraints.

Figure 1-2 shows that the first $2 billion of investment provides the most benefit to customers per dollar invested, with a benefit cost ratio of 8.4. This level of benefit meets the second and third principles outlined above but would leave a substantial number of customers still exposed to major events and not meeting principle number 1 above. An investment level of approximately $9.4 billion (2022 dollars), the 'point of diminishing returns' meets principles one and two but violates principle three. Entergy's investment level of approximately $7.6 billion (2022 dollars) or $8.8 billion (nominal dollars) meets all three principles outlined above.

Figure 1-3 shows the Comprehensive Hardening Plan investment profile. The figure includes the build-up by program to the total. The investment capital costs are in nominal dollars, that is, the dollars of that day. The plan is approximately $8.8 billion in nominal terms or $7.6 billion in 2022 dollars. Feeder hardening rebuilds make up the single largest portion of the total, accounting for 48 percent of the total investment. Lateral hardening is next, with 28 percent. Transmission hardening follows with 17 percent. Lateral undergrounding makes up 5 percent, while feeder undergrounding, substation control house remediation, and substation storm surge mitigation make up the final 2 percent.

Figure 1-3: Comprehensive Hardening Plan Investment Profile



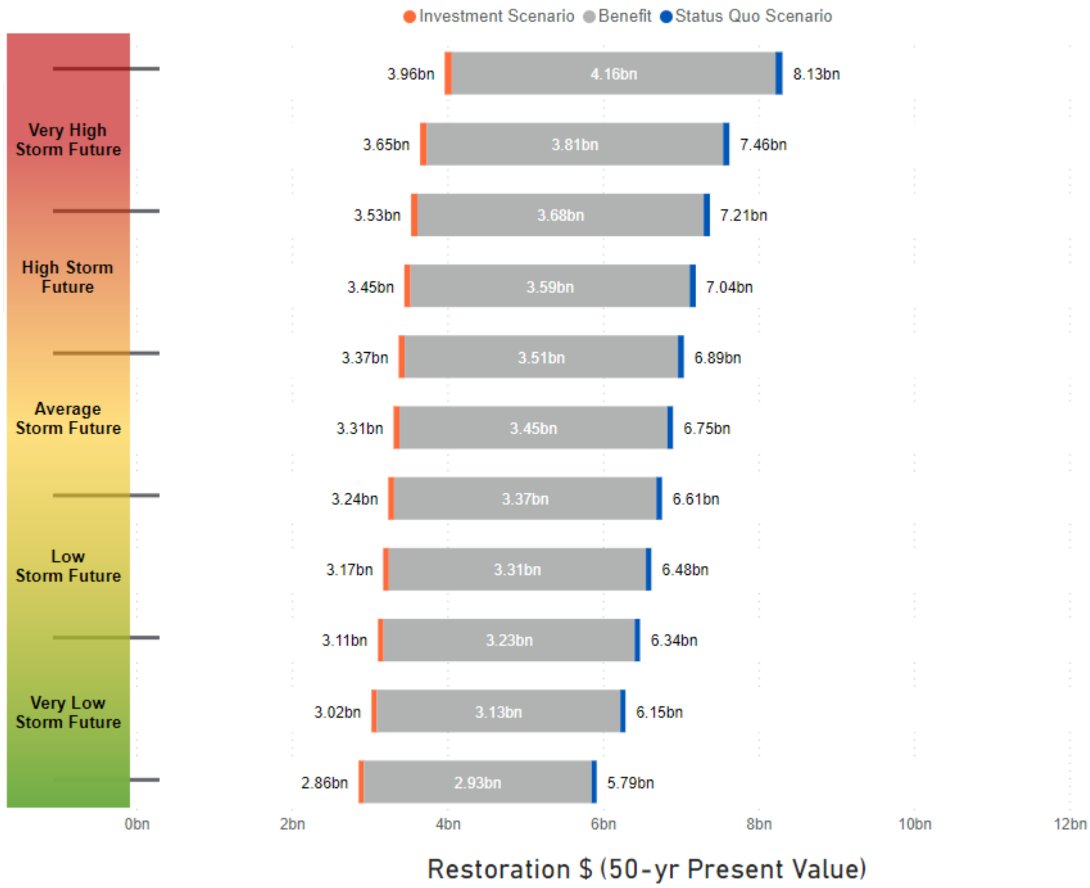
1.3 Benefits

Customer benefits are calculated in terms of the:

1. Reduction in the Storm Restoration Costs
2. Reduction in the number of customers impacted and the duration of the overall outage, calculated as CMI

Figure 1-4 shows the range in restoration cost reduction at various storm futures. The values are shown in 50-year present value terms. It should be noted that the figure does not include the $8.8 billion of investment, it only shows the benefits if the plan is executed over the next 10 years.

Figure 1-4: Comprehensive Hardening Plan Restoration Cost Benefit



The figure shows that the 50-year Present Value ("PV") of future storm restoration costs in a Status Quo scenario from a resilience perspective is $5.8 billion to $8.1 billion. The Comprehensive Hardening Plan is reasonably projected to produce a reduction in storm restoration costs of approximately 50 percent. The decrease in restoration costs is approximately $2.9 billion to $4.2 billion. From a present value perspective, the benefit attributable to decreased (avoided) restoration costs, expressed in 2022 dollars, represents approximately 37 to 54 percent of the total plan costs in 2022 dollars. In other words, the avoided restoration cost benefits alone pay for approximately 37 to 54 percent of the investment plan. Avoided storm CMI benefit covers the remaining 46 to 63 percent of the plan investment.

Figure 1-5 shows the range in avoided storm CMI at various storm futures. The values are shown for a 50-year period. The figure shows the 50-year total of future storm CMI in a Status Quo scenario from a resilience perspective ranges from 109.7 billion to 160.2 billion. Assuming approximately one million customers for Entergy Louisiana, this is equivalent to approximately 37 to 53 storm outage hours per year per customer for the Status Quo scenario. With the Comprehensive Hardening Plan, CMI from major storm events decrease by approximately 55 percent.

Figure 1-5: Comprehensive Hardening Plan Customer Benefit

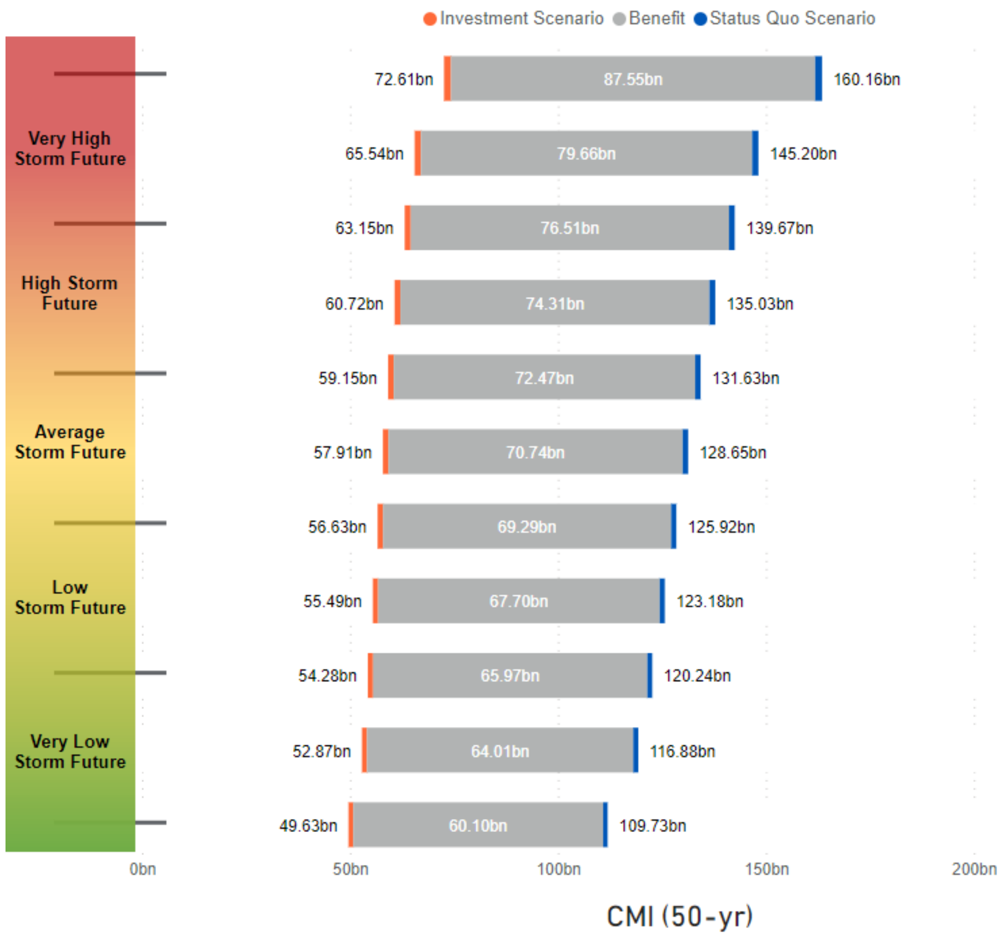
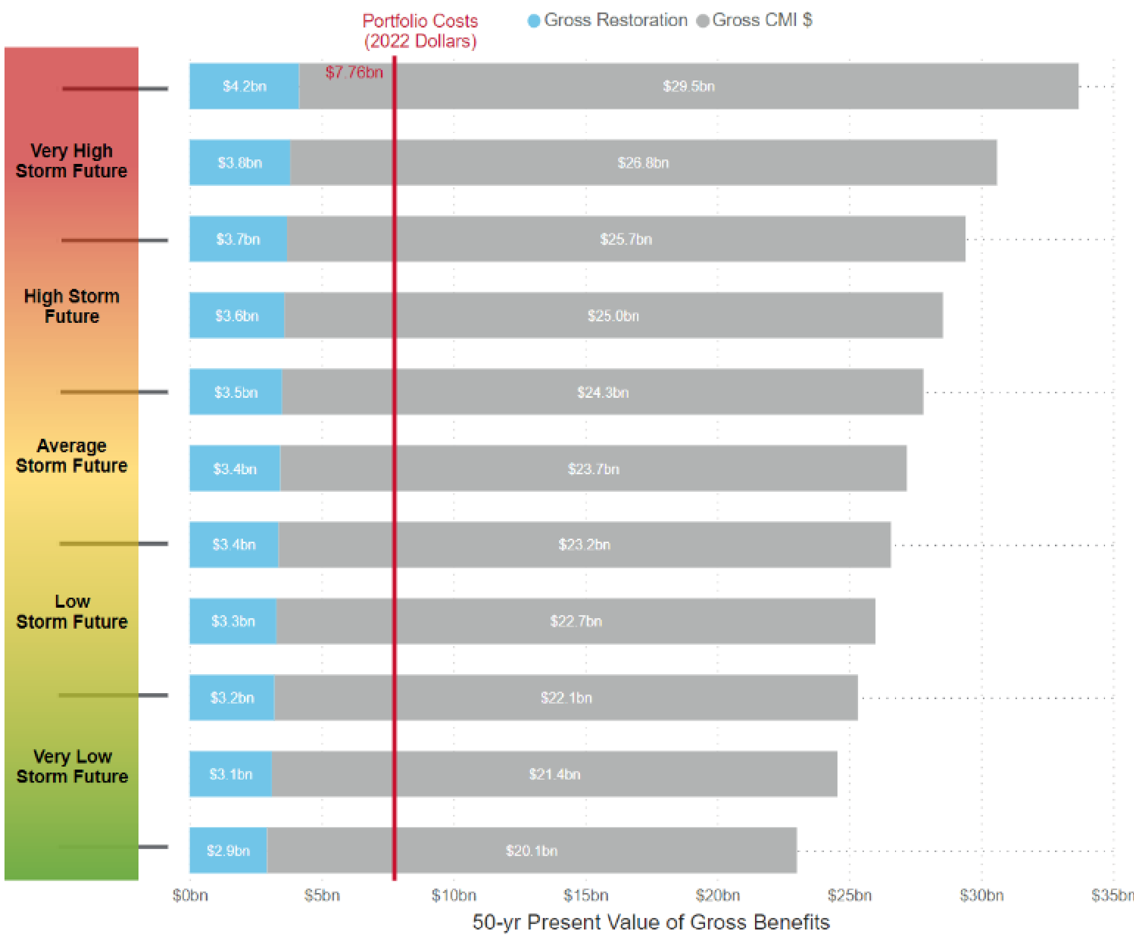


Figure 1-6 monetizes the avoided CMI benefits from Figure 1-5 and adds them to the avoided restoration costs benefit stream from Figure 1-4. The figure also compares these two benefit streams to the plan investment cost. This figure shows that the overall investment plan has a Resilience Benefit Cost Ratio as low as 3.0 in a very low storm future and as high as 4.3 in a very high storm future scenario. The average storm future scenario has a Resilience Benefit Cost Ratio of 3.5. This figure and the others above demonstrate that Entergy Louisiana's Comprehensive Hardening Plan is reasonably expected to provide significant benefits to customers in excess of cost.

Figure 1-6: Gross Benefit vs Costs



1.4 Conclusions

The following conclusions reasonably can be drawn from the evaluation of Entergy Louisiana's Comprehensive Hardening Plan using the Storm Resilience Model:

- The overall investment level of $8.8 billion (nominal dollars) for Entergy Louisiana's Comprehensive Hardening Plan provides significant benefits for customers, is reasonable, and provides customers with optimal benefits given execution constraints. The Investment Optimization analysis (see Figure 1-2) shows that the overall investment level is below the point of diminishing returns (i.e., below the point at which an incremental dollar spent produces benefits of less than a dollar in return) showing over-investment is not occurring. In fact, more investment could be made to decrease the impact to customers if execution constraints for labor and materials could be unlocked.

- Entergy Louisiana's Comprehensive Hardening Plan is reasonably projected to produce a reduction in storm restoration costs of approximately 50 percent. In relation to the plan's capital investment, the amount of the restoration costs savings (expressed in 2022 dollars), ranges from 37 to 54 percent of the total plan cost (in 2022 dollars) depending on future storm frequency and impacts. In other words, the avoided restoration cost benefits alone pay for approximately 37 to 54 percent of the investment plan.
- The projected customer minutes interrupted decrease by approximately 55 percent over the next 50 years. This decrease includes eliminating outages, reducing the number of customers interrupted, and decreasing the length of the outage time.
- Based on the monetization of outage assumptions, the investment plan provides Resilience Benefit Cost Ratios in the 3.0 to 4.3 range showing significant benefits to customers.
- Entergy Louisiana's mix of hardening investment strikes a balance between investment in the substations and transmission system targeted mainly at increasing resilience for the high impact/low probability events and investment in the distribution system, which increases resilience for all ranges of event types.
- The plan will benefit all Entergy Louisiana customers. The avoided storm restoration costs are shared by all customers. Additionally, customers will experience fewer storm outages from both direct and indirect factors. Direct benefits are realized by those customers whose infrastructure directly upstream was hardened. Indirect benefits are realized by all customers since storm restoration crews will be able to rebuild the system quicker because less infrastructure should fail.
- The hardening investment benefits are conservative. Firstly, the benefits outlined above only constitute "direct" benefits of investments to specific investments in the grid and do not factor in the "indirect benefits" from lower overall storm restoration durations. Secondly, the investments will also provide 'blue sky' benefits from decreased outages that occur during non-major storm events. Third, the evaluation does not take into account other utilities served by the Entergy Louisiana transmission system who would reasonably benefit from the transmission hardening investments. These additional benefits streams are not factored into the evaluation.

2.0 INTRODUCTION

Hurricanes have inflicted significant damage to Louisiana in recent years, and parts of the state face years of recovery. One of the most important actions Louisiana can take to prepare for the next major storm is to make the electric grid more resilient. When the grid can better withstand the impacts of storms, everyone benefits. Louisiana businesses and families save money because they can get back on their "feet" more quickly. Proactive investment in the grid also allows utilities to design integrated programs to address all phases of resilience (described below) which, in turn, will reduce storm-related restoration costs and outage times. This document outlines the approach to:

1. Calculate the benefit of the 'universe' of hardening projects through reduced utility restoration costs after major storms and the decrease (in both number and duration) in storm-related customer outages
2. Prioritize hardening projects based on which projects deliver the highest resilience benefit per dollar invested into the system
3. Establish an overall investment level and mix that maximizes customer benefits while working within labor and material technical execution constraints provided by Entergy Louisiana

The resilience-based approach is an integrated, data-driven decision-making strategy, comparing various storm resilience projects and alternatives on a normalized and consistent basis. This approach takes an integrated asset management perspective, that is, a bottom-up approach starting at the asset level. Each asset is evaluated for its likelihood of failure in a storm event as well as its consequence of failure in terms of restoration cost and customer minutes interrupted. Assets are rolled up to hardening projects, and hardening projects are then rolled up to programs. Where applicable, hardening alternatives are evaluated such as undergrounding a lateral as opposed to rebuilding it to a hardened overhead standard. Each project includes only the assets that do not meet the hardened design standards. This allows for the identification of project scopes that harden all vulnerable components to provide the most benefit to customers and that align with Entergy Louisiana's design standards.

This report outlines project prioritization and benefits calculations for the following Entergy Louisiana storm resilience programs:

- Distribution Feeder Hardening (Rebuild)
- Distribution Feeder Undergrounding
- Lateral Hardening (Rebuild)
- Lateral Undergrounding
- Transmission Rebuild
- Substation Control House Remediation
- Substation Storm Surge Mitigation

The following sections outline the foundation and background necessary to understand the rest of this report. These sections include a review of:

- Topic of resilience
- Resilience as the project assessment approach
- Entergy Louisiana's asset base evaluated for resilience measures
- Resilience-based planning approach
- Resilience Investment Business Case Results

2.1 Resilience as the Benefits Assessment

In a 2013 paper, the National Association of Regulatory Utility Commissioners ("NARUC") offered its own definition of resilience in a manner that is simple and easy to understand.

> *"it's the gear, the people and the way the people operate the gear immediately before, during and after a bad day that keeps everything going and minimizes the scale and duration of any interruptions."*

Before that, the National Infrastructure Advisory Council ("NIAC") provided a definition that is often quoted, and which includes elements used in many other definitions. It states that resilience is

> *"The ability to reduce the magnitude and/or duration of disruptive events. The effectiveness of a resilient infrastructure or enterprise depends upon its ability to anticipate, absorb, adapt to, and/or rapidly recover from a potentially disruptive event."*

The NIAC definition includes a system's ability to absorb and adapt. These important characteristics were also used by Argonne National Laboratory's ("ANL") in its work on state and social resilience and were incorporated into Pacific Northwest National Laboratory's ("PNNL") work on the resilience impacts of transactive energy systems. The ANL approach can be used to break resilience into four phases that also align with NARUC's elegantly simple description – the difference being that ANL explicitly includes the ability of the system to recognize and mitigate potential failures before they happen. These four phases are described below.

- Prepare (Before)

  The grid is running normally but the system is preparing for potential disruptions.
- Mitigate (Before)

  The grid resists and absorbs the event until, if unsuccessful, the event causes a disruption.
- Respond (During)

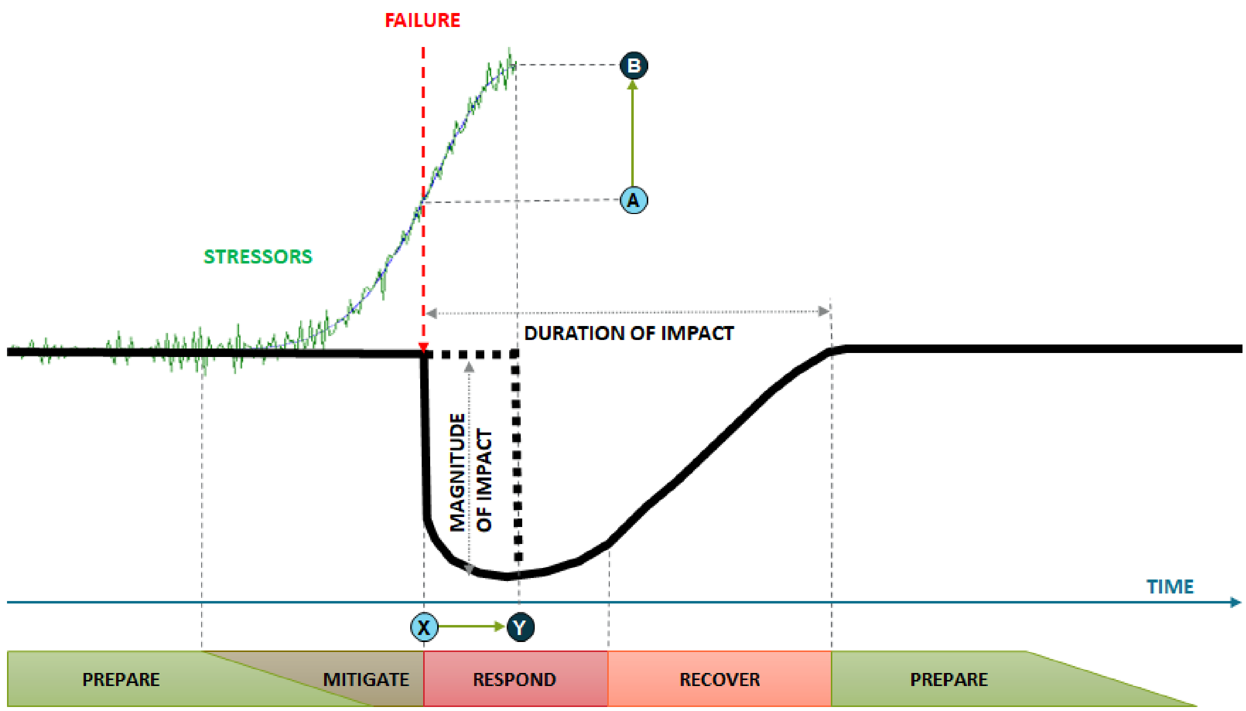
  The grid responds to the immediate and cascading impacts of the event. The system is in a state of flux, and fixes are being made while new impacts are felt. This stage is largely reactionary (even if using prepared actions).
- Recover (After)

  The state of flux is over, and the grid is stabilized at low functionality. Enough is known about the current and desired (normal) states to create and initiate a plan to restore normal operations.

This is depicted graphically in the figure below. The green line represents an underlying issue that is stressing the grid, which increases in magnitude until it reaches a point where it impacts the operation of the grid and causes an outage. The origin of the stress may be electrical due to a failing component, or external due to storms or other events. The black line shows the status of the entire system or parts of the system (e.g., transmission circuits). The "pit" depicted after the event occurs represents the impact on a system in terms of the magnitude of impact (vertical) and the duration (horizontal). For utilities this can be measured after the event and is used by the Institute of Electrical and Electronics Engineers ("IEEE") 1366 to calculate reliability metrics. If Entergy Louisiana detects the strain on the grid caused by these stresses, then it increases the opportunity to act before a failure occurs, thus avoiding or reducing the impact of the subsequent event.

Figure 2-1 represents a conceptual view of resilience. It can be used to depict a specific transmission line or the whole transmission system or the entire grid. If the figure is used to represent a specific line, it represents the impact of the event on only that line. If the figure is used to represent the impact on the whole Entergy Louisiana system, it represents the aggregated impacts of the event (storm) and the multiple outages that may result from it. Note that whether this is a specific or overall depiction of resilience there is no quantification of time. Time increases from left to right, but due to the nature of events that may occur, there are no timescales used.

Figure 2-1: Phases of Resilience



For example, hardening of the overhead transmission system is targeted at the "prepare" phase. Mitigation depends on the ability to detect developing issues and includes the capability to detect stresses on the grid by monitoring it. Effectively responding to an event as it is impacting the grid depends on the ability to make informed decisions, deploy crews rapidly to the right place at the right time, and for the grid to adapt to the stresses through reconfiguration. Recovery depends on coordinated activity and planning.

In Figure 2-1, the level of strain on the grid caused by the early effects of an event that could cause asset failure is represented by 'A'. As an example, this might be a wooden transmission pole, with failure occurring at time 'X'. In this example, suppose a steel monopole were used to replace the wood pole transmission structure. The monopole might succumb to failure at higher strain levels depicted by 'B' and would result in later failure at time 'Y'.

For the line where this occurred, this illustrates how hardening did not prevent failure but delayed it and shortened the outage duration. If it takes more work to erect a new monopole it might increase recovery time for a specific line, yet if fewer steel monopoles failed relative to the number of wood poles that would have failed, there would be fewer poles to replace, and the overall system outage time and recovery time would be reduced. Fewer asset failures means that more crews will be able to work on the assets that do fail, which can have a beneficial multiplying effect on outage reduction time.

The Storm Resilience Model evaluates the phases of resilience for storms on both the entire system and at the sub-system level (substations, transmission circuit, feeder, and lateral). Section 2.2 provides additional detail on this evaluation approach.

2.2 Evaluated System for Resilience Investment

The Storm Resilience Model (described in more detail in Section 2.3) is comprehensive in that it evaluates nearly all of Entergy Louisiana's T&D systems. Table 2-1 shows the asset types and counts included in the Storm Resilience Model.

Table 2-1: Entergy Louisiana Asset Base Modeled

Asset Type	Units	Number
Distribution Circuits	**Count**	**1,249**
Feeder Poles	Count	345,740
Lateral Poles	Count	550,513
Feeder OH Primary	Miles	12,156
Lateral OH Primary	Miles	15,274
Transmission Circuits	**Count**	**888**
Wood Poles	Count	19,816
Steel / Concrete / Lattice Structures	Count	30,508
Conductor	Miles	5,580
Substations	**Count**	**249**

All assets are strategically grouped into potential hardening projects, and only the assets that require hardening are included in the projects. The following sub-sections outline the approach to identifying hardening candidate assets and grouping them into projects.

2.2.1 Distribution Projects Identification

For distribution projects, assets were grouped by their most upstream protection device, which was either a breaker, recloser, sectionalizer, auto transfer switch, vacuum fault interrupter, or a fuse. This approach focuses on reducing customer outages. The objective is to harden each asset that could fail and cause a customer outage. Since only one asset needs to fail downstream of a protection device to cause a customer outage, failure to harden all the necessary assets still leaves vulnerable components that could potentially fail in a storm and result in an outage. Rolling assets into projects at the protection device level allows for hardening of all vulnerable components in the circuit and for capturing the full benefit for customers including avoidance or mitigation of an outage.

For distribution circuit projects (laterals and feeders), both rebuilding to a storm resilient overhead design standard and undergrounding, where possible, were considered when evaluating project types. Overhead hardening rebuilds are generally lower cost than undergrounding projects, but they generally provide fewer resilience benefits than undergrounding since the hardened overhead infrastructure is still exposed to wind and debris from vegetation and other materials. The Storm Resilience Model balances this tradeoff for every project zone across the Entergy Louisiana service area. Assets in these projects include older wood poles and those designed to a previous wind rating, as well as copper conductors. Physical hardening addresses the weakened infrastructure storm failure component, while undergrounding greatly mitigates the storm exposure.

Distribution assets were evaluated under multiple criteria to determine whether they are hardening candidates. Distribution structures were evaluated based on height, class, transformer count, and other attachments to calculate a percentage of maximum loading. For a distribution conductor, the asset was included in a project as a hardening candidate if either of the conductor's adjacent poles are selected as hardening candidates. Additionally, small conductor, such as copper, was included as a hardening candidate since it is at risk of failing in high wind events.

2.2.2 Transmission Projects Identification

At the transmission circuit level, poles identified for hardening will be replaced with higher wind rated structures and materials. Transmission structures were grouped at the transmission line/circuit level into projects. Transmission assets were deemed to be hardening candidates if the structures' wind rating did not meet or exceed the wind hardening standard for that geographic region.

2.2.3 Substation Projects Identification

Entergy Louisiana's control houses were identified as a particular risk due to some roofs not being designed to withstand winds that exceed certain speeds. If the roof gets broken or ripped off during a storm, rainfall results in substantial water inside the control house and will damage much of the substation protection equipment, rendering it out of service. Entergy Louisiana provided a list of control houses and known current wind ratings. In turn, control houses with non-hardened ratings were added as potential projects.

1898 & Co. used the Sea, Land, and Overland Surges from Hurricanes ("SLOSH") model to evaluate the storm surge risk for substations. Substations with any potential storm surge risk were considered as candidate projects. Those substations that are behind a levee are not considered to be at risk of storm surge, as they already have a level of protection.

2.2.4 Potential Hardening Projects Evaluated

Table 2-2 contains a list of potential hardening projects based on the methodology outlined above. As seen below, there are a significant number of potential hardening projects, nearly 170,000. The following sections outline the approach to selecting the hardening projects that provide the most value to customers from a perspective of reducing both restoration cost and CMI.

Table 2-2: Potential Hardening Projects Evaluated

Program	Project Count
Distribution Feeder Hardening (Rebuild)	**5,858**
Distribution Feeder Undergrounding	**5,858**
Lateral Hardening (Rebuild)	**78,174**
Lateral Undergrounding	**78,174**
Transmission Rebuild	**888**
Substation Control House Remediation	**53**
Substation Storm Surge Mitigation	**212**
Total	**169,217**

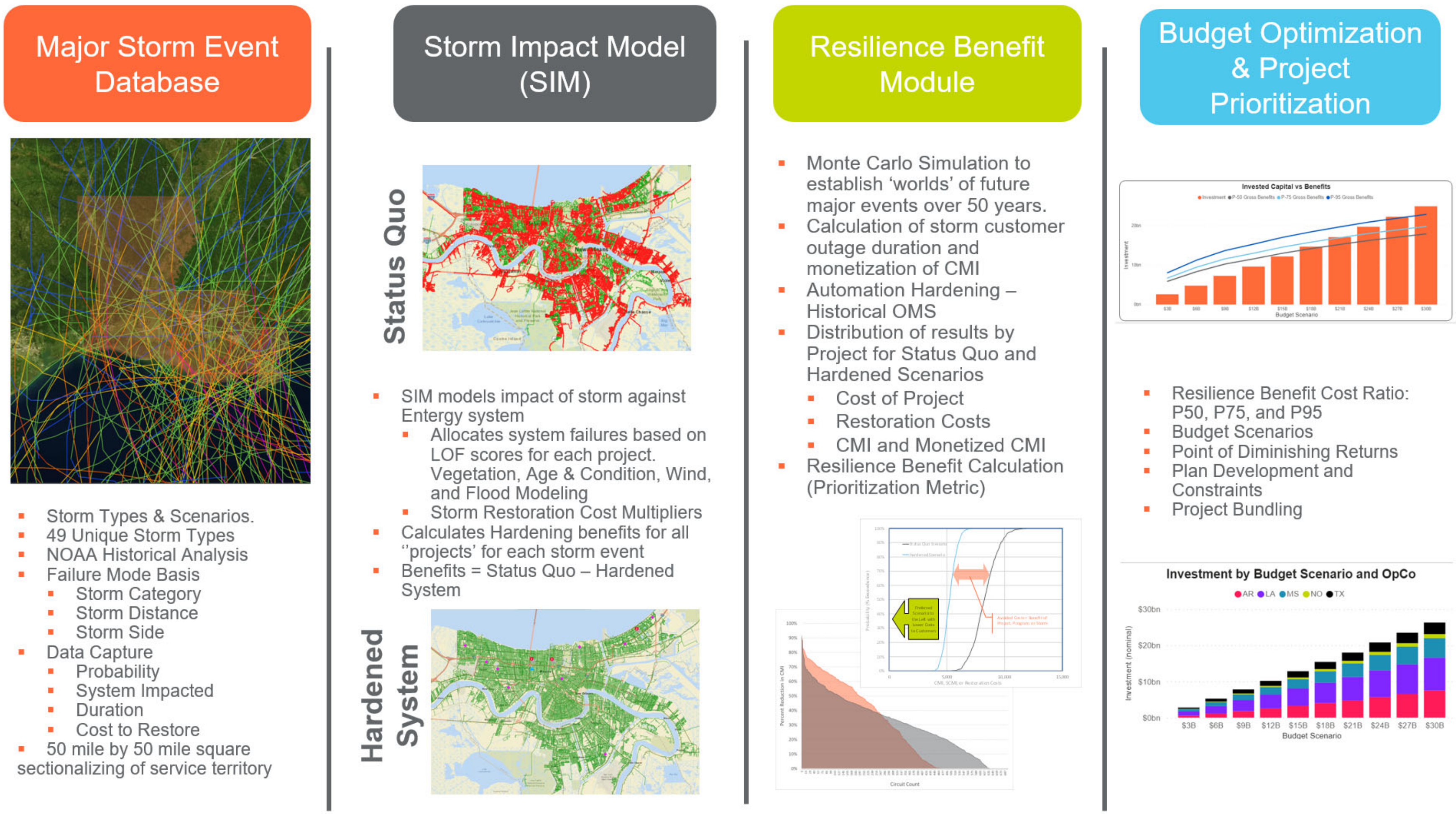
2.3 Resilience Planning Approach Overview

The resilience-based planning approach calculates the benefit of storm resilience projects from a customer perspective. This approach calculates the resilience benefit at the asset, project, and program level within the Storm Resilience Model. The results of the Storm Resilience Model are a:

1. Reduction in the Storm Restoration Costs
2. Reduction in the number of customers impacted and the duration of the overall outage, calculated as CMI

Figure 2-2 provides an overview of the resilience planning approach to calculate the restoration cost reduction and CMI reduction of hardening projects and the approach to prioritizing those projects into an executable plan. It also includes the approach to perform investment optimization by Entergy Louisiana.

Figure 2-2: Resilience Planning Approach Overview



2.3.1 Major Storms Event Database

Since the magnitude of the restoration cost decrease and CMI decrease is dependent on the frequency and magnitude of future major storm events that may impact the areas that Entergy Louisiana serves, the Storm Resilience Model starts with the 'universe' of major storm events that could impact Entergy Louisiana's service area, the Major Events Storms Database. The system was broken down into 31 50-mile by 50-mile square system sections to understand the frequency and magnitude of major events across the service area.

The Major Storms Event Database provides the high-level impact to the system of the storm stressor for each of the 50-mile by 50-mile system sections. The major events database includes the following for each of the 31 system sections:

- Storm Type
- Probability of a storm occurring
- Restoration Costs
- Percentage of the system impacted
- Duration of the storm

The major storm events database includes 49 unique storm types for each system section. The storm types include the various hurricane categories, system section distance from the storm, and side of the storm to impact the system section (the 'right' side of a hurricane is typically more destructive than the 'left' side). Each storm type has a range of probabilities and impacts that is based on historical evaluation of the National Oceanic and Atmospheric Administration ("NOAA") hurricane data, and the range of these impacts is based on expectations of system impacts from the 49 different storm types. These storm types include modifiers for vegetation density, asset age, structure 'right-of-way' access, and terrain including wetland and rocky areas. With these various combinations (high probability with lower consequence and low probability with high consequence, etc.), the Major Storms Event Database includes a vast range of different storm scenarios. Section 4.0 provides additional details on the Major Storms Event Database.

2.3.2 Storm Impact Model

Each storm scenario, up to 49 for each system section, is modeled within the Storm Impact Model to identify which parts of the system are most likely to fail given each type of storm. The Storm Impact

Model calculates the restoration costs and customers impacted by system failures for both the Status Quo and Hardened Scenarios. The Storm Impact Model identifies the damaged portions of the system by modeling the elements that cause failures in the Entergy Louisiana asset base.

The Storm Impact Model calculates a storm LOF score for each asset based on a combination of the vegetation density around the infrastructure, the current structure wind loading rating versus the desired wind loading, and the infrastructure age. The vegetation rating factor is based on the vegetation density around the conductor (see Section 3.4). The wind design differential rating is based on the delta between the desired wind loading capacity and the asset's current wind loading capacity (see Section 3.5). The age rating utilizes expected remaining life curves with the asset's age. The wind zone rating is based on the wind zone that the asset is located within. The Storm Impact Model includes a framework that normalizes the three ratings with each other to develop one overall storm LOF score for all circuit assets. The project level scores are equal to the sum of the asset scores normalized for length. The project level scores are then used to rank each project against each other to identify the likely lateral, backbone, or transmission circuit to fail for each storm type. The model estimates the weighted storm LOF based on the asset level scoring.

The model determines which substations are likely to flood during various storm types based on the flood modeling analysis. That analysis provides the flood level, meaning feet of water above the site elevation, for various storm types (see Section 3.10).

The Storm Impact Model estimates which control houses are likely to fail during various storm types based on the current structure wind loading rating versus the desired wind loading.

Once the Storm Impact model identifies the portions of the system that are damaged and caused an outage for a specific storm, it then calculates the restoration costs to rebuild the system to provide service. The restoration costs are based on the multipliers for storm replacement over the planned replacement costs using Entergy Louisiana labor and procured materials only. The restoration cost multipliers are based on historical storm events, including storm events that affected Entergy Louisiana's service area, and the expected outside labor and expedited material cost needed to restore the system.

Similarly, the Storm Impact Model calculates the CMI for each project. Since circuit projects are organized by protection device, the customer counts and customer types are known for each asset in the Storm Impact Model. Substation projects' customers have been calculated as a sum of the circuits at each substation, assuming that flooded substations and damaged control houses result in a complete outage of the substation and the feeders leaving those stations. For transmission projects, customers have been estimated as the customers in the project's system section and the eight surrounding system sections. This reflects the large, regional impacts that outages of transmission lines have on a system. The time it will take to restore each protection device, or project, is calculated based on the expected storm duration and the hierarchy of restoration activities. This restoration time is then multiplied by the known customer count to calculate the CMI. The CMI benefit is monetized using DOE's ICE Calculator for project prioritization purposes. It bears noting that the DOE's ICE Calculator does not consider the specific circumstances that would be necessary to assess the causes and impacts of an outage to customers in specific circumstances, particularly during longer outages. Again, this plan uses the DOE's ICE Calculator to evaluate the societal impacts to customers generally for project prioritization purposes.

Finally, the Storm Impact Model calculates the reductions in project storm LOF, restoration costs, and CMI for each hardening project alternative. The output of the Storm Impact Model is the project LOF, CMI, monetized CMI, and restoration costs for each of the 49 storms for both the Status Quo and Hardened scenarios.

2.3.3 Resilience Benefit Calculation

The Resilience Benefit Calculation utilizes stochastic modeling, or Monte Carlo simulation, to select a 50-year storm probability scenario for each of the 49 storm types. This produces 1,000 different future "storm worlds" and the expected range of benefit values depending on the different probabilities and impact ranges to the Entergy Louisiana system. The probability of each storm scenario is multiplied by the benefits calculated for each project from the Storm Impact Model to provide a resilience-weighted benefit for each project in dollars.

2.3.4 Project Scheduling and Investment Optimization

The Project Scheduling and Investment Optimization model prioritizes the projects based on the highest ratio of resilience benefit to cost. It also performs an Investment Optimization simulation to identify the point of diminishing returns for hardening investments for the 10-year period and portions of the system evaluated.

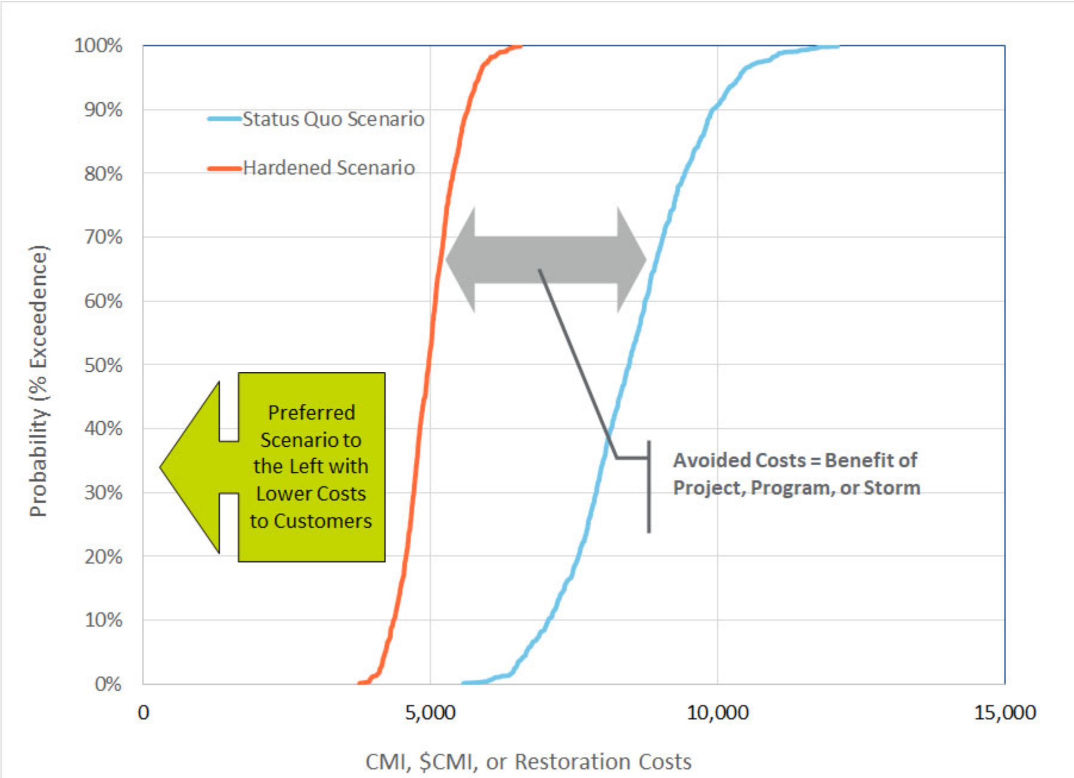
The model prioritizes each project based on the sum of the restoration cost benefit and monetized CMI benefit divided by the project cost. This calculation is performed for the range of potential benefit values to create the resilience benefit cost ratio. The model also incorporates technical and operational constraints in scheduling the projects applicable to Entergy Louisiana such as contractor capacity and material availability. Using the Resilience Benefit Calculation and project scheduling model, the Storm Resilience Model calculates the net benefit in terms of reduced restoration costs and CMI for the 10-year investment profile.

Investment Optimization is performed by running the model over a wide range of investment scenarios. Each investment scenario calculates the range in reduction of restoration costs and CMI. The Investment Optimization calculates the point where incremental hardening investments result in diminishing returns in customer benefit.

2.4 S-Curves and Resilience Benefit

The results of the 1,000 iterations are graphed in a cumulative density function, also known as an 'S-Curve'. In layman's terms, the thousand results are sorted from lowest to highest (cumulative ascending) and then charted. Figure 2-3 shows an illustrative example of the 1,000 iteration simulation results for the 'Status Quo' and Hardened Scenarios.

Figure 2-3: Status Quo and Hardened Results Distribution Example

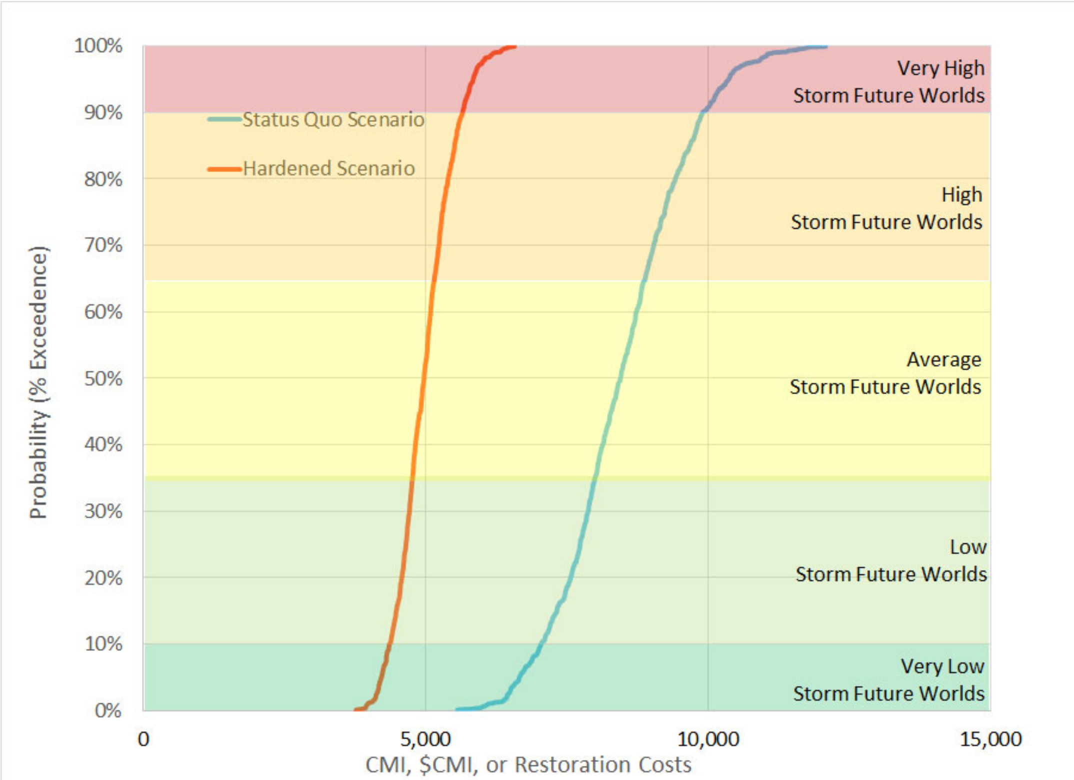


The horizontal axis shows the storm cost in terms of CMI, monetized CMI, or restoration costs. The values in the figure are illustrative. The vertical axis shows the percent exceedance values. For the Hardened Scenario, the chart shows a value of 5,000 at the 40-percentile level. This means there is a 40 percent confidence that the Hardened Scenario will have a value of 5,000 or less. Each of the probability levels is often referred to as the P-value. In this case the P40 (40 percentile) has a value of 5,000 for the Hardened Scenario.

Since the figure shows the overall cost (in minutes or dollars) to customers, the preferred scenario is the S-Curve further to the left. The gap or delta between the two curves is the overall benefit.

The S-Curves typically have a linear slope between the P10 and P90 values with 'tails' on either side. The tails show the extremes of the scenarios. The slope of the line shows the variability in results. The steeper the slope (i.e., vertical) the less range in the result. The more horizontal the slope the wider the range and variability in the results. Figure 2-4 provides additional guidance on understanding the S-Curves and the kind of future storm worlds they represent.

Figure 2-4: S-Curves and Future Storms



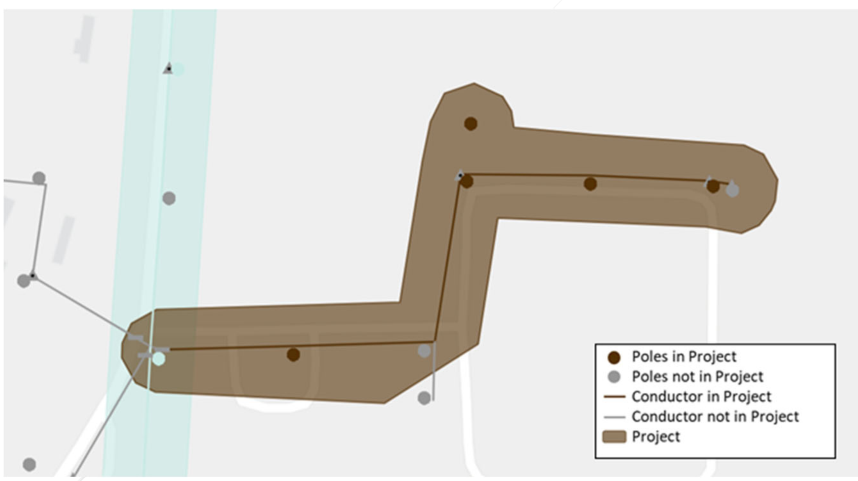
3.0 CORE DATA AND ANALTYICS

The resilience-based approach and methodology is data driven. This section outlines the core data sets and base algorithms employed within the Storm Resilience Model, while Sections 4.0 and 5.0 describe how these core data items are used within the Storm Resilience Model. This section includes both data from Entergy Louisiana's systems and external data sources.

3.1 Geographical Information System

The Geographic Information System ("GIS") provides the list of assets in Entergy Louisiana's system and how they are connected to each other. Since the resilience-based approach is fundamentally an asset management bottom-up based methodology, it starts with the asset data, then rolls all the assets up to projects, and all projects up to programs, and finally the programs up to the Comprehensive Hardening Plan. The relationship between assets and projects is illustrated in the geospatial figure below.

Figure 3-1 Asset to Project Relationship



In alignment with this methodology, 1898 & Co. utilized the connectivity in their GIS and distribution circuit models to link each distribution voltage asset up to a lateral (fuse protection device) or feeder (breaker or recloser protection device). This provides a granular evaluation of the distribution system that allows projects to be created to target only portions of a circuit for resilience investment. Through this approach, Entergy Louisiana and 1898 & Co. were able to use the asset level information from Table 3-1 and convert it to the project level summaries in Table 3-2. It is important to note that each asset in Table 3-1 is tied to one of the projects listed in Table 3-2, which provides a bottom-up analysis.

Table 3-1: Entergy Louisiana Asset Base

Asset Type	Units	Value
Distribution Circuits	**[count]**	**1,249**
Feeder Poles	[count]	**345,740**
Lateral Poles	[count]	**550,513**
Feeder OH Primary	[miles]	**12,156**
Lateral OH Primary	[miles]	**15,274**
Transmission Circuits	**[count]**	**888**
Wood Poles	[count]	**19,816**
Steel / Concrete / Lattice Structures	[count]	**30,508**
Conductor	[miles]	**5,580**
Substations	[count]	**249**

Table 3-2: Projects Created from Entergy Louisiana Data Systems

Program	Project Count
Distribution Feeder Hardening (Rebuild)	**5,858**
Distribution Feeder Undergrounding	**5,858**
Lateral Hardening (Rebuild)	**78,174**
Lateral Undergrounding	**78,174**
Transmission Rebuild	**888**
Substation Control House Remediation	**53**
Substation Storm Surge Mitigation	**212**
Total	**169,217**

3.2 Outage Management System

The outage management system ("OMS") includes detailed outage information by cause code for each protection device over the last 22 years. The Storm Resilience Model utilized this information to understand the historical storm related outages for the various distribution laterals and feeders on the system to include non-named tropical storm Major Event Days ("MED") in the Major Storms Event Database.

3.3 Customer Type Data

Entergy Louisiana provided customer count and type information that featured connectivity to the GIS and OMS. This allowed the Storm Resilience Model to directly link the number and type of customers impacted to each project and the project's assets. For example, the Storm Resilience Model 'knows' that if pole 'Y' fails, fuse '1' will operate causing a set number of customers to be without service. The model also knows what type of customers are served by each asset: residential, small or large commercial, small or large industrial, critical, and national critical infrastructure customers. This customer information is included for every distribution asset in the Entergy Louisiana system. The customer information is used within the Storm Impact Model to calculate the CMI (customers affected * outage duration) for each storm for each lateral or feeder project. Table 3-3 below shows the count of customers by class from Entergy Louisiana's service area that have been linked to assets in the Storm Impact Model.

Table 3-3: Customer Counts by Type

Customer Type	Customer Count
Residential	941,306
Small Commercial and Industrial	133,932
Large Commercial and Industrial	9,370
Critical Customers	530
National Critical Infrastructure	61
Total	1,085,199

3.4 Vegetation Density Algorithm

The vegetation density for each overhead conductor is a core data set for identifying and prioritizing resilience investment for the circuit assets because vegetation, both inside and outside of the trim zone, blowing into conductor is a significant cause of outages during major storm events. The Storm Impact Model calculates the vegetation density around each transmission and distribution overhead conductor. The Storm Impact Model utilizes satellite tree canopy data to calculate the percentage of vegetation for 100 feet by 100 feet areas across the entire Entergy Louisiana system. The 1,000 square foot area is indicative of the vegetation density on the system from a major storm perspective. For each span of conductor (approximately 897,000), a vegetation density is assigned based on the square foot area the conductor goes through. This information is used within the LOF framework to identify the portions of the system most likely to have an outage for each type of storm.

Figure 3-2 and Figure 3-3 show the range of vegetation density for OH Primary and Transmission Conductor, respectively. The figures rank the conductors from highest to lowest level of vegetation density. As shown in the figures, approximately 60 to 65 percent of the conductor spans (not weighted by length) for OH Primary have near zero tree canopy coverage, while approximately 30 to 35 percent have some level of coverage all the way up to 90 percent coverage. For transmission conductor, approximately 35 percent has near zero tree canopy coverage while approximately 65 percent has some level of coverage all the way up to 100 percent.

Figure 3-2: Vegetation Density on Entergy Louisiana Primary Conductor

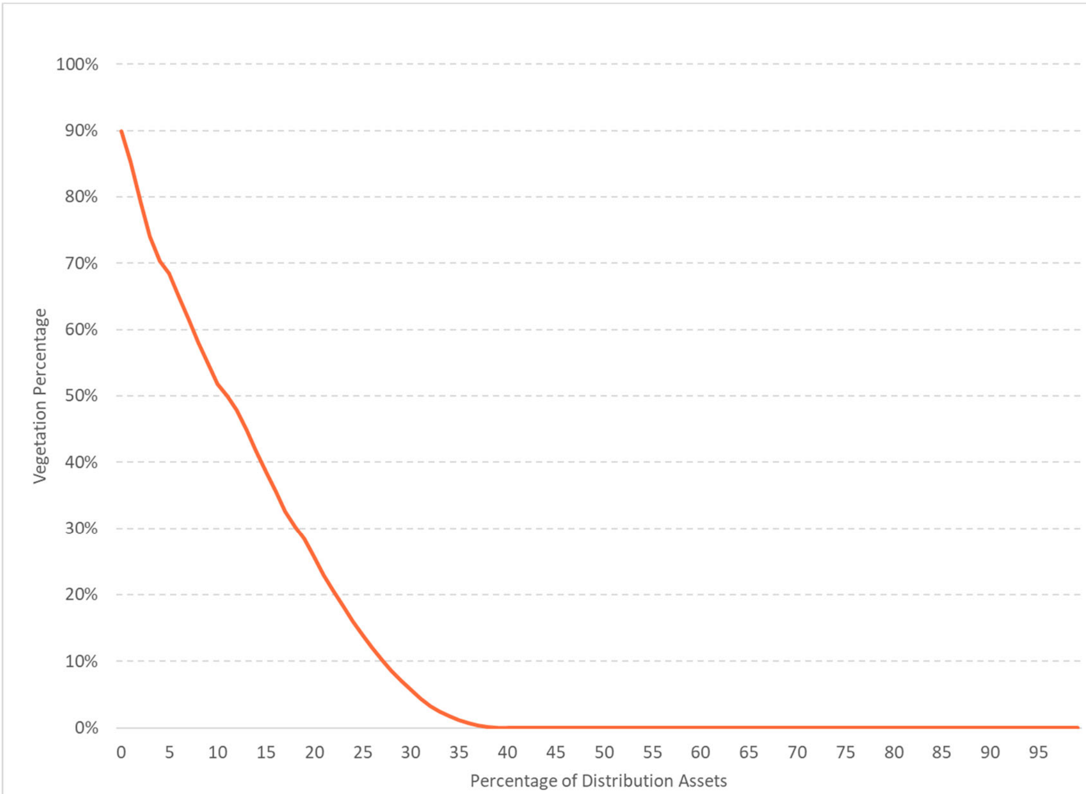
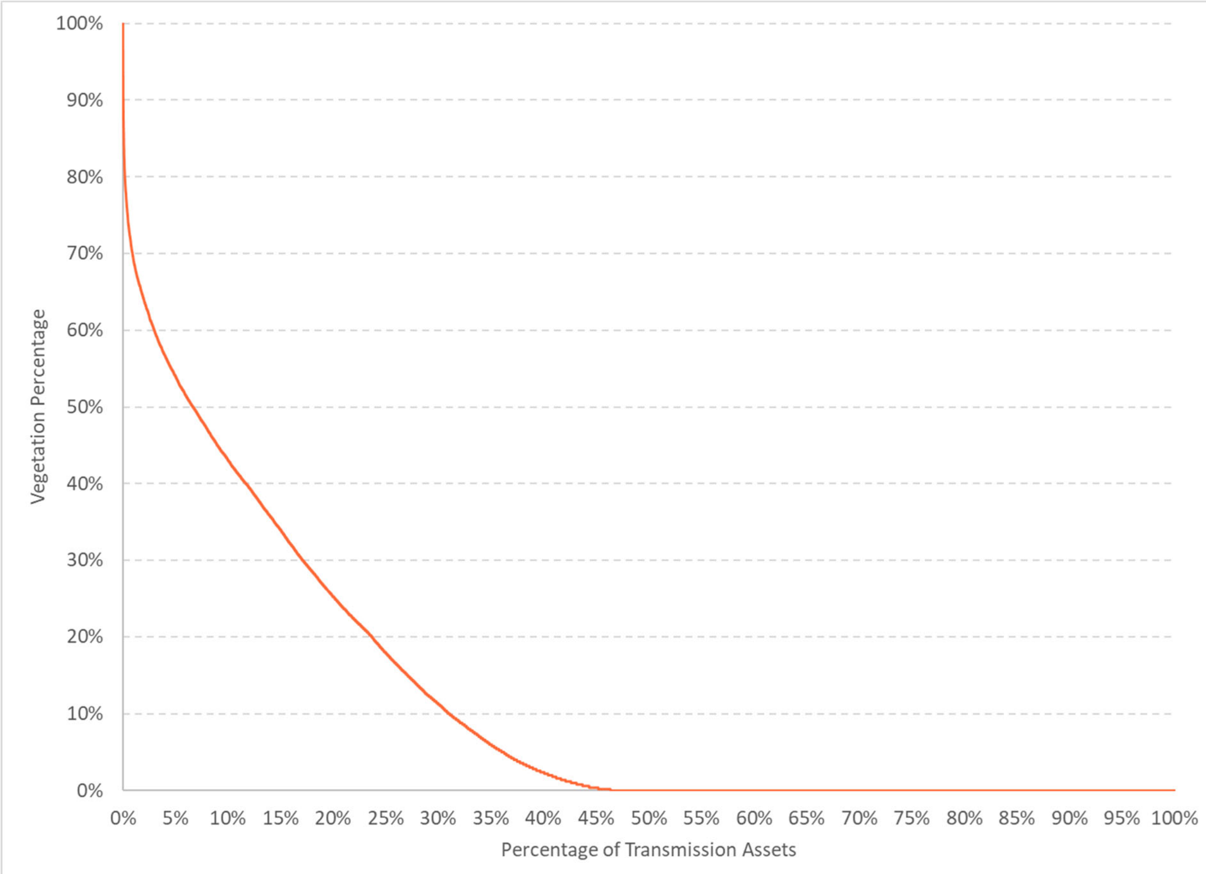


Figure 3-3: Vegetation Density on Entergy Louisiana Transmission Conductor

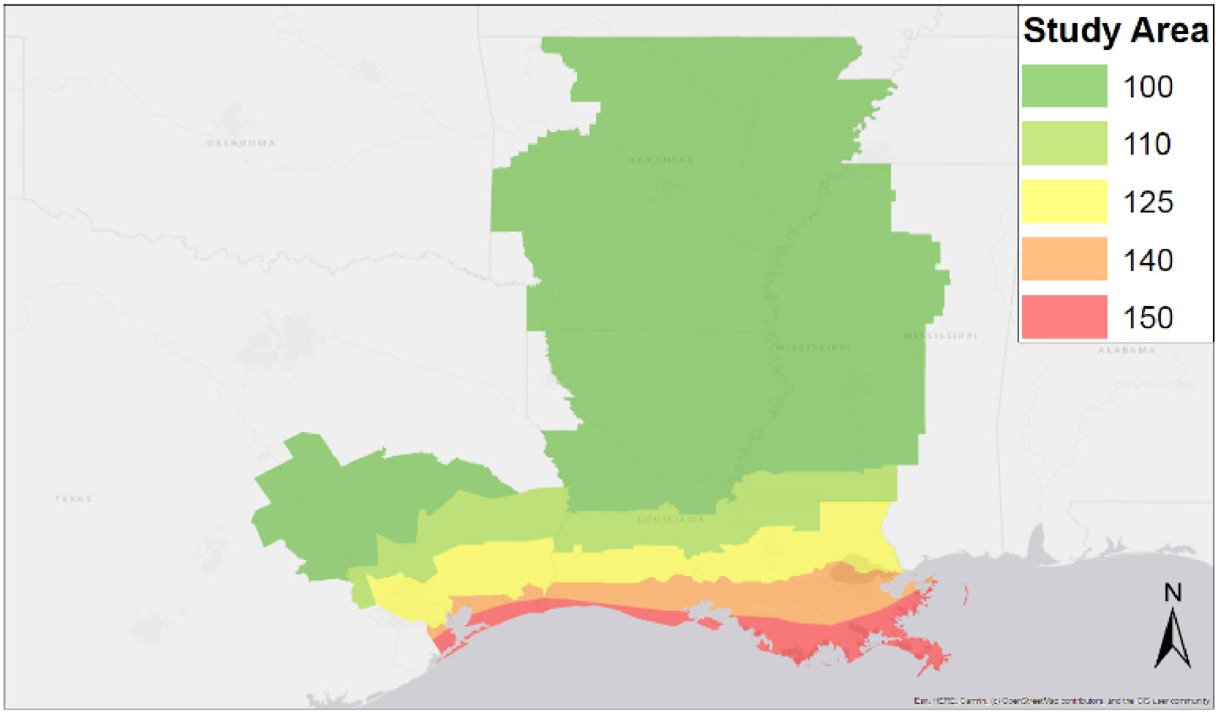


3.5 Overhead Structure Wind Design Differential

Structures are designed to various loading standards. Over time, the standards change as the requirements of the infrastructure increase to meet customer needs. As the impact of grid outages to customers has increased over the last decade as well as the wind speeds seen across the service area have heightened, the wind loading standard of infrastructure across Entergy Louisiana's system has increased. While new infrastructure is built to the existing standard, the delta between older infrastructure and current standards grows. Infrastructure that has a differential between its actual wind loading rating and the newer hardened wind loading standard is at greater risk of failing given major storm events. The Storm Resilience Model uses the differential in wind loading to estimate the number of assets that would fail during a major event.

Entergy Louisiana provided wind loading standards based on geographical areas. Figure 3-4 shows five wind zones and the hardening wind loading ratings for each zone. The zones show that wind speeds are typically higher closer to the coast and lower further inland.

Figure 3-4: Entergy Extreme Wind Zones



Using data from Entergy Louisiana and known attributes of transmission and distribution structures and control houses on the system, each asset's current wind rating was assessed. This rating is the wind speed the pole or control house is currently rated to withstand. 1898 & Co. performed a comprehensive analysis of the current actual wind rating vs the existing wind rating standard from Figure 3-4 for all distribution, transmission, and control house assets. The analysis shows that approximately 694,000 structures are candidates for hardening for resilience. These assets are at a higher risk of failure during storms due to the information discussed above.

3.6 Age

As poles age, they lose some of their original design strength. Therefore, aged poles (all else equal) will fail at lower dynamic load levels than poles with their original design strength. The Storm Impact Model utilizes 1898 & Co.'s asset management solution, AssetLens Solutions, to estimate the age based LOF for each wood pole, metal structure, overhead primary, and transmission conductor. 1898 & Co.'s AssetLens Solutions utilizes industry standard survivor curves with an asset class expected average service life and the asset's age to estimate the age based LOF over the next 10 years.

3.7 Accessibility

The accessibility of an asset has an impact on the duration of the outage and the cost to restore that part of the system. Rear lot structures take much longer to restore and cost more to restore than front lot structures. To take differences in accessibility into account, the Storm Resilience Model (within Storm Impact Model) performs a geospatial analysis of each structure against a data set of roads. Structures within a certain distance of the road were designated as having roadside access; others were designated as in the deep right-of-way ("ROW"). This designation was used when calculating restoration and hardening project costs in the Storm Impact Model.

3.8 Terrain

Like accessibility, the terrain where assets are located impacts both duration and cost to restore following a major storm event. Terrain such as marshes and swamps, defined as wetlands in the model, is much harder to navigate and access following these events, resulting in higher costs and longer outage times. To take these differences into account, the Storm Resilience Model performs a geospatial analysis of each structure against a data set from the U.S Department of Fish & Wildlife to determine if the structure is in wetlands or flat terrain. This information is used to estimate storm restoration costs by structure, outage duration, and higher hardening project costs.

3.9 ICE Calculator

To monetize the cost of a storm outage for the purpose of prioritizing projects and performing Investment Optimization, the Storm Impact Model and Resilience Benefit Calculation utilizes the ICE Calculator. The ICE Calculator is an electric reliability planning tool developed by Freeman, Sullivan & Co. and Lawrence Berkeley National Laboratory. This tool is designed for electric reliability planners at utilities, government organizations, or other entities that are interested in estimating interruption costs and/or the benefits associated with reliability improvements in the United States. The ICE Calculator was funded by the Office of Electricity Delivery and Energy Reliability at the DOE.

The Storm Impact Model includes the estimated storm interruption costs for residential, small commercial and industrial ("C&I"), and large C&I customers. The data from the calculator was extrapolated for the longer outage durations associated with major storms. The extrapolation includes diminishing costs as the storm duration extends. Additionally, multipliers of the ICE Calculator were used for critical customers and national critical infrastructure customers.

These rough indications of outage cost for each customer are multiplied by the specific customer count and expected duration for each storm for each project to calculate the monetized CMI at the project level.

3.10 Substation Flood Modeling

1898 & Co. utilized storm surge modeling from the SLOSH model. The SLOSH models perform simulations to estimate surge heights above ground elevation for various storm types. The simulations are based on historical, hypothetical, and predicted hurricanes. The model uses a set of physics equations applied to the specific location shoreline, incorporating the unique bay and river configurations, water depths, bridges, roads, levees, and other physical features to establish surge height. These results are simulated several thousand times to develop the Maximum of the Maximum Envelope of Water, the worst-case scenario for each storm category. The SLOSH model results were overlaid with the location of Entergy Louisiana's substations to estimate the height above the ground elevation for storm surge. This data is then used in the Storm Impact Model to estimate the likelihood of substation failure for every storm scenario.

3.11 Transmission Outage Scenarios

Due to the complex interconnected nature of the transmission system, 1898 & Co. and Entergy Louisiana developed a transmission outage framework based off historical performance of the transmission system in major storm events and the known redundancies of the transmission system. This framework outlines the customer impact if a given line, or combination of lines should fail. The impact of these outages is significant, resulting in regional, widespread customer outages. Additionally, these scenarios affect the ability to supply electricity to metropolitan areas like Baton Rouge and New Orleans, resulting in large blackouts involving large numbers of customers. 1898 & Co. modeled seven specific scenarios, capturing the potentially significant risk to the transmission system major storms can cause.

4.0 MAJOR STORMS EVENT DATABASE

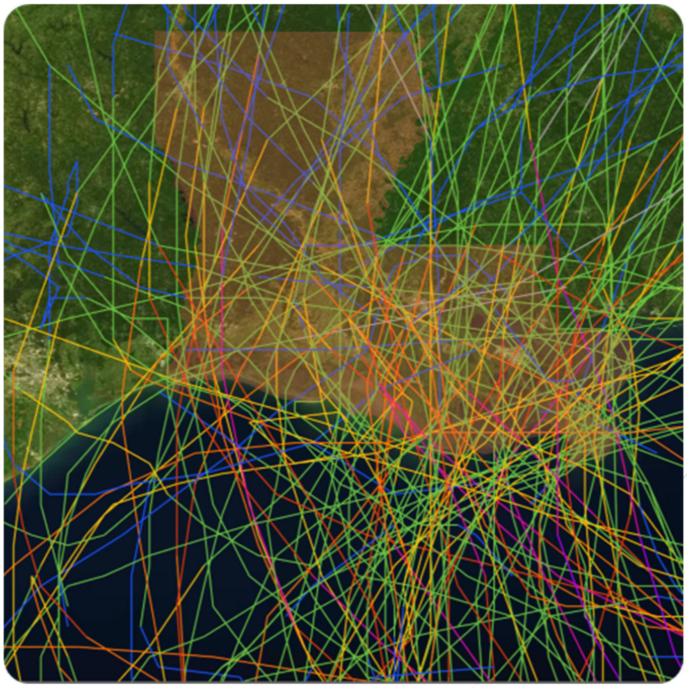
The first component of the Storm Resilience Model is the Major Storms Event Database. The database describes the phases of resilience (see Figure 2-1) for the range of storm events to impact the Entergy Louisiana service area. It includes the probabilities for each of the events as well as range of impacts to the transmission system, substations, and distribution system while also outlining the duration and customers impacted and the restoration costs. This section describes the data sources and approach used to develop the database. Since the benefits of hardening projects are directly related to the frequency and impact of major storm events, the resilience-based planning approach starts with developing the range and frequency of storm types that could impact Entergy Louisiana's service area.

4.1 Historical Storm Overview

4.1.1 Storm Count and Type

The NOAA includes a database of major storm events over the past 170 years, beginning in 1852. This database was mined to evaluate the different types and frequency of major storms to impact the Entergy Louisiana service area. Figure 4-1 provides an example screenshot from NOAA's storm database. It shows all the events, including path and category, to come within 150 miles of Entergy Louisiana's service area. Review of the figure shows the changing category of the storm as it moves through Louisiana.

Figure 4-1: NOAA Example Output — Louisiana



Source: https://coast.noaa.gov/hurricanes/

The NOAA database was mined for all major event types up to 150 miles from Entergy Louisiana's service area boundary. The 150-mile radius was selected since hurricanes can have diameters of 300 miles, where some hurricane storm bands impact a significant portion of the Entergy Louisiana service area. Additionally, the database was mined for the storm category as it hit the Entergy Louisiana service area. Section 4.2 includes additional details on the mining process to understand the historical events as they moved through the Entergy Louisiana service area, including the range of permutations for storm side, storm distance, and storm category.

Figure 4-2 includes the summary results from the NOAA database of storms to hit or nearly hit the Entergy Louisiana service area since 1852. It categorizes each storm at its strongest point in the service area. If a storm directly hit the service area, its strength was recorded upon landfall. If a storm remained a peripheral hit, the strength was recorded at the closest point to the system. Hence, only 1 category 5 storm has been recorded since 1852.

Figure 4-2: Summary of Storms in Entergy Louisiana's Service Area since 1852[1]

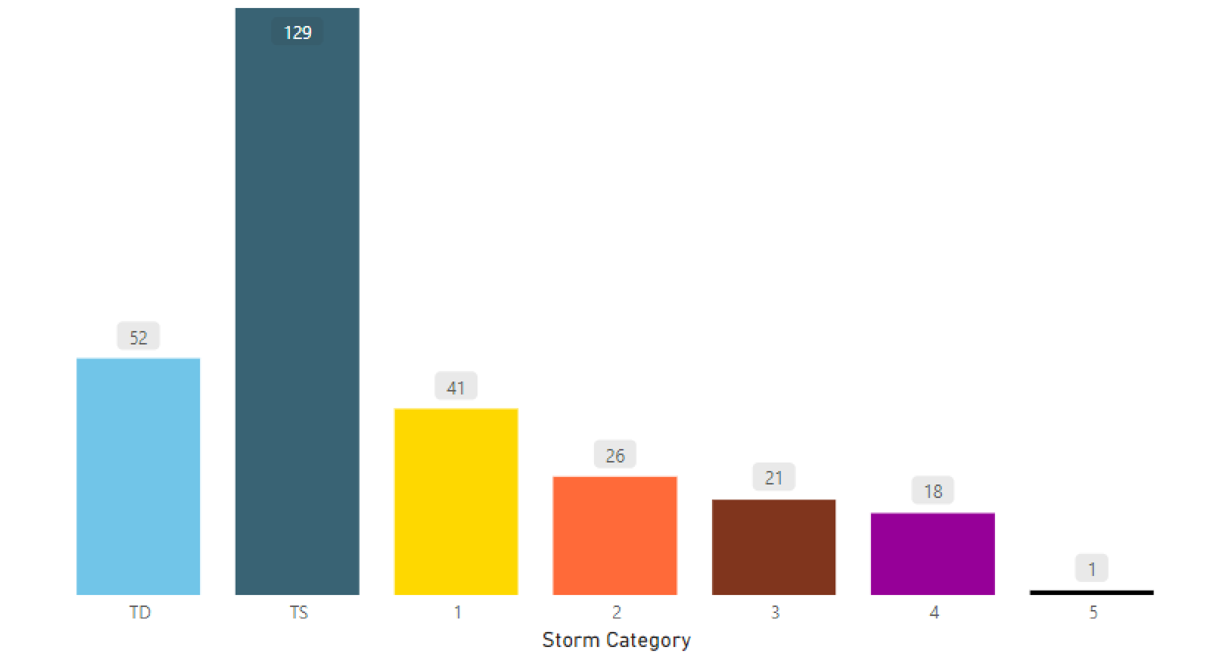
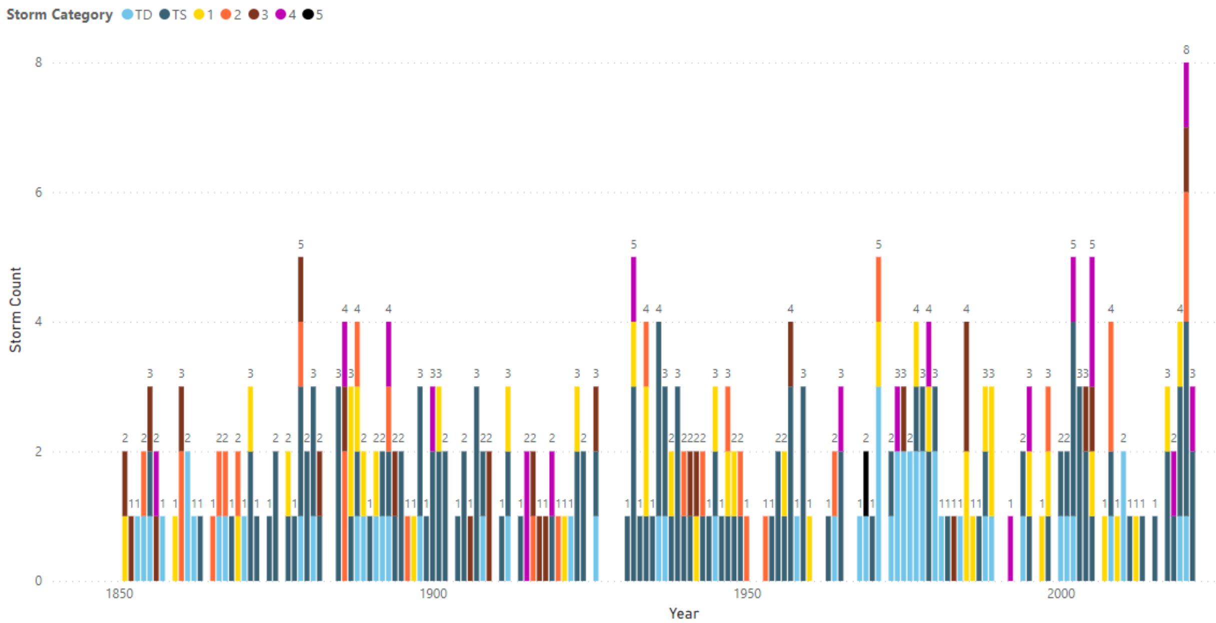


Figure 4-2 shows that a total of 288 storm eyes came within 150 miles of Entergy Louisiana's service area since 1852. Of those, 250 storm eyes came directly through Entergy Louisiana's service area. Approximately 6 percent of storms were Category 4 or higher. Almost 17 percent were Category 2 or 3 storms, and Category 1 storms made up 14 percent of the events. Nearly 63 percent of the events were Tropical Storms or Tropical Depressions.

Figure 4-3 shows storm count by category for all 288 major events for each year since 1852. The figure shows that storm activity over the past 170 years has been random. Some years may see as low as 0 storms events with others as high as 8.

[1] U.S. Department of Commerce, Historical Hurricane Tracks, National Oceanic and Atmospheric Administration (August 24, 2022), *available at* https://coast.noaa.gov/hurricanes/, with further analysis by 1898 & Co.

Figure 4-3: Count of Storms for Entergy Louisiana's System by Year[2]



Converting the data in Figure 4-3 into 10-year and 100-year rolling averages provides additional insights into storm activities to impact the Entergy Louisiana service area. Figure 4-4 and Figure 4-5 show the storm activity in Entergy Louisiana's service area over time using a 10-year and 100-year rolling average, respectively.

Figure 4-4 shows the sum of all the storms occurring in that year and the 9 years before, from 2012 through 2021. It is further broken down into storm categories. The 2021 column on the far right shows 23 storms hit Entergy Louisiana between 2012-2021. The rolling 10-year average profile from 1950 to 2021 shows wide swings in major storm counts and types. For instance, 2006-2015 saw only 12 storms, with no category 3 or above storms, and 2012-2021 saw 23 storms, with 4 category 3 or higher storms. Further, no Category 5 storms hit the system in the past 44 years. While it may be tempting to focus on the last 10 years of storm activity to start understanding storm frequency, Figure 4-4 shows that there have been worse periods and would exclude a Category 5 hurricane from the resilience modeling if only the most recent 10 years were considered.

[2] *Id.*

Figure 4-4: 10-Year Rolling Count of Storms for Entergy Louisiana's System[3]

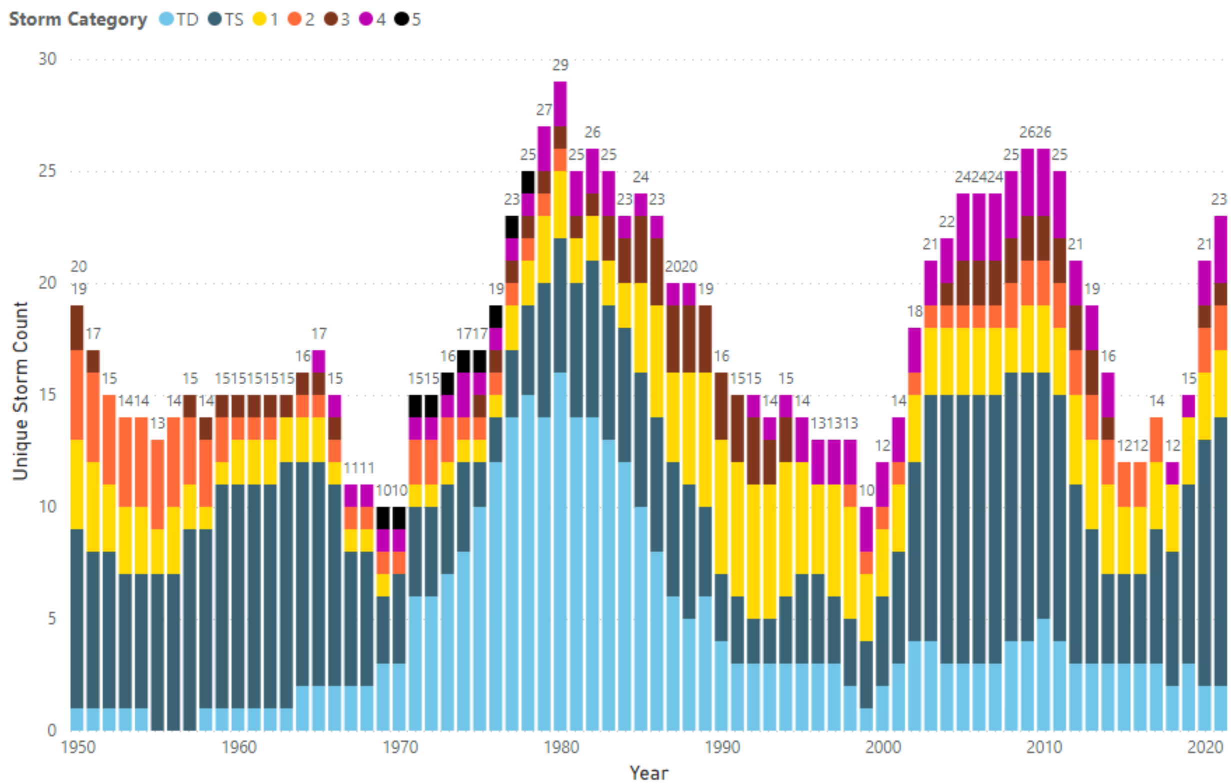


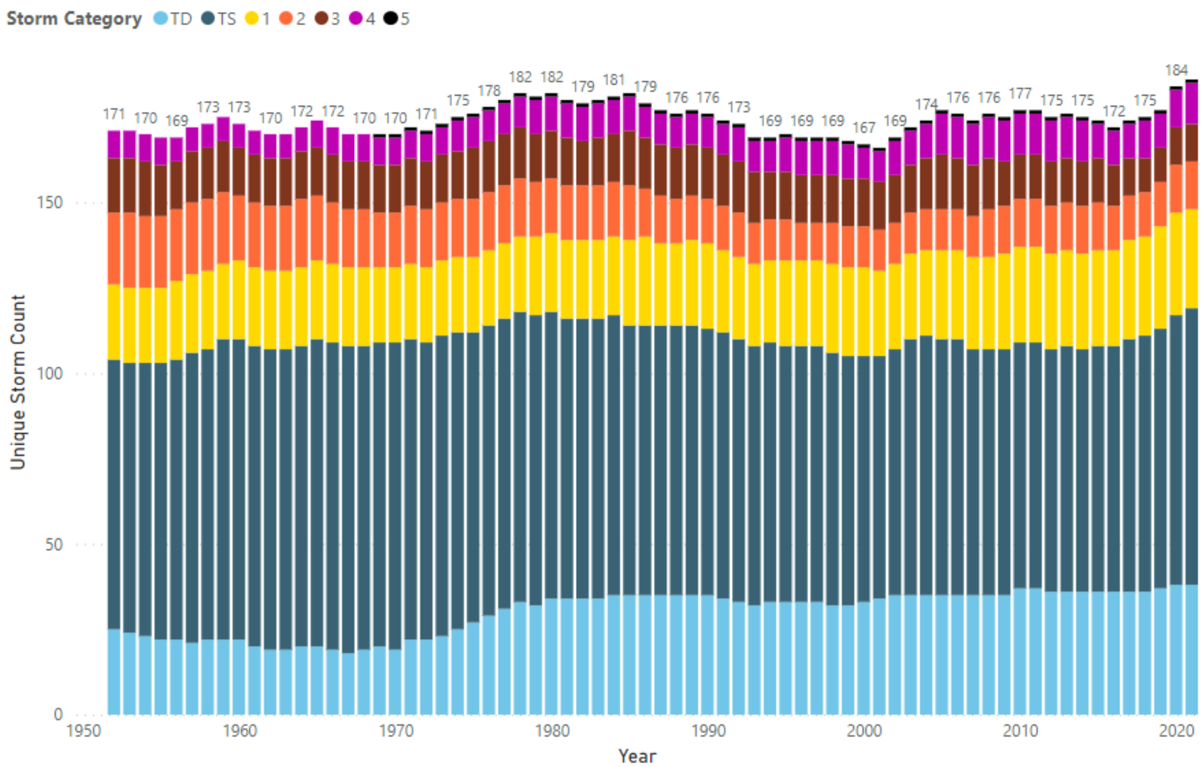
Figure 4-5 depicts the 100-year rolling count of storms. For a resilience-based assessment, this time horizon provides insights for those 'one in a 100-year' types of devasting events while also including 'one in twenty' and 'one in ten' and more regularly occurring events. As the figure shows, the variability between high and low storm activity periods is much lower, ranging from a low of approximately 166 storms to a high of 186. Analysis of the overall storm count activity from Figure 4-5 shows:

1. Activity generally increasing during the 1852-1951 period (171 storms) to 1879-1978 period (182 storms). That is an increase of 11 storms (182-171) over a 27-year period (1978-1951).
2. Activity generally decreasing from the 1879-1978 period (182 storms) to 1902-2001 period (166 storms). That is a decrease of 16 storms (182-166) over a 23-year period (2000–1978).
3. Activity generally increasing from the 1902-2001 period (166 storms) to 1922-2021 (186 storms). That is an increase of 20 storms (186-166) over a 20-year period (2021-2000).
4. The last 100-year period (1922-2021) has the highest storm count compared to any 100-year period from 1852 to 2021.

[3] *Id.*

The figure also shows the relative consistency of the mix of storm activity over the period. The rest of the report utilizes these 100-year rolling averages to understand storm frequency across Entergy Louisiana's service area.

Figure 4-5: 100-Year Rolling Count of Storms for Entergy Louisiana's System[4]



MED events such as thunderstorms and ice storms are evaluated along with tropical cyclones. These were defined by IEEE 1466-2012 using the 2.5-beta method for MED definition.

4.1.2 Historical Major Event Impacts

The Entergy storm reports provide information on the system impacts and restoration costs of historical events to hit the Entergy service area. Figure 4-6 and Figure 4-7 provides a summary of the storm reports for Hurricane Ida and Laura, two of the most recent major events to impact Entergy.

[4] *Id.*

Figure 4-6: Hurricane Ida Impact to Entergy Service Area[5]

Storm Name: Ida

Year: 2021

Entergy Cost: $2.1-$2.5 billion

Category: 4

Outage Duration: 27 Days

System Impact:
211 T-Lines
597 Circuits
30% of Customers

Figure 4-7: Hurricane Laura Impact to Entergy Service Area[6]

Storm Name: Laura

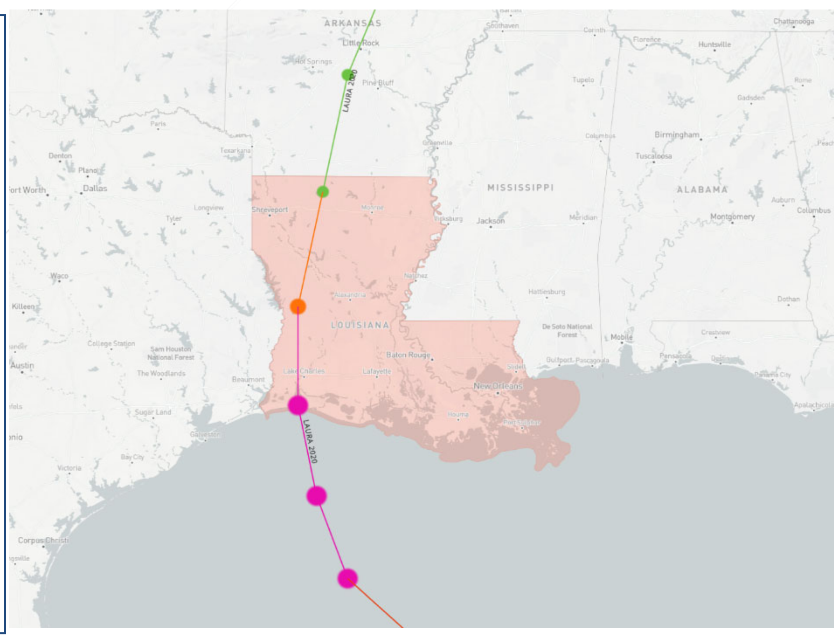
Year: 2020

Entergy Cost: $1.5-$1.7 Billion

Category: 4

Outage Duration: 31 Days

System Impact:
225 T-Lines
411 Circuits
22% of Customers



[5] U.S. Department of Commerce, Historical Hurricane Tracks, National Oceanic and Atmospheric Administration (August 24, 2022), *available at* https://coast.noaa.gov/hurricanes/, and Entergy Storm Reports
[6] *Id.*

Table 4-1 provides a summary of other recent Entergy storm reports going back to 2005. It should be noted that Table 4-1 and the Entergy storm reports include impacts for all of the Entergy Operating Companies, not just Entergy Louisiana. The information from the storm reports served as the foundation for developing the expected impacts for future major events.

Table 4-1: Entergy Storm Reports Summary

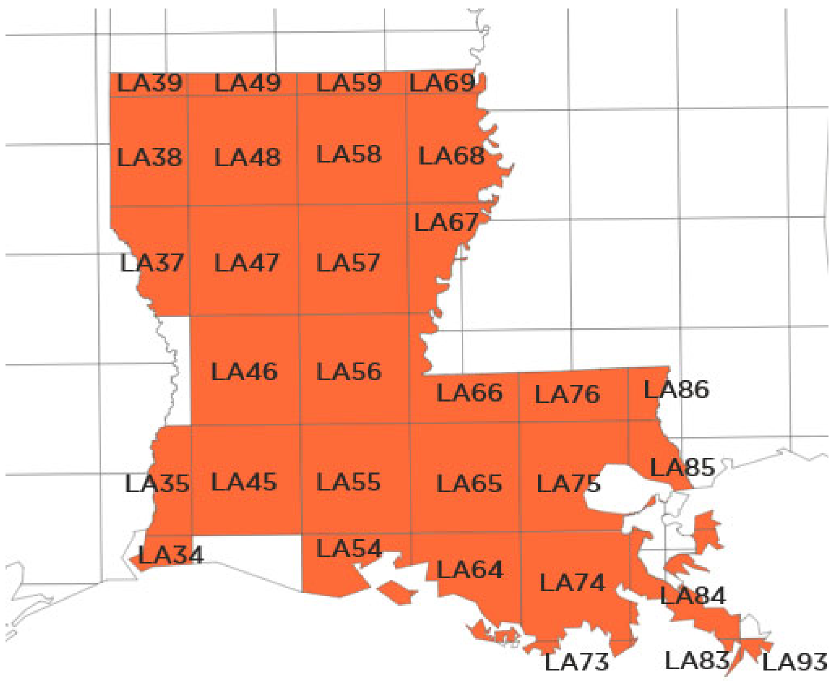
Storm Name	Landfall Category	Year	Restoration Cost (Nominal $Millions)	% of Customers Impacted	% of Transmission System Impacted	% of Distribution Circuits Impacted	Restoration Duration (Days)
Ida	4	2021	$2,300	30%	17.0%	17%	28
Zeta	3	2020	$220	6%	3.3%	11%	7
Laura	4	2020	$1,800	22%	20.0%	11%	31
Delta	2	2020	$280	6%	13.1%	15%	7
Isaac	1	2012	$450	28%	5.0%	43%	7
Gustav	2	2008	$640	36%	-	33%	12
Ike	2	2008	$520	26%	-	18%	12
Cindy	TS	2005	$11	10%	-	-	3
Katrina	3	2005	$800	41%	-	-	26
Rita	3	2005	$620	33%	-	-	21
Winter Storm	-	2021	-	2%	7.8%	4%	5
Easter Storm	-	2020	-	15%	2.8%	12%	8

4.2 Storm Activity and Service Area Merging

Section 4.1 provided the storm activity for the entire state of Louisiana. The first step in developing the Major Storms Event Database was to understand the various storm activity types, their intensity, and how they mapped to as large of a service area as Entergy Louisiana. It is important to note that hurricane events can be over 300 miles wide. Additionally, Entergy Louisiana's service area is 145,000 mi^2 with 121,600 circuit miles. Further complicating the assessment is that storms weaken as they move inland through an area.

To better understand the historical frequency and intensity of various major events in the Entergy Louisiana service area, 1898 & Co. broke up the service area into 50-mile by 50-mile sections creating 31 system sections. Figure 4-8 shows the 31-system sections overlaid against the Entergy Louisiana service area.

Figure 4-8: 50x50 mile System sections and Louisiana



The system section-based storm assessment methodology allows analysis of major event intensity on a granular scale across the system. The system section approach is necessary to understand storm intensity against the infrastructure (represented by the system section) for the following drivers:

- Storm category

- Storm distance
- Storm side (right/left)

4.2.1 Storm Intensity Factors

4.2.1.1 Storm Category

The category of the storm as it encounters the infrastructure is the first key driver of the expected consequence of an event. As the storm paths show from Figure 4-1, the storm category changes as it moves through the service area and loses energy. Table 4-2 shows each category and the associated sustained wind speeds.

Table 4-2: Storm Categories and their Wind Speeds

Category	Sustained Wind Speed (mph)
MED	N/A
Tropical Depression (TD)	< 38
Tropical Storm (TS)	39-73
Category 1	74-95
Category 2	96-110
Category 3	111-129
Category 4	130-156
Category 5	> 157

4.2.1.2 Storm Distance

The distance of the storm as it encounters the infrastructure is the second key driver of the expected consequence of an event. The closer the storm is to the infrastructure, the more expected damage. However, hurricanes can be nearly 300 miles wide causing damage to infrastructure that is 150 miles away from the storm center as a few storm bands come across the service area. Because of this wide range, the Major Storms Event Database categorizes the second storm intensity factor into the following categories:

- **'Direct Hits'** are defined by when the eye of the storm comes within a 25-mile radius from the system section centroid in any direction. The max wind speed hits all or significant portions of system section twice, once from the front end and again on the back end of the storm. Additionally, the wind speeds cause all the assets and vegetation to move in one direction as the storm comes in and in the opposite direction as it moves out. This double exposure to the system causes significant system failures.

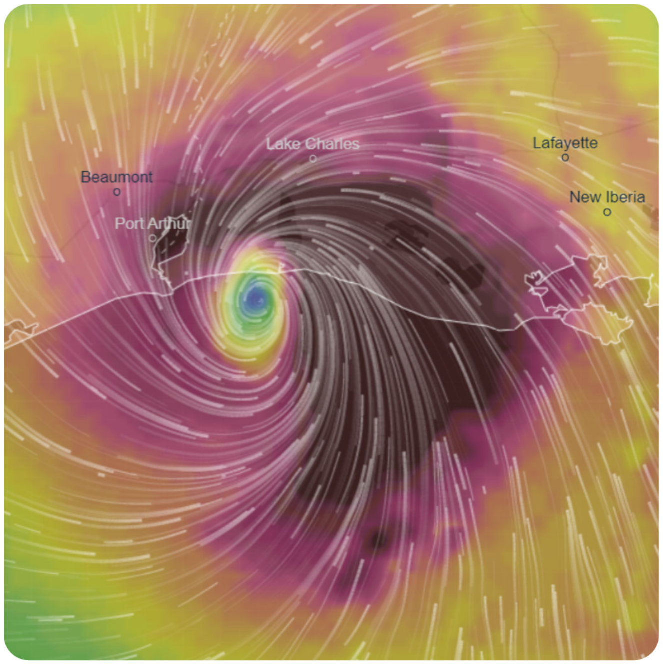
- **'Near Direct Hits'** are defined by when the eye of the storm comes within a 26 to 50-mile radius from the system section centroid in any direction. In many cases, assets experience opposite directional wind as the storm moves through the area, exposing the system to significant potential damage.
- **'Partial Hits'** are defined by when the eye of the storm comes within a 51 to 100-mile radius from the system section centroid in any direction. At this distance, the storm bands hit a significant portion of the assets in a system section. The storm passes through the territory once (compared to twice with direct hits), causing less damage relative to a 'direct hit' or a 'near-direct hit'. For large category storms, the 'Partial Hit' could still cause more damage than a 'Direct Hit' small storm.
- **'Peripheral Hits'** are defined by when the eye of the storm comes within a 101 to 150-mile radius from the system section centroid in any direction. Since hurricanes can be 300 miles wide in diameter, some storm bands can hit a fairly large portion of the system, even if the main body of the storm misses the service area. Very strong winds still comprise these storm bands for large storms, but the damage is less than a 'Partial Hit' of the same strength and side.

4.2.1.3 Storm Side

The third intensity factor included within the Major Storms Event Database is the side of the storm that impacts the infrastructure. Due to the Coriolis effect, tropical storms and hurricanes have stronger east (right-side) winds than west (left-side) winds. These increased wind speeds on the right side of the storm cause more damage to assets on that side of the storm than those assets equally distant from the eye on the left side.

The figure below depicts this effect, the storm's eye is the blue dot in the middle of the red. The right side of the storm is a darker red than the left side, which shows the winds are faster there than on the pink/orange left side of the storm.

Figure 4-9: Storm Wind Strength Heat Map[7]



4.2.2 Storm Types

Combining all the permutations from the three storm activity intensity factors outlined above produces 49 different storm types included within the Major Storms Event Database. Table 4-3 shows the 49 different storm types. Direct hits are categorized under the right-side table. Tropical Depressions are not included within the 101–150-mile range since they are typically smaller events. Similarly, MEDs are only within the 'Direct Hit' distance.

[7] Ventusky, *available at* https://www.ventusky.com/?p=29.43;-94.05;8&l=gust&t=20200827/0600

Table 4-3: Storm Types

Right / Strong Side of the Storm				
	Distance (miles from system section centroid to storm eye)			
Category	25 (Direct)	50	100	150
5	1	9	23	37
4	2	10	24	38
3	3	11	25	39
2	4	12	26	40
1	5	13	27	41
TS	6	14	28	42
TD	7	15	29	
MED	8			

Left / Weak Side of the Storm				
	Distance (miles from system section centroid to storm eye)			
Category	25 (Direct)	50	100	150
5		16	30	43
4		17	31	44
3		18	32	45
2		19	33	46
1		20	34	47
TS		21	35	48
TD		22	36	49
MED				

4.2.3 Capturing Storm Types Against System Sections

1898 & Co. utilized geospatial analytics to identify the historical count of the 49 different storm types against each system section based on storm path datasets available for download from NOAA's website. The basis for the analytics was to capture the storm's intensity factors as it is closest to a given system section. For each storm over the past 170 years, 1898 & Co. identified the storm's category, distance from the centroid of the system section, and side of the event. This was done for all 31 system sections. Figure 4-10 provides an illustration of the approach for one example system section.

Figure 4-10: Geospatial Analytics Approach Illustration

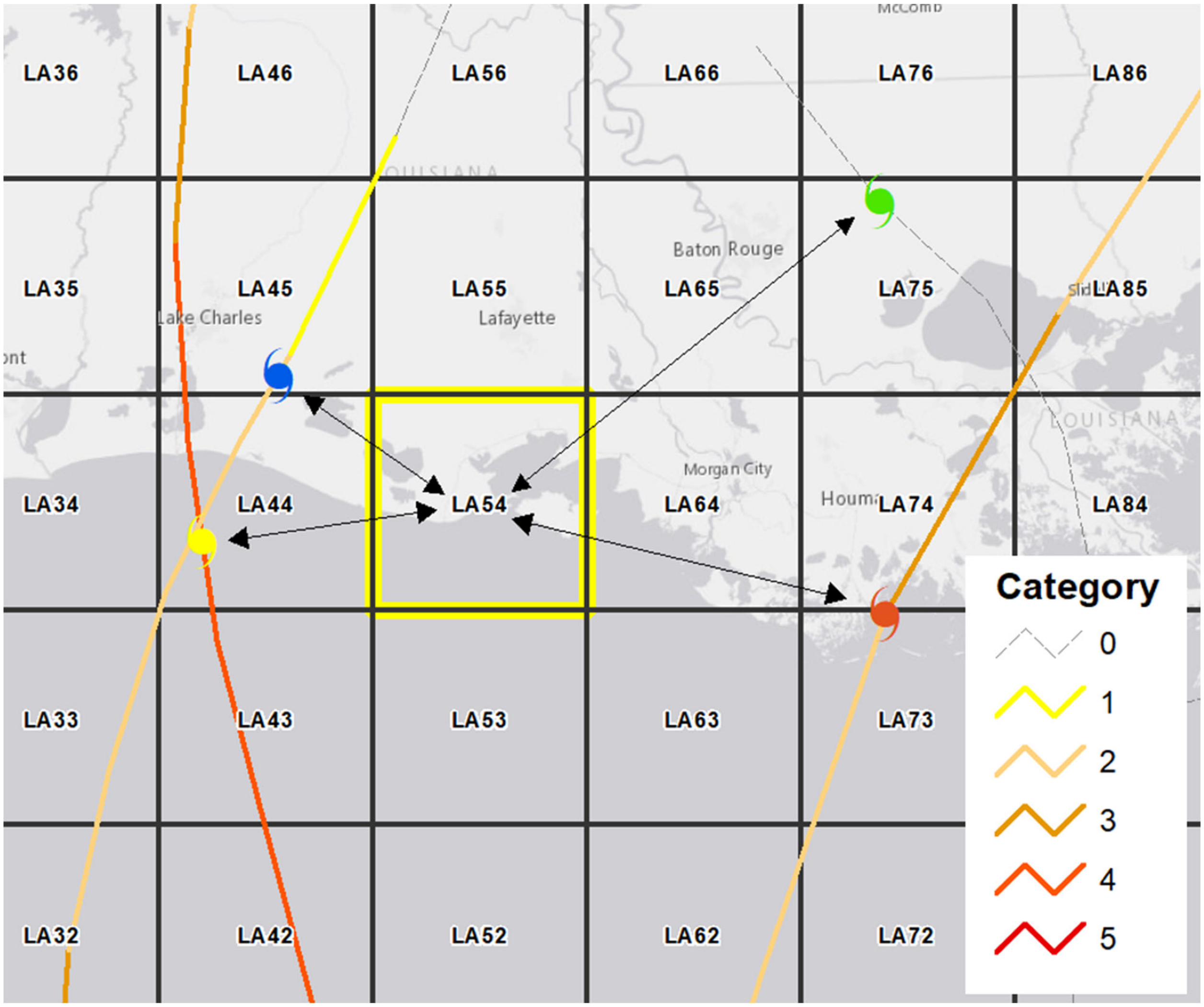


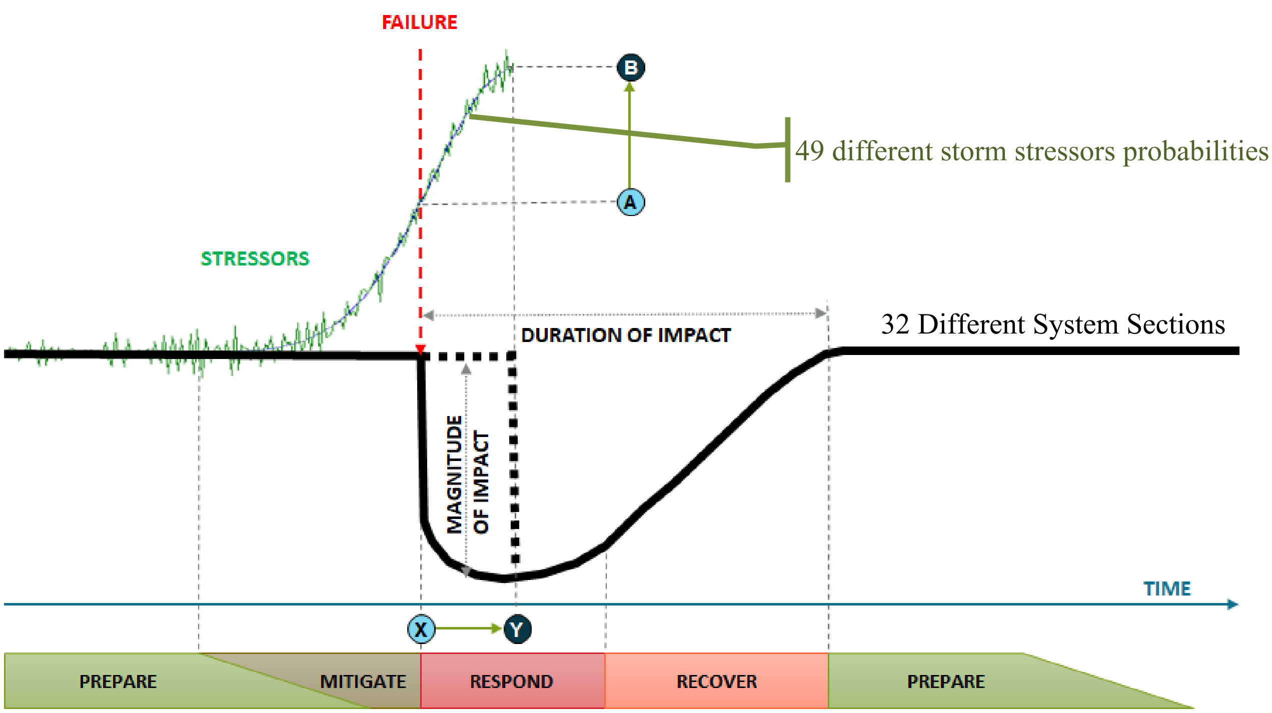
Table 4-4: Storm Statistics for Example System Section for 2020 Storms

Name	Time	Storm Location	Storm Side	Storm Category	Storm Distance (miles)	Storm Distance Bucket (miles)
Laura	8/27/2020 3:00	W	Right	4	65.5	100
Zeta	10/28/2020 18:00	ESE	Left	2	98.1	100
Delta	10/9/2020 23:00	NW	Right	2	55.5	100
Cristobal	6/8/2020 6:00	ENE	Left	TS	116.4	150

4.2.4 Major Storms Event Database and Resilience Framework

The Major Storms Event Database includes 49 different storm events against 31 different system sections. Figure 4-11 depicts how both factors map to the phases of resilience concept that serves as the theory behind the Storm Resilience Model approach to evaluating system vulnerability and benefits of hardening investments. The Major Storms Event Database will include 49 different 'stressors' and outline the status of the 31 system sections. Section 4.3 outlines the approach to forecast the frequency of each of the 49 storm stressors for each of the 31 system sections. Section 4.4 outlines the expected impacts to each system section for each of the 49 storm stressors.

Figure 4-11: Phases of Resilience Framework & Major Storms Event Database



4.3 Estimating Future Storm Probabilities

From a high-level perspective, the future storm probabilities (49 types) within the Major Storms Event Database for each of the 31 system sections are based on the historical 100-year rolling average of events for the last 30 100-year periods with some modifications explained below. Only the last 30 100-year periods were used because of concerns relative to recording bias and more recent climate factors.

The Major Storms Event Database includes a range of probabilities for each of the 49 storm types by the 31 system sections. As discussed in Section 6.3, the Storm Resilience Model employs Monte Carlo, or stochastic modeling, to select a future storm probability from a distribution. This is done for 1,000 iterations to create 1,000 storm futures for each system section.

4.3.1 100-Year Rolling Storm Probabilities

Figure 4-12 shows the rolling probability of a direct hit to an example system section for each 100-year window ending in the year shown. This figure shows all the hurricane events to directly come through the system section. As the figure shows, the historical probability of a tropical depression directly hitting this example system section ranges from 1 percent a year to 4 percent a year.

Figure 4-12: 'Direct Hit' Probabilities for Example System section[8]

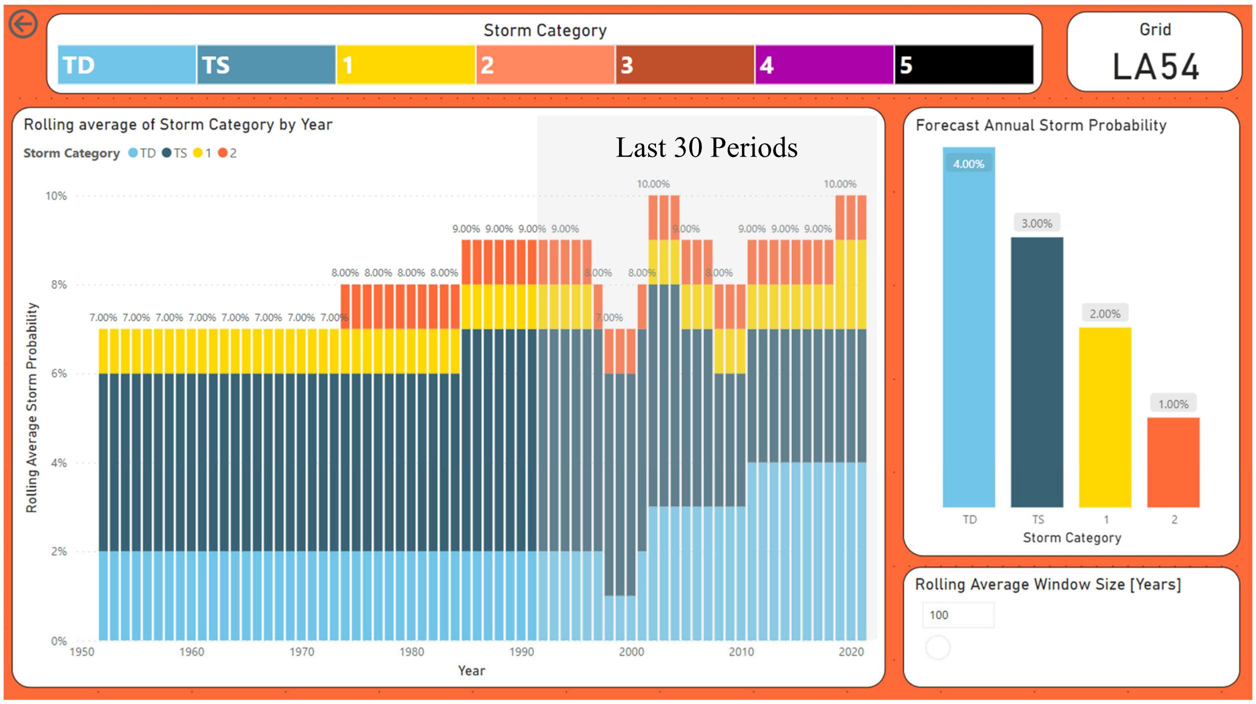


Figure 4-13, Figure 4-14, and Figure 4-15 show similar probabilities for the example system section for 'Near Direct Hits' (26 to 50 miles), 'Partial Hits' (51 to 100 miles), and 'Peripheral Hits' (101 – 150 miles), respectively. This same analysis was performed for all 31 system sections.

[8] *See,* footnote 1.

Figure 4-13: 'Near Direct Hit' Probabilities for Example System Section[9]

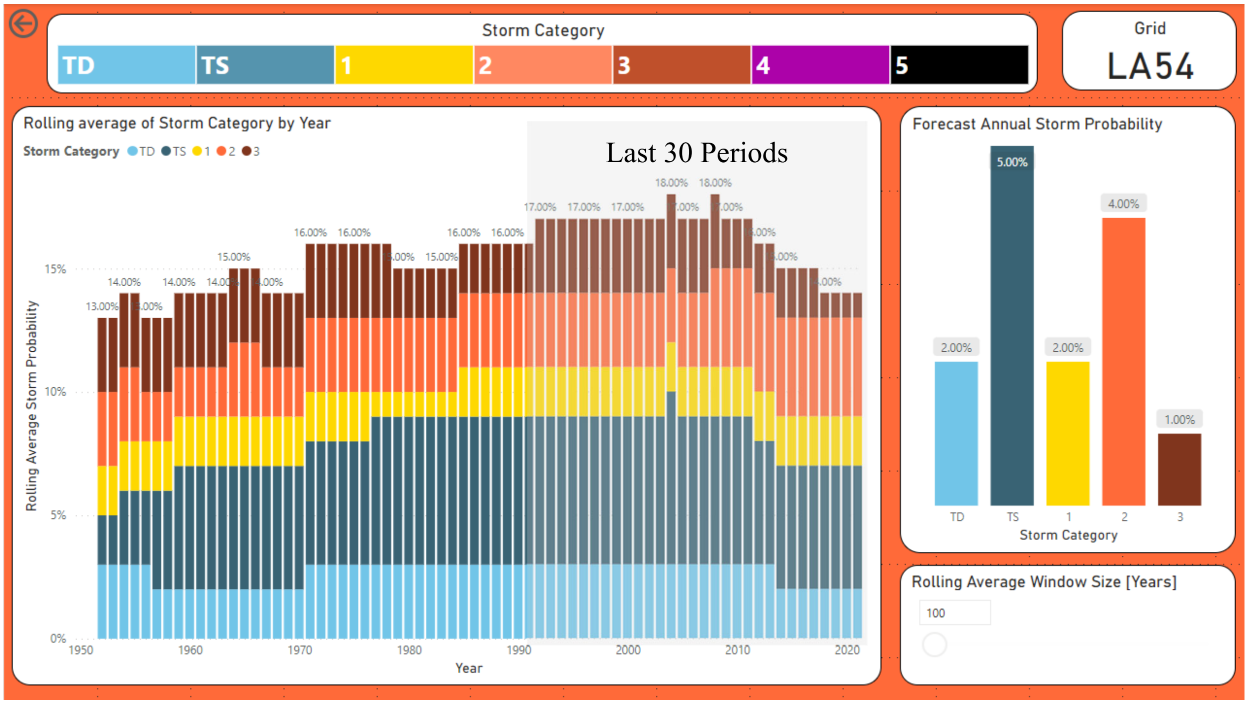
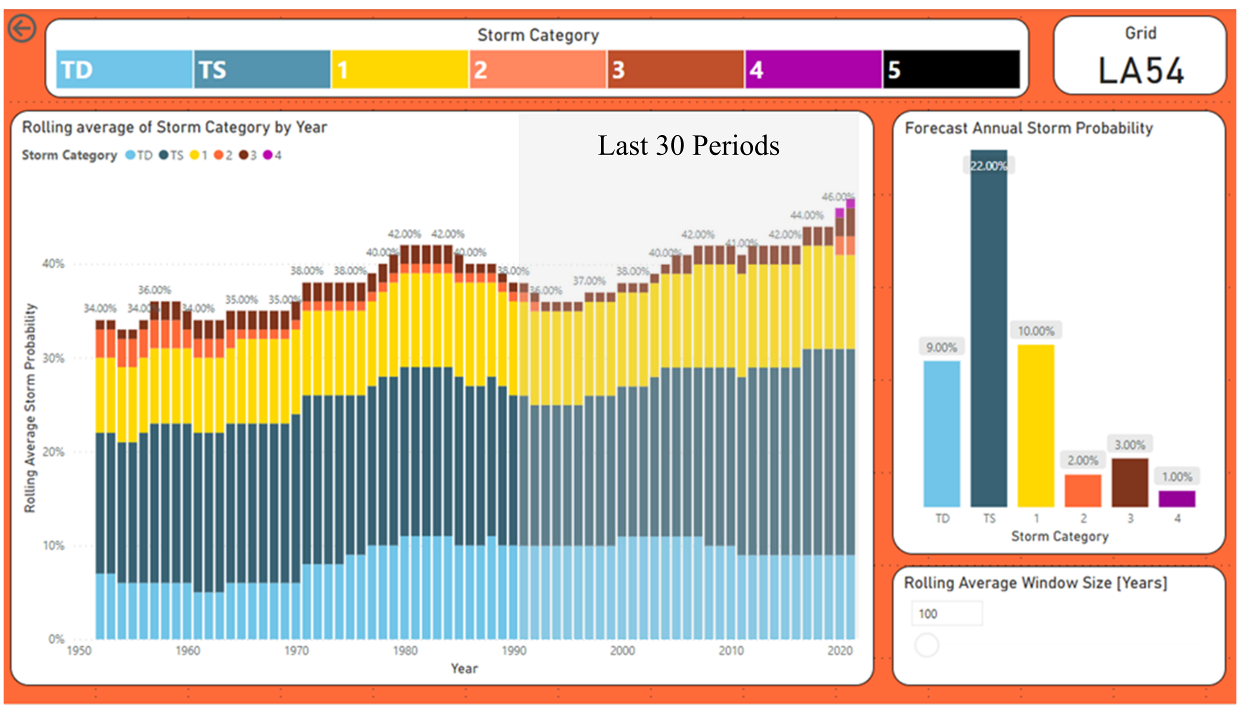
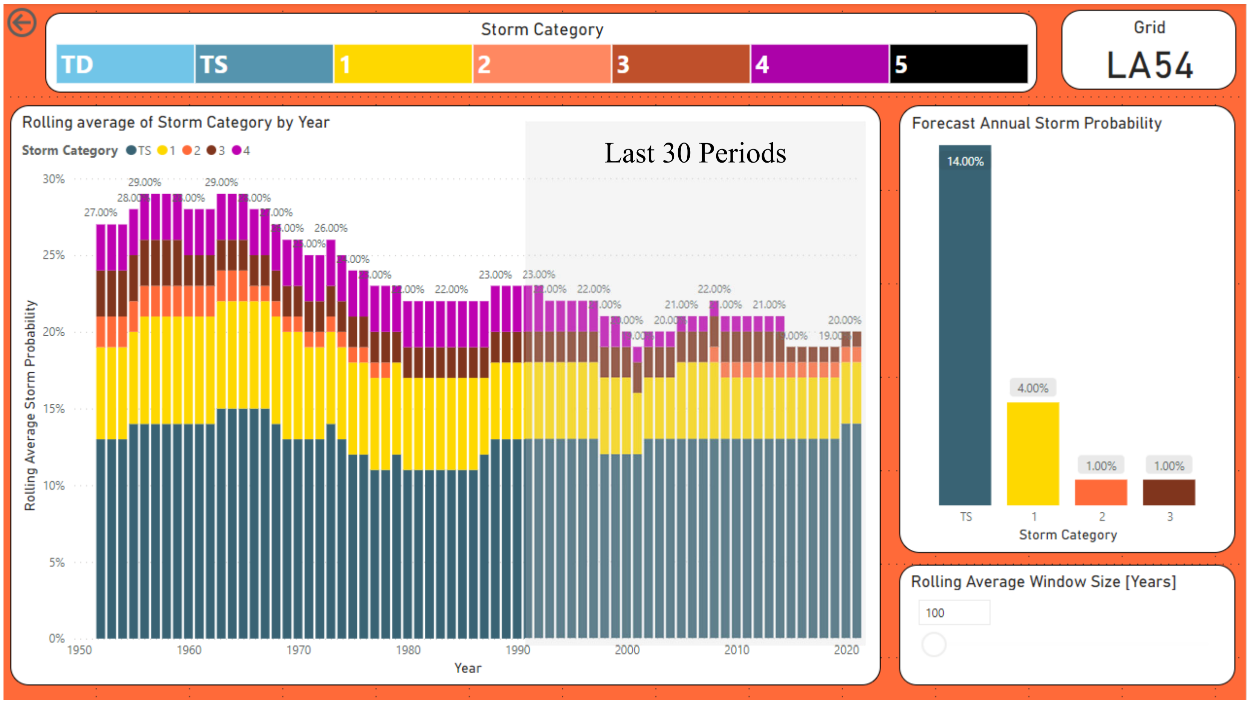


Figure 4-14: 'Partial Hit' Probabilities for Example System Section[10]



[9] *See,* footnote 1.
[10] *See,* footnote 1.

Figure 4-15: 'Peripheral Hit' Probabilities for Example System Section[11]



4.3.2 Recent Storm Activity Modifiers

As discussed above, the model uses the last 30 100-year periods (1893-1992 through 1922-2021) to estimate the probabilities of future storms. If the 30 100-year periods are equally weighted, storms occurring during the middle years of the study period will more strongly influence future storm probabilities. The model weights the most recent years more heavily to incorporate the high frequencies of large category 4 storms the past few years.

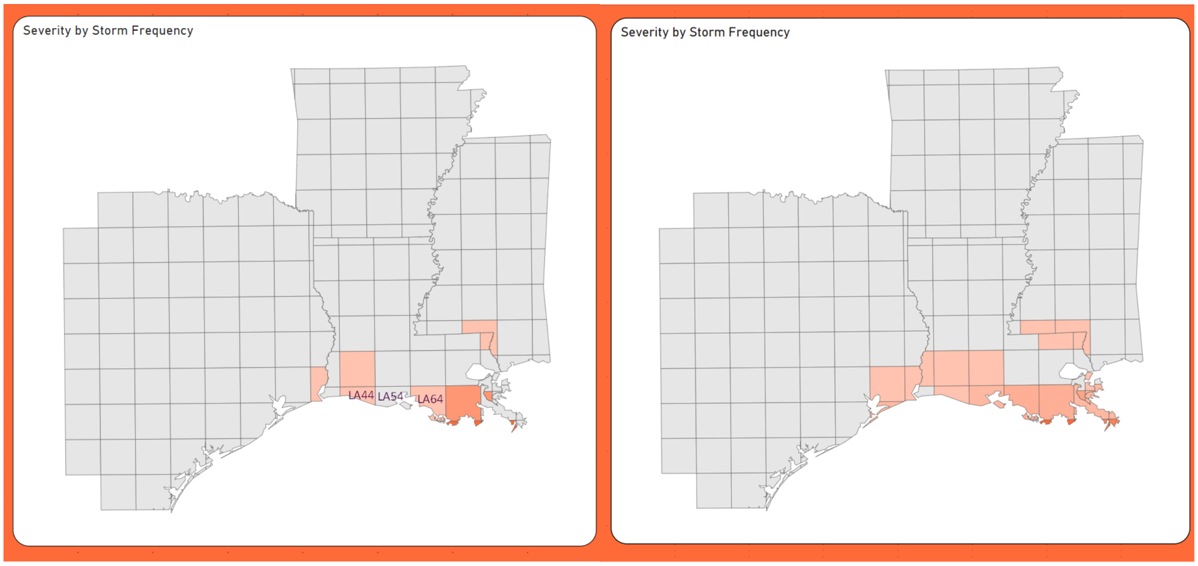
4.3.3 Averaging across East and West System sections

Due to the random nature of storm paths and the granularity of the 50x50 system sections, some system sections may see no strong storms over the entire 170 years of data. However, their neighbors may see multiple. The left image of Figure 4-16 offers an example for Category 4 Direct Hits to the example system section. Analysis of Figure 4-16 shows that system section LA54 has had no Category 3 or 4s over the past 170 years, although both system sections surrounding it have Category 4 direct hits. The major storms event database averages neighboring system sections to the east and west to adjust for this historical bias since those hurricanes could have easily moved east or west by 25 miles. The

[11] *See,* footnote 1.

averaging is done for each of the 49 storm types. The image on the right side of Figure 4-16 shows the resulting probabilities after the averaging.

Figure 4-16: Category 4 Direct Hits in the Past 100 Years Before and after East-West Averaging



4.4 Major Storms Impact

While the major storm frequency into the future is based on a direct link to historical major events, the consequence of the events is more challenging to estimate. Review of the historical record shows significant variation in the impacts from events that have similar characteristics, which leads to significant uncertainty in the modeling of such impacts from future storms. In some cases, lower category events have produced more damage and impact than higher category events due to a host of variables, including differences in the storm paths, speed, the infrastructure's design standards, customer density, and the vegetation density around the infrastructure.

Further complicating the evaluation of storm impacts is that the Entergy Louisiana service area is ever evolving with a changing and growing customer base. While the historical record shows the potential for a Category 5 hurricane that occurred in 1969 (Camille), any impact data, if even available, would not be valuable in understanding the impact to Entergy Louisiana's system if it were to happen today because the customer base and system are vastly different. For this reason, the Major Storms Event Database leverages more recent events from the past 10 to 15 years and linearly interpolates to fill in gaps for major events that have occurred in the historical past but not within the most recent past. The Major Storms Event Database includes impact assumptions around the following three categories for each of the 49 events to impact a system section:

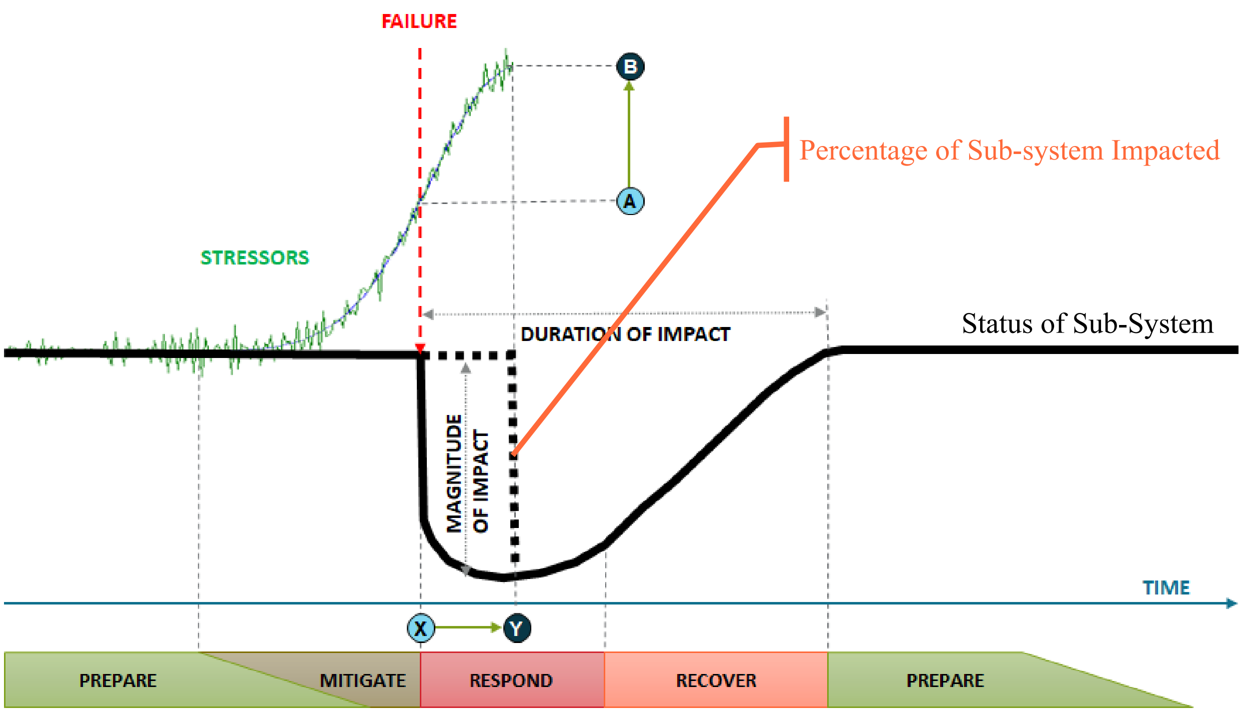
- Percentage of sub-systems Impacted
- Duration to restore each sub-system
- Cost to restore each sub-system.

The next section outlines the historical major event impacts. This information was foundational in developing the three-system section impacts outlined above. The following sections describe each of these three-system section impacts that are part of the Major Storms Event Database.

4.4.1 Percentage of Sub-System Expected Impacts

The Major Storms Event Database outlines and describes the state of the system in terms of magnitude of impact in alignment with the resilience framework outlined in Figure 2-1 and shown below in Figure 4-17.

Figure 4-17: Phases of Resilience Framework & Sub-System Impact



For each of the 49 storm events (stressors or the 'green' line from Figure 4-17), the database includes the expected range of impacts at the system section level for the following sub-systems:

- Percentage of Transmission Circuits Down
- Percentage of sub-Transmission Circuits Down
- Percentage of at-risk Substation Flooded due to storm surge

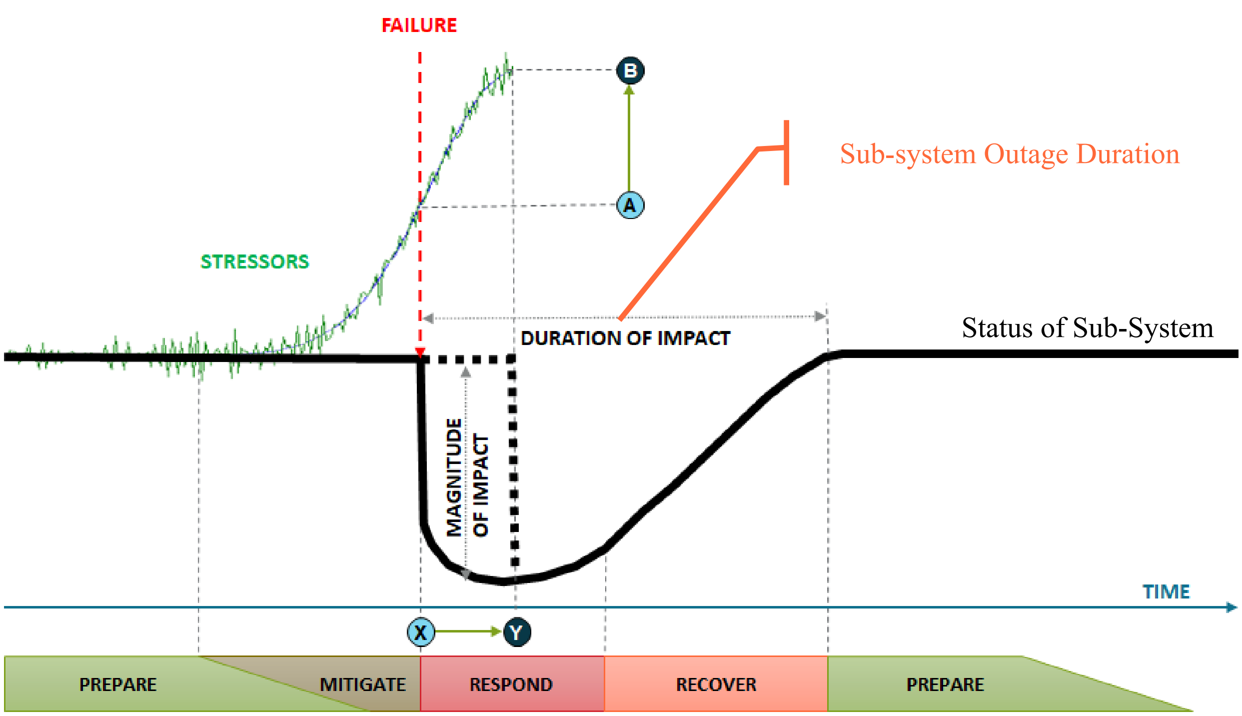
- Percentage of at-risk Control Houses Damaged
- Percentage of Backbone (or Mainline) Protection Zones to Lock-out
- Percentage of Lateral Protection Zones to Lock-out

1898 & Co. and Entergy collaboratively developed the expected impact ranges for each of these sub-systems based on the historical storm reports adjusting for the system section modeling structure and the 49 storm events.

4.4.2 Major Event Duration

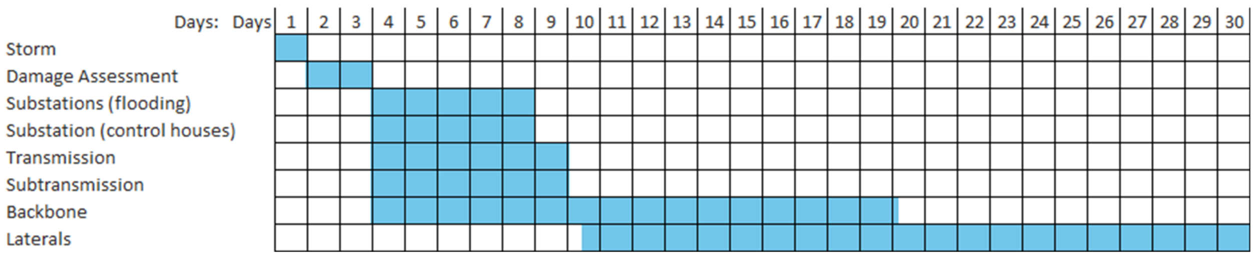
The Major Storms Event Database also includes the expected restoration profiles for each of the sub-systems for each of the 49 storm stressors ('green' line). While the previous section describes the impact to the system, this part of the database outlines the duration of restoration in alignment to the resilience framework outlined in Figure 2-1 and show below in Figure 4.

Figure 4-: Phases of Resilience Framework & Sub-System Duration



1898 & Co. and Entergy collaboratively developed the expected total duration of each of the 49 storm events ('stressors') to impact each system section. The overall durations are in alignment to historical events from the last 15 years linearly interpolating for major events that have not occurred in the recent past. For the duration of restoration for each sub-section, the database includes historical experience from recent restoration efforts. Figure 4-18 shows the sub-system restoration profile for a category 4 hurricane direct hit. Similar restoration profiles were developed for all 49 storm event types. These restoration profiles by sub-system are critical for the calculation of customer outages completed within the Storm Impact Model. The Storm Impact Model considers the downstream customers of each protection device and where within the restoration profile that part of the system is likely to be restored.

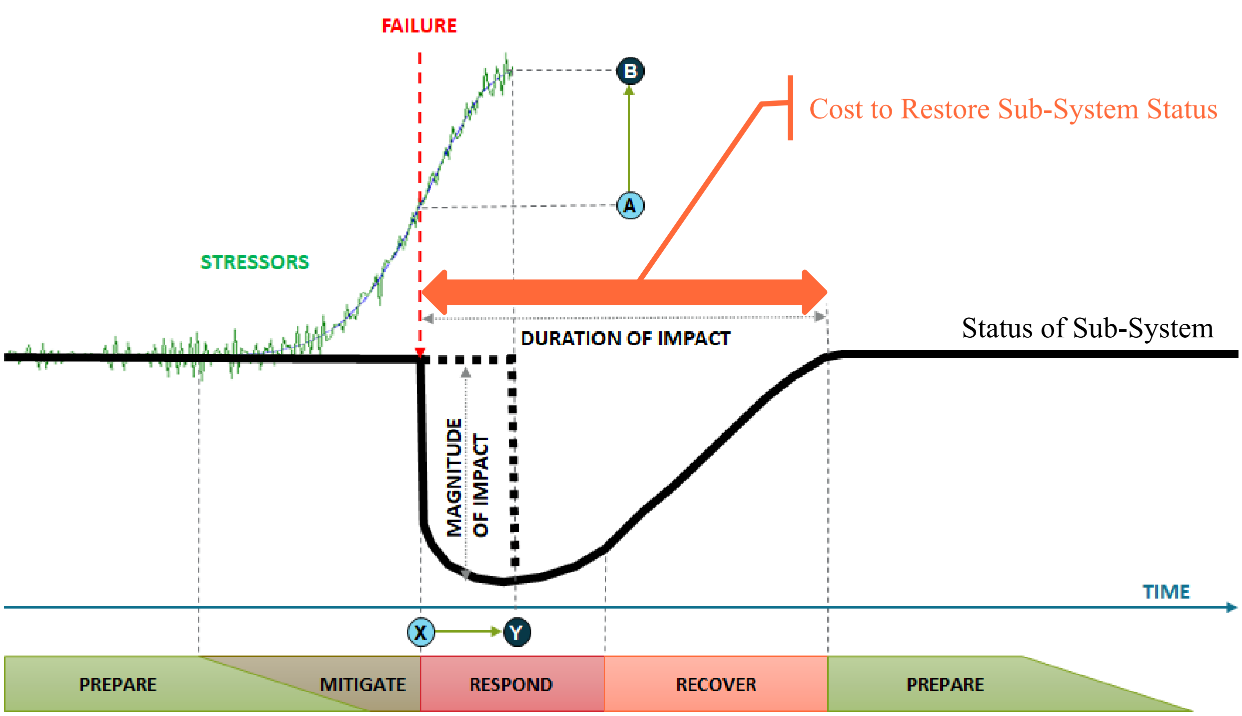
Figure 4-18: Sub-System Storm Restoration Profile for Cat 4 Direct Hit



4.4.3 Major Event Restoration Cost

The third impact category included in the Major Storms Event Database is the expected restoration costs for each of the 49 storm events (system 'stressors'). Figure 4-19 depicts the storm impact within the phase of resilience framework.

Figure 4-19: Phases of Resilience Framework & Sub-System Restoration Costs



The database includes the estimated restoration costs for each of the 49 major events to impact each of the 31 system sections. The database includes restoration costs for each system section and sub-system. This is needed because there are several drivers of restoration costs. For instance, system sections with more assets, all else equal, would have more restoration costs than system sections with fewer assets.

For distribution circuits and transmission circuits, the database includes a similar approach to estimating the expected restoration costs for each of the events and system sections. The database factors in the following to estimate restoration costs for each of the 49 events and system sections:

- **Structure count and type** within the system section. System sections with high asset counts will have more failures and restoration costs. Additionally, some structures are more costly to restore like a lattice tower vs. a wood mono pole.
- **Entergy Crews vs. non-Entergy Crew mix**. Replacing assets during and immediately after major events is much costlier than replacing assets in a more methodical manner during 'blue-sky' hours. Overtime fees, unavoidable inefficiencies that arise from storm restoration logistical and other challenges, are a few of the drivers for higher costs for storm restoration work. Because of these factors the cost of replacing assets, during storm events, even if only Entergy crews perform the work to restore infrastructure, can be 1.5 to 2.0 times higher than infrastructure replacements during 'blue-sky' rebuilds. For high category named events, Entergy relies also on mutual assistance and contractors to restore the system, with non-Entergy crews being brought in from across the nation to hasten restoration times and manage the massive scale of the restoration work that arises from such high category storm events. It should be noted that Entergy often provides mutual assistance to other utilities as part of the reciprocal obligations between member utilities. Given the per-diems, overtime rules, mobilization and demobilization, and demands of managing outside resources, on top of the factors outlined above the costs can be even higher. The estimation approach factors in the mix of Entergy and non-Entergy crews for each of the 49 storm events based on these multipliers.
- **Side of the storm** impacting the system section (right or left side). The right side of a storm causes more damage than the left side of the storm.
- **Structure current wind loading vs. hardening wind loading standards**. System sections with assets that meet more recent hardened wind loading standards will have fewer failures than system sections where the assets' current wind loading rating has a differential to the hardening standard. See Section 3.5 for additional details.

- **Vegetation density** around the infrastructure in the system section. The existence of more dense vegetation around infrastructure will drive more failures because wind blowing vegetation into circuits is a driver of storm-based outages. See Section 3.4 for additional details.
- **Age** of the infrastructure in the system section. System sections with infrastructure that is older are more likely to have higher instances of asset failures than system sections with younger assets. See Section 3.6 for additional details.
- **ROW access** for the infrastructure in the system section. Assets with road access typically cost less to restore than assets in the deep ROW. See Section 3.7 for additional details.
- **Terrain** Infrastructure in wetlands will be more costly to restore than infrastructure in flat terrain. See Section 3.8 for additional details.

The Major Storms Event Database includes a framework to incorporate all these factors to estimate the expected range in restoration costs for each of the 49 storm events to impact each of the 31 system sections.

For Substation Storm Surge Mitigation, restoration costs are based on the number of assets in the substation and the expected cost multipliers to replace those assets during major events. Control house restoration costs employ a similar approach.

5.0 STORM IMPACT MODEL

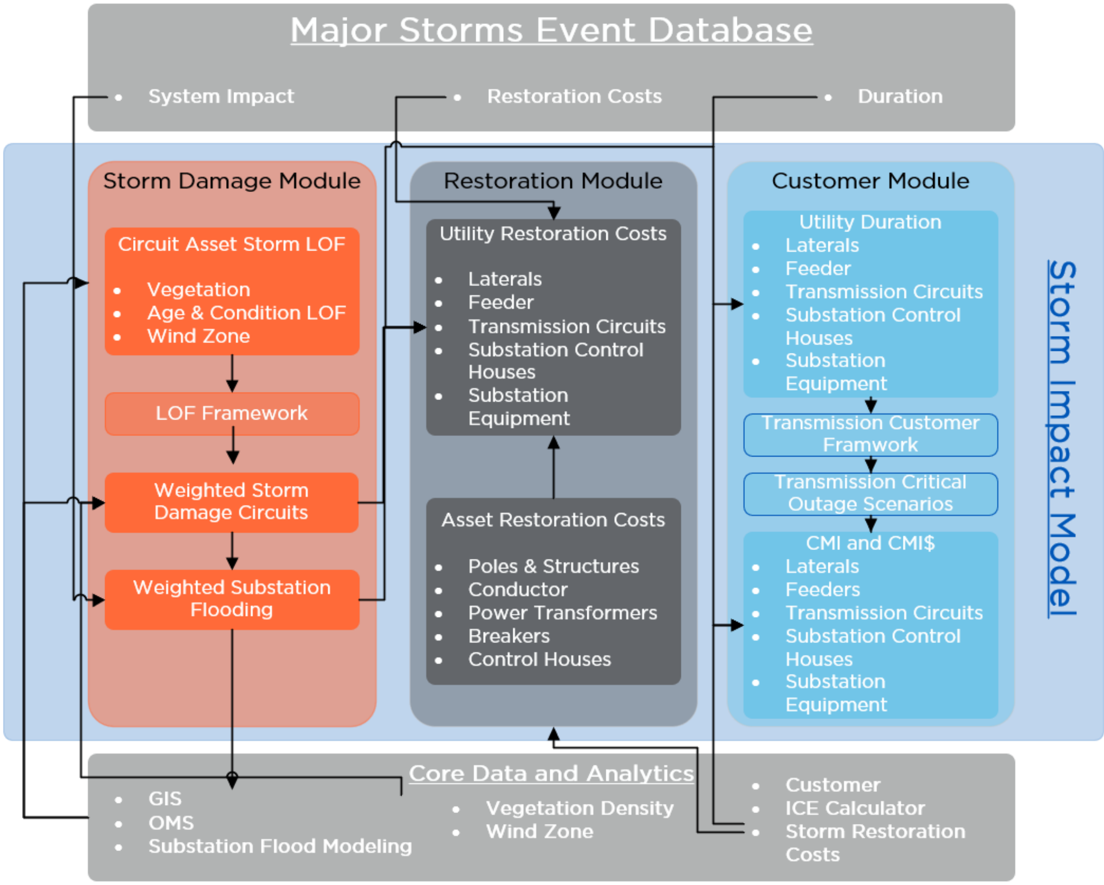
The second major component of the Storm Resilience Model is the Storm Impact Model. Whereas the Major Storms Event Database describes the phases of resilience for the Entergy Louisiana high-level system; the Storm Impact Model goes a layer deeper and develops the phases of resilience for each potential hardening project on the Entergy Louisiana system for each storm scenario.

The Storm Impact Model models the impact to the system of any type of major storm event. Specifically, it identifies, from a weighted perspective, the particular laterals, feeders, transmission lines, and substations that are likely to fail for each type of storm in the Major Storms Event Database. The model also estimates the restoration costs associated with the specific sub-system failures and calculates the impact to customers in terms of CMI. Finally, the Storm Impact Model models each storm event for both a Status Quo and Hardened scenario(s). The Hardened scenario(s) assumes the assets that make up each project have been hardened. The Storm Impact Model then calculates the benefit of each hardening project from a reduced restoration cost and CMI perspective.

The Storm Impact Model utilizes a robust and sophisticated set of data and algorithms to model the benefits of each hardening project for each storm scenario. Section 3.0 of the report outlines the core data, algorithms, and frameworks that are part of the Storm Impact Model. It outlines a very granular level of analysis of the Entergy Louisiana System. This granular level of data and analysis allows for the Storm Resilience Model to reasonably project the ratio of resilience benefit to cost, resulting in more efficient hardening investment. This also provides confidence that investments are targeted to the portions of the system that provide the most value for customers.

Figure 5-1 provides an overview of the Storm Impact Model architecture. The following sections describe in more detail each of the core modules in more detail.

Figure 5-1: Storm Impact Model Overview



5.1 Core Data Sets and Algorithms

The core data sets and algorithms that feed into the Storm Impact Model are described in further detail in Section 3.0.

5.2 Weighted Storm Likelihood of Failure Module

The Weighted Storm LOF Module of the Storm Impact Model identifies the parts of the system that are likely to fail given the specific storm loaded from the Major Storms Event Database for each system section. The module is grounded in the primary failure mode of the asset base, storm surge for substations, wind and rain for control houses, and wind, structure design gaps, asset age, and vegetation for circuit assets.

5.2.1 Substation Storm Likelihood of Failure

The main driver of substation failures during major storm events is storm surge flooding and control house failures. The Major Storms Event Database designates the number of substations expected to experience flooding for each of the 49 storm scenarios and the number of control houses expected to have wind damage.

To identify which substations would be the most likely to experience flooding, the Storm Impact Model uses the substation flood modeling described in Section 3.10. This model provides the estimated feet of flooding above site elevation assuming the “maximum of maximum” approach, that is, a worst of the worst-case scenario. Because of this extreme worst-case scenario, the results could not be used for a typical hurricane category to hit the Entergy Louisiana service area. The flood modeling has flood height data for all 5 hurricane category types. The Storm Impact Model uses the flooding height values as likelihood scores to identify the substation Probability of Failure (“POF”) for each storm event in the Major Storms Event Database.

To evaluate what control houses are likely to experience wind damage, the Storm Impact model uses wind zone differential.

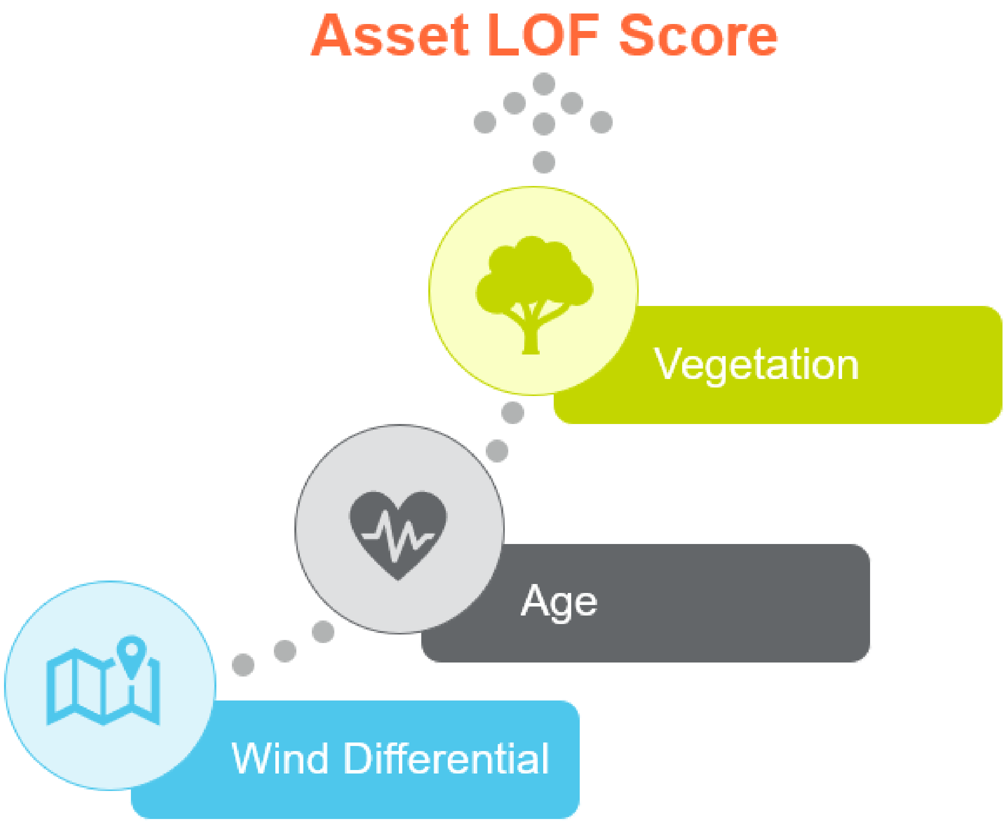
5.2.2 Circuits Storm Likelihood of Failure

The main driver of circuit failures during storms is wind blowing vegetation (and other debris) into the conductor, weighing it down. The additional weight, when combined with the wind loading, causes the structures holding up the conductor to fail. Typically, the vegetation touching the conductor triggers the protection device to operate; however, the enhanced loading on the poles causes asset failures that are costly to repair both in terms of restoration costs and in CMI. The storm LOF of an overhead distribution asset is a function of the vegetation around it, the age of the asset, and the applicable wind zone differential (coastal zones see higher wind speeds).

Figure 5-2 depicts the framework used to calculate the storm LOF score for each circuit asset on Entergy Louisiana’s T&D system. Assets included within the framework are wood poles, steel poles, concrete poles, lattice towers, overhead primary, and overhead transmission conductor.

For the vegetation LOF scores, the Storm Impact Model uses the vegetation density of each overhead primary and transmission conductor normalized for length. Section 3.4 outlines the approach to estimate the vegetation density for approximately 897,000 primary and transmission conductors. Each primary and transmission conductor is one span from structure to structure. The vegetation density, normalized for length, is used in the LOF framework to calculate an LOF score for vegetation.

Figure 5-2: Storm LOF Framework for Circuit Assets



For the age LOF, the Storm Impact Model utilizes 1898 & Co.'s asset management solution, AssetLens Solutions, to estimate the age-based LOF for each wood pole, metal structure, overhead primary, and transmission conductor. Section 3.6 includes additional details on the approach and LOF results.

The wind design differential criteria use the wind zone designation data from Section 3.5 inside the asset LOF framework to develop the LOF scores.

The Storm Impact Model uses the sum of the three criteria (vegetation, age, and wind design differential) to calculate the total storm LOF for each asset. The assets are then totaled up to the project level, providing a granular understanding of the LOF for each project. The Storm Impact Model uses the storm LOF scores to identify the circuit project POF for each storm event in the Major Storms Event Database.

5.3 Project & Asset Reactive Storm Restoration

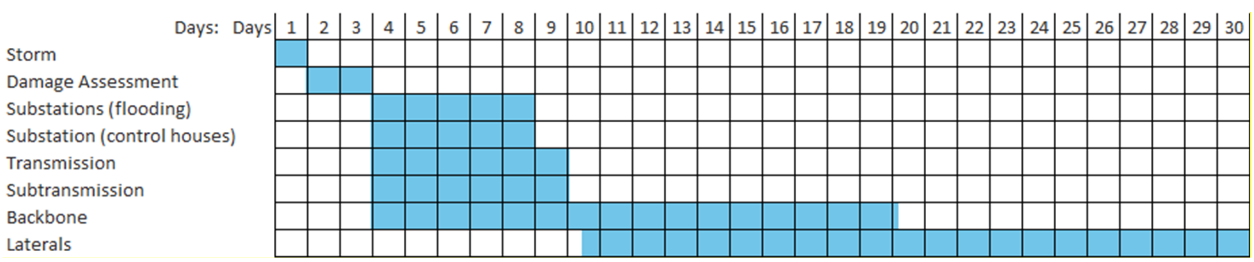
The Storm Impact Model estimates the cost to repair assets from a storm-based failure on a system section by system section basis. Storm restoration costs were calculated for every asset in the Storm Impact Model including wood poles, overhead primary, transmission structures (steel, concrete, and lattice), transmission conductors, power transformers, relays, and breakers. The costs were based on storm restoration costs multipliers above planned replacement costs These multipliers were developed by Entergy Louisiana and 1898 & Co. collaboratively. They are based on historical events, the expected inventory constraints, and expected mix of Entergy Louisiana and non-Entergy Louisiana crews needed for the various asset types and storms.

For each storm event, the restoration costs at the asset level are aggregated up to the project level and then weighted based on the project LOF (Section 5.2) and the overall restoration costs for the storm event outlined in the Major Event Storms Database.

5.4 Duration and Customer Impact

The Storm Impact Model calculates the duration to restore each project in the Status Quo Scenario. The assumptions for major asset class outage duration are outlined in the Major Event Storms Database. Figure 5-3 provides an example duration profile for the Category 4 and above storm event.

Figure 5-3: Example Storm Duration Profile



The project-specific duration is based on percent complete vs percent time curves for each major asset class. The projects are ranked by metrics that are similar to those Entergy Louisiana uses to prioritize storm restoration activity, such as priority customers and customer count. Specific project durations are calculated based on completion vs time curves. For example, using the example from the figure above, a lateral project may have a relatively high priority (i.e., customer count is high with more critical customers). That lateral would be restored by day 10 of the profile above for a Category 4 event. However, the lowest ranked laterals will have project durations in the 30-day range for this category storm event.

The project duration is then multiplied by the number of affected customers for each project (see Section 3.3) to calculate the CMI for each project. Some of the storm scenarios include significant outages to the transmission system (see Section 3.11). The percentage of the system impacted is so high that the designed resilience and redundancy (looping) of the system are lost for a short period of time, which in turn causes very large numbers of customer outages across the system from the transmission system. The Storm Impact Model allocates customer outages from these events to the various parts of the Entergy Louisiana transmission system based on transmission system operating capacity and the relevant assets' overall importance to the Bulk Electric System ("BES").

Finally, the CMI for each project for each storm event is monetized using the ICE Calculator. Section 3.9 provides additional details on the ICE Calculator. The monetization is performed for each type of customer; residential, small C&I, large C&I, and the various priority customers. The monetization of CMI is calculated for project prioritization purposes as discussed below in Section 6.0.

5.5 'Status Quo' and Hardening Scenarios

The Storm Impact Model calculates the storm restoration costs and CMI for the 'Status Quo' and Hardening Scenarios for each project by each of the 49 storm events. The delta between the two scenarios is the benefit for each project. This is calculated for each storm event based on the change to the core assumptions (vegetation density, age, wind zone, flood level, restoration costs, duration, and customers impacted) for each project.

The output from the Storm Impact Model is a project-by-project probability-weighted estimate of annual storm restoration costs, annual CMI, and annual monetized CMI for both the 'Status Quo' and Hardened Scenarios for all 49 major storm scenarios. The following section describes the methodology utilized to model all 49 major storms and calculate the resilience benefit of each project.

6.0 RESILIENCE NET BENEFIT CALCULATION MODULE

The Resilience Benefit Calculation Module of the Storm Resilience Model uses the annual benefit results of the Storm Impact Model and the estimated project costs to calculate the net benefits for each project. Since the benefits for each project are dependent on the type and frequency of major storm activity, the Resilience Benefit Module utilizes stochastic modeling, or Monte Carlo Simulation, to randomly select a thousand future worlds of major storm events to calculate the range of both 'Status Quo' and Hardened restoration costs and CMI. The benefit calculation is performed for a 50-year time horizon, matching the expected life of hardening projects.

The following sections provide additional detail on the project costs, Monte Carlo Simulation, and feeder automation.

6.1 Economic Assumptions

The resilience net benefit calculation includes the following economic assumptions:

- Period: 50 years – most of the hardening infrastructure will have an average service life of 50 or more years
- Escalation Rate: 2.5 percent
- Discount Rate: 7.5 percent

6.2 Project Cost

Project costs were estimated for the approximately 170,000 projects in the Storm Resilience Model. Some of the project costs were provided by Entergy Louisiana while others were estimated using the data within the Storm Resilience Model to estimate scope (asset counts and lengths) and then multiplying by unit cost estimates to calculate the project costs. The following sub-sections outline the approach to calculate project costs for each of the programs.

6.2.1 Distribution Feeder and Lateral Hardening

6.2.1.1 Rebuild

For each project, Entergy Louisiana's GIS data, GIS analysis for vegetation, underlying terrain, and road access were leveraged to estimate:

- Number of structures that need to be hardened to meet the desired wind standard;

- Length and phase count of conductor that would be replaced along with newly hardened structures; and
- Vegetation, distance to a road, and terrain type for the structures to be hardened.

Each of these values creates the scope for each of the projects. 1898 & Co. collaborated with Entergy Louisiana to develop unit costs estimates, which are multiplied by the scope activity (asset counts and lengths) and other cost drivers (vegetation, access, and terrain) to calculate the project cost.

6.2.1.2 Overhead to Underground Conversion

For each project, Entergy Louisiana's GIS data was used to determine the length of overhead conductor to be converted to underground, and additional GIS analysis determined the population density used for the cost per mile rate in rural, suburban, and urban areas.

6.2.2 Transmission Rebuild

For each transmission project, Entergy Louisiana's GIS data, GIS analysis for vegetation, underlying terrain, and road access were leveraged to estimate:

- Number of structures that need to be hardened to meet the desired wind standard;
- Length of conductor that would be replaced along with newly hardened structures; and
- Vegetation, distance to a road, and terrain type for the structures to be hardened.

Each of these values creates the scope for each of the projects. 1898 & Co. collaborated with Entergy Louisiana to develop unit costs estimates, which are multiplied by the scope activity (asset counts and lengths) and other cost drivers (vegetation, access, and terrain) to calculate the project cost.

6.2.3 Substation Control House Roof Remediation

Control house roof remediation costs are dependent on several factors. The condition of the roof, its vintage, and its size all determine what type of remediation is needed to get the roof up to the wind standard. Entergy's substation and transmission teams provided a base cost for substation storm surge mitigation projects that was intended to be generally conservative. As Entergy Louisiana is working through the portfolio, it will identify the mitigation measures needed and develop scoping-level costs specific to each substation project.

6.2.4 Substation Storm Surge Mitigation

Substations are a complex system of assets. Although the modeling done by 1898 & Co. identifies substations that are at risk of storm surge flooding, the mitigation measures required may differ widely from substation to substation. Therefore, the costs can vary widely as well. Entergy's substation and transmission teams provided a base cost for substation storm surge mitigation projects that was intended to be generally conservative. As Entergy Louisiana is working through the portfolio, it will identify the mitigation measures needed and develop scoping-level costs specific to each substation project.

6.3 Resilience-weighted Life-Cycle Benefit

The benefits of storm resilience projects are driven by the frequency, intensity, and location of future major storm events over the next 50 years. Each storm type has a range of potential probabilities and consequences. For this reason, the Storm Resilience Model employs stochastic modeling, specifically, Monte Carlo Simulation. Monte Carlo Simulation is a random sampling methodology.

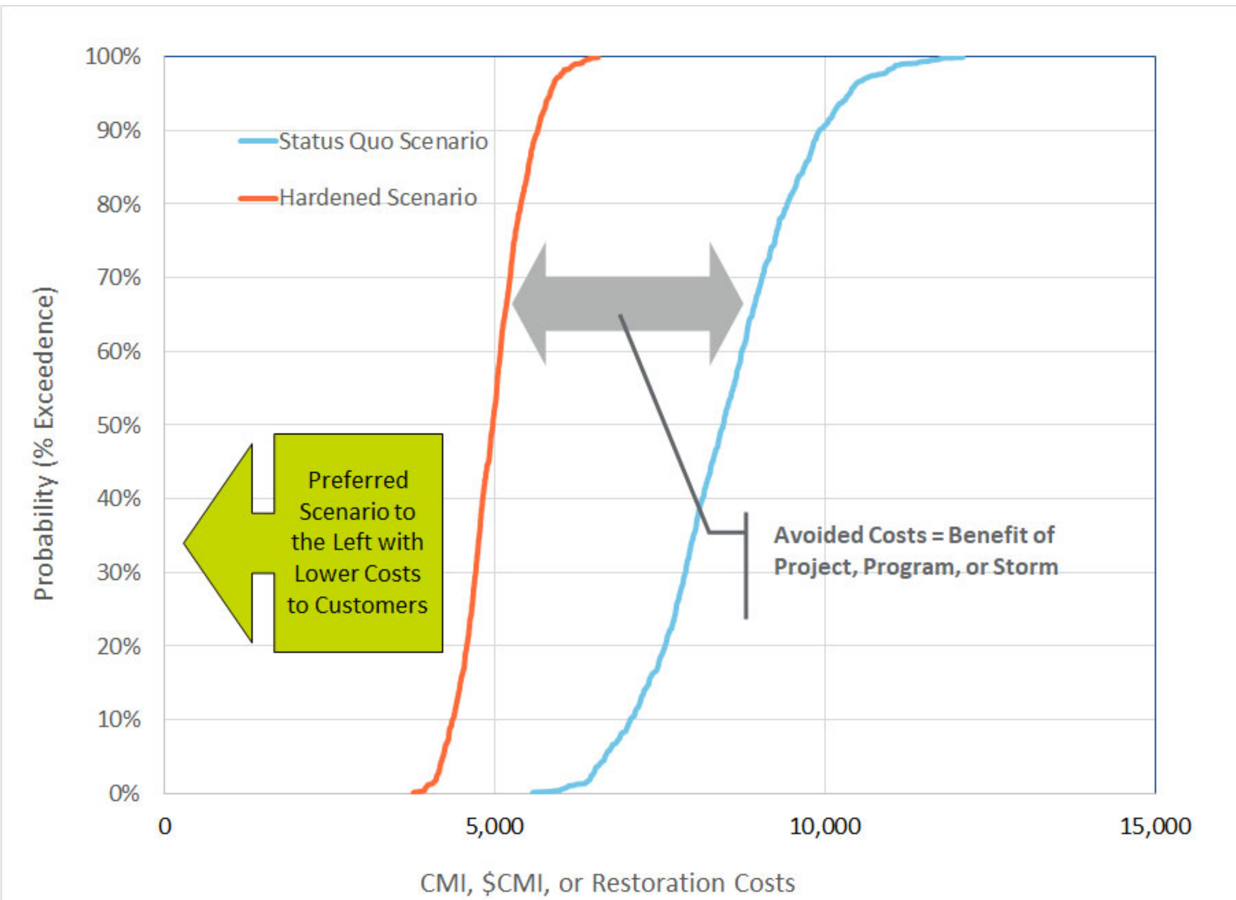
In the context of the Storm Resilience Model, the Monte Carlo simulator selects the major storm events to impact the Entergy Louisiana service area over the next 50 years from the Major Storms Event Database (Section 4.0). That database outlines the 'universe' of storm event types that could impact the Entergy Louisiana service area.

During the Monte Carlo simulation, each of the system sections is subjected to the range of 49 storm types and frequencies discussed in Section 4.0. For each iteration, storm types, and system section, the Monte Carlo simulator looks that the range of 50-year frequencies and selects the annual frequency for that iteration. For sections of the system where a storm type is not a valid choice, the Monte Carlo chooses zero percent. An example is for Northern Louisiana, where hurricanes are extremely unlikely to remain a category 5 when they reach these system sections; so, for these system sections, storm types with a category 5 hurricane are chosen to be zero percent by the Monte Carlo simulation. Once the annual probability is selected for a system section, it is used in that iteration for each project developed from the Storm Impact Model.

Once an annual frequency is calculated for all storm types in a system section, the Monte Carlo simulator determines the benefits that each project provides annually under each iteration and its storm probability choices. Using information from the Storm Impact Model, the Monte Carlo simulator chooses a Status Quo value for each project and the benefits if that project were to be hardened, both under the same storm type. The Monte Carlo simulator performs these calculations for each project for 1,000 iterations.

The results of the 1,000 iterations are graphed in a cumulative density function, also known as an 'S-Curve'. The figure below shows an illustrative example of the 1,000 iteration simulation results for the 'Status Quo' and Hardened Scenarios. The resilience benefit of the project, program, or plan is the gap between the S-curves for the top part of the curve. Section 2.4 describes this in further detail.

Figure 6-1: Status Quo and Hardened Results Distribution Example



7.0 INVESTMENT OPTIMIZATION AND PROJECT SELECTION

The Storm Resilience Model consistently models the benefits of all potential hardening projects for an 'apples to apples' comparison. Sections 3.0, 4.0, 5.0, and 6.0 described the approach and methodology to calculate the resilience benefit for the nearly 170,000 potential hardening projects. Resilience benefit values include:

- CMI 50-year Benefit
- Restoration Cost 50-year PV Benefit
- Lifecycle 50-year PV gross Benefit (monetized CMI benefit + restoration cost benefit)
- Lifecycle 50-year PV net Benefit (monetized CMI benefit + restoration cost benefit – project costs)

Each of these values includes a distribution of results from the 1,000 iterations. For ease of understanding and in alignment with the resilience base strategy, the approach focuses on the values for the average storm futures and above, specifically considering:

- P50 – Average Storm Future
- P75 – High Storm Future
- P95 – Extreme Storm Future

The following sections discuss the prioritization metric, Investment Optimization, and approach to developing the Comprehensive Hardening Plan.

7.1 Prioritization Metric – Resilience Benefit Cost Ratio

With all the projects being evaluated on a consistent basis, they can all be ranked against each other and compared. The Storm Resilience Model ranks all the projects based on their benefit cost ratio using the life cycle 50-year PV gross benefit value listed above. The ranking is performed for each of the following storm futures as well as a weighting of the three.

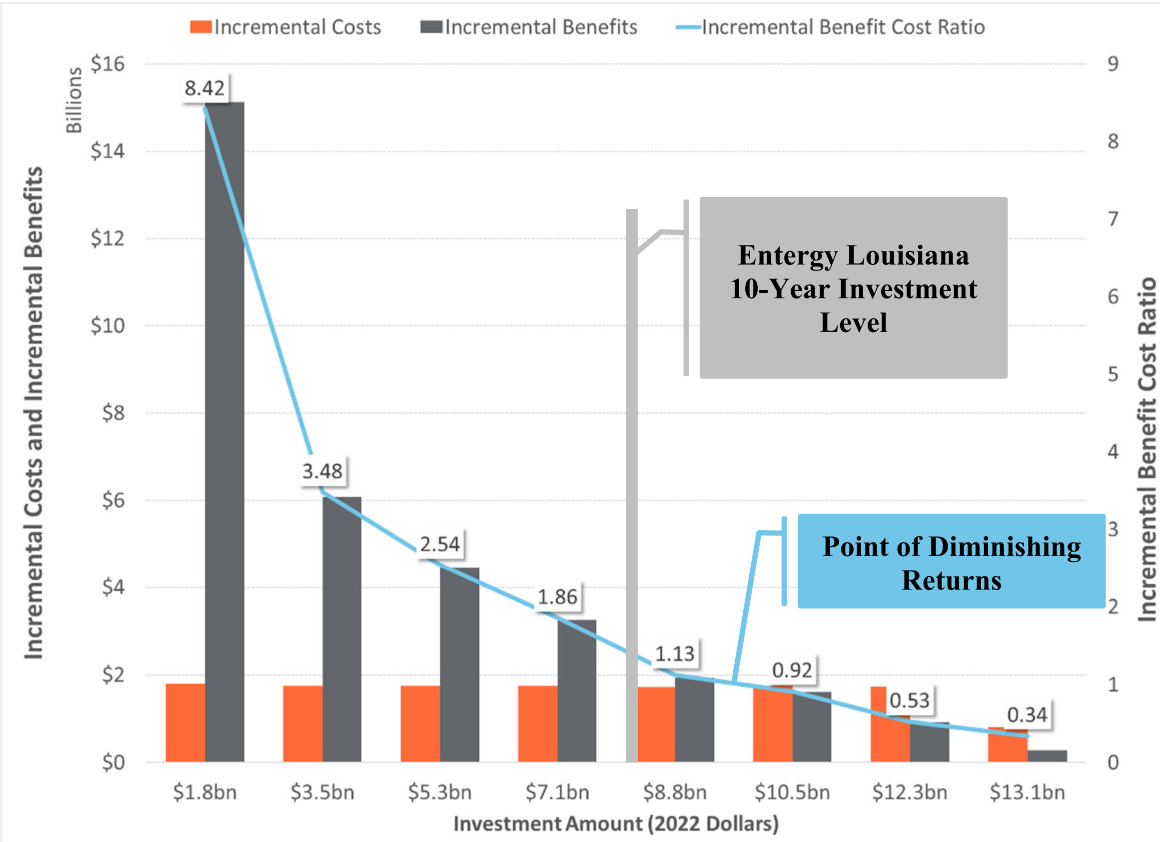
- Average Storm Future
- High Storm Future
- Extreme Storm Future

Performing prioritization for the four benefit cost ratios is important since each project has a different slope in its benefits from an average storm future to a very high storm future. Entergy Louisiana and 1898 & Co. settled on weighting the three values for the base prioritization metric.

7.2 Investment Optimization

Entergy Louisiana and 1898 & Co. utilized a resilience-based planning approach to understand the 'point of diminishing' returns and identify and prioritize resilience investment in the T&D systems. It would cost approximately $22 billion (2022 dollars) to harden all Entergy Louisiana infrastructure. Given the total level of potential investment, the Investment Optimization analysis was performed in approximately $1.8 billion increments ($1.8B in 2022 dollars is approximately $2.0 billion in nominal terms when escalated) up to $13.1 billion (in 2022 dollars). Figure 7-1 shows the results of the Investment Optimization analysis comparing the incremental costs to the incremental benefits at each investment level.

Figure 7-1: Investment Optimization Results



The figure shows the that the point of diminishing returns occurs at an investment level of approximately $9.4 billion in 2022 dollars (linearly interpolating between $8.8b and $10.5b scenario); when that level of investment is exceeded, the incremental costs begin to exceed the incremental benefits. Approximately $7.6 billion (in 2022 dollars) is Entergy Louisiana's recommended investment level based on technical constraints where the incremental benefit cost ratio is approximately 1.5. Section 7.1 shows the benefit cost ratio for the overall investment level. While additional investments could be made that would provide value to customers, technical execution constraints due to labor and materials availability constrained the overall investment level, not the business justification.

Resilience-based planning establishes an overall investment level with the following principles:

1. Fundamentally mitigating the impact of major disruptions to system stakeholders, for storm resilience events that includes maximizing the decrease in restoration costs and customer outages.
2. Investing in infrastructure upgrades that provide customer benefits that outweigh their costs.

3. Establishing a portfolio of projects, and the resulting funding level, that is executable given labor, materials, and other constraints.

Figure 1-2 shows that the first $2 billion of investment provides the most benefit to customers per dollar invested, with a benefit cost ratio of 8.4. This level of benefit meets the second and third principles outlined above but would leave a significant number of customers still exposed to major events and not meeting principle number 1 above. An investment level of approximately $9.4 billion (2022 dollars), the 'point of diminishing returns' meets principles one and two, but violates principle three. Entergy's investment level of approximately $7.6 billion (2022 dollars) or $8.8 billion (nominal dollars) meets all three principles outlined above.

7.3 Comprehensive Hardening Plan Portfolio Development

With a resilience plan investment level identified using analysis of diminishing returns, additional factors were incorporated to develop a recommended plan that is feasible, given what information Entergy Louisiana has regarding supply chain, labor, and other market conditions. The summary of factors and assumptions is outlined below.

- Annual equipment installation limits are imposed on the portfolio based on projected material supply availability in upcoming years for structures and transformers.
- Project earliest start year assumptions for ELL and T&D wind zone rating. The plan focuses on the Gulf Coast region in early years of the plan due to the higher relative risk and the amount of work required over the entire 10 years to harden the system
- All projects on a given circuit must be completed in a 2 year window. This helps organize and sequence projects so that crews can be efficiently mobilized and demobilized around the system to construct the portfolio.

8.0 RESULTS & CONCLUSIONS

Entergy Louisiana and 1898 & Co. utilized a resilience-based planning approach to identify and prioritize resilience investment in the T&D systems. This section presents the costs and benefits of Entergy Louisiana's Comprehensive Hardening Plan. Customer benefits are shown in terms of the:

1. Decrease in the Storm Restoration Costs
2. Decrease in the customers impacted and the duration of the overall outage, calculated as CMI

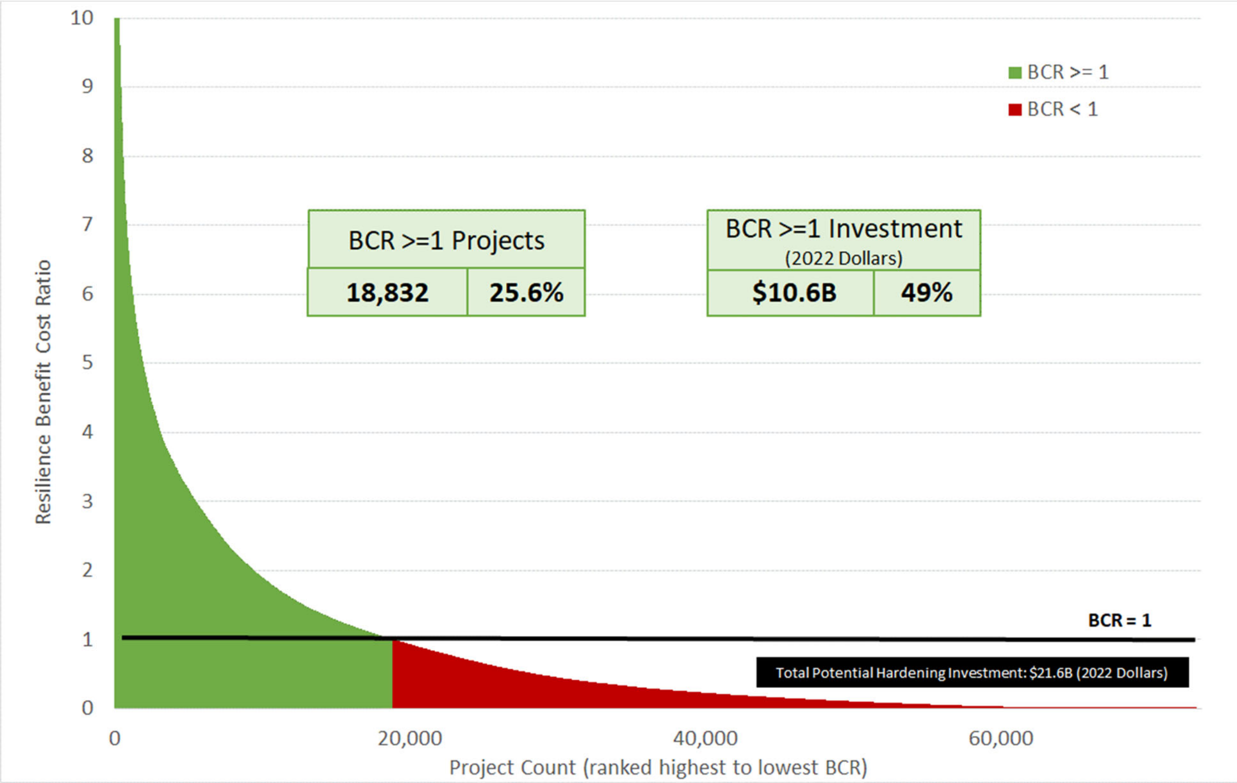
Additionally, the results are presented assuming monetization of the CMI using the ICE Calculator, modified for resilience. The ICE Calculator is discussed in Section 3.9. The monetization of the CMI allows for the calculation of a benefit cost ratio for each project. As discussed above, this was done for the purposes of allowing Entergy Louisiana to prioritize projects and establish overall investment levels.

8.1 Resilience Benefit Cost Ratio

As discussed above in Section 7.1, the Storm Resilience Model calculates the Resilience Benefit Cost Ratio for project prioritization purposes. The Resilience Benefit Cost Ratio ("BCR") is the sum of the avoided restoration cost and the monetized avoided customer outages divided by the project cost. A weighted value of the BCRs for different storm futures is used to calculate the final Resilience Benefit Cost Ratio for each hardening project.

Figure 8-1 shows the results of the Resilience Benefit Cost Ratio for all preferred potential hardening projects across the Entergy Louisiana service area. Each alternative (e.g., hardened rebuild vs undergrounding) was given a BCR, and the higher BCR is preferred. The preferred potential hardening project is the overhead hardening or undergrounding alternative that provides the higher Resilience Benefit Cost Ratio. The figure shows approximately 74,000 potential hardening projects for a total potential hardening investment of $22 billion in today's terms. Figure 8-1 shows that approximately 26 percent of the potential hardening projects have a Resilience Benefit Cost Ratio greater than 1. The figure also shows that approximately $10.6 billion of investment has a Resilience Benefit Cost Ratio greater than 1. This is equivalent to 49 percent of the total hardening investments. Most of the projects with a positive Resilience Benefit Cost Ratio are in the 1 to 10 range.

Figure 8-1: Project Resilience Benefit Cost Ratio Summary



8.2 Storm Resilience Ten Year Investment Profile

As outlined above, the Resilience Benefit Cost Ratio results for each potential hardening project were used to prioritize investments based on investment and execution constraints. Additionally, the Resilience Benefit Cost Ratio was leveraged to identify the point of diminishing returns. Section 7.0 describes the process to develop the Comprehensive Hardening Plan based on the Resilience Benefit Cost Ratio results shown in Section 8.1.

Table 8-1 shows the Comprehensive Hardening Plan investment profile. The table includes the build-up by program to the total. The investment capital costs are in nominal dollars, the dollars of that day. The plan is approximately $8.8 billion in nominal terms or $7.6 billion in 2022 dollars. Feeder hardening rebuilds make up most of the total, accounting for 48 percent of the total investment. Lateral hardening is next, with 28 percent. Transmission hardening follows with 17 percent. Lateral undergrounding makes up 5 percent, while feeder undergrounding, substation control house remediation, and substation storm surge mitigation make up the final 2 percent.

Table 8-1: Comprehensive Hardening Plan Investment Profile by Program (Nominal $000)

Year	Distribution Feeder Hardening (Rebuild)	Distribution Feeder OH to UG Conversion	Lateral Hardening (Rebuild)	Lateral OH to UG Conversion	Transmission Rebuild	Substation Control House Remediation	Substation Storm Surge Mitigation	Total
2023	$0	$0	$54,700	$0	$0	$700	$3,800	**$59,200**
2024	$48,000	$0	$252,700	$26,648	$11,800	$3,100	$16,900	**$359,148**
2025	$382,100	$0	$281,900	$68,260	$80,500	$5,000	$40,900	**$858,660**
2026	$556,200	$25,800	$257,600	$61,062	$258,400	$3,400	$51,200	**$1,213,662**
2027	$364,000	$5,800	$241,300	$29,273	$271,300	$0	$27,800	**$939,473**
2028	$532,200	$0	$269,100	$49,533	$326,900	$0	$5,000	**$1,182,733**
2029	$555,300	$0	$319,900	$42,690	$217,500	$0	$5,600	**$1,140,990**
2030	$513,300	$0	$250,000	$58,223	$226,200	$0	$5,300	**$1,053,023**
2031	$419,700	$0	$166,000	$50,045	$133,100	$0	$3,600	**$772,445**
2032	$222,100	$0	$261,900	$25,311	$12,200	$0	$0	**$521,511**
2033	$441,100	$0	$74,800	$20,403	$0	$0	$0	**$536,303**
2034	$183,900	$7,800	$15,900	$1,210	$0	$0	$0	**$208,810**
Total	**$4,217,900**	**$39,400**	**$2,445,800**	**$432,659**	**$1,537,900**	**$12,200**	**$160,100**	**$8,845,959**

8.3 Storm Resilience Benefits Summary

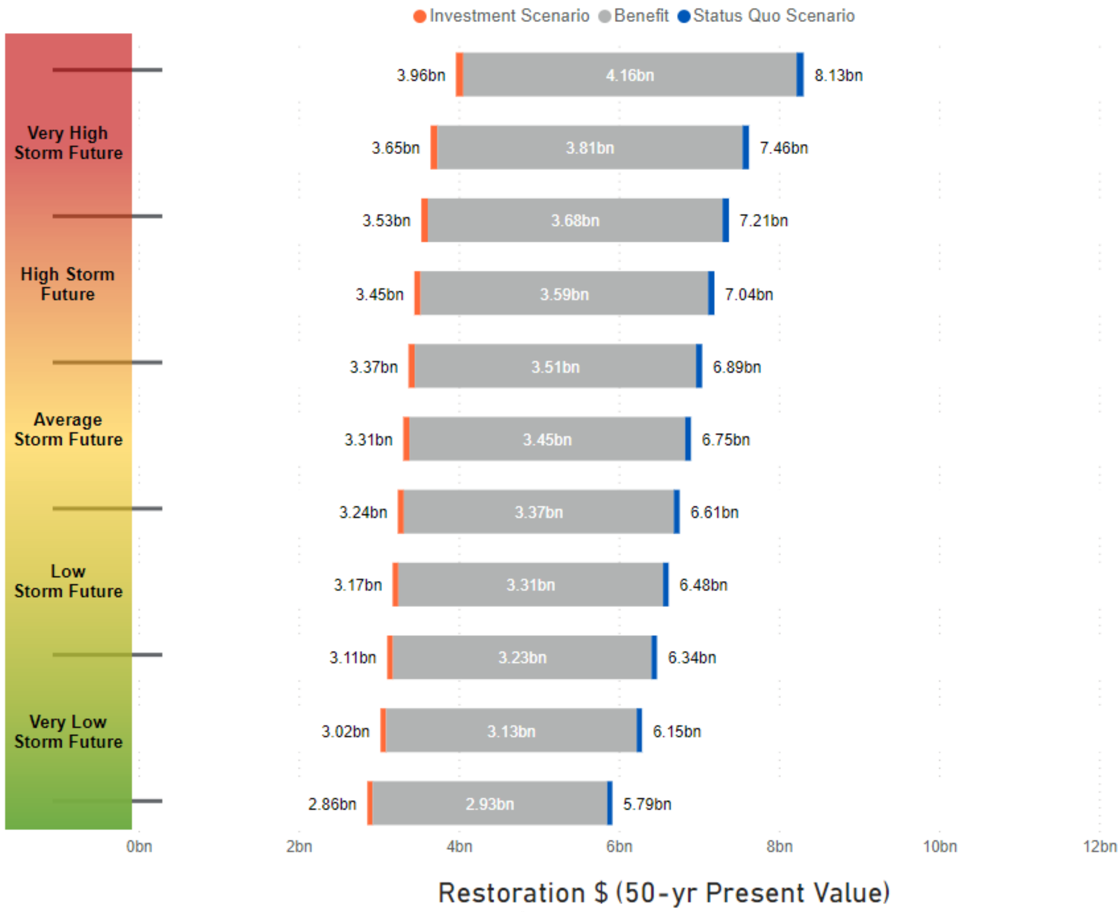
The resilience-based planning evaluation employed for the Entergy Louisiana Comprehensive Hardening Plan is customer centric. This section shows the expected customer centric benefits of the $8.8 billion investment plan from Section 8.2. It also shows the results based on the monetization of the avoided customer outages. The following sub-sections show the results in terms of restoration costs reduction and reduction in customer minutes interrupted.

8.3.1 Avoided Restoration Cost Benefits

Figure 8-2 shows the range in restoration cost reduction at various storm futures. The values are shown in 50-year present value terms. It should be noted that the figure does not include the $8.8 billion of investment; it only shows the benefits if the plan is executed over the next 10 years.

As a refresher, the very low storm future level represents a future world in which storm frequency and impact are less than average, the average storm future level represents a future world where storms frequency and impact are reflective of historical trends discussed in Section 4.3. The very high storm future levels represent a future world where storm frequency and impact are all high.

Figure 8-2: Comprehensive Hardening Plan Restoration Cost Benefit

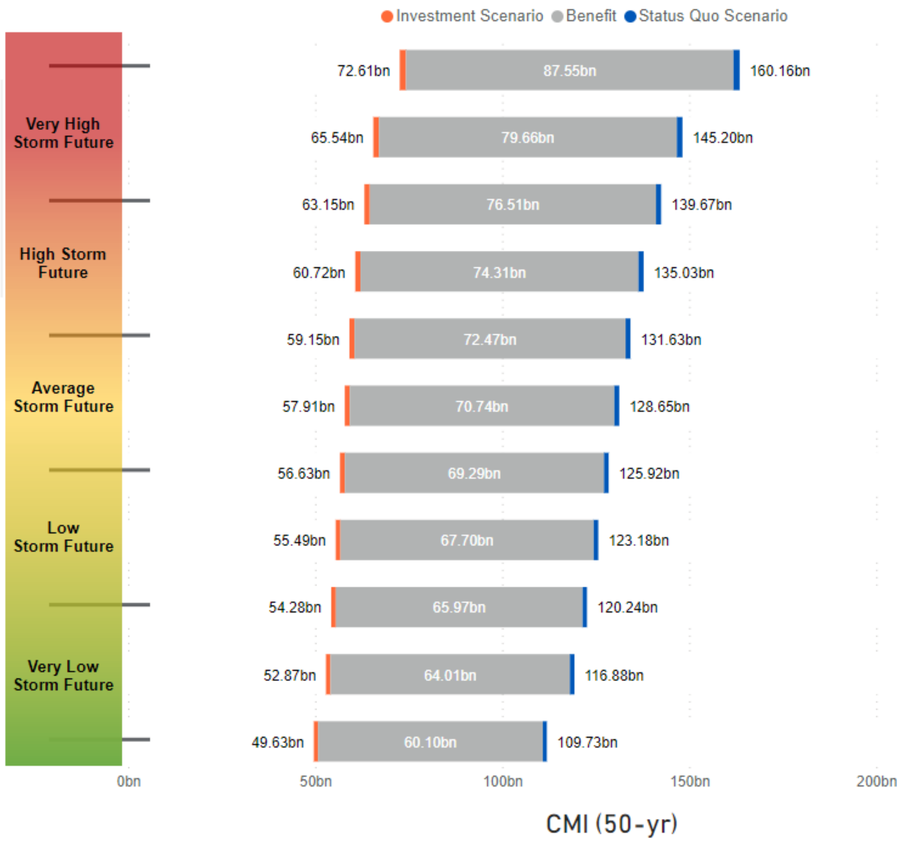


The figure shows that the 50-year PV of future storm restoration costs in a Status Quo scenario from a resilience perspective is $5.8 billion to $8.1 billion. With the Comprehensive Hardening Plan, the storm restoration costs decrease by approximately 50 percent across all storm futures. The decrease in restoration costs is approximately $2.9 billion to $4.2 billion. From a present value perspective, the benefit attributable to decreased (avoided) restoration costs, expressed in 2022 dollars, represents approximately 37 to 54 percent of the total plan costs in 2022 dollars. In other words, the avoided restoration cost benefits alone pay for approximately 37 to 54 percent of the investment plan. Avoided storm CMI benefit covers the remaining 46 to 63 percent of the plan investment.

8.3.2 Avoided Customer Outage Benefit

Figure 8-3 shows the range in avoided storm CMI at various storm futures. The values are shown for a 50-year period. The figure shows the 50-year total of future storm CMI in a Status Quo scenario from a resilience perspective ranges from 109.7 billion to 160.2 billion. Assuming approximately one million customers for Entergy Louisiana, this is equivalent to approximately 37 to 53 storm outage hours per year per customer for the Status Quo scenario. With the Comprehensive Hardening Plan, customer outages, storm CMI, from major storm events decrease by approximately 55 percent.

Figure 8-3: Comprehensive Hardening Plan Customer Benefit



8.4 Investment Plan Resilience Benefit Cost Ratio

Section 8.1 shows the Resilience Benefit Cost Ratio results for all the individual projects. This section shows the Resilience Benefit Cost Ratio for the investment portfolio. It also includes the path from the two main benefit streams (Section 8.3) to calculating the Resilience Benefit Cost Ratio. It is important to note that the business case of the Comprehensive Hardening Plan is based upon the avoided restoration costs and avoided customer outages that reasonably can be expected to be achieved from the proposed investment. The Resilience Benefit Cost Ratio results for the investment plan are only presented to show weighted average project prioritization for the portfolio.

A key piece of that path is the monetization of the storm CMI. Figure 8-4 shows the companion figure to Figure 8-3 based on the monetization of the storm CMI using the DOE ICE Calculator modified for resilience purposes. The values are shown in 50-year present value terms. It should be noted that the figure does not include the $8.8 billion of investment; it only shows the benefits if the plan is executed over the next 10 years.

Figure 8-5 shows the sum of the restoration cost (Figure 8-2) and monetized CMI (Figure 8-4) for the Status Quo and Storm Resilience Investment Plan scenarios.

Figure 8-4: Comprehensive Hardening Plan Monetized Customer Benefit

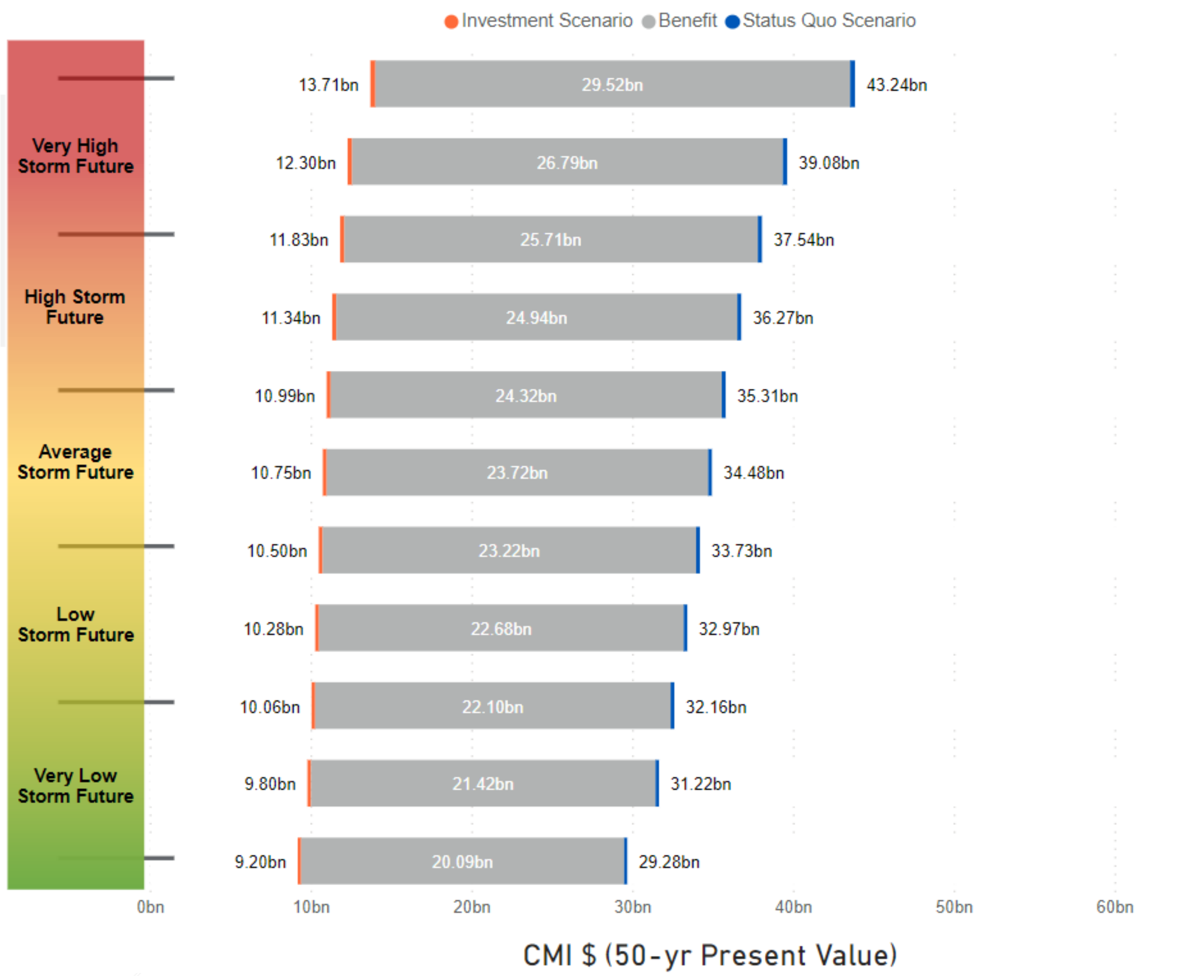


Figure 8-5: Comprehensive Hardening Plan Total Monetized Benefit (Restoration + $CMI)

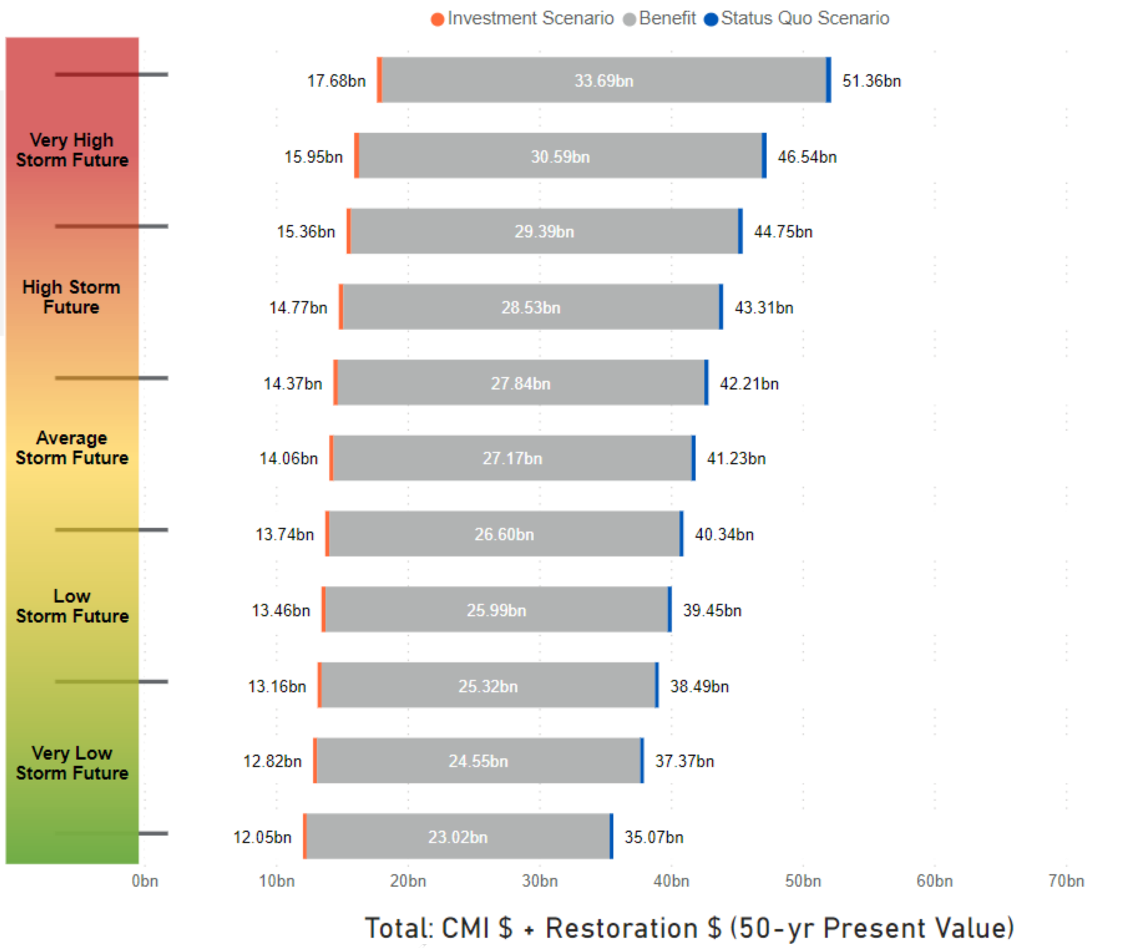


Figure 8-6 takes the benefits from Figure 8-5, the 'grey areas', and shows the portion of the total monetized benefit that comes from the avoided restoration costs and the portion from the monetized avoided customer outages. The figure also includes the total cost of the Comprehensive Hardening Plan in 2022 dollars, approximately $7.6 billion.

Figure 8-6: Gross Benefit vs Costs

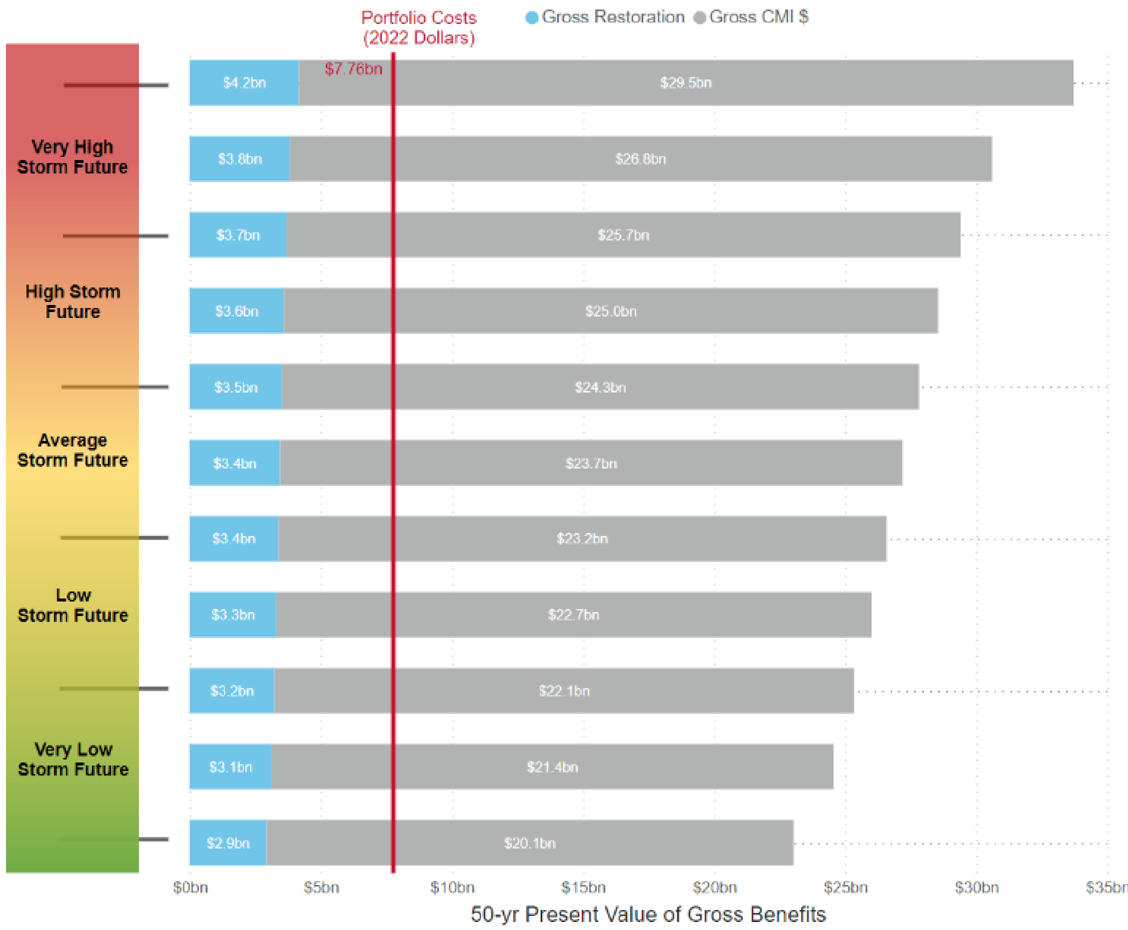
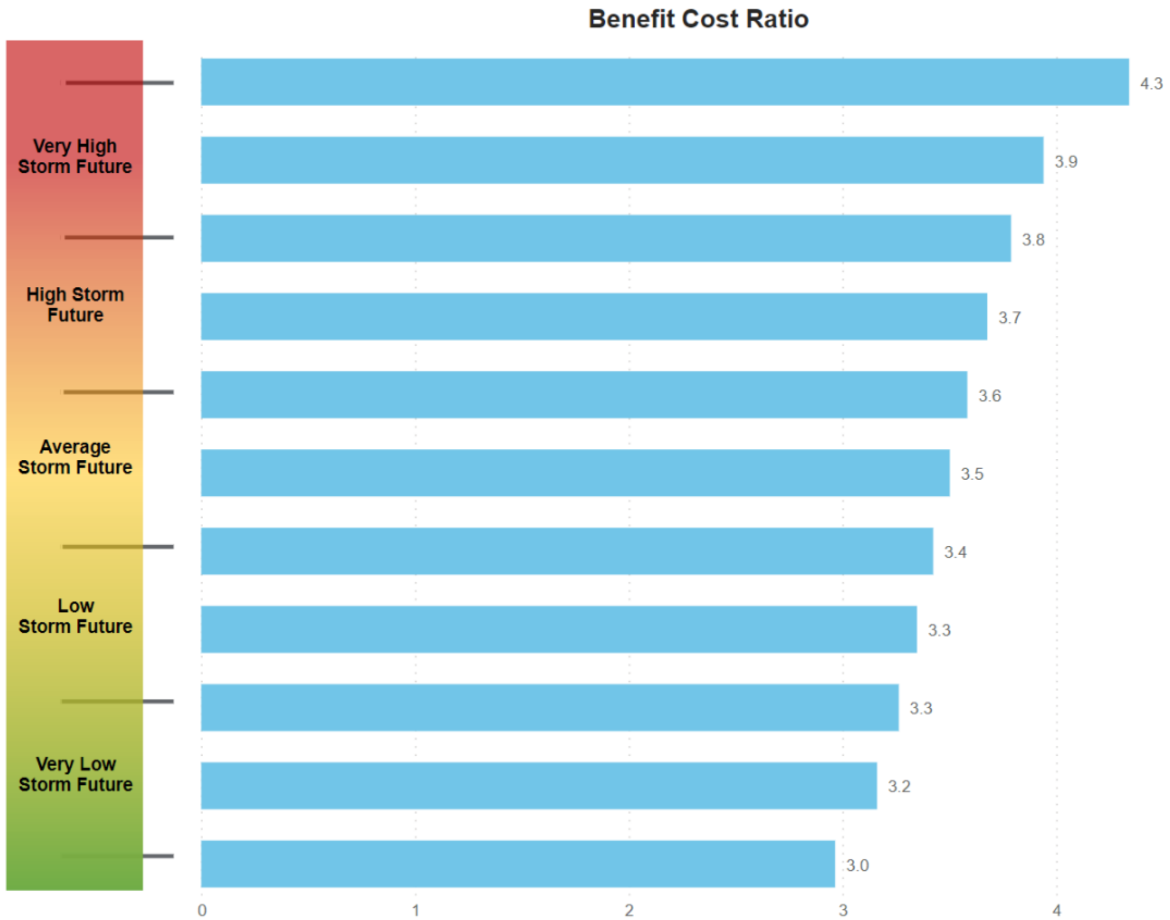


Figure 8-7 converts the gross benefits and costs from Figure 8-6 into the Resilience Benefit Cost Ratio for the Storm Resilience Investment Plan. Figure 8-7 shows that the overall investment plan has a Resilience Benefit Cost Ratio as low as 3.0 in a very low storm future and as high as 4.3 in a very high storm future scenario. The average storm future scenario has a Resilience Benefit Cost Ratio of 3.5. This figure and the others above show that Entergy Louisiana's Comprehensive Hardening Plan reasonably can be expected to provide significant benefits to customers in excess of cost.

Figure 8-7: Portfolio Resilience Benefit Cost Ratio



8.5 Conclusions

The following include the conclusions of Entergy Louisiana's Comprehensive Hardening Plan evaluated within the Storm Resilience Model:

- The overall investment level of $8.8 billion (nominal dollars) for Entergy Louisiana's Comprehensive Hardening Plan provides significant benefits for customers, is reasonable, and provides customers with optimal benefits given execution constraints. The Investment Optimization analysis (see Figure 7-1) shows that the overall investment level is below the point of diminishing returns (i.e., below the point at which an incremental dollar spent produces benefits of less than a dollar in return) showing over-investment is not occurring. In fact, more investment could be made to decrease the impact to customers if execution constraints did not exist.

- Entergy Louisiana's Comprehensive Hardening Plan is reasonably projected to produce a reduction in storm restoration costs of approximately 50 percent. In relation to the plan's capital investment, the amount of the restoration costs savings (expressed in 2022 dollars), ranges from 37 to 54 percent of the total plan cost (in 2022 dollars) depending on future storm frequency and impacts. In other words, the avoided restoration cost benefits alone pay for approximately 37 to 54 percent of the investment plan.
- The projected customer minutes interrupted decrease by approximately 55 percent over the next 50 years. This decrease includes eliminating outages, reducing the number of customers interrupted, and decreasing the length of the outage time.
- Based on the monetization of outage assumptions, the investment plan provides Resilience Benefit Cost Ratios in the 3.0 to 4.3 range showing significant benefits to customers.
- Entergy Louisiana's mix of hardening investment strikes a balance between investment in the substations and transmission system targeted mainly at increasing resilience for the high impact/low probability events and investment in the distribution system, which increases resilience for all ranges of event types.
- The plan will benefit all Entergy Louisiana customers. The avoided storm restoration costs are shared by all customers. Additionally, customers will experience fewer storm outages from both direct and indirect factors. Direct benefits are realized by those customers whose infrastructure directly upstream was hardened. Indirect benefits are realized by all customers since storm restoration crews will be able to rebuild the system quicker because less infrastructure will fail.
- The hardening investment benefits are conservative. Firstly, the benefits outlined above are only direct benefits of investments to specific investments in the grid and do not factor in the indirect benefits from lower overall storm restoration durations. Secondly, the investments will also provide 'blue sky' benefits from decreased outages that occur during non-major storm days. Third, the evaluation did not take into account other utilities served by the Entergy Louisiana transmission system who would reasonably benefit from the transmission hardening investments. These additional benefits streams are not factored into the evaluation

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BEFORE THE

LOUISIANA PUBLIC SERVICE COMMISSION

***IN RE*: APPLICATION OF ENTERGY LOUISIANA, LLC FOR APPROVAL OF THE ENTERGY FUTURE READY RESILIENCE PLAN (PHASE I)**	**))))**	**DOCKET NO. U- _______**

DIRECT TESTIMONY

OF

TODD A. SHIPMAN, CFA

ON BEHALF OF

ENTERGY LOUISIANA LLC

DECEMBER 2022

TABLE OF CONTENTS

LIST OF EXHIBITS

I. INTRODUCTION

Q1. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Todd A. Shipman. My business address is 51 Woodsneck Rd., Orleans, MA 02653. I am a Principal with Utility Credit Consultancy LLC.

Q2. ON WHOSE BEHALF ARE YOU SUBMITTING THIS TESTIMONY?

A. I am testifying on behalf of Entergy Louisiana, LLC ("ELL" or "Company"). ELL is a wholly owned electric utility subsidiary of Entergy Corporation ("Entergy").

Q3. WHAT IS YOUR EDUCATION AND BUSINESS EXPERIENCE?

A. I graduated from Texas Christian University with a Bachelor of Business Administration (B.B.A.) degree with a major in economics and from Texas Tech University School of Law with a Juris Doctor (J.D.) degree. I was awarded the Chartered Financial Analyst (C.F.A.) designation in 1989. I have over 37 years of experience in the financial services and utility industries. I began in the financial services industry as an analyst with a research firm that specialized in analyzing and reporting the investment implications of the actions and behavior of utility regulators. Subscribers to the research included investment bankers and analysts at major Wall Street firms, large institutional investors such as insurance companies and mutual funds, utilities, and regulators. I then joined an independent power producer Sithe Energies Inc. ("Sithe"). My primary responsibility was in regulatory affairs, and I coordinated Sithe's participation in state regulatory proceedings.

I spent 21 years at S&P Global Ratings ("S&P"), a major ratings agency that has been in business over 150 years and issues more than one million ratings on over $46 trillion of debt across all global capital markets. I performed credit surveillance of utilities and pipelines, midstream energy, and diversified energy companies. I was the primary analyst on over 150 different issuers during my tenure at S&P. In the final ten years, I was the Sector Specialist on the North American utilities team. In that role, I was the sector lead analyst charged with ensuring ratings quality, assisting in the training and development of new analysts, and creating and refining the criteria used to establish ratings on utilities. I also led outreach efforts to investors and the regulatory community and performed a lead analytical role in the development and application of global ratings criteria for hybrid capital securities such as preferred stock.

After retiring from S&P, I became a management consultant specializing in advising utilities and other entities on credit and ratings issues, balance sheet management, and capital markets strategies. I was also an adjunct faculty member of Boston University's Questrom School of Business, where I taught advanced undergraduate courses in corporate finance and capital markets. My curriculum vitae is provided as Exhibit TAS-1.

Q4. HAVE YOU PREVIOUSLY SPONSORED TESTIMONY BEFORE REGULATORY AUTHORITIES?

A. Yes. I have submitted testimony to the Federal Energy Regulatory Commission, the Hawaii Public Utilities Commission, the Wisconsin Public Service Commission, the California Public Utilities Commission, the New York Public Service Commission, the

Virginia State Corporation Commission, the Mississippi Public Service Commission, the Public Utility Commission of Texas, the New Mexico Public Regulation Commission, the Arizona Corporation Commission, and the Washington Utilities and Transportation Commission. A list of filings and testimonies since I began consulting is provided in Exhibit TAS-2.

Q5. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to apprise the Louisiana Public Service Commission ("Commission") on the likely reaction of the credit rating agencies monitoring ELL – Moody's Investor Service ("Moody's") and S&P Global Ratings ("S&P") – to the proposed multi-year Entergy Future Ready Resilience Plan ("Resilience Plan") and the accompanying proposed Resilience Plan Cost Recovery Rider that I have reviewed. By way of background, I explain what credit ratings are, the importance of utility credit ratings to regulators, and the analytical framework used for determining utility credit ratings. I also provide information regarding the overall utility industry's financial outlook from a ratings perspective. I then summarize ELL's current credit ratings and outlook, and, in that context, I opine on how Moody's and S&P may react to ELL's proposals.

Q6. WHY ARE YOU QUALIFIED TO OPINE ON THESE MATTERS?

A. I am qualified to opine on these matters because of the degree and scope of my involvement in rating utilities and other energy companies over many decades. For instance, as Sector Specialist at S&P, I chaired a vast majority of the rating committees conducted over more than a decade. The chairperson role is critical to achieving effective committee deliberations and assuring a fully vetted ratings opinion. Along with the primary analyst, the chairperson has the most influence over the ratings that emerge from each committee. The chairperson also brings a broader perspective to the committee to help them focus on how the proposed rating fits into the entire industry risk picture. In addition, I was the primary analyst on over 150 different issuers during my time at S&P. Between the two roles, my work had a direct and lasting effect on the ratings of every investor-owned utility in the United States ("U.S.") and Canada, and therefore the rates of a large majority of electricity customers in North America.

The breadth of my ratings experience beyond the utility industry also informs my perspective when opining on ratings matters. Prior to specializing in utilities, I followed many types of energy companies along the energy value chain, from upstream (oil & gas producers) to midstream (natural gas and petroleum products, pipelines, refiners) to downstream (natural gas distributors, energy marketers). My role in developing S&P's published ratings criteria exposed me to all corporate issuer ratings across all industries, as well as insurance and structured finance ratings. Furthermore, I participated in the major modification and rewriting of S&P's corporate ratings methodology in 2013 and wrote most of the utilities-related elements in the methodology.[1] For example, most U.S. utilities are assessed on financial risk using the "medial volatility" set of metric

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[1] S&P, *Criteria | Corporates | General: Corporate Methodology, Dec. 5, 2021 (originally published Nov. 19, 2013),* S&P, *Criteria | Corporates | Utilities: Key Credit Factors for the Regulated Utilities Industry*, July 7, 2021 (*originally published Nov. 19, 2013*).

benchmarks. I conceived, designed, and named the benchmarks, which sit between the standard table and low-volatility table.[2]

Q7. PLEASE SUMMARIZE YOUR CONCLUSIONS AND RECOMMENDATIONS.

A. My conclusions and recommendations are as follows:

- Credit ratings directly affect a utility's cost of capital supporting utility infrastructure investment and thereby directly affect customers' rates with higher credit ratings lowering a utility's cost of capital. Credit ratings agencies base their credit ratings on both qualitative factors to assess a utility's business risk and quantitative factors to assess a utility's financial risk. Regulatory environment is the most important element in the credit ratings analysis of a utility. Credit rating agencies examine regulatory environment in their business risk assessment. In that assessment, credit rating agencies consider the regulatory framework, the mechanics of regulation (*e.g.*, how long does it take rates to adjust to cost changes), and the consistency and transparency of regulation. Regulatory environment, however, also affects a utility's financial risk because of rate setting.
- The present time is an especially vulnerable period for utility ratings due to the confluence of so many threats to the financial integrity of utilities beyond their control: rising inflation, rising interest rates, the need to invest heavily in the energy transition amid growing environmental, social, and governance risks being scrutinized, and the weakened cash flow position from which utilities are entering this

[2] *See* S&P, *Criteria | Corporates | General: Corporate Methodology*, pp. 33-34.

heightened risk environment, with a significant contributing factor to this circumstance being the Tax Cut and Jobs Act of 2017 ("TCJA"). Accordingly, customers are likely to experience benefits if regulators use their authority constructively to reduce risks on which they have significant influence and to put downward pressure on capital costs.

- If the Commission does not show support for reducing storm restoration costs for customers through accelerated storm hardening of ELL's transmission and distribution infrastructure, like that proposed in ELL's Resilience Plan, then ELL is likely to experience adverse credit ratings actions and its customers are likely to see increasing costs of capital in the coming years. Such support should include approval of a rate recovery mechanism, such as ELL's proposed rider, that supports stable cash flow and mitigates financial risk. At the same time, there must be a balance between accelerated storm hardening and customer affordability so that the regulatory environment remains supportive.

II. CREDIT RATINGS AND CAPITAL MARKETS

Q8. WHAT IS A CREDIT RATING, AND WHAT DISTINGUISHES IT FROM OTHER MEASURES OF THE FINANCIAL CONDITION OF A UTILITY?

A. In its most narrow sense, a credit rating summarizes credit risk, which is the ability and willingness of an issuer of fixed income securities to fulfill its contractual financial obligations in full and on time. Ratings address the relative probability that an issuer or an issue will experience default, *i.e.*, the failure to pay either the required periodic payment or the principal when it matures under the terms of the security.

More broadly, credit ratings reflect a more comprehensive view of financial health than other, more familiar financial measures such as quarterly financial results, earnings per share, rate of return for a particular reporting period, and the market prices of a company's securities. Ratings are also an independent opinion offered by firms that have no financial stake in the outcome of their analyses. The *long-term* and *independent* nature of credit ratings makes them an ideal benchmark to assist utility regulators as they navigate the many decisions they must make as they balance competing interests. I think that as disinterested observers with a long-term mindset, rating agencies are well aligned with the perspectives of regulators.

Q9. WHAT DOES A CREDIT RATING AGENCY DO?

A. The primary role of a credit rating agency is to provide an assessment of the creditworthiness of a company or a financial instrument to facilitate access to fixed income capital markets at the most efficient cost. The agencies publish analyses of the issuers and issuances to communicate to the market with more detail the nuances of the current ratings, the analysis behind them, and the important factors driving the ratings and that could change ratings. Ratings are expressed in a series of letters, numbers, and/or symbols to encapsulate the relative creditworthiness of the entity or issue. The ratings scales of the two major rating agencies, S&P and Moody's, appear in Exhibit TAS-3.

As depicted in the ratings scale exhibit, ratings in the BBB/Baa category and above are considered "investment-grade" by market participants. Ratings below BBB-/Baa3 are known as "speculative-grade," or colloquially "junk," securities. Because a significant number of prominent and active investors are precluded from holding speculative-grade issues, the difference between investment-grade and speculative-grade ratings is profound and is recognized as such by rating agencies and market participants.

Q10. ARE CREDIT RATINGS A USEFUL AND ACCURATE MEASURE OF A COMPANY'S RISK PROFILE AND FINANCIAL STRENGTH?

A. Yes. The risk of default is a good proxy for overall risk and an issuer's financial strength. The default experience of issuers validates the usefulness of credit ratings as a measure of risk. According to Moody's, from 1994 through 2020 the five-year average, volume-weighted corporate bond default rate increases sequentially from one rating category to the next lower one in the ratings scale, from a low of 0.4% for the Aaa category to 39.3% for the combined "Caa-C" categories.[3] In other words, the risk to investors increases as you go down each step in the rating scale. This track record is the main reason investors pay attention to credit ratings. They have proven to be a reliable and transparent measure of risk over a long period of time.

Q11. WHO USES CREDIT RATINGS?

A. Investors consult them when making investment decisions on choosing companies for investment and the price that they will demand to lend to or invest in a company. Ratings are valuable to investors because they are based on a consistent approach to assessing risk across time. Investors generally fall into two basic categories with distinct risk appetites. Fixed-income investors (*e.g.*, lenders or bondholders) extend capital to a company in

[3] *See* Moody's Investor Service, *Sector-In-Depth, Default Trends – Global, Annual Default Study: Following a sharp rise in 2020, corporate defaults will drop in 2021*, at Ex. 48 (January 28, 2021).

exchange for a fixed return and the obligation to be repaid the original investment. Equity investors (*i.e.*, stockholders) receive only a residual return after all expenses are paid with no ability to demand a return of the investment. Fixed-income investors use ratings as one, very important consideration when deciding whether, and at what cost, to lend capital to a utility. Both fixed-income and equity investors use the credit analyses performed by rating agencies to help them understand the overall risk of an issuer.

Q12. HOW DO CREDIT RATINGS AND ACTIONS AFFECT A UTILITY AND ITS CUSTOMERS?

A. Credit ratings directly affect the cost of capital needed for investment and, thereby, drive overall customer rates.[4] Fixed-income investors and other creditors use ratings to assist them in determining the price they will charge the utility for the use of their money. The total price is the combination of the interest rate of the instrument and its initial value in relation to the stated amount on the instrument. There is an inverse relationship between debt cost and ratings: the higher the rating, the lower the cost. Equity investors (i.e., stockholders) also use credit ratings as a risk guide to help them decide when and at what price they will offer their capital to a utility. The more risk they detect, the greater return they will require to compensate them for bearing that risk. The effect is not as direct or precisely quantifiable as it is with fixed-income instruments, but in my experience equity investors often take notice of credit ratings and react to ratings upgrades and downgrades.

[4] Phillips, Charles F., Jr., *The Regulation of Public Utilities*, Arlington, Virginia: Public Utilities Reports, Inc., 1993, at p. 250.

Q13. HOW IS A CREDIT RATING DETERMINED?

A. The process begins with the preliminary credit assessment of the issuer. The primary analyst evaluates the creditworthiness as the first step and continually refines the evaluation as the process unfolds. The next step is meeting with the issuer's management to assess their effect on credit quality and elicit more information that is not always accessible from securities filings and other public sources. The primary analyst conducts the meeting with the assistance of senior analysts on the team. They question and challenge management to understand their commitment to credit quality, their grasp of business operations and financial matters, and their views of future strategy, capital plans, and financial policies that could affect creditworthiness. After analyzing the credit profile and incorporating the insights gleaned from the management meeting and follow-up interactions, the ratings process culminates in a rating committee.

Q14. WHAT IS THE ROLE OF THE RATING COMMITTEE?

A. Ratings are established by a committee of analysts that specialize in the industry or industries of the rated entity. When warranted, other analysts with relevant expertise in other areas needed to accurately assess the risk of an issuer will participate in the committee. Ratings conform to common standards of credit risk across all issuers, industries, and markets by employing consistently applied ratings criteria. The committee first decides on the issuer credit rating, which corresponds to the fundamental credit quality of the entity before any legal and structural considerations that inform the ratings on specific issues. The committee then assigns ratings to the various rated debt or other securities in the capital structure. After the committee has made its decisions, they are communicated to the public by publishing and disseminating the credit opinion. The process then returns to the beginning as the issuer and its ratings are placed under constant surveillance.

Q15. WHAT KIND OF ANALYSES GO INTO A CREDIT RATING?

A. The analysis is a two-fold examination comprised of *quantitative* elements and *qualitative* elements. The quantitative side of the analysis develops financial ratios and other metrics to analyze the financial risk of the issuer. The qualitative side is the assessment of business risk, which is built up from the broad macro risks at the country and industry level. After the broad risk environment is determined, the committee establishes the issuer's individual business risk within that business and economic environment.

Business risk and financial risk are best understood as complementary sides of the total risk of an entity. For example, two utilities, Utility A and Utility B, may have the same credit rating, but Utility A may have more business risk than Utility B. In such a situation, one would expect Utility A to have less financial risk to arrive at a particular rating. Because utilities are tightly regulated on financial matters that limit how much financial metrics can vary over time, I have found that it is more often that qualitative business risk drives ratings outcomes in the utility industry. This finding is supported by more than my experience. The utility credit analyses at Moody's and S&P are both designed to favor business risk slightly over financial risk considerations when arriving at a rating. Moody's is explicit in this bias, as the weighting in their scorecard for utilities is a 60%/40% split between business and financial factors.[5]

Q16. WHAT BUSINESS RISK CONSIDERATIONS CONSTITUTE THE QUALITATIVE SIDE OF CREDIT ANALYSIS?

A. For a utility, the main business risks are regulatory risk, operating risk, and cash flow diversity, but the first, regulatory risk, is *the* major factor in the analysis. Evaluating regulatory risk almost invariably circles back to cost recovery, notably full recovery of a utility's cost of capital, including the cost of both debt and equity, through a reasonable authorized return on rate base, that is, the utility's capital investment. The nature and pace of the process of recognizing an incurred cost as recoverable through rates is the paramount business risk factor for a utility credit analyst. The other elements of regulatory risk, such as the political influences on regulation, are analyzed to discern the risk surrounding the ultimate factor of covering all costs sufficiently to earn a reasonable return.

Q17. HOW IS REGULATORY RISK ANALYZED?

A. In the Moody's methodology for utilities, regulatory risk constitutes over 80% of business risk, and for S&P, it is 60%.[6] Each focuses on the basic regulatory framework, including (1) the legal foundation for utility regulation, (2) the ratemaking policies and

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[5] Moody's, *Rating Methodology, Regulated Electric and Gas Utilities*, Sept. 10, 2020, p. 4.

[6] Moody's, *Rating Methodology*, p.4; S&P, *Corporate Methodology*, p. 22 (Table 12).

procedures that determine how well the utility is afforded the opportunity to earn a reasonable return with a reasonable cash component, and (3) the history of regulatory behavior by the governing bodies applying those laws, policies and procedures.

Q18. AFTER THE OVERALL REGULATORY FRAMEWORK IS ANALYZED, HOW IS REGULATORY RISK DETERMINED?

A. Next, credit rating agencies examine the mechanics of regulation, particularly the rate-setting process and the details of how a utility's rate structure translates into the stability of its cash flows. In the past, rate cases took up much of the analysis, but now, the totality of a utility's tariff and rate structure are assessed to capture the effect on business risk of revenues generated outside base rates set in base rate cases. Formula rates, decoupling mechanisms, fuel clauses, and other varieties of rate mechanisms prevail across the utility industry and are the most common kind of rate mechanisms that stabilize earnings and cash flows to the benefit of the business risk profile. Creditors and therefore rating agencies attribute less risk to rate mechanisms that operate outside the rate case cycle and adjust rates automatically, in short time frames or flexible time frames to match revenues with costs, thereby minimizing regulatory lag.

Q19. ARE THE FRAMEWORK AND THE MECHANICS OF REGULATION THE ONLY CONSIDERATIONS THAT GO INTO DETERMINING REGULATORY RISK?

A. No. Rating agencies also look at the *consistency* and *transparency* exhibited in a regulatory jurisdiction's decisions.[7] Rating agencies rate many types and tenors of fixed income securities, but they regard debtholders who extend credit over long periods as their primary audience. They view their mandate as rating long-term debt as accurately as possible over the longest timeframe as possible. Utilities ultimately fund capital expenditures with long-dated maturities to match the long-lived assets they are supporting, and utility investors (debt and equity holders) expect ratings to be forward-looking and stable. Regulatory frameworks and practices that allow rating agencies to confidently project future cash flows and debt leverage will naturally be accorded a better business risk profile. The predictability that comes from the *consistency* and *transparency* exhibited in a regulatory jurisdiction's decisions offers creditors the ability to assess risk accurately over most of the debt's term and improves the ability of the company to manage its business activities and capital program for the long-term benefit of its customers. Thus, consistency and transparency are hallmarks of a supportive regulatory jurisdiction.

[7] Moody's, *Rating Methodology, Regulated Electric and Gas Utilities,* p. 4 (Sept. 10, 2020); S&P, *Assessing U.S. Investor-Owned Utility Regulatory Environments*, p. 2 (May 18, 2015).

Q20. DO REGULATORY ACTIONS ONLY AFFECT THE ANALYSIS OF BUSINESS RISK?

A. No. Regulatory behavior affects both the business risk and financial risk sides of the credit rating equation I articulated above. The manner of establishing rates and the level and timing of cost recovery has a direct effect on a utility's ability to earn its authorized return on rate base and produce enough earnings and cash flow to support its credit metrics that measure financial risk. A regulatory jurisdiction's approval of a rate mechanism using a fully compensatory rate of return, including a capital structure that offers sufficient risk protection to bondholders and other creditors, is a feature of a credit-supportive regulatory environment that would factor in assessing business risk as well.

Q21. WHAT FINANCIAL CONSIDERATIONS UNDERLIE THE QUANTITATIVE SIDE OF CREDIT RATING ANALYSIS?

A. Credit rating analysis is distinguished by its emphasis on cash flow. Recognizing that debt is serviced with cash, not earnings, credit analysts strive to understand the cash flow dynamics of a company's financial results as much as or more than the accounting-derived earnings. The most recent example that highlighted this dichotomy is the effect of the TCJA on utilities, which placed downward pressure on utility ratings because of its negative cash flow impact despite relatively neutral earnings implications. The other major element of financial risk to a credit analyst is the total amount of debt or debt-like obligations on the issuer's balance sheet and from other activities. Items that the rating agency regards as debt-like are underfunded pension obligations, lease liabilities, long-term power purchase obligations, and deferred taxes.

Credit metrics are calculated for both historical periods and future forecasts and fall into two basic types: leverage and coverage ratios. Since ratings are forward-looking, the forecast is given more weight in the analysis. Leverage metrics assess the relative burden of debt and other fixed-income obligations compared to the financial responsibility being carried by shareholders. Leverage is measured against cash flow, for the most part, and represents a longer term view of credit protection. Because of its long-term perspective, credit analysis tends to emphasize leverage metrics in the assessment of financial risk. Coverage metrics are something of the opposite, gauging the more immediate question of how cash flow compares to the near-term need to service the fixed-income obligations.

Q22. HOW IS CASH FLOW MEASURED IN LEVERAGE AND COVERAGE METRICS?

A. The primary measure that rating agencies use as a base for most cash flow metrics is cash flow from operating activities. Moody's calls its preferred cash flow measure "Cash Flow From Operations Before Changes in Working Capital" ("CFO pre-WC"), which removes the effects of transitory changes in working capital from CFO to pinpoint the ongoing ability of an issuer to generate cash flow from its normal operating activities.[8] S&P uses a similar measure, called "Funds-From-Operations," ("FFO"), although for consistency reasons they base their FFO calculation off the more familiar income statement measure of "Earnings Before Interest, Taxes, Depreciation, and Amortization" ("EBITDA"). S&P

[8] Moody's, *Rating Methodology*, p. 20.

then removes the actual cash paid for taxes and interest to arrive at a figure that aligns with operating cash flows stripped of the influence of working capital.[9]

Q23. WHAT CREDIT METRIC OR CREDIT METRICS DO CREDIT RATING AGENCIES TEND TO FOCUS ON?

A. FFO/Debt or the Moody's equivalent is the preferred credit metric of utility credit analysts. The leverage measure is more stable and has a more long-term character than the coverage ratios that are given a secondary role in the financial analysis. The conventional leverage metric, debt-to-capitalization, is not regarded as a reliable measure of debt leverage for most corporate issuers, although Moody's does give it a minor weighting for utilities based on the importance of the capital structure in setting utility rates.

Q24. WHICH SIDE OF THE CREDIT ANALYSIS EQUATION, BUSINESS OR FINANCIAL RISK, IS THE MOST IMPACTFUL ON UTILITY CREDIT QUALITY?

A. As I noted above, the business risk side is a bit more weighted in the balance of the two when utilities are analyzed, but that really doesn't capture the true dynamic of utility credit quality. Because of the outsized influence of regulation on the industry, which again is the primary factor in assessing business risk, the actions of regulators materialize in the credit analysis in business and financial risks alike, as I mentioned above. This "feedback loop," wherein regulatory decisions act on business risk factors *and* directly

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[9] S&P, *Criteria | Corporates | General: Corporate Methodology: Ratios and Adjustments*, Oct. 21, 2021, p. 3.

affect a utility's ability to manage financial performance, tends to intensify the impact of regulation on ratings outcomes. I cannot stress enough the unique role that regulators play in determining utility credit quality.

III. THE UTILITY INDUSTRY'S OUTLOOK

Q25. WHAT IS THE OUTLOOK FOR THE UTILITY INDUSTRY?

A. The broader credit ratings environment for utilities portends even more downward momentum for ratings. S&P first observed the credit quality of the utility industry deteriorating in 2020, with downgrades exceeding upgrades for the first time in a decade.[10] The downgrade-to-upgrade ratio for utilities stood at an astonishing 7-to-1 as of the middle of 2021.[11] I cannot recall a 7-to-1 downgrade ratio for utilities except perhaps during the post-Enron credit environment. As it now stands, S&P still carries a negative outlook on the industry after noting the second straight year of downgrades exceeding upgrades.[12] In a subsequent commentary, S&P cautioned that "increasing interest rates, the threat of inflation, and higher commodity prices will have a marginal but widespread negative effect" along with "considerable increase[s] in the typical customer bill" that ultimately means "regulatory fatigue could follow."[13]

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[10] S&P, *North American Regulated Utilities' Negative Outlook Could See Modest Improvement*, January 20, 2021, p. 1.

[11] S&P, *North American Corporate Credit Midyear Outlook 2021, Industry Top Trends Update, Regulated Utilities*, July 15, 2021, p. 1.

[12] S&P, *Industry Top Trends 2022, North American Regulated Utilities, Credit Quality Remains Pressured*, Jan. 26, 2022.

[13] S&P, *How Will North American Utilities Cope with High Interest Rates, Steeper Commodity Prices, and Inflation?* March 8, 2022.

Q26. WHY DO YOU THINK THOSE MACROECONOMIC FACTORS ARE A CHALLENGE TO UTILITY CREDIT QUALITY?

A. Rising interest rates and inflation are threats because of the unique nature of the utility business model, which combines comprehensive rate regulation with an obligation to serve that compels high capital expenditure trends that are difficult to reverse. While either higher interest costs or price levels can harm utility credit quality, together they can be quite harmful to a utility's ratings. Moreover, the industry is confronting these credit headwinds in a financial position that was weakened by earlier trends in thinner cash flow metrics stemming from tax reform[14] and pressure to maintain or increase capital commitments.[15]

Q27. WHY IS INFLATION PARTICULARLY HARMFUL TO REGULATED UTILITIES?

A. Regulatory lag. As damaging as regulatory lag is under mildly inflationary economic conditions, continued inflation at today's levels would be absolutely devastating to utility credit quality. Unregulated firms generally can pass higher costs contemporaneously to consumers as inflation builds. A utility can be faced with a situation where its costs significantly diverge from the levels that rates are based upon, leading to persistent and widening underearning and cash flow problems. If this coincides with a period of high capital spending, the inflationary pressures multiply as spiraling input costs combine with

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[14] Moody's, Rating Action: "*Moody's changes outlooks on 25 regulated utilities primarily impacted by tax reform,*" January 19, 2018; S&P, "*U.S. Tax Reform: For Utilities' Credit Quality, Challenges Abound*," January 24, 2018.

[15] S&P, *Industry Top Trends 2022*, p. 1.

ongoing regulatory lag to outpace the ability of the utility to accurately reflect the costs in rates.

Q28. AS YOU NOTED, IT'S BEEN DECADES SINCE INFLATION HAS BEEN AN ISSUE. HOW CAN YOU BE CONFIDENT IT WOULD AFFECT UTILITIES LIKE ELL?

A. I saw it myself. I started following the industry in the mid-1980's, reporting and analyzing regulatory decisions as the era of high inflation and double-digit interest rates was winding down. Capital expenditures were high due to a peak in the generation construction cycle that was exacerbated by inflationary pressures. In some cases, utilities were forced to "pancake" rate filings – that is, file a new case while the previous one was still in process – in a futile attempt to overcome regulatory lag.

The same thing is occurring now. The rate of inflation is increasing to unaccustomed levels. Interest rates are increasing in response. Utilities' capital expenditures are being driven higher as new technologies are incorporated into utilities' infrastructure and regulators' and customers' expectations of the utilization of electric service evolve. The modern rate mechanisms that prevail, however, tend to mitigate regulatory lag. For example, regulators generally authorize automatic adjustment clauses, formula rates, and decoupling mechanisms to address changes in costs in an efficient and expeditious manner.

Q29. CAN YOU IDENTIFY ANY OTHER INDUSTRY OR RATINGS TRENDS THAT ARE RELEVANT TO THIS PROCEEDING?

A. Yes. In addition to the overall negative sentiment in the credit markets and capital markets, the Commission and parties should be aware of another emerging development that will further depress utility credit quality over time. The emphasis on environmental, social, governance ("ESG") risk in the credit analysis of utilities is evolving and will only increase and sharpen scrutiny in the years ahead. Rating agencies are increasingly pinpointing ESG risk factors in their analyses.[16]

Q30. WHAT HAS THE EVOLUTION IN ESG RISK ASSESSMENT MEANT TO UTILITIES AND UTILITY RATINGS?

A. The ESG framework for evaluating risk is, to my mind, a means for organizing the thinking around risks that have always been a part of assessing a utility's risk profile. The rating agencies are raising the importance of these factors by segregating and spotlighting them as investors become more attuned to the risks. Regulators can facilitate a utility's ability to manage ESG risks by recognizing their importance and factoring the materiality and structure of ESG risks into their deliberations.

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[16] *See*, for example, S&P, *How ESG Factors are Shaping North American Investor-Owned Utilities' Credit Quality*, April 28, 2021, p. 7.

Q31. IF THE RISKS PREEXISTED THE ESG PHENOMENON, WHY ARE THEY DEMANDING GREATER RATING AGENCY ATTENTION?

A. The ESG effort doesn't merely repackage the risks. It changes how investors and rating agencies view them and factor them into their analyses. For example, "E" risks have affected utility operations for decades, but the emphasis that ESG brings to environmental issues has accelerated a transformation to an almost exclusively carbon and climate change focus and away from traditional concerns about air and water quality.[17] Another example is "S" risks, which are less susceptible to quantification and have always posed a challenge to analysts. I found it interesting that Moody's employed the ESG framework as it tried to evaluate how the COVID-19 pandemic is a social risk to utilities.[18]

Q32. DO YOU HAVE ANOTHER EXAMPLE OF HOW THE ESG APPROACH IS AFFECTING THE RATING AGENCIES' ASSESSMENT OF UTILITY RISK?

A. Yes, S&P has organized its new "ESG credit indicator"[19] scores. In its compilation of credit indicators, utilities like ELL appear in the "Power Generator" Report Card,[20] not the "Regulated Utility Network" listing.[21] For as long as I can remember, S&P has

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[17] *See*, for example, Moody's, *Sector In-Depth, Regulated electric utilities, US: Intensifying climate hazards to heighten focus on infrastructure investments*, January 2020, and Moody's, *Sector In-Depth, Regulated electric and gas utilities, US: Grid hardening, regulatory support key to credit quality as climate hazards worsen* (March 2020).

[18] Moody's, *Sector Comment, Electric and Gas Utilities - US: Supporting customers during coronavirus outbreak to have positive ESG implications*, April 23, 2020.

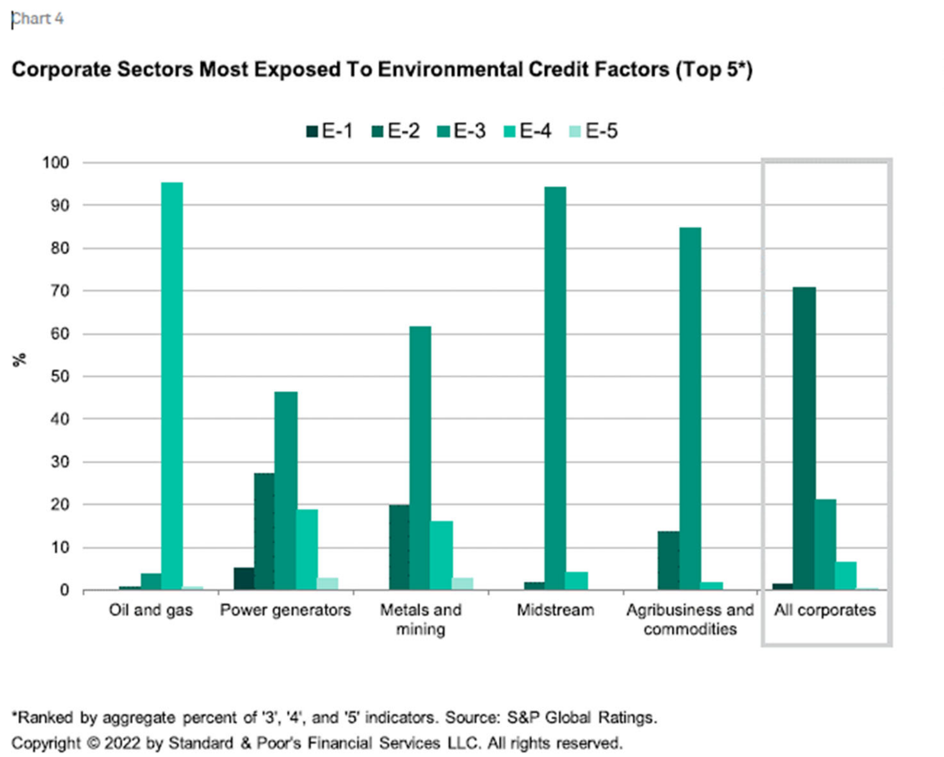
[19] S&P, *ESG Credit Indicator Definitions and Application,* October 13, 2021.

[20] S&P, *ESG Credit Indicator Report Card: Power Generators,* November 18, 2021.

[21] S&P, *ESG Credit Indicator Report Card: Regulated Utility Networks,* November 18, 2021.

regarded the independent, unregulated power generation companies as significantly higher risk than integrated electric utilities like ELL. By lumping them together in the ESG analysis, S&P is sending a telling message about the environmental risk of generating electricity: the 'E' risk is pervasive regardless of whether a generating plant's cost is recovered through regulated rates or not.

As the following graph reveals, according to S&P the 'E' risk of power generators is exceeded only by the 'E' risk of the oil and gas sector. (The higher the number, the more risk.) The graph provides a distribution of companies within each line of business based on 'E' risk. The companies having grades of 'E-1' have the least 'E' risk. 'E-1' means that environmental factors are, on a net basis, a positive consideration in S&P's credit rating analysis, affecting at least one analytical component. The companies having grades of 'E-5' have the most 'E' risk. 'E-5' means that environmental factors are, on a net basis, a very negative consideration in S&P's credit rating analysis, affecting several analytical components or one very severely. The majority of power generators, which includes regulated vertically integrated utilities like ELL, have grades of 'E-3' or worse. In contrast, the most common rating across all lines of business is 'E-2.'



Q33. GIVEN THE STATE OF THE INDUSTRY AT THIS TIME, WOULD IT BE REASONABLE FOR REGULATORS TO IGNORE UTILITY CREDIT QUALITY?

A. No. I don't think it's ever prudent for regulators to ignore credit quality when making decisions because of the pervasive influence ratings have on a utility's cost of service and therefore rates. The present time, however, is an especially vulnerable period for utility ratings due to the confluence of so many threats to the financial integrity of utilities that I have recounted in my testimony: rising inflation, rising interest rates, the need to invest heavily in the energy transition amid growing ESG risks, and the weakened cash flow position from which utilities are entering this heightened risk environment. These risks are largely out of the control of utilities like ELL that have an obligation to serve customers. This fact argues for regulators to give even greater attention to lowering those risks that can be managed. Interest rates are an instructive example. It's clear that the long period of gradual interest rate declines that marked the last four decades of the fixed-income markets has ended. We are now faced with increasing capital costs just as investments in resiliency and clean energy are poised to grow. Accordingly, customers are likely to experience benefits if regulators use their authority constructively to reduce risks on which they have significant influence to put downward pressure on capital costs and thus on the rates that customers pay for electricity.

IV. THE COMPANY'S RATINGS AND OUTLOOK

Q34. WHAT ARE ELL'S CREDIT RATINGS?

A. Moody's last reviewed its 'Baa1' issuer rating on ELL in August 2022 and detailed its credit opinion in October 2022.[22] A copy of the credit opinion is attached as Exhibit TAS-4. It left unchanged the negative outlook that was imposed in 2021 in the wake of the large restoration costs tied to Hurricane Ida.[23] S&P's issuer rating on the Company as of August 2022 is 'BBB+' with a stable outlook.[24] A copy of the report is attached as Exhibit TAS-5. S&P downgraded ELL last year out of the 'A' category precipitated by the same storm.[25] The fundamental opinions of the Company's creditworthiness are identical, although the Moody's opinion is more precarious due to the negative outlook.

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22 Moody's, *Entergy Louisiana, LLC Credit Opinion*, October 4, 2022; Moody's, *Moody's announces completion of a periodic review for a group of North American Utilities issuers,* August 24, 2022.

23 Moody's, *Rating Action: Moody's changes the outlooks of Entergy Louisiana-based utilities to negative from stable,* September 23, 2021.

24 S&P, *Entergy Louisiana, LLC*, August 25, 2022.

25 S&P, *Research Update: Entergy Louisiana LLC Downgraded to 'BBB+' From 'A-'On Weaker Financial Metrics Due to Storm Damage: Outlook Stable.*, September 2, 2021.

Q35. WHAT ARE THE MAIN DRIVERS OF MOODY'S OPINION OF ELL'S CREDIT QUALITY?

A. With regard to ELL, Moody's is focused on "1) environmental risks associated with its concentration in a storm prone service territory, where hurricanes have caused nearly $5.0 billion of damage at the utility in 2020 and 2021, 2) social risks around customer, political and regulatory relationships amid outstanding storm cost recovery, inflationary pressures and annual rate increases to recovery [*sic*] capital investments, 3) weak financial metrics due to outstanding storm cost recovery proceedings."[26]

Q36. WHAT ARE THE MAIN DRIVERS OF S&P'S OPINION OF ELL'S CREDIT QUALITY?

A. S&P also concentrates on ELL's storm risk and identifies "[e]xposure to severe hurricanes and storms in its service territory" as a key risk and explains that ELL "remains exposed to hurricanes as evidenced by the recent 2021 category 4 Hurricane Ida which was the most destructive hurricane in Louisiana since the 2005 Hurricane Katrina."[27] S&P also identifies as a key risk the "[l]ack of sufficient system hardening [that] limits the company's ability to protect against severe storms and increases its business risk relative to peers."[28]

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[26] Moody's, *Credit Opinion, Entergy Louisiana, LLC, Update to credit analysis*, October 4, 2022, p. 1.

[27] S&P, *Entergy Louisiana LLC,* August 25, 2022, p. 1.

[28] *Ibid*.

Q37. WHAT IS THE MOST STRIKING PASSAGE IN THE REPORTS?

A. S&P observed while commenting on ELL's business risk that storm cost securitization, although beneficial, has limits when it comes to contributing to effective risk management. "While we view securitization as a good backstop for storm restoration costs, securitization takes time to receive the ultimate funds and takes up headroom in the customer bill, potentially increasing the risk of the company consistently managing regulatory risk."[29] S&P identifies a better path to contain risk for the benefit of ratepayers:

> We believe that for ELL to reduce its credit risk exposure to severe storms, it is important for the company to have a more resilient infrastructure that withstands severe storms, reducing the rate of recovery of pass-through costs to customers. Parent, Entergy Corp, intends to spend about $4 billion in accelerated resiliency spending within the next five years and about $15 billion over the next ten years, which we assess as supportive of the company's long-term credit quality.[30]

I project that failure to support a robust Resilience Plan would, in conjunction with the challenging credit environment (*see* Section III, *supra*) and the risk associated with industrial load growth, pose a threat to ELL's ratings. Financial performance could weaken, but the larger threat is in the business risk profile, which is already "at the lower end of its business risk category."[31] A further drop of ELL's business risk category from 'excellent' to 'strong' would be a damaging outcome for all stakeholders. Instead of the more common one-notch difference in the base rating indication, a move into a 'strong' business risk profile would push the S&P anchor score down two notches. That would

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29 *Ibid*. at 4.

30 *Ibid.*

31 *Ibid.*

bring everything much closer to the edge of being non-investment grade, or "junk," status on a stand-alone basis. Customers would bear higher capital costs in the future, all else being equal.

Q38. WHY DO YOU CONSIDER GREATER EXPOSURE TO INDUSTRIAL SALES AS AN ADDED RISK TO THE ELL RATING?

A. Industrial customer concentration sets ELL apart from most electric utilities. It stands at 35% of its customer mix, according to Moody's,[32] which contrasts with the average electric utility figure of about 16%.[33] Very few peers have that degree of industrial load exposure, and Entergy projects continued growth in this segment that will only exacerbate this risk factor.[34] Rating agencies and investors regard industrial sales as inherently more volatile (and therefore more risky) than residential and small commercial loads.[35] This alone is not a near-term risk to the ELL rating but would be one more stress point for the ELL ratings if storm risk is not addressed.

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[32] Moody's, Credit Opinion, p. 3.

[33] *See* https://www.eei.org/resources-and-media/industry-data.

[34] *See* Entergy Corp. *Analyst Day 2022 Presentation, Rod West – Group President, Utility Operations*, June 16, 2022, pp. 2 & 6.

[35] S&P, *Criteria | Corporates | Utilities: Key Credit Factors for the Regulated Utilities Industry*, July 7, 2021, ¶ 35.

Q39. DOES MOODY'S MAKE A SIMILAR STATEMENT TO S&P'S REGARDING THE NEED FOR STORM HARDENING AND RESILIENCY IMPROVEMENTS?

A. No. Moody's, however, may be moving in that direction. First, Moody's is aware that ELL is "looking to accelerate storm hardening efforts" but notes that customer affordability presents a challenge in that area.[36] Second, Moody's assumes that the Commission will continue to be able to use securitization for future storm cost recovery[37] but ignores the risk that ELL's storm cost securitization capacity could be limited after the 2023 Ida Securitization, as discussed by Company witness Alyssa Maurice-Anderson. The limitation of this tool would be a significant concern to Moody's. That concern could prompt Moody's to recognize that accelerated storm hardening is necessary to mitigate risk and that storm cost securitization is not a substitute for accelerated storm hardening, which would reduce future storm restoration costs for the benefit of customers.

Q40. DOES S&P SHARE MOODY'S CONCERNS ABOUT CUSTOMER AFFORDABILITY?

A. Yes. Echoing Moody's social risk discussion, S&P cites "increasing commodity prices, interest rates, inflationary pressures, and the company's robust capital spending [that] could all pressure customer bill[s], potentially weakening the company's consistent

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36 Moody's, Credit Opinion, p. 4.

37 *Ibid*.

ability to effectively manage regulatory risk."[38] But S&P does not appear to think that affordability means that accelerated storm hardening can be ignored.

Q41. CONSISTENT WITH YOUR PERSPECTIVE THAT BUSINESS RISK DOMINATES UTILITY CREDIT ANALYSIS, DO YOU VIEW THE RATING AGENCIES AS DRIVEN BY REGULATORY RESPONSES TO RISING ENVIRONMENTAL RISK IN THEIR OUTLOOK ON ELL'S RATINGS?

A. Not entirely. While I stand by my point that regulatory decisions naturally radiate throughout the credit analysis, I detect a near-term focus on financial performance and credit metrics in both the Moody's and S&P credit reports. The S&P downside scenario as it pertains to ELL is solely a matter of maintaining credit metrics. The S&P core metric, a leverage-based one that looks at their preferred cash flow measure of FFO as a percentage of debt, is supposed to stay above 13% to ensure ratings stability.[39] S&P shows ELL generating FFO-to-debt figures gradually declining in recent years to the cusp of the downgrade trigger, from around 16% to barely above 13% in 2021.[40]

Moody's, too, dwells on the financial deterioration founded on "the added cost burden resulting from recent storm activity" that holds "the potential for prolonged financial metric weakness."[41] Its primary financial metric, CFO Pre-W/C / Debt, a similar measure to S&P's, shows a more precipitous drop, from the 17%-18% range to single-

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[38] S&P, *Entergy Louisiana LLC,* August 25, 2022, p. 2.

[39] *Ibid.*

[40] *Id.* at 6.

[41] Moody's, *Credit Opinion,* p. 2.

digit figures in the 7% to 9% range.[42] Moody's outlook is more comprehensive than S&P's, delineating storm cost recovery decisions, the prospect of more major storms, and regulatory behavior in general, reinforcing my reminders that business and financial risks feed on each other, but in the end Moody's comes to the same trigger, a financial one, and they're looking for financial results that support at least an 18% CFO Pre-W/C to Debt over the long-term.[43] The considerable distance between that trigger and recent performance explains the negative outlook and the urgent need to address it.

Q42. WHERE DO S&P AND MOODY'S SCORE ELL ON ESG RISK FACTORS?

A. Moody's slots ELL into a 'moderately negative' category, denoted by a "Credit Impact Score" of "3" (CIS-3) on a 1-to-5 scale. That composite ESG score obscures much of ELL's ESG exposure, though, due to a low-risk sub-score on governance. The social sub-score is "Moderately Negative," and the environmental sub-score is even worse at "Highly Negative." S&P groups and scores the risks with slightly different nomenclature, but the results are the same as Moody's. 'G' comes in at low-risk, 'S' as moderately negative (citing health and safety concerns), and 'E' as negative due to physical risks, and waste and pollution. As I noted in Section III when reviewing the industry and credit quality outlook, ESG is steadily becoming more of a ratings driver for utilities. The negative stances on environmental and social risk factors are a warning sign to the Company and its stakeholders, including ratepayers, that managing these risks will

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[42] *Ibid.*

[43] *Ibid.*

be crucial to achieving ratings goals and minimizing the impact of the risk on customer bills in the future.

Q43. GIVEN THE NEGATIVE TREND IN CREDIT QUALITY IN THE INDUSTRY AND AT ELL AND THE ADDED AND GROWING PRESSURE COMING FROM ESG FACTORS, HOW DOES THE RESILIENCE PLAN POTENTIALLY AFFECT ELL CREDIT QUALITY?

A. The need for the Resilience Plan comes amid a background of a confluence of negative credit factors. As noted earlier in my testimony, overall negative credit trends for utilities are coupled with ELL-specific issues that have the potential to lead to further ratings downgrades that would be costly for customers. However, I believe the Resilience Plan represents both an opportunity and a risk. With careful planning and execution, the Company, and its stakeholders, including the LPSC, can take advantage of the opportunity side and manage the risk side of the equation to keep the ratings impact neutral.

Q44. WHAT ARE THE CREDIT UPSIDES AND DOWNSIDES OF THE PLAN?

A. Recall that credit analysis encompasses two complementary risk profiles, business risk (qualitative) and financial risk (quantitative). The opportunity appears in the improvement to ELL's business risk that would come with an emphatic "buy-in" by all stakeholders to the adoption of the Resilience Plan. Acknowledgement of the prudence of mitigating restoration costs and storm outages would make a positive impression on the credit rating agencies. The downside to the plan is the financial risk it imposes on

ELL and its customers. There is no escaping the up-front nature of the Resilience Plan's cost. Since both credit rating agencies have highlighted the weakness in ELL's financial metrics in credit reports (see question 41, *supra*), it is imperative that the Plan's effect on financial risk be addressed with the same care that goes into the review and oversight of the specifics of the Plan.

Q45. WHY ARE YOU CONFIDENT THE RESILIENCE PLAN COULD DEPRESS FINANCIAL PERFORMANCE AND THREATEN RATINGS?

A. I have reviewed the Direct Testimony of Alyssa Maurice-Anderson and the Accelerated Resilience Plan Financial Model ("Financial Model")[44] supporting the testimony. Ms. Maurice-Anderson's explanation of the Plan's effect on ELL's cash flow and core credit metric, (FFO/Debt), is compelling.[45] It is also a matter of utility and regulatory economics. Anyone familiar with how utilities operate recognizes that aggressive capital spending entails more financial risk because of the lag between the outlays and the cost recovery. That is why the credit rating agencies are so focused on the level and direction of capital expenditures when assessing risk. [46]

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[44] Direct Testimony of Alyssa Maurice-Anderson, Exhibit AMA-3.

[45] *Id*. at 16-17.

[46] See Moody's, *Credit Opinion,* p. 4 and S&P, *Entergy Louisiana, LLC*, p. 2.

Q46. DOES THE PROPOSED RESILIENCE PLAN COST RECOVERY ("RPCR") RIDER MITIGATE THE PRESSURE THE RESILIENCE PLAN PLACES ON ELL'S CREDIT RATINGS?

A. As the Financial Model demonstrates, the RPCR Rider eases the financial deterioration accompanying the Resilience Plan considerably, and by the end of the forecast period in 2028 the RPCR Rider produces marginal cash flow that makes the Resilience Plan closer to credit-neutral from a financial risk perspective.[47] Credit rating agencies look at a broad set of credit metrics when rating a utility like ELL, but as explained earlier in my testimony, the leverage measure of FFO to Debt predominates in the credit analysis and exerts more influence on rating outcomes than any other metric. Placed alongside the credit-positive aspects of the Resilience Plan, I believe approval of the Resilience Plan with the RPCR Rider, as proposed, would be slightly credit-negative but close to credit-neutral for ELL.

Q47. DO YOU SEE OTHER POSITIVE OUTCOMES POSSIBLE FROM THIS PROCEEDING?

A. Yes. I think the net effect of the Resilience Plan and adoption of the RPCR Rider could tip over to solidly neutral for credit quality and ratings, if approval is accompanied by messaging to ELL, its customers, and its investors that the Resilience Plan is well supported. I have spent a lot of time discussing the effect of capital spending on credit

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[47] Direct Testimony of Alyssa Maurice-Anderson, Table 4. The marginal cash flow to debt starts as negative in the "Without Rider" scenario and improves to a single-digit percentage by 2028, still well below the rating agency FFO/Debt triggers. The "With Rider" scenario reaches a 14% contribution by 2028, which is right around the trigger point for S&P but still below the Moody's 18% inflection point.

quality, but in fact, the effect is not only about the level of capital spending. Credit analysis is more complex than that. It focuses as much on what the capital spending is for and the preparation that went into the capital spending plan. It also focuses on the reception of the capital spending plan by stakeholders. Capital spending that improves the customer experience and customer satisfaction, as well as regulatory support and oversight, will be viewed more favorably by the credit rating agencies. I encourage the Commission with stakeholder support to provide an approval that clearly communicates the prudence of the Resilience Plan, the process that will be employed to assess the execution of the Resilience Plan, and the reasonableness of the RPCR Rider.

Q48. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, at this time.

AFFIDAVIT

STATE OF NORTH CAROLINA

COUNTYOF GUILFORD

NOW BEFORE ME, the undersigned authority, personally came and appeared, **TODD A. SHIPMAN**, who after being duly sworn by me, did depose and say:

That the above and foregoing is his sworn testimony in this proceeding and that he knows the contents thereof, that the same are true as stated, except as to matters and things, if any, stated on information and belief, and that as to those matters and things, he verily believes them to be true.

Todd A. Shipman

SWORN TO AND SUBSCRIBED BEFORE ME
THIS 14th DAY OF DECEMBER, 2022

R. David Guise

NOTARY PUBLIC

My commission expires: 3/27/2027

R. DAVID GUISE
NOTARY PUBLIC
Guilford County
North Carolina
My Commission Expires 3/27/27

BEFORE THE

LOUISIANA PUBLIC SERVICE COMMISSION

***IN RE*: APPLICATION OF ENTERGY LOUISIANA, LLC FOR APPROVAL OF THE ENTERGY FUTURE READY RESILIENCE PLAN (PHASE I)**	**))))**	**DOCKET NO. U- _______**

EXHIBIT TAS-1

DECEMBER 2022

TODD A. SHIPMAN, CFA

tshipman@utility-credit.com
857.260.0656

Experience

Utility Credit Consultancy LLC **Orleans, MA**

Principal May 2018 - Present

Founded a consulting firm to provide utilities with expert witness services and advice on capital market strategies. Specialize in capital markets issues, credit rating advisory, and hybrid securities.

Boston University **Boston, MA**

Lecturer January 2017 – June 2020

Adjunct faculty member in the Questrom School of Business, Department of Finance. Taught advanced undergraduate finance courses covering capital markets, monetary and economic policy, and corporate finance.

S&P Global Ratings **New York, NY and Boston, MA**

Senior Director April 2014 - May 2018
Director April 2000 - April 2014
Associate Director March 1997 - April 2000

Sector Specialist on the Global Infrastructure Ratings North American Utilities team. Performed credit surveillance of utilities, pipelines, midstream energy, and diversified energy companies. Chaired most team rating committees. Wrote credit reports and commentaries and led outreach efforts to investors and the regulatory community, including speeches and training seminars. Lead analytical role developing global rating criteria for utilities, master limited partnerships, and hybrid capital securities.

Electric Utility Research Inc (defunct), San Francisco, CA

Senior Vice President May 1996 - March 1997

Edited and contributed to an investor newsletter covering the electric utility industry

Sithe Energies Inc. **New York, NY**

Manager, Regulatory Affairs November 1993 - May 1996

Managed state regulatory matters for a major independent power company. Coordinated interventions in regulatory proceedings. Assisted in identifying development opportunities. Participated in investor relations activities.

Regulatory Research Associates **Jersey City, NJ**

Vice President October 1993 - November 1993
Senior Analyst August 1989 - October 1993
Analyst August 1985 - August 1989

Analyzed and reported on actions by state regulators affecting the financial status of electric, gas, and telephone utilities for a firm that provided research to the Wall St. community. Contributed to the firm's sell-side research.

Education

J.D., Texas Tech University School of Law, Lubbock, TX	May 1984
B.B.A., Texas Christian University, Fort Worth, TX	May 1981

Professional Affiliations & Other Activities

Executive Advisor, Concentric Energy Advisors, Marlborough MA

Chartered Financial Analyst

Wall Street Utility Group

Fixed Income Analysts Society Inc

Society of Utility and Regulatory Financial Analysts

BEFORE THE

LOUISIANA PUBLIC SERVICE COMMISSION

***IN RE*: APPLICATION OF ENTERGY LOUISIANA, LLC FOR APPROVAL OF THE ENTERGY FUTURE READY RESILIENCE PLAN (PHASE I)**	**))))**	**DOCKET NO. U- _______**

EXHIBIT TAS-2

DECEMBER 2022

Utility
Credit
Consultancy LLC

FILINGS

Unless otherwise noted, the proceeding was a rate case.

Client: Hawaiian Electric Companies
State: Hawaii
Docket/Proceeding: # 2018-0088, *Instituting a Proceeding to Investigate Performance-Based Regulation*
Date: October 25, 2018
Submittal: Regulatory Assessment Brief (Appendix: Effect of Major Regulatory Reform on Credit Quality)

Client: Avista / Hydro One
State: Washington
Docket/Proceeding: #UM 1897, *In the matter of HYDRO ONE LIMITED, Application for Authority to Exercise Substantial Influence over the Policies and Actions of AVISTA CORPORATION*
Date: October 4, 2018
Submittal: Rebuttal Testimony of John R. Reed (Exhibit 2601: Independent Report of Todd A. Shipman)

Client: Wisconsin Electric Power Co. / Wisconsin Gas LLC
State: Wisconsin
Docket/Proceeding: #05-UR-109
Date: March 28, 2019 / September 17, 2019
Submittal: Direct and Rebuttal Testimony

Utility
Credit
Consultancy LLC

FILINGS

Client Wisconsin Public Service Corp.
State: Wisconsin
Docket/Proceeding: #6690-UR-126
Date: March 28, 2019
Submittal: Direct Testimony

Client: San Diego Gas & Electric Co.
State: California
Docket/Proceeding: #A.19-04-017 (Cost of Capital)
Date: April 2019 / August 1, 2019 / August 21, 2019
Submittal: Direct, Supplemental, and Rebuttal Testimony

Client: Consolidated Edison of New York Co.
State: New York
Docket/Proceeding: #19-E-0065 & 19-G-0066
Date: June 14, 2019
Submittal: Rebuttal Testimony

Client : Roanoke Gas Co.
State: Virginia
Docket/Proceeding: #PUR-2018-00013
Date: July 30, 2019
Submittal: Rebuttal Testimony

Utility
Credit
Consultancy LLC

FILINGS

Client: Hawaii Electric Light Co.
State: Hawaii
Docket/Proceeding: #2018-0368
Date: October 9, 2019
Submittal: Rebuttal Testimony

Client: Mississippi Power Co.
State: Mississippi
Docket/Proceeding: #2019-UN-219
Date: November 26, 2019
Submittal: Direct Testimony

Client: Southwestern Public Service Co.
State: New Mexico
Docket/Proceeding: #19-00170-UT
Date: December 20, 2019
Submittal: *Rebuttal Testimony*

Client: Southwestern Public Service Co.
State: Texas
Docket/Proceeding: #49831
Date: March 11, 2020
Submittal: Rebuttal Testimony

Utility
Credit
Consultancy LLC

FILINGS

Client: Southwest Gas Corp
State: Arizona
Docket/Proceeding: #G-01551A-19-0055
Date: March 11, 2020
Submittal: Rebuttal Testimony

Client: Hawaiian Electric Companies
State: Hawaii
Docket/Proceeding: # 2018-0088, *Instituting a Proceeding to Investigate Performance-Based Regulation*
Date: June 18, 2020
Submittal: Phase 2 Statement of Position (Exhibit C2: Financial Integrity and Credit Ratings)

Client : Arizona Public Service Co.
State: Arizona
Docket/Proceeding: #E-01345A-19-0236
Date: November 6, 2020
Submittal: Rebuttal and Rejoinder Testimony

Utility
Credit
Consultancy LLC

FILINGS

Client: Southwestern Public Service Co.
State: New Mexico
Docket/Proceeding: #20-00238-UT
Date: December 18, 2020
Submittal: Direct Testimony; Rebuttal Testimony

Client: Southwestern Public Service Co.
State: Texas
Docket/Proceeding: #51802
Date: February 8, 2021
Submittal: Direct Testimony, Rebuttal Testimony

Client: Orange and Rockland Utilities Co.
State: New York
Docket/Proceeding: #21-E-0074 & 21-G-0073
Date: January 29, 2021
Submittal: Direct Testimony, Rebuttal Testimony

Client: Puget Sound Energy, Inc.
State: Washington
Docket/Proceeding: #UE-220066 & UG-220067
Date: January 31, 2022
Submittal: Direct Testimony, Testimony In Support of Settlement

Utility
Credit
Consultancy LLC

FILINGS

Client: Wisconsin Electric Power Co. / Wisconsin Gas LLC
State: Wisconsin
Docket/Proceeding: #5-UR-110
Date: April 28, 2022
Submittal: Direct Testimony

Client Wisconsin Public Service Corp.
State: Wisconsin
Docket/Proceeding: #6690-UR-127
Date: April 28, 2022
Submittal: Direct Testimony

Client: Consolidated Edison of New York Co.
State: New York
Docket/Proceeding: #22-E-0064 & 21-G-0065
Date: June 17, 2022
Submittal: Rebuttal Testimony

BEFORE THE

LOUISIANA PUBLIC SERVICE COMMISSION

***IN RE*: APPLICATION OF ENTERGY LOUISIANA, LLC FOR APPROVAL OF THE ENTERGY FUTURE READY RESILIENCE PLAN (PHASE I)**	**))))**	**DOCKET NO. U- _______**

EXHIBIT TAS-3

DECEMBER 2022

EXHIBIT TAS-3

RATINGS SCALES

MOODY'S INVESTOR SERVICE	S&P GLOBAL RATINGS
Aaa	**AAA**
Aa1	**AA+**
Aa2	**AA**
Aa3	**AA-**
A1	**A+**
A2	**A**
A3	**A-**
Baa1	**BBB+**
Baa2	**BBB**
Baa3	**BBB-**
Ba1	***BB+***
Ba2	***BB***
Ba3	***BB-***
B1	***B+***
B2	***B***
B3	***B-***
Caa1	***CCC+***
Caa2	***CCC***
Caa3	***CCC-***
Ca	***CC***
C	***C***
D	***D***

Note: The line demarcates the investment-grade/speculative-grade divide

BEFORE THE

LOUISIANA PUBLIC SERVICE COMMISSION

***IN RE*: APPLICATION OF ENTERGY LOUISIANA, LLC FOR APPROVAL OF THE ENTERGY FUTURE READY RESILIENCE PLAN (PHASE I)**	**))))**	**DOCKET NO. U- _______**

EXHIBIT TAS-4

DECEMBER 2022

LPSC Docket No. U-_____
Exhibit TAS-4
Page 1 of 11

MOODY'S
INVESTORS SERVICE

CREDIT OPINION

4 October 2022

Update

Send Your Feedback

RATINGS

Entergy Louisiana, LLC

Domicile	New Orleans, Louisiana, United States
Long Term Rating	Baa1
Type	LT Issuer Rating - Dom Curr
Outlook	Negative

Please see the ratings section at the end of this report for more information. The ratings and outlook shown reflect information as of the publication date.

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CLIENT SERVICES

Americas	1-212-553-1653
Asia Pacific	852-3551-3077
Japan	81-3-5408-4100
EMEA	44-20-7772-5454

Entergy Louisiana, LLC

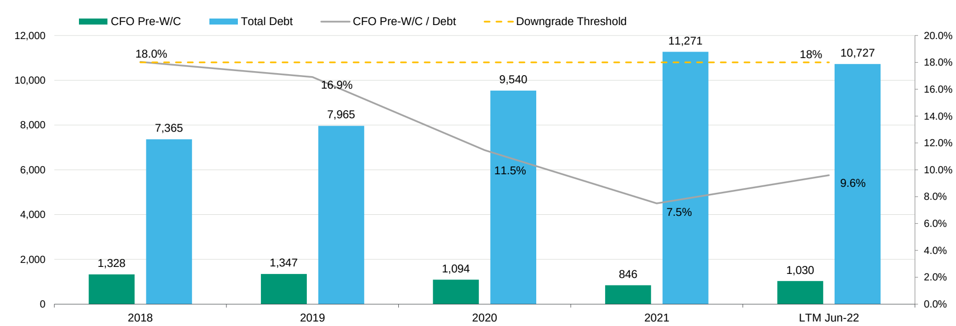
Update to credit analysis

Summary

Entergy Louisiana, LLC's (ELL, Baa1 negative) credit profile is supported by 1) a constructive formula rate plan regulatory framework in Louisiana, where utilities typically generate predictable earnings at the level of their authorized ROEs, 2) a run-rate financial profile expected to generate cash flow to debt ratios in the high teens percent range and 3) the state's track record of providing storm cost recovery via securitization.

ELL's credit profile is constrained by 1) environmental risks associated with its concentration in a storm prone service territory, where hurricanes have caused nearly $5.0 billion of damage at the utility in 2020 and 2021, 2) social risks around customer, political and regulatory relationships amid outstanding storm cost recovery, inflationary pressures and annual rate increases to recovery capital investments, 3) weak financial metrics due to outstanding storm cost recovery proceedings.

Exhibit 1
Historical CFO pre-WC, Total Debt and CFO pre-WC to debt



The downgrade threshold indicated above is one of several factors that could lead to a downgrade if the metric is below this level for an extended period of time.
Source: Moody's Investor Service

Credit strengths

» Supportive and consistent regulatory framework oversees over $14 billion of rate base

» Formula rate plan enhances earnings predictability

» Growing demand due to customer electrification efforts

Credit challenges

» Storm-prone service territory

» Potential for customer, political or regulatory pushback on forthcoming rate increases

» Financial metrics continue to be weak as storm cost securitization process continues

» High exposure (i.e., around two-thirds of historical demand) to commercial and industrial customers

Rating outlook

The negative outlook for ELL reflects the added cost burden resulting from recent storm activity and the potential for prolonged financial metric weakness.

Factors that could lead to an upgrade

» An upgrade over the near term is unlikely given the negative outlook but could happen if the following occurs:

» CFO pre-WC to debt above 21% on a sustained basis

» More forward-looking cost recovery mechanisms are incorporated into rates

Factors that could lead to a downgrade

» If significant storm costs are not recovered on a timely basis

» Another major storm in 2022 adds materially to unrecovered costs

» A pattern of adverse regulatory decisions

» CFO pre-WC to debt below 18% for an extended period of time

Key indicators

Entergy Louisiana, LLC

	Dec-18	Dec-19	Dec-20	Dec-21	LTM Jun-22
CFO Pre-W/C + Interest / Interest	5.3x	5.2x	4.2x	3.4x	3.8x
CFO Pre-W/C / Debt	18.0%	16.9%	11.5%	7.5%	9.6%
CFO Pre-W/C – Dividends / Debt	16.3%	14.3%	11.2%	7.0%	7.9%
Debt / Capitalization	47.9%	47.6%	49.9%	51.5%	47.6%

All ratios are based on 'Adjusted' financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations
Source: Moody's Financial Metrics

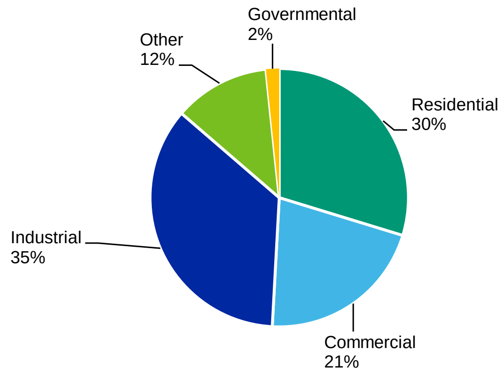
Profile

Entergy Louisiana, LLC (ELL, Baa1 negative) is a vertically integrated utility regulated by the Louisiana Public Service Commission (LPSC), serving around 1.1 million electric and gas customers in Louisiana. ELL is comprised of two legacy Entergy utilities: the former Entergy Louisiana and Entergy Gulf States Louisiana (EGSL).

ELL, Entergy Corporation's (Entergy, Baa2 negative) largest utility subsidiary, is expected to contribute over 40% of the parent company's EBITDA in 2022. ELL's revenue is typically more weighted toward industrial customers, as seen in Exhibit 3.

Exhibit 3

ELL has a relatively high exposure of electricity sales to industrial customers% of 2021 revenue per customer class



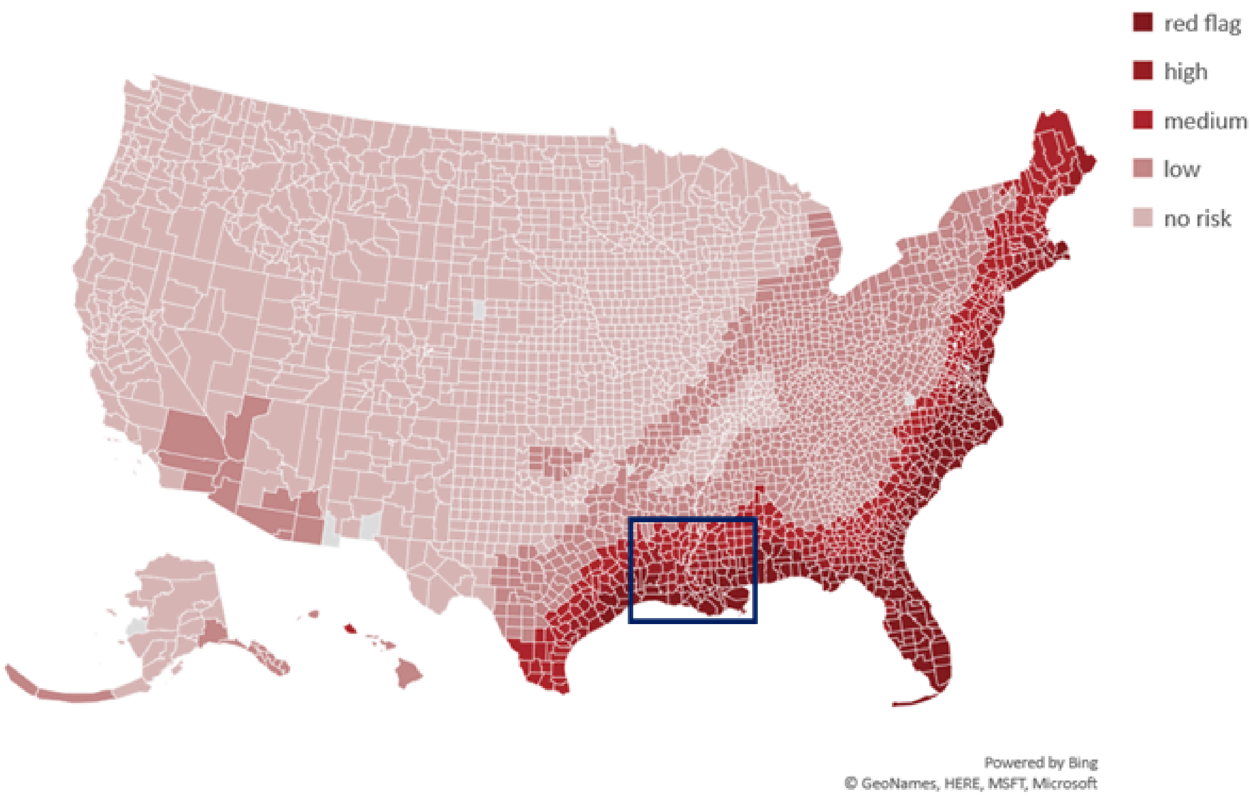
Source: Entergy Corporation 2021 Statistical Report and Investor Guide

Detailed credit considerations

Potential for operational, financial and affordability pressures due to ELL's location in a storm-prone service territory

Over the past 2 years, Hurricanes Laura, Delta, Zeta and Ida have caused nearly $5.0 billion of storm damage to ELL's asset base, which represents over 35% of ELL's approximately $14 billion in total rate base. While we have long cited the company's geographical footprint as a risk for ongoing storm activity, the frequency and severity of recent storms is unprecedented and the most active on record, as illustrated in the exhibit below. This reflects a higher risk operating environment due to the physical effects of climate change and the capital required to bolster infrastructure and recover from damaging events.

Exhibit 4
ELL's significant storm activity has resulted in nearly $7.0 billion of costs since 2005



The indicator reflects the cumulative wind velocity from recorded cyclones over the period 1980-2016
Source: Entergy SEC filings

Storm cost recovery is on track, but customer affordability remains a challenge

ELL has been successfully addressing some of the key challenges that prompted its negative outlook in September 2021. For example, the company completed roughly $3.2 billion of storm cost securitizations this year, primarily due to Hurricanes Laura, Delta and Zeta, but also included $1.0 billion of 2021's Hurricane Ida recovery, with the remaining $1.6 billion of Ida cost recovery currently pending before the LPSC.

There is a strong precedent for storm cost securitization in Louisiana (see the exhibit below which lists storm activity affecting ELL's service territory since 2005), and we expect that the LPSC will continue to authorize ELL to use this tool for future cost recovery. We view securitization to be credit positive, since it incorporates the lowest cost of financing to minimize the customer rate impact and is non-recourse to the utility, which acts as a pass through conduit for collections. As such, we expect the remaining $1.6 billion of Ida cost recovery to be securitized in early 2023.

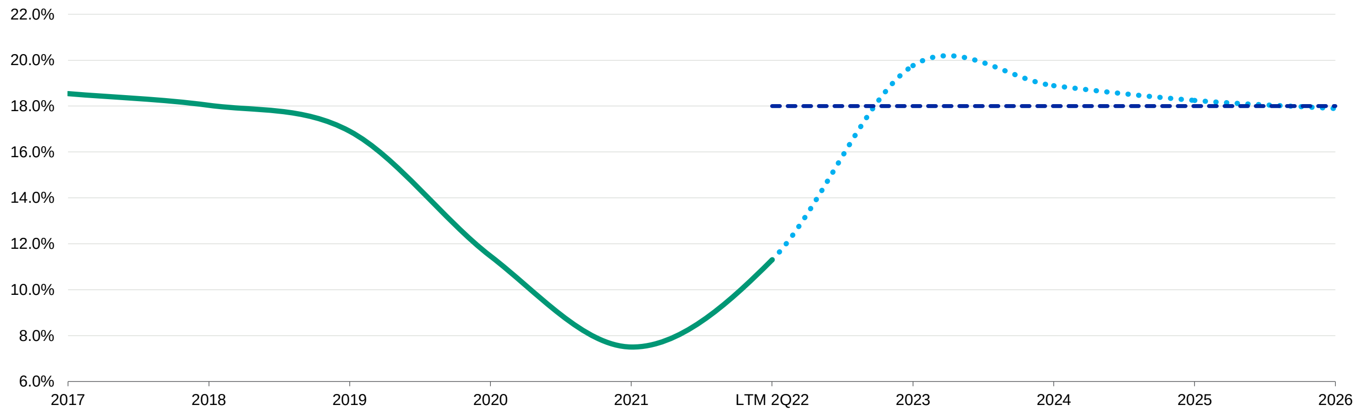
While Louisiana has been supportive of the recovery of these exogenous costs to date, customer affordability issues will remain an ongoing challenge for ELL, since management is looking to accelerate storm hardening efforts of its transmission and distribution assets. These rising capital costs, on top of inflation, high interest rates and other economic pressures, could result in challenged customer relations and the prospect of political intervention into rate making, which would make ELL's financial improvement more difficult.

Financial metrics will rebound after securitization, but could remain weakly positioned

The company's ratio of CFO pre-WC to debt is under 10% through LTM Q2 2022; however, when excluding $1.6 billion of debt the remaining Ida costs to be securitized, this metric would improve to just over 11%. On a run-rate basis, we expect the utility's cash flow to improve commensurate with rate base (capital spending) growth and return to levels above 18%, as seen in the exhibit below.

However, our projected metrics are sensitive to several items that could cause ELL's actual performance to deviate from this level, including our assumptions that 1) most capital spending is recovered on a timely basis, 2) cash tax payments remain very low, 3) the company earns the midpoint of its allowed ROE levels, 4) there are no material changes to regulatory asset and liability balances and 5) no major storms.

Exhibit 5
ELL's ratio of CFO pre-WC to debt should rebound to over 18% once the Ida storm securitization is complete



Source: Moody's Financial Metrics and Moody's Investors Service projections

Regarding the latter, if we incorporate a $750 million storm event into our projections (excluding the cash flow decline from nonpaying customers) every three years, ELL's CFO pre-WC to debt would be around 17-18% on a rolling three year average, assuming its average adjusted debt capitalization (i.e., debt / (debt + equity)) remains around 48%.

Supportive and predictable regulatory environment with a history of providing storm cost recovery

Louisiana is a credit supportive regulatory environment, where formula rate plans (FRPs) provide clarity on future cost recovery, including operating and capital expenditures. ELL's FRP helps to reduce regulatory lag and increase the predictability of future cash flow and financial metrics by incorporating these costs into rates without the need for periodic general rate case proceedings. These features allow for higher predictability and consistency of the rate making process, as well as contributing to stability of earnings and cash flow.

ESG considerations

ELL's ESG Credit Impact Score is CIS-3 (Moderately Negative)

Exhibit 6
ESG Credit Impact Score

CIS-3

Moderately Negative

For an issuer scored CIS-3 (Moderately Negative), its ESG attributes are overall considered as having a limited impact on the current rating, with greater potential for future negative impact over time. The negative influence of the overall ESG attributes on the rating is more pronounced compared to an issuer scored CIS-2.

Source: Moody's Investors Service

ELL's ESG Credit Impact Score is moderately negative (**CIS-3**), reflecting highly negative environmental risks, moderately negative social risks and neutral-to-low exposure to governance risks.

Exhibit 7
ESG Issuer Profile Scores

ENVIRONMENTAL
E-4
Highly Negative

SOCIAL
S-3
Moderately Negative

GOVERNANCE
G-2
Neutral-to-Low

Source: Moody's Investors Service

Environmental

ELL's very high exposure to environmental risks (**E-4** issuer profile score) reflects over $5.0 billion of storm related costs incurred in the past two years, affecting roughly 35% of its rate base. The company's service territory is concentrated on the Gulf of Mexico, which exposes ELL to material and extreme weather events that can cause customer outages and costly repairs. The company also operates nuclear-fueled generation, which includes operational risks around spent fuel waste and pollution management of radioactive uranium.

Social

Exposure to social risks is moderately negative (**S-3** issuer profile score) reflecting the fundamental utility risk that demographics and societal trends could include social pressures or public concern around affordability, utility reputational or environmental risks. In turn, these pressures could result in adverse political intervention into utility operations or regulatory changes. ELL's nuclear generation also carries unique public safety risks that other forms of generation do not.

Governance

ELL's governance is driven by that of its parent, Entergy's governance, is broadly in-line with other utilities and does not pose particular risk (**G-2** issuer profile score). This is supported by our neutral-to-low scores on financial strategy and risk management, management credibility and track record, despite the above average use of aggressive tax policies that have caused some cash flow volatility and recent challenges by regulators.

ESG Issuer Profile Scores and Credit Impact Scores for ELL are available on Moodys.com. In order to view the latest scores, please click here to go to the landing page for ELL on MDC and view the ESG Scores section.

Liquidity analysis

ELL's internal liquidity is insufficient to cover its capital expenditure plans. However, ample liquidity has been provided through external arrangements with its parent and affiliate money pool, which have been instrumental in providing a bridge to more permanent long-term financing for recent storm costs.

We expect ELL's internal liquidity to consist of around $1.7 billion of cash flow from operations, compared to about $1.6 billion of capital expenditures over the next 12 months. As a result, ELL's free cash flow position will largely depend on its dividend policy. Through LTM 30 June 2022, ELL had upstreamed $185 million dividends to Entergy, compared to an average of $102 million over the past five years.

ELL's external liquidity includes access to the Entergy System money pool along with its own $350 million revolving credit facility, which matures in June 2027. The stand-alone facility requires ELL to meet a 65% debt to capitalization covenant. At 30 June 2022, ELL was in compliance with its credit facility covenant and had no revolver borrowings and no letters of credit outstanding.

ELL also has two separate $105 million facilities under the nuclear fuel company variable interest entities, each set to expire in June 2025. At 30 June 2022, ELL had around $20 million and $70 million outstanding on the respective facilities. Additionally, ELL has access to an uncommitted standby letter of credit facility, in order to support its MISO obligations, on which the utility had no letters of credit outstanding at 30 June 2022.

ELL's next long-term debt maturity is $200 million of collateralized mortgage bonds due in December 2022.

Rating methodology and scorecard factors

Exhibit 8

Entergy Louisiana, LLC

Regulated Electric and Gas Utilities Industry [1][2]	Current LTM 6/30/2022		Moody's 12-18 Month Forward View As of 9/7/2022 [3]	
Factor 1 : Regulatory Framework (25%)	**Measure**	**Score**	**Measure**	**Score**
a) Legislative and Judicial Underpinnings of the Regulatory Framework	A	A	A	A
b) Consistency and Predictability of Regulation	A	A	A	A
Factor 2 : Ability to Recover Costs and Earn Returns (25%)				
a) Timeliness of Recovery of Operating and Capital Costs	A	A	A	A
b) Sufficiency of Rates and Returns	A	A	A	A
Factor 3 : Diversification (10%)				
a) Market Position	Baa	Baa	Baa	Baa
b) Generation and Fuel Diversity	Baa	Baa	Baa	Baa
Factor 4 : Financial Strength (40%)				
a) CFO pre-WC + Interest / Interest (3 Year Avg)	4.3x	Baa	4.5x - 5.5x	A
b) CFO pre-WC / Debt (3 Year Avg)	11.8%	Ba	17% - 19%	Baa
c) CFO pre-WC – Dividends / Debt (3 Year Avg)	10.8%	Baa	14% - 16%	Baa
d) Debt / Capitalization (3 Year Avg)	48.8%	Baa	47% - 51%	Baa
Rating:				
Scorecard-Indicated Outcome Before Notching Adjustment		Baa1		A3
HoldCo Structural Subordination Notching	0	0	0	0
a) Scorecard-Indicated Outcome		Baa1		A3
b) Actual Rating Assigned		Baa1		Baa1

[1] All ratios are based on 'Adjusted' financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations.
[2] As of 6/30/2022.
[3] This represents Moody's forward view; not the view of the issuer; and unless noted in the text, does not incorporate significant acquisitions and divestitures.
Source: Moody's Investors Service

Appendix

Exhibit 9

Credit metrics and financial statistics

CF Metrics	Dec-18	Dec-19	Dec-20	Dec-21	LTM Jun-22
As Adjusted					
FFO	**1,488**	**1,548**	**1,503**	**1,661**	**1,542**
+/- Other	-160	-202	-409	-816	-512
CFO Pre-WC	**1,328**	**1,347**	**1,094**	**846**	**1,030**
+/- ΔWC	81	-99	-7	242	-255
CFO	**1,409**	**1,247**	**1,087**	**1,087**	**774**
- Div	128	208	22	60	185
- Capex	1,840	1,666	2,250	3,695	3,622
FCF	**-558**	**-627**	**-1,185**	**-2,668**	**-3,033**
(CFO Pre-W/C) / Debt	18.0%	16.9%	11.5%	7.5%	9.6%
(CFO Pre-W/C - Dividends) / Debt	16.3%	14.3%	11.2%	7.0%	7.9%
FFO / Debt	20.2%	19.4%	15.8%	14.7%	14.4%
RCF / Debt	18.5%	16.8%	15.5%	14.2%	12.6%
Revenue	4,296	4,285	4,070	5,068	5,475
Interest Expense	310	324	344	348	364
Net Income	555	578	1,086	713	997
Total Assets	19,713	21,429	24,686	27,676	27,827
Total Liabilities	13,914	15,137	17,244	19,495	18,306
Total Equity	5,800	6,292	7,443	8,181	9,522

All figures & ratios calculated using Moody's estimates & standard adjustments. Periods are Financial Year-End unless indicated. LTM=Last Twelve Months
Source: Moody's Financial Metrics

Exhibit 10
Peer comparison

	Entergy Louisiana, LLC Baa1 (Negative)			Cleco Power LLC A3 (Stable)			Duke Energy Florida, LLC. A3 (Stable)			Alabama Power Company A1 (Stable)		
(In US millions)	FYE Dec-20	FYE Dec-21	LTM Jun-22	FYE Dec-20	FYE Dec-21	LTM Jun-22	FYE Dec-20	FYE Dec-21	LTM Jun-22	FYE Dec-21	FYE Dec-21	LTM Jun-22
Revenue	4,070	5,068	5,475	1,032	1,242	1,419	5,188	5,259	5,816	5,830	6,413	6,878
CFO Pre-W/C	1,094	846	1,030	182	135	231	1,701	1,853	1,984	2,276	2,288	2,125
Total Debt	9,540	11,271	10,727	1,791	2,023	2,173	8,543	8,982	9,252	9,257	9,957	10,079
CFO Pre-W/C + Interest / Interest	4.2x	3.4x	3.8x	3.3x	2.7x	3.8x	6.0x	6.6x	6.8x	7.5x	7.4x	6.8x
CFO Pre-W/C / Debt	11.5%	7.5%	9.6%	10.2%	6.7%	10.6%	19.9%	20.6%	21.4%	24.6%	23.0%	21.1%
CFO Pre-W/C – Dividends / Debt	11.2%	7.0%	7.9%	10.2%	6.7%	8.2%	19.9%	20.6%	21.4%	14.3%	13.2%	11.2%
Debt / Capitalization	49.9%	51.5%	47.6%	42.3%	43.2%	44.3%	46.7%	45.6%	45.2%	41.0%	40.8%	39.5%

All figures & ratios calculated using Moody's estimates & standard adjustments. Periods are Financial Year-End unless indicated. LTM=Last Twelve Months
Source: Moody's Financial Metrics

Ratings

Exhibit 11

Category	Moody's Rating
ENTERGY LOUISIANA, LLC	
Outlook	Negative
Issuer Rating	Baa1
First Mortgage Bonds	A2
Senior Secured	A2
PARENT: ENTERGY CORPORATION	
Outlook	Negative
Issuer Rating	Baa2
Senior Unsecured	Baa2
Commercial Paper	P-2

Source: Moody's Investors Service

LPSC Docket No. U-_____
Exhibit TAS-4
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REPORT NUMBER 1340172

CLIENT SERVICES

Americas	1-212-553-1653
Asia Pacific	852-3551-3077
Japan	81-3-5408-4100
EMEA	44-20-7772-5454

MOODY'S INVESTORS SERVICE

BEFORE THE

LOUISIANA PUBLIC SERVICE COMMISSION

***IN RE*: APPLICATION OF ENTERGY**	**)**	
LOUISIANA, LLC FOR APPROVAL	**)**	**DOCKET NO. U- _______**
OF THE ENTERGY FUTURE READY	**)**	
RESILIENCE PLAN (PHASE I)	**)**	

EXHIBIT TAS-5

DECEMBER 2022

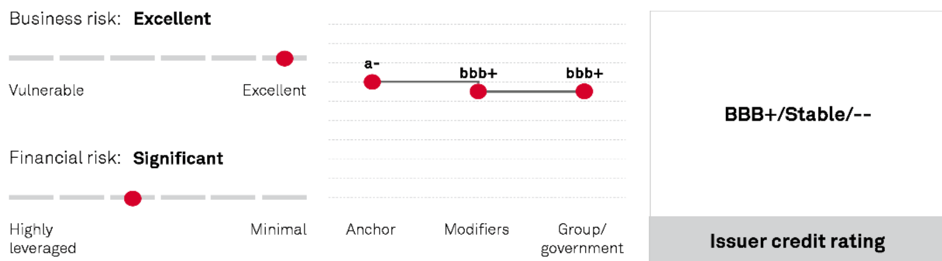
S&P Global Ratings

RatingsDirect®

Entergy Louisiana LLC

August 25, 2022

Ratings Score Snapshot



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Credit Highlights

Overview

Key strengths	Key risks
Mid-sized rate-regulated vertically integrated electric utility operations.	Mid-sized rate-regulated vertically integrated electric utility operations.
Relatively supportive regulatory jurisdiction with formula rate plans (FRP), providing an element of cash flow stability and predictability. Additionally, Louisiana has a well-established procedure for allowing utilities to securitize their storm related costs, which we assess as credit supportive.	Exposure to severe hurricanes and storms within its service territory.
	Lack of sufficient system hardening limits the company's ability to protect against severe storms and increases its business risk relative to peers.
	High dependence on industrial customers that could increase cash flow volatility.

Exposure to hurricane activity. Entergy Louisiana (ELL) remains exposed to hurricanes as evidenced by the recent 2021 category 4 Hurricane Ida which was the most destructive hurricane in Louisiana since the 2005 Hurricane Katrina. Furthermore, the National Oceanic and Atmospheric Administration is predicting an above-average Atlantic hurricane season for 2022, potentially raising risk for the company. Although the state has a well-established law that enables utilities to seek securitization to recover such costs, increasing commodity prices, interest rates, inflationary pressures, and the company's robust capital spending could all pressure the customer bill, potentially weakening the company's consistent ability to effectively manage regulatory risk.

ELL raised its three-year capital spending program. ELL raised its three-year capital plan to about $4.7 billion from approximately $4.2 billion. The increase in capital spending is driven by the projected increase in industrial demand in the Gulf region and to address the resiliency of its transmission and distribution system due to the increased frequency and intensity of storms. Given the rising customer bill from rising commodity costs and other rising costs from inflation, ELL's ability to effectively manage regulatory risk could become increasingly challenging.

ELL filed a prudence review of Hurricane Ida restoration costs of $2.6 billion. In April 2022, ELL filed with the Louisiana Public Service Commission (LPSC) for determination on the prudence and to certify Hurricane Ida costs of about $2.6 billion, of which $1 billion of costs were already recovered through securitization in 2022. Following the LPSC's certification of Hurricane Ida costs, ELL will request the use of securitization for the unrecovered costs (about $1.6 billion), and we expect the securitization bonds to be issued in the first half of 2023.

Outlook

The stable outlook on ELL over the next 24 months reflects our stable outlook on parent Entergy and our expectations that ELL's standalone financial measures will consistently reflect the lower end of the range for its financial risk profile category. Specifically, we expect that ELL's standalone adjusted funds from operations (FFO) to debt will reflect the 14%-17% range through 2024.

Downside scenario

We could lower our ratings on ELL over the next 24 months if:

- We lower our ratings on its parent Entergy; and
- Stand-alone financial measures for the utility weaken such that its adjusted FFO to debt is consistently below 13%.

Upside scenario

We could raise our ratings on ELL over the next 24 months if:

- The utility's stand-alone adjusted FFO to debt is consistently above 18%; or
- We raise our rating on parent Energy.

Our Base-Case Scenario

Assumptions

- Gross profit increase averaging about 5% per year;
- Expected EBITDA margin averaging about 35% per year;
- Annual capital spending averaging about $1.6 billion through the forecast period;
- About $785 million in capital spending to restore hurricane damage from hurricane Ida in 2022;
- Negative discretionary cash flow indicating external funding needs;
- Securitization proceeds received in 2023; and
- All debt maturities are refinanced.

Key metrics

Entergy Louisiana, LLC--Key Metrics*

Mil. $	2021a	2022f	2023f	2024f
FFO to debt (%)	13.1	14-16	15-17	14-16
Debt to EBITDA (x)	6.2	5.0-6.0	5.0-6.0	5.0-6.0
FFO cash interest coverage (x)	5.2	5.0-6.0	9.0-10	8.0-9.0

*All figures adjusted by S&P Global Ratings. a--Actual. f--Forecast. FFO—Funds from operations.

Company Description

ELL is a mid-sized electric and gas utility in Louisiana and is a subsidiary of Entergy Corp. ELL serves about 1.2 million customers in Louisiana, consisting of about 1.1 million electric customers and about 100 thousand gas customers. The company has about 10,700 MW of operating capacity and its electric generation is highly dependent on natural gas-fired generation (about 75%) and nuclear power (about 20%), with only limited exposure to coal-fired generation (about 5%).

Peer Comparison

Entergy Louisiana, LLC--Peer Comparisons

	Entergy Louisiana LLC	Union Electric Co. d/b/a Ameren Missouri	Arizona Public Service Co.	Alabama Power Co.	MidAmerican Energy Co.
Foreign currency issuer credit rating	BBB+/Stable/--	BBB+/Stable/A-2	BBB+/Negative/A-2	A-/Stable/A-2	A/Stable/A-1
Local currency issuer credit rating	BBB+/Stable/--	BBB+/Stable/A-2	BBB+/Negative/A-2	A-/Stable/A-2	A/Stable/A-1
Period	Annual	Annual	Annual	Annual	Annual
Period ending	2021-12-31	2021-12-31	2021-12-31	2021-12-31	2021-12-31
Mil.	$	$	$	$	$
Revenue	5,058	3,353	3,804	6,413	3,547
EBITDA	1,829	1,355	1,719	3,025	1,361
Funds from operations (FFO)	1,495	1,115	1,447	2,509	1,815
Interest	431	180	295	519	333
Cash interest paid	352	222	252	331	292
Operating cash flow (OCF)	982	900	951	2,088	1,604
Capital expenditure	3,666	2,049	1,472	1,738	1,899
Free operating cash flow (FOCF)	(2,683)	(1,150)	(521)	350	(295)

Entergy Louisiana, LLC--Peer Comparisons

Discretionary cash flow (DCF)	(2,743)	(1,175)	(919)	(626)	(295)
Cash and short-term investments	19	0	9	1,060	232
Gross available cash	19	248	9	1,060	232
Debt	11,390	5,723	6,787	9,190	7,547
Equity	8,181	5,871	6,750	10,859	8,960
EBITDA margin (%)	36.2	40.4	45.2	47.2	38.4
Return on capital (%)	7.1	5.9	7.2	10.2	3.2
EBITDA interest coverage (x)	4.2	7.5	5.8	5.8	4.1
FFO cash interest coverage (x)	5.2	6.0	6.7	8.6	7.2
Debt/EBITDA (x)	6.2	4.2	3.9	3.0	5.5
FFO/debt (%)	13.1	19.5	21.3	27.3	24.1
OCF/debt (%)	8.6	15.7	14.0	22.7	21.3
FOCF/debt (%)	(23.6)	(20.1)	(7.7)	3.8	(3.9)
DCF/debt (%)	(24.1)	(20.5)	(13.5)	(6.8)	(3.9)

Business Risk

Our assessment of ELL's business risk profile reflects its lower-risk, fully rate-regulated utility business that provides an essential service in its service territory. Given material barriers to entry, ELL and the regulated utility industry as a whole effectively operate insulated from competitive market challenges. This underlines our view of regulated utilities' very low industry risk compared to other industries.

ELL benefits from a constructive regulatory framework by the LPSC, where it operates under an FRP, providing stability to its cash flows and enabling it to generally earn close to its allowed return on equity. ELL's business risk profile also benefits from various riders, including capacity, transmission, fuel, and gas infrastructure. Overall, we expect the ELL will continue to effectively manage regulatory risk, focusing on further reducing its regulatory lag.

However, we view ELL at the lower end of the excellent business risk profile category compared with peers, given the propensity and severity of storm activity within ELL's service territory along the Gulf Coast and the limited ability of the utility to protect against severe storms. While we view securitization as a good backstop for storm restoration costs, securitization takes time to receive the ultimate funds and takes up headroom in the customer bill, potentially increasing the risk of the company consistently managing regulatory risk. We believe that for ELL to reduce its credit risk exposure to severe storms, it is important for the company to have a more resilient infrastructure that withstands severe storms, reducing the rate of recovery of pass-through costs to customers. Parent, Entergy Corp, intends to spend about $4 billion in accelerated resiliency spending within the next five years and about $15 billion over the next ten years, which we assess as supportive of the company's long-term credit quality.

ELL is a mid-sized utility serving roughly 1.2 million electric and gas customers in Louisiana, accounting for about 40% of parent Entergy's total adjusted operating income. Most of ELL's operations are the electric utility; its customer base comprises approximately 90% electric and 10% gas customers. About 50% of ELL's operating revenues are from residential and commercial customers, providing a measure of cash flow stability, this is partially offset by about 50% of operating revenues coming from industrial customers, which could expose the company to cash flow volatility, especially in an economic downturn.

The company owns around 10,700 megawatts (MW) of generating capacity, only about 30% of which is from nuclear and coal generation. We believe nuclear generation has a higher operating risk than other forms of power generation, and we believe coal generation potentially has greater environmental risk.

Financial Risk

Over the next three years, we expect ELL's elevated capital spending to average roughly $1.6 billion through 2024, driving its financial performance. We expect that the company's regulatory construct will provide periodic annual rate increases as its rate base grows, and we forecast operating cash flow will fund about 50%-70% of total funding needs. We anticipate the shortfall will be funded with a combination of debt and capital contributions from parent Entergy. Furthermore, we expect ELL's financial measures will remain at the lower end of the range for its financial risk profile category, primarily reflecting the company's robust capital spending. We anticipate securitization proceeds to provide relief starting in 2023.

Our base case includes adjusted FFO to debt in the 14%-17% range through 2024 and is predicated on the company's robust capital spending program, 2023 securitization proceeds of about $1.6 billion, annual dividends of about $200 million, and annual FRP increases. In addition, we forecast the company's ability to cover annual cash interest payments based on FFO, bolstering our assessment of ELL's financial risk, with coverage averaging 5x-6x per year through 2024. Finally, we forecast leverage, as indicated by adjusted debt to EBITDA, to be elevated in the 5.5x-6x range through 2024.

We assess ELL's financial risk profile using our medial volatility financial benchmarks, reflecting the company's steady cash flow and rate-regulated utility operations. These benchmarks are more relaxed than the benchmarks we use for typical corporate issuers.

Debt maturities

- 2022 - $200 million
- 2023 - $1.445 billion
- 2024 - $1.782 billion
- 2025 - $300 million
- 2026 - $775 million
- Thereafter - $6.412 billion

Entergy Louisiana, LLC--Financial Summary

Period ending	Dec-31-2016	Dec-31-2017	Dec-31-2018	Dec-31-2019	Dec-31-2020	Dec-31-2021
Reporting period	2016a	2017a	2018a	2019a	2020a	2021a
Display currency (mil.)	$	$	$	$	$	$
Revenues	4,154	4,277	4,273	4,262	4,047	5,058
EBITDA	1,518	1,752	1,410	1,646	1,723	1,829
Funds from operations (FFO)	1,008	1,677	1,191	1,294	1,396	1,495
Interest expense	343	349	364	383	411	431
Cash interest paid	354	309	324	337	341	352
Operating cash flow (OCF)	987	1,278	1,311	1,161	1,023	982
Capital expenditure	1,069	1,842	1,799	1,652	2,001	3,666
Free operating cash flow (FOCF)	(83)	(563)	(488)	(491)	(978)	(2,683)
Discretionary cash flow (DCF)	(368)	(655)	(616)	(699)	(999)	(2,743)
Cash and short-term investments	214	36	43	2	728	19
Gross available cash	214	36	43	2	728	19
Debt	6,290	6,927	7,425	7,971	8,998	11,390
Common equity	5,082	5,309	5,903	6,397	7,458	8,181

Entergy Louisiana, LLC--Financial Summary

Adjusted ratios

EBITDA margin (%)	36.6	40.9	33.0	38.6	42.6	36.2
Return on capital (%)	9.9	11.3	9.0	8.5	7.3	7.1
EBITDA interest coverage (x)	4.4	5.0	3.9	4.3	4.2	4.2
FFO cash interest coverage (x)	3.8	6.4	4.7	4.8	5.1	5.2
Debt/EBITDA (x)	4.1	4.0	5.3	4.8	5.2	6.2
FFO/debt (%)	16.0	24.2	16.0	16.2	15.5	13.1
OCF/debt (%)	15.7	18.5	17.7	14.6	11.4	8.6
FOCF/debt (%)	(1.3)	(8.1)	(6.6)	(6.2)	(10.9)	(23.6)
DCF/debt (%)	(5.9)	(9.5)	(8.3)	(8.8)	(11.1)	(24.1)

Reconciliation Of Entergy Louisiana, LLC Reported Amounts With S&P Global Adjusted Amounts (Mil. $)

	Debt	Shareholder Equity	Revenue	EBITDA	Operating income	Interest expense	S&PGR adjusted EBITDA	Operating cash flow	Dividends	Capital expenditure
Financial year	Dec-31-2021									
Company reported amounts	10,914	8,181	5,068	1,651	927	337	1,829	1,053	60	3,679
Cash taxes paid	-	-	-	-	-	-	18	-	-	-
Cash interest paid	-	-	-	-	-	-	(338)	-	-	-
Lease liabilities	65	-	-	-	-	-	-	-	-	-
Operating leases	-	-	-	14	1	1	(1)	13	-	-
Postretirement benefit obligations/ deferred compensation	429	-	-	-	-	-	-	-	-	-
Accessible cash and liquid investments	(19)	-	-	-	-	-	-	-	-	-
Capitalized interest	-	-	-	-	-	13	(13)	(13)	-	(13)
Securitized stranded costs	-	-	(10)	(10)	-	-	-	(10)	-	-
Asset-retirement obligations	-	-	-	80	80	80	-	-	-	-
Nonoperating income (expense)	-	-	-	-	263	-	-	-	-	-

Reconciliation Of Entergy Louisiana, LLC Reported Amounts With S&P Global Adjusted Amounts (Mil. $)

	Debt	Shareholder Equity	Revenue	EBITDA	Operating income	Interest expense	S&PGR adjusted EBITDA	Operating cash flow	Dividends	Capital expenditure
U.S. decommissioning fund contributions	-	-	-	-	-	-	-	(60)	-	-
EBITDA: other income/ (expense)	-	-	-	94	94	-	-	-	-	-
D&A: other	-	-	-	-	(94)	-	-	-	-	-
Total adjustments	476	-	(10)	178	344	94	(334)	(70)	-	(13)
S&P Global Ratings adjusted	**Debt**	**Equity**	**Revenue**	**EBITDA**	**EBIT**	**Interest expense**	**Funds from Operations**	**Operating cash flow**	**Dividends**	**Capital expenditure**
	11,390	8,181	5,058	1,829	1,271	431	1,495	982	60	3,666

Liquidity

We assess the company's stand-alone liquidity as adequate because we believe its liquidity sources will likely cover uses by more than 1.1x over the next 12 months and meet cash outflows even if EBITDA declines 10%. The assessment also reflects the company's generally prudent risk management, sound relationship with banks, and a generally satisfactory standing in credit markets.

Principal liquidity sources

- Cash and liquid investments of about $150 million as of March 2022;
- Total availability under the revolving credit facility of $350 million as of March 2022;
- Estimated cash FFO of about $1.6 billion; and
- May 2022 securitization proceeds of about $3.1 billion.

Principal liquidity uses

- Debt maturities of about $200 million;
- Working capital outflows of about $200 million;
- Capital spending of about $2.25 billion; and
- Dividends of about $200 million.

Environmental, Social, And Governance

ESG Credit Indicators

E-1	E-2	E-3	**E-4**	E-5	S-1	S-2	**S-3**	S-4	S-5	G-1	**G-2**	G-3	G-4	G-5

Environmental	Social	Governance
- Physical risks - Waste and pollution	- Health and safety	- N/A

N/A—Not applicable. ESG credit indicators provide additional disclosure and transparency at the entity level and reflect S&P Global Ratings' opinion of the influence that environmental, social, and governance factors have on our credit rating analysis. They are not a sustainability rating or an S&P Global Ratings ESG Evaluation. The extent of the influence of these factors is reflected on an alphanumerical 1-5 scale where 1 = positive, 2 = neutral, 3 = moderately negative, 4 = negative, and 5 = very negative. For more information, see our commentary "ESG Credit Indicator Definitions And Applications," published Oct. 13, 2021.

Environmental factors are a negative consideration in our credit rating analysis of ELL because the geographical position of the utility is exposed to extreme weather conditions. Consequently, hurricanes like Hurricane Ida negatively affect the company's transmission and distribution infrastructure and therefore impact the company's cash flow leverage via high restoration costs. Social factors are a moderately negative consideration in our credit rating analysis based on the nuclear generation's health and safety risks.

Group Influence

Under our group rating methodology, we assess ELL to be an insulated subsidiary of Entergy, reflecting our view that ELL is a stand-alone legal entity that functions independently, financially, and operationally, files its rate cases, and is independently regulated by its state commission. ELL has its own books and records, including financials. ELL also has its own funding arrangements, including issuing its own long-term debt and having separate committed credit facilities to cover short-term funding needs. The company does not commingle funds, assets, or cash flows, as demonstrated by parent Entergy's inability to borrow from the Entergy money pool; however, Entergy can lend to the pool. Based on the insulating measures in place, we could potentially rate ELL up to one notch higher than its group credit profile (GCP). Currently, we rate ELL's issuer credit rating the same as the 'bbb+' GCP because ELL's stand-alone credit profile is also at 'bbb+'.

We assess ELL as a core subsidiary of parent Entergy. This reflects our view that ELL represents a significant portion of Entergy's operating revenues, which are used to pay shareholder dividends, thus providing strong economic incentives to Entergy to preserve ELL's credit strength, and we do not expect a default by either Entergy or another entity within the group would lead to a default of the utility.

Issue Ratings--Recovery Analysis

Key analytical factors

ELL's first mortgage bonds benefit from a first-priority lien on substantially all of the utility's real property owned or subsequently acquired. Collateral coverage of more than 1.5x supports a recovery rating of '1+' and an issue rating two notches above the issuer credit rating.

Rating Component Scores

Foreign currency issuer credit rating	**BBB+/Stable/--**
Local currency issuer credit rating	**BBB+/Stable/--**
Business risk	**Excellent**
Country risk	Very Low
Industry risk	Very Low
Competitive position	Strong
Financial risk	**Significant**
Cash flow/leverage	Significant
Anchor	**a-**
Diversification/portfolio effect	Neutral (no impact)
Capital structure	Neutral (no impact)
Financial policy	Neutral (no impact)
Liquidity	Adequate (no impact)
Management and governance	Satisfactory (no impact)
Comparable rating analysis	Negative (-1 notch)
Stand-alone credit profile	**bbb+**
Group Credit Profile	bbb+
Entity status within the group	Insulated (no impact)

Related Criteria

- General Criteria: Group Rating Methodology, July 1, 2019
- General Criteria: Hybrid Capital: Methodology And Assumptions, July 1, 2019
- Criteria | Corporates | General: Corporate Methodology: Ratios And Adjustments, April 1, 2019
- Criteria | Corporates | General: Reflecting Subordination Risk In Corporate Issue Ratings, March 28, 2018
- General Criteria: Methodology For Linking Long-Term And Short-Term Ratings, April 7, 2017
- Criteria | Corporates | General: Recovery Rating Criteria For Speculative-Grade Corporate Issuers, Dec. 7, 2016
- Criteria | Corporates | General: Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers, Dec. 16, 2014
- General Criteria: Methodology: Industry Risk, Nov. 19, 2013
- General Criteria: Country Risk Assessment Methodology And Assumptions, Nov. 19, 2013
- Criteria | Corporates | Utilities: Key Credit Factors For The Regulated Utilities Industry, Nov. 19, 2013
- Criteria | Corporates | General: Corporate Methodology, Nov. 19, 2013
- Criteria | Corporates | Utilities: Collateral Coverage And Issue Notching Rules For '1+' And '1' Recovery Ratings On Senior Bonds Secured By Utility Real Property, Feb. 14, 2013
- General Criteria: Methodology: Management And Governance Credit Factors For Corporate Entities, Nov. 13, 2012
- General Criteria: Principles Of Credit Ratings, Feb. 16, 2011

Related Research

Ratings Detail (as of August 25, 2022)*

Entergy Louisiana LLC	
Issuer Credit Rating	BBB+/Stable/--
Senior Secured	A
Issuer Credit Ratings History	
02-Sep-2021	BBB+/Stable/--
14-Aug-2019	A-/Stable/--
03-May-2018	BBB+/Stable/--
Related Entities	
Entergy Arkansas LLC	
Issuer Credit Rating	A-/Stable/--
Senior Secured	A
Entergy Corp.	
Issuer Credit Rating	BBB+/Stable/A-2
Commercial Paper	
Local Currency	A-2
Senior Unsecured	BBB
Entergy Mississippi LLC	
Issuer Credit Rating	A-/Stable/--
Senior Secured	A
Entergy New Orleans LLC	
Issuer Credit Rating	BB/Developing/--
Senior Secured	BBB
Entergy Texas Inc.	
Issuer Credit Rating	BBB+/Stable/--
Preferred Stock	BBB-
Senior Secured	A
System Energy Resources Inc.	
Issuer Credit Rating	BBB+/Stable/--
Senior Secured	A

*Unless otherwise noted, all ratings in this report are global scale ratings. S&P Global Ratings credit ratings on the global scale are comparable across countries. S&P Global Ratings credit ratings on a national scale are relative to obligors or obligations within that specific country. Issue and debt ratings could include debt guaranteed by another entity, and rated debt that an entity guarantees.

BEFORE THE

LOUISIANA PUBLIC SERVICE COMMISSION

***IN RE*: APPLICATION OF ENTERGY**	**)**	
LOUISIANA, LLC FOR APPROVAL	**)**	**DOCKET NO. U- _______**
OF THE ENTERGY FUTURE READY	**)**	
RESILIENCE PLAN (PHASE I)	**)**	

DIRECT TESTIMONY

OF

JAY A. LEWIS

ON BEHALF OF

ENTERGY LOUISIANA, LLC

DECEMBER 2022

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EXHIBIT LIST

I. QUALIFICATIONS AND PURPOSE OF TESTIMONY

Q1. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND OCCUPATION.

A. My name is Jay A. Lewis. My business address is 3 Melrose Court, Monroe, Louisiana 71203. I am employed by the University of Louisiana at Monroe as an Instructor of Accounting. I am also a Principal of ASD@Work, LLC, through which I perform financial consulting services.

Q2. ON WHOSE BEHALF ARE YOU SUBMITTING THIS DIRECT TESTIMONY?

A. I am testifying on behalf of Entergy Louisiana, LLC ("ELL").[1]

Q3. PLEASE DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

A. I have a Master of Business Administration from Tulane University and a Bachelor of Business Administration in Accounting from the University of Louisiana at Monroe. I am a Certified Public Accountant, licensed to practice in Louisiana and Mississippi. I am a member of the American Institute of Certified Public Accountants and the Society of Louisiana Certified Public Accountants. I am also the past Chairman of the Accounting Standards Committee of the Edison Electric Institute.

[1] On October 1, 2015, pursuant to Louisiana Public Service Commission ("LPSC" or "Commission") Order No. U-33244-A, Energy Gulf States Louisiana, L.L.C. ("Legacy EGSL") and Entergy Louisiana, LLC ("Legacy ELL") combined substantially all of their respective assets and liabilities into a single operating company, Entergy Louisiana Power, LLC, which subsequently changed its name to Entergy Louisiana, LLC ("ELL") ("Business Combination"). Upon consummation of the Business Combination, ELL became the public utility that is subject to LPSC regulation and now stands in the shoes of Legacy EGSL and Legacy ELL in pending Commission dockets.

I began my career with Entergy Services, Inc. (now Entergy Services, LLC ("ESL"))[2] in 1999 as Director of Accounting Policy and Research. Beginning in 2004, I served as the Vice President and Chief Financial Officer of the Utility Operations Group. In 2008, I was named Vice President and Chief Accounting Officer-Designate for Enexus, a company proposed to be created by Entergy Corporation through a spinoff transaction. I assumed the position of Vice President, Finance, for ESL in May 2010, and transferred to the position of Vice President, Regulatory Strategy in July 2011. I assumed the position of Vice President, Regulatory Policy in January 2014, and I retired from ESL in August 2018. Prior to my career with ESL, I was employed for 16 years in public accounting roles with Legier & Materne and Deloitte & Touche. In August 2016, I became an Instructor of Accounting at the University of Louisiana at Monroe.

Q4. HAVE YOU PREVIOUSLY TESTIFIED IN ANY REGULATORY PROCEEDING?

A. Yes, I have testified before the Federal Energy Regulatory Commission ("FERC"), the Arkansas Public Service Commission ("APSC"), the Louisiana Public Service Commission ("LPSC"), the Public Utility Commission of Texas, the Council of the City of New Orleans (the "Council"), and the Mississippi Public Service Commission ("MPSC") on a variety of accounting and financial matters. A list of my prior testimony is attached as Exhibit JAL-1.

[2] ESL is a service company to the five Entergy Operating Companies ("EOCs"), which are Entergy Arkansas, LLC ("EAL"), ELL, Entergy Mississippi, LLC ("EML"), Entergy New Orleans, LLC ("ENO"), and Entergy Texas, Inc. ("ETI").

Q5. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony discusses a number of Commission orders that may be implicated by the Company's request regarding an accelerated resilience program and provides context for how the Company's proposal may be considered. Additionally, my testimony discusses the public interest standard that has been historically used at the LPSC and how that standard should be applied in the context of an accelerated resilience program that has both traditional benefits, as well as non-traditional benefits. I also discuss the periodic reporting required by the Business Combination order and the proposed monitoring plan for the resilience investments. Finally, I summarize the regulatory requests being made by ELL.

II. COMPLIANCE WITH COMMISSION ORDERS

Q6. ARE THERE ANY COMMISSION ORDERS THAT MAY BE RELEVANT TO THE COMMISSION'S CONSIDERATION OF THE COMPANY'S REQUEST IN THIS PROCEEDING?

A. Yes. While I am not an attorney, there are three orders of the Commission that are potentially relevant to the Company's request:

1. The Commission's General Order dated May 7, 1982 ("1982 GO"), as amended and superseded by the Commission's General Order dated June 7, 2019, issued in Docket No. R-34246 ("2019 GO");[3]

[3] The 1982 GO, as amended by the 2019 GO, defines a "major capital outlay" as "one in which it is reasonably anticipated that the utility's rate base, exclusive of retirements, will be increased by a factor in excess of 3%."

2. The Commission's General Order dated September 20, 1983, as amended by the General Order in Docket No. R-30517 dated May 27, 2009 ("1983 GO"); and
3. The Commission's General Order R-26018 ("Transmission Siting GO").

Q7. WOULD YOU PLEASE DISCUSS THE 1982 GO?

A. Yes. The 1982 GO requires notification to the Commission when a "major capital outlay" is being contemplated, prior to undertaking such projects. A major capital outlay is defined as one that is reasonably anticipated to increase utility rate base, net of retirements, by more than 3%. In recommending to reduce the threshold from the original 10%, LPSC staff noted that a regulatory gap existed for projects that do not fall under the 1983 GO (which I discuss below) or under the 1982 GO with a 10% threshold; as a result, certain large capital projects, such as replacement projects that do not add generating capacity, could be constructed and completed with no prior knowledge of the Commission until the utility sought rate recovery. Accordingly, the threshold was reduced to 3% as per the 2019 GO. As discussed by ELL witnesses Messrs. Sean Meredith and Jason De Stigter, the Comprehensive Hardening Plan, which is a subset of the Entergy Future Ready Resilience Plan ("Resilience Plan"), is a portfolio of over 9,600 projects. Three percent of ELL's current net rate base is approximately $420 million, and none of the individual projects included in the Resilience Plan are reasonably anticipated to exceed $420 million. Thus, the 1982 GO as amended by the 2019 GO does not appear to be applicable. Nonetheless, considering the overall significance and importance of the Resilience Plan, I believe it is appropriate to provide notification to the Commission before undertaking these projects, and it is appropriate for the Commission to make a public interest finding regarding a matter of such significance to the State of Louisiana.

Q8. PLEASE DISCUSS THE APPLICABILITY OF THE COMMISSION'S 1983 GO TO THE PROJECT.

A. The 1983 GO provides, in pertinent part, that:

> No electric public utility subject to the jurisdiction of the Commission shall commence any on site construction activity or enter into any contract for construction or conversion of electric generating facilities or contract for the purchase of capacity or electric power, other than emergency or economy power purchases, without first having applied to the Commission for a certification that the public convenience and necessity would be served through completion of such project or confection of such contract. Feasibility and engineering studies, site acquisition and related activities preliminary to a determination of the desirability or need for plant construction or conversion on purchase power contracts are exempted from this requirement.

On its face, the 1983 GO applies only to the addition of generation resources, whether by construction, acquisition, or purchased power. The LPSC Staff acknowledged in its testimony in Docket No. U-30670 that approval under the 1983 GO was not required for replacement of two steam generators at the Waterford Steam Electric Station, Unit 3 ("Waterford 3") facility because it was effectively a large maintenance project that did not add generation capacity. Nonetheless, the LPSC Staff recommended that the Commission issue a public interest determination because the Waterford 3 project represented a large capital expenditure and a major planning decision for ELL.[4] The Commission issued the requested public interest finding in Order No. U-30670.

4 *See* Direct Testimony on Matthew I. Kahal in Docket No. U-30670 at p. 51.

The resilience program proposed by ELL in its application in this docket similarly represents a large capital investment – and one that is vital for the future wellbeing of the State of Louisiana. As such, it would be appropriate for the Commission to issue a public interest finding regarding ELL's proposal or, alternatively, to determine the level of resilience investment that the Commission believes serves the public interest. As explained by Company witnesses Messrs. Meredith and De Stigter, the proposed resilience investment consists of multiple projects that have a positive benefit to cost ratio ("BCR"). The Company's recommendation reflects and represents its judgment regarding the proper balance of costs and benefits, as well as execution constraints, but because there is policy judgment involved in making this recommendation, the Commission may reach a different conclusion. The Commission may determine, for example, that the public interest is better served by pursuing a smaller number of projects with a higher BCR, or a larger number of projects that include a lower BCR (though presumably still in excess of 1.0).

Q9. PLEASE DISCUSS THE TRANSMISSION SITING GO.

A. The Commission's General Order R-26018 requires Commission approval before constructing transmission facilities in Louisiana, subject to multiple exceptions. For purposes of the Order only, transmission facilities are defined as a system of poles, wires, and equipment operating at a voltage greater than 100 kilovolts, exceeding one mile in length and having a cost greater than $20 million. A group of projects that solve a "common transmission related concern" are treated as a single transmission facility and are to be addressed in a single application. The Order indicates that the Commission may approve a transmission facility if it finds the facility to "be in the public interest and the interests of affected ratepayers, enhances reliability of service, and/or provides economic benefit, and/or advances policy goals."

Q10. DO YOU BELIEVE THE TRANSMISSION SITING GO IS APPLICABLE TO THE COMPANY'S PROPOSED RESILIENCE INVESTMENT?

A. I do not believe it directly applies. As discussed by Company witnesses Messrs. Meredith and De Stigter, the vast majority of projects included in the Company's proposals are distribution projects operating at voltages below 100 kilovolts, which are expressly exempted from the rule. While the Company's proposal does include several projects that fit the definition of transmission projects under the Order, it is possible that most of those projects may fall under exemption 7 to the rule: "the replacement, construction or modification of existing equipment or facilities with similar equipment or facilities in substantially the same location or rebuilding, upgrading, modernizing, or reconstruction of equipment on facilities that increase capacity of existing facilities." In my opinion, the resilience investment proposed by the Company generally constitutes replacement of existing equipment with similar equipment in the same general location, albeit with equipment that meets a higher wind rating. Nonetheless, the Company is seeking a public interest determination and, to the extent the Transmission Siting GO is applicable, a public interest finding by the Commission would satisfy the order.

Q11. WHILE YOUR CONCLUSION IS THAT THESE VARIOUS COMMISSION ORDERS DO NOT APPLY TO THE COMPANY'S RESILIENCE PROPOSAL, IS THERE A COMMON THEME FOUND IN EACH OF THESE COMMISSION ORDERS?

A. Yes. Even though the 1982 GO, the 1983 GO, and the Transmission Siting GO are not directly applicable, they all acknowledge that public interest findings are appropriate by the Commission on significant investments that can affect broader interests in Louisiana.

Q12. YOU INDICATED PREVIOUSLY THAT YOU WOULD DISCUSS WHY, IN YOUR OPINION, THE PROPOSED INVESTMENT IN RESILIENCE WOULD SERVE THE PUBLIC INTEREST. WHAT IS THE PUBLIC INTEREST?

A. The public interest is that which is thought to best serve everyone; it is the common good. If the net effect of a decision is believed to be positive or beneficial to society as a whole, it can be said that the decision serves the "public interest."

Public utilities in general, and electric utilities in particular, affect nearly all elements of society. Public utilities have the ability to influence the cost of production of the businesses that are served by them, to affect the standard of living of their customers, to affect employment levels in the areas they serve, and to affect the interests of their investors. In sum, public utilities affect the general economic activity in the state.

In determining whether a particular decision or policy is in the public interest, there is no immutable law or principle that can be applied. While the public interest is often defined in terms of "net benefits," such a test or standard merely substitutes one expression for another. The difficulty is in defining and, if possible, quantifying the "net benefits."

It is recognized that "net benefits" cannot simply be defined as lower prices. For example, if lower prices are achieved through a reduction in the reliability or quality of service, it may very well be perceived that the lower prices have not produced net benefits. Similarly, higher prices might not produce negative net benefits or detriments. For example, if an existing price is low due to a cross-subsidy, removing that subsidy would raise that price, but doing so would not necessarily be detrimental. The Louisiana Supreme Court reached just such a conclusion in *City of Plaquemine v. Louisiana Public Service Commission*, 282 So. 2d 440, 442-43 (1973), when it found that:

> The entire regulatory scheme, including increases as well as decreases in rates, is indeed in the public interest, designed to assure the furnishing of adequate service to all public utility patrons at the lowest reasonable rates consistent with the interest both of the public and of the utilities.
>
> Thus the public interest necessity in utility regulation is not offended, but rather served by reasonable and proper rate increases notwithstanding that an immediate and incidental effect of any increase is improvement in the economic condition of the regulated utility company.

Objective measurement of how a decision affects the public interest is problematic at best. For the past seventy or more years, regulatory decision-making has been tested in the courts by a balancing-of-interests standard. In these cases, beginning with *Federal Power Commission v. Hope Natural Gas Company*, 320 U.S. 591, 603 (1944), the courts have found that if the regulatory body's decision reflected a reasonable balancing of customer and investor interests, the decision was to be affirmed as just and reasonable.

In sum, determining whether a decision is in the "public interest" requires a balancing of the various effects of a particular course of action measured subjectively over the longer run. Whether a course of action is in the public interest will depend upon factors that are potentially quantifiable on an estimated basis, such as likely changes in costs, as well as upon other factors that are not quantifiable, such as the effect of that course of action on the robustness of a competitive market.[5] Finally, while witnesses can provide facts and opinions that bear on this issue, the decision-maker (the Commission) must ultimately weigh all of these factors and conclude whether the particular proposed course of action is in the public interest.

Q13. HAVE YOU REVIEWED THE RESILIENCE INVESTMENT AND BENEFITS REPORT THAT IS ATTACHED TO MR. DE STIGTER'S TESTIMONY, AND IF SO, WHAT ARE YOUR IMPRESSIONS?

A. I have read that report, and I find the approach taken by 1898 & Co. to be a comprehensive, thoughtful, customer-centric approach to analyzing the investments that ELL could make to reduce the effects of future storms on customers through system "hardening." 1898 & Co.'s approach is comprehensive because it relies on an analysis of both (1) all of the storms that have affected ELL's service area over a long period of time, and (2) virtually all of ELL's grid assets, in reaching its conclusions regarding resilience investments to be pursued. It is thoughtful in that it considers a multitude of factors in its analysis, including the strength and location of storms as well as the age and condition of ELL's assets. It is customer-centric in that it quantifies benefits of investments directly in relation to the effects of those investments on customers, both on the storm restoration costs they will bear after future storms, as well as, even more importantly in my view, the

[5] See *Permian Basin Area Rate Cases*, 390 U.S. 747, 815 (1968).

duration of the outages that customers will experience as a result of those storms. ELL uses this information to select resilience investments that reflect overall customer benefits exceeding the costs of the related investments, and this is an important point to emphasize – customers are projected to achieve net benefits from all of the investments proposed to be undertaken by ELL in this docket, based on 1898 & Co.'s analysis. I believe that 1898 & Co.'s framework is a solid framework upon which the Commission can make its public interest determinations regarding ELL's proposed resilience investments in this docket.

Q14. IN YOUR OPINION, IS THE COMPANY'S PROPOSED RESILIENCE INVESTMENT IN THE PUBLIC INTEREST?

A. Yes. I base this opinion on a number of factors discussed in detail by other witnesses. I base it on the recent increasing frequency and intensity in storms, the effectiveness of Florida utilities' resiliency investments during the recent Hurricane Ian, and the estimated reductions from the proposed resilience investments in future storm restoration costs as well as the duration of storm customer interruptions balanced against the costs of the proposed resilience investments.

Company witness Mr. Phillip May discusses in his testimony that Louisiana was impacted by multiple hurricane events in 2020 and 2021, including one category 4 storm in each of those years, and Company witness Mr. Todd Shipman explains that both S&P Global and Moody's Investor Service have identified ELL's being located in a hurricane-prone area as a key risk for the Company. In 2022, Florida was severely impacted by a category 4 storm – Hurricane Ian. The need to accelerate resilience investment for electric utilities situated on the Gulf Coast is evident.

Q15. HOW DOES THE EFFECTIVENESS OF FLORIDA UTILITIES' RESILIENCY INVESTMENTS DURING HURRICANE IAN SUPPORT A FINDING THAT THE COMPANY'S PROPOSED RESILIENCE INVESTMENT IS IN THE PUBLIC INTEREST?

A. The effectiveness of the Florida resiliency investments, based on initial information, shows that ELL's resiliency investments should prove effective in mitigating storm restoration costs and the duration of customer interruptions. As discussed by Mr. Meredith, although Florida experienced wide-spread outages from Hurricane Ian in 2022, a more resilient system reduced damage to the system and enabled more prompt restoration to those customers whose homes and businesses were in a condition that allowed them to take service. These are the same types of benefits expected from ELL's proposed accelerated resilience investment: reduced restoration costs and reduced customer minutes interrupted, both of which are discussed by Company witnesses Messrs. Meredith and De Stigter.

Public interest determinations should consider all relevant and material factors. As I discussed above, such factors include those that are capable of being quantified fairly easily, those that are difficult to quantify or estimate, and even those that cannot be quantified and are more qualitative in nature.

Q16. HOW DOES THE REDUCTION IN STORM RESTORATION COSTS SUPPORT A FINDING THAT THE COMPANY'S PROPOSED RESILIENCE INVESTMENT IS IN THE PUBLIC INTEREST?

A. The estimated amount of reduced restoration costs discussed by Messrs. Meredith and De Stigter is the product of an objective, transparent analysis, and the amount is substantial. ELL retained 1898 & Co to identify hardening projects and to prioritize investments on ELL's transmission and distribution systems utilizing a Storm Resilience Model. The model uses extensive information on past hurricanes, detailed information on ELL's current transmission and distribution system assets, and recent storm restoration cost information to quantify an estimate of restoration cost savings. These inputs are logical, transparent, and objective.

Moreover, the benefits to customers with respect to storm restoration costs are substantial. As explained by Mr. De Stigter, under any reasonably anticipated future storm activity level, ELL's proposed resiliency investments would reduce storm restoration costs by approximately fifty percent over a fifty-year period. The expected range of savings to customers would be from $3 billion, assuming a very low storm future, to $4 billion, assuming a very high storm future.

Q17. HOW DOES THE REDUCTION IN CUSTOMER MINUTES INTERRUPTED SUPPORT A FINDING THAT THE COMPANY'S PROPOSED RESILIENCE INVESTMENT IS IN THE PUBLIC INTEREST?

A. The other element included in ELL's measurement of the benefits from its proposed resilience investment program is the reduction in customer minutes interrupted following future storm events. From a customer's perspective, this is the more compelling and direct benefit of an accelerated resilience investment. While reduced restoration costs are obviously relevant and beneficial to customers, fewer minutes interrupted, *i.e.,* shortening the period during which customers are without electricity, following disruption events are in my view even more important from a customer perspective. Shorter outages allow customers to get back to normal quicker, whether those customers are residents, businesses, or industrial facilities.

Quantifying this benefit from a customer perspective is challenging, but necessary in order to gain a more fulsome view of the public interest of the proposed resilience investments. In its cost-benefit analysis, ELL and 1898 & Co. have used results from the Interruption Cost Estimate ("ICE") Calculator from the U.S. Department of Energy to quantify in dollars the societal benefit from reduced customer interruption duration. The advantage to using the ICE Calculator is that it is an existing tool developed by an independent entity, the Department of Energy, as opposed to a benefits quantification approach developed by ELL, which could be criticized as having a bias.[6] Thus, in my opinion, based on my experience, this quantification approach is reasonable for purposes of this public interest determination.

[6] As Mr. Meredith explains, the DOE's ICE calculator does not consider the specific circumstances that would be necessary to assess the causes and impacts of an outage to customers in specific circumstances, and it was developed to estimate the economic impact of outages of relatively short duration. As such, and for purposes of the Resilience Plan, the ICE calculator was extrapolated for the longer outage durations associated with storm outages to evaluate the societal impacts to customers generally as described by Mr. Meredith. Stated another way, the Company's use of the DOE's ICE calculator to help prioritize projects within the Comprehensive Hardening Plan is not an endorsement of the calculator's ability to calculate accurately or effectively the economic impact of a particular outage on any particular customer.

Nevertheless, the Commission should carefully consider the Company's quantification of the estimated benefits from reduced customer interruption duration and determine whether the Company's benefits quantification is overstated, understated, or reasonable.

Two things, however, are clear: reduced customer interruption duration resulting from the plan is a benefit, and that benefit is material to customers and reasonably cannot be ignored in this public interest determination. As I said above, ELL has used the ICE Calculator Results to quantify the benefit, and such quantification is in my view reasonable under the circumstances.

Q18. ARE THERE OTHER FACTORS THAT YOU CONSIDER RELEVANT TO A PUBLIC INTEREST DETERMINATION REGARDING THE RESILIENCE PLAN?

A. Yes. There is a significant cost associated with the Resilience Plan that cannot be overlooked, but the level of proposed investment is expected to be exceeded by customer benefits in terms of reduced restoration costs and fewer minutes interrupted following future storms. In addition to these net benefits, there are important financial and credit implications associated with the Resilience Plan, as discussed by Company witnesses Ms. Maurice-Anderson and Mr. Shipman, that further support a finding that ELL's Resilience Plan is in the public interest. As Mr. Shipman discusses, a more resilient system will likely be necessary for ELL to avoid future credit downgrades that would increase ELL's financing costs and thus increase customer bills, should they occur. As Ms. Maurice-Anderson discusses, there is a need for ELL to have a more resilient and hardened system because the Commission and ELL may not be able to rely on securitization as a low cost means to manage storm costs for the foreseeable future. These additional factors further support my conclusion that ELL's Resilience Plan is in the public interest.

Q19. WHEN THE COMMISSION APPROVED THE BUSINESS COMBINATION OF LEGACY ELL AND LEGACY EGSL, WHAT WAS REQUIRED OF THE COMPANY IN TERMS OF ENSURING THAT THE BUSINESS COMBINATION WOULD NOT DETRIMENTALLY IMPACT SERVICE QUALITY AND RELIABILITY?

A. Commission Order No. U-33244-A approving the Business Combination included certain protections to ensure that the benefits of the Business Combination would not come at the expense of safe, reliable, and affordable service, such as requiring certain reports to the Commission on matters that could impact service quality and reliability.[7] For a number of years, the Company has been providing periodic reports containing the information required by Order No. U-33244-A, including, but not limited to:

- Annual compliance filings regarding reliability and results of operations;
- Annual filings of the Company's vegetation management plan;
- Annual reports with transmission-only System Average Interruption Duration Index ("SAIDI") and System Average Interruption Frequency Index ("SAIFI") results and other data on transmission outages; and
- Quarterly reports for outages incurred on the Entergy transmission system resulting in a loss of power supply to industrial customer load of 5 MW or more in Louisiana.

[7] *See* Commission Order No. U-33244-A, *In Re: Potential Business Combination of Entergy Louisiana, LLC and Entergy Gulf States Louisiana, L.L.C.*, at Subsection G of Attachment "A" thereto.

Through these reports, the Company has kept stakeholders apprised of its efforts, and the results of such efforts, to ensure reliable electric service.[8]

And now, through its Application in this Docket, the Company is taking the important step of formalizing its plans to build a stronger and more resilient electric infrastructure, which plans are intended to facilitate the Company's responsibility to continue to provide safe, reliable service to customers.

Q20. IS THE COMPANY SIMILARLY PROPOSING A MONITORING PLAN AS PART OF ITS RESILIENCE PLAN?

A. Yes. As discussed in more detail by Mr. Meredith, to keep the LPSC informed on the progress and costs of the Resilience Plan, the Company is proposing to file progress reports every six months beginning August 15, 2024. The reports generally will provide information regarding the preceding two quarters. For example, the report filed on August 15, 2024, will discuss projects completed and developments in the execution of the plan for the period of January 1, 2024, through June 30, 2024; and the report filed on February 15, 2025, will discuss projects completed and developments in the execution of the plan for the period of July 1, 2024, through December 31, 2024. Near the end of Phase I, the Company will evaluate the impact of its efforts and make a recommendation about completing the portfolio of resilience projects in Phase II of the Resilience Plan.

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8 The Company also submits its annual report in compliance with the Commission's General Order dated April 30, 1998, Docket No. U-22389, *In re: Ensuring Reliable Electric Service.*

Q21. WHAT SPECIFIC FINDINGS DOES ELL REQUEST THAT THE COMMISSION MAKE IN THIS PROCEEDING?

A. ELL is seeking the following actions by the Commission (the specifics of which are discussed above and/or in the testimony of other witnesses supporting the Company's Application):

- That the Commission approve Phase I of the Resilience Plan as prudent and in the public interest subject to an ongoing obligation of ELL to prudently manage the Resilience Plan;
- That the Commission deem the prudently incurred costs to be incurred under the Resilience Plan to be eligible for cost recovery via the rate mechanisms proposed by the Company;
- That the Commission approve the Resilience Plan Cost Recovery Rider to permit timely recovery of the Resilience Plan's revenue requirement and to provide for true-up reporting, prudence review and dispute resolution procedures;
- That the Commission approve the creation of a regulatory asset for addressing recovery of (and on, if applicable) the remaining net book value of assets that are replaced through the Resilience Plan, at the level currently reflected in ELL's rates;
- That the Commission approve the Company's proposed monitoring plan; and
- That the Commission acknowledge that ELL will be requesting FERC approval to capitalize certain conductor handling expenses that would otherwise be treated as expenses, and express support or non-opposition to the contemplated FERC waiver request.

Q22. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, at this time.

AFFIDAVIT

STATE OF LOUISIANA

PARISH OF OUACHITA

NOW BEFORE ME, the undersigned authority, personally came and appeared, **JAY A. LEWIS**, who after being duly sworn by me, did depose and say:

That the above and foregoing is his sworn testimony in this proceeding and that he knows the contents thereof, that the same are true as stated, except as to matters and things, if any, stated on information and belief, and that as to those matters and things, he verily believes them to be true.

Jay A. Lewis

Jay A. Lewis

SWORN TO AND SUBSCRIBED BEFORE ME
THIS 15 DAY OF DECEMBER, 2022

NOTARY PUBLIC

My commission expires: At Death

WILLIAM STRATTON
Notary Public
Notary ID No. 88515
Ouachita Parish, Louisiana

BEFORE THE

LOUISIANA PUBLIC SERVICE COMMISSION

***IN RE*: APPLICATION OF ENTERGY LOUISIANA, LLC FOR APPROVAL OF THE ENTERGY FUTURE READY RESILIENCE PLAN (PHASE I)**	**))))**	**DOCKET NO. U- _______**

EXHIBIT JAL-1

DECEMBER 2022

Listing of Previous Testimony Filed by Jay A. Lewis

DATE	TYPE	JURISDICTION	DOCKET NO.
August 2004	Direct	PUCT	30123
March 2007	Rebuttal	APSC	06-101-U
April 2007	Sur-Surrebuttal	APSC	06-101-U
September 2007	Direct	PUCT	34800
February 2008	Rebuttal	APSC	06-152-U
March 2008	Sur-Surrebuttal	APSC	06-152-U
May 2008	Rebuttal	PUCT	34800
October 2008	Direct	MPSC	2008-AD-381
November 2010	Supplemental	FERC	EL10-55-001
May 2011	Supplemental Direct	APSC	10-011-U
August 2011	Rebuttal	APSC	10-011-U
August 2011	Sur-Surrebuttal	APSC	10-011-U
September 2011	Direct	PUCT	39741
November 2011	Direct	CNO	UD-11-01
November 2011	Rebuttal	APSC	11-069-U
December 2011	Sur-Surrebuttal	APSC	11-069-U
December 2011	Supplemental Direct	PUCT	39896
April 2012	Rebuttal	PUCT	39896
June 2012	Cross Answering	CNO	UD-11-01
August 2012	Rebuttal	CNO	UD-11-01
September 2012	Direct	APSC	12-069-U
September 2012	Direct	CNO	UD-12-01
September 2012	Direct	FERC	ITC Application
September 2012	Direct	LPSC	U-32538
October 2012	Direct	MPSC	2012-UA-358
January 2013	Direct	LPSC	U-32148
January 2013	Direct	CNO	UD-08-03
February 2013	Direct	PUCT	41223

DATE	TYPE	JURISDICTION	DOCKET NO.
February 2013	Direct	PUCT	41235
February 2013	Direct	LPSC	U-32707
February 2013	Direct	LPSC	U-32708
March 2013	Direct	APSC	13-028-U
March 2013	Supplemental	ENO	UD-12-01
April 2013	Direct	PUCT	41235
April 2013	Supplemental	PUCT	41235
May 2013	Rebuttal	PUCT	41223
May 2013	Rebuttal	APSC	12-069-U
May 2013	Rebuttal	LPSC	U-32538
June 2013	Rebuttal	CNO	UD-08-03
June 2013	Rebuttal	CNO	UD-12-01
June 2013	Sur-Surrebuttal	APSC	12-069-U
July 2013	Supplemental	APSC	12-069-U
July 2013	Rebuttal	LPSC	U-32675
August 2013	Rejoinder Testimony	CNO	UD-12-01
August 2013	Rebuttal	APSC	13-028-U
August 2013	Supplemental Rebuttal	APSC	12-069-U
September 2013	Sur-Surrebuttal	APSC	13-028-U
September 2013	Direct	PUCT	41850
September 2013	Direct	PUCT	41791
November 2013	Rebuttal	PUCT	41850
December 2013	Settlement	LPSC	U-32708
February 2014	Rebuttal	CNO	UD-13-01
April 2014	Rejoinder Testimony	CNO	UD-13-01
June 2014	Direct	MPSC	EC-123-0082-00
June 2014	Direct	MPSC	EC-123-0082-00
September 2014	Direct	LPSC	U-33244
October 2014	Direct	CNO	UD-14-02

DATE	**TYPE**	**JURISDICTION**	**DOCKET NO.**
November 2014	Direct	CNO	UD-14-03
January 2015	Supplemental	CNO	UD-14-01
January 2015	Direct	LPSC	UD-33510
January 2015	Direct	APSC	14-118-U
February 2015	Direct	CNO	UD-15-01
April 2015	Direct	APSC	15-015-U
April 2015	Rebuttal	CNO	UD-14-01
May 2015	Rebuttal	LPSC	U-33244
June 2015	Rebuttal	LPSC	U-33510
June 2015	Direct	PUCT	44704
June 2015	Direct	LPSC	U-33033
June 2015	Direct	LPSC	U-33645
July 2015	Rebuttal	APSC	14-118-U
August 2015	Sur-Surrebuttal	APSC	14-118-U
August 2015	Supplemental	CNO	UD-15-01
August 2015	Direct	LPSC	U-33770
September 2015	Supplemental Rebuttal	LPSC	U-33510
October 2015	Rebuttal	APSC	15-015-U
December 2015	Sur-Surrebuttal	APSC	15-015-U
January 2016	Rebuttal	LPSC	33633
March 2016	Rebuttal	LPSC	33770
September 2016	Direct	APSC	16-060-U
October 2016	Direct	CNO	UD-16-04
November 2016	Direct	LPSC	U-34320
November 2016	Direct	MPSC	2016-UA-261
June 2017	Rebuttal	APSC	16-060-U
January 2022	Answering	FERC	EL20-72-000
July 2022	Sur-Rebuttal	FERC	EL20-72-000