Edward R. Wicker, Jr.
Assistant General Counsel
Entergy Services, LLC
504-576-3101 | ewicker@entergy.com
639 Loyola Avenue, New Orleans, LA 70113

December 19, 2025

Via Electronic Delivery
Clerk of Council
City Hall - Room 1E09
1300 Perdido Street
New Orleans, LA 70112

Re: IN RE: SYSTEM RESILIENCY AND STORM HARDENING
Council Docket No. UD-21-03

Dear Clerk of Council:

Entergy New Orleans, LLC ("ENO") attaches for filing its Application for Approval of Phase 2 Resilience Plan and Related Requests for Relief.

This filing includes the Direct Testimony and Exhibits of Deanna Rodriguez, Chris Gremillion, Arlin Mire, Keith Wood, and Alyssa Maurice-Anderson. ENO submits this filing electronically and will submit the requisite original and number of hard copies once the Council resumes normal operations, or as you direct. ENO requests that you file this submission in accordance with Council regulations as modified for the present circumstances.

Please note that two exhibits (CG-1 & CG-2), which are attached to Mr. Gremillion's testimony, and Ms. Maurice-Anderson's testimony contain Highly Sensitive Protected Material ("HSPM"). The HSPM exhibits and testimony are being provided via electronic means only to those appropriate reviewing representatives who have executed the Official Protective Order in this docket, and as further provided therein.

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

Sincerely,

Edward R. Wicker, Jr.

ERW/jlc

cc: Official Service List (UD-21-03)

BEFORE THE

COUNCIL OF THE CITY OF NEW ORLEANS

IN RE: SYSTEM RESILIENCY AND STORM HARDENING	**))**	**DOCKET NO. UD-21-03**

APPLICATION OF ENTERGY NEW ORLEANS, LLC FOR APPROVAL OF PHASE 2 RESILIENCE PLAN AND RELATED REQUESTS FOR RELIEF

Entergy New Orleans, LLC ("ENO" or "the Company"), respectfully submits this Application for Approval of ENO's Phase 2 Resilience Plan and Related Requests for Relief ("Application").

As discussed herein, in Resolution No. R-24-625, the Council of the City of New Orleans ("Council") approved an initial set of accelerated infrastructure hardening projects to strengthen the resilience of the Company's electric grid against increasingly frequent and severe weather events impacting New Orleans ("Phase 1"). Through this Application, the Company now requests that the Council approve a second set of accelerated hardening projects, referred to herein as the Phase 2 Resilience Plan, and related requests for relief. The Phase 2 Resilience Plan builds on the Company's progress in Phase 1 and moves ENO closer to the goal of having a more resilient energy grid that further supports a sustainable community for all residents and businesses with economic growth and opportunity for decades to come. Thus, investing in the grid now will get the lights back on quicker after severe weather events and make customers' bills more affordable by reducing storm costs and mitigating other lengthy storm outage-related costs experienced by customers in the past.

The Company further requests that the Council issue a procedural schedule at its January 2026 public meeting, establishing appropriate deadlines such that the Council can issue all necessary approvals relative to the Application no later than its October 2026 public meeting. Proceeding pursuant to that timeline will allow the Company to continue to expeditiously and efficiently implement hardening projects for the benefit of customers. For the reasons discussed herein, ENO respectfully requests that the Council approve the Application.

OVERVIEW

Considering severe weather is impacting the New Orleans area with increased frequency and intensity, and that higher demand is being placed on resilience than even the very recent past, the Council opened this docket to "increase resiliency and storm hardening on ENO's system, with a particular focus on reducing weather-related power outages." In opening the docket, the Council correctly observed that "this cycle of damage and repair [from extreme weather] is not sustainable for the Company or ratepayers."[1] The goals of this docket – to get the lights back on quicker and to minimize restoration costs for New Orleans residents after extreme weather events – are vital and shared by the Company and its customers, as well as New Orleans as a whole. As an important first step, the Council approved a $100 million set of accelerated infrastructure hardening projects through December 2026, which is Phase 1.

ENO and the Council, however, must continue to make resilience investments to better position New Orleans for future weather events and to keep costs low for customers. It is not a matter of *if* another severe storm hits New Orleans, but *when*. For example, Hurricane Francine made landfall in 2024 as a Category 2 hurricane and resulted in approximately $200 million in repair and restoration costs for ENO and Entergy Louisiana, LLC ("ELL"). These storms pose an increasing threat to the Company's electric system, which has reinforced the need to further invest in resilience. Indeed, the storms are not stopping; New Orleans remains vulnerable; and the City

[1] Resolution No. R-21-401, p. 2.

should not stop its resilience progress. Cognizant of this reality, the Company has developed its Phase 2 Resilience Plan aimed at further addressing the risks associated with more frequent and intense severe weather.

The Phase 2 Resilience Plan consists of approximately $400 million in distribution hardening projects to be completed over the five-year period from 2027 to 2031.[2] The projects are a significant next step in the Company's ongoing efforts to strengthen the grid. As Ms. Rodriguez discusses in her testimony, Councilmembers have highlighted the importance of strengthening the grid to improve quality of life in New Orleans. The Phase 2 Resilience Plan is designed to deliver exactly that: a more resilient energy grid that protects customers today while enabling economic growth and opportunity for decades to come. In this way, the Phase 2 Resilience Plan is more than an infrastructure proposal to enable customers to come back online more quickly after severe weather – it represents a deliberate investment in the future of New Orleans and a commitment to the City's long-term economic prospects.

Indeed, the Company's electric grid must become sufficiently more resilient to support New Orleans as an economic driver, and maintain existing customers in New Orleans and also attract new customers, all while minimizing outages and storm restoration costs for customers. The Company estimates that the Phase 2 Resilience Plan will decrease future restoration costs after major weather events by approximately $83 million, and will lead to an estimated reduction of 3.4 billion customer minutes interrupted ("CMI") after major events, which corresponds to an estimated reduction of over $1.3 billion in estimated overall outage costs to customers, over the

[2] The specific projects contained in the Phase 2 Resilience Plan are attached to the testimony of Company witness Chris Gremillion as Highly Sensitive Protected Materials ("HSPM") Exhibit CG-2. Although the Company's Phase 2 Resilience Plan sets forth the Company's best efforts to identify the scope and timing of the projects, the precise work performed (as well as the exact timing of when that work will be performed) will be subject to continual refinement as the Company implements the Phase 2 Resilience Plan ultimately approved by the Council.

next fifty years assuming an above average frequency of storms. Moreover, the harmful non-bill impacts to all customers – but residential customers in particular – from major storm events cannot be overlooked. Given that so many residents in New Orleans are low income, ENO understands that evacuating is difficult if not impossible for them. It is therefore important for ENO to get power back on as quickly as possible following a storm. To make that goal possible, the Phase 2 hardening projects are critical.

Hardening projects have produced positive results. For example, as Mr. Gremillion discusses in his testimony, in 2024, Hurricane Francine heavily impacted portions of ELL's service area, including the Bayou Region, River Parishes, and Grand Isle. In replacing the facilities devastated in the same areas following Hurricane Ida in 2021, ELL rebuilt its facilities to modern, hardened standards. Those poles fared well during Hurricane Francine, with fewer damaged or destroyed, which resulted in fewer outages and quicker restoration time. Moreover, no structures that were hardened as part of ELL's accelerated resilience program were damaged or destroyed in Hurricane Francine, demonstrating the effectiveness of those upgrades.

The Phase 2 Resilience Plan must commence in January 2027, immediately following completion of Phase 1, to capture cost and operational efficiencies, retain skilled work crews in New Orleans, and maintain the momentum of hardening efforts already underway. Any disruption of continuity between the ongoing projects and the Phase 2 Resilience Plan will increase costs to customers and delay the benefits of hardening the grid. Moreover, while the Company is proud that its rates remain below the national average, the Phase 2 Resilience Plan will make customers' bills more affordable by reducing future storm costs and mitigating other storm-related costs borne by customers. To ensure customers are receiving benefits, the Company proposes to enter into a monitoring plan that would include certain accountability metrics and reporting requirements that already are in place for Phase 1.

ENO has supported its Application with testimony, analysis, and a data-driven decision-making methodology, demonstrating that the Phase 2 Resilience Plan strikes an appropriate balance between costs to customers and the continued need for accelerated infrastructure hardening. The Company proposes to use the existing Resilience and Storm Hardening Cost Recovery Rider ("Resilience Rider"), which ENO uses for cost recovery of Phase 1 projects, to permit timely recovery of the Phase 2 Resilience Plan's revenue requirement. The Resilience Rider would help support ENO's ability to finance the projects in the Phase 2 Resilience Plan and ensure that those projects can be done timely and efficiently. As ENO continues to pursue public funds for resilience, there is flexibility in the Resilience Rider to offset investment and reduce the rate timely should such funds be obtained.

In support of the relief requested in this Application, the Company has attached hereto the testimonies of the following witnesses:

- Deanna Rodriguez – President and CEO of ENO – Ms. Rodriguez presents ENO's Application, and explains that the Phase 2 Resilience Plan is more than an infrastructure hardening proposal – it represents a deliberate investment in the future of New Orleans and a commitment to the City's long-term economic prospects, while also keeping costs down for customers. She also introduces the additional witnesses supporting the Application.

- Chris Gremillion – Director, Project Management – Project Delivery for Entergy Services, LLC ("ESL"). Mr. Gremillion presents ENO's Phase 2 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 Phase 2 Resilience Plan are in the public interest and should be made, and summarizes the Company's proposed monitoring plan in terms of reporting and metrics.

- Arlin Mire – Project Manager, 1898 & Co. Mr. Mire summarizes the results and methodology used to develop the Phase 2 Resilience 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 Resilience Event Simulation Model ("Resilience Model"), which includes a Major Events Database, System Vulnerability and Event Impact Module ("Event Impact Module"), Resilience Benefit Module, and Plan Development Module. He also reviews historical major storm events that have impacted ENO's service area, describes the datasets used in the Event Impact Module 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 Resilience Model.

- Alyssa Maurice-Anderson – Director, Regulatory Filings and Policy for ESL. Ms. Maurice-Anderson supports the Company's requested use of the existing Resilience and Storm Hardening Cost Recovery Rider ("Resilience Rider") to permit timely cost recovery of the Phase 2 Resilience Plan under the Resilience Rider and associated ratemaking treatment for the projects in the Phase 2 Resilience Plan, as well as certain additional ratemaking treatment. She also discusses bill impacts to customers from the Phase 2 Resilience Plan. In addition, she supports a finding from the Council that the Company's Phase 2 Resilience Plan is in the public interest and therefore is prudent.

- Keith Wood – Director, Resource Planning and Market Operations for ENO. Mr. Wood discusses an opportunity to partner with the Sewerage and Water Board of New Orleans ("SWBNO") to pursue a grant for needed backup generation at four critical SWBNO pumping sites, and the resilience and reliability improvements that would result from the projects and benefit ENO customers.

BACKGROUND

A. Procedural Background

In response to Resolution No. R-23-74, and consistent with the goals of this docket, the Company filed an application in 2023 that contained a comprehensive resilience plan that spanned ten years. In that application, the Company recommended, among other things, approval of approximately $559 million in hardening projects proposed to be implemented in an initial five-year period. Thereafter, in Resolution No. 24-73, the Council directed the Company to present a smaller set of projects over a shorter period. In response, the Company in 2024 presented a set of hardening projects totaling approximately $168 million to be completed over an initial three-year period. In Resolution No. R-24-625, as a first step, the Council approved the Phase 1 projects totaling approximately $100 million over a two-year period (2025 to 2026), as well as the Company's Resilience Rider, and directed the development of certain metrics and reporting requirements for the Phase 1 projects.[3] The Company informed the Council that, to continue to deliver resilience benefits to customers across New Orleans, ENO would submit additional sets of hardening projects beyond Phase 1.[4]

B. <u>Phase 1 Projects</u>

As Mr. Gremillion explains in his testimony, Phase 1 consists of 63 accelerated infrastructure hardening projects that have been consolidated and grouped into a set of 32 projects for execution[5] and are located in each Council District. To date, the Company has completed and placed in service a total of 6 projects in Phase 1, and is projecting that it will complete construction on a total of 10 of the 32 Phase 1 projects in 2025. The remaining projects in Phase 1 are on schedule for completion by the end of 2026. Once completed, the projects are expected to produce significant customer benefits by lowering post-storm restoration costs, reducing outages, and getting the lights back on more quickly after storms.

---

[3] In addition, while not in response to a specific Company request in this docket, in Resolution No. R-24-73, the Council approved the Company's line hardening and battery microgrid project in New Orleans East, to be partially funded by the Department of Energy's Grid Resilience and Innovation Partnerships ("GRIP") program ("GRIP Project"). While the GRIP Project is an important part of ENO's resilience strategy, the Company does not consider the GRIP Project to be part of Phase 1. The GRIP Project and Phase 1 were separately considered and approved by the Council. Moreover, the GRIP Project is on a different timeline than the Phase 1 projects.

[4] *E.g.*, ENO's Proposed 2025-27 Resilience Plan and Request to Expedite Fourth Technical Conference, filed March 21, 2024.

[5] As Mr. Gremillion further explains, the geographic and circuit coverage of the 32 consolidated projects is the same as the original list of 63 projects, as is the expected system hardening.

The Phase 1 projects are an important first step for enhancing resilience, but those projects are not located throughout the entire New Orleans area and do not achieve the benefits that comprehensive storm hardening could reasonably and prudently achieve. Thus, additional resilience projects are needed to continue to meet the goals of this docket and provide benefits for more ENO customers in more areas of New Orleans. The Company has been working to build on the hardening efforts previously approved by the Council in Phase 1. The Company's work, in conjunction with 1898 & Co. (an outside industry consultant that provides strategic asset planning services and has experience in developing resilience plans for electric utilities, including ENO's Phase 1) led to the development of the Phase 2 Resilience Plan, which identifies additional cost-effective and achievable hardening projects to further increase the resilience of the electric system in New Orleans. The collaborative process and work undertaken in this docket also has helped inform and direct the development of the Phase 2 Resilience Plan.

RESILIENCE MODEL

As noted above, the Phase 2 Resilience Plan involves significant incremental spending in hardening the Company's distribution system 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 beneficial hardening projects and prioritize investment in ENO's assets through the Resilience Model. As Messrs. Mire and Gremillion discuss in their testimonies, the Resilience Model employs a data-driven decision-making methodology utilizing robust and sophisticated algorithms to evaluate the assets on ENO's system and calculate resilience costs and estimated benefits of hardening those assets in terms of reduced customer minutes interrupted and avoided future storm restoration costs.

The ultimate purpose of the Resilience Model is to identify and prioritize projects that would have the highest benefits to customers. Because it is not feasible, both logistically and financially, to address the risks arising from every single asset on the ENO electric system, the Resilience Model serves to identify and prioritize hardening the sets of assets that would deliver the most benefits to customers in terms of avoided customer outage minutes and avoided future storm restoration costs for the money spent. In this way, the Resilience Model facilitates the prudent and efficient use of finite resources to achieve the most benefits for customers. This methodology is described in more detail in the testimonies and exhibits of Messrs. Mire and Gremillion.

PHASE 2 RESILIENCE PLAN

As Messrs. Mire and Gremillion discuss in their testimonies, the projects in the Phase 2 Resilience Plan result from the comprehensive and rigorous analysis in the Resilience Model employed by the Company and 1898 & Co., with a focus on maximizing customer benefits for the dollars invested.

A. Proposed Projects and Costs

Under the Phase 2 Resilience Plan, the Company proposes to complete 36 identified distribution hardening projects, which will harden approximately 5,523 structures over more than 188 line miles at a cost of approximately $400 million over the course of the five-year period from 2027 to 2031. The projects in the Phase 2 Resilience Plan are spread across New Orleans and touch each Council District. Moreover, as Mr. Gremillion discusses in his testimony, the length of the Phase 2 Resilience Plan will allow ENO to keep more resources and crews in New Orleans for a longer period of time, rather than potentially starting and stopping and diverting those resources and crews to other utilities and areas of Louisiana as well as neighboring states implementing resilience. Continuity of work on the projects is critical to keeping costs low for customers and positioning New Orleans to be ready for future weather events.

Further, as Mr. Gremillion explains in his testimony, the projects address critical infrastructure and customers and encompass parts of New Orleans that are ripe for economic development, which the Company expects will help attract new customers to New Orleans and maintain existing ones. By way of example, the projects in the Phase 2 Resilience Plan include work on 9 feeders out of Derbigny Substation, which is located north of the Superdome. These feeders serve critical facilities such as hospitals, nursing homes, fire and police facilities, and a number of pumping stations. The scope of the work is to replace approximately 436 poles to harden over 12 miles of distribution circuits in the area providing customers with significant benefits over the next 50 years.

B. <u>Customer Benefits</u>

The Phase 2 Resilience Plan will produce significant customer benefits. As discussed by Mr. Mire and Mr. Gremillion, assuming each hardening project in the Phase 2 Resilience Plan is performed, the Company estimates that those projects will decrease future restoration costs after major weather events by approximately $83 million. The Company also estimates that completion of the projects in the Phase 2 Resilience Plan will lead to an estimated reduction in the total number of CMI after major events of 3.4 billion minutes, which corresponds to an estimated reduction of over $1.3 billion in overall estimated outage costs to customers, over the next fifty years assuming an above average frequency of storms.

Another anticipated benefit of implementing the Phase 2 Resilience Plan is that "blue sky" resilience work can be more carefully planned, executed, and overseen as opposed to waiting to upgrade and replace infrastructure until it is damaged in a storm. As Mr. Gremillion discusses, such 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 – can be extremely costly.

In addition, although the focus of the Phase 2 Resilience Plan is on protection of the Company's systems against major storm events, taking an accelerated approach to hardening projects allows customers to enjoy the enhanced reliability benefits of the projects sooner than if the projects were delayed. This is a significant benefit considering customers' ever-increasing reliance upon electricity.

MONITORING PLAN

As discussed by Mr. Gremillion in his testimony, in Resolution No. R-24-625, the Council directed the Council Utilities Regulatory Office ("CURO"), the Advisors, and ENO to develop a reporting format crafted to provide the Council with information on the project status and cost of each project in Phase I, "as well as ongoing data gathering that would assist the Council in evaluating future resilience investments and performance."[6] As contemplated by the Council, CURO, the Advisors, and ENO recently have prepared and submitted that reporting format, including a template for Quarterly Monitoring Reports as well as information for Post-Event Reports following certain storms and major weather events. The Company filed its first Quarterly Monitoring Report with the Council on November 17, 2025. For the Phase 2 Resilience Plan, ENO proposes to continue providing Quarterly Monitoring Reports and Post-Event Reports as it is currently providing for Phase 1.

Moreover, as discussed by Mr. Gremillion, in its prior resilience filings in this docket, ENO proposed a pole performance metric (the "Pole Performance Metric") that would assess against the Company a predetermined fee for each pole failure after a single qualifying weather event under

---

[6] Resolution No. R-24-625, at p. 14 (Ordering Paragraph 3).

certain circumstances. In Resolution No. R-24-625 approving the Phase 1 Resilience Plan, the Council directed CURO, in consultation with the Advisors and ENO, to modify and finalize the Pole Performance Metric.[7] As contemplated by the Council, CURO, the Advisors, and ENO recently have prepared and submitted a revised Pole Performance Metric. For the Phase 2 Resilience Plan, ENO proposes use of the same Pole Performance Metric (as revised by CURO, the Advisors, and ENO) to help ensure that the Phase 2 Resilience Plan is delivering resilience benefits for customers.

RATE RECOVERY AND BILL IMPACTS

A. Resilience Rider

As Ms. Maurice-Anderson discusses in her testimony, ENO is entitled to a reasonable opportunity to recover its prudently incurred costs under the Phase 2 Resilience Plan.[8] Given the large capital investment involved in implementing the Phase 2 Resilience Plan and ENO's small size and risk profile, it is essential that ENO have assurance that it can recover its investment in a timely manner. As authorized by Resolution No. R-24-625, ENO currently uses the Resilience Rider to recover from customers, on a timely basis, the cost of the Phase 1 projects. ENO proposes that the revenue requirement associated with the Phase 2 Resilience Plan be recovered through the Resilience Rider.

The Resilience Rider will continue to help support ENO's ability to finance accelerated infrastructure hardening projects on reasonable terms and ensure that they can be done timely and

---

[7] Resolution No. R-24-625, at p. 15 (Ordering Paragraph 4).

[8] *South Cent. Bell Tel. Co. v. Louisiana Pub. Serv. Comm'n*, 594 So. 2d 357, 366 (La. 1992) ("Under that principle, South Central Bell is entitled to be compensated for all prudent investments at their actual cost when made (their 'historical' cost) irrespective of whether individual investments are deemed necessary or beneficial in hindsight; and the utility is entitled to the presumption that the investments were prudent, unless the contrary is shown."); *see also Federal Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591, 605 (1944); *Bluefield Waterworks & Improvement Co. v. Pub. Serv. Comm' of West Virginia*, 262 U.S. 679, 690 (1923).

efficiently. Contemporaneous cost recovery also is appropriate because as ENO completes projects, customers receive the benefits. An additional benefit of the Resilience Rider is that, in the event ENO receives federal (or other public) funds for projects in the Phase 2 Resilience Plan, there is flexibility to offset investment and reduce the rate timely pursuant to the methodology contained therein. Further, as part of the true-up portion of the Resilience Rider, the Company will provide the Council with an annual report comparing the actual project costs with projected costs, along with variance explanations.

B. <u>Bill Impacts</u>

ENO's objective is to continue to accelerate its resilience efforts to provide a more hardened system, while simultaneously maintaining affordable electric rates for customers. The Company understands that bill impacts are critically important in setting the appropriate pace of resilience investment. At the same time, however, New Orleans will experience hurricanes and other storm events in the future. Considering that inevitability and the consequences to customers and New Orleans itself, Mr. Mire discusses in his testimony that customers are expected to be better off with the Phase 2 Resilience Plan, paying reduced storm restoration costs, and experiencing shorter and fewer outages, as opposed to paying greater storm restoration costs and experiencing longer and more frequent storm outages without the Phase 2 Resilience Plan projects. Indeed, as the Company witnesses discuss, the Phase 2 Resilience Plan is a tool that is expected to make customers' bills more affordable over the long run. As further discussed by Ms. Maurice-Anderson, the estimated bill effects for a typical residential customer are $1.01 per month in 2027 and $3.28 per month in 2028 and continue to increase over the course of the Phase 2 Resilience Plan.

C. Additional Ratemaking and Accounting Treatment

As discussed by Ms. Maurice-Anderson in her testimony, ENO requests authorization to create a regulatory asset for the remaining net book value associated with assets to be retired and replaced with new assets as part of the Phase 2 Resilience Plan. The Council granted such relief in Resolution No. R-24-625 with regard to the Phase 1 projects. In future rate proceedings, ENO 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 the Company recovers its prudently incurred costs, all else being equal. The net book value of these assets is already reflected in ENO's rate base and, therefore, its rates. Additionally, the prudent retirement of these assets to advance resilience objectives should not change ENO's right to recover a return on these assets. In addition, the Company requests that the Council acknowledge and not oppose ENO's forthcoming request to the Federal Energy Regulatory Commission ("FERC") seeking approval to continue capitalizing certain conductor handling costs associated with the Phase 2 Resilience Plan that would otherwise be treated as expenses. The FERC granted such relief with regard to the Phase 1 projects.

PUBLIC INTEREST

The approvals sought in this Application are in the public interest. As Ms. Maurice-Anderson discusses in her testimony, the Company, along with 1898 & Co., has taken a comprehensive, thoughtful approach to developing the Phase 2 Resilience Plan, among other aspects of this Application, with the goal of reducing the effects of future storms on customers. The approach is customer-centric in that it quantifies benefits of the Phase 2 Resilience Plan directly in relation to the effects of those investments on customers, both on the storm restoration costs that customers will bear after future storms and the duration of the outages that customers will experience because of those storms. The Phase 2 Resilience Plan contains projects that produce overall customer benefits, and the Company's customers are expected to be better off paying for the proposed Phase 2 Resilience Plan in return for reduced storm restoration costs and reduced outage durations, rather than continuing on the current path without the Phase 2 Resilience Plan. Again, it is not a matter of *if* another severe storm hits New Orleans, but *when*.

The projects in the Phase 2 Resilience Plan, and the other projects proposed in this Application, will continue to improve the resilience of the Company's electric system across New Orleans. Moreover, "blue sky" resilience work can be more carefully performed and cost-effective than reactive, post-storm restoration work, and customers will see the benefits of such "blue sky" work sooner than if the projects were delayed. Further, there are potentially positive credit implications associated with the Phase 2 Resilience Plan. Other factors discussed by the Company's witnesses also support finding that the proposed Phase 2 Resilience Plan, among other requests for relief, serves the public interest, is therefore prudent, and should be approved by the Council.[9]

ADDITIONAL RESILIENCE MEASURES

The Company continues to consider additional resilience measures that potentially can complement the Phase 2 Resilience Plan to enhance local resilience. To that end, the Company has and will continue to aggressively seek state and federal grants to mitigate the rate impact to customers. As Ms. Rodriguez explains in her testimony, and as the Council knows, ENO was awarded a federal grant for the GRIP Project involving transmission and distribution line hardening, as well as a microgrid, in New Orleans East. In addition, the Joliet hardening project

[9] For all requests in this Application, as Ms. Maurice-Anderson states in her testimony, the Company has complied with, or is not in conflict with, the provisions of all applicable Council Resolutions and any other laws, regulations, or requirements that may be applicable.

– which involves replacing approximately 94 distribution poles that will harden approximately 1.6 miles of distribution network and implementing targeted vegetation management in the project area – was selected for an award under a state resilience grant provided for through the Infrastructure Investment and Jobs Act ("IIJA").

The Company continues to monitor additional opportunities that may arise with federal entities, and continues to be engaged with local and state entities on potential funding opportunities for investments intended to modernize its infrastructure for the benefit of its customers. In particular, as Mr. Wood discusses in his testimony, while not presently a part of the Phase 2 Resilience Plan, the Company has identified and included in this Application an opportunity to partner with the SWBNO to pursue a grant through the Louisiana Hubs for Energy Resilient Energy Operation ("HERO") program to provide 50% of the funding for needed backup generation at four critical SWBNO pumping sites providing services to critical care facilities and other customers across New Orleans. Assuming the funding is received, ENO would propose to install, own, and maintain the four backup generators, with the remaining 50% portion of the total costs not covered by the grant shared between SWBNO and ENO.[10]

Further, as the Company has and continues to discuss, for New Orleans to be truly resilient, it will require more than just a strong electric grid and related enhancements. It will require consideration of additional measures such as building code standards, urban planning, elevation requirements, water management, and coastal restoration. In each of these ways, New Orleans must become more resilient to protect its community and assets, generate economic activity, and

[10] As Mr. Wood explains in his testimony, if the project receives a 50% HERO grant, ENO would supplement this docket to provide detailed cost estimates, project execution timelines, and proposed cost recovery for consideration by the Council. If the Council were to approve the project as being in the public interest, ENO would proceed from that point to procure the necessary equipment and plan for the installation.

preserve the economic competitiveness of the region. The Company has and continues to engage in discussions with local and state agencies and representatives, among others, regarding these issues. Should the Council wish to consider these issues in an overall resilience strategy for New Orleans, the Company is open to collaborating as part of wider efforts to develop and pursue a community approach to resilience.

REQUEST FOR TIMELY TREATMENT

The Company seeks to timely commence the Phase 2 Resilience Plan in January 2027 – immediately upon the conclusion of the Phase 1 period which expires at the end of 2026. For the reasons discussed herein, ENO urges that the Council consider and approve the Application expeditiously, and no later than October 2026. Moreover, the Company requests that the Council, at its January 2026 meeting, issue a procedural schedule that allows for consideration and approvals within the requested timeframe.

PRAYER FOR RELIEF

For the foregoing reasons, ENO respectfully requests that its Application be approved. In particular, the Company requests that the Council:

1. Approve the Phase 2 Resilience Plan as serving the public convenience and necessity, and in the public interest and therefore prudent, subject to an ongoing obligation of ENO to prudently manage the Phase 2 Resilience Plan;
2. Approve the continuation of the Company's Resilience Rider and deem the prudently-incurred costs under the Phase 2 Resilience Plan to be eligible for cost recovery via the Company's Resilience Rider;
3. Approve a regulatory asset to be included in rate base for the remaining net book value associated with assets that must be retired and replaced with new assets as

part of the Phase 2 Resilience Plan, with the amortization of the unrecovered balance occurring over the remaining useful life of the assets;

4. Approve the Company's proposed monitoring plan as described herein regarding the Phase 2 Resilience Plan;

5. Rule that, with respect to the Phase 2 Resilience Plan and associated requested relief, the Company has complied with, or is not in conflict with, the provisions of all applicable Council Resolutions and any other laws, regulations, or requirements that may be applicable;

6. Acknowledge and not oppose ENO's forthcoming request to the FERC seeking approval to continue capitalizing certain conductor handling expenses associated with the Phase 2 Resilience Plan (and other resilience projects as appropriate) that would otherwise be treated as expenses;

7. Approve the ENO-SWBNO project, in the event it receives a 50% HERO grant and after due proceedings had, as serving the public convenience and necessity, and in the public interest and therefore prudent, subject to an ongoing obligation of ENO to prudently manage the project, with the remaining 50% portion of the total costs not covered by the grant shared between SWBNO and ENO, and finding that ENO's share of prudently-incurred costs is eligible for cost recovery via the Company's Resilience Rider or other appropriate cost recovery mechanism;

8. Grant a waiver of any applicable Council requirement to the extent that such a waiver may be required to facilitate approval of the Phase 2 Resilience Plan and associated requested relief;

9. Issue a procedural schedule at its January 2026 public meeting resulting in a Council decision on the matters contained in this Application no later than the October 2026 public meeting; and

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

Respectfully submitted,

By: ______________________________

Courtney R. Nicholson, La. Bar #32618
Regina Bartholomew-Woods, La. Bar #26577
Edward R. Wicker, Jr., La. Bar #27138
Entergy Services, LLC
639 Loyola Avenue, Mail Unit L-ENT-26E
New Orleans, Louisiana 70113
Telephone: (504) 576-3101
Facsimile: (504) 576-5579
cnicho2@entergy.com
rbartho@entergy.com
ewicker@entergy.com

ATTORNEYS FOR
ENTERGY NEW ORLEANS, LLC

BEFORE THE

COUNCIL OF THE CITY OF NEW ORLEANS

***IN RE*: SYSTEM RESILIENCY AND STORM HARDENING**	**))**	**DOCKET NO. UD-21-03**

DIRECT TESTIMONY

OF

DEANNA RODRIGUEZ

ON BEHALF OF

ENTERGY NEW ORLEANS, LLC

DECEMBER 2025

TABLE OF CONTENTS

I. INTRODUCTION AND QUALIFICATIONS

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

A. My name is Deanna Rodriguez, and I am President and Chief Executive Officer ("CEO") of Entergy New Orleans, LLC ("ENO" or the "Company"). My business address is 1600 Perdido Street, New Orleans, Louisiana 70112.

Q2. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?

A. I am testifying before the Council of the City of New Orleans ("Council") on behalf of ENO.

Q3. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I was promoted to my current position as President and CEO of ENO in May 2021 after serving for 27 years in various roles at Entergy. Before this position, I had served as the Vice President of Regulatory and Public Affairs for Entergy Texas, Inc., since 2012. From 2010-2012, I served as Vice President of Regulatory Affairs for ENO, where I worked closely with the Council and other key stakeholders to successfully launch several strategic initiatives, such as the Energy Smart program. Prior to these positions, I held several other strategic positions since I began in 1999, such as the Director of External Affairs for Entergy Corporation and Vice President of Corporate Contributions. I hold a Master's Degree in Public Affairs from the Lyndon B. Johnson School of Public Affairs at the University of Texas at Austin and a Bachelor's Degree in Government from the University of Texas at Austin.

Q4. WHAT ARE YOUR CURRENT DUTIES?

A. As President and CEO of ENO, 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 electric distribution and transmission systems, customer service, economic development, public affairs, regulatory affairs, and governmental affairs.

Q5. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to present ENO's Application seeking Council approval of the set of accelerated infrastructure hardening projects that comprise the Company's Phase 2 Resilience Plan. Each project in the Phase 2 Resilience Plan is designed to reduce the frequency and duration of outages and to improve restoration times so that families, businesses, and institutions that anchor our New Orleans community can come back online more quickly after severe weather. In this way, the Application is more than an infrastructure proposal – it represents a deliberate investment in the future of New Orleans and a commitment to the City's long-term economic prospects. Further, I introduce the additional witnesses supporting the Application, who each provide important technical, operational and customer perspectives regarding the Phase 2 Resilience Plan. Together, our testimony demonstrates that continued, focused investment in infrastructure hardening is a forward-looking strategy to secure a stronger New Orleans for future generations, while also keeping costs down for our customers.

Q6. PLEASE INTRODUCE THE WITNESSES WHO ARE ALSO FILING TESTIMONY IN SUPPORT OF ENO'S APPLICATION.

A. Certainly.

- Chris Gremillion – Director, Project Management – Project Delivery for Entergy Services, LLC ("ESL"). Mr. Gremillion presents ENO's Phase 2 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 Phase 2 Resilience Plan are in the public interest and should be made, and summarizes the Company's proposed monitoring plan in terms of reporting and metrics.

- Arlin Mire – Project Manager, 1898 & Co. Mr. Mire summarizes the results and methodology used to develop the Phase 2 Resilience 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 Resilience Event Simulation Model ("Resilience Model"), which includes a Major Events Database, System Vulnerability and Event Impact Module ("Event Impact Module"), Resilience Benefit Module, and Plan Development Module. He also reviews historical major storm events that have impacted ENO's service area, describes the datasets used in the Event Impact Module 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 Resilience Model.

- Alyssa Maurice-Anderson – Director, Regulatory Filings and Policy for ESL. Ms. Maurice-Anderson supports the Company's requested use of the existing Resilience and Storm Hardening Cost Recovery Rider ("Resilience Rider") to permit timely cost recovery of the Phase 2 Resilience Plan under the Resilience Rider and associated ratemaking treatment for the projects in the Phase 2 Resilience Plan, as well as certain additional ratemaking treatment. She also discusses bill impacts to customers from the Phase 2 Resilience Plan. In addition, she supports a finding from the Council that the Company's Phase 2 Resilience Plan is in the public interest and therefore is prudent.

- Keith Wood – Director, Resource Planning and Market Operations for ENO. Mr. Wood discusses an opportunity to partner with the Sewerage and Water Board of New Orleans ("SWBNO") to pursue a grant for needed backup generation at four critical SWBNO pumping sites, and the resilience and reliability improvements that would result from the projects and benefit ENO customers.

Q7. WHY SHOULD THE COUNCIL APPROVE THE APPLICATION?

A. The Council should approve the Application because the Phase 2 Resilience Plan meets the goals of this docket, as discussed by each Company witness supporting the Application. Considering severe weather is impacting the New Orleans area with increased frequency and severity, and that higher demand is being placed on resilience than even the very recent past, the Council opened this docket to "increase resiliency and storm hardening on ENO's system, with a particular focus on reducing weather-related power outages."[1]

The goals of this docket – to get the lights back on quicker and to minimize restoration costs for New Orleans residents after extreme weather events – are vital and shared by the Company and its customers, as well as New Orleans as a whole. As an important first step, the Council approved a $100 million set of accelerated infrastructure hardening projects through December 2026. ENO and the Council, however, must continue to make resilience investments to position New Orleans to be ready for future weather events and to keep costs low for customers. The Phase 2 Resilience Plan builds on the Company's continued progress implementing the Phase

[1] Resolution R-21-401, p. 2. In opening the docket, the Council correctly observed that "this cycle of damage and repair [from extreme weather] is not sustainable for the Company or ratepayers." Resolution R-21-401, p. 2.

1 projects, and represents a reasonable next step on the path to comprehensive hardening for New Orleans.

It is not a matter of *if* another severe storm hits New Orleans, but *when*. For example, Hurricane Francine made landfall in 2024 as a Category 2 hurricane and resulted in approximately $200 million in repair and restoration costs for ENO and Entergy Louisiana, LLC ("ELL"). These storms pose an increasing threat to the Company's electric system, which has reinforced the need to further invest in resilience. Without further action, communities like New Orleans in "high-risk zones are going to continue to experience economic and social upheaval."[2] Indeed, the storms are not stopping; New Orleans remains vulnerable; and the City should not stop its resilience progress.[3]

Councilmembers have highlighted the importance of strengthening the Company's electric grid to improve quality of life in New Orleans, particularly with regard to public health, our local businesses, and future job creation.[4] The Phase 2 Resilience Plan is designed to deliver exactly that: a more resilient energy grid that protects customers today while enabling economic growth and opportunity for decades to come.

---

[2] "How prepared is New Orleans for future climate threats? A global report ranks the city last," https://www.nola.com/news/environment/new-orleans-least-prepared-climate-report/article_b8d7aefd-3403-4cb8-bbf3-9c67c89b91b0.html (Nov. 18, 2025).

[3] *Id.*

[4] *See, e.g.*, "Entergy New Orleans kicks off Phase 1 of Accelerated Resilience Plan in District C," https://www.entergy.com/blog/entergy-new-orleans-kicks-off-phase-1-of-accelerated-resilience-plan-in-district-c (June 16, 2025).

To that end, it is essential the Phase 2 Resilience Plan commence in January 2027, immediately following completion of Phase 1, to capture cost and operational efficiencies, retain skilled work crews in New Orleans, and maintain the momentum of hardening efforts already underway. Any disruption of continuity between the ongoing projects and the Phase 2 Resilience Plan will increase costs to customers and delay the benefits of hardening the grid. Moreover, while the Company is proud that its rates remain significantly below the national average, the Phase 2 Resilience Plan will make customers' bills more affordable over the long term by reducing storm costs and mitigating other costs borne by customers.

II. STATUS OF PHASE 1 RESILIENCE PROJECTS

Q8. WHAT ARE THE PHASE 1 RESILIENCE PROJECTS?

A. Phase 1 consists of accelerated infrastructure hardening projects over a two-year period (2025 to 2026). The Council approved these projects, and they are located in each Council District. Mr. Gremillion discusses the Phase 1 project status in his testimony.

Q9. ARE THE PHASE 1 HARDENED ASSETS PERFORMING AS EXPECTED?

A. Since the Company began the Phase 1 projects in 2025, the New Orleans area has not experienced a significant hurricane to demonstrate the benefits of the completed projects. However, we know that hardening works.

Hardening projects implemented in other parts of Louisiana have produced results. For example, as Mr. Gremillion discusses in his testimony, in 2024, Hurricane Francine heavily impacted portions of ELL's service area, including the Bayou Region, River Parishes, and Grand Isle. In replacing the facilities devastated in the same areas following Hurricane Ida in 2021, ELL rebuilt its facilities to modern, hardened standards. Those poles fared well during Hurricane Francine, with fewer damaged or destroyed, which resulted in fewer outages and shorter restoration time. In fact, in the aftermath of Hurricane Francine, the Mayor of Grand Isle stated that over 90% of ELL customers there retained power, and those who lost power were restored within 2 days. The Mayor of Grand Isle credited ELL's hardened electrical infrastructure for the favorable outcome.[5] Because ELL did not have to replace as many poles after the storm, ELL was instead able to focus on performing repairs. Repairing poles requires less time than replacing damaged poles, which translates to a quicker restoration time.

Thus, resilience efforts have been shown to produce positive results. With the Phase 2 Resilience Plan, ENO and the Council should build on the Company's progress implementing the Phase 1 projects to further strengthen the electric grid and reduce costs and outages for customers.

Q10. IN ADDITION TO PHASE 1, HAVE CREDIT RATING AGENCIES INDICATED ENO NEEDS ADDITIONAL RESILIENCE?

A. Yes. As Ms. Maurice-Anderson discusses in her testimony, credit rating agencies maintain that the Company's infrastructure needs additional resilience because New Orleans remains vulnerable to severe weather. The agencies' assessment of key risks

[5] https://www.youtube.com/watch?v=HJA6bDhYeog (Interview of Mayor David Camardelle, Sept. 12, 2024); "Entergy: Power was restored post-Francine at a record-setting pace," https://www.fox8live.com/2024/09/21/entergy-power-was-restored-post-francine-record-setting-pace/

to ENO includes exposure to severe hurricanes and storms within its service area, as well as a lack of sufficient system hardening, which increases overall business risk relative to peers. These risks affect ENO's financial stability and indicate a need for additional resilience projects.

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

Q11. DO YOU BELIEVE THAT CONTINUED INVESTMENT IN RESILIENCE IS IMPORTANT?

A. Yes. The Phase 1 projects are an important first step for enhancing resilience; however, additional resilience projects are needed to meet the goals of this docket and provide benefits and protections for more ENO customers in more areas of New Orleans. Accordingly, the Company has continued to consult its own internal subject matter experts and stakeholders, evaluate the practices of other utilities and demonstrated benefits, and undertake a holistic analysis of the opportunities available for creating a more resilient system. The Company also has continued to engage its outside industry consultant, 1898 & Co., for strategic asset planning services and assistance in developing additional resilience projects and estimating the costs and benefits of those projects. The result of these efforts is the Phase 2 Resilience Plan.

III. PHASE 2 RESILIENCE PLAN

Q12. WHY IS ENO PRESENTING ITS RESILIENCE PLAN IN PHASES?

A. Initially, the Company filed an application in 2023 that contained a comprehensive resilience plan that spanned ten years. The Council then directed the Company to present a smaller set of projects over a shorter period. The Company did so, and the Council approved a set of projects over a two-year period (2025 to 2026). Those projects comprise Phase 1. The Company informed the Council that, to continue to deliver resilience benefits to customers across New Orleans, ENO would submit additional sets of hardening projects beyond Phase 1 for Council approval consistent with the goals of this docket.[6] The Company is now presenting the Phase 2 Resilience Plan in its Application. ENO believes the Phase 2 Resilience Plan is a reasonable next step on the path to comprehensive hardening for New Orleans.

Q13. CAN YOU PROVIDE AN OVERVIEW OF THE PHASE 2 RESILIENCE PLAN?

A. As discussed by Mr. Gremillion, the Phase 2 Resilience Plan includes accelerated infrastructure hardening projects at an estimated cost of approximately $400 million over the five-year period from 2027 through 2031. The projects are spread across New Orleans and benefit each Council District. Moreover, the projects address critical

[6] *E.g.*, ENO's Proposed 2025-27 Resilience Plan and Request to Expedite Fourth Technical Conference, filed March 21, 2024.

infrastructure and customers and encompass parts of New Orleans that are ripe for economic development, which the Company expects will help attract new customers to New Orleans and maintain existing ones. The projects in the Phase 2 Resilience Plan result from a comprehensive and rigorous analysis employed by the Company and 1898 & Co.

Q14. HOW DID THE COMPANY DECIDE TO PROPOSE $400 MILLION OVER 5 YEARS FOR THE PHASE 2 RESILIENCE PLAN?

A. The Phase 2 Resilience Plan strikes an appropriate balance between costs to customers and the need for comprehensive accelerated infrastructure hardening to address the frequency and intensity of storms that pose an increasing threat to the Company's electric system. The Phase 2 Resilience Plan is expected to produce significant customer benefits by reducing the costs of future restorations and the duration of outages after severe weather events over the next fifty years, assuming an above average frequency of storms. Mr. Gremillion and Mr. Mire discuss the Phase 2 Resilience Plan further in their testimony.

Q15. WHY IS THE PHASE 2 RESILIENCE PLAN LONGER THAN PHASE 1?

A. The Phase 2 Resilience Plan covers a five-year period, whereas Phase 1 is a two-year period. Phase 1 was the Company' first step in accelerated resilience, and the Phase 2 Resilience Plan builds on those efforts with more projects across New Orleans and a more sustained approach to resilience. As Mr. Gremillion discusses in his testimony, the length of Phase 2 will allow ENO to keep more resources and crews in New Orleans for a longer period of time, rather than potentially starting and stopping and diverting those resources and crews to other utilities and areas of Louisiana as well as neighboring states implementing resilience. Continuity of work on the projects is critical to keeping costs low for customers and positioning New Orleans to be ready for future weather events.

Q16. WHY IS ADDITIONAL RESILIENCE IMPORTANT TO ENO'S RESIDENTIAL CUSTOMERS?

A. The Company takes seriously its responsibility to provide customers with safe and reliable service at the lowest reasonable cost. ENO understands that there is a high personal and societal burden when people are without electric service in the aftermath of a severe storm. Urgent restoration is needed to protect the health and welfare of citizens in the areas served by the Company. Therefore, a paramount concern is the health and safety of the community, which requires restoring service timely to hospitals, water treatment and pumping facilities, and other critical facilities, as well as grocery stores, gas stations, and pharmacies, all of which serve ENO's residential customers.

Thus, it is imperative to restore service as quickly and safely as possible, and to minimize the amount and scope of restoration costs that are borne by ENO and its customers. And, more than storm restoration costs, the harmful non-bill impacts to all customers – but residential customers in particular – from major storm events (such as water/sewer system outages, evacuation inconvenience and costs, school and business closings, gas and gasoline price increases, and supply chain disruptions) cannot be overlooked. Given that so many residents in New Orleans have limited income, ENO understands that evacuating is difficult if not impossible for them. It is therefore even more important for ENO to get power back on as quickly as possible following a storm. To do so, the hardening projects in the Phase 2 Resilience Plan are critical.

Q17. WHY IS ADDITIONAL RESILIENCE IMPORTANT TO THE NEW ORLEANS ECONOMY?

A. New Orleans is a significant economic driver for the nation and the world. The Company serves critical infrastructure such as the NASA Michoud Assembly Facility, a key national aerospace manufacturing site that relies on uninterrupted power to support mission-critical operations. Moreover, the strategic location of New Orleans near the mouth of the Mississippi River is critical for the nation's supply chain and economy and a major shipping hub for global trade. The Company serves a large number of industries and related businesses that are essential to those economies. If those customers are interrupted for an extended time, it will affect energy supply and prices nationally, as occurred in the aftermath of Hurricanes Katrina, Gustav, Isaac, and Ida. Through the Phase 2 Resilience Plan, ENO seeks to support New Orleans as an economic driver, and maintain existing customers in New Orleans and also attract new customers – and the Company's electric grid must be sufficiently resilient to do so.

Q18. HOW DOES THE COMPANY PROPOSE TO RECOVER THE COSTS OF THE PHASE 2 RESILIENCE PLAN?

A. As explained by Ms. Maurice-Anderson in her testimony, the Company proposes to continue to use the Resilience Rider, with certain ministerial changes, to recover the costs of the Phase 2 Resilience Plan. ENO currently uses the Resilience Rider for Phase 1. The Resilience Rider would provide a stable, long-term recovery mechanism for the duration of the Phase 2 Resilience Plan, and would allow the projects in the Phase 2 Resilience Plan to be executed efficiently. Without the continuation of the Resilience Rider, undertaking the proposed Phase 2 Resilience Plan would compromise ENO's cash flow and credit metrics and be a step backwards in terms of improving ENO's financial health and program execution.

Q19. WILL THE COMPANY BE ACCOUNTABLE FOR THE PHASE 2 RESILIENCE PLAN DELIVERING BENEFITS TO CUSTOMERS?

A. Yes. As Mr. Gremillion discusses in his testimony, ENO proposes to use the same Pole Performance Metric as Phase 1 to ensure the Phase 2 Resilience Plan is delivering resilience benefits to customers. In addition, ENO proposes to continue providing quarterly reports (and post-event reports) in the same format that it is currently providing for Phase 1.

Q20. IS THE COMPANY OFFERING ANY OTHER POTENTIAL PROJECTS FOR APPROVAL WITH THIS FILING?

A. Yes. While not presently part of the Phase 2 Resilience Plan, the Company has identified an opportunity to partner with the SWBNO to pursue a grant for needed backup generation at four critical SWBNO pumping sites. ENO expects that resilience and reliability improvements would result from the projects and benefit ENO customers. Company witness Keith Wood discusses this opportunity in his testimony.

Q21. IS ENO CONTINUING TO PURSUE PUBLIC FUNDING FOR RESILIENCE?

A. Yes. Maintaining customer affordability remains one of the top pillars for ENO, with the Company's rates remaining significantly below the national average. The Company has and will continue to aggressively seek state and federal grants to mitigate the rate impact to customers. As the Council knows, ENO was awarded a federal grant under the Department of Energy's Grid Resilience and Innovation Partnerships ("GRIP") program for its project involving transmission and distribution line hardening and the installation of a battery energy storage system ("BESS"), connected to the Company's New Orleans Solar Station to support a microgrid, in New Orleans East ("GRIP Project").[7] In addition, the Joliet hardening project – which involves replacing approximately 94 distribution poles to harden approximately 1.6 miles of the distribution network and implementing targeted vegetation management in the project

[7] In Resolution No. R-24-73, the Council approved the Company's GRIP Project. The GRIP Project is an important part of ENO's resilience strategy, but the Company does not consider the GRIP Project to be part of Phase 1. The GRIP Project and Phase 1 were separately considered and approved by the Council. Moreover, the GRIP Project is on a different timeline than the Phase 1 projects.

area – was selected for an award through a state resilience grant program under the Infrastructure Investment and Jobs Act ("IIJA"). The Company continues to monitor additional opportunities that may arise with federal entities. Moreover, ENO continues to be engaged with local and state entities on potential funding opportunities for investments intended to modernize its infrastructure for the benefit of its customers. ENO intends to keep the Council, the parties, and other key stakeholders informed of its efforts to secure additional funding for resilience, all in an effort to further reduce cost to customers.

Q22. ARE THE APPROVALS SOUGHT IN THE APPLICATION IN THE PUBLIC INTEREST?

A. Yes. As Ms. Maurice-Anderson discusses in her testimony, the Company, along with 1898 & Co., has taken a comprehensive, thoughtful approach to developing the Phase 2 Resilience Plan, among other aspects of the Application, with the goal of continuing to reduce the effects of future storms on customers. The approach is customer-centric in that it quantifies benefits of the Phase 2 Resilience Plan directly in relation to the effects of those investments on customers, both on the storm restoration costs that customers will bear after future storms and the duration of the outages that customers will experience because of those storms. The Phase 2 Resilience Plan contains projects that produce overall customer benefits, and the Company's customers are expected to be better off paying for the proposed Phase 2 Resilience Plan in the near term in return for reduced storm restoration costs and reduced outage durations over the long term.

The projects in the Phase 2 Resilience Plan, and the other projects proposed in this Application, will continue to improve the resilience of the Company's electric system across New Orleans. Without approval of these projects, vast areas of New Orleans will experience very little, if any, improvement in resilience. In addition, "blue sky" resilience work can be more carefully performed and cost-effective than reactive, post-storm restoration work, and customers will see the benefits of such "blue sky" work sooner than if the projects were delayed. Further, there are potentially positive credit implications associated with the Phase 2 Resilience Plan. Other factors discussed by the Company's witnesses also support finding that the proposed Phase 2 Resilience Plan, among other requests for relief, serve the public interest, are therefore prudent, and should be approved by the Council.

Q23. WHEN DOES ENO SEEK TO HAVE THE COUNCIL ACT ON THE APPLICATION?

A. Considering the threat of future storms, the Company seeks to timely commence execution of the Phase 2 Resilience Plan on January 1, 2027 – immediately upon the conclusion of Phase 1, at the end of 2026. Accordingly, ENO urges that the Council consider and approve the Application expeditiously, and no later than October 2026. This timing will promote cost and operational efficiencies and, importantly, maintain resources and work crews in New Orleans, as other utilities in Louisiana and neighboring states are executing their own resilience plans, as Mr. Gremillion explains in his testimony. Moreover, the Company is requesting that the Council, at its January

2026 meeting, issue a procedural schedule that allows for consideration and approvals within the requested timeframe.

IV. CONCLUSION

Q24. PLEASE PROVIDE A SUMMARY OF YOUR TESTIMONY.

A. Because extreme weather events are impacting the New Orleans area with increasing frequency and severity, the Council opened this docket to improve the resilience of the Company's electric system and lower costs to customers from severe weather. The Phase 2 Resilience Plan presented in the Company's Application would do just that. As explained by each Company witness, the Phase 2 Resilience Plan is an investment in the people and future of New Orleans. It builds on the Company's continued progress in Phase 1, and will result in a more resilient energy grid that protects customers today while enabling economic growth and opportunity for decades to come. Indeed, when the grid is stronger, the lights stay on longer. Thus, investing in the grid now will reduce outages, get the lights back on quicker, and make customers' bills more affordable by reducing storm costs and mitigating other costs borne by customers.

Q25. IS THERE ANYTHING ELSE YOU WISH TO SAY?

A. Yes. While the Phase 2 Resilience Plan includes the next set of accelerated hardening projects to address the frequency and intensity of storms that continue to pose an increasing threat to its electric system, ENO understands that the Council and the Company must always balance service improvements with customer affordability. In this next phase of resilience, the Company looks forward to continuing to work with the Council on advancing necessary hardening objectives while maintaining affordable electric rates for ENO's customers.

Q26. 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, **DEANNA RODRIGUEZ**, who after being duly sworn by me, did depose and say:

That the above and foregoing is her sworn testimony in this proceeding and that she 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, she verily believes them to be true.

Deanna Rodriguez
DEANNA RODRIGUEZ

SWORN TO AND SUBSCRIBED BEFORE ME
THIS 15th DAY OF DECEMBER 2025

Courtney R. Nicholson
NOTARY PUBLIC

My commission expires: at death

Courtney R. Nicholson
La. Bar. No. 32618
Notary Public
State of Louisiana
Commission Expires at Death

BEFORE THE

COUNCIL OF THE CITY OF NEW ORLEANS

***IN RE*: SYSTEM RESILIENCY AND STORM HARDENING**	**))**	**DOCKET NO. UD-21-03**

DIRECT TESTIMONY

OF

CHRIS GREMILLION

ON BEHALF OF

ENTERGY NEW ORLEANS, LLC

DECEMBER 2025

TABLE OF CONTENTS

Page

EXHIBIT LIST

I. INTRODUCTION AND PURPOSE

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

A. My name is Chris Gremillion. My business address is 4809 Jefferson Highway, Jefferson, Louisiana 70121. I am employed by Entergy Services, LLC ("ESL")[1] as Director of Capital Projects.

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

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

Q3. PLEASE DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

A. I have a Bachelor of Science degree in Mechanical Engineering from Louisiana State University. I previously served in the Louisiana Army National Guard. My service in the National Guard ended when I was honorably discharged.

I joined Entergy in 2000 as a project manager. In that role, I was responsible for project scope, cost, and schedule adherence. In 2004, I became a construction engineer, and my responsibilities included construction plan development and overall execution of assigned projects. I was promoted to construction supervisor in 2014. In that capacity, I supervised a group of internal and contract construction engineers in

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

development and execution of transmission construction-related projects in ENO's and ELL's service areas. In 2016, I became senior manager of project management and construction, overseeing the project management and construction departments for all stages of transmission projects, including scoping, planning, execution, and closeout, within ENO's service area and ELL's service area in south Louisiana ("ELL South"). From 2019 to 2022, I served as senior manager of ENO's and ELL South's grid operations, where I managed all substation and line day-to-day operations. I also was responsible for renewal projects in addition to overall bulk electric system and distribution substation reliability. Additionally, I led ENO/ELL South's transmission and restoration response for several major hurricanes, including Laura, Delta, Zeta, and Ida. Since 2022, I have been employed as Director of Capital Projects for ENO/ELL South.

Q4. PLEASE DESCRIBE YOUR CURRENT JOB RESPONSIBILITIES.

A. As Director of Capital projects, I am responsible for the overall execution of the ENO and ELL resilience portfolios. I also am responsible for the overall development and execution of an annual transmission and distribution portfolio of projects. I provide strategic direction to and am responsible for managing leaders who develop all aspects of transmission and distribution resilience projects, including organizational contract structure; engineering, procurement, and construction strategy and vendor sources; capital outlay; and construction.

Q5. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony presents Phase 2 of ENO's Resilience Plan (sometimes referred to herein as "Phase 2" or the "Phase 2 Resilience Plan"), provides details regarding the proposed projects in Phase 2, and summarizes the estimated costs and benefits of implementing those projects. I provide support for the conclusion that the Phase 2 projects are in the public interest and should be approved and undertaken.

Q6. HOW IS YOUR TESTIMONY ORGANIZED?

A. In Section II of my testimony, I provide a summary of the Company's prior filings in this docket regarding the Company's course of action to improve overall electric system resilience through accelerated infrastructure hardening projects (the "Resilience Plan"). I also provide an update with respect to the projects included in the initial phase of the Company's Resilience Plan that was approved by the Council of the City of New Orleans (the "Council") in Resolution No. R-24-625 ("Phase 1 Resilience Plan" or "Phase 1"). In Section III, I provide details about Phase 2 and the benefits that the Company expects to achieve by implementing the projects, including why Phase 2 is a necessary next step to reduce customer outages and storm costs. I also discuss the Company's efforts to coordinate Phase 2 with its existing reliability programs. In Section IV, I provide an overview of the development of Phase 2 in conjunction with 1898 & Co. In Section V, I explain the Company's plans to manage Phase 2, including mitigating potential risks associated with Phase 2. Finally, in Section VII, I describe the Company's proposals with respect to reporting and performance-based metrics for Phase 2.

II. RESILIENCE PLAN AND THE COUNCIL'S PRIOR APPROVALS

Q7. WHAT IS THE RESILIENCE PLAN?

A. As detailed in the Company's prior filings in this docket, the Resilience Plan is the result of the Company's efforts to identify cost-effective and achievable accelerated infrastructure hardening projects to build a more resilient electric system in New Orleans. 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 first used to determine a broad set of assets that the Company initially identified as targets for accelerated hardening – a $100 million subset of which received Council approval in October 2024 (Phase 1 of the Resilience Plan).

Phase 1 is a significant first step to improve resilience across the Company's system, but more is needed to position New Orleans to be ready for future weather events. The Company has been working to build on the hardening efforts previously approved by the Council in Phase 1. The Company's work, in conjunction with 1898 & Co. (an outside industry consultant that provides strategic asset planning services and has experience in developing resilience plans for electric utilities, including ENO's Phase 1) led to the development of the Phase 2 Resilience Plan, which identifies additional cost-effective and achievable hardening projects to further increase the resilience of the electric system in New Orleans. The collaborative process and work undertaken in this docket also has helped inform and direct the development of Phase 2.

As I discuss in more detail below, assuming each hardening project in Phase 2 is performed, which together total approximately $400 million in costs, the Company estimates that those projects will decrease future restoration costs after major weather events by approximately $83 million. The Company also estimates that completion of the projects in Phase 2 will lead to a reduction of 3.4 billion minutes in the total number of customer minutes interrupted ("CMI") after major events, which corresponds to an estimated reduction of over $1.3 billion in overall outage costs to customers, over the next fifty years assuming an above average frequency of storms.

Q8. PLEASE ELABORATE ON HOW THE RESILIENCE PLAN IS DESIGNED TO IMPROVE 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, wildfires, and other major weather disruptions.[2] Thus, the projects included in Phase 1, and those that are being proposed as part of Phase 2, 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, the Company's resilience efforts include hardening certain distribution assets to standards designed to better withstand the extreme conditions caused by severe weather events. While such projects should be expected to have positive impacts on the day-to-day operations of the Company's

[2] I note that this view of resilience is consistent with the explanation provided in the Phase 2 Resilience Plan and Benefits Report ("Report") prepared by 1898 & Co. and attached as an exhibit to the direct testimony of Company witness Arlin Mire.

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.

Q9. PLEASE SUMMARIZE THE COMPANY'S PRIOR FILINGS IN THIS DOCKET.

A. In April 2023, ENO filed an application seeking Council approval of a set of hardening projects estimated to cost approximately $559 million over the 5-year period of 2024 to 2028. Thereafter, in March 2024, consistent with the Council's directive in Resolution No. R-24-73, the Company developed a set of hardening projects totaling approximately $168 million to be completed over an initial 3-year period.

Q10. WHY DID THE COMPANY SEEK THAT APPROVAL?

A. The Company sought approval of those projects because, as the Council has recognized, "the frequency and intensity of severe weather events has increased dramatically."[3] Customers' dependence upon the electric grid also has increased, which, in turn, has raised demands and expectations for a resilient system. It is therefore critical that the Company's system be more resilient and reliable so that it can withstand conditions caused by severe weather events, avoid and mitigate customer outages, and enable faster, less costly restorations.

[3] Resolution R-21-401 at p. 1.

Concerning severe weather, over the last decade, hurricanes have become more frequent and intense,[4] bringing greater costs and disruptions to ENO and its customers. As the Council has observed, “this cycle of damage and repair is not sustainable for the Company or ratepayers.”[5] Therefore, the Company developed what ultimately became the Phase 1 Resilience Plan to address that cycle head on through accelerated hardening of the grid.[6]

Although New Orleans has not experienced a major hurricane since 2021, the pattern and risk of more intense hurricanes that ENO addressed in its Phase 1 application has continued. Florida has been struck by three major hurricanes since 2023.[7] More recently, Hurricane Melissa made landfall in Jamaica on October 28, 2025, as a Category 5 hurricane with maximum sustained winds of 185 mph. Fueled by warm waters in its path, and continuing the recent, dangerous trend of rapid intensification, Hurricane Melissa is among the strongest hurricanes to have formed in the Atlantic Ocean since records have been kept, and it ranks as one of the most powerful in terms of wind speed and pressure. The continuing trend of more frequent and intense severe weather underscores the need to make investments to improve the resilience of ENO’s electric system.

[4] Since 2017, eleven 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), Ian (2022), Idalia (2023), Helene (2024), and Milton (2024).

[5] Resolution R-21-401 at p. 2.

[6] *Id.* at p. 2.

[7] Those storms are Idalia (2023), Helene (2024), and Milton (2024).

Q11. ARE THE SEVERE WEATHER EVENTS THAT THE RESILIENCE PLAN IS INTENDED TO ADDRESS LIMITED TO HURRICANES?

A. No. The severe weather events include not only hurricanes but also extreme cold temperatures. In February 2021, back-to-back winter storms brought freezing rain and ice to Louisiana. More recently, in January 2025, New Orleans experienced a snowstorm that blanketed the city. Ice and snow accumulation that such storms bring can sag or down power lines, causing damage to utility systems. The additional weight of ice and snow also causes trees and limbs to fall into power lines and other electric equipment. When the ice and snow melts, it affects vegetation and electrical equipment, causing incremental outages. Resilience investment helps with such vegetation impacts due to snow and ice buildup as well as conductor ice buildup because stronger poles can hold more weight, resulting in fewer broken poles and shorter outages when not having to replace poles.

Tornadoes also have become increasingly common across Louisiana. In 2017, a powerful EF-3 tornado with maximum winds of 150 mph touched down in New Orleans East, destroying or damaging more than 600 homes and snapping hundreds of trees and power poles. In March 2022, another EF-3 tornado (with maximum winds of 160 mph) damaged homes, trees, and power poles in Algiers, New Orleans East, Gretna in Jefferson Parish, and the Arabi community of St. Bernard Parish. The City was impacted by yet another tornado in December 2022 when an EF-2 with maximum winds of 125 mph caused significant damage in Algiers. So far in 2025, at least 15 tornadoes have impacted southeastern Louisiana and southern Mississippi.

In short, recent and current trends in severe weather pose a serious risk to ENO and its customers, which reinforces the need to further invest, and to evaluate ways to accelerate that investment where appropriate, to address the increased frequency and intensity of such weather events.

Q12. WHAT ACTION DID THE COUNCIL TAKE WITH RESPECT TO ENO'S PRIOR RESILIENCE PROPOSALS?

A. Citing ongoing concerns about ratepayer impacts, the Council determined that it was appropriate to adjust the timing and scope of the resilience improvements that originally were proposed by the Company.[8] As such, in Resolution No. R-24-625 (October 24, 2024), the Council approved a $100 million investment for ENO for accelerated hardening projects over a two (2) year period (2025-2026). The Council expressly recognized in Resolution No. R-24-625 that it was "in the public interest" to approve such a subset of projects "that would provide significant resilience improvements while also providing time to gather and evaluate data useful in guiding the Council's future actions."[9] The Council acknowledged that the initial $100 million investment was an important first step in ENO's Resilience Plan, and directed ENO to provide a subset of projects totaling $100 million that ENO intended to execute. The Council also directed the Council Utilities Regulatory Office ("CURO") to develop certain metrics and reporting requirements for the Phase 1 projects.

---

8 Resolution No. R-24-625 at p. 5.

9 Resolution No. R-24-625 at p. 12.

In compliance with the Council's instruction, ENO submitted to the Council a subset of projects totaling $100 million in December 2024 – which is what I refer to in my testimony as the Phase 1 Resilience Plan. More specifically, the Company's submission included a total of 63 projects[10] that would harden structures across the City in every Council district. A listing of the accelerated hardening projects comprising Phase 1 is attached to my testimony as Highly Sensitive Protected Materials ("HSPM") Exhibit CG-1.[11] Those projects generally involve constructing more robust infrastructure through replacement and upgrading of distribution poles and related equipment.

In addition, although not part of Phase 1, the Council also approved the Department of Energy's ("DOE") Grid Resilience and Innovative Partnerships ("GRIP")-funded projects.[12]

Q13. PLEASE SUMMARIZE THE PROGRESS THAT ENO HAS MADE IN 2025 WITH RESPECT TO THE PROJECTS INCLUDED IN PHASE 1.

A. To date, ENO has completed and placed in service 6 out of the 32 projects[13] included in Phase 1. These projects involved hardening 54 structures, replacing 0.8 miles of

---

10 As I explain below, the 63 projects have since been consolidated and grouped into a set of 32 projects for execution, but the geographic and circuit coverage is the same, as is the expected system hardening.

11 An overview and breakdown of the Phase 1 projects can also be found here: https://www.entergyneworleans.com/resiliency.

12 Resolution No. R-24-73 (February 22, 2024).

13 The approved Phase 1 portfolio attached to my testimony as HSPM Exhibit CG-1 contained 63 individual projects, but ENO has bundled those projects into 32 project groupings to streamline program management and execution. In doing so, ENO leveraged project attributes, completion year, geographic location, identified circuit, asset volume, and estimated cost. Additional information regarding the status of the Phase 1 projects is included in ENO's Accelerated Resilience Program Quarterly Monitoring Report submitted to the Council on November 17, 2025.

copper conductor, and strengthening 0.9 total line miles. The completed projects are situated in Council Districts A, D, and E. Examples of the steps taken to complete these projects are depicted in Figures 1, 2, and 3 below.

Figure 1: Seabrook to Alabama Street

Figure 2: Treme – North Derbigny

Figure 3: Venetian Isles – Eden Isles

In addition, the Company has been engaged in critical front-end-loading activities for all 32 projects in Phase 1 and is projecting that it will complete construction on a total of 10 Phase 1 projects in 2025. The remaining projects in Phase 1, some of which already are in construction, are on schedule for completion by the end of 2026.

As a further update, the Company previously had identified certain poles falling within the scope of the Phase 1 projects that were owned by other entities. To ensure that those poles would be hardened along with the ENO poles as part of each project, ENO has since purchased the poles in question in advance of executing the Phase 1 projects. The Company plans to take that same approach for Phase 2.

Q14. PLEASE SUMMARIZE THE COSTS ASSOCIATED WITH THE HARDENING PROJECTS IN PHASE 1.

A. As I noted above, Phase 1 includes projects totaling an estimated $100 million to be completed in 2025 and 2026. The Company projects that it will spend approximately $30 million of that total in 2025, with the remaining approximately $70 million to be spent in 2026. This spending breakdown reflects that the initial year of Phase 1 has included various planning activities necessary to ramp up the projects and resources. While those activities are critical, they are completed at a lower cost than construction-related activities.

Q15. ARE RESILIENCE EFFORTS IN LOUISIANA LIKE THOSE IN PHASE 1 ALREADY RESULTING IN BENEFITS TO CUSTOMERS?

A. Yes. New Orleans has not experienced a hurricane since the Company began to implement the Phase 1 projects earlier this year. But hardening projects implemented in other areas of Louisiana have demonstrated positive results for customers in the face of severe weather. For example, Hurricane Francine, which made landfall near Morgan City, Louisiana, in September 2024, heavily impacted portions of ELL’s service area, including the Bayou Region and River Parishes. In replacing the facilities devastated in that same area after Hurricane Ida in August 2021, ELL rebuilt its facilities to modern, hardened standards, installing Class 1 distribution poles, many of which were tested during Hurricane Francine. Those poles fared well during Hurricane Francine, with fewer poles that were damaged or destroyed, which translated to fewer outages. Moreover, no structures that were hardened as part of ELL's accelerated resilience program were damaged or destroyed in Hurricane Francine, demonstrating the effectiveness of those upgrades. Because fewer poles were destroyed, ELL did not have to replace as many poles and was instead able to focus on repairs. Repairing poles requires less time than replacing damaged poles and thus translates to a quicker restoration time.

ELL's investments in Grand Isle after Hurricane Ida also proved effective during Hurricane Francine. In response to the widespread devastation to ELL's infrastructure in that area brought about by Ida, ELL committed to building its system back in a stronger and more resilient way, including by installing Class 1 utility poles with extra hardened footings for critical power lines designed to withstand 150 mph winds. That infrastructure largely withstood the effects from Hurricane Francine, and residents of Grand Isle saw very few power outages. Grand Isle Mayor David Camardelle attributed the low number of outages to ELL's investments, stating "Entergy came in after Hurricane Ida, spent millions of dollars, and rebuilt it right."[14]

---

[14] https://www.youtube.com/watch?v=HJA6bDhYeog (Interview of Mayor David Camardelle, Sept. 12, 2024).

Figure 4 below reflects the condition of ELL's hardened infrastructure in Grand Isle after Hurricane Francine.

Figure 4: Grand Isle after Hurricane Francine

III. PHASE 2 RESILIENCE PLAN

Q16. WHY IS THE COMPANY SEEKING APPROVAL OF ITS PHASE 2 RESILIENCE PLAN AT THIS TIME?

A. The Company is seeking approval of Phase 2 now so that it can build on the momentum of Phase 1. While Phase 1 is expected to result in significant resilience improvements for the customers directly impacted by completed Phase 1 projects, the overall system remains at risk. Phase 2 will build on the progress made in Phase 1 to extend the benefits associated with accelerated hardening to more customers. As I noted above, those benefits include fewer and shorter outages as well as decreased storm restoration costs and overall outage-related costs to customers. Therefore, as I and other witnesses discuss, Phase 2 is in the public interest and should be approved and undertaken.

Additionally, commencing Phase 2 immediately upon the conclusion of the two-year period of Phase 1 projects at the end of 2026 will allow the Company to maintain and extend work for its qualified contractor ("Alliance Partner") and work crews that are currently executing Phase 1 projects. With other resilience efforts by utilities in Louisiana and neighboring states, such as Texas and Florida, beginning to ramp up, being able to keep the current resources working on the ENO system is advantageous and beneficial to customers to maintain an efficient project pipeline. Therefore, as discussed by Ms. Rodriguez, the Company is presenting its Phase 2 Resilience Plan now and seeking a Council determination no later than October 2026 authorizing ENO to commence execution of Phase 2 in January 2027.

Q17. PLEASE DESCRIBE THE PHASE 2 RESILIENCE PLAN.

A. Under Phase 2, the Company proposes to complete 36 identified distribution hardening projects over the course of the 5-year period from 2027 to 2031. Those projects will harden approximately 5,523 structures over more than 188 line miles. A listing of the specific projects contained in the Phase 2 Resilience Plan is attached to my testimony as HSPM Exhibit CG-2.

The 36 projects in Phase 2, which are spread across New Orleans and touch each Council District, are generally grouped into two programs: Distribution Feeder Hardening (Rebuild) and Lateral Hardening (Rebuild). I discuss the scope of those programs later in my testimony. In addition, as with Phase 1, the projects in Phase 2 will complement the Company's non-resilience projects that are geared toward improving the reliability of the Company's system. More resilience is expected to lead to enhanced reliability, as I discuss below.

Q18. HOW WERE THE PROJECTS IN PHASE 2 SELECTED?

A. The initial project list for Phase 2 was developed by the Company in collaboration with its consultant 1898 & Co. in the same manner as the project list for Phase 1. Using the methodology that I discuss in greater detail in Section IV below, potential hardening candidates were identified from among the Company's distribution and transmission assets by comparing their wind loading capability to the Company's current design basis standard for wind loading. The identified assets were strategically grouped into potential hardening zones,[15] and only the assets that require hardening were included in the hardening zones. Hardening zones were then exposed to storm simulations to determine a probability of future failure and to calculate the associated benefits for replacing the assets on an accelerated basis. The initial screening identified hardening zones with a positive benefit to cost ratio ("BCR"). The screening was then further refined based on the highest BCR with consideration for resource, material, and timeline constraints for the proposed portfolio of hardening zones. In addition, the Company then consolidated the individual hardening zones into projects at the circuit

[15] As used in my testimony, the term "hardening zone" refers to a collection of assets grouped by 1898 & Co.'s Resilience Model (defined below) for potential hardening. A "project" is made up of one or more hardening zones that have been bundled by ENO to streamline program management and execution.

and/or substation level for the Phase 2 Resilience Plan to increase efficiency when executing the projects and to minimize the overall cost of Phase 2.[16]

Q19. ARE THERE ANY PARTICULAR PROJECTS INCLUDED IN PHASE 2 THAT YOU WISH TO HIGHLIGHT?

A. Yes. There are proposed projects on 9 of the 22 feeders out of Derbigny Substation, which is located north of the Superdome. Those 9 feeders serve critical facilities such as hospitals, nursing homes, fire and police facilities, and a number of pumping stations. The scope of the projects is to replace approximately 436 poles and to harden over 12 miles of distribution circuits in the area, providing customers with an estimated $105 million in total benefits over the next 50 years based on a storm forecast that is above average compared to historical storm activity.

Q20. IS ENO PROPOSING ANY TRANSMISSION PROJECTS IN PHASE 2?

A. No. After evaluating all potential hardening zones, the modeling utilized by 1898 & Co. (which modeling I describe below) determined that the potential distribution hardening zones have a greater BCR than the potential transmission hardening zones that were evaluated. Therefore, the distribution hardening zones evaluated by 1898 & Co. and then consolidated into distribution projects that were selected for inclusion in the Phase 2 Resilience Plan provide the most "bang for the buck" toward achieving improved resilience throughout the City.

[16] As I mentioned above, the 63 Phase 1 projects that are separately itemized by hardening zone in HSPM Exhibit CG-1 to my testimony also subsequently were consolidated by ENO into 32 projects for execution.

Q21. IS ENO ADDRESSING THE TRANSMISSION SYSTEM THROUGH OTHER PROGRAMS?

A. Yes. Phase 2's focus on the distribution system does not mean that ENO is not working to improve its transmission system. In fact, earlier this year, ENO completed a hardening project on its Sherwood Forest to Paterson 115 kV line that involved replacing 2 existing wooden H-frame structures with single pole steel structures, increasing the wind loading from 90 mph to 150 mph. Two additional transmission hardening projects are planned for execution in early 2026 that likewise entail replacing existing wood pole structures on ENO's Notre Dame to Market 115 kV line and existing steel single pole structures on ENO's Delta to Notre Dame 115 kV line with hardened single pole steel structures in order to increase wind loading on those lines to 150 mph.

Additionally, transmission hardening projects outside of the City will benefit ENO customers. ELL is planning to construct several transmission projects over the next few years that will provide more pathways into the Downstream of Gypsy load pocket where New Orleans is located. Those projects are expected to improve load-serving capabilities as well as the resilience of both ELL's and ENO's systems.

Q22. WERE ANY UNDERGROUNDING PROJECTS SELECTED FOR INCLUSION IN PHASE 2?

A. No. The cost of converting existing overhead distribution lines to underground is significant, and the increased cost of doing so was higher than the estimated benefits that undergrounding those segments would provide. As the modeling utilized by 1898 & Co. determined, the potential resilience benefits did not justify the selection of any undergrounding hardening zones for Phase 2. To explain, there are areas of the City where converting overhead to underground is not feasible. For example, undergrounding in wetlands and in certain dense urban settings is typically not possible or cost effective. Furthermore, the increased ground area required for underground equipment further increases the cost of such projects. I also note that prioritizing the undergrounding of existing distribution lines to a level above that indicated in 1898 & Co.'s modeling could have limited the impact of Phase 2 on overall system resilience. Given the 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 not selecting any undergrounding projects, the Company was able to incorporate more rebuild hardening projects in Phase 2, thereby hardening larger portions of the overall distribution system and providing the direct benefits of a resilient system to more customers.

Q23. WHY IS ENO PROPOSING THAT IMPLEMENTATION OF PHASE 2 SPAN FIVE YEARS?

A. Resilience projects typically take 14-18 months to develop and execute; however, the duration of projects varies with respect to permitting requirements, as well as coordination to avoid conflicts with other programs and projects occurring within ENO's service area. With that in mind, shorter plan durations not only have a steep ramp up and ramp down period, but they also require a higher peak demand on resources that may not be available in short bursts. In contrast, a longer duration plan, as is proposed for Phase 2, allows for a ramp up period for field scoping and engineering activities followed by a consistent resource demand that facilitates continuous work. In addition, a 5-year period would allow ENO to maintain an appropriate pace and volume of work, which not only avoids premium charges for materials and manpower, but also results in efficiencies and reduced competition for resources.

Q24. HOW MUCH WILL PHASE 2 COST?

A. The Company estimates that Phase 2 will cost approximately $400 million. While this cost is significant, as I discuss below, completing infrastructure upgrades and replacements during "blue-sky" hours is typically at a reduced cost compared to post-storm restoration work. Thus, taking additional proactive steps to harden the Company's infrastructure is expected to deliver significant benefits to customers over time.

Q25. WHAT BENEFITS DOES THE COMPANY EXPECT TO ACHIEVE BY IMPLEMENTING THE PROJECTS IN PHASE 2?

A. As with the Phase 1 projects, there are generally three sets of benefits that can be achieved in undertaking resilience efforts like the Company is proposing for Phase 2. *First*, "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 mentioned above, the "blue-sky" work can typically be executed at a reduced cost as compared to post-storm restoration work. *Third*, the Company believes that undertaking this work will result in fewer and shorter outages experienced by its customers during and following major weather events, and also reduce customer restoration costs and overall outage-related costs after major storms. I discuss how these benefits were analyzed later in my testimony.

Q26. ARE THERE OTHER BENEFITS THAT THE PROPOSED PROJECTS IN PHASE 2 ARE EXPECTED TO PROVIDE TO CUSTOMERS?

A. Yes. Although the focus of both Phase 1 and Phase 2 is protection against major storm events, 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. While this benefit is incidental, it is not insignificant, particularly considering customers' ever-increasing reliance upon electricity. With that said, the Company intends to perform as much work as possible while keeping the Company's facilities energized; however, some planned outages will be necessary to ensure that such work can be performed safely. The configuration, topography, asset physical condition, and material types are key factors that will drive the need for planned outages. Outages will be planned with a customer focus, and the Company will seek to minimize impacts to customers.

Q27. WILL ENO COORDINATE ITS PHASE 2 PROJECTS WITH ITS PROGRAMS DESIGNED TO IMPROVE RELIABILITY?

A. Yes. As the Company works to implement all phases of its Resilience Plan, reliability projects will continue to be developed, planned, and executed. The Company's resilience projects will complement the programs historically developed to improve reliability and will not detract from or replace the Company's ongoing reliability efforts. Moreover, the Company has and will continue to evaluate and compare its resilience projects and its ongoing reliability work to help avoid inefficiencies between these parallel efforts, to optimize the work done on its distribution and transmission systems, and to maintain focus on affordability for customers.

Q28. PLEASE ELABORATE ON HOW ENO WILL ENSURE THAT ITS RESILIENCE EFFORTS DO NOT DUPLICATE WORK DONE AS PART OF THE COMPANY'S RELIABILITY PROGRAMS.

A. To avoid any overlap between the Company's reliability programs and the proposed resilience projects, the Company will continue to carefully coordinate resilience projects with its reliability programs to promote cost and operational efficiency and mitigate the costs and impact to customers of necessary planned outages. For example, after a pole is identified as a priority replacement pole as part of the Company's pole inspection program, the Company determines whether that pole also has been selected for accelerated hardening in connection with the Company's resilience efforts. If the pole is included in a resilience project and resilience construction is scheduled to begin within 6 months, the pole is hardened as scheduled. If the pole is included in a resilience project but construction is not scheduled to begin within 6 months, the pole is removed from the resilience project scope, and the Company will proceed with hardening the pole as part of the Company's reliability efforts. It should be emphasized that all poles are hardened to the same standards, whether as part of a resilience project or a reliability program.

Q29. DOES THE PHASE 2 RESILIENCE PLAN CONTAIN THE ONLY RESILIENCE PROJECTS BEING CONSIDERED BY THE COMPANY?

A. No. Resilience planning is an ongoing process of identifying opportunities and evaluating options to improve and adapt the ability of the Company's electric system 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 Phase 2 Resilience Plan at this time. Additionally, as ENO replaces poles in the normal course of its business, such poles are replaced with new poles that are built to the same wind loading standards as those employed in the Company's Resilience Plan projects. Company witnesses Ms. Rodriguez and Keith Wood also discuss other resilience projects and opportunities in their testimonies.

IV. DEVELOPMENT OF THE PHASE 2 RESILIENCE PLAN

Q30. PLEASE EXPLAIN THE METHODOLOGY USED TO DEVELOP THE PHASE 2 RESILIENCE PLAN.

A. In collaboration with its consultant 1898 & Co., the Company utilized a resilience-based planning approach to identify hardening projects and prioritize investment in ENO's transmission and distribution assets through the Resilience Event Simulation Model ("Resilience Model"), which Company witness Arlin Mire discusses in his testimony. Using a four-step process, the Resilience Model employs a data-driven decision-making methodology utilizing robust and sophisticated algorithms to evaluate the assets on ENO's system and calculate the estimated resilience costs and benefits of hardening those assets in terms of reduced CMI and avoided future storm restoration costs. The ultimate purpose of the Resilience Model is to identify and prioritize hardening zones 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 ENO electric system. The Resilience Model thus serves to identify and prioritize the set of assets to harden to deliver the most customer benefits in terms of avoided customer outage minutes and avoided future storm restoration costs for the money spent. In this way, the Resilience Model 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. Mire, a consultant with 1898 & Co.

Q31. WHAT ASSETS DID THE RESILIENCE MODEL EVALUATE?

A. As discussed more fully by Mr. Mire in his direct testimony and in the Report prepared by 1898 & Co., the Resilience Model is comprehensive and evaluated nearly all of ENO's transmission and distribution systems, including poles, circuits, transmission structures, and conductor.

Q32. HOW WERE THE HARDENING PROJECTS IN THE PHASE 2 RESILIENCE PLAN IDENTIFIED?

A. As an initial matter, the Company (and 1898 & Co.) considered potential hardening zones for inclusion in Phase 2 based on a combination of data driven assessments, operational knowledge of the system, and historical performance of ENO's system during major storm events. As I mentioned above, a "hardening zone" refers to a collection of assets identified for hardening and evaluated by the Resilience Model under a variety of different programs, which I discuss later in my testimony. The approach to identifying hardening zones employs asset management principles utilizing a bottom-up approach starting at the asset level. The following describes the approach to identifying and grouping the Company's assets into hardening zones for consideration.

- **Distribution Hardening Zones:** For distribution hardening zones, 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.

1898 & Co.'s evaluation of hardening zone types – including laterals (assets grouped by a fuse protection device) and feeders (assets grouped by a breaker or recloser protection device) – considered both rebuilding to a storm resilient overhead design standard and undergrounding, where possible. While undergrounding may provide significant resilience benefits, as I noted above, overhead hardening rebuilds are generally lower cost. The Resilience Model balances this tradeoff for every hardening zone across ENO's service area where both options are technically feasible. Assets identified for inclusion in overhead hardening zones 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 hardening zone 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 Hardening Zones:** At the transmission circuit level, poles identified for hardening are replaced with higher wind rated structures and materials. Transmission structures were grouped at the transmission line or circuit level into hardening zones. For Phase 2, transmission assets were only deemed to be hardening candidates if they were wood structures.
- **Substation Hardening Zones:** 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 hardening zones. Those substations that are located behind a levee are not considered to be at risk of storm surge, as they already have a level of protection.

Q33. AFTER THE COMPANY'S ASSETS WERE GROUPED IN THAT WAY, DID THE RESILIENCE MODEL USE CERTAIN PROGRAMS TO CONSIDER HARDENING ZONES?

A. Yes. As part of the Resilience Model, the potential hardening zones were grouped into five different programs: Distribution Feeder Hardening (Rebuild), Distribution Feeder Undergrounding, Lateral Hardening (Rebuild), Transmission Rebuild, and Substation Storm Surge Mitigation.

Q34. PLEASE EXPLAIN WHAT THE DIFFERENT PROGRAMS ENTAIL.

A. The Distribution Feeder Hardening (Rebuild), Lateral Hardening (Rebuild), and Transmission Rebuild programs involve the evaluation of the identified hardening zones (*i.e.*, the set of grouped assets) to determine the level of work needed to harden the assets contained in those hardening zones (*i.e.*, bring those assets up to the current design standards for distribution and transmission assets). As discussed in the Company's prior filings seeking approval of Phase 1, the Company's distribution and transmission design standards have been revised in recent years in the light of the severe weather conditions experienced.[17] Those revisions recognize that customers and communities are demanding a more resilient grid, and the increased standards reflect what researchers and New Orleans and other Gulf Coast residents have learned about the challenges that communities on or near the coast are facing and may face in the future. Just like in Phase 1, if Phase 2 is approved, the Company will thoroughly design and plan the work needed to bring each asset in the selected Phase 2 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 Council advised of any material changes between the projected and actual costs of a project.

As might be expected, Distribution Feeder Undergrounding involves the undergrounding of overhead lines. Finally, the Substation Storm Surge Mitigation

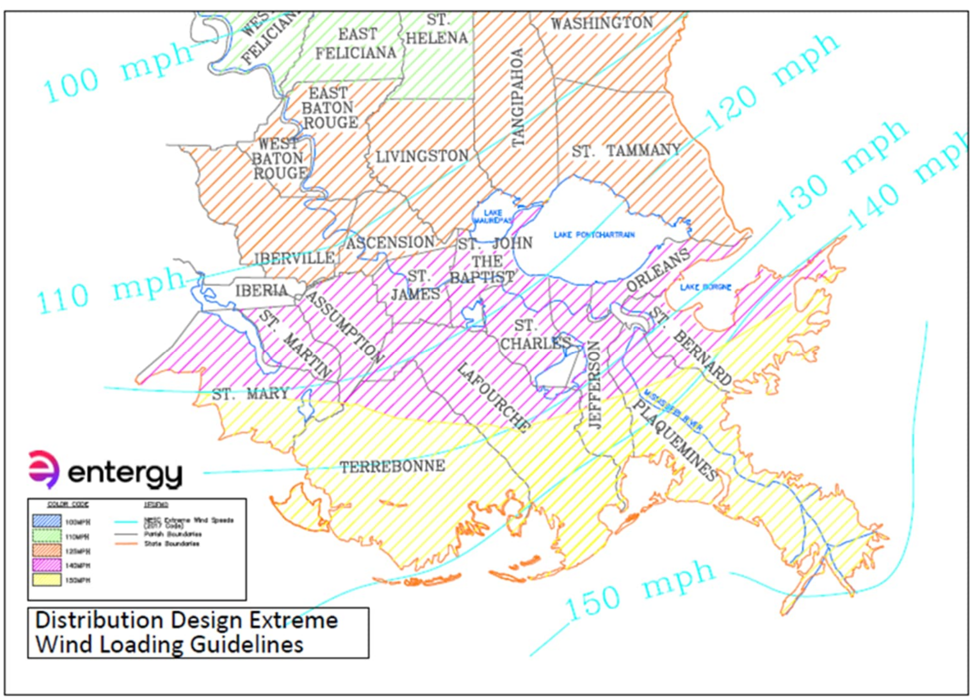
[17] The Company's design standards with respect to wind ratings have not changed since its Phase 1 filing in this docket.

program involves undertaking identified work such as constructing flood walls at specific substations to protect against storm surge caused by severe weather.

Q35. YOU MENTIONED THAT THE COMPANY HAS REVISED ITS WIND DESIGN CRITERIA. PLEASE DESCRIBE THE REVISED WIND LOADING STANDARDS FOR DISTRIBUTION STRUCTURES.

A. The Company's distribution lines have always been designed to meet or exceed the applicable National Electric Safety Code ("NESC") standards. And, over the years, additional design practices have been adopted to harden distribution assets to prepare for severe weather. After Hurricane Ida, the Company developed increased design standards for its distribution structures reflective of the extreme wind loading requirements of NESC Rule 250C as shown in Figure 5.

Figure 5: <u>Wind Loading Guidelines for Distribution Lines</u>



As indicated in Figure 5, distribution assets and structures in Orleans Parish are now designed to the 140-mph extreme wind loading requirements, which exceeds the requirements of NESC Rule 250C for Orleans Parish. This is the same standard used for the Company's Phase 1 projects and assets hardened through the Company's reliability programs.

Q36. HOW WILL THE COMPANY IMPLEMENT THESE STANDARDS AS PART OF PHASE 2?

A. As it did in Phase 1, the Company will evaluate and replace or rebuild the identified distribution assets as part of the "Hardening" and "Rebuild" programs. The Company will design and harden new structures using the revised wind zones to help determine the wind forces that are exerted on those 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 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.*, wood, steel, 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.

Q37. TURNING BACK TO THE METHODOLOGY USED TO DEVELOP THE PHASE 2 RESILIENCE PLAN, YOU STATED THAT THE RESILIENCE MODEL USED A FOUR-STEP PROCESS. CAN YOU GIVE AN OVERVIEW OF THAT PROCESS?

A. Yes. *First,* the Resilience Model starts with a universe of major storm events that could impact ENO's service area, called the "Major Events Database," from which 45 different storm types were identified. *Second*, each storm type is modeled within a "System Vulnerability and Event Impact Module" ("Event Impact Module") that identifies which parts of the system are most likely to fail in the event of each type of storm. The Event Impact Module estimates the restoration costs and CMI for each potential hardening zone for each storm type and calculates the benefit in decreased restoration costs and CMI if that hardening zone is hardened to ENO's standards. *Third*, a "Resilience Benefit Module" utilizes stochastic modeling to determine a weighted benefit for each hardening zone in the programs over the next fifty years. And *fourth*, a "Plan Development Module" prioritizes hardening zones based on their BCR to develop an overall 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. Mire's testimony as well as in the Report prepared by 1898 & Co. that is attached as an exhibit to his testimony.

Q38. DID THE COMPANY FURTHER REFINE THE LIST OF HARDENING ZONES IDENTIFIED BY THE RESILIENCE MODEL?

A. Yes. The Phase 2 hardening zone list was coordinated with ENO's grid operations and customer service teams to reprioritize the execution schedule based on an evaluation of local reliability performance as well as growth opportunities. While the focus of resilience projects is decreased outage durations and restoration costs during a major event, there are ancillary benefits to hardening distribution assets that complement reliability improvements and assist in growth for the community.

A. <u>Major Events Database</u>

Q39. PLEASE BRIEFLY EXPLAIN THE MAJOR EVENTS DATABASE AND HOW IT WAS USED IN THE RESILIENCE MODEL.

A. The Major Events Database utilizes information drawn from the National Oceanic and Atmospheric Administration ("NOAA"), including a database of historical hurricane tracks that has data from events back to 1851, as well as a detailed weather event database at the parish level beginning in 1998 that includes non-named, non-hurricane events such as thunderstorms, tornadoes, and ice storms. These databases were mined to evaluate the different types and frequency of major storms to impact Louisiana, including ENO's service area. The universe of information comprising the Major Events Database included information regarding the major storm events that have impacted ENO's service area over the last 174 years (1851 to 2024). This historical information was used to identify 45 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 Events 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.

B. Event Impact Module

Q40. PLEASE EXPLAIN THE EVENT IMPACT MODULE FURTHER.

A. The Event Impact Module 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 Events Database. The Event Impact Module also estimates the restoration costs associated with the specific hardening zone failures and calculates the impact to customers in terms of CMI. Finally, the Event Impact Module models each storm event for both a "Status Quo" and "Hardened" scenario, which are more fully discussed by Mr. Mire and in the Report attached to his testimony. The Hardened scenario assumes that the assets that make up each hardening zone have been hardened in accordance with the programs I discussed above. The Event Impact Module then calculates the resilience benefit of each hardening zone from a reduced restoration cost, CMI, and monetized CMI perspective.

Q41. HOW DOES THE EVENT IMPACT MODULE IDENTIFY THE ASSETS THAT ARE LIKELY TO FAIL DURING MAJOR STORM EVENTS?

A. The Event Impact Module 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 Event Impact Module, assumes that a storm has impacted a hardening zone (*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 hardening zone. The likelihood of that hardening zone failing, among all the possible hardening zones, is based on the collective attributes of the assets (poles, structures, wires, etc.) inside that hardening zone. The calculation of the Likelihood of Failure score for a hardening zone is based on a vegetation rating, an age rating, and a wind zone rating for each asset inside each hardening zone. 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 rating utilizes expected remaining life curves with the asset's actual or estimated age. The wind zone rating is based on the wind zone within which the asset is located. The actual wind rating of the asset is 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.

Q42. HOW DOES THE EVENT IMPACT MODULE DETERMINE THE COST OF RESTORATION FOLLOWING EACH STORM EVENT?

A. The Event Impact Module calculates the restoration costs for every asset – including wood poles, transmission structures (steel, concrete, and lattice), power transformers, relays, and breakers – required to rebuild the system to provide service. Once the Event Impact Module identifies the portions of the system that are damaged and cause 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 storm restoration cost multipliers over planned replacement costs and were developed collaboratively by ENO and 1898 & Co. For each storm event, the restoration costs at the asset level are aggregated up to the hardening zone level and then weighted based on the hardening zone Likelihood of Failure and the overall restoration costs for the storm event outlined in the Major Events Database. This produces a Status Quo restoration cost to represent a world without the hardening zone being hardened. The Hardened restoration cost of a hardening zone 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. The restoration cost benefit is calculated as the difference between Status Quo restoration cost and Hardened restoration cost.

Q43. PLEASE EXPLAIN WHAT YOU MEAN WHEN YOU SAY THAT RESTORATION COSTS WERE BASED ON STORM RESTORATION COST MULTIPLIERS.

A. As I mentioned above, 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 using expected outside labor and taking into account expedited materials cost needed to restore the system, 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, unavoidable inefficiencies that arise from storm restoration, and logistical and other challenges. For major weather events, the Company relies on mutual assistance to restore the system with non-Company crews from across the nation. Given the 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.

Q44. HOW DOES THE EVENT IMPACT MODULE ESTIMATE THE CUSTOMER MINUTES INTERRUPTED FOR EACH STORM EVENT?

A. The Event Impact Module calculates the CMI by assets/hardening zone for each storm scenario. Since distribution hardening zones are organized by protection device, the customer counts and customer types are known for each asset in the Event Impact Module. The Event Impact Module calculates the duration to restore each hardening zone in the Status Quo scenario, and the hardening zone duration is then multiplied by the number of affected customers for each hardening zone to calculate the CMI for each hardening zone. The Event Impact Module also calculates CMI for the Hardened scenario based on changes to the core assumptions (*e.g.*, vegetation density, age, wind zone, restoration costs, duration, and customers impacted) for each hardening zone. The output from the Event Impact Module is a hardening zone-by-hardening zone, probability weighted estimate of annual storm restoration costs and annual CMI for both the Status Quo and Hardened scenarios for all 45 major storm types.

Q45. YOU MENTIONED THAT A RESILIENCE BENEFIT WAS CALCULATED FOR EACH HARDENING ZONE BY MAJOR STORM EVENT. PLEASE EXPLAIN HOW THAT RESILIENCE BENEFIT WAS CALCULATED.

A. The resilience benefit for each hardening zone 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 Report attached to Mr. Mire's testimony.

Q46. WERE BOTH RESTORATION COSTS AND CMI CONSIDERED?

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. The neighborhoods 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.

Q47. WHY WERE CMI BENEFITS MONETIZED?

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

Q48. HOW WERE CMI BENEFITS MONETIZED?

A. CMI benefits were monetized using the U.S. Department of Energy's ("DOE") Interruption Cost Estimate ("ICE") Calculator. This tool provides information that can 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 Resilience Model, 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 hardening zone to calculate the monetized CMI at the hardening zone level.

Q49. ARE THERE ANY LIMITATIONS ON USING THE DOE'S ICE CALCULATOR?

A. Yes. The DOE's ICE Calculator does not consider all the factors that would be necessary to assess the causes and impacts of an outage to customers in specific circumstances. Again, for hardening zone prioritization purposes, the Resilience Model 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 use of the DOE's ICE Calculator to help prioritize hardening zones within the Phase 2 Resilience 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. As explained by Company witness Alyssa Maurice-Anderson, however, the Company's and 1898 & Co.'s use of the results from the ICE Calculator to quantify in dollars the societal benefit from reduced CMI is reasonable under the circumstances because such quantification provides the Council a way to assess that significant material benefit to customers when determining whether Phase 2 serves the public interest.

C. Resilience Benefit Module

Q50. PLEASE EXPLAIN THE RESILIENCE BENEFIT MODULE.

A. The Resilience Benefit Module uses the benefit calculated from the Event Impact Module and the estimated costs to estimate the net benefits for each hardening zone over the next fifty years. To be clear, such benefits 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 Events Database that may impact the Company's service area over the next 50 years at various levels of storm frequency. Each hardening zone's CMI, monetized CMI, and restoration costs were calculated for the 45 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 hardening zone for that storm event. The sum of the benefits for all 45 storm types for each iteration of the simulation equals the total benefits for the hardening zone. The

CMI, monetized CMI, and restoration benefits are then weighted by the probability of the 45 storm types to calculate the weighted benefit. To calculate the net benefits, the project costs are determined.

Q51. 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 hardened infrastructure will have an average service life of 50 or more years;
- 2.5 percent escalation rate; and
- 7 percent discount rate.

Q52. HOW WERE COSTS DETERMINED FOR EACH OF THE HARDENING ZONES CONSIDERED IN THE RESILIENCE MODEL AND THAT ULTIMATELY WERE SELECTED FOR PHASE 2?

A. Costs were estimated for the hardening zones considered in the Resilience Model. Some of the estimated costs were provided by the Company, while others were estimated using the data within the Resilience Model to estimate the scope of the hardening zone, 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 costs.

To be clear, if the Phase 2 Resilience Plan is approved, the Company will continue to review and refine the projects selected for Phase 2, and the final costs for any particular project may need to be adjusted. As I discuss more fully below, the Company will keep the Council informed regarding these adjustments.

D. Plan Development Module

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

A. As part of the Resilience Model, an optimized investment and prioritization list is determined from consideration of the hardening zones in the programs I discussed above based on the highest ratio of resilience benefit to cost. Specifically, the model prioritizes each hardening zone using a benefit cost ratio based on the sum of the restoration cost benefit and monetized CMI benefit divided by the hardening zone cost. This calculation is performed for the range of potential benefit values to create the overall resilience benefit cost ratio. The model also incorporates technical and operational constraints in scheduling the hardening zones applicable to ENO and its service area, such as contractor capacity and material availability. Using the benefit cost ratio as a guide, the Resilience Model performs an investment optimization simulation to identify the point of diminishing returns for hardening investments for the 5-year period. Prioritizing and optimizing hardening zones in this way is intended to ensure that the overall investment level is appropriate and that customers get the most cost-effective solutions.

Q54. HOW WERE THE HARDENING ZONES IN THE PROGRAMS PRIORITIZED IN THE RESILIENCE MODEL?

A. Because all hardening zones in the Resilience Model were evaluated on a consistent basis, they can all be ranked against each other and compared. The Resilience Model ranks all the hardening zones based on their benefit cost ratio using the life cycle 50-year present value 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 hardening zone has a different slope in its benefits from an average storm future to a very high 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.

E. <u>Further Evaluation and Estimated Benefits</u>

Q55. IS THE COMPANY PROPOSING TO COMPLETE, IN PHASE 2, PROJECTS FOR EVERY HARDENING ZONE WITH A POSITIVE BENEFIT COST RATIO?

A. No, the Company is not proposing to undertake projects for every hardening zone with a positive benefit cost ratio, much less proposing to harden every asset in the Company's distribution and transmission systems. While additional projects beyond the Phase 2 proposal could be completed and provide value to customers, the Company has considered other factors, including the potential bill impact to customers and supply chain limitations, to determine a proposed investment level that the Company believes is achievable, addresses affordability concerns, will improve the resilience of the system, and will provide benefits to customers.

Q56. PLEASE EXPLAIN HOW THOSE OTHER FACTORS WERE EVALUATED.

A. Using the point of diminishing return identified by the prioritization and investment optimization process of the Resilience Model (*i.e.*, the point at which the incremental costs of each hardening zone outweighed the potential incremental benefits of completing more hardening zones) as a starting point, the Company and 1898 & Co. further refined the total number of hardening zones considering certain technical execution constraints such as supply chain limitations. This resulted in a portfolio of hardening zones comprising Phase 2 that cost approximately $400 million. In addition, although the analysis I have just described that was performed as part of the Resilience Model and with 1898 & Co. served as a necessary and useful guide, the Company ultimately evaluated the hardening zones based upon its own operational experience and judgment in determining (1) the hardening zones to propose as part of the Phase 2 Resilience Plan, (2) how those hardening zones ultimately should be scheduled, and (3) how to consolidate and group the hardening zones into projects. In identifying and scheduling projects, the Company has given priority to projects that will either benefit critical customers and infrastructure, serve potential areas for economic growth, ensure coverage of all Council districts, or improve the Company's worst performing feeders from the previous 2 years.

Q57. WHAT PROJECTS WERE IDENTIFIED FOR INCLUSION IN PHASE 2 AS A RESULT OF THE RESILIENCE MODEL AND ADDITIONAL EVALUATION?

A. Based on the results of the Resilience Model and the additional evaluation, the Company has proposed in its Phase 2 Resilience Plan to undertake 36 accelerated infrastructure hardening projects (consolidated from 422 selected hardening zones) across its system which are listed in the attached HSPM Exhibit CG-2. Like Phase 1, the Phase 2 projects involve replacing and upgrading distribution poles and related equipment using materials such as wood, steel, composite, and concrete poles; insulators; and conductor.

Q58. WHAT ARE THE ESTIMATED BENEFITS OF COMPLETING THE PROJECTS IN THE PHASE 2 RESILIENCE PLAN?

A. 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. Specifically, assuming each hardening project in Phase 2 is performed, the Resilience Model projects that the Company and customers will see future restoration costs after storms decrease by approximately $83 million and the total number of CMI after major events decrease by 3.4 billion minutes, which corresponds to an estimated reduction of over $1.3 billion in overall outage costs to customers, over the next fifty years assuming an above average frequency of storms.

Q59. WILL THE PHASE 2 RESILIENCE PLAN NEED REVISION AND REFINEMENT AS IT IS IMPLEMENTED?

A. Yes. The projects proposed in Phase 2 and the years in which costs are expected to be incurred are based on the results of the investment optimization and prioritization process that I discuss above. Although the Phase 2 Resilience Plan sets forth the Company's best efforts to identify and estimate the scope, cost, and timing of those projects, the precise work performed will be subject to continual review and refinement as the Company implements Phase 2 after approval by the Council. And, as I discuss above, the Company will work to coordinate and avoid overlap between the Phase 2 Resilience Plan and any ongoing reliability work. As I discuss below, the Company will keep the Council informed of material changes.

Q60. WILL THE PHASE 2 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 Phase 2 Resilience Plan – like the Phase 1 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 accelerated hardening projects are directly affected by how frequently ENO's service area is impacted by extreme weather events and where those impacts are felt. No one can predict with absolute certainty how frequently such events will occur or where precisely they will strike.

Nonetheless, the expectation is that the proposed Phase 2 Resilience Plan will increase the resilience of ENO'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 ENO's customers.

V. PROJECT MANAGEMENT, CONTRACTING APPROACH, AND RISK MANAGEMENT

Q61. HOW WILL THE COMPANY MANAGE THE PHASE 2 RESILIENCE PLAN?

A. ENO will manage Phase 2 as it has Phase 1, following Company policies, systems, and guidelines. Specifically, as with Phase 1, the project management approach will follow the Company's Project Delivery System ("PDS") Policy, Standards and Guidelines. 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 gate reviews and approvals.

Additionally, the Company will continue to maintain appropriate project controls in the areas of project safety, cost, and schedule. The Company will also continue to 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.

Q62. WILL THE COMPANY CONTINUE TO USE THE ALLIANCE PARTNER APPROACH IN PHASE 2?

A. Yes. The Company intends to utilize the same Alliance Partner approach for Phase 2 as it did for Phase 1, including using the Alliance Partner currently executing Phase 1 to execute Phase 2, in addition to the Company's management team. The Company also remains focused on supporting the local economy and plans to continue utilizing vendors that are based in New Orleans.

The Company is continuing to use the Alliance Partner approach because it is the best method for controlling costs and to consistently and reliably execute the large portfolio of projects contained in the Phase 2 Resilience Plan. The advantages of this approach have been demonstrated as the Company has worked to execute projects composing Phase 1. In addition, as I mentioned above, maintaining the resources and work crews that currently are executing Phase 1 in New Orleans further promotes cost and operational efficiencies.

Q63. WHAT ARE SOME OF THE KEY RISKS TO IMPLEMENTING THE PHASE 2 RESILIENCE PLAN AND WHAT ARE THE COMPANY'S PLANS TO MANAGE AND MITIGATE THOSE RISKS?

A. Key risks include, among other things, acquiring and managing adequate labor resources; ensuring an adequate supply of materials and managing lead time to acquire those materials; materials costs; the potential for wage inflation to affect estimated costs; and potential delays to project scoping and execution. The Company has managed such risks as work on Phase 1 has proceeded through its oversight of the work being completed by its Alliance Partner, and through its project management system and PDS, which I discuss above. The Company will continue to manage those key risks as well as other risks that emerge in Phase 2 using the same strategies.

Q64. YOU MENTIONED THAT HAVING AN ADEQUATE SUPPLY OF MATERIALS IS A RISK TO IMPLEMENTING THE PHASE 2 RESILIENCE PLAN. WHAT IS THE COMPANY'S STRATEGY FOR SOURCING MATERIALS TO USE TO COMPLETE PHASE 2?

A. To address this risk in Phase 1, the Company has contracted with a third-party material integrator to manage materials and provide logistical support. By using a third-party material integrator for Phase 1, which the Company plans to continue into Phase 2, the Company is able to operate cost-effectively and: (a) isolate materials for directly-planned projects; (b) assure visibility into near- and long-term availability of materials; (c) isolate 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 also will continue to evaluate the materials markets to ensure that this risk is managed appropriately.

Q65. WHAT HAPPENS IF DISRUPTIVE EVENTS, SUCH AS A SERIES OF STORMS, HAVE A MATERIAL EFFECT ON THE ANTICIPATED COSTS OR PROGRESS OF PHASE 2?

A. Unanticipated delays and unforeseen circumstances are a part of any project. The Company will work to address any issues that might arise and, as I mentioned above, refine or revise the Phase 2 Resilience Plan as necessary given the realities of the situation. Furthermore, the Company will keep the Council advised of material changes to Phase 2 and its progress and the causes of any material changes.

VI. PROJECT MONITORING AND PERFORMANCE METRICS

Q66. DID THE COUNCIL ADDRESS HOW THE COMPANY SHOULD MONITOR AND REPORT ON THE PHASE 1 PROJECTS?

A. Yes. In Resolution No. R-24-625, the Council directed CURO, the Advisors, and ENO to develop a reporting format crafted to provide the Council with information on the project status and cost of each project in Phase I, "as well as ongoing data gathering that would assist the Council in evaluating future resilience investments and performance."[18] As directed by the Council, CURO, the Advisors, and ENO recently have prepared and submitted that reporting format ("Grid Hardening Projects

[18] Resolution No. R-24-625, at p. 14 (Ordering Paragraph 3).

Reporting Requirements"), including a template for monitoring reports to be submitted quarterly by the Company ("Quarterly Monitoring Report") as well as information that is to be included in reports to the Council following certain storms and major weather events ("Post-Event Report"). The Company filed its first Quarterly Monitoring Report with the Council on November 17, 2025.

Q67. WHAT INFORMATION AND REPORTING IS ENO PROPOSING TO PROVIDE TO THE COUNCIL IN CONNECTION WITH ITS IMPLEMENTATION OF PHASE 2?

A. ENO proposes that it will continue providing Quarterly Monitoring Reports in the same format that it is currently providing for Phase 1. ENO also will provide Post-Event Reports that include the information specified in the Grid Hardening Projects Reporting Requirements recently submitted to the Council.

Q68. DID ENO PROPOSE ANY PERFORMANCE-BASED METRICS IN CONNECTION WITH ITS PRIOR RESILIENCE FILINGS IN THIS DOCKET?

A. Yes. ENO proposed a pole performance metric (the "Pole Performance Metric") that would assess against the Company a predetermined fee for each pole failure after a single qualifying weather event under certain circumstances. In Resolution No. R-24-625 approving the Phase 1 Resilience Plan, the Council directed CURO, in consultation with the Advisors and ENO, to modify and finalize the Pole Performance Metric.[19] As

[19] Resolution No. R-24-625 at p. 15 (Ordering Paragraph 4).

directed by the Council, CURO, the Advisors, and ENO recently have prepared and submitted a revised Pole Performance Metric that will be triggered if there is a single weather event that qualifies for a Federal Disaster Declaration and 150 or more ENO-owned poles fail (meaning that such poles require repair, reinforcement, or replacement not resulting from conditions outside of the design basis of the pole). If the Pole Performance Metric is triggered, and if more than 5% of the poles installed as part of ENO's Phase 1 hardening projects fail, the Company will be assessed a fee for each failed pole in excess of the 5% threshold. This 5% threshold is applied individually to four pole types (concrete, composite, steel, and wood), with specific fees assessed for each failed pole type in excess of the 5% metric threshold.

Q69. WHAT METRICS IS ENO PROPOSING TO UTILIZE IN CONNECTION WITH THE PHASE 2 RESILIENCE PLAN?

A. ENO proposes use of the same Pole Performance Metric (as revised by CURO, the Advisors, and ENO) to help ensure that the Phase 2 Resilience Plan is delivering resilience benefits for customers.

Q70. 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, **CHRIS GREMILLION**, 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.

CHRIS GREMILLION

SWORN TO AND SUBSCRIBED BEFORE ME
THIS 9th **DAY OF DECEMBER 2025**

NOTARY PUBLIC

My commission expires: death

ENO's 2025-26 Accelerated Infrastructure Hardening Project List

Expected Priority Order	OpCo	Local Office	Council District	Sub-system ID	Program Name	Project Type	Start Year	End Year	Investment (Nominal)	BCR	50-yr CMI Benefits Weighted	50-yr PV Total Dollars Benefits Weighted	50-yr PV CMI Dollars Benefits Weighted	50-yr PV Restoration Dollars Benefits Weighted	Device Type	Circuit	Total Line Structures	Structures to be Hardened	Total Line Miles
1	NO	East Orleans	Council District E	Internal Vac Fault Interrupter-88623037-2216	Lateral Hardening-Rebuild	Rebuild	2025	2025	[redacted]	13.31	[redacted]	[redacted]	[redacted]	[redacted]	Internal Vac Fault Interrupter	2216	11	4	0.186282257
2	NO	East Orleans	Council District E	Internal Vac Fault Interrupter-462803417-2213	Lateral Hardening-Rebuild	Rebuild	2025	2025	[redacted]	11.71	[redacted]	[redacted]	[redacted]	[redacted]	Internal Vac Fault Interrupter	2213	6	6	0.177195132
3	NO	East Orleans	Council District E	Internal Vac Fault Interrupter-374244151-2211	Lateral Hardening-Rebuild	Rebuild	2025	2025	[redacted]	9.57	[redacted]	[redacted]	[redacted]	[redacted]	Internal Vac Fault Interrupter	2211	10	10	0.129390193
4	NO	East Orleans	Council District E	Internal Vac Fault Interrupter-388491104-1609	Lateral Hardening-Rebuild	Rebuild	2025	2025	[redacted]	8.01	[redacted]	[redacted]	[redacted]	[redacted]	Internal Vac Fault Interrupter	1609	1	1	0.003164774
5	NO	East Orleans	Council District E	Internal Vac Fault Interrupter-258880978-1602	Lateral Hardening-Rebuild	Rebuild	2025	2025	[redacted]	4.69	[redacted]	[redacted]	[redacted]	[redacted]	Internal Vac Fault Interrupter	1602	2	2	0.004221592
6	NO	Algiers	Council District C	Fuse Switch-88681317-W1714	Lateral Hardening-Rebuild	Rebuild	2025	2025	[redacted]	5.53	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	W1714	2	2	0.063545475
7	NO	Algiers	Council District C	Fuse Switch-88754955-W1712	Lateral Hardening-Rebuild	Rebuild	2025	2025	[redacted]	5.44	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	W1712	10	9	0.141503833
8	NO	Orleans	Council District A	Fuse Switch-88720214-409	Lateral Hardening-Rebuild	Rebuild	2025	2025	[redacted]	8.18	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	409	12	12	0.189729227
9	NO	Orleans	Council District A	Fuse Switch-130171082-409	Lateral Hardening-Rebuild	Rebuild	2025	2025	[redacted]	6.45	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	409	14	14	0.173376949
10	NO	Orleans	Council District A	Breaker-249133844-903	Distribution Feeder Hardening-Rebuild	Rebuild	2025	2026	[redacted]	4.98	[redacted]	[redacted]	[redacted]	[redacted]	Breaker	903	206	184	3.767510675
11	NO	Orleans	Council District A	Breaker-159170502-911	Distribution Feeder Hardening-Rebuild	Rebuild	2025	2026	[redacted]	4.57	[redacted]	[redacted]	[redacted]	[redacted]	Breaker	911	296	288	5.788768898
12	NO	Orleans	Council District D	Fuse Switch-218246872-1712	Lateral Hardening-Rebuild	Rebuild	2025	2025	[redacted]	9.26	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	1712	9	8	0.171134524
13	NO	East Orleans	Council District D	Fuse Switch-88682117-1010	Lateral Hardening-Rebuild	Rebuild	2025	2025	[redacted]	3.74	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	1010	20	20	0.474390303
14	NO	Orleans	Council District B	Breaker-137437628-2135	Distribution Feeder Hardening-Rebuild	Rebuild	2025	2025	[redacted]	6.24	[redacted]	[redacted]	[redacted]	[redacted]	Breaker	2135	129	122	1.91345137
15	NO	Orleans	Council District B	Fuse Switch-88734398-2135	Lateral Hardening-Rebuild	Rebuild	2025	2025	[redacted]	8.26	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	2135	7	7	0.08082389
16	NO	Orleans	Council District B	Fuse Switch-88734406-2135	Lateral Hardening-Rebuild	Rebuild	2025	2025	[redacted]	5.36	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	2135	23	23	0.216564463
17	NO	Orleans	Council District B	Fuse Switch-88745165-2135	Lateral Hardening-Rebuild	Rebuild	2025	2025	[redacted]	5.23	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	2135	27	27	0.270596678
18	NO	East Orleans	Council District E	Breaker-88120741-2212	Distribution Feeder Hardening-Rebuild	Rebuild	2025	2025	[redacted]	3.67	[redacted]	[redacted]	[redacted]	[redacted]	Breaker	2212	48	47	0.990439711
19	NO	East Orleans	Council District E	Fuse Switch-230205976-1204	Lateral Hardening-Rebuild	Rebuild	2025	2025	[redacted]	17.48	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	1204	7	7	0.060814413
20	NO	East Orleans	Council District E	Fuse Switch-88731824-1204	Lateral Hardening-Rebuild	Rebuild	2025	2025	[redacted]	3.25	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	1204	5	5	0.097164804
21	NO	East Orleans	Council District E	Fuse Switch-88695450-1204	Lateral Hardening-Rebuild	Rebuild	2025	2026	[redacted]	5.05	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	1204	130	127	3.767241736
22	NO	Orleans	Council District B	Breaker-88129843-2137	Distribution Feeder Hardening-Rebuild	Rebuild	2025	2026	[redacted]	6.25	[redacted]	[redacted]	[redacted]	[redacted]	Breaker	2137	69	66	1.222945467
23	NO	Orleans	Council District B	Recloser Bank-331960909-2137	Distribution Feeder Hardening-Rebuild	Rebuild	2025	2026	[redacted]	5.51	[redacted]	[redacted]	[redacted]	[redacted]	Recloser Bank	2137	76	74	0.805608212
24	NO	Orleans	Council District B	Fuse Switch-121634957-2137	Lateral Hardening-Rebuild	Rebuild	2025	2026	[redacted]	3.81	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	2137	44	43	0.439272868
25	NO	Orleans	Council District B	Breaker-88129100-2147	Distribution Feeder Hardening-Rebuild	Rebuild	2025	2026	[redacted]	5.17	[redacted]	[redacted]	[redacted]	[redacted]	Breaker	2147	240	226	4.419012778
26	NO	Orleans	Council District B	Fuse Switch-88744021-1921	Lateral Hardening-Rebuild	Rebuild	2025	2026	[redacted]	5.24	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	1921	20	20	0.188638318
27	NO	Orleans	Council District B	Fuse Switch-88739250-2132	Lateral Hardening-Rebuild	Rebuild	2025	2026	[redacted]	4.88	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	2132	31	31	0.503335388
28	NO	Orleans	Council District B	Fuse Switch-259160137-2132	Lateral Hardening-Rebuild	Rebuild	2025	2026	[redacted]	3.50	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	2132	28	28	0.26319516
29	NO	Orleans	Council District B	Breaker-88124978-1915	Distribution Feeder Hardening-Rebuild	Rebuild	2025	2026	[redacted]	5.25	[redacted]	[redacted]	[redacted]	[redacted]	Breaker	1915	76	75	2.578445901
30	NO	Orleans	Council District B	Recloser Bank-331712099-1923	Distribution Feeder Hardening-Rebuild	Rebuild	2025	2026	[redacted]	4.77	[redacted]	[redacted]	[redacted]	[redacted]	Recloser Bank	1923	40	40	1.277443591
31	NO	Orleans	Council District A	Fuse Switch-127166924-1916	Lateral Hardening-Rebuild	Rebuild	2025	2025	[redacted]	4.66	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	1916	9	9	0.1044792
32	NO	Orleans	Council District D	Fuse Switch-88710681-627	Lateral Hardening-Rebuild	Rebuild	2025	2026	[redacted]	7.82	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	627	22	22	0.440276656
33	NO	Orleans	Council District D	Fuse Switch-88671926-627	Lateral Hardening-Rebuild	Rebuild	2025	2026	[redacted]	6.04	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	627	21	21	0.272651602
34	NO	East Orleans	Council District D	Fuse Switch-88679155-613	Lateral Hardening-Rebuild	Rebuild	2025	2026	[redacted]	7.25	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	613	39	39	0.615492621
35	NO	East Orleans	Council District D	Fuse Switch-88682531-613	Lateral Hardening-Rebuild	Rebuild	2025	2026	[redacted]	4.07	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	613	17	17	0.332509576
36	NO	Orleans	Council District D	Fuse Switch-88739218-615	Lateral Hardening-Rebuild	Rebuild	2025	2026	[redacted]	4.60	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	615	83	83	1.134892409
37	NO	Orleans	Council District D	Breaker-88122274-615	Distribution Feeder Hardening-Rebuild	Rebuild	2025	2026	[redacted]	4.16	[redacted]	[redacted]	[redacted]	[redacted]	Breaker	615	120	117	3.42170564
38	NO	Orleans	Council District C	Fuse Switch-88737457-614	Lateral Hardening-Rebuild	Rebuild	2025	2026	[redacted]	5.43	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	614	26	25	0.272244405
39	NO	Orleans	Council District C	Fuse Switch-88746475-614	Lateral Hardening-Rebuild	Rebuild	2025	2026	[redacted]	3.97	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	614	21	21	0.909059003
40	NO	Orleans	Council District C	Fuse Switch-88746535-614	Lateral Hardening-Rebuild	Rebuild	2025	2026	[redacted]	3.66	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	614	27	27	0.396647854
41	NO	Orleans	Council District C	Fuse Switch-121295426-614	Lateral Hardening-Rebuild	Rebuild	2025	2026	[redacted]	3.56	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	614	2	2	0.04892047
42	NO	Orleans	Council District C	Recloser Bank-132157198-614	Distribution Feeder Hardening-Rebuild	Rebuild	2025	2026	[redacted]	3.72	[redacted]	[redacted]	[redacted]	[redacted]	Recloser Bank	614	181	172	3.037114608
43	NO	Orleans	Council District D	Breaker-88122252-614	Distribution Feeder Hardening-Rebuild	Rebuild	2025	2026	[redacted]	3.96	[redacted]	[redacted]	[redacted]	[redacted]	Breaker	614	117	116	3.322254851
44	NO	East Orleans	Council District D	Breaker-88122448-622	Distribution Feeder Hardening-Rebuild	Rebuild	2025	2026	[redacted]	3.79	[redacted]	[redacted]	[redacted]	[redacted]	Breaker	622	103	99	2.128919242
45	NO	East Orleans	Council District C	Recloser Bank-330174411-623	Distribution Feeder Hardening-Rebuild	Rebuild	2025	2026	[redacted]	3.73	[redacted]	[redacted]	[redacted]	[redacted]	Recloser Bank	623	137	136	2.284362473
46	NO	East Orleans	Council District C	Auto Transfer Switch-248675498-2347	Lateral Hardening-Rebuild	Rebuild	2025	2026	[redacted]	5.43	[redacted]	[redacted]	[redacted]	[redacted]	Auto Transfer Switch	2347	86	86	2.26610868
47	NO	East Orleans	Council District E	Breaker-88127655-2347	Distribution Feeder Hardening-Rebuild	Rebuild	2025	2026	[redacted]	3.89	[redacted]	[redacted]	[redacted]	[redacted]	Breaker	2347	111	105	2.957555871
48	NO	Orleans	Council District A	Breaker-88125240-2014	Distribution Feeder Hardening-Rebuild	Rebuild	2025	2026	[redacted]	5.21	[redacted]	[redacted]	[redacted]	[redacted]	Breaker	2014	110	110	3.120605165
49	NO	Orleans	Council District A	Fuse Switch-88693400-2014	Lateral Hardening-Rebuild	Rebuild	2025	2026	[redacted]	6.17	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	2014	23	23	0.42208915
50	NO	Orleans	Council District A	Fuse Switch-88737497-2014	Lateral Hardening-Rebuild	Rebuild	2025	2026	[redacted]	5.35	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	2014	27	27	0.399125128
51	NO	Orleans	Council District A	Fuse Switch-115300771-2014	Lateral Hardening-Rebuild	Rebuild	2025	2026	[redacted]	3.74	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	2014	31	31	0.376890272
52	NO	Orleans	Council District A	Fuse Switch-88698468-2016	Lateral Hardening-Rebuild	Rebuild	2025	2026	[redacted]	4.97	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	2016	40	40	0.657793771
53	NO	Orleans	Council District A	Fuse Switch-88692572-2026	Lateral Hardening-Rebuild	Rebuild	2025	2026	[redacted]	4.47	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	2026	6	6	0.090126923
54	NO	Algiers	Council District C	Fuse Switch-88732344-W0712	Lateral Hardening-Rebuild	Rebuild	2025	2026	[redacted]	6.33	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	W0712	30	29	0.394517172
55	NO	Algiers	Council District C	Fuse Switch-119458300-W0712	Lateral Hardening-Rebuild	Rebuild	2025	2026	[redacted]	3.24	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	W0712	1	1	0.005714017
56	NO	Algiers	Council District C	Fuse Switch-88703080-W0118	Lateral Hardening-Rebuild	Rebuild	2025	2026	[redacted]	3.02	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	W0118	32	32	0.319642148
57	NO	Algiers	Council District C	Breaker-88129374-W0713	Distribution Feeder Hardening-Rebuild	Rebuild	2025	2026	[redacted]	4.07	[redacted]	[redacted]	[redacted]	[redacted]	Breaker	W0713	136	133	2.286387095
58	NO	Algiers	Council District C	Fuse Switch-88709988-W0715	Lateral Hardening-Rebuild	Rebuild	2025	2026	[redacted]	6.43	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	W0715	3	3	0.109179959
59	NO	Algiers	Council District C	Fuse Switch-88715772-W0715	Lateral Hardening-Rebuild	Rebuild	2025	2026	[redacted]	5.16	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	W0715	9	9	0.132784133
60	NO	Algiers	Council District C	Fuse Switch-119231622-W0715	Lateral Hardening-Rebuild	Rebuild	2025	2026	[redacted]	4.61	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	W0715	12	10	0.183926195
61	NO	Algiers	Council District C	Fuse Switch-88714070-W0715	Lateral Hardening-Rebuild	Rebuild	2025	2026	[redacted]	4.60	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	W0715	9	9	0.133528452
62	NO	Algiers	Council District C	Fuse Switch-88700712-W0713	Lateral Hardening-Rebuild	Rebuild	2025	2026	[redacted]	3.78	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	W0713	1	1	0.005011365
63	NO	Algiers	Council District C	Fuse Switch-88698564-W0715	Lateral Hardening-Rebuild	Rebuild	2025	2026	[redacted]	2.92	[redacted]	[redacted]	[redacted]	[redacted]	Fuse Switch	W0715	12	12	0.211278477
								Total	[redacted]		[redacted]	[redacted]	[redacted]	[redacted]					

ENO's 2027-2031 Accelerated Infrastructure Hardening Project List
Phase 2 Resilience Plan

Project ID	OpCo	Council District	Project Type	Start Year	End Year	Investment (Nominal)	BCR	50-yr CMI Benefits Weighted	50-yr PV CMI Dollars Benefits Weighted	50-yr PV Restoration Dollars Benefits Weighted	50-yr PV Total Dollars Benefits Weighted	Substation	Circuit(s)	Total Structures	Structures to be Hardened	Total Line Miles	Copper Conductor Miles	Future Wind Load (MPH)	Protection Zones
3100-Market	NO	B	Rebuild	2026	2027	[redacted]	2.822	[redacted]	[redacted]	[redacted]	[redacted]	Market	2135, 2137, 2142, 2146, 2147	192	181	4.4	1.5	140	Fuse Switch-88728103-2137, Fuse Switch-129591785-2135, Fuse Switch-127417253-2147, Breaker-88129043-2142, Recloser Bank-274369428-2142, Breaker-88129001-2146, Recloser Bank-357793422-2146
3101-Joliet 2025	NO	B	Rebuild	2026	2027	[redacted]	5.439	[redacted]	[redacted]	[redacted]	[redacted]	Joliet	2025	325	315	11.1	5.6	140	Breaker-136420380-2025, Fuse Switch-127896107-2025
3102-Joliet 2021	NO	A	Rebuild	2027	2028	[redacted]	5.077	[redacted]	[redacted]	[redacted]	[redacted]	Joliet	2021	278	275	8.0	4.5	140	Breaker-88125327-2021, Recloser Bank-324480421-2021, Fuse Switch-88707702-2021
3103-Joliet	NO	A	Rebuild	2027	2027	[redacted]	3.441	[redacted]	[redacted]	[redacted]	[redacted]	Joliet	2012, 2026	94	91	3.6	1.3	140	Breaker-88125371-2012, Breaker-88125197-2026
3104-Joliet 2024	NO	A	Rebuild	2027	2028	[redacted]	4.413	[redacted]	[redacted]	[redacted]	[redacted]	Joliet	2024	159	146	6.3	2.0	140	Breaker-88125153-2024
3105-Joliet	NO	B	Rebuild	2027	2028	[redacted]	10.343	[redacted]	[redacted]	[redacted]	[redacted]	Joliet	2011, 2017, 2027	192	186	4.4	3.0	140	Breaker-88125349-2011, Fuse Switch-136626753-2011, Breaker-88125393-2017, Recloser Bank-332104930-2017, Fuse Switch-88747271-2017, Fuse Switch-88747295-2017, Breaker-88125415-2027
3106-Almonaster	NO	D	Rebuild	2027	2028	[redacted]	3.597	[redacted]	[redacted]	[redacted]	[redacted]	Almonaster	613, 621	198	185	6.9	2.8	140	Fuse Switch-121503488-613, Breaker-88122470-621
3107-Almonaster	NO	D	Rebuild	2028	2028	[redacted]	7.093	[redacted]	[redacted]	[redacted]	[redacted]	Almonaster	625, 626	233	227	8.1	1.8	140	Breaker-117400346-625, Breaker-88122384-626
3108-Almonaster	NO	D	Rebuild	2028	2028	[redacted]	3.377	[redacted]	[redacted]	[redacted]	[redacted]	Almonaster	616, 617	211	200	5.9	2.4	140	Breaker-88122230-616, Breaker-88122208-617
3109-Derbigny	NO	B	Rebuild	2028	2029	[redacted]	5.279	[redacted]	[redacted]	[redacted]	[redacted]	Derbigny	1553, 1554	133	129	4.0	0.9	140	Breaker-88126115-1553, Fuse Switch-135373137-1553, Fuse Switch-193217358-1553, Fuse Switch-135390911-1553, Fuse Switch-88703980-1554
3110-Derbigny 1512	NO	B	Rebuild	2028	2029	[redacted]	2.943	[redacted]	[redacted]	[redacted]	[redacted]	Derbigny	1512	120	116	4.0	1.7	140	Breaker-88126312-1512
3111-Derbigny	NO	B	Rebuild	2028	2029	[redacted]	4.302	[redacted]	[redacted]	[redacted]	[redacted]	Derbigny	1513, 1543	124	120	3.3	1.1	140	Breaker-88126290-1513, Breaker-88126071-1543
3112-Derbigny	NO	B	Rebuild	2028	2029	[redacted]	5.560	[redacted]	[redacted]	[redacted]	[redacted]	Derbigny	1504, 1510, 1506, 1511	71	71	1.3	0.1	140	Breaker-88126268-1504, Fuse Switch-127602202-1504, Breaker-88126488-1510, Fuse Switch-121492609-1510, Fuse Switch-88751617-1510, Breaker-88126224-1506, Breaker-88126510-1511
3113-Napoleon	NO	B	Rebuild	2028	2029	[redacted]	2.947	[redacted]	[redacted]	[redacted]	[redacted]	Napoleon	1914, 1915, 1923	157	155	2.9	1.5	140	Fuse Switch-88694160-1923, Fuse Switch-88750103-1923, Fuse Switch-88694168-1923, Fuse Switch-88729787-1923, Fuse Switch-88705338-1923, Fuse Switch-121408899-1923, Fuse Switch-122417722-1923, Recloser Bank-276327501-1915, Fuse Switch-88701781-1915, Fuse Switch-128404973-1915, Fuse Switch-129920464-1915, Fuse Switch-88701789-1915, Fuse Switch-129824857-1915, Fuse Switch-129824999-1915, Recloser Bank-92578325-1914
3114-Napoleon	NO	B	Rebuild	2028	2029	[redacted]	3.082	[redacted]	[redacted]	[redacted]	[redacted]	Napoleon	1911, 1913, 1924, 1925	170	169	3.8	2.0	140	Recloser Bank-246127972-1924, Fuse Switch-88750187-1925, Breaker-88124934-1911, Fuse Switch-88732110-1913, Fuse Switch-122788513-1913
3115-Holiday	NO	C	Rebuild	2028	2029	[redacted]	4.534	[redacted]	[redacted]	[redacted]	[redacted]	Holiday	W0712, W0714, W0723	112	110	3.4	0.0	140	Breaker-88124560-W0714, Breaker-156513448-W0723, Fuse Switch-88715555-W0723, Breaker-156513448-W0723, Fuse Switch-88715555-W0723
3116-Algiers	NO	C	Rebuild	2028	2029	[redacted]	2.325	[redacted]	[redacted]	[redacted]	[redacted]	Holiday, Gretna	W0726, W0115	64	64	2.1	0.5	140	Breaker-156513488-W0726, Fuse Switch-88715790-W0115
3117-Paterson	NO	D	Rebuild	2029	2029	[redacted]	6.741	[redacted]	[redacted]	[redacted]	[redacted]	Paterson	1001, 1002	189	182	6.0	0.6	140	Fuse Switch-88732084-1001, Breaker-123923474-1002
3118-Paterson 1010	NO	D	Rebuild	2029	2029	[redacted]	3.288	[redacted]	[redacted]	[redacted]	[redacted]	Paterson	1010	156	148	4.8	0.9	140	Breaker-88120961-1010, Recloser Bank-129987299-1010, Recloser Bank-138104189-1010, Fuse Switch-229759488-1010
3119-Pauger	NO	D	Rebuild	2029	2029	[redacted]	2.706	[redacted]	[redacted]	[redacted]	[redacted]	Pauger	1702, 1711, 1712	261	251	9.3	2.9	140	Breaker-88122624-1712, Breaker-88127567-1711, Breaker-118535969-1702
3120-Pauger 1708	NO	D	Rebuild	2029	2030	[redacted]	3.388	[redacted]	[redacted]	[redacted]	[redacted]	Pauger	1708	162	157	5.3	1.3	140	Breaker-88122536-1708, Fuse Switch-88680969-1708, Fuse Switch-88735182-1708
3121-Pauger 1701	NO	D	Rebuild	2029	2030	[redacted]	2.625	[redacted]	[redacted]	[redacted]	[redacted]	Pauger	1701	112	110	3.6	1.0	140	Breaker-88127677-1701
3122-Pauger 1713	NO	D	Rebuild	2029	2030	[redacted]	2.289	[redacted]	[redacted]	[redacted]	[redacted]	Pauger	1713	102	96	5.1	0.7	140	Breaker-88127473-1713
3123-Sherwood Forest 1612	NO	E	Rebuild	2029	2030	[redacted]	3.974	[redacted]	[redacted]	[redacted]	[redacted]	Sherwood Forest	1612	151	138	6.6	0.3	140	Breaker-88126940-1612

ENO's 2027-2031 Accelerated Infrastructure Hardening Project List
Phase 2 Resilience Plan

3124-Sherwood Forest	NO	E	Rebuild	2029	2030	[redacted]	3.353	[redacted]	[redacted]	[redacted]	[redacted]	Sherwood Forest	1604, 1605, 1610, 1611	189	185	5.9	0.8	140	Internal Vac Fault Interrupter-88618352-1610, Breaker-88127115-1604, Recloser Bank-109361501-1604, Breaker-88127006-1605, Breaker-88127049-1611, Fuse Switch-88712514-1611
3125-Avenue C	NO	A	Rebuild	2029	2030	[redacted]	2.464	[redacted]	[redacted]	[redacted]	[redacted]	Avenue C	409, 411	227	220	9.0	2.1	140	Breaker-88125830-409, Recloser Bank-327198641-409, Breaker-88125852-411
3126-Avenue C	NO	A	Rebuild	2029	2030	[redacted]	3.027	[redacted]	[redacted]	[redacted]	[redacted]	Avenue C	406, 407	193	184	7.2	2.4	140	Breaker-88125786-407, Breaker-88125633-406
3127-Avenue C	NO	A	Rebuild	2030	2031	[redacted]	3.997	[redacted]	[redacted]	[redacted]	[redacted]	Avenue C	401, 404, 405, 408, 413	244	238	8.9	2.8	140	Breaker-88125808-408, Fuse Switch-130121819-408, Breaker-88125917-413, Breaker-88125655-405, Breaker-88125677-404, Breaker-88125743-401
3128-Curran	NO	E	Rebuild	2030	2031	[redacted]	3.290	[redacted]	[redacted]	[redacted]	[redacted]	Curran	2212, 2216	7	7	0.1	0.0	140	Fuse Switch-88718004-2216, Fuse Switch-88741819-2212
3129-Midtown	NO	B	Rebuild	2030	2031	[redacted]	2.490	[redacted]	[redacted]	[redacted]	[redacted]	Midtown	903, 904, 911	132	132	3.0	1.9	140	Fuse Switch-88694920-903, Fuse Switch-121486878-911, Breaker-242883487-904, Fuse Switch-88735114-904
3130-Pontchartrain Park	NO	D	Rebuild	2030	2031	[redacted]	1.885	[redacted]	[redacted]	[redacted]	[redacted]	Pontchartrain Park	501, 512	167	162	6.5	1.9	140	Fuse Switch-88671572-501, Breaker-88123854-512
3131-Pontchartrain Park 513	NO	D	Rebuild	2030	2031	[redacted]	3.167	[redacted]	[redacted]	[redacted]	[redacted]	Pontchartrain Park	513	104	101	4.1	0.1	140	Breaker-88123876-513
3132-Southport	NO	A	Rebuild	2030	2031	[redacted]	3.497	[redacted]	[redacted]	[redacted]	[redacted]	Southport	B0525, B0526	168	163	5.6	0.6	140	Breaker-88127364-B0526, Fuse Switch-88699557-B0526, Fuse Switch-88694232-B0526, Breaker-88127385-B0525
3133-Gulf Outlet 1202	NO	E	Rebuild	2030	2031	[redacted]	2.942	[redacted]	[redacted]	[redacted]	[redacted]	Gulf Outlet	1202	130	101	4.9	0.1	140	Breaker-88127310-1202
3134-Gulf Outlet 1203	NO	E	Rebuild	2030	2031	[redacted]	2.506	[redacted]	[redacted]	[redacted]	[redacted]	Gulf Outlet	1203	114	91	4.9	0.0	140	Breaker-88127451-1203, Recloser Bank-434222172-1203
3135-Tricou	NO	E	Rebuild	2030	2031	[redacted]	2.621	[redacted]	[redacted]	[redacted]	[redacted]	Tricou	2325, 2326	122	117	3.9	0.4	140	Breaker-88127699-2325, Breaker-88127535-2326
Total						**$398,550,234**		**3,388,062,310**	**$1,341,626,940**	**$82,636,698**	**$1,424,263,641**			**5,763**	**5,523**	**188.2**	**53.4**		

BEFORE THE

COUNCIL OF THE CITY OF NEW ORLEANS

***IN RE*: SYSTEM RESILIENCY AND STORM HARDENING**	**))**	**DOCKET NO. UD-21-03**

DIRECT TESTIMONY

OF

ARLIN M. MIRE

ON BEHALF OF

ENTERGY NEW ORLEANS, LLC

DECEMBER 2025

TABLE OF CONTENTS

EXHIBIT LIST

I. INTRODUCTION

Q1. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Arlin Mire, 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 Senior Project Manager in 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 over 600 consulting professionals serving the Manufacturing & Industrial, Oil & Gas, Power Generation, Transmission & Distribution, Transportation, and Water industries.

Burns & McDonnell has been in business since 1898, serving multiple industries, including the electric power industry. It is a family of companies comprising over 10,000 engineers, architects, construction professionals, scientists, consultants, and entrepreneurs, with more than 40 offices nationwide and worldwide.

Q3. PLEASE DESCRIBE BRIEFLY YOUR EDUCATIONAL BACKGROUND.

A. I received a Bachelor of Arts in Business Administration from Baker University in Baldwin, Kansas, and a Master of Business Administration from St. Edward's University in Austin, Texas. My full resume is included as Exhibit AMM-1.

Q4. PLEASE DESCRIBE BRIEFLY YOUR PROFESSIONAL EXPERIENCE.

A. I am an experienced asset management consultant with 19 years of experience providing consulting services to electric utilities. Through my work at 1898 & Co. and Burns & McDonnell, I have extensive experience in infrastructure asset management, evaluating a wide range of risks to utility client systems, including asset failure analysis, customer outage impacts, weather and resilience risks, and lifecycle cost analysis. I have served as Project Manager and Project Director for numerous studies that involve the development of capital and O&M plans, including portfolio optimization and business case development for multi-billion dollar portfolios for a wide range of utility system types and sizes. A list of regulatory filings in which I have been a project manager or project director is included in Exhibit AMM-1. These studies have included risk and economic analyses and detailed modeling that involve resilience and reliability analysis for electric utility systems, including transmission, substation, and distribution assets and infrastructure. My primary responsibilities are project delivery and business development within the Utility Consulting Practice, with a focus on developing risk and resilience-based business cases for large capital projects/programs.

Before joining 1898 & Co. and Burns & McDonnell, I served as a Project Manager at Black & Veatch inside its Asset Management Practice, where I also performed risk and resilience studies.

Q5. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY IN THIS PROCEEDING?

A. Entergy New Orleans, LLC ("ENO" or the "Company") engaged 1898 & Co. to assist with modeling, identifying, and prioritizing potential hardening zones[1] to further improve and accelerate the Company's system resilience, and also estimating the costs and benefits of those hardening zones. My testimony introduces, summarizes, and incorporates by reference the Phase 2 Resilience Plan and Benefits Report ("Report"), which is attached hereto as Exhibit AMM-2, that was developed as part of that effort.

Q6. WHAT WAS THE EXTENT OF YOUR INVOLVEMENT IN THE ACTIVITIES UNDERTAKEN FOR THE ENGAGEMENT WITH ENO?

A. I served as the 1898 & Co. Project Manager in connection with ENO's previous resilience filing in 2023 (Council Docket No. UD-21-03), and I have served as the Project Director in this engagement. I have worked directly with personnel representing ENO who provided engineering knowledge and experience for the analysis, including the resilience-based planning approach as part of the development of the Company's Phase 2 Resilience Plan that is the subject of the current filing. For the Phase 2 Resilience Plan, I was directly involved in developing the methodology used to identify and prioritize infrastructure hardening zones, evaluate plan investment levels, and calculate potential costs and benefits, for which the Resilience Event Simulation Model ("Resilience Model") was used. I was also involved in the assessment and results of

[1] The term "hardening zone" refers to a collection of assets grouped by 1898 & Co.'s Resilience Model (defined below) for potential hardening.

the Resilience Model. I further describe the Resilience Model herein, as well as in the attached Report.

Q7. BRIEFLY OUTLINE THE RESULTS OF THE RESILIENCE MODEL AND EVALUATION CONTAINED IN THE ATTACHED REPORT.

A. As shown in the attached Report, ENO's overall resilience investment level for its Resilience Plan has a positive business case, and is technically achievable given current execution constraints, such as materials and labor supply.

Q8. BRIEFLY, WHAT ARE THE EXPECTED BENEFITS SHOWN IN THE ATTACHED REPORT?

A. As shown in the attached Report, ENO's proposed investment level includes a portfolio of storm hardening zones that are expected to: (1) decrease storm restoration costs after major weather events; and (2) decrease the number of customers impacted and the duration of the overall outage after major weather events *(i.e.*, reduce customer minutes interrupted ("CMI")). First, the approximately $400 million of identified hardening zones ($359 million in 2025 dollars) are reasonably projected to produce a reduction in storm restoration costs of approximately $83 million dollars (50-year present value). Second, the identified hardening zones are reasonably projected to produce a decrease in the projected customer minutes interrupted after a major storm by approximately 3.4 billion minutes over the next 50 years. This decrease includes reducing the number of outages, reducing the number of customers interrupted, and decreasing the length of the outage time, which corresponds to an estimated reduction of over $1.3 billion in monetized customer outages to customers over the next 50 years assuming an above average frequency of storms.

Q9. HOW DID THE COMPANY AND 1898 & CO. USE THE RESILIENCE MODEL TO HELP EVALUATE VARYING LEVELS OF HARDENING INVESTMENT?

A. The Company and 1898 & Co. used the Resilience Model as part of a multi-stage process to develop investment levels over the next 5 years for the Phase 2 Resilience Plan:

- Stage 1 – Update the previous model and analysis with new information, including system information, configuration, assets, weather, outages, costs, and accounting for completed or planned-to-be completed hardening zones. Use the updated model to develop benefits and costs for all potential hardening zones in ENO.
- Stage 2 – Determine what level of annual investment is most likely feasible over the 2027 – 2031 period with updated labor and equipment constraints.
- Stage 3 – Develop the 2027-2031 investment portfolio to provide a set of hardening zones costing approximately $400 million (nominal) that could be performed during the 5-year period.

Q10. PLEASE SUMMARIZE THE UPDATES MADE TO THE RESILIENCE MODEL FROM THE PREVIOUS ANALYSIS IN 2023.

A. 1898 & Co. made four types of updates to the Resilience Model: ENO system data and attributes, weather and outage history, module configurations, and module enhancements. These updates reflect and incorporate information and lessons learned as ENO and other Entergy Operating Companies have been planning, engineering, and constructing accelerated resilience projects developed in their respective Phase 1 resilience plans. The Resilience Model enhancements reflect updates to 1898 & Co.'s resilience modeling techniques as we evolve with the needs of the industry. The summary of updates includes:

- ENO System Data and Attributes – GIS (new assets, updated ages, pole classes, locations, etc.), customer information/counts/types
- Weather and Outage History – Hurricanes Francine and Beryl, including paths, strengths, outages, costs, and additional outage management system data from 2023 and 2024
- Module Configurations – Updated hardening zone cost buildup, hardening zone cost data, and asset grouping to hardening zones
- Module Enhancements – Increased granularity from 50 x 50-mile system sections to parish-level analysis and increased granularity of non-hurricane weather analysis

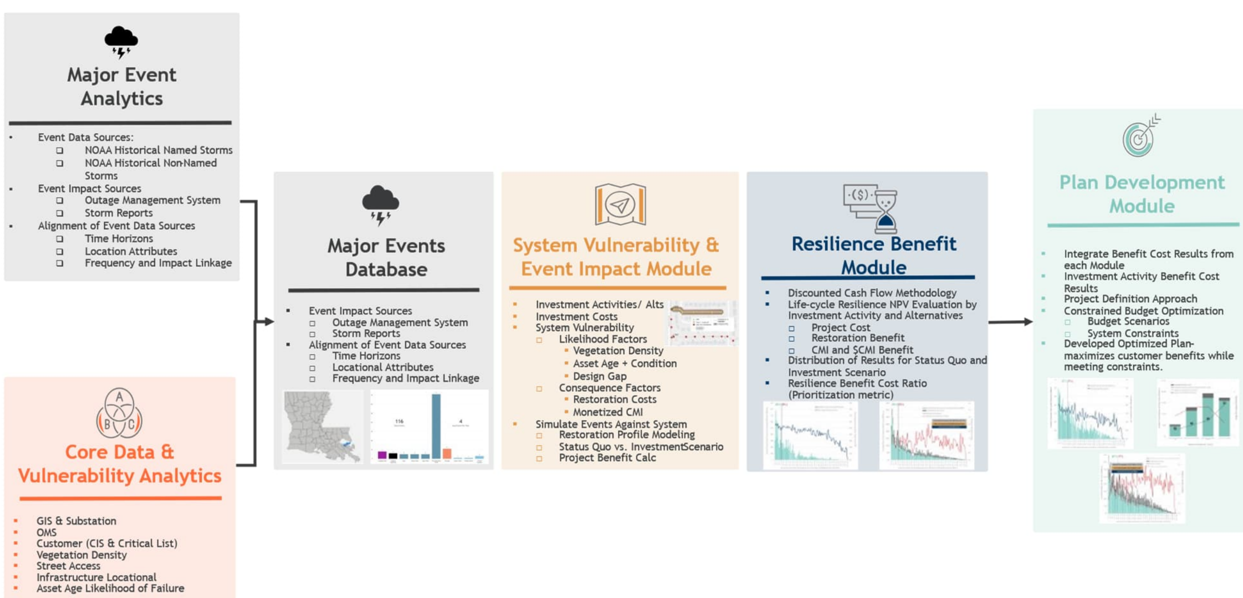
II. RESILIENCE-BASED PLANNING

Q11. PLEASE DESCRIBE THE ANALYSIS 1898 & CO. CONDUCTED FOR THE COMPANY.

A. 1898 & Co. utilized a resilience-based planning approach to identify hardening zones and to assist the Company in prioritizing investments in the Company's transmission and distribution systems using the Resilience Model. The Resilience Model models the benefits of all potential hardening zones for an "apples to apples" comparison across the systems. The resilience-based planning approach calculates the direct benefit of storm hardening zones from a customer perspective (*i.e.*, outage avoidance/duration and costs). This approach calculates the resilience benefit at the asset, hardening zone, and program levels.

The Resilience Model employs a data-driven, decision-making methodology utilizing robust and sophisticated algorithms to calculate resilience benefits, including a decrease in storm restoration costs after major weather events and a reduction in customer minutes interrupted during outages. Figure 1 provides a high-level overview of the Resilience Model (and its components) used to calculate hardening zone benefits and prioritize hardening zones.

Figure 1: Resilience Model Overview



Q12. CAN YOU EXPLAIN THE COMPONENTS OF THE RESILIENCE MODEL?

A. Yes. The Major Events Analytics and Core Data and Vulnerability Analytics components are responsible for generating data attributes used in the Resilience Model associated with linking National Oceanic and Atmospheric Administration data to historical events, customers to assets, and determining information about assets regarding nearby vegetation, road access, etc. The Major Events Database contains storm probability distributions (*i.e.*, the range of likely outcomes across alternative scenarios), along with the range of sub-system impacts (*i.e.*, transmission lines, substations, backbones, laterals) for 45 different storm types. The 45 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 (*i.e.*, the direction from which the storm approaches the asset). The database includes probabilities and impacts of the 45 storm types against the infrastructure for Orleans Parish.

Each storm type is then modeled within the System Vulnerability and Event Impact Module ("EIM") 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, including poles, circuits, transmission structures, and conductor. The EIM also estimates the restoration costs and CMI for each of the potential hardening zones for each storm type. For purposes of the Report, the term "hardening zone" refers to a collection of assets grouped by 1898 & Co.'s Resilience Model for potential hardening. Assets are typically organized from a customer impact perspective based on their upstream protection device. The EIM calculates the benefit in decreased restoration costs and CMI if that hardening zone is hardened per ENO's hardening standards. The CMI benefit is monetized using the Department of Energy's ("DOE") Interruption Cost Estimator ("ICE") for hardening zone prioritization purposes.

The benefits of storm hardening zones are highly dependent on the frequency, intensity, duration, 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 Module 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 hardening zone. The probability of each storm scenario is multiplied by the benefits calculated for each hardening zone (*i.e.*, the difference between the calculated values for the Status Quo and Hardened scenarios) from the EIM to provide a resilience-weighted benefit for each hardening zone in dollars.

The Plan Development Module prioritizes the hardening zones based on the highest resilience benefit/cost ratio, factoring in execution and investment-level constraints. It also performs an investment optimization simulation considering the $400 million investment over 5 years. The module prioritizes each hardening zone based on the sum of the restoration cost benefit and monetized CMI benefit divided by the hardening zone 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 hardening zones applicable to ENO and its service area, such as contractor capacity, logistics, and limits on materials. Using the Resilience Benefit Module and Plan Development Module, the Resilience Model calculates the net benefit of the hardening zones to customers in terms of reduced restoration costs and CMI for the 5-year Phase 2 Resilience Plan.

This resilience-based prioritization facilitates the identification of the critical hardening zones that provide the most benefit to customers. 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."

Q13. WHY IS THIS APPROACH TO HARDENING ZONE IDENTIFICATION IMPORTANT?

A. This approach to hardening zone identification is important for several reasons.

1. The approach is comprehensive in that it evaluates nearly all of the assets on the Company's transmission and distribution systems. By considering and evaluating those systems on a consistent and uniform basis, the results of the Phase 2 Resilience 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, and priority customers (police, fire, schools, nursing homes, etc.). 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 potentially could fail in a storm. Rolling assets into hardening zones at the protection device level allows for hardening of all vulnerable components in the hardening zone and for capturing the full benefit for customers.

3. The granularity at the asset and hardening zone 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 Resilience Model 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 zones. Data-only approaches may drive decisions that do not match reality, while experience-based solutions can reflect bias. The approach balances the two to better identify types of hardening zones.

Q14. WHY IS IT ADVANTAGEOUS TO MODEL STORM HARDENING ZONE BENEFITS USING THIS RESILIENCE-BASED PLANNING APPROACH AND THE RESILIENCE MODEL?

A. The Resilience Model was designed for the purpose of calculating storm hardening zone benefits in terms of reduced restoration costs and CMI to build a plan with an appropriate level of investment that provides the most benefit for customers. It was appropriate to model storm hardening zones using the resilience-based planning approach and the Resilience Model for the following reasons:

1. The benefits of hardening zones are wholly dependent on the number, type, and overall impact of future storms that impact the region served by the Company. Different storms have dramatically different impacts on ENO's transmission and distribution systems. For this reason, the resilience-based planning approach includes the "universe" of potential major events that could impact ENO's service area over the next 50 years.

2. Major events cause assets to fail, and it only takes one asset failure in a protection zone to cause customer outages. The cost to restore the failed assets is dependent on the extent of the damage and the resources used to fix the system. The duration of restoration for affected customers is dependent on the extent of the asset damage and the extent of the damage to 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. The pace of restoration depends on the type of storm to impact the system. Modeling this series of events for the entire system at the asset and hardening

zone level for both Status Quo and Hardened scenarios is needed to accurately model hardening zone benefits. Therefore, the resilience-based planning approach includes the EIM to calculate the phases of asset and hardening zone resilience for each of the 45 storm types for both scenarios. The core data and calculations of the EIM to develop the phases of resilience for every asset, hardening zone, program, and plan are discussed in further detail in the attached Report.

3. The output of the EIM is the resilience benefit of each hardening zone for each of the 45 storm types. The life-cycle resilience benefit for each hardening zone is dependent on the probability of each storm and the mix of storm events to occur over the life of the hardening zones. A hardening zone'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 that there are 45 unique types of storm events that could impact grid infrastructure. To model this range of combinations, the Resilience Model employs stochastic modeling, or a Monte Carlo simulation, to randomly select from the 45 storm types to create a future "world" of the unique storm events that could hit ENO's service area. The Monte Carlo simulation creates a 1,000-future storm "worlds." From this, the life-

cycle resilience benefit of each hardening zone can be calculated. This is done in the Resilience Benefit Module, which is discussed in more detail in the attached Report.

4. To inform the questions of how much hardening investment is prudent and where that investment should be made, it was necessary to include a Plan Development Module within the Resilience Model. The investment optimization algorithm develops the hardening zone plan and associated benefits, while considering that the plan needs to be executable, by prioritizing hardening zones that provide the most benefit while balancing ENO's technical constraints, such as contractor capacity, logistics, and materials limits.

Q15. CAN YOU SUMMARIZE THE KEY POINTS REGARDING HOW THE RESILIENCE-BASED PLANNING ASSESSMENT WAS PERFORMED IN THE RESILIENCE MODEL?

A. Yes. The following are the key points regarding how the resilience-based planning assessment was performed in the Resilience Model:

- **Customer- and Asset-Centric**: The Resilience 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 Resilience Model identifies hardening zones 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 transmission and distribution system, the results of the Resilience Plan provide confidence that portions of the ENO system are not overlooked for potential resilience benefit.
- **Consistency**: The Resilience Model calculates benefits consistently for all hardening zones. The model carefully normalizes for a more accurate comparison of potential benefits between asset types. For example, the model can compare a substation hardening zone to a feeder undergrounding hardening zone. This is a significant achievement allowing the assessment to perform hardening zone prioritization across the entire asset base for circuits with a benefit-cost ratio of 1.0 or greater.
- **Rooted in Cause of Failure**: The Resilience Model is rooted in the causes of asset and system failure from two perspectives. First, the Major Events Database outlines the range of storm stressors and the high-level impact to the system. Second, the detailed data streams and algorithms within the EIM 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 Company’s system that are more likely to fail in a major storm.
- **Drives Prudency**: The assessment and modeling approach drives prudency for the Resilience Plan on two main levels. First, the granularity of potential hardening zones, approximately 4,200, 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 development of a plan that simultaneously considers many technical and execution constraints to build a plan that is reasonable and executable.

Q16. WHAT ARE SOME OF THE CONCLUSIONS THAT CAN BE MADE FROM THE RESULTS OF THE RESILIENCE MODEL AND EVALUATION CONTAINED IN THE ATTACHED REPORT?

A. The following contain the conclusions of the evaluation performed within the Resilience Model:

- There is opportunity for additional resilience investment in the New Orleans system.
- An overall investment level of $400 million (nominal dollars) over the next 5 years, as developed through the Resilience Model, is technically achievable and has a positive business case (3.97 BCR overall). This investment level provides customers with optimal benefits given execution constraints. Assuming an above average frequency of storms, this investment level is reasonably expected to:
    - Decrease storm restoration cost by approximately $83 million over the 50-year time horizon.
    - Decrease storm customer outages by approximately 3.4 billion minutes over the 50-year time horizon.

  - □ Reduce overall monetized outage costs to customers by over $1.3 billion over the 50-year time horizon.

- ■ If enough of the Entergy New Orleans system is made resilient, 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. All customers realize indirect benefits 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. Both of these benefit streams are not factored into the evaluation performed by the Resilience Model.

III. CONCLUSION

Q17. 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, **ARLIN M. MIRE**, 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.

ARLIN M. MIRE

SWORN TO AND SUBSCRIBED BEFORE ME
THIS 15 DAY OF DECEMBER 2025

Sydney Elayne Miller
NOTARY PUBLIC

My commission expires: 09-16-2027

SYDNEY ELAYNE MILLER
Notary Public, Notary Seal
State of Missouri
Jackson County
Commission # 19628064
My Commission Expires 09-16-2027

1898 & Co.

Arlin Mire

Arlin is a Senior Project Manager at 1898 & Co. He specializes in developing capital asset plans and business cases for large capital programs. He is part of the Utility Investment Planning team and focuses on risk management solutions for clients. He has nearly two decades of project management and consulting experience including risk and economic analysis engagements for several multi-billion-dollar capital projects and large utility systems. He has 10 years of extensive experience in developing and performing a wide range of business case evaluations to help utility clients justify and defend investment decisions. Arlin also specializes in budget prioritization, asset management, business case evaluation, resilience planning, risk-based planning and analysis, financial modeling, decision analysis, Monte Carlo simulation and investment optimization utilizing genetic algorithms.

Education

B.A. / Business Administration

MBA / Business Management

7 years with 1898 & Co.

19 years of experience

Visit my LinkedIn profile.

REGULATORY FILING EXPERIENCE

The table below represents regulatory filings for which Arlin was a project lead or major contributor.

Utility Company	Regulatory Agency	Docket No. | Year	Subject
Cleco	Louisiana Public Service Commission	U-37479 | 2024 Direct Testimony Filing/Sponsoring Report Rebuttal Testimony	Resilience Investment and Benefits Study
Ohio Power Company (AEP Ohio)	Public Service Commission of Ohio	24-787-EL-RDR | 2024 Direct Testimony (pg. 1-13) Filing/Sponsoring Report (pg. 27-50)	gridSMART® Phase 3 DACR Project
Entergy Texas	Public Utility Commission of Texas	56735 | 2024 Direct Testimony (pg. 52-71) Filing/Sponsoring Report (pg. 84-193)	Texas Future Ready Resiliency Plan (Phase 1)
Entergy New Orleans	New Orleans City Council	UD-21-03 | 2022	2023-2033 Storm Resiliency Plan
Entergy Louisiana	Louisiana Public Service Commission	U-36625 | 2022 Direct Testimony Filing/Sponsoring Report LPSC Approved First 3 Yrs or the plan	2023-2033 Storm Resiliency Plan
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)
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

PROJECT EXPERIENCE

Substation, Transmission, and Distribution Resilience Capital Plan / Cleco

Louisiana / 2024–2025

Arlin served as project director for the development of Cleco's Resilience Capital Plan, initiated in response to the significant hurricane activity along the Gulf Coast in 2020 and 2021. The objective of the plan was to reduce the long-term risk of storm-related restoration costs and customer outages associated with extreme weather events through a data-driven system hardening and resilience strategy.

The 1898 & Co. analytics automatically generated distribution feeder and lateral projects, evaluating both the hardening of existing overhead infrastructure and undergrounding alternatives for each project. The effort also assessed substation flood risk from storm surge and identified potential mitigation projects, while a companion analysis evaluated transmission structure risk and developed corresponding resilience investments.

Arlin oversaw the preparation of the final report and expert witness testimony submitted to the Louisiana Public Service Commission and directed technical support during post-filing regulatory activities, including discovery and data requests. The resulting five-year capital plan established a structured investment roadmap for improving Cleco's system resilience across all asset classes.

Resilience Transmission and Distribution Due Diligence / Confidential Client

Canada / 2025

Arlin served as project director for a due diligence engagement supporting a client seeking to acquire an equity stake in a vertically integrated electric utility. Leveraging prior experience with resilience planning and analytics, the team was tasked with independently evaluating the utility's latest resilience plan and assessing its long-term ability to sustain investment in transmission and distribution system improvements.

The effort included a detailed review of the utility's data and the development of a 50-year financial model to evaluate projected spending on resilience and system hardening initiatives, including undergrounding, line rebuilding, substation flood mitigation, transmission structure hardening, and vegetation management. Arlin also directed the benchmarking analysis comparing the target utility to peer organizations in terms of system size, resilience maturity, and investment opportunity. The assessment also examined long-term storm exposure risks, particularly in densely populated areas and regions with high vegetation density and aging infrastructure, to provide a comprehensive view of system vulnerability and investment outlook.

Resilience Metrics Support / AEP Texas

Texas / 2025

Arlin served as project director for the development of AEP Texas's resilience metrics framework following the approval of the company's Distribution Resilience Plan. As part of the Public Utility Commission of Texas's directive, each utility is required to provide an annual metrics report to demonstrate the effectiveness of its resilience programs in achieving the plan's objectives.

Arlin led the effort to develop a comprehensive memorandum detailing all metrics AEP Texas is responsible for reporting. The document identified required data sets, data owners, metric objectives, and detailed calculation methods, establishing a centralized, repeatable process for compiling and reporting resilience performance. The resulting framework enables AEP Texas to efficiently evaluate program outcomes following qualifying events and to prepare annual reports that clearly communicate measurable progress toward improved system resilience.

Overhead to Underground Conversion Study / Austin Energy

Texas / 2024–2025

Arlin served as project director for a comprehensive study evaluating the long-term feasibility of converting Austin Energy's overhead distribution system to underground construction. The initiative assessed the unique engineering, environmental, and logistical challenges of large-scale undergrounding within Austin's predominantly urban and suburban service territory.

The study analyzed the cost and constructability implications of undergrounding, accounting for factors such as easement acquisition, local wildlife habitat impacts, rocky subsoils, critical tree root zones, and the complexity of engineering design within densely developed areas. The resulting analysis estimated that full system undergrounding would exceed $50 billion and provided a business case framework to guide strategic prioritization. Ultimately, the study recommended a targeted approach, focusing on selective undergrounding projects that address specific resilience, reliability, or community needs rather than pursuing a systemwide conversion.

Long-Term Infrastructure Improvement Plan (LTIIP) / FirstEnergy

Pennsylvania / 2024

Arlin served as project director for the development of FirstEnergy's Long-Term Infrastructure Improvement Plan (LTIIP) for its Pennsylvania operating companies. Building upon the modeling framework, processes, and analytics established through the Unencumbered Distribution Capital Plan, the project adapted those tools to meet Pennsylvania's specific regulatory and programmatic requirements.

The analysis reconfigured the capital programs from the broader unencumbered plan to align with prior LTIIP filings, including circuit improvements, pole replacements, circuit rehabilitation, substation asset replacements, distribution automation, and low-voltage conversion initiatives. The model produced business cases and quantified reliability benefits for a five-year portfolio of projects, providing FirstEnergy with a data-driven foundation for scheduling and inclusion within its regulatory filing.

Unencumbered Distribution Capital Plan / FirstEnergy

Ohio, Pennsylvania, Maryland, West Virginia, and New Jersey / 2024

Arlin served as project director for the development of an unencumbered distribution capital plan for FirstEnergy, which operates ten utility companies across five states. The objective of the initiative was to plan for gradually increasing levels of capital investment across the entire distribution system over a 10-year horizon, providing FirstEnergy with a long-term roadmap for proactive infrastructure renewal and capacity enhancement.

The analysis incorporated future hosting capacity needs, including projected load growth from electric vehicle adoption, conversion of 4 kV circuits and step-down areas to higher voltages, and large-scale rebuilding of overhead distribution infrastructure. The plan also examined opportunities to expand distribution automation through new circuit ties, increased sectionalization, implementation of manual FLISR capabilities, and deployment of smart fusing technologies such as TripSavers. The resulting capital plan provided a comprehensive, data-driven investment strategy designed to strengthen reliability, improve operational flexibility, and enhance system capacity for decades to come.

Hurricane Damage Analysis / Confidential Client

U.S. Gulf Coast / 2024

Arlin served as project director for a hurricane damage analysis conducted for a confidential client operating along the U.S. Gulf Coast. Following the extensive impacts of the 2020 and 2021 hurricane seasons and in the wake of regional events such as Winter Storm Uri, many utilities across Texas, Louisiana, and Florida developed long-term resilience plans to strengthen their systems against extreme weather. The client, which had already implemented a resilience plan, sought an independent evaluation to estimate the reduction in system damage that could be expected if a storm of comparable strength and path were to occur again.

Arlin led the analysis using advanced resilience modeling and system analytics to quantify the benefits of infrastructure improvements, including the replacement of aging structures with hardened assets designed to meet modern standards. The resulting study provided a data-driven estimate of future damage reduction and system performance under similar storm conditions. Results were delivered through a GIS-based visualization and an executive-level presentation summarizing key findings and strategic implications for the client's board.

Distribution Resilience Capital Plan / Entergy Texas

Texas / 2023–2024

Arlin served as project manager for the development of Entergy Texas's Distribution Resilience Capital Plan, prepared in accordance with House Bill 2555, which established a regulatory framework for utilities in Texas to propose grid-hardening and resilience investments. The plan focused on reducing long-term storm restoration costs and customer outages through strategic investments in transmission and distribution infrastructure.

The analytics evaluated a range of system hardening strategies, including targeted feeder and lateral rebuilds, replacement of aging and non-standard assets, and selective transmission structure upgrades designed to withstand extreme weather events. Using long-term projections of hurricane and severe storm activity, the study quantified the benefits of resilience-driven investments in terms of avoided restoration costs and reduced customer minutes of interruption (CMI).

Arlin led the development of the three-year capital plan, accompanying technical report, and regulatory filing materials submitted to the Public Utility Commission of Texas. The plan was approved by the Commission in 2024, establishing a structured, data-driven foundation for Entergy Texas's ongoing resilience investment strategy.

Distribution Resilience Plan / AEP Texas

Texas / 2023–2024

Arlin served as project director for the development of AEP Texas's Distribution Resilience Plan, initiated in response to House Bill 2555, which established a regulatory framework for utilities to propose grid hardening and resilience investments. The project leveraged resilience analytics previously applied in Florida and Louisiana to evaluate a range of system hardening strategies tailored to the AEP Texas distribution network.

The analysis examined feeder and lateral hardening options, undergrounding of critical highway crossings, and the benefits of a one-time, resilience-driven vegetation trimming program across the service area. Using a 50-year projection of hurricanes and other extreme weather events, the analytics quantified long-term benefits associated with reduced storm restoration costs and avoided customer minutes of interruption (CMI), monetized using the U.S. Department of Energy's ICE Calculator.

Arlin led the team in developing the comprehensive plan, accompanying report, and expert witness testimony for AEP Texas's regulatory filing with the Public Utility Commission of Texas. The team also provided technical support throughout the discovery process and other post-filing regulatory activities.

Distribution Overhead Conductor Renewal Plan / AEP Texas

Texas / 2023

Arlin served as project manager for an asset management evaluation of AEP Texas's overhead distribution infrastructure. The engagement built upon the methodology established in prior conductor renewal initiatives to identify where aging overhead assets present the highest reliability and safety risks, both currently and over the coming decades. The study evaluated the age, condition, failure criticality, and risk of overhead conductor assets across the system to support proactive capital investment planning.

The analytics effort auto-generated capital projects at the protection zone level and organized them into backbone and lateral groupings focused on replacement of non-standard, small wire sizes designated by AEP Texas as high-priority targets. These projects were integrated with the broader risk-based analysis framework to produce an optimized five-year renewal plan aimed at reducing future reactive maintenance costs, minimizing customer outages, and mitigating environmental risks. Results were delivered through a GIS-based platform, enabling AEP Texas and its partners to visualize asset data and implement the prioritized project portfolio efficiently.

Substation, Transmission, and Distribution Resilience Capital Plan / Entergy

Louisiana, Arkansas, Texas, and Mississippi / 2022–2023

Arlin served as project manager for the development of Entergy's comprehensive Resilience Capital Plan, which evaluated system hardening and risk reduction strategies across all five of Entergy's operating companies—Louisiana, New Orleans, Arkansas, Texas, and Mississippi. The initiative was undertaken in response to the significant hurricane activity and extreme weather events that have repeatedly affected the Gulf Coast region.

The project team conducted detailed analyses of substation, transmission, and distribution assets to identify resilience investments aimed at reducing storm restoration costs and customer outages. The analytics platform evaluated more than 500,000 potential projects and alternatives, including distribution feeder and lateral hardening, substation flood mitigation, transmission structure upgrades, and undergrounding options for critical segments. The outcome was an integrated 10-year, $15-billion resilience plan that provided Entergy with a data-driven roadmap for targeted system hardening across its service territory.

Arlin managed the preparation of the final reports and expert witness testimony supporting regulatory filings for Entergy Louisiana and Entergy New Orleans. The filings were successfully approved, establishing comprehensive resilience investment programs for both operating companies.

Full Distribution System Analysis and Capital Plan with AssetLens / Evergy

Kansas and Missouri / 2020–2021

Arlin served as project manager for an enhancement to Evergy's previous capital planning pilot study, expanding the scope to a full-system evaluation of distribution infrastructure across Kansas and Missouri. Following the success of the pilot, Evergy engaged the team to broaden the analytics and implement results within AssetLens, 1898 & Co.'s software-as-a-service platform designed to operationalize investment planning analytics and provide clients with accessible, data-driven capital planning tools.

The analysis incorporated a wider range of infrastructure assets, including civil structures such as manholes, vaults, handholes, and underground network cables, as well as transformers, protectors, and other components supporting Evergy's four downtown networks. Arlin oversaw the integration of ongoing ("in-flight") projects to ensure they remained unaffected during the updated optimization of systemwide capital investment. The effort culminated in a refreshed five-year capital plan encompassing the entire distribution system, providing Evergy with a comprehensive, risk-informed roadmap to guide future asset renewal and investment decisions.

Distribution Overhead and Underground Conductor Renewal Plan / AEP Ohio

Ohio / 2020

Arlin served as project manager for an asset management evaluation of AEP Ohio's distribution infrastructure. The initiative aimed to identify where aging conductor assets present elevated reliability and safety risks across the service territory, both currently and over the next several decades. The project encompassed thousands of miles of overhead and underground conductor and assessed asset age, condition, failure criticality, and system risk.

Arlin led the team's analytics effort to auto-generate capital projects at the protection zone level, including conceptual scopes and cost estimates. The resulting analysis produced a five-year proactive renewal plan designed to reduce future reactive maintenance costs, minimize customer outages, and mitigate environmental risks. The plan was delivered through a GIS-based platform, enabling AEP Ohio and its partners to visualize updated asset data and access the optimized project portfolio for implementation and ongoing planning.

Transmission Structure Asset Management Plan / Confidential Client

U.S. West / 2019 - 2020

Project manager for a transmission structure asset management plan for a confidential client. The client is currently undergoing wood to steel conversion of its transmission structures in areas where wildfire threats are high. Arlin is leading the effort that uses AssetLens to provide a communicable picture of age, condition, criticality, and risk for all of its transmission structures. The project team combined various data sources, including GIS, structure inspections, transmission planning contingencies, and other information to produce a holistic picture of risk that the client has access to via the web application.

Fiber Installation Resilience Business Case / Confidential Client

U.S. West / 2019 - 2020

Project manager for a resiliency study for a confidential client seeking to evaluate a unique, limited window opportunity. A nearby entity is offering to engage in a fiber access swap where the client would build approximately 100 miles of fiber and give access to the nearby entity, which, in turn, would provide 6 times the amount of geographic coverage back to the client (600 miles). This would allow the client to save nearly $1M every year in current fiber lease contract costs. Arlin led the team responsible for evaluating the economic and strategic viability to the client.

Storm Protection Plan Resilience Assessment / Tampa Electric Company

Florida / 2020-Current

Project manager for supporting the development of TEC's 10-year Storm Protection Plan for its transmission and distribution system in accordance with Florida Statute 366.96. Arlin oversaw configuration of 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 postulates 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. and further utilizes Stochastic Modeling 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 filed its plan for over $1.5 billion on early April 2020 and received approval in early 2021.

Distribution Asset Risk Model and Project Identification / Evergy

Missouri / 2019 - 2020

Project manager for an asset risk assessment and capital plan for Evergy's distribution Missouri assets. The capital plan was focused on identifying and justifying overhead reconductor projects that also captured poles in poor condition. Projects were developed at the protection zone level to appropriately gauge the direct impact to customers interrupted and duration in minutes. The study leveraged the AssetLens solution and Evergy is using the web application to communicate projects to its service centers and project justifications. The team developed a 3-year capital plan with over 1,000 projects in just 3 months.

Ice Storm Resiliency Study / East River Power Electric Cooperative, Inc.

South Dakota / 2019

Project manager for a resiliency study for East River Power Electric Cooperative, Inc. in South Dakota. Over the last 15 years, four ice storms (2005, 2010, 2016, and 2019) have caused cascading outages along a 69 kV tap that feeds a substation, despite the tap being rebuilt to higher standards in 2014. Our team and East River investigated improvements that could be made to the system to minimize extended outages experienced from severe ice storms. Potential projects included:

- Rebuilding the tap to higher standards or undergrounding
- Building new tie lines from nearby sources
- Building new distribution tie ins from nearby systems
- Installing local emergency diesel generation
- Reinforcing the tap with value engineering

We evaluated the potential projects using a resiliency approach that considers risk-weighted net present value. The resiliency model used Monte Carlo analysis to simulate a range of ice storm frequency and severity to examine the cost of operating the status quo and alternatives over 40 years, including the O&M of any new solutions and repair costs associated with failures. East River is moving forward with the study's recommendations and has incorporated some of the project's cost into its upcoming budget cycle.

Underground Structure Flooding Risk Prioritization / Confidential Client

North America / 2019

Project lead for performing a risk-based prioritization of underground facilities at an air force base in North America. The client has been experiencing failures of splices and T-bodies in its manholes on the air force base, especially following heavy rain and flooding events where the manholes fill up with water. These failures have led to significant outages of buildings on the base and subsequently sending thousands of troops off the base, multiple times in early 2019, which is unacceptable. Arlin led the asset risk model effort that evaluated likelihood of splice failures and consequence of failure for underground assets and as well as likelihood and consequence for overhead assets (wood poles). The risk model effort recommended and prioritized replacements. Arlin's team coordinated with the distribution grid modernization team, which evaluated configuration changes, such as movement of circuits into other manholes to reduce consequence of multiple lines going out in the event of a catastrophic failure. The two teams developed a combined plan aimed at reducing risk holistically, using multiple project strategies. The client approved the plan and is moving forward immediately.

ISO 55001 Certification Assessment / New York Power Authority

New York / 2019-Present

Project manager for performing an assessment of NYPA's asset management systems for ISO 55001 certification. Our team is the prime and the subconsultant conducted the audit using its endorsed assessors. The team conducted a pre-certification audit, a week-long audit at NYPA headquarters involving interviews with personnel from several functions and a review of documentation to assess their readiness for a final audit. The final certification audit was conducted at several sites around the state of New York to evaluate how well NYPA has embraced and implemented ISO 55001 at all levels of the organization. NYPA was awarded certification in September 2019 by the Institute of Asset Management. Our team and its subconsultant will return for two follow-up surveillance audits in 2020 and 2021.

Long Term Electric Transmission and Distribution Capital Plan / Indianapolis Power & Light

Indiana / 2018-Present

Project advisor for development of a long-term capital plan for the IPL's electric transmission and distribution infrastructure based on Indiana's Senate Bill 560. The project identifies assets by their consequence and likelihood of failure (risk) and develops long-term capital expenditure requirements to manage the risk over time. Arlin is providing strategic project guidance, and advice to the team based on his extensive experience with asset-level risk models inside Indiana and across the country.

Long Term Electric Transmission and Distribution Capital Plan Annual Update / Vectren Indiana

Indiana / 2018-Present

Project manager for assisting Vectren with updating its annual TDSIC reporting requirements. The risk model annual update involves collecting data from TDSIC-approved work orders, including actual costs and timing of replacements, merging the data with other system changes, such as assets that were TDSIC-approved, but removed/replaced for other reasons, and producing results showing actual performance against projections from the originally approved TDSIC filing.

PRIOR EXPERIENCE

Transmission Seismic Resiliency Study / Pacific Gas & Electric

California / 2016-2018

Project manager for a resilience study on three underground transmission cables in downtown San Francisco. PG&E has identified these cables as having a high likelihood of failure during a major seismic event and has asked for a resiliency methodology to conduct a cost-benefit analysis of several alternatives, including retrofitting the existing lines and building new ones that mitigate the risk of power outages during an earthquake. Arlin was the project manager for the resiliency analysis and coordinated input from subject matter experts from PG&E, transmission planning and engineering, and PG&E's geotechnical subconsultants. PG&E is expected to conduct a detailed feasibility analysis once the recommended alternative is approved. PG&E is applying the methodology for future seismic cost-benefit risk analyses.

Long Term Electric Distribution Capital Plan Filing / Public Service Electric and Gas (PSEG)

New Jersey / 2017

Project manager for updating PSE&G's electric asset risk model to incorporate the latest depreciation study. The depreciation curves in the study were used to update the likelihood of failure component for the asset risk model. Arlin was responsible for directing the update effort and collating the results for inclusion in PSE&G's regulatory filing. Arlin supported PSE&G throughout the filing effort by writing testimony, preparing exhibits, and providing QA for other witnesses and petition documents. PSE&G filed their petition for cost recovery in early 2018 and is awaiting decision from the commission.

Long Term Electric Transmission and Distribution Capital Plan / Vectren Indiana

Indiana / 2015-2017

Project manager for development of a long-term capital plan for the client's electric transmission and distribution (T&D) infrastructure based on Indiana's Senate Bill 560. The risk model identified assets with a high consequence of failure and a high likelihood of failure in the coming years. These high-risk assets were prioritized into a capital plan that was approved by the Indiana Utility Regulatory Commission to get cost recovery for this aging infrastructure. Arlin supported Vectren throughout the regulatory process and responded to discovery and interrogatory requests.

Long Term Electric Transmission and Distribution Capital Plan / Duke Indiana

Indiana / 2014-2017

Subject matter expert for development of a risk-based electric T&D capital plan that included Duke's long-term electric transmission and distribution (T&D) investments as part of their Transmission, Distribution, and Storage system Improvement Charge (TDSIC) filing. This work provided evidence of how Duke's investments in its system provided risk reduction benefits and focused spending on high risk assets. Arlin assisted with development of capital plan profiles and resulting risk reduction solutions which were key to showing the value of the 7-year capital plan. Duke Indiana's TDSIC filing was approved 29 June 2016 for $1.4 billion (originally asked for $1.6 billion) showing a ~31% risk reduction.

Project manager for supporting Duke during regular risk model updates that include incorporating new project information, removing retired assets, and updating budget forecasts. The risk model updated results support Duke's regulatory requirements for periodic TSDIC plan updates submitted for commission review.

Long Term Electric Transmission Capital Plan / Arizona Public Service Company

Arizona / 2016

Project manager an asset-level pilot electric transmission capital plan. The plan utilizes asset capital prioritization processes and tools to project long-term risk and recommend investment levels that mitigate the risk through proactive asset replacements. In this plan, we prioritized APS' transmission circuits and transmission circuit breakers. As part of the effort, Arlin also developed an asset health index and methodology for incorporating APS' transmission circuit tower condition assessments in the analysis to reflect the latest condition data for the circuits.

Regional Water System Resiliency Study / Metropolitan Water Council of Governments (MWCOG)

Washington, D.C. / 2015-2016

Project manager for the risk effort as part of a regional resiliency study for a Washington, D.C. Arlin performed a regional level study to assess the system's resiliency against events with high consequences to the water system, such as extreme weather and raw water contamination. Arlin also built the resiliency model that analyzed potential improvement initiatives based on cost-benefit analysis. The result of the project was a roadmap of initiatives for the region to implement over the next several years to increase the ability to withstand extreme events. The study methodology and the model are still being used by utilities in the region as a way of evaluating projects and their abilities to add incremental resiliency to the region.

Long Term Electric Transmission and Distribution Capital Plan / Northern Indiana Public Service Company (NIPSCO)

Indiana / 2013-2016

Subject matter expert for development of a risk-based electric T&D capital plan for NIPSCO's electric T&D infrastructure investment as part of their Transmission, Distribution, and Storage system Improvement Charge filing (TDSIC). 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. Arlin played a significant role in development of a system risk model that analyzed and scored asset risk across the T&D system for NIPSCO. NIPSCO's TDSIC filing was approved 12 July 2016 for $1.25 billion (originally asked for $1.33 billion) showing a ~30% risk reduction.

Task lead for enhancing NIPSCO's risk model to include an asset health index (AHI) assessment. The addition of AHI to the risk model involved enhancing NIPSCO's model to incorporate asset testing and visual inspection asset data collected by O&M staff. Arlin updated the data attributes and fields for the handheld devices used by O&M staff. He also coded the AHI algorithms directly into NIPSCO's Cascade software to produce AHI results for use in the risk model.

Deep Tunnel Sewerage System (DTSS) Phase 2 Resiliency Assessment / Singapore Public Utilities Board (PUB)

Singapore / 2014-2015

Resiliency and risk modeler for an alternatives resiliency assessment of several deep tunnel sewerage systems alternatives for Singapore PUB. Arlin managed and operated a risk model that evaluated the resiliency of several tunneling alternatives including total risk weighted level of service and cost over the assets life cycle. The assessment identified several key risks impacting each alternative and quantified 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. The effort allowed Singapore PUB to feel confident that a single tunnel alternative provided sufficient reliability such that a dual tunnel option was not needed, thereby avoiding approximately $800 million in capital costs.

Long Term Electric Transmission and Distribution Capital Plan/ Duquesne Light Company

Pennsylvania / 2014-2015

Project manager for development of an electric transmission and distribution capital plan. Duquesne Light has an aging electric infrastructure we were asked to develop a model and a prioritization list to assist in capital planning. The model evaluated over 20 different asset classes, prioritized them by risk, and also provided budgetary level estimates. This project helped Duquesne prioritize their capital spending to address their highest risk assets on the system. The result was seen favorably by Duquesne's board as a business case tool and allowed the asset management team to get several million dollars in projects approved that had been on hold for several years. The risk model was also used to support a successful regulatory filing for aging distribution system assets known as a Long-Term Infrastructure Improvement Plan (LTIIP) that Arlin also managed.

Long Term Electric Distribution Capital Plan / United Illuminating Company

Connecticut / 2014-2015

Lead analyst responsible for developing an electric distribution capital prioritization plan for the United Illuminating Company. As part of the project, we focused on aging assets at distribution voltage levels at or below 100kV. We developed deterioration curves based on failure and asset condition data specific to UI. The model contained over 160,000 assets and was used to develop a 10-year capital plan recommending over $250 million in capital replacements of high-risk assets for a 12 percent reduction in system risk over the same period.

Capital Prioritization Pilot Project / Salt River Project (SRP)

Arizona / 2013-2014

Analyst for a 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. Arlin was responsible for operating the Monte Carlo model that incorporated the financial, quantitative data with qualitative criteria to develop a recommended implementation plan.

Financial Modeling for Water Delivery Project / Arkansas Valley Conduit

Colorado / 2016-2017

Project manager for development of a complex financial model for a client that is looking to fund a treated water delivery pipeline capable of improving the water quality for over 30 communities. Arlin was the project manager for this effort responsible for building and enhancing the model's capabilities to support increasingly complex funding scenarios. The client is seeking funding through federal grants/loans with the Bureau of Reclamation, bank financing, and the project participants to support the capital and O&M requirements for the project's construction and operation. The model is being used to propose several financing combinations and construction timelines to support the process of drafting legislation that will support the project's funding goals.

Power Plant Outage Cost Tracking / Confidential Client

Eastern U.S. / 2014-2015

Subject matter expert for outage cost tracking. The project was oversight of a 3-month, major coal plant outage in Spring 2015. The tasks include scheduling the outage tasks, managing the vendor bid process, overseeing the outage work progress, and developing a system to track actual costs on a daily basis. Arlin developed the daily cost tracking system that automatically collects vendor timesheet data, compiles it for client approval, and delivers a daily cost report to the outage team for near real-time outage cost management. The project, of which Arlin was an integral part, resulted in the first on-time, on-budget outage experienced by the power plant since commercial operation.

FY2017 Executive Asset Management Plan Alternatives Evaluation / Washington Suburban Sanitation Commission (WSSC)

Laurel, Maryland / 2015

Lead analyst for an 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 makers.

Research Study on Energy Balance Opportunities / Water Environment Research Foundation (WERF)

Virginia / 2013

Arlin participated in part of a WERF research study on energy-neutral recovery (wastewater) facilities. He assisted in development of a triple bottom line analysis of different biosolids management scenarios and related energy recovery technologies. The analysis considered economic and financial criteria to arrive at the best design solution from a cost-benefit standpoint.

Integrated Resource Plan / Golden Valley Electric Authority (GVEA)

Alaska / 2012

Project analyst for an integrated resource planning study for GVEA that evaluated several self-builds, power purchase, demand-side and renewable capacity options in order to determine the least-cost plan for the utility. The project involved a conditions assessment and retirement analysis of existing units, a detailed production costing model of the GVEA system, evaluation of power purchase alternatives and fuel price forecasting. Results were presented to the GVEA Capacity Expansion Committee and the GVEA Board. Arlin was responsible for the analysis and operation of the PROMOD and Strategist production cost models.

Southeast Alaska Integrated Resource Plan / Alaska Energy Authority

Alaska / 2011

Project analyst for the Alaska Energy Authority's (AEA) Southeast Alaska Integrated Resource Plan. The project involved developing a recommended action plan for the region to reduce dependence on fuel oil and interconnect various isolated communities where economically feasible. The project included characterization of unconventional alternatives evaluated in the study such as biomass, wave energy conversion, tidal, wind and geothermal. Arlin also operated the optimum generation expansion planning production cost model, STRATEGIST, developed by Ventyx, to perform a 50-year evaluation of all of the generating alternatives available to the region. The program's output is an economic ranking of the least-cost expansion plans based on the cumulative present worth costs of the plans.

Energy Market Perspective / Black & Veatch

Kansas City / 2010-2011

Project analyst for Black & Veatch's Energy Market Perspective. The project used an integrated market modeling approach to develop price forecasts for energy and natural gas prices. As part of the modeling team, Arlin 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 uses an interactive process of a production cost model for electric prices and a fundamental market model for natural gas prices. Arlin's responsibilities included developing forecasts, running and evaluating the production cost model for several regions in the United States, and drawing conclusions for the regions. The main forecasts developed included energy and peak demand, generation retirements and generation expansion.

Solar and Wind Integration Study / Black Hills Colorado Electric

Colorado / 2010

Project analyst for a solar and wind integration study to estimate the feasibility and cost impact of integrating various levels of renewable energy into the system. The study concluded that it should be technically feasible to integrate up to 20 percent renewable resources, but there would be an added system cost. Arlin was responsible for the production cost modeling analysis that evaluated the different integration scenarios.

Railbelt Integrated Resource Plan / Alaska Energy Authority

Alaska / 2009-2010

Project analyst for the production cost modeling analysis, load forecasting, and various report sections, for the AEA's Railbelt Integrated Resource Plan (RIRP). The RIRP was developed for the six interconnected utilities of the Alaska Railbelt consisting of Anchorage Municipal Power & Light, Chugach Electric Association, city of Seward Electric System, GVEA, Homer Electric Association, and Matanuska Electric Association. The RIRP was conducted with all six interconnected utilities considered as one integrated utility. The RIRP evaluated numerous conventional alternatives including simple-cycle combustion turbine plants, combined-cycle units, and pulverized coal units. Renewable energy alternatives considered included large and small hydroelectric, wind, geothermal, municipal solid waste, and tidal. Combined heat and power and small modular nuclear units were also considered. The supply-side alternatives were fully integrated with an evaluation of cost-effective demand-side management/energy efficiency programs. Extensive transmission system analysis was also conducted as part of the RIRP.

Combined Cycle Conversion Need for Power Application, Greenland Energy Center / JEA

Florida / 2008-2009

Project analyst for the filing of the Greenland Energy Center Need for Power Application (NFP). The NFP provides a determination of the most cost-effective capacity addition to satisfy forecasted capacity requirements for the utility participating in the project. The analysis considered self-build and purchase-power alternatives, including renewable energy technologies and demand-side management. Arlin was responsible for production costing and economic analysis using Ventyx's STRATEGIST optimal generation expansion and production costing program. His work also included responding to interrogatories and production of document requests from the Florida Public Service Commission (FPSC) throughout discovery and other regulatory procedures.

Alaska Railbelt Electrical Grid Authority / Alaska Energy Authority

Alaska / 2008

Project analyst responsible for various report deliverable sections discussing the modeling assumptions and results in determining a least-cost formation option of a proposed regional generation and transmission entity called the Railbelt Electrical Grid Authority (REGA), whose purpose is to manage and dispatch electric power on the REGA grid. Arlin gathered and analyzed data submitted by the six utilities involved and developed input assumptions, such as generator characteristics, transmission limits, losses, economic interchange hurdle rates, discount rates, fuel prices, etc., for Ventyx's STRATEGIST optimal generation expansion and production costing program. The modeling effort included the setup of six individual utility systems with multiple interconnected transmission links with different transfer limits, losses, and constraints. Optimal expansion planning and production costing simulations were evaluated under different planning and dispatch assumptions, such as joint versus individual utility resource planning, to meet firm capacity requirements and joint versus utility economic dispatching of generation facilities.

Cane Island 4 Need for Power Application / Florida Municipal Power Agency

Florida / 2007-2008

Project analyst for development of the Cane Island 4 Need for Power Application (NFP). His work included the development of fuel price and emission allowance price forecasts specific to the Florida region using prices published by the United States Environmental Protection Agency. Arlin was responsible for the report deliverable sections, which discussed the methodology behind the development of the forecasts. He also worked with a project team to evaluate more than 100 DSM measures to be used in evaluating the cost effectiveness of a potential DSM program. The NFP provided a determination of the most cost-effective capacity addition to satisfy forecasted capacity requirements for the utility participating in the project. The analysis considered self-build and purchase-power alternatives, including renewable energy technologies and demand-side management. The Florida Public Service Commission approved the Cane Island 4 NFP in August 2008.

Conservation Plan Docket / Florida Public Utilities Company (FPUC)

Florida / 2010-2011

Project analyst for the Conservation Plan Docket before the Florida Public Service Commission (FPSC). Every five years the FPSC requires Conservation Plans to be filed containing conservation programs to meet the conservation goals set by the FPSC. Arlin assisted FPUC in the development of its plan by developing conservation programs including the program descriptions, program costs, program demand and energy savings, and program penetration levels. Arlin was responsible for running the Florida Integrated Resource Evaluator (FIRE) Model that calculates the net benefits of various DSM programs. Arlin also provided assistance after the Conservation Plan was filed to answer FPSC staff information requests. Arlin further assisted FPUC in filing its Annual Conservation Report, which summarizes the year's DSM activities with respect to the FPSC approved goals.

Independent Engineering Report / Confidential Client

2010

Project analyst for a confidential client to develop an independent engineering report for their unregulated assets. The report provided a condition assessment of 44 units consisting of coal, combined-cycle, simple-cycle and cogeneration units. The report also contained a financial evaluation which estimated the 20-year revenue from the portfolio and the 20-year operating and capital addition costs. Arlin was responsible for developing the multi-step financial model that integrated input from various team members that included production cost modeling output, fixed operations and maintenance calculations, capital expenditures and depreciation forecasts, capacity and ancillary market revenue forecasts, and corporate-level expense forecasts.

Portfolio Technical Due Diligence / Confidential Client

2010

Project analyst for independent engineering services for a confidential client in support of their bid for an equity position in various Tenaska simple-cycle and combined-cycle facilities in Alabama, Georgia, Virginia, Texas and Oklahoma. The portfolio included 4,780 megawatts of power generation using GE 7FA combustion turbine technology. Arlin was responsible for developing the financial model used to estimate the value of the portfolio.

Combined Cycle Technical Due Diligence / Competitive Power Ventures

Connecticut / 2010

Project analyst for independent engineering services for Competitive Power Ventures in support of the sale of the Milford Power Plant. We provided an independent engineer's report, which included a review of the plant site, facility, environmental compliance and existing operational agreements. Arlin was responsible for developing the financial pro forma used in estimating the value of the plant to the Earnings Before Interest, Taxes and Depreciation and Amortization level.

Fair Market Valuation / Confidential Client

Western U.S. / 2010

Project analyst for assistance in the development of a fair market valuation for the portion of the power plant that the confidential client did not own but was considering purchasing. Arlin developed each of the three valuation approaches utilized in the study—the market approach, the cost approach, and the discounted cash flow approach.

Meter Relocation / Baltimore Gas & Electric

Maryland / 2016-2018

Solution architect responsible for implementing a mobile forms-based system to QA meter relocation work performed by contractors for Baltimore Gas & Electric. Arlin was responsible for development of the layout for the mobile forms, data requirements, and business rules required for data validation. He was responsible for deploying the system, updating the forms, and implementing the method of extracting form data and sending to the project teams.

Solar Site Condition Assessments / Live Oak Bank

Northeast / 2016-2018

Solution architect responsible for implementing a mobile forms-based system for project teams to use for conducting over 200 condition site assessments for solar sites. Arlin and the project team developed an integrated process for storing pictures for the solar site components, scoring their condition, capturing notes, and automatically building a condition assessment report with the data and pictures. Arlin was responsible for development of the layout for the mobile forms, data requirements, and business rules required for data validation. He was responsible for deploying the system, updating the forms, and implementing the method of extracting form data and sending to the project teams.

1898 & CO
PART OF BURNS & McDONNELL

entergy

PHASE 2 RESILIENCE PLAN AND BENEFITS REPORT

ENTERGY NEW ORLEANS, LLC

December 5, 2025

CONTENTS

FIGURES

TABLES

ABBREVIATIONS

Abbreviation	Term/Phrase/Name
ANL	Argonne National Laboratory
BCR	Benefit Cost Ratio
Burns & McDonnell	Burns & McDonnell Engineering Company, Inc.
C&I	Commercial & Industrial
CMI	Customer Minutes Interrupted
DOE	Department of Energy
EIM	Event Impact Model
Entergy New Orleans	Entergy New Orleans, LLC
FEMA	Federal Emergency Management Agency
GIS	Geographic Information System
ICE	Interruption Cost Estimate
IEEE	Institute of Electrical and Electronics Engineers
LA	Louisiana
LOF	Likelihood of Failure
MED	Major Event Day
NARUC	National Association of Regulatory Utility Commissioners
NIAC	National Infrastructure Advisory Council
NOAA	National Oceanic and Atmospheric Administration
OH	Overhead
OMS	Outage Management System
PNNL	Pacific Northwest National Laboratory
POF	Probability of Failure
PV	Present Value
ROW	Right-of-Way
SLOSH	Sea, Land, and Overland Surges from Hurricanes
T&D	Transmission and Distribution
TD	Tropical Depression
TS	Tropical Storm

1.0 Executive Summary

1898 & Co., the advisory and technology consulting arm of Burns & McDonnell, was engaged on behalf of Entergy New Orleans, LLC ("Entergy New Orleans" or the "Company") to assist with the development of Phase 2 ("Phase 2") of Entergy New Orleans' Resilience Plan to invest in storm resilience for the period 2027-2031. In collaboration, Entergy New Orleans and 1898 & Co. utilized a resilience-based planning approach to identify and prioritize investments in the Company's transmission and distribution (T&D) system utilizing its Resilience Event Simulation Model ("Resilience Model"), previously referred to as the Storm Resilience Model.[1] The Resilience Model evaluates each hardening zone's ability to reduce the magnitude and/or duration of disruptive storm events. The term "hardening zone" refers to a collection of assets grouped by 1898 & Co.'s Resilience Model for potential hardening. A "project" is one or more hardening zones grouped together by Entergy New Orleans based on execution, operational, or other requirements. Key objectives for the Resilience Model include:

1. Calculating the customer benefit of hardening zones through reduced utility restoration costs and impacts to customers;
2. Prioritizing hardening zones with the highest resilience benefit per dollar invested into the system; and
3. Providing insights on various investment funding levels and execution constraints and their relationship to customer benefits.

The Resilience Model employs a data-driven decision-making methodology utilizing robust and sophisticated algorithms to calculate the resilience benefit of hardening zones in terms of the range of reduced restoration costs and Customer Minutes Interrupted (CMI). The hardening zones provide resilience benefit from several perspectives. Some of the hardening zones help avoid storm-based outages, and others decrease the duration of storm-related outages. This report shows only the reduction in CMI, which accounts for both types of benefits. However, there is a strong relationship between reduction in CMI and reduction in Customers Interrupted (CI).

[1] 1898 & Co. has enhanced its Storm Resilience Model to handle additional resilience events beyond storms and hurricanes, rebranded it as the Resilience Event Simulation Model, and integrated it into a larger set of models called the "Integrated Resilience & Risk Investment Model."

Resilience-based prioritization facilitates the identification of hardening zones that provide the most benefit to customers. 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 hardening zone prioritization and benefits calculations for the following Entergy New Orleans storm hardening programs:

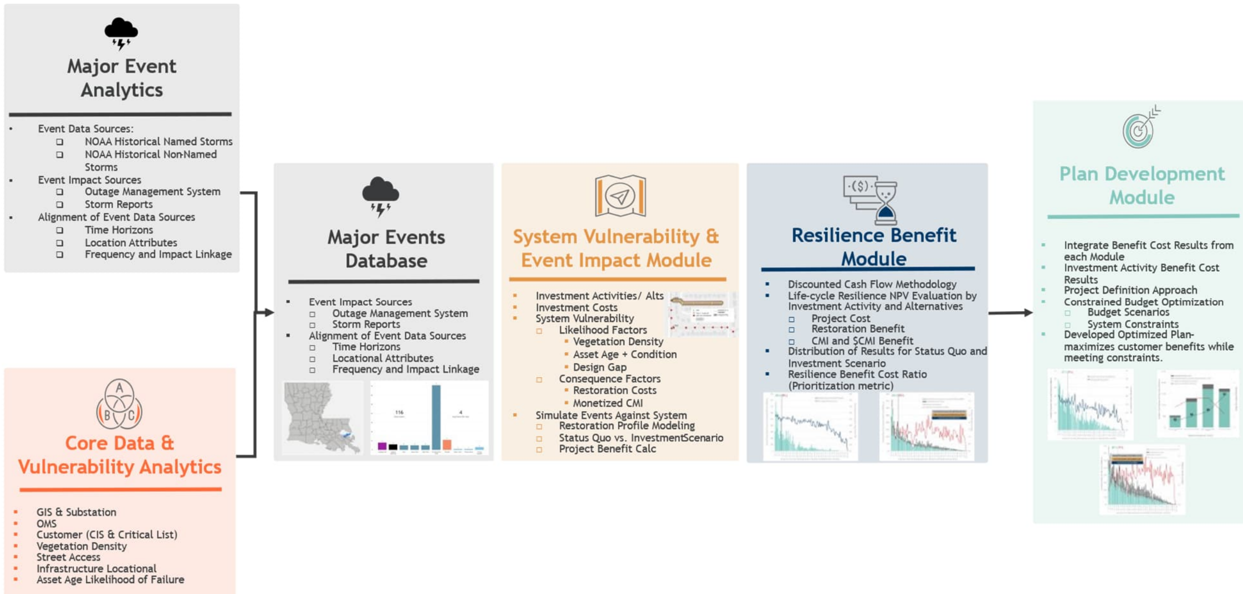
- Distribution Feeder Hardening (Rebuild)
- Distribution Feeder Undergrounding
- Lateral Hardening (Rebuild)
- Transmission Rebuild
- Substation Storm Surge Mitigation

1.1 Resilience Based Planning Approach

Figure 1-1 provides an overview of the 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 Events Database contains storm probability distributions, and the range of impacts for 45 different storm types. The 45 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 includes probabilities and impacts for all 45 different storm types for Orleans Parish.

Figure 1-1: Resilience Model



Each storm type for Orleans Parish is then modeled within the System Vulnerability & Event Impact Module ("EIM") 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 gap in the current wind loading of the asset versus 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 New Orleans' T&D system. Table 1-1 provides an overview of the potential hardening zone options for each of the programs.

Table 1-1: Potential Hardening Zone Options Evaluated for Phase 2[2]

Program	Hardening Zone Count
Distribution Feeder Hardening (Rebuild)	829
Distribution Feeder Undergrounding	1
Lateral Hardening (Rebuild)	3,370
Transmission Rebuild	9
Substation Storm Surge Mitigation	5
Total	4,214

[2] 4,213 unique hardening zones were modeled. There is 1 distribution feeder hardening zone that also has an undergrounding alternative that was modeled, bringing the total hardening zone options evaluated to 2,414.

The EIM also estimates the restoration costs and CMI for each of the hardening zones in Table 1-1 above for each storm type. Assets are typically organized from a customer impact perspective (see Section 2.2). Finally, the EIM calculates the benefit in decreased restoration costs and CMI if a hardening zone is hardened per Entergy New Orleans' design standards. The CMI benefit is monetized using the United States Department of Energy's (DOE) Interruption Cost Estimate (ICE) calculator for hardening zone prioritization purposes.

The Resilience Benefit Module utilizes stochastic modeling, also known as a Monte Carlo simulation, to select a storm probability for each of the 45 storm types for Orleans Parish 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 New Orleans system. The probability of each storm scenario is multiplied by the benefits calculated for each hardening zone from the EIM to provide a resilience-weighted benefit for each hardening zone in dollars.

The Plan Development Module prioritizes the hardening zones based on the highest resilience benefit cost ratio factoring in execution constraints.

The model prioritizes each hardening zone based on the sum of the restoration cost benefit and monetized CMI benefit divided by the hardening zone 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 hardening zones applicable to Entergy New Orleans and its service area, such as contractor capacity, logistics, and materials limits. Using the Resilience Benefit Module and the Plan Development Module, the Resilience Model calculates the net benefit in terms of reduced restoration costs and CMI for the Phase 2 Resilience Plan.

1.2 Key Updates to Entergy New Orleans' Model from the 2023 Phase 1 Resilience Plan

The following are the key updates from Entergy New Orleans' Phase 1 Resilience Plan filed in 2023, converting to this Phase 2 Resilience Plan:

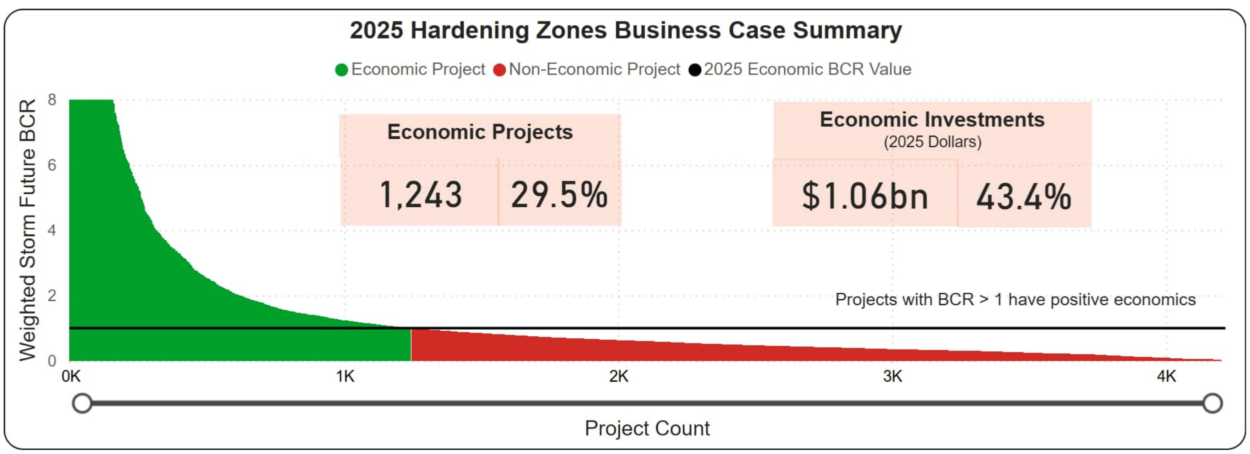
- Entergy New Orleans System Data and Attributes - GIS (new assets, updated ages, pole classes, locations, etc.), customer information/counts/types
- Weather and Outage History - Hurricanes Francine and Beryl, including paths, strengths, outages, and costs and additional outage management system data from 2023 and 2024

- Module Configurations - Updated hardening zone cost buildup, hardening zone cost data, asset grouping to hardening zones, evaluation of overhead to underground alternatives, ICE calculator adjustments
- Module Enhancements - Increased granularity from 50 x 50-mile system sections to parish-level analysis and increased granularity of non-hurricane weather analysis

1.3 Resilience Business Case Results

Figure 1-2 shows the results of the Resilience Benefit Cost Ratio for all potential hardening zones across the Entergy New Orleans service territory. The figure shows approximately 4,200 potential hardening zones were modeled.[3] It should be noted that the evaluation considered both overhead hardening and express feeder undergrounding, where applicable, but, for simplicity, the chart only shows rebuild options. The figure shows that approximately 30 percent of the 4,213 hardening zones (by hardening zone count) have a Resilience Benefit Cost Ratio greater than 1. The figure also shows that approximately $1.06 billion of investment has a Resilience Benefit Cost Ratio greater than 1. This is equivalent to 43 percent of the total hardening investments across all potential hardening zones.

Figure 1-2: Hardening Zone Resilience Benefit Cost Ratio Summary



1.4 Conclusions

The following include the conclusions of the Phase 2 Resilience Plan:

- There is opportunity for additional resilience investment in the New Orleans system. The resilience business case modeled over 4,200 hardening zones, with approximately 30 percent having a positive business case. There is approximately $1.06 billion of positive BCR investment across the Company's system.

[3] *See supra*, note 2.

- An overall investment level of $400 million is technically achievable over the time horizon. This investment plan provides significant benefits for customers, is reasonable, and provides customers with optimal benefits given execution constraints. This investment level is reasonably expected to:
  - o Decrease storm restoration cost by approximately $83 million over the 50-year time horizon.
  - o Decrease total number of CMI by 3.4 billion minutes over the 50-year time horizon.
  - o Reduce overall monetized customer outages by over $1.3 billion over the 50-year time horizon.
- The $400 million of investment ($359 million in 2025 dollars) produces a plan level benefit cost ratio of 3.97, indicating the plan provides benefit to customers in excess of the plan costs.
- If enough of the Entergy New Orleans system is made resilient, 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. Both of these benefit streams are not factored into the evaluation within the Resilience Model.

2.0 Introduction

Hurricanes and extreme weather events have inflicted significant damage to New Orleans and the state of Louisiana in the last several years. One of the most important actions New Orleans can take to prepare for the next major storm is to continue to make the electric grid more resilient. When the grid can better withstand the impacts of storms, everyone benefits. New Orleans businesses and families save money because they can get back on their "feet" quickly. Proactive investing 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. Entergy New Orleans took a step in that journey with its Phase 1 Resilience Plan that was approved in 2024[4] and it has begun construction on those projects. This report describes the Phase 2 Resilience Plan and carries similar themes and drivers from the previous report. This document outlines the approach to:

1. Calculate the benefit of the 'universe' of hardening zones through reduced utility restoration costs after major storms and the decrease (in both number and duration) in storm-related customer outages.
2. Prioritize hardening zones based on which hardening zones deliver the highest resilience benefit per dollar invested into the system.

The resilience-based approach is an integrated data-driven, decision-making strategy comparing various storm resilience hardening zones 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 zones, and hardening zones are then rolled up to programs. Where applicable, hardening alternatives are evaluated, such as undergrounding express feed[5] segments as opposed to rebuilding to a hardened overhead standard. For overhead rebuild hardening zones, each hardening zone includes only the assets that do not meet the hardened design standards. This allows for the identification of hardening zone scopes that harden all vulnerable components to provide the most benefit to customers and that align with Entergy New Orleans' design standards.

[4] Docket: UD-21-03. Link: https://www.all4energy.org/docket/ud-21-03/
[5] Feeders at least one mile long directly serving 5 or fewer customers and/or transformers, with 5 or fewer lateral taps, serving at least 100 customers in downstream protection zones.

This report outlines hardening zone prioritization and benefit calculations for the following Entergy New Orleans storm resilience programs:

- Distribution Feeder Hardening (Rebuild)
- Distribution Feeder Undergrounding
- Lateral Hardening (Rebuild)
- Transmission Rebuild
- 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 hardening zone assessment approach
- Entergy New Orleans 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:

> Robustness and recovery characteristics of utility infrastructure operations, which avoid or minimize interruptions of service during an extraordinary and hazardous event. In other words, 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.[6]

Before that, the National Infrastructure Advisory Council (NIAC) provided a definition that is often quoted, and includes elements used in many other definitions. It states that resilience is:

[6] Keogh, M., Cody Christina, & NARUC Grants & Research. (2013). Resilience in Regulated Utilities. In *https://pubs.naruc.org/pub/536F07E4-2354-D714-5153-7A80198A436D#:~:text=Resilience%20%2Fri%CB%88zily%C9%99ns%2F%20noun%2C%20regulatory,an%20extraordinary%20and%20hazardous%20event*. The National Association of Regulatory Utility Commissioners.

> 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.[7]

The NIAC definition includes a system's ability to absorb and adapt. These important characteristics were also used by Argonne National Laboratory (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.[8]

---

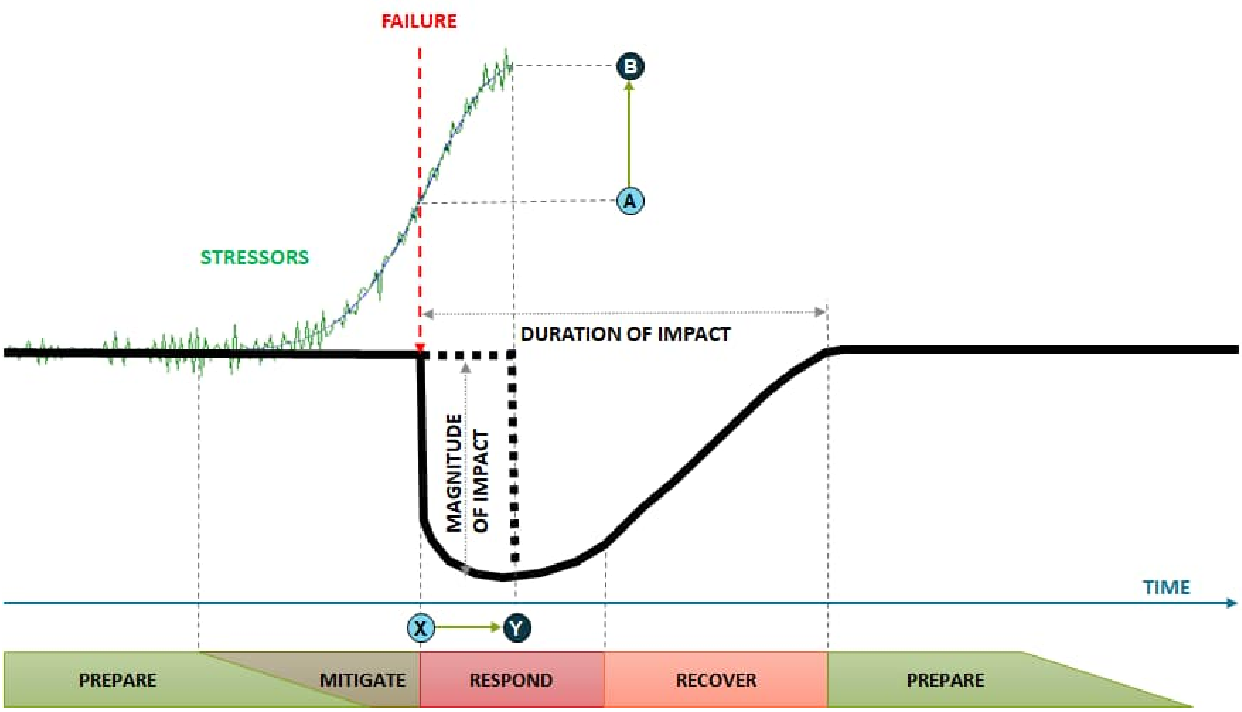
[7] Bush Wes, Grayson Margaret, Berkeley III, A., & Thompson John. (2009). CRITICAL INFRASTRUCTURE RESILIENCE FINAL REPORT AND RECOMMENDATIONS. In a*https://www.cisa.gov/sites/default/files/publications/niac-critical-infrastructure-resilience-final-report-09-08-09-508.pdf*. NATIONAL INFRASTRUCTURE ADVISORY COUNCIL.

[8] Argonne National Laboratory. (n.d.). *Resilience Measurement Index: An Indicator of Critical Infrastructure Resilience*. https://publications.anl.gov/anlpubs/2013/07/76797.pdf.

This is depicted graphically in Figure 2-1 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). If Entergy New Orleans 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 New Orleans 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 was 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 Resilience Model evaluates the phases of resilience for storms on both the entire system and at the hardening zone 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 Resilience Model (described in more detail in Section 2.3) is comprehensive in that it evaluates nearly all of Entergy New Orleans' T&D systems. Table 2-1 shows the asset types and counts included in the Resilience Model.

Table 2-1: Entergy New Orleans Asset Base Modeled

Asset Type	Units	Number
Distribution Circuits	[count]	240
Feeder Poles	[count]	22,648
Lateral Poles	[count]	24,725
Feeder OH Primary	[miles]	648
Lateral OH Primary	[miles]	515
Transmission Circuits	[count]	48
Wood Poles	[count]	221
Steel / Concrete / Lattice Structures	[count]	1,803
Conductor	[miles]	138
Substations	[count]	22

All assets are strategically grouped into potential hardening zones, and only the assets that require hardening are included in the hardening zones. The following sub-sections outline the approach to identifying hardening candidate assets and grouping them into hardening zones.

2.2.1 Distribution Hardening Zones Identification

For distribution hardening zones, assets were grouped by their 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 hardening zones at the protection device level allows for hardening of all vulnerable components in the protection zone and for capturing the full benefit for customers, including avoidance or mitigation of an outage.

For distribution circuit hardening zones (laterals and feeders), both rebuilding to a storm resilient overhead design standard and undergrounding, where feasible, were considered when evaluating hardening zone alternatives. Overhead hardening rebuilds are generally lower cost than undergrounding, but they provide less resilience benefits than undergrounding since the hardened overhead infrastructure is still exposed to wind, debris from vegetation, and other materials. For this iteration of the plan, undergrounding was modified to only be considered for express feeds, which are feeders with relatively few customers directly on the feeder and cover several miles, but still serve many customers in downstream protection zones. Assets in overhead hardening zones include older wood poles and those designed to a previous wind rating, as well as copper conductor. Physical hardening addresses the infrastructure storm failure component, while undergrounding 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 distribution conductor, the asset was included in a hardening zone 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 Hardening Zones 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 hardening zones. For this iteration of the plan, transmission assets were only deemed to be hardening candidates if they were wood structures.

2.2.3 Substation Hardening Zones Identification

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 hardening zones. 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.

1898 & Co. also utilized flood hazard data from FEMA to analyze a substation's flood risk based on the 1% annual chance floodplain, also known as the 100-year floodplain.

2.2.4 Potential Hardening Zones Evaluated

Table 2-2 contains a list of potential hardening zones based on the methodology outlined above. As seen below, there are a significant number of potential hardening zones, approximately 4,200. The following sections outline the approach to selecting the hardening zones that provide the most value to customers from a perspective of reducing both storm restoration costs and CMI. It should be noted that planned resilience projects from the Phase 1 Resilience Plan through 2027 are not included in the counts below.

Table 2-2: Potential Hardening Zones Evaluated for Phase 2

Program	Hardening Zone Count
Distribution Feeder Hardening (Rebuild)	829
Distribution Feeder Undergrounding	1
Lateral Hardening (Rebuild)	3,370
Transmission Rebuild	9
Substation Storm Surge Mitigation	5
Total	4,214

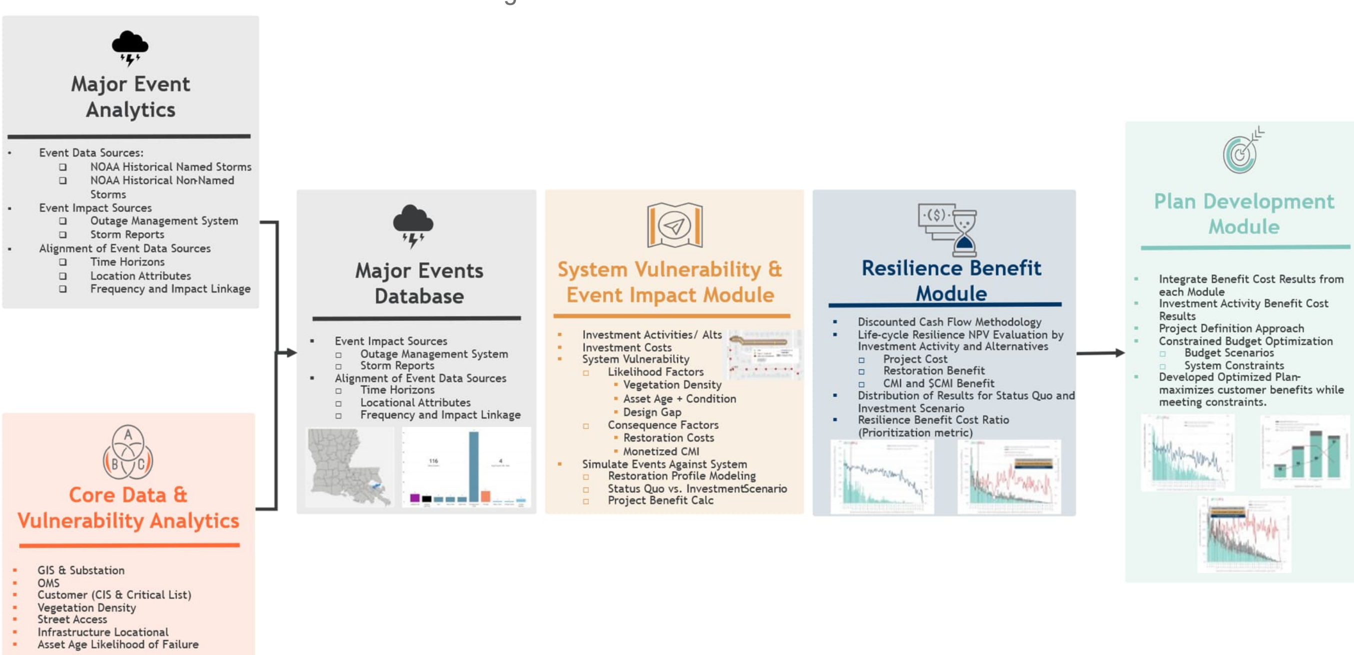
2.3 Resilience Planning Approach Overview

The resilience-based planning approach calculates the benefit of storm resilience hardening zones from a customer perspective. This approach calculates the resilience benefit at the asset, hardening zone, and program level within the Resilience Model. The results of the 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 zones and the approach to prioritizing those hardening zones into an executable plan.

Figure 2-2: Resilience Model



2.3.1 Major Events Database

Since the magnitude of the restoration cost decrease and the CMI decrease are dependent on the frequency and magnitude of future major storm events that may impact Orleans Parish, the Resilience Model starts with the 'universe' of major storm events that could impact the Parish, which is the Major Events Database. The assessment does this to understand the frequency and magnitude of major events across Orleans Parish.

The Major Events Database provides the high-level impact of the storm stressor to the ENO system. The Major Events Database includes the following:

- Storm Type
- Storm Strength
- Historical Storm Frequency

The Major Events Database includes 45 unique storm types for Orleans Parish. The storm types include the various hurricane categories, the parish-storm distance, and side of the storm that impacts the parish (the right side of a northern-moving hurricane has higher wind speeds and increased destructive capability). Along with hurricane and related storms, the Major Events Database includes localized, Major Events and 100-year floods. Each storm type has a range of probabilities and impacts that is based on historical evaluation of National Oceanic and Atmospheric Administration (NOAA) hurricane data, and the range of these impacts is based on expectations of system impacts from the 45 different storm types. These system impacts incorporate the effects of vegetation density, asset age, structure 'right-of-way' access, and terrain including wetland and rocky areas on likelihoods of failure and resulting failure costs. Section 4.0 provides additional details on the Major Events Database.

2.3.2 System Vulnerability & Event Impact Module

Each storm type, up to 45 for Orleans Parish, is modeled within the System Vulnerability & Event Impact Module ("EIM") to identify likelihood and consequence of failures for various parts of the system, during each type of storm. The EIM calculates the restoration costs and customers impacted by system failures in each of the Status Quo and Hardened cases. The EIM identifies the damaged portions of the system by modeling the elements that cause failures in the Entergy New Orleans asset base.

The EIM calculates a storm LOF 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 gap 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 (see Section 3.6). The wind zone rating is based on the wind zone within which the asset is located. The resulting LOF for each asset is used in projecting restoration costs and hardening zone-level LOF for a storm for use in estimating future outages.

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, i.e., feet of water above the site elevation, for various storm types. The analysis also determines whether the substation is within a 100-year floodplain (see Section 3.10).

Once the EIM 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 New Orleans labor and procured materials. The restoration cost multipliers are based on historical storm events and the expected outside labor and expedited material cost needed to restore the system.

Similarly, the EIM calculates the CMI for each hardening zone. Since distribution hardening zones are organized by protection device, the customer counts and customer types are known for each asset in the EIM. Each substation's customer count is the sum of the customers across all feeders at the substation. In the event of substation flooding, the EIM assumes a complete outage of the substation and the feeders leaving those stations.

For transmission hardening zones, the Resilience Model represents substation-transmission lines and substation-distribution circuit linkages to represent the criticality of transmission lines to customers. Likelihoods of failure and expected restoration times consider storm and transmission line/asset characteristics. The Resilience Model considers two categories of transmission failures/outages:

1. During each of Entergy's seven extreme outage scenarios, multiple, simultaneous transmission line failures produce widespread, long-duration outages with extreme customer consequences.

2. Non-extreme failures, in which one or more transmission lines fail, but do not produce large-scale, widespread, or long-lasting outages like those in the extreme outage scenarios. These non-extreme, transmission failure(s) only produce substation/customer outages when every transmission line feeding a substation simultaneously fails.

When outages do occur for transmission, distribution, or substation hardening zones in the model, the restoration time is then multiplied by the known customer count to calculate the CMI. The CMI benefit is monetized using DOE's ICE Calculator. 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, the model uses the DOE's ICE Calculator to evaluate the societal impacts to customers generally for hardening zone prioritization purposes.

Finally, the EIM calculates the reductions in hardening zone storm LOF, restoration costs, and CMI for each hardening zone alternative. The output of the EIM is the hardening zone LOF, CMI, monetized CMI, and restoration costs for each of the 45 storm types for both the Status Quo and Hardened scenarios.

2.3.3 Resilience Benefit Module

The Resilience Benefit Module utilizes stochastic modeling, or Monte Carlo simulation, to produce 1,000 iterations of 50-year storm futures based upon historical frequencies of the 45 storm types. These storm futures each contain a historically representative collection of hurricanes, each of which is modeled as a complete storm, affecting Orleans Parish. The storm futures also contain a historically representative quantity of localized Major Events and 100-year floods for Orleans Parish. These future "storm worlds" produce an expected range of benefit values depending on the different probabilities and impact ranges to the Entergy New Orleans system. Benefits calculation uses a weighted approach, balancing the most-likely outcomes with the possibility of worse outcomes, under the Status Quo case.

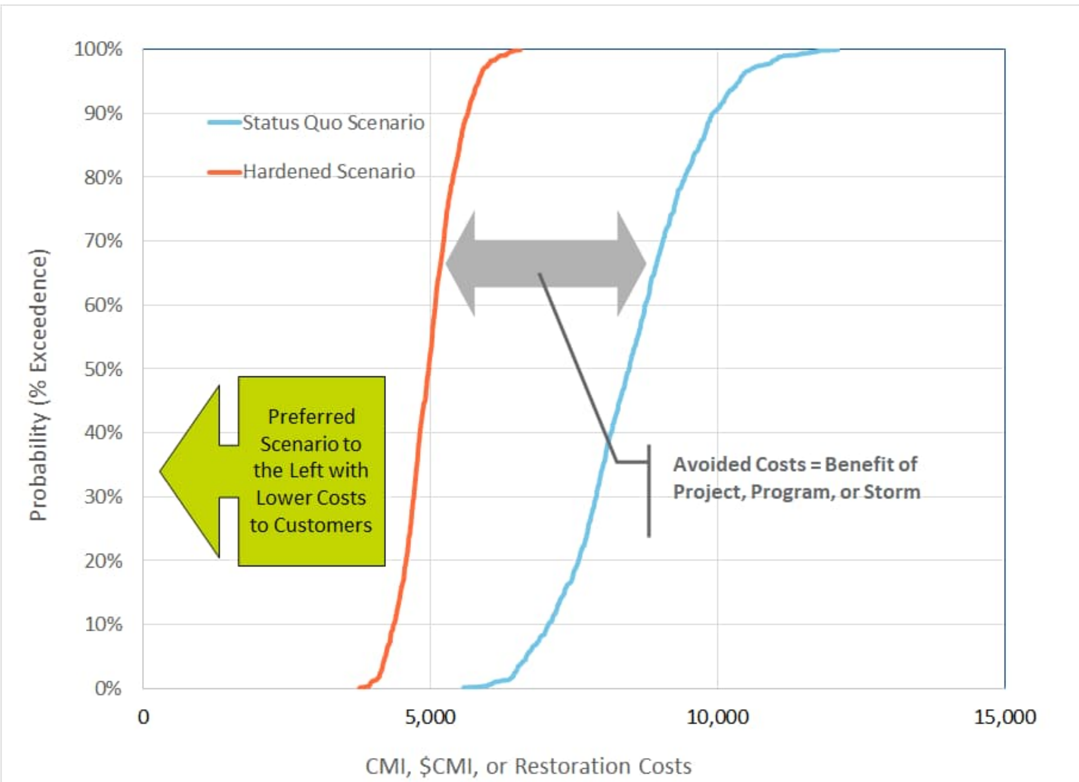
2.3.4 Plan Development Module

The Plan Development Module prioritizes the hardening zones based on the highest ratio of resilience benefit to cost. The model prioritizes each hardening zone based on the sum of the restoration cost benefit and monetized CMI benefit divided by the hardening zone 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 hardening zones applicable to Entergy New Orleans, such as contractor capacity and material availability. Using the Resilience Benefit Module and Plan Development Module, the Resilience Model calculates the net benefit in terms of reduced restoration costs and CMI for an investment profile.

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 1,000 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

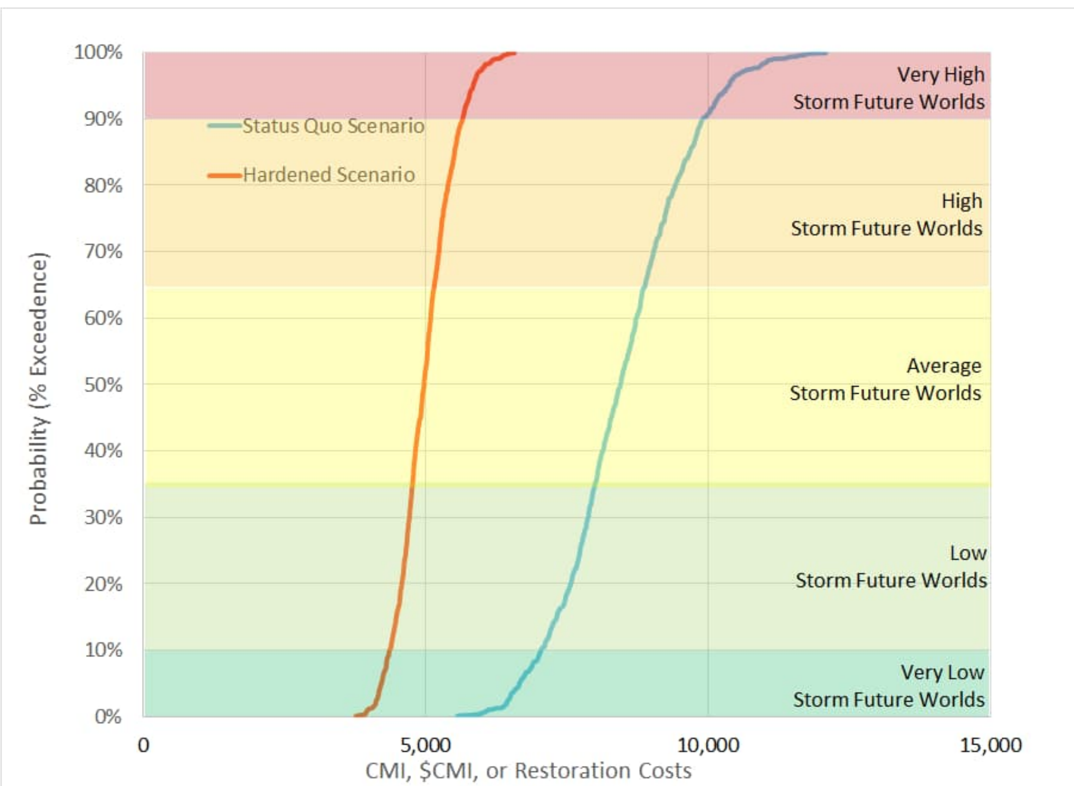


The horizontal axis shows the storm cost in terms of CMI, monetized CMI, or restoration costs. The values in the figure are illustrative. The vertical axis shows the percent exceedance values. For the Hardened Scenario, the chart shows a value of 5,000 at the 40-percentile level. This means there is 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



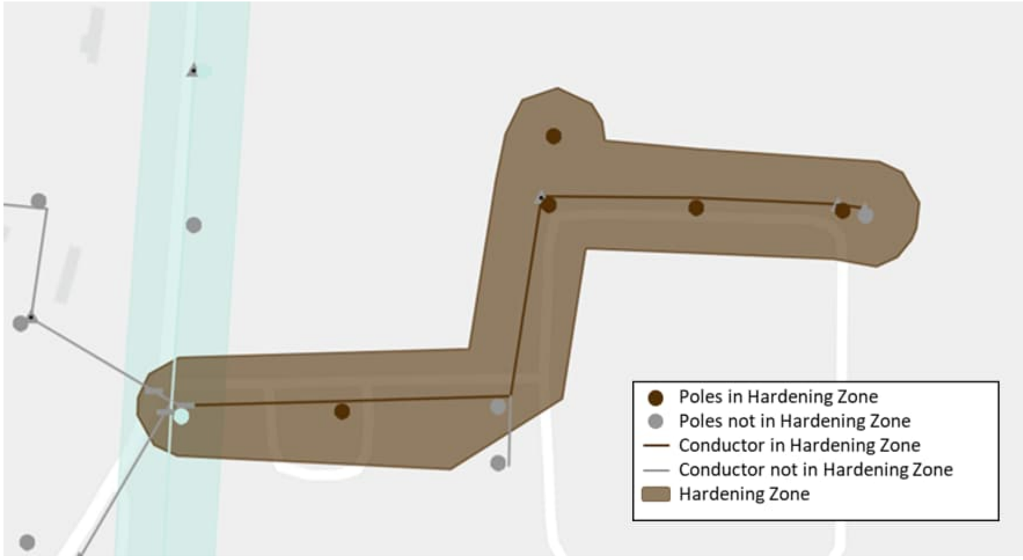
3.0 Core Data and Analytics

The resilience-based approach and methodology are data-driven. This section outlines the core data sets and base algorithms employed within the Resilience Model, while Sections 4.0 and 5.0 describe how these core data items are used within the Resilience Model. This section includes both data from Entergy New Orleans' systems and external data sources.

3.1 Geographical Information System

The Geographic Information System (GIS) provides the list of assets in Entergy New Orleans' 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 hardening zones, and all hardening zones up to programs, and finally the programs up to an overall plan. The relationship between assets and hardening zones is illustrated in the geospatial figure below.

Figure 3-1: Asset to Hardening Zone Relationship



In alignment with this methodology, 1898 & Co. utilized the connectivity in the 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 hardening zones to be created to target only portions of a circuit for resilience investment. Through this approach, Entergy New Orleans and 1898 & Co. were able to use the asset level information from Table 3-1 and convert it to the hardening zone level summaries in Table 3-2. It is important to note that each asset in Table 3-1 is tied to one of the hardening zones listed in Table 3-2, which provides a bottom-up analysis.

Table 3-1: Entergy New Orleans Asset Base Modeled

Asset Type	Units	Number
Distribution Circuits	[count]	240
Feeder Poles	[count]	22,648
Lateral Poles	[count]	24,725
Feeder OH Primary	[miles]	648
Lateral OH Primary	[miles]	515
Transmission Circuits	[count]	48
Wood Poles	[count]	221
Steel / Concrete / Lattice Structures	[count]	1,803
Conductor	[miles]	138
Substations	[count]	22

Table 3-2: Potential Hardening Zones Evaluated for Phase 2

Program	Hardening Zone Count
Distribution Feeder Hardening (Rebuild)	829
Distribution Feeder Undergrounding	1
Lateral Hardening (Rebuild)	3,370
Transmission Rebuild	9
Substation Storm Surge Mitigation	5
Total	4,214

3.2 Outage Management System

The outage management system (OMS) includes detailed outage information by cause code for each protection device over the last 15 years. The 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 extreme weather Major Event Days (MED) in the Major Events Database.

3.3 Customer Type Data

Entergy New Orleans provided customer count and type information that featured connectivity to the GIS and OMS. This allowed the Resilience Model to directly link the number and type of customers impacted to each hardening zone and the hardening zone's assets. For example, the 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, and critical customers. This customer information is included for every distribution asset in the Entergy New Orleans system. The customer information is used within the EIM to calculate the CMI (customers affected * outage duration) for each storm for each lateral or feeder hardening zone. Table 3-3 below shows the count of customers by class from Entergy New Orleans' service territory that have been linked to assets in the EIM.

Table 3-3: Customer Counts by Type

Customer Type	Customer Count
Residential	175,838
Small Commercial and Industrial	15,652
Large Commercial and Industrial	1,397
Critical	37
Total	192,924

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 blowing into conductor is a primary failure mode for major storm events for Entergy New Orleans. The EIM calculates the vegetation density around each transmission and distribution overhead conductor. The EIM utilizes tree canopy data to calculate the percentage of vegetation for 30-meter by 30-meter areas across the entire Entergy New Orleans system. The 900 square meter area is indicative of the vegetation density on the system from a major storm perspective. For each span of conductor (approximately 70,000 spans), 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.

3.5 Overhead Structure Wind Design Gap

Structures are designed to various loading standards. Over decades, 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 and the wind speeds across the service area have heightened, the wind loading standard of infrastructure across Entergy New Orleans' system increased in 2022. While new infrastructure is built to the new standard, the delta between older infrastructure and current standards can grow. Infrastructure that has a wide gap between its actual wind loading rating and the newer hardened wind loading standard is at greater risk of failing given major storm events. The Resilience Model uses the gap in wind loading to estimate the number of assets that would fail during a major event.

Entergy New Orleans provided extreme wind loading standards based on geographical areas. Figure 3-2 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 3-2: Entergy Distribution Extreme Wind Zones

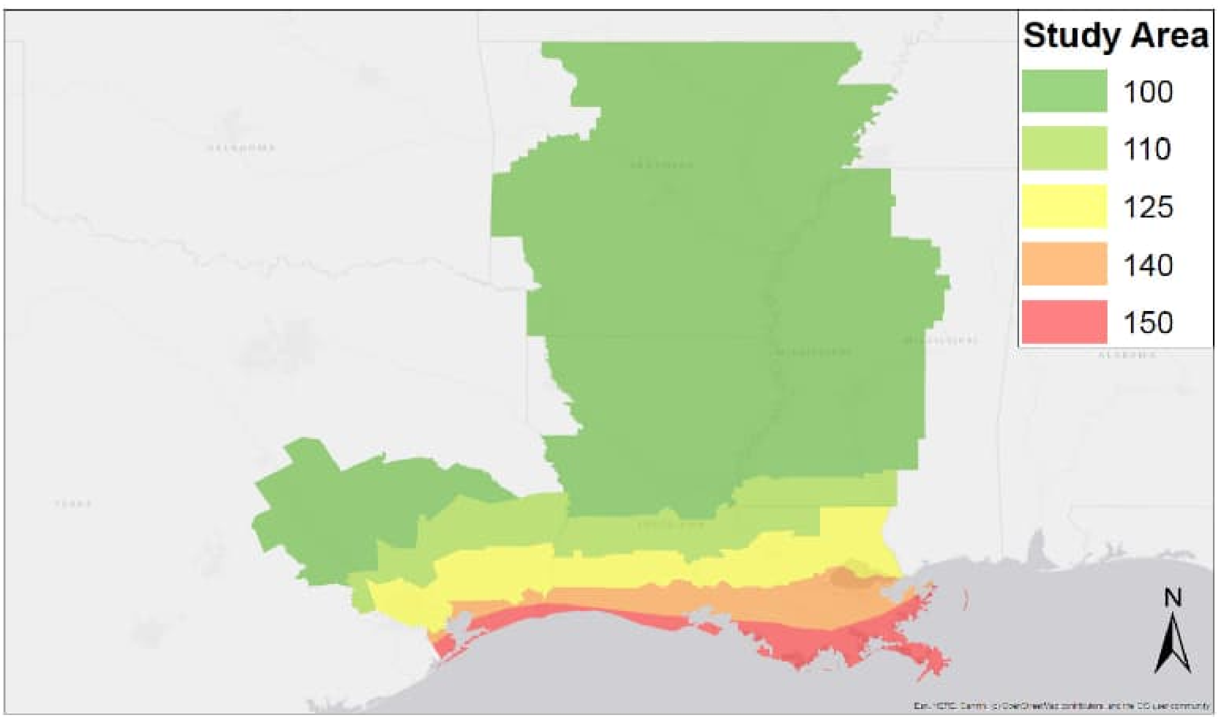
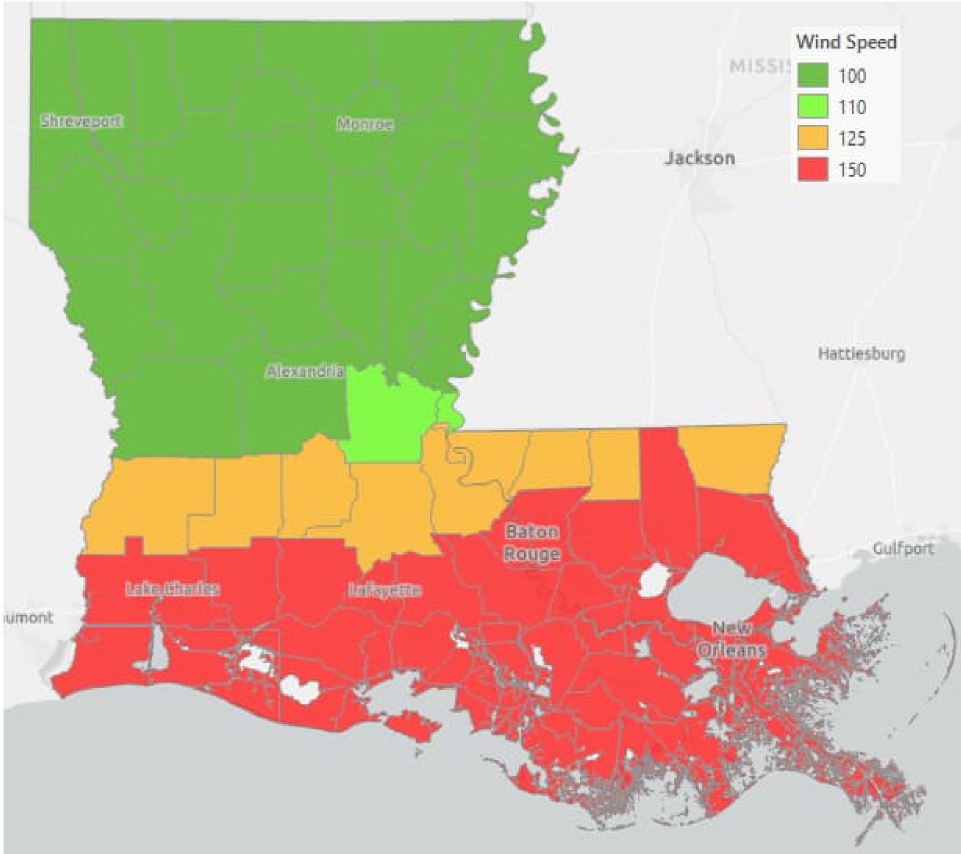


Figure 3-3: Entergy Transmission Extreme Wind Zones in Louisiana



Using data from Entergy New Orleans and known attributes of transmission and distribution structures, each asset's current wind rating was assessed. This rating is the wind speed the structure is currently rated to withstand. 1898 & Co. performed a comprehensive analysis of the current actual wind rating versus the hardened wind rating standard for all distribution and transmission assets. Entergy New Orleans' transmission and distribution systems have approximately 47,000 structures with an actual wind speed rating below the current extreme wind hardened standard. These assets are at a much higher risk of failure during storms due to the information discussed above.

3.6 Age

As assets age, they lose some of their original design strength and capability. For example, aged poles (all else equal) will fail at lower dynamic load levels than poles with their original design strength. The same concept applies to other overhead, underground, and substation assets. 1898 & Co.'s analysis utilized industry-standard survivor curves using an asset class's expected average service life as well as the specific asset's age to estimate the age-based likelihood of failure during specific events.

3.7 Accessibility

The ability of work crews to access an asset has an impact on the duration of the outage and the cost to restore that part of the system. For example, rear lot structures take much longer and cost more to restore than front lot structures. To take differences in accessibility into account, the Resilience 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, while others were designated as in the deep right-of-way (ROW). These designations were used when calculating restoration and resilience investment activity costs in the Resilience 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 Resilience Model performs a geospatial analysis of each structure against a data set from the U.S. Fish & Wildlife Service 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 zone costs.

3.9 DOE's ICE Calculator

To monetize the cost of a storm outage for the purpose of prioritizing hardening zones and performing Investment Optimization, the Resilience Model utilizes the DOE's 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 EIM 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, in Phase 1 of the Resilience Plan, the ICE Calculator extrapolation values were further reduced for large C&I and small C&I customers, which resulted in multiple layers of conservatism with the monetized CMI benefits from the Resilience Model. For the Phase 2 Resilience Plan, the Resilience Model uses the extrapolated, diminishing costs and the unadjusted ICE Calculator values to better represent the monetized CMI benefits for Entergy New Orleans' hardening zones.

These rough indications of outage cost for each customer are multiplied by the specific customer count and expected duration for each storm for each hardening zone to calculate the monetized CMI at the hardening zone level.

3.10 Substation Flood

1898 & Co. utilized storm surge modeling from the Sea, Land, and Overland Surges from Hurricanes (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 New Orleans' substations to estimate the height above the ground elevation for storm surge. This data was then used in the Storm Impact Model to estimate the likelihood of substation failure for every storm scenario.

1898 & Co. also utilized flood hazard data from FEMA to analyze flood-risk areas. The data provides the 1% annual chance floodplain, also known as the 100-year floodplain. The FEMA floodplain was overlaid with the location of Entergy New Orleans' substations to identify substations at risk of flooding. This data was then used to estimate the likelihood and consequence of substation flooding based on which flood zone each substation is located in.

3.11 Transmission Outage Scenarios

Due to the complex interconnected nature of the transmission system, 1898 & Co. and Entergy New Orleans developed a transmission outage framework based on the 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. Certain combinations of these outages, those that simultaneously interrupt service on large, parallel lines, are extremely consequential, resulting in regional, widespread customer outages. Additionally, these scenarios affect the ability to supply electricity to metropolitan areas like New Orleans, resulting in large blackouts impacting large numbers of customers.

4.0 Major Events Impacting Entergy New Orleans' System

The first component of the Resilience Model is the Major Events Database. The database describes the phases of resilience (see Figure 2-1) for the range of storm events to impact the Entergy New Orleans service territory. It includes the probabilities for each of the events as well as the range of impacts to the transmission, substation, and distribution systems, as well as event durations, customers impacted, and the restoration costs. This section describes the data sources and approach used to develop the database. Since the benefits of hardening zones 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 New Orleans' service area.

4.1 Historical Storm Overview

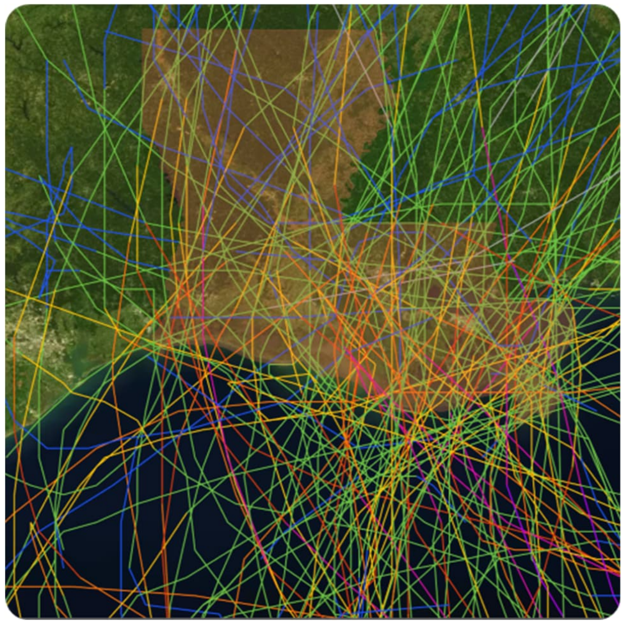
For development of the Major Events Database, 1898 & Co. utilized two sources of historical storm data from the National Oceanic and Atmospheric Administration (NOAA). The first is a database of Historical Hurricane Tracks ("NOAA Hurricanes") that has data from events back to 1851,[9] while the second is a detailed weather event database ("NOAA Storm Events Database") at the parish level beginning in 1998.[10] These databases were mined to evaluate the different types and frequency of major storms to impact Louisiana, including Entergy New Orleans' service area.

4.1.1 Storm Count and Types: NOAA Hurricanes

Figure 4-1 provides an example screenshot from NOAA's Hurricane database. It shows all the events, including path and category, to come within 150 miles of Entergy's service area. A review of the figure shows the changing category of the storms as they move through Louisiana.

[9] Source: https://coast.noaa.gov/hurricanes/.
[10] Source: https://www.ncdc.noaa.gov/stormevents/.

Figure 4-1: NOAA Example Output - Louisiana[11]



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 New Orleans service area. Additionally, the database was mined for the storm category as it hit the Entergy New Orleans service area.

Figure 4-2 includes the summary results of hurricanes that have hit or nearly hit the Entergy New Orleans service area since 1851. 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. Only one category 5 storm has been recorded since 1851 to be a peripheral or closer hit to New Orleans.

[11] Source: https://coast.noaa.gov/hurricanes/.

Figure 4-2: Summary of Hurricanes in Entergy New Orleans' Territory since 1851[12]

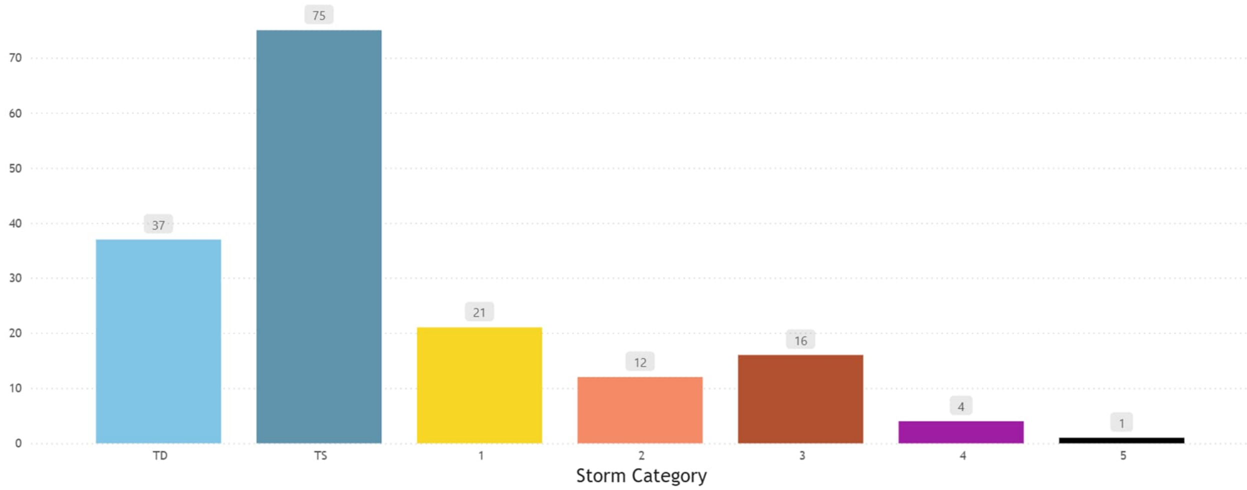
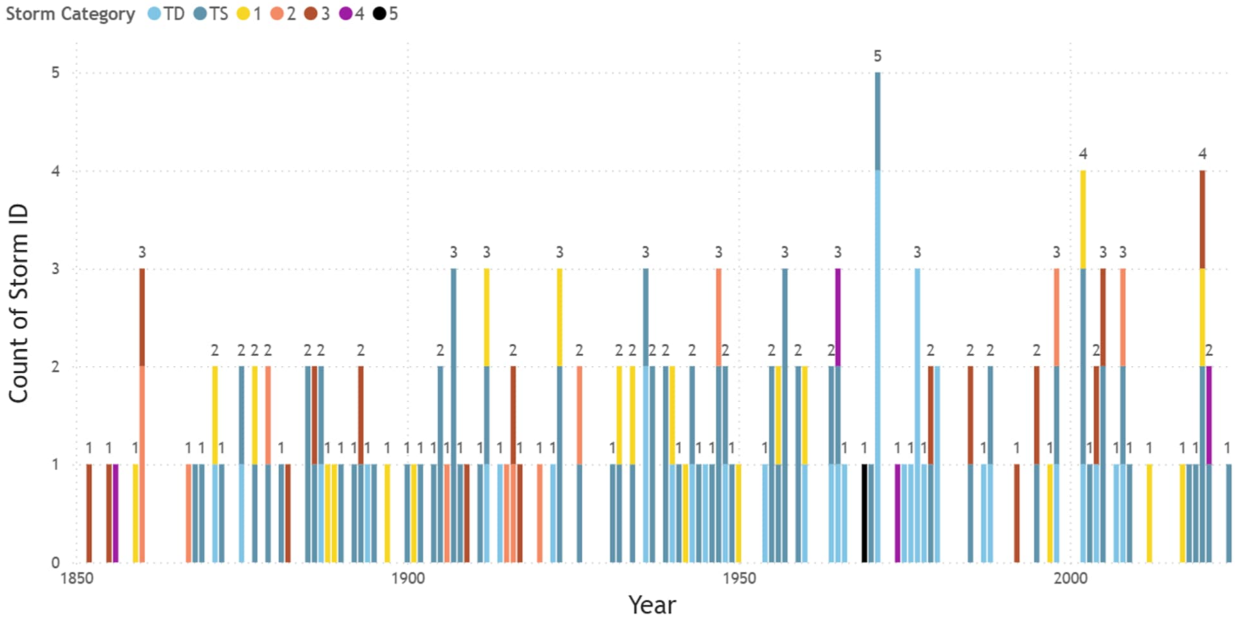


Figure 4-2 shows a total of 166 storm eyes came within 150 miles of Entergy New Orleans' service area since 1851. Of those, 26 storm eyes came directly through Entergy New Orleans' service area. Approximately three percent of storms were Category 4 or higher. Approximately 17 percent were Category 2 or 3 storms, and Category 1 storms make up 13 percent of the events. 67 percent of the events are Tropical Storms or Tropical Depressions.

Figure 4-3 shows storm count by category for all 166 major events for each year since 1851. The figure shows that storm activity over the past 170 years has varied from year to year. Some years may see as low as zero storms events with others as high as five.

[12] Source: https://coast.noaa.gov/hurricanes/ with analysis by 1898 & Co.

Figure 4-3: Count of Hurricanes for Entergy New Orleans System by Year[13]



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 New Orleans service area. Figure 4-4 and Figure 4-5 show the hurricane activity in Entergy New Orleans' service area over time using a 10-year and 100-year rolling average, respectively.

Figure 4-4 shows the sum of all the hurricanes occurring in that year and the nine years before, for example from 2015-2024. It is further broken down into storm categories. The 2024 column on the far right shows 10 storms hit New Orleans from 2015 to 2024. The rolling 10-year average profile from 1950 to 2024 shows wide swings in major storm counts and types. For instance, the period from 2009 to 2018 saw only four storms, with no Category 2 or above storms, and the period 2015 to 2024 saw 10 storms, with two Category 2 or higher storms. No Category 5 storms hit the system since the 1969 to 1978 10-year period. While it may be tempting to focus on the last 10 years of storm activity to start understanding storm frequency, the figure 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.

---

[13] *Id.*

Figure 4-4: 10-Year Rolling Count of Hurricanes for Entergy New Orleans' System[14]

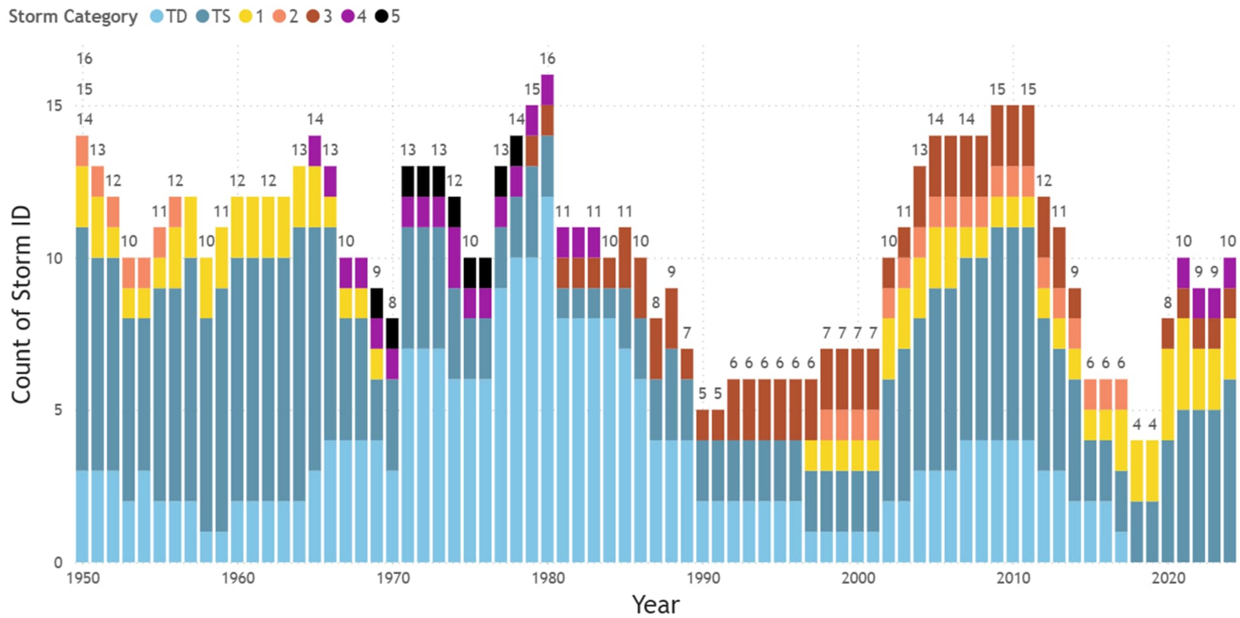


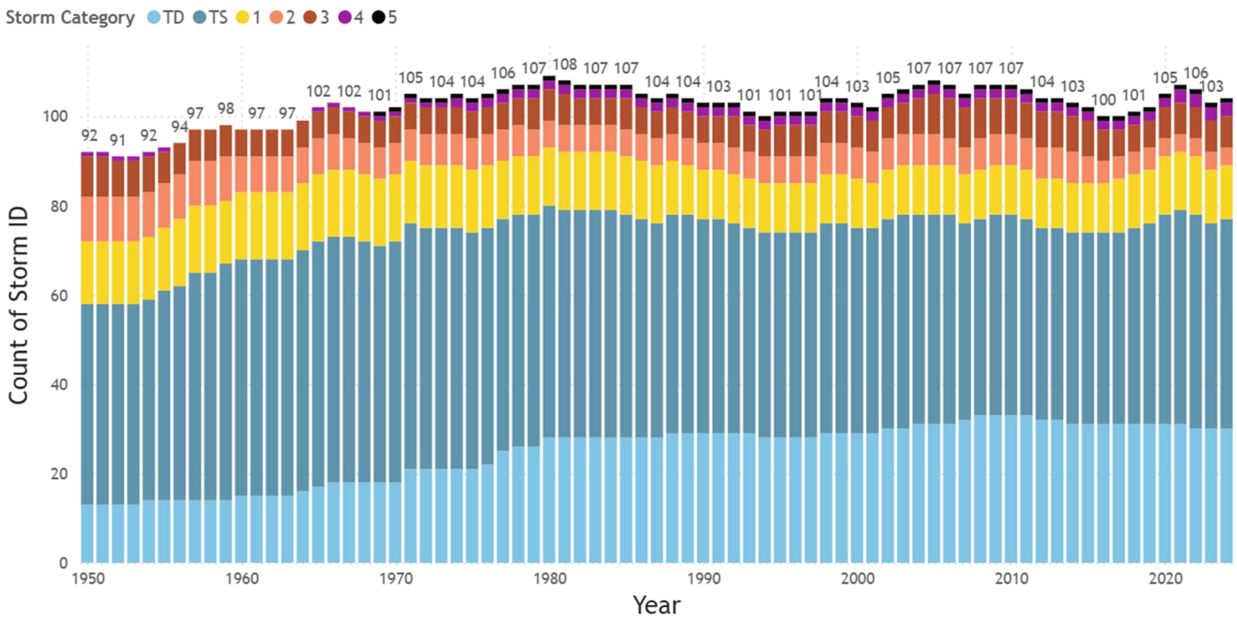
Figure 4-5 depicts the 100-year rolling count of storms. For a resilience-based assessment, this time horizon provides insights for those 'one in a 100-year' types of devastating events while also including 'one in 20' and 'one in 70' and more regularly occurring events. As the figure shows, the variability between high and low storm activity periods is much lower, ranging from a low of 91 storms to a high of 109. Analysis of the overall storm count activity from the figure shows:

1. Activity generally increasing from the 1851-1950 period (92 storms) to the 1881-1980 period (109 storms). That is an increase of 17 storms (109-92) over a 30-year period (1980-1950).
2. Activity generally decreasing from the 1881-1980 period (109 storms) to the 1895-1994 period (100 storms). That is a decrease of nine storms (109-100) over a 14-year period (1994-1980).
3. Activity generally increasing from the 1895-1994 period (100 storms) to the 1910-2009 period (107 storms). That is an increase of seven storms (107-100) over a 15-year period (2009-1994).

The figure also shows the relative consistency of the mix of storm activity over the period.

[14] See footnote 12

Figure 4-5: 100-Year Rolling Count of Hurricanes for Entergy New Orleans' System[15]



4.1.2 Storm Count and Types: NOAA Extreme Weather Events

The extreme weather events within the Major Events Database include non-named, non-hurricane events (e.g., thunderstorms and ice storms) going back to 1998. This database helped identify the types and expected frequency of different extreme weather events impacting the Entergy New Orleans service area.

The NOAA extreme weather database records events at the parish or sub-parish level. 1898 & Co. mined this data for Orleans Parish. The database includes several types of weather-based events and their definitions from NOAA for Entergy New Orleans' service area, described in Appendix A.

Figure 4-6 includes the summary results from the extreme weather NOAA database of storms to hit the Entergy New Orleans service area from 1998 to 2024.

[15] See footnote 12

Figure 4-6: Extreme Weather Events in Entergy New Orleans' Service Area since 1998

Of the extreme weather events to impact Entergy New Orleans' service area, thunderstorm wind events are the most common. Thunderstorm wind events were subdivided into Thunderstorm Wind and Extreme Thunderstorm Wind. The Extreme Thunderstorm Wind events tend to cause the majority of the outages and damage throughout the territory attributed to non-hurricane MEDs.

4.2 Storm Activity and Service Area Merging

The next step in developing the Major Events Database was to understand the various storm activity types, their intensity, and how they mapped to Entergy New Orleans. It is important to note that hurricane events can be over 300 miles wide.

To better understand the historical frequency and intensity of various major events in the Entergy New Orleans service area, 1898 & Co. focused the analysis on Orleans Parish.

The parish-based storm assessment methodology allows analysis of major event intensity across the Entergy New Orleans service territory. The parish approach is necessary to understand storm intensity against the infrastructure (represented by the parish) for the following drivers:

- Hurricane category or extreme weather event type
- Hurricane distance
- Hurricane side (right / left)

The parish approach also allows the mapping of storms to the Entergy New Orleans service territory from the NOAA Storm Events Database, which reports events at the parish level.

4.2.1 Storm Intensity Factors

4.2.1.1 Storm Category

The category of a hurricane as it encounters the infrastructure is the first key driver of the expected consequence of an event. As the hurricane paths show from Figure 4-1, the category changes as it moves through the service area and loses energy. Table 4-1 shows each category and the associated sustained wind speeds as well as the Major Event Day category for reference.

Table 4-1: 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 Hurricane Distance

The distance of the hurricane as it encounters the infrastructure is the second key driver of the expected consequence of an event. The closer the hurricane is to the infrastructure, the more the expected damage. However, hurricanes can be nearly 300 miles wide causing damage to infrastructure that is 150 miles away from the hurricane center as a few hurricane bands come across the service area. Because of this wide range, the Major Events Database categorizes the second hurricane intensity factor into the following categories:

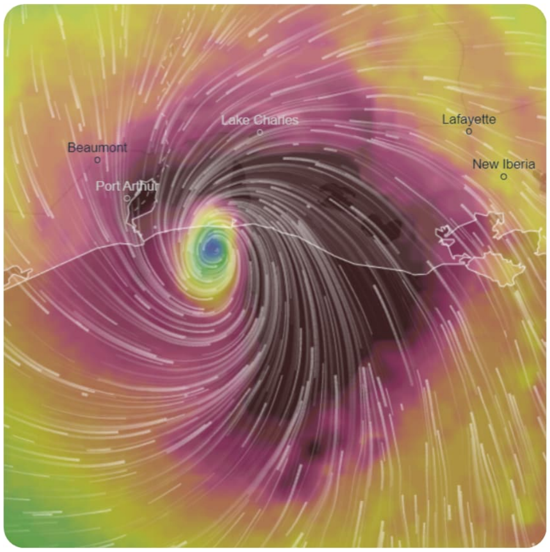
- 'Direct Hits' are defined by when the eye of the hurricane comes within a 25-mile radius from the parish centroid in any direction. The max wind speed hits all or significant portions of the parish twice, once from the front end and again on the back end of the hurricane. Additionally, the wind speeds cause the assets and vegetation to move in one direction as the hurricane 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 hurricane comes within 26 to 50-mile radius from the parish centroid in any direction. In many cases, assets experience opposite directional wind as the hurricane moves through the area, exposing the system to significant potential damage.
- 'Partial Hits' are defined by when the eye of the hurricane comes within 51 to 100-mile radius from the parish centroid in any direction. At this distance, the hurricane bands hit a significant portion of the assets in a parish. The hurricane 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 hurricanes, the 'Partial Hit' could still cause more damage than a 'Direct Hit' from a small hurricane.
- 'Peripheral Hits' are defined by when the eye of the hurricane comes within 101 to 150-mile radius from the parish centroid in any direction. Since hurricanes can be 300 miles wide in diameter, some hurricane bands can hit a fairly large portion of the system, even if the main body of the hurricane misses Orleans Parish. Very strong winds still comprise these hurricane bands for large hurricanes, but the damage is less than a 'Partial Hit' of the same strength and side.

4.2.1.3 Hurricane Side

The third intensity factor included within the Major Events Database is the side of the hurricane 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 hurricane cause more damage to assets on that side of the hurricane than those assets equidistant from the eye on the left side.

The figure below depicts this effect; the hurricane's eye is the blue dot in the middle of the red. The right side of the hurricane is a darker red than the left side, which shows the winds are faster there than on the pink/orange left side of the hurricane.

Figure 4-7: Hurricane Wind Strength Heat Map[16]



4.2.2 Storm Types

Combining all the permutations from the three hurricane activity intensity factors outlined above produces 45 different storm types included within the Major Events Database. Table 4-2 shows the 45 different storm types. Direct hits are categorized under the right-side table. Tropical Depressions are not included within the 26-150-mile range since they are typically smaller events. Similarly, MED (extreme weather) events are only within the 'Direct Hit' distance.

16 Sourced from Ventusky (https://www.ventusky.com/?p=29.43;-94.05;8&l=gust&t=20200827/0600)

Table 4-2: Storm Types

Category	Right / Strong Side of the Storm Distance (miles from parish centroid to storm eye) 25 (Direct)	50	100	150
5	1	10	22	34
4	2	11	23	35
3	3	12	24	36
2	4	13	25	37
1	5	14	26	38
TS	6	15	27	39
TD	7			
MED	8			
100-Year Flood	9			
Category	**Left / Weak Side of the Storm Distance (miles from parish centroid to storm eye) 25 (Direct)**	**50**	**100**	**150**
5		16	28	40
4		17	29	41
3		18	30	42
2		19	31	43
1		20	32	44
TS		21	33	45
TD				
MED				
100-Year Flood				

4.2.3 Capturing Storm Types Against Parishes

1898 & Co. utilized geospatial analytics to identify the historical count of the 45 different storm types against Orleans Parish based on the Hurricanes and Extreme Weather datasets available for download from NOAA's website. The basis for the hurricane analytics was to capture the storm's intensity factors as it is closest to a given parish. For each hurricane over the past 170 years, 1898 & Co. identified the storm's category, distance from the centroid of Orleans Parish, and side of the event. Figure 4-8 provides an illustration of the approach for Orleans Parish.

Figure 4-8: Geospatial Analytics Approach Illustration

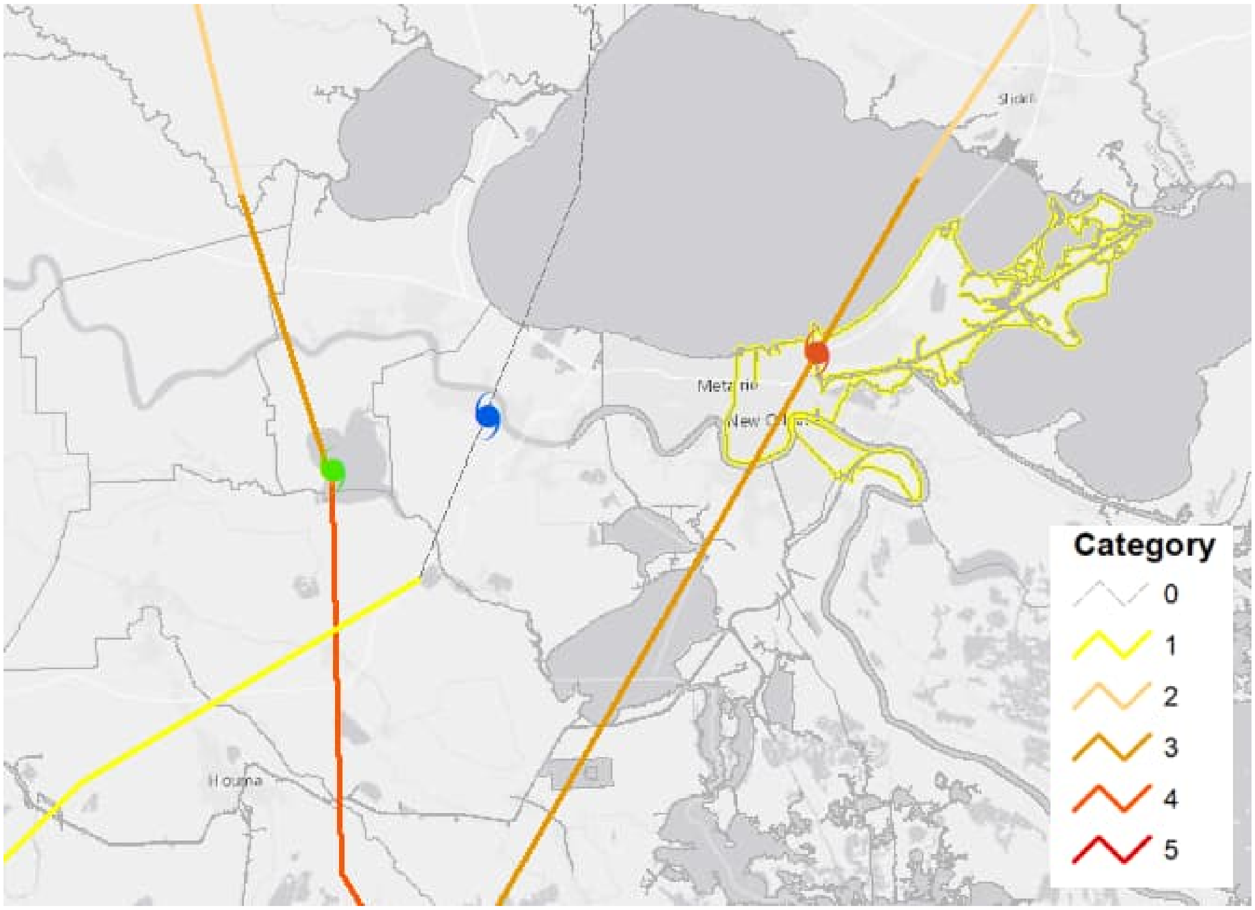


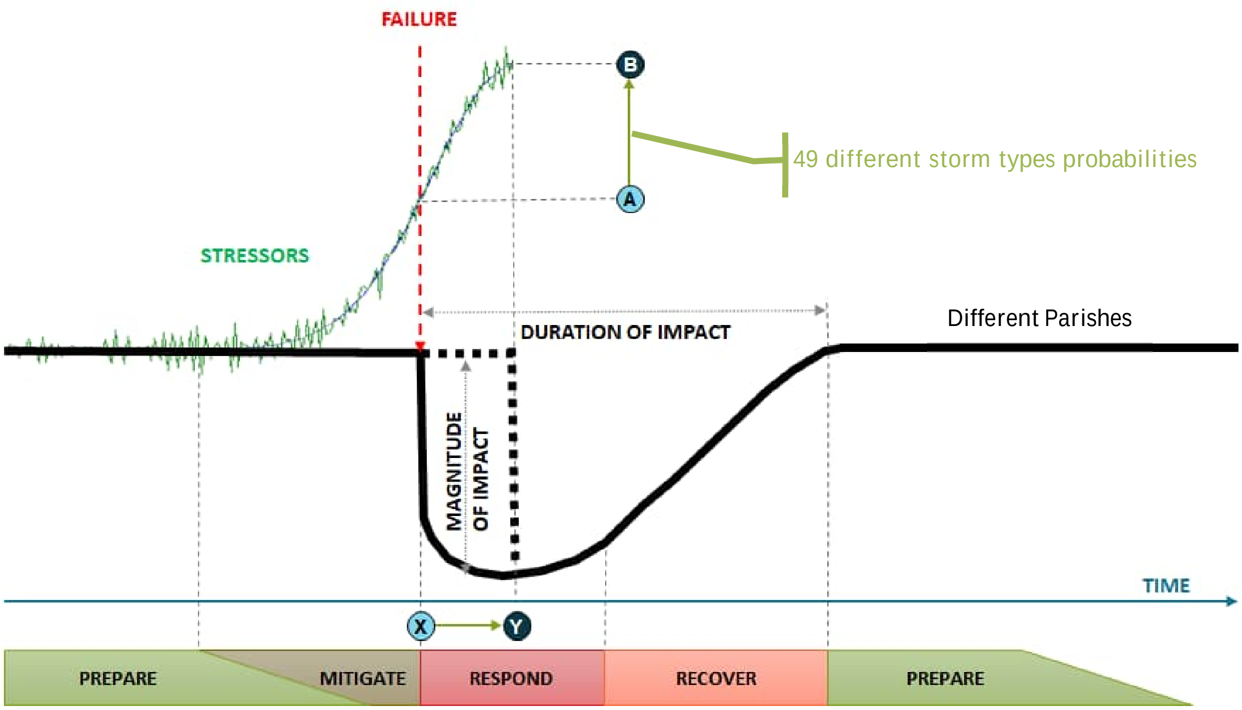
Table 4-3: Hurricane Statistics for Orleans Parish for Recent Storms

Name	Time	Storm Location	Storm Side	Storm Category	Storm Distance (miles)	Storm Distance Bucket (miles)
Zeta	10/28/2020 21:00	W	Right	3	4.1	50
Francine	9/12/2024 3:00	W	Right	TS	30.4	50
Ida	8/30/2021 1:00	W	Right	3	41.6	50

4.2.4 Major Events Database and Resilience Framework

The Major Events Database includes 45 different storm types or “stressors” that could impact Orleans Parish. Figure 4-9 depicts how the duration and magnitude of these impacts map to the phases of resilience concept that serves as the theory behind the Resilience Model approach to evaluating system vulnerability and benefits of hardening investments. Section 4.3 shows the approach to forecast the frequency and consequences of each of the 45 storm types for Orleans Parish. Section 4.4 outlines the expected impacts for each of the storm types.

Figure 4-9: Phases of Resilience Framework & Major Event Database



4.3 Estimating Future Event Frequency & Consequences

To estimate the future probabilities of the 45 storm types within the Major Events Database, 1898 & Co. utilized the historical record from NOAA. The future frequency of events is based on the time period from 1851 to 2024, 174 years.

The Major Events Database includes probabilities for each of the 45 storm types. As discussed in Section 6.3, the 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 4-10 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 parish. As shown in the figure, annual chances of direct hits have been slowly increasing over the last several decades.

Figure 4-10: 'Direct Hit' Probabilities for Orleans Parish

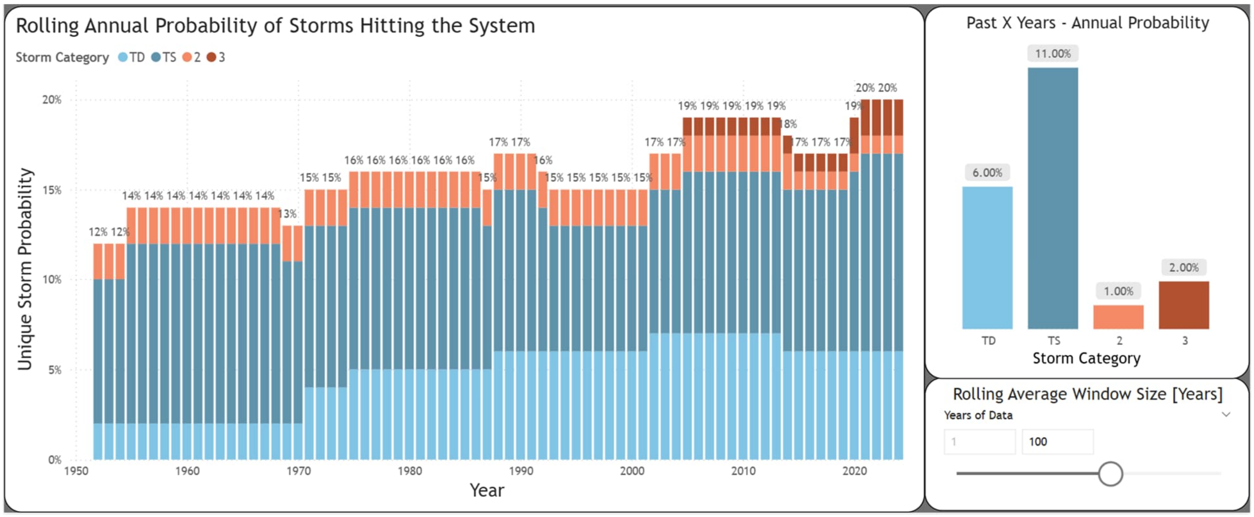


Figure 4-11, Figure 4-12, and Figure 4-13 show similar probabilities for Orleans Parish for 'Near Direct Hits' (26 to 50 miles), 'Partial Hits' (51 to 100 miles), and 'Peripheral Hits' (101 – 150 miles), respectively. Like direct hit probabilities, near direct hit probabilities have been gradually increasing over the last several decades. Partial hit probabilities have been slowly declining over the last several decades, while peripheral hit probabilities have remained steady.

Figure 4-11: ‘Near Direct Hit’ Probabilities for Orleans Parish

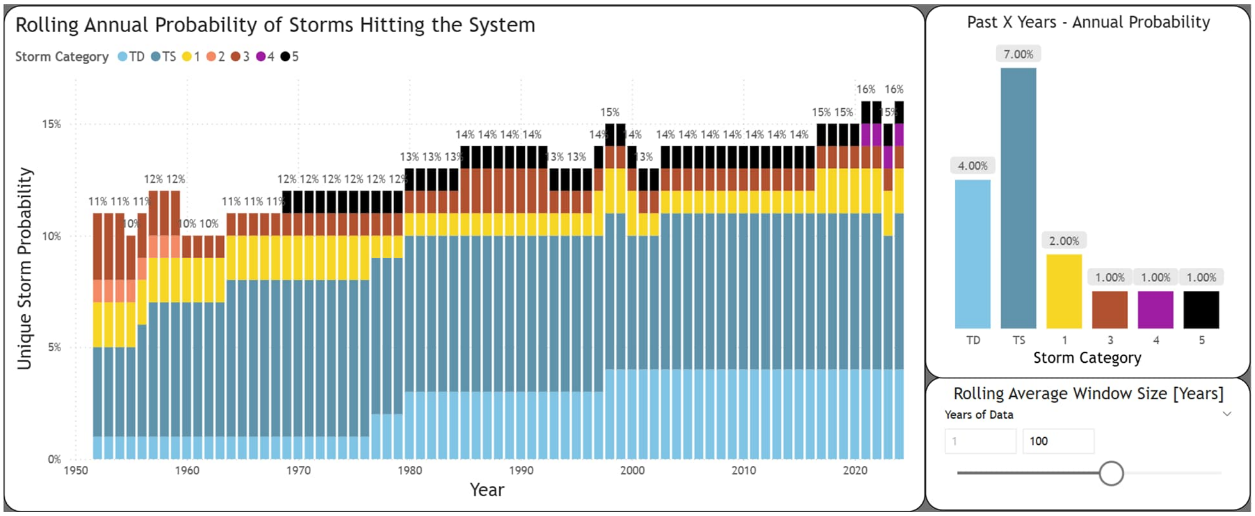


Figure 4-12: ‘Partial Hit’ Probabilities for Orleans Parish

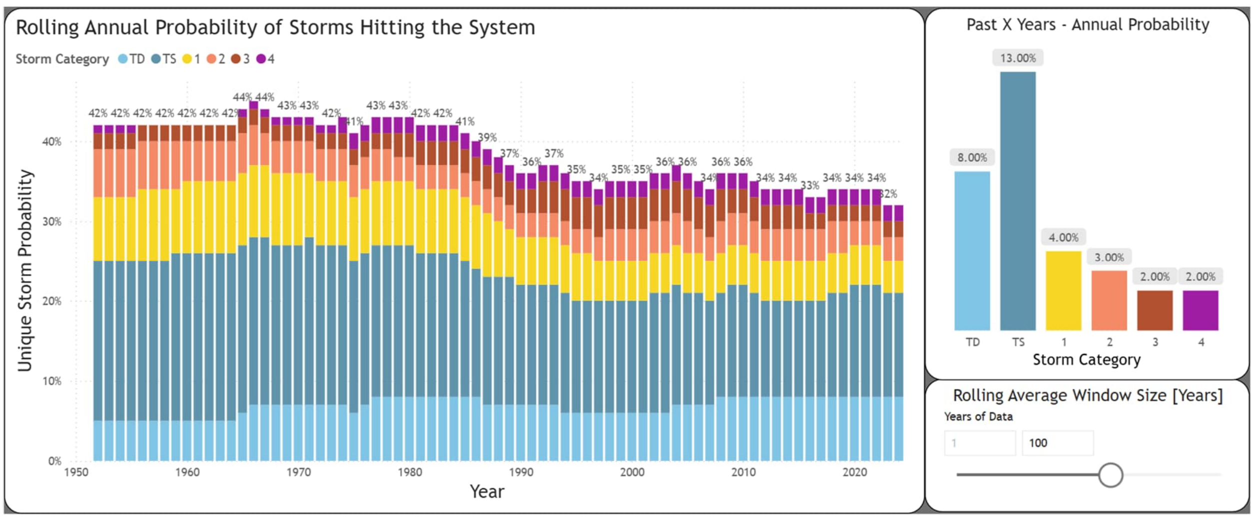
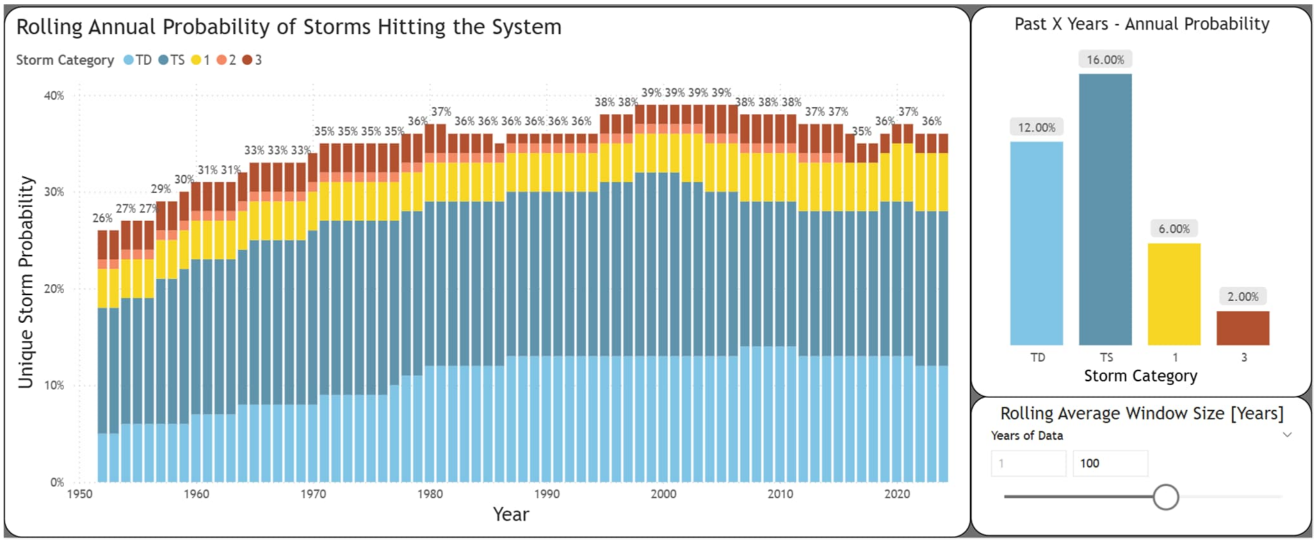


Figure 4-13: 'Peripheral Hit' Probabilities for Orleans Parish



4.3.2 Hurricane Path Uncertainty

Due to the random nature of storm paths and variation in intensity as storms travel through the area, some parishes may see no strong storms over the entire 170 years of data. However, their neighbors may see multiple strong storms. The Major Events Database accounts for the possibility that a storm could have taken a different path or had a stronger intensity by shifting or upgrading historical storms and adding them to the pool of possible storms to draw from to create the 1,000 storm futures.

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 New Orleans service area is ever evolving with a changing 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 New Orleans' system if it were to happen today because the customer base and system are completely different. For this reason, the Major Events Database leverages more recent event consequences 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 Events Database includes impact assumptions around the following three categories for each of the 45 storm types to impact the system:

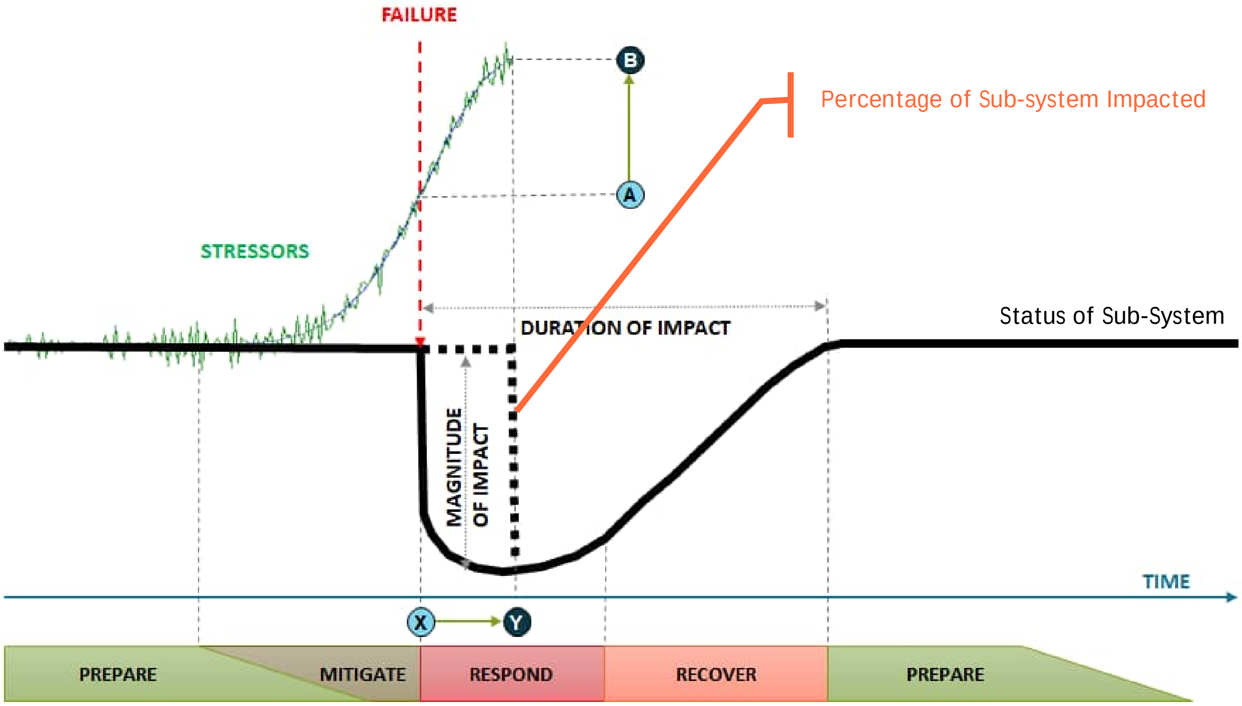
- LOF percentage for each hardening zone impacted
- Duration to restore each hardening zone
- Cost to restore each hardening zone

The next section outlines the historical major event impacts. This information was foundational in developing the three impacts outlined above. The following sections describe each of the impacts that are part of the Major Events Database.

4.4.1 Expected Hardening Zone Impacts

The Major Events Database represents the state of the system in terms of magnitude of impact to a sub-system (representative system segment) in alignment with the resilience framework in Figure 2-1 and shown below in Figure 4-14.

Figure 4-14: Phases of Resilience Framework & Sub-System Impact

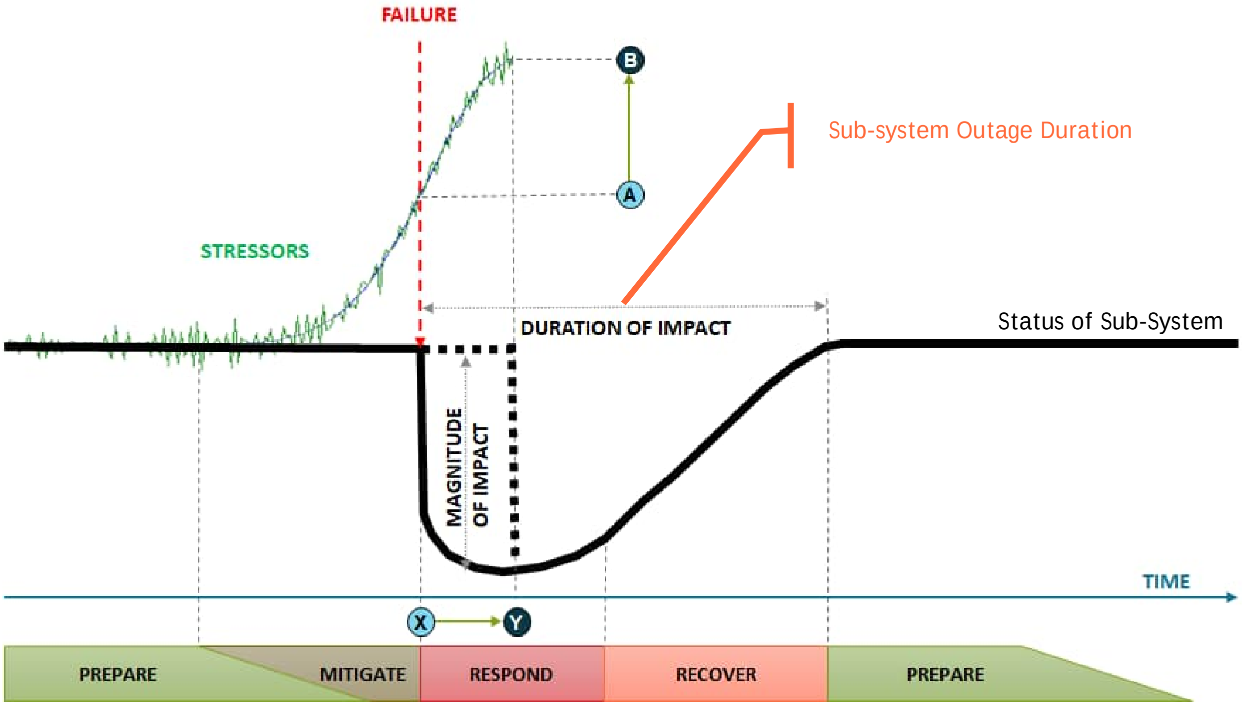


For each of the 45 storm types (stressors or the 'green' line from Figure 4-14), the database includes the expected range of impacts at the parish level for each hardening zone.

4.4.2 Major Event Duration

The Major Events Database also includes the expected restoration profiles for each of the hardening zones for each of the 45 storm types ('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 in Figure 2-1 and shown below in Figure 4-15.

Figure 4-15: Phases of Resilience Framework & Sub-System Duration

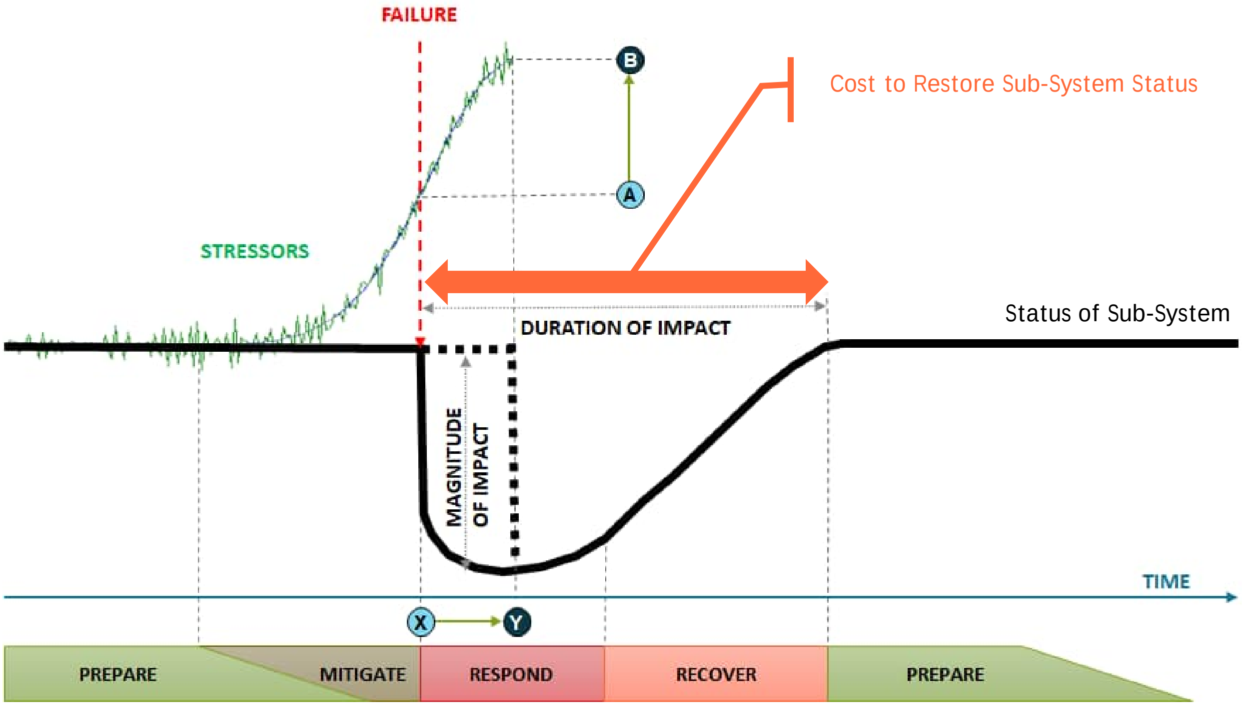


1898 & Co. and Entergy New Orleans developed the expected total duration of each of the 45 storm types ('stressors') to impact Orleans parish. The overall durations are in alignment to historical events from the last 15 years, linearly interpolating for major events that have not occurred in the recent past. For the duration of restoration for each hardening zone, the database includes historical experience from recent restoration efforts. These restoration profiles are critical for the calculation of customer outages completed within the Event Impact Model. The Event 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.

4.4.3 Major Event Restoration Cost

The third impact category included in the Major Events Database is the expected restoration costs for each of the 45 storm types ('stressors'). Figure 4-16 depicts the storm impact within the phase of resilience framework.

Figure 4-16: Phases of Resilience Framework & Sub-System Restoration Costs



The database includes estimated restoration costs for each hardening zone based on estimated restoration costs for each of the 45 storm types. For distribution circuits and transmission circuits, the database includes a similar approach to estimating the expected restoration costs for each of the events and parishes. The database factors in the following to estimate restoration costs for each of the 45 storm types and hardening zones:

- Structure count and type within the hardening zone. Hardening zones with high asset counts will have more failures and restoration costs. Additionally, some structures are more costly to restore like a lattice tower versus a wood mono pole.
- Entergy Crews versus 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, and 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 New Orleans also relies 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 45 storm types based on these multipliers.

- Side of the storm impacting the hardening zone (right or left side). The right side of a storm causes more damage than the left side of the storm.
- Structure current wind loading versus hardening wind loading standards. Hardening zones with assets that meet more recent hardened wind loading standards will have fewer failures than hardening zones where the assets' current wind loading rating has a wide gap to the hardening standard. See Section 3.5 for additional details.
- Vegetation density around the infrastructure in the hardening zone. The existence of more dense vegetation around infrastructure will drive more failures because wind blowing vegetation into circuits is a key driver of storm-based outages. See Section 3.4 for additional details.
- Age of the infrastructure in the hardening zone. Hardening zones with infrastructure that is older are more likely to have higher instances of asset failures than hardening zones with younger assets. See Section 3.6 for additional details.
- Right-of-Way access for the infrastructure in the hardening zone. 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 Events Database includes a framework to incorporate these factors to estimate the expected range in restoration costs for each of the 45 storm types to impact each of the hardening zones.

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.

5.0 System Vulnerability & Event Impact Model

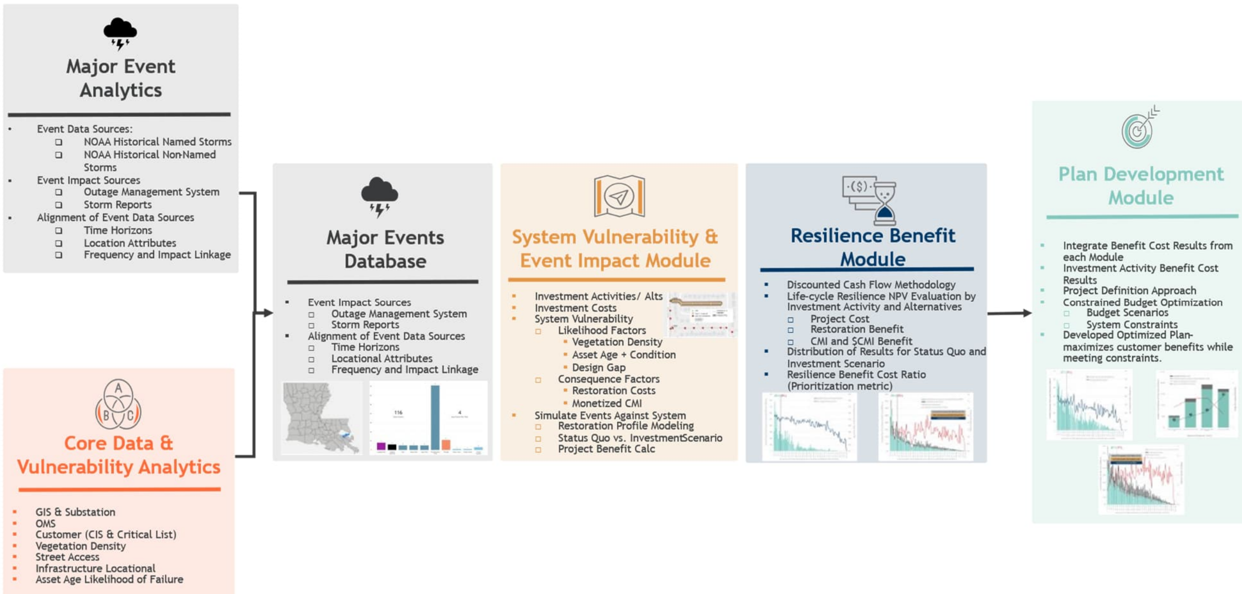
The second major component of the Resilience Model is the System Vulnerability & Event Impact Module. Whereas the Major Events Database describes the phases of resilience at a high level for the Entergy New Orleans system, the EIM goes a layer deeper and develops the phases of resilience for each potential hardening zone on the Entergy New Orleans system for each storm scenario.

The EIM 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 Events Database. The model also estimates the restoration costs associated with the specific hardening zone failures and calculates the impact to customers in terms of CMI. Finally, the EIM models each storm event for both a Status Quo and Hardened Scenario(s). The Hardened Scenario(s) assumes the assets that make up each hardening zone have been hardened. The EIM then calculates the benefit of each hardening zone from a reduced restoration cost and CMI perspective.

The EIM utilizes a robust and sophisticated set of data and algorithms to model the benefits of each hardening zone for each storm scenario. Section 3.0 outlines the core data, algorithms, and frameworks that are part of the EIM, and also outlines a very granular level of analysis of the Entergy New Orleans system. This granular level of data and analysis allows for the 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 Resilience Model architecture. The Major Events Database is described in Section 4.0, and the Resilience Benefit Module is described in Section 6.0. The following sections describe the EIM in further detail.

Figure 5-1: Resilience Model



5.1 Core Data Sets and Algorithms

The core data sets and algorithms that feed into the EIM are described in further detail in Section 3.0.

5.2 Likelihood of Failure

The System Vulnerability component of the EIM identifies the parts of the system that are likely to fail given the specific storm loaded from the Major Events Database. The module is grounded in the primary failure mode of the asset base; storm surge for substations; and wind, structure design gaps, asset age, and vegetation for circuit assets.

5.2.1 Substation Storm Likelihood of Failure

A main driver of substation failures during major storm events is storm surge and general flooding. The Major Events Database designates the number of substations expected to experience flooding for each of the 45 storm types.

To identify which substations would be the most likely to experience flooding, the EIM 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. The flood modeling has flood height data for all five hurricane category types. The EIM uses the flooding height values as likelihood scores to identify the substation probability of failure for each storm event in the Major Events Database.

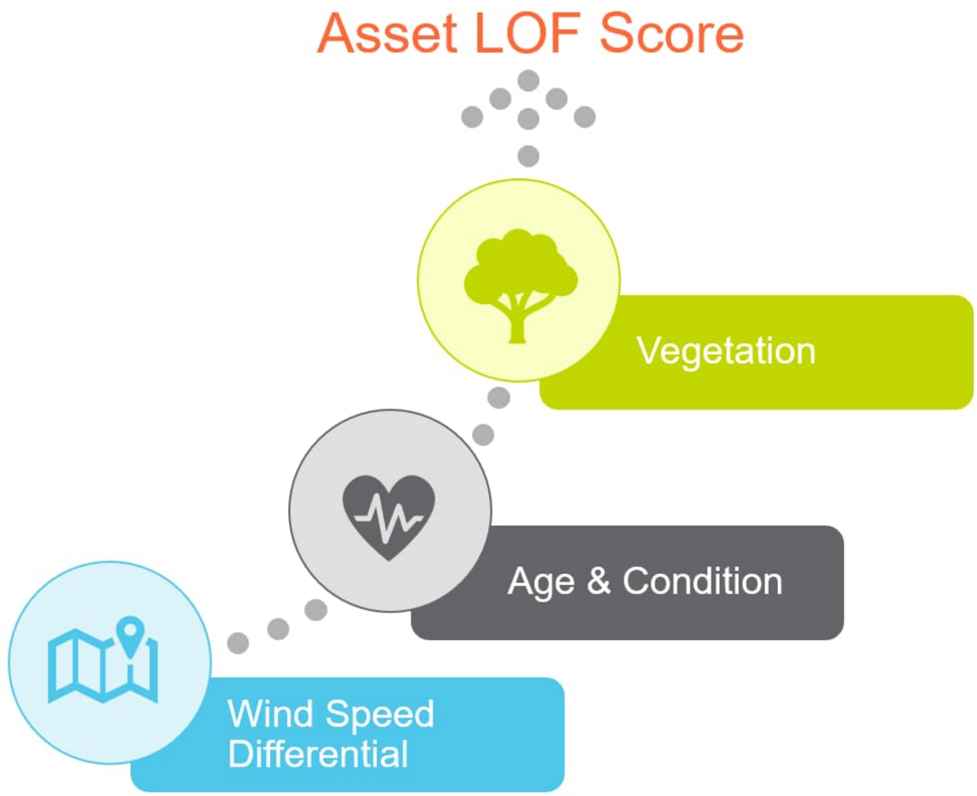
5.2.2 Circuits Storm Likelihood of Failure

A 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 for each circuit asset on Entergy New Orleans' T&D system. Assets included within the framework are wood poles, steel poles, concrete poles, and lattice towers.

For the vegetation LOF scores, the EIM 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 1,300 miles of 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



The EIM estimates the LOF for each wood and metal structure on the system. Section 3.6 includes additional details on the approach.

The wind design gap criteria use the wind zone designation data from Section 3.5 inside the asset LOF framework to develop the LOF scores.

The EIM uses the three criteria (vegetation, age, and wind design gap) to calculate the storm LOF for each asset. The assets LOF for each storm are used to provide a granular understanding of the LOF for each hardening zone. The EIM uses the hardening zone LOF for each storm event in the Major Events Database.

5.3 Hardening Zone & Asset Reactive Storm Restoration

The EIM estimates the cost to repair assets from a storm-based failure. Storm restoration costs were calculated for every asset in the EIM including wood poles, transmission structures (steel, concrete, and lattice), power transformers, relays, and breakers. The costs were based on storm restoration costs multipliers above planned replacement costs. These multipliers were developed by Entergy New Orleans and 1898 & Co. collaboratively. They are based on historical events, the expected inventory constraints, and expected mix of Entergy New Orleans and non-Entergy New Orleans 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 hardening zone level and then weighted based on the hardening zone 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 EIM calculates the duration to restore each hardening zone in the Status Quo Scenario. The assumptions for major asset class outage duration are outlined in the Major Event Storms Database. The hardening zones are ranked for restoration by metrics that are similar to those that Entergy New Orleans uses to prioritize storm restoration activity, such as priority/critical customers and customer count. Specific hardening zone durations are calculated based on completion versus time curves. For example, a lateral hardening zone may have a relatively high priority (i.e., customer count is high with more critical customers). That lateral would be restored by day 10 for a Category 4 event. However, the lowest ranked laterals will have durations in the 30-day range for this category storm event.

The hardening zone duration is then multiplied by the number of affected customers for each hardening zone (see Section 3.3) to calculate the CMI for each hardening zone. 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 large numbers of customer outages across the area from the transmission system.

Finally, the CMI for each hardening zone for each storm event is monetized using the DOE's ICE Calculator (see Section 3.9). The monetization is performed for each type of customer: residential, small commercial and industrial, large commercial and industrial, and the various priority customers. The monetization of CMI is calculated for hardening zone prioritization purposes as discussed below in Section 6.0.

5.5 Status Quo and Hardening Scenarios

The EIM calculates the storm restoration costs and CMI for the Status Quo and Hardening Scenarios for each hardening zone for each of the 45 storm types. The delta between the two scenarios is the benefit for each hardening zone. 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 hardening zone.

The output from the EIM is a hardening zone-by-hardening zone, probability-weighted estimate of annual storm restoration costs, annual CMI, and annual monetized CMI for both the Status Quo and Hardened Scenarios for all 45 storm types. The following section describes the methodology utilized to model all 45 storm types and calculate the resilience benefit of each hardening zone.

6.0 Resilience Benefit Module

The Resilience Benefit Module of the Resilience Model uses the annual benefit results of the System Vulnerability & Event Impact Module and the estimated hardening zone costs to calculate the net benefits for each hardening zone. Since the benefits for each hardening zone are dependent on the type and frequency of major storm activity, the Resilience Benefit Module utilizes stochastic modeling, or Monte Carlo Simulation, to select a thousand future worlds of 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 zones.

The following sections provide additional detail on the hardening zone costs, Monte Carlo Simulation, and feeder and lateral hardening.

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 percent

6.2 Hardening Zone Cost

Hardening zone costs were estimated for the approximately 4,200 hardening zones in the Resilience Model.[17] Certain hardening zone costs were provided by Entergy New Orleans while others were estimated using the data within the Resilience Model to estimate scope (asset counts and lengths) and then multiplying by unit cost estimates to calculate the hardening zone costs. The following sub-sections outline the approach to calculate hardening zone costs for each of the programs.

6.2.1 Distribution Feeder and Lateral Hardening

6.2.1.1 Rebuild

For each hardening zone, Entergy New Orleans' GIS data, GIS analysis for vegetation, underlying terrain, and road access were leveraged to estimate:

[17] *See supra*, note 2.

- 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 hardening zones. 1898 & Co. collaborated with Entergy New Orleans 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 hardening zone cost.

6.2.1.2 Overhead to Underground Conversion

For each express feed, Entergy New Orleans' GIS data was used to determine the length of overhead conductor to be converted to underground. The length was multiplied by the Entergy New Orleans cost per mile to develop the total hardening zone cost.

6.2.2 Transmission Rebuild

For each transmission hardening zone, Entergy New Orleans' GIS data, GIS analysis for vegetation, underlying terrain, and road access were leveraged to estimate:

- Number of wood 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 hardening zones. 1898 & Co. collaborated with Entergy New Orleans 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 hardening zone cost.

6.2.3 Substation Storm Surge and Flood Mitigation

Substations are a complex system of assets. Although the modeling done by 1898 & Co. identifies substations that are at risk of storm surge or flooding, the mitigation measures required may differ widely from substation to substation. Therefore, the costs can vary widely as well. Entergy New Orleans provided a base cost for substation storm surge mitigation hardening zones that was intended to be generally conservative.

6.3 Resilience-Weighted Lifecycle Benefit

The benefits of storm resilience hardening zones 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 Resilience Model employs stochastic modeling, specifically Monte Carlo Simulation, which is a random sampling methodology.

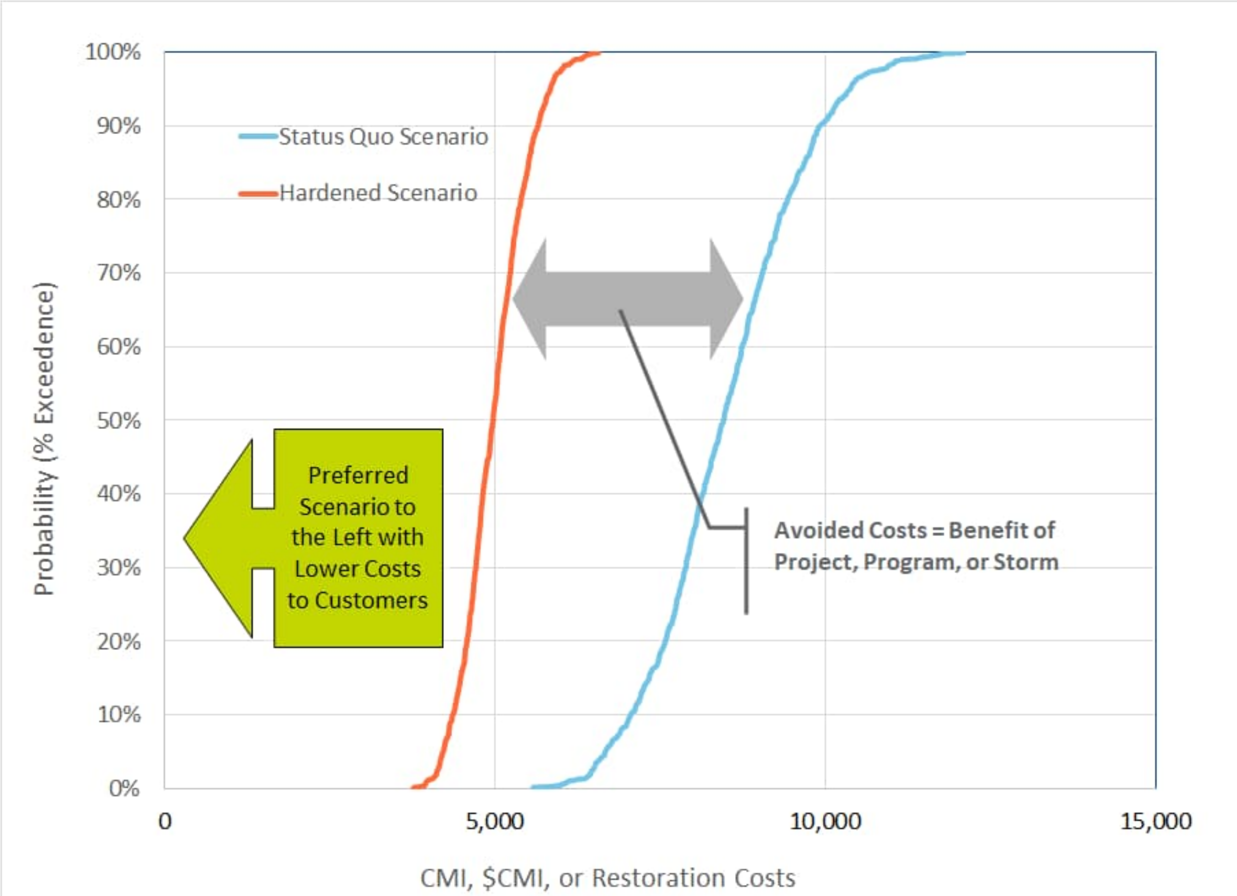
In the context of the Resilience Model, the Monte Carlo simulator selects the major storm events to impact the Entergy New Orleans service area over the next 50 years from the Major Events Database (see Section 4.2.4). That database outlines the 'universe' of storm event types that could impact the Entergy New Orleans service area.

During the Monte Carlo simulation, Orleans Parish is subjected to the range of 45 storm types and frequencies discussed in Section 4.0. For each iteration, the Monte Carlo simulator considers the historical record of the storms that have come within the 150-mile range of the Entergy New Orleans service area. Using this historical record, the Monte Carlo simulator develops 1,000 iterations of 50-year storm futures. Each storm future has a 50-year profile of storm events from the 45 storm types.

Once the iterations are completed, the Resilience Benefit Module determines the benefits that each hardening zone provides annually under each iteration and storm event. Using information from the EIM, the Resilience Benefit Module chooses a Status Quo value for each hardening zone and the benefits if that hardening zone were to be hardened, both under the same storm type.

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 hardening zone, 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 Hardening Zone Selection

7.1 Investment Optimization

The Resilience Model evaluates the benefits of all potential hardening zones 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 approximately 4,200 hardening zones.[18] 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 – hardening zone 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-based 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

With all the hardening zones being evaluated on a consistent basis, they can all be ranked against each other and compared. The Resilience Model ranks all the hardening zones 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

[18] *See supra*, note 2.

Performing prioritization for the four benefit cost ratios is important since each hardening zone has a different slope in its benefits from an average storm future to a very high storm future. Entergy New Orleans and 1898 & Co. settled on weighting the three values for the base prioritization metric.

7.2 Comprehensive Hardening Plan Portfolio Development

With a resilience plan investment level identified, additional factors were incorporated to develop a recommended plan that is feasible, given what information Entergy New Orleans has regarding supply chain, labor, and other market conditions. Annual equipment installation limits are imposed on the portfolio based on projected material supply availability in upcoming years for structures and transformers. All hardening zones on a given circuit must be completed in a 2-year window. This helps organize and sequence hardening zones so that crews can be efficiently mobilized and demobilized around the system to construct the portfolio.

8.0 Results & Conclusions

Entergy New Orleans 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 as determined by the foregoing analysis. 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 DOE's ICE Calculator, modified for resilience. The DOE's ICE Calculator is discussed in Section 3.9. The monetization of the CMI allows for the calculation of a benefit cost ratio for each hardening zone. As discussed above, this was done for the purposes of prioritization of hardening zones and establishing overall investment levels for consideration.

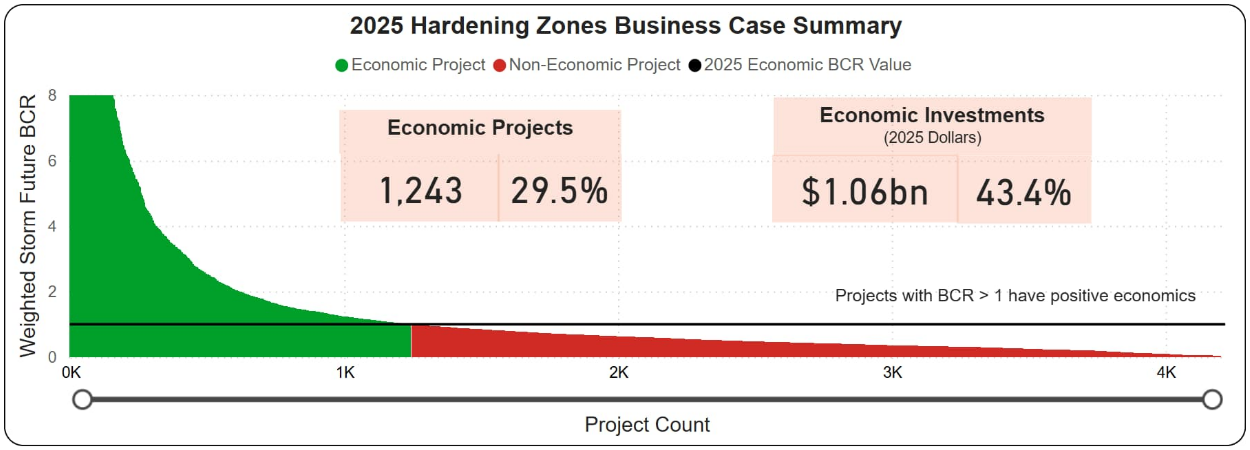
8.1 Resilience Benefit Cost Ratio

As discussed above in Section 7.1, the Resilience Model calculates the Resilience Benefit Cost Ratio for hardening zone prioritization purposes. The Resilience BCR is the sum of the avoided restoration cost and the monetized avoided customer outages divided by the hardening zone cost. A weighted value of the BCRs for different storm futures is used to calculate the final Resilience Benefit Cost Ratio for each hardening zone.

Figure 8-1 shows the results of the Resilience Benefit Cost Ratio for all potential hardening zones across the Entergy New Orleans service territory. For each alternative (e.g. hardened rebuild versus undergrounding), the model determined a BCR, and the higher BCR is preferred. The preferred potential hardening zone is the overhead hardening or undergrounding alternative that provides the higher Resilience Benefit Cost Ratio. The figure shows approximately 4,200 potential hardening zones were included in the evaluation.[19] The figure shows that approximately 30 percent of the potential hardening zones (by hardening zone count) have a Resilience Benefit Cost Ratio greater than 1. The figure also shows that approximately $1.06 billion of investment has a Resilience Benefit Cost Ratio greater than 1. This is equivalent to 43 percent of the total hardening investments across all potential hardening zones.

[19] *See supra*, note 2.

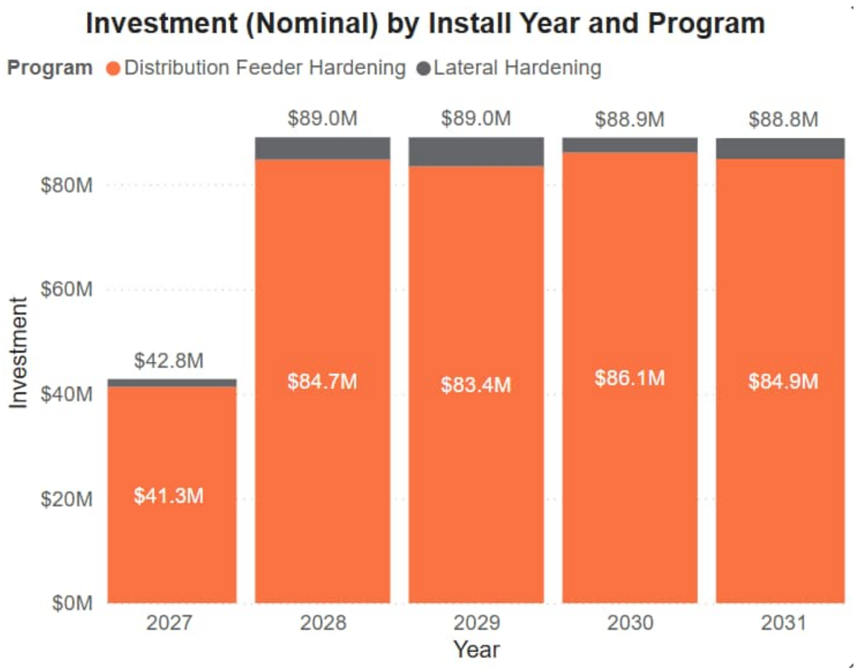
Figure 8-1: Hardening Zone Resilience Benefit Cost Ratio Summary



8.2 Investment Plan Results

Figure 8-2 shows the investment profile for the Phase 2 Resilience Plan. 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. Distribution Feeder Hardening (Rebuild) hardening zones make up the largest portion of the total, accounting for 95 percent of the total investment, followed by Lateral Hardening (Rebuild) hardening zones with 5 percent.

Figure 8-2: Investment Profile

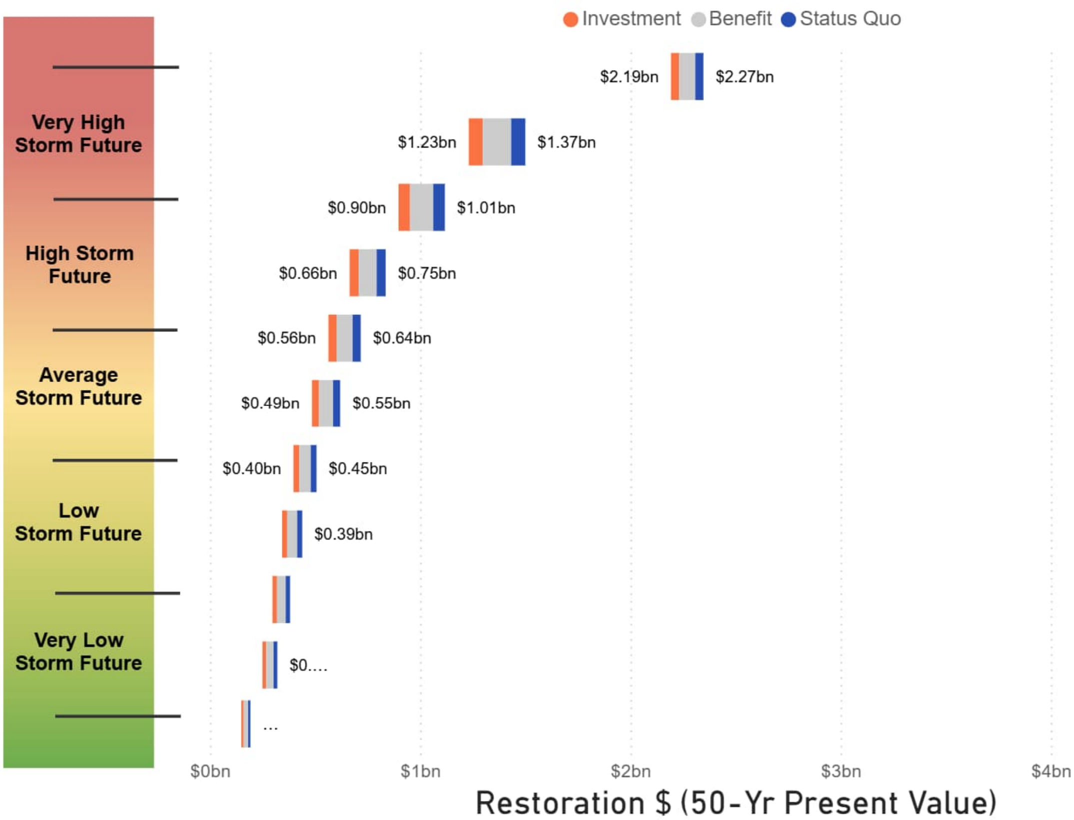


8.2.1 Avoided Restoration Cost Benefits

Figure 8-3 shows the range in restoration cost reduction at various storm futures for the Resilience Plan. The values are shown in 50-year present value terms. The figure shows the benefits of this level of investment, the benefit values do not include the $400 million of investment.

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 storm frequency and impact are reflective of historical trends discussed in Section 4.1. The very high storm future levels represent a future world where storm frequency and impact are all high.

Figure 8-3: Restoration Cost Benefit

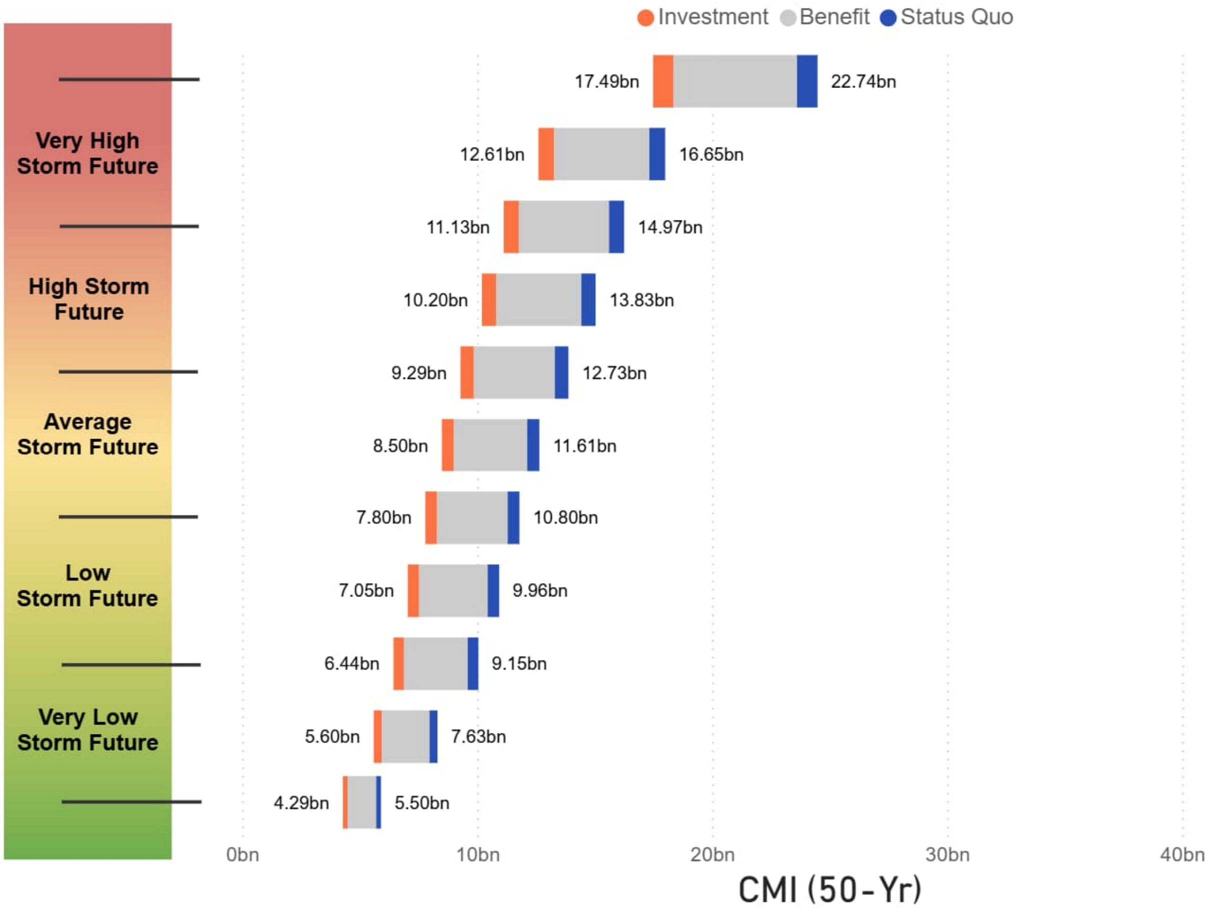


With the $400 million Phase 2 Resilience Plan, the storm restoration costs are reasonably expected to decrease by approximately $83 million (~13 percent) for the weighted storm future.

8.2.2 Avoided Customer Outage Benefit

Figure 8-4 shows the range in avoided storm customer minutes interrupted at various storm futures for the $400 million Phase 2 Resilience Plan. The values are shown for a 50-year period. For the Phase 2 Resilience Plan, storm customer outages are reasonably expected to decrease by approximately 3.4 billion CMI (~27 percent) for the weighted storm future.

Figure 8-4: Customer Benefits



8.2.3 Resilience Benefit Cost Ratio

This section shows the Resilience Benefit Cost Ratio for the Phase 2 Resilience Plan. It also includes the path from the two main benefit streams to calculating the Resilience Benefit Cost Ratio. It is important to note that the business case of the scenario is based upon the avoided restoration costs and avoided customer outages that reasonably can be expected to be achieved from the proposed investment.

A key piece of that path is the monetization of the storm CMI. Figure 8-5 shows the companion figure to Figure 8-4 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 for the Phase 2 Resilience Plan. The figure shows the benefits of this level of investment, the benefit values do not include the $400 million of investment.

Figure 8-5: Monetized Customer Benefit

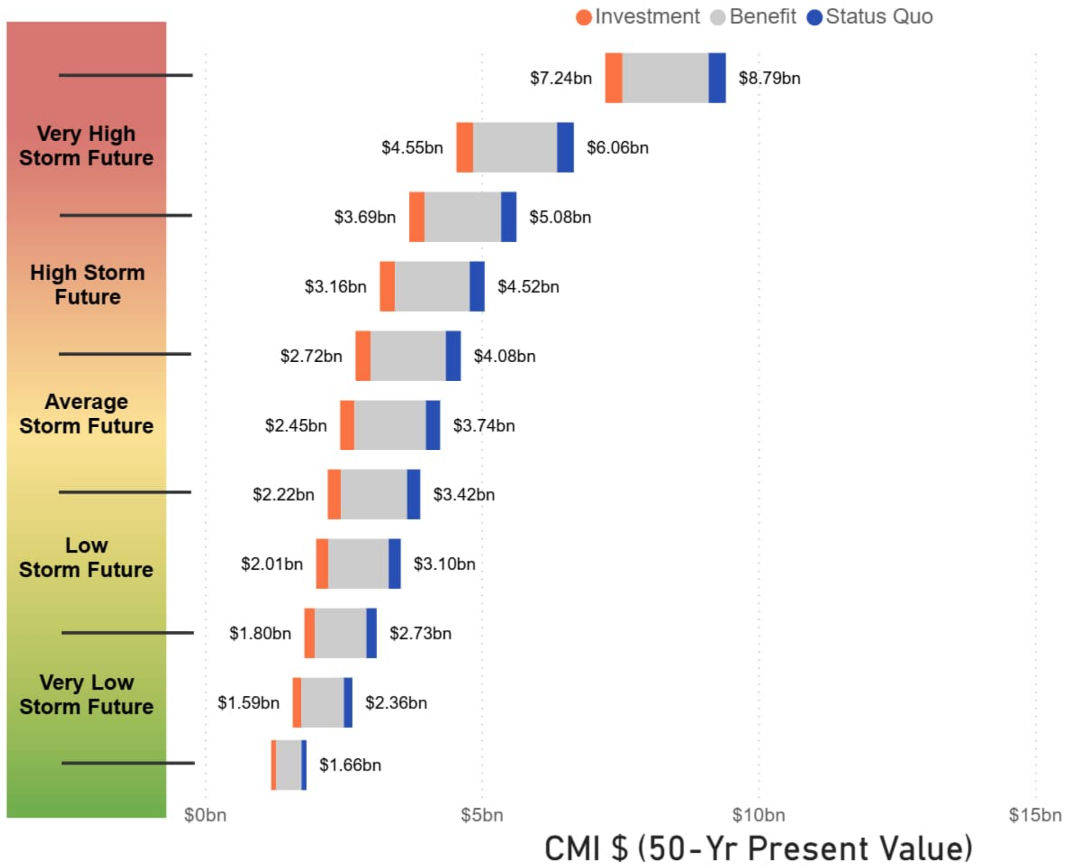


Figure 8-6 shows the sum of the restoration cost and monetized CMI for the Status Quo and the Phase 2 Resilience Plan.

Figure 8-6: Total Monetized Benefit (Restoration + $CMI)

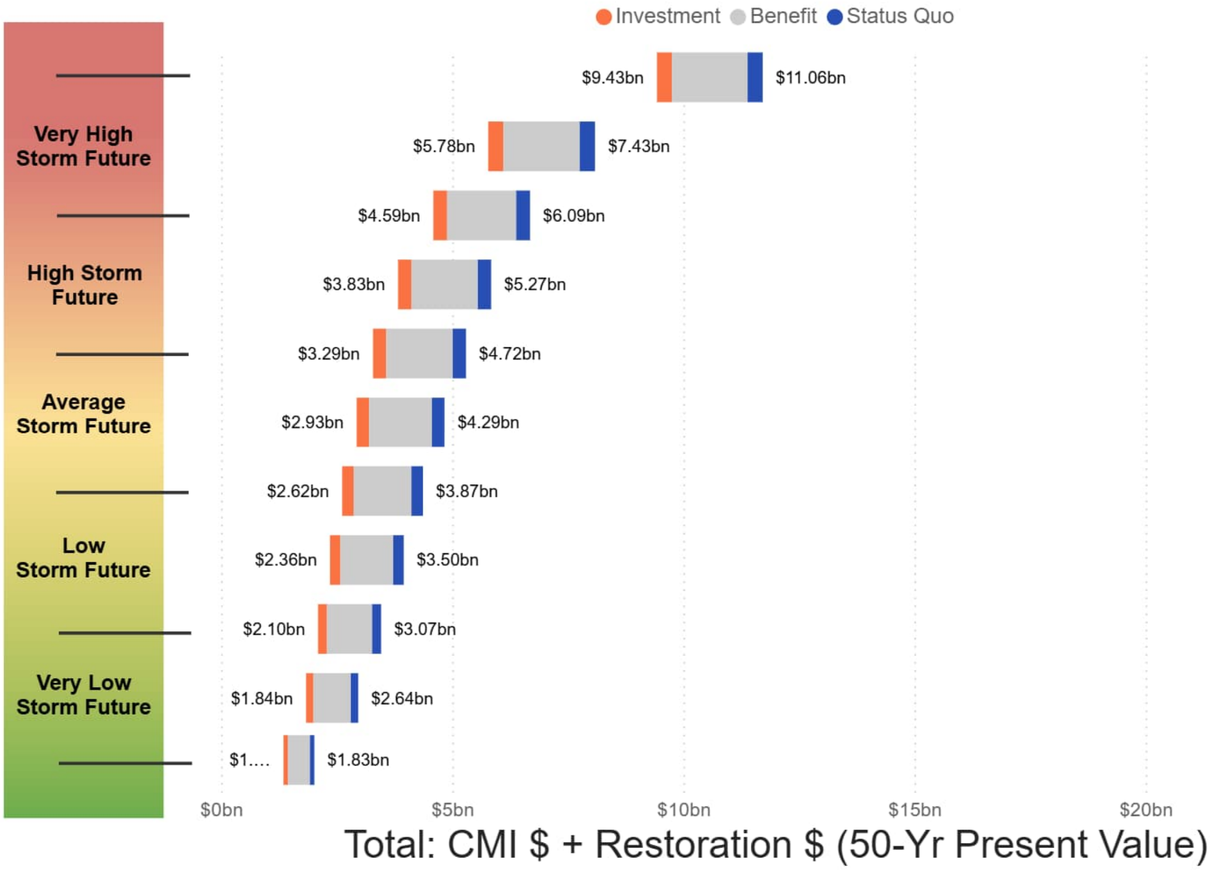


Figure 8-7 shows the portion of the total monetized benefit that comes from the avoided restoration costs and the portion from the monetized avoided customer outages. The figure also includes the total cost of the scenario in 2025 dollars, approximately $359 million ($400 million nominal).

Figure 8-7: Gross Benefit versus Costs

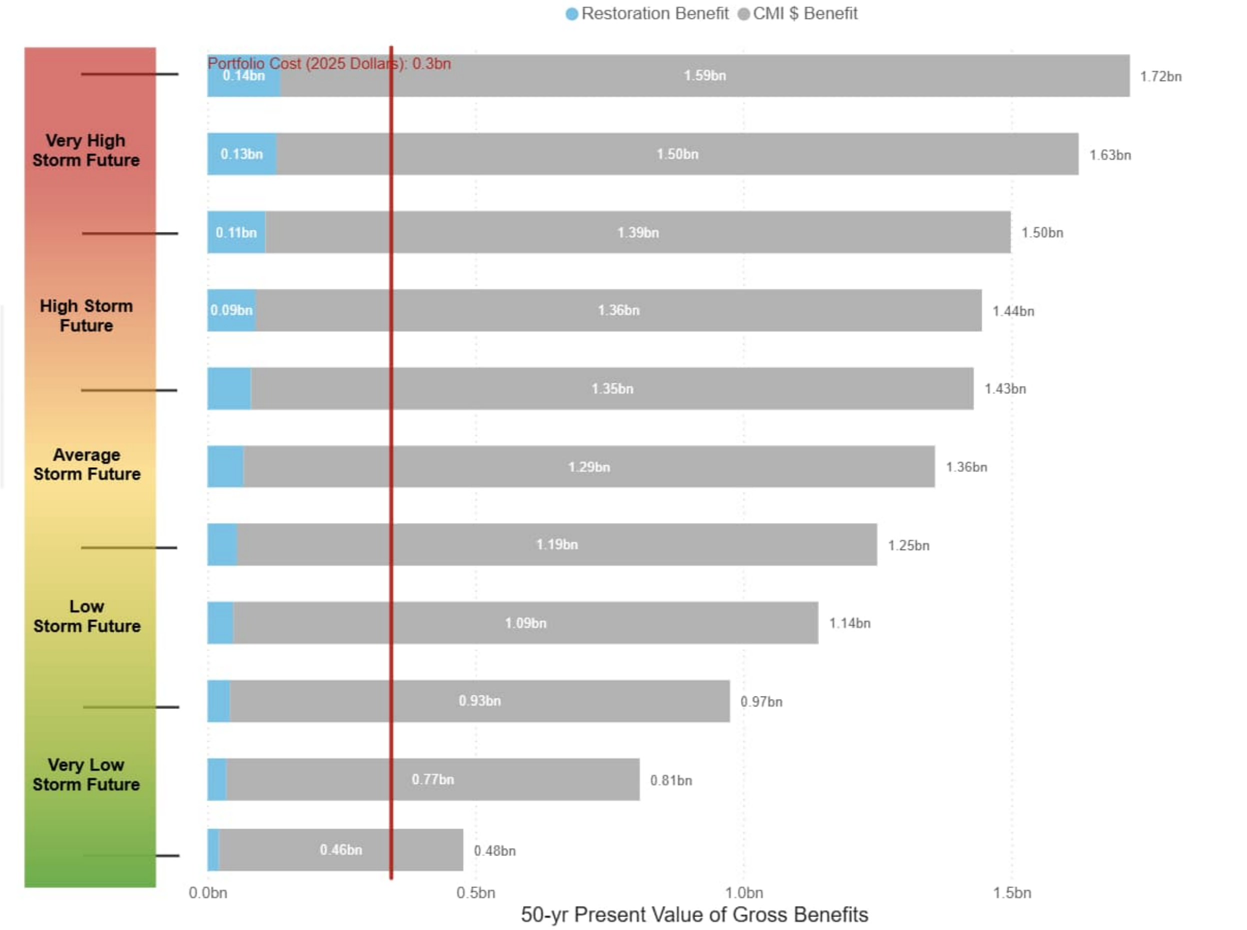
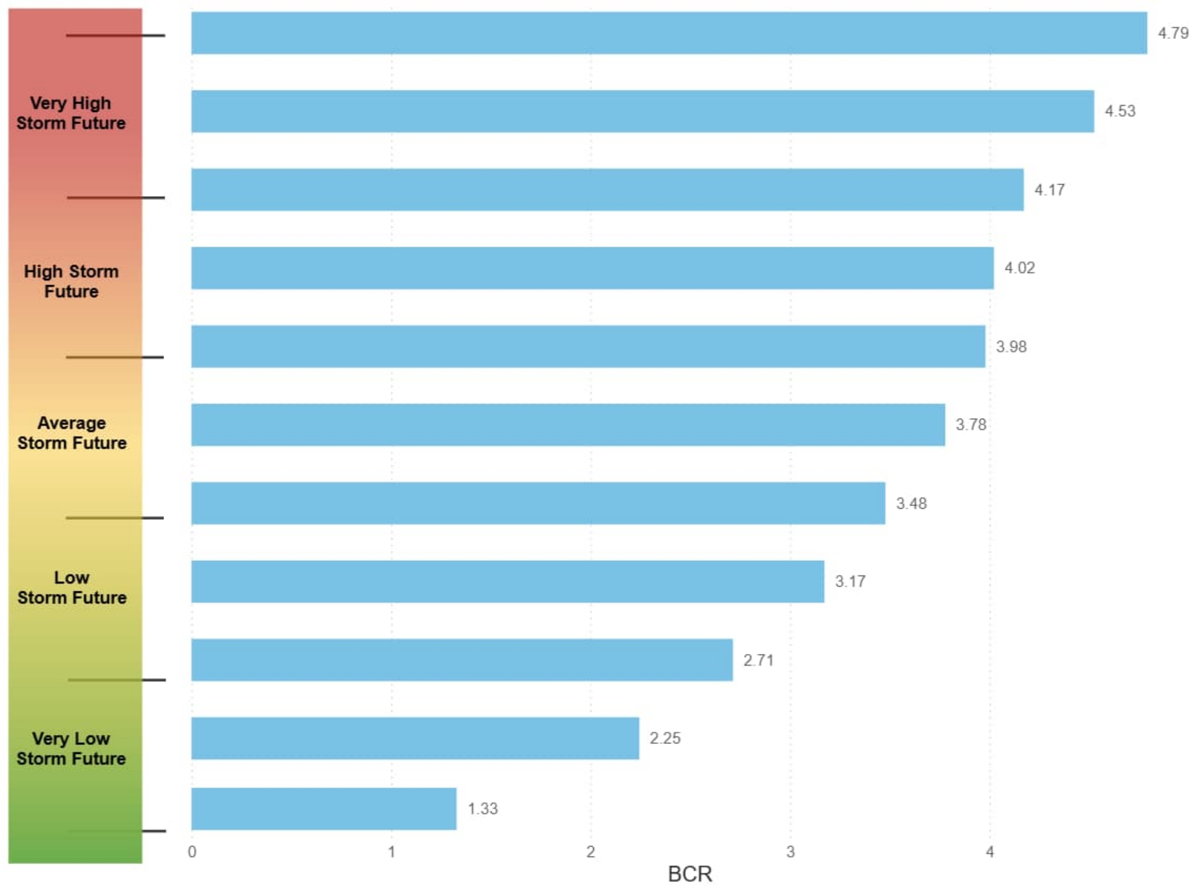


Figure 8-8 converts the gross benefits and costs from Figure 8-7 into the non-weighted Resilience Benefit Cost Ratio range for the Phase 2 Resilience Plan. The figure shows that the investment plan has a Resilience Benefit Cost Ratio range as low as 1.33 in a very low storm future and as high as 4.79 in a very high storm future scenario. The weighted storm future scenario for the investment has a Resilience Benefit Cost Ratio of 3.97. This figure and the others above show that the hardening zones included in the Phase 2 Resilience Plan can reasonably be expected to provide significant benefits to customers in excess of cost.

Figure 8-8: Portfolio Resilience Benefit Cost Ratio



8.3 Conclusions

The following include the conclusions of the Phase 2 Resilience Plan:

- There is opportunity for additional resilience investment in the New Orleans system. The resilience business case evaluated over 4,200 potential hardening zones,[20] with approximately 30 percent having a positive business case. There is approximately $1.06 billion of positive BCR investment across the Company's system.
- An overall investment level of $400 million is technically achievable over the time horizon. This investment plan provides benefits for customers, is reasonable, and provides customers with optimal benefits given execution constraints. This investment level is reasonably expected to:
    - Decrease storm restoration cost by approximately $83 million over the 50-year time horizon.
    - Decrease total number of CMI by 3.4 billion minutes over the 50-year time horizon.

[20] *See supra*, note 2.

    - Reduce overall monetized outage costs to customers by over $1.3 billion over the 50-year time horizon.
- The $400 million of investment ($359 million in 2025 dollars) produces a plan level benefit cost ratio of 3.97, indicating the plan provides benefit to customers in excess of the plan costs.
- If enough of the Entergy New Orleans system is made resilient, 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. Both of these benefit streams are not factored into the evaluation within the Resilience Model.

APPENDIX A – NOAA EXTREME WEATHER EVENT DEFINITIONS

No.	Resiliency Event Type	Resiliency Event	Definition
1	Wind	Thunderstorm Wind	Winds, arising from convection (occurring within 30 minutes of lightning being observed or detected), with speeds of at least 50 knots (58 mph), or winds of any speed (non-severe thunderstorm winds below 50 knots) producing a fatality, injury, or damage.
2		Lightning	A sudden electrical discharge from a thunderstorm, resulting in a fatality, injury, and/or damage.
3		Hail-Wind	Hail is defined as, Frozen precipitation in the form of balls or irregular lumps of ice. Hail of any size may be reported, in hundredths of an inch, although the smallest measure in the hail conversion table is 0.25 inches. This report uses "Hail-Wind" to refer to hail that occurs not in connection with a winter-weather event and not during the months of December, January, and February.
4		High Wind	Sustained non-convective winds of 35 knots (40 mph) or greater lasting for 1 hour or longer, or gusts of 50 knots (58 mph) or greater for any duration (or otherwise locally/regionally defined).
5		Strong Wind	Non-convective winds gusting less than 50 knots (58 mph), or sustained winds less than 35 knots (40 mph), resulting in a fatality, injury, or damage.
6	Flood	Flood	Any high flow, overflow, or inundation by water which causes damage.
7		Heavy Rain	Unusually large amount of rain which does not cause a Flash Flood or Flood event, but causes damage, e.g., roof collapse or other human/economic impact.
8		Flash Flood	A life-threatening, rapid rise of water into a normally dry area beginning within minutes to multiple hours of the causative event (e.g., intense rainfall, dam failure, ice jam). Six inches or more of swiftly moving water flowing over a road or bridge, posing a threat to life or property is one of many suggested guidelines for determining if an event was a Flash Flood.
9	Tornado	Tornado	A violently rotating column of air, extending to or from a cumuliform cloud or underneath a cumuliform cloud, to the ground, and often (but not always) visible as a condensation funnel.
10	Winter	Winter Weather	A winter precipitation event that causes a death, injury, or a significant impact to commerce or transportation, but does not meet locally/regionally defined warning criteria. A Winter Weather event could result from one or more winter precipitation types (snow, or blowing/drifting snow, or freezing rain/drizzle).
11		Sleet	Sleet accumulations meeting or exceeding locally/regionally defined warning criteria (typical value is ½ inch or more).
12		Winter Storm	A winter weather event that has more than one significant hazard (i.e., heavy snow and blowing snow; snow and ice; snow and sleet; sleet and ice; or snow, sleet and ice) and meets or exceeds locally/regionally defined 12 and/or 24-hour warning criteria for at least one of the precipitation elements.

No.	Resiliency Event Type	Resiliency Event	Definition
13		Heavy Snow	Snow accumulation meeting or exceeding locally/regionally defined 12 and/or 24 hour warning criteria. This could mean values such as 4, 6, or 8 inches or more in less than 12 hours or less; or 6, 8, or 10 inches in 24 hours or less.
14		Ice Storm	Ice accretion meeting or exceeding locally/regionally defined warning criteria (typical value is ¼ or ½ inch or more)."
15		Hail-Winter	Hail is defined as, Frozen precipitation in the form of balls or irregular lumps of ice. Hail of any size may be reported, in hundredths of an inch, although the smallest measure in the hail conversion table is 0.25 inches. This report uses "Hail-Winter" to refer to hail that occurs in connection with a winter-weather event, and/or during the months of December, January, and February.
16		Blizzard	A winter storm which produces the following conditions for three (3) consecutive hours or longer: (1) sustained winds or frequent gusts of 30 knots (35 mph) or greater, and (2) falling and/or blowing snow reducing visibility frequently to less than ¼ mile.
17	Heat	Heat	A period of heat resulting from the combination of high temperatures (above normal) and relative humidity. A Heat event occurs and is reported in Storm Data whenever heat index values meet or exceed locally/regionally established advisory thresholds.
18		Excessive Heat	Excessive Heat results from a combination of high temperatures (well above normal) and high humidity. An Excessive Heat event occurs and is reported in Storm Data whenever heat index values exceed locally/regionally established excessive heat warning thresholds.
19	Drought	Drought	Drought is a deficiency of moisture that results in adverse impacts on people, animals, or vegetation over a sizeable area.
20	Cold	Cold/Wind Chill	Period of low temperatures or wind chill temperatures reaching or exceeding locally/regionally defined advisory (typical value is -18°F or colder) conditions.
21		Extreme Cold/Wind Chill	A period of extremely low temperatures or wind chill temperatures reaching or exceeding locally/regionally defined warning criteria (typical value around -35°F or colder).

PART OF BURNS & McDONNELL

1898andco.com

BEFORE THE

COUNCIL OF THE CITY OF NEW ORLEANS

***IN RE*: SYSTEM RESILIENCY AND STORM HARDENING**	**))**	**DOCKET NO. UD-21-03**

DIRECT TESTIMONY

OF

KEITH D. WOOD

ON BEHALF OF

ENTERGY NEW ORLEANS, LLC

DECEMBER 2025

TABLE OF CONTENTS

Page

EXHIBIT LIST

I. INTRODUCTION AND QUALIFICATIONS

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

A. My name is Keith D. Wood. I am employed by Entergy New Orleans, LLC ("ENO" or "the Company") as Director, Resource Planning and Market Operations. My business address is 1600 Perdido Street, New Orleans, Louisiana 70112.

Q2. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?

A. I am testifying before the Council of the City of New Orleans ("Council") on behalf of ENO.

Q3. PLEASE DESCRIBE YOUR PROFESSIONAL EXPERIENCE AND EDUCATIONAL BACKGROUND.

A. I began my career at Entergy Services, LLC ("ESL") in 2002. Between 2002 and 2010, I held various roles of increasing responsibility in the Supply Chain organization, with a focus on procuring information technology products and services, as well as other contract services for the EOCs. Between 2010 and 2017, I served as Manager, Regulatory Affairs for Entergy Louisiana, LLC ("ELL"), where I worked on various resource certifications, rulemakings, and disputes involving the Commission's rules, and helped to administer ELL's filed rate and rider schedules.

In January 2017, I joined ENO as Manager, Resource Planning, with responsibility for the Company's integrated resource planning, resource certifications, and relevant policies. I was promoted to Senior Manager, Resource Planning, in July 2019, and to Director, Resource Planning and Market Operations, in November 2021.

As Senior Manager, and now as Director, I am also responsible for the Company's planning and implementation of demand side management programs, participation in markets administered by the Midcontinent Independent System Operator ("MISO"), and transmission planning. I am responsible for the development of policy and implementation of programs related to sustainable and distributed resource technologies.

I received a Bachelor of Arts degree in English and German from the University of Richmond. I earned a Juris Doctorate degree from Loyola University College of Law and a Master of Business Administration degree, with a concentration in Finance, from the A.B. Freeman School of Business at Tulane University. I am a member of the Louisiana State Bar Association.

Q4. HAVE YOU PREVIOUSLY TESTIFIED IN ANY REGULATORY PROCEEDING?

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

Q5. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony will provide an overview of a project that would enhance local resilience of critical infrastructure in New Orleans. The Company has identified an opportunity to partner with the Sewerage and Water Board of New Orleans ("SWBNO") to pursue a grant through the Louisiana Hubs for Energy Resilient Energy Operation ("HERO") program to provide 50% of the funding for needed backup generation at four (4) critical SWBNO pumping sites. Assuming 50% grant funding is received, ENO would propose to install, own, and maintain the four (4) backup generators, with the remaining

50% portion of the total costs not covered by the grant shared between SWBNO and ENO. My testimony will generally describe the critical pumping backup generation project (the "Project"), the resilience and reliability improvements that would result from the Project and benefit ENO customers, the process to pursue the HERO grant, and the subsequent steps ENO and SWBNO would take to pursue the Project following award of a HERO grant.

II. PROJECT OVERVIEW

Q6. WHAT IS THE CRITICAL PUMPING BACKUP GENERATION PROJECT AND WHY IS IT NEEDED?

A. SWBNO has identified a need for new, permanently installed backup generation at four (4) key sites—three (3) drainage pumping stations and one (1) sewer pumping station—to replace outdated equipment or provide backup power where there currently is none.

Q7. PLEASE DESCRIBE THE FOUR (4) KEY PUMPING SITES AND THE BACKUP GENERATION REQUIRED TO SERVE THEM.

A. The four locations include: 1) Drainage Pumping Station ("DPS") #4, 5700 Warrington Dr., New Orleans, LA, 70122; 2) DPS #14, 1200 Hayne Blvd., New Orleans, LA, 70128; 3) DPS #16, 7200 Wales St., New Orleans, LA, 70126; and 4) Sewer Pumping Station ("SPS") A, 1321 Orleans Ave., New Orleans, LA, 70116. DPS #4 is powered in part by a 25 Hz feeder from SWBNO's distribution system and a 60 Hz feeder from ENO's distribution system. SWBNO's power generation system includes redundancy for the 25-hz power, but there is currently no backup generation onsite for the 60 Hz

ENO feeder. DPS #14 and #16 are powered by 60 Hz ENO distribution feeders with onsite backup generation that is near end of life and in need of replacement. SPS A is powered in part by a 25 Hz feeder from SWBNO's distribution system and a 60 Hz feeder from ENO's distribution system. SWBNO's power generation system includes redundancy for the 25-hz power, but there is currently no backup permanent generation onsite for the 60 Hz ENO feeder.

These four sites provide drainage pumping service for over 30,000 residents and businesses in New Orleans East and Gentilly and sewer pumping service for over 50,000 residents and businesses in the French Quarter, Central Business District, Uptown, and Mid-City. A number of critical care facilities are also served in these areas, including five (5) hospitals, dozens of nursing homes and dialysis clinics, and eleven (11) fire stations. The Project would comprise approximately 15 MW of backup generation among the four (4) sites, all of which would be connected to natural gas facilities installed at each location to provide fuel. The backup generators would be interconnected to the electric distribution grid to allow for grid synchronous operation, enabling them to deliver power to the grid if required.

III. RESILIENCE BENEFITS OF THE PROJECT

Q8. HOW WOULD THE BACKUP GENERATORS OPERATE TO INCREASE RESILIENCE IN NEW ORLEANS?

A. The generators would provide backup power to the four (4) pumping stations in question during times when grid power is not available, thus ensuring those locations can continue pumping operations as needed and help prevent damage to homes, businesses, and property caused by excessive street flooding. As part of the larger SWBNO pumping system, it is important that these four (4) sites remain operational during times of high pumping need so as not to become pinch points that impede the flow of water and sewerage and compromise the ability of the larger SWBNO system to function optimally. While the generators would not be used to serve the electric needs of ENO's customers under normal conditions, they would be installed and configured such that they could potentially be available in the future to provide demand response or grid support, depending on ENO's resource planning needs.

IV. HERO GRANT PROCESS AND PROJECT NEXT STEPS

Q9. WHAT IS THE GOAL OF THE HERO GRANT PROGRAM AND HOW DO ENTITIES APPLY TO RECEIVE FUNDING THROUGH IT?

A. The HERO grant program is administered by the Louisiana Department of Conservation and Energy[1] and seeks to provide matching funds to support reliability for mission critical facilities in vulnerable areas of the state. To seek grant funding, state and municipal agencies must partner with a local utility company to submit an application.

[1] Prior to October 1, 2025, the Department was known as the Louisiana Department of Energy and Natural Resources.

Q10. WHAT IS THE EXPECTED TIMELINE AROUND THE HERO GRANT PROCESS?

A. It is expected that the grant application window will open in early 2026, and that notifications of awards could occur in the second half of the year.

Q11. IF THE PROJECT RECEIVES A HERO GRANT, HOW WOULD ENO PROCEED FROM THERE?

A. If the Project receives a 50% HERO grant, ENO would supplement this docket to provide detailed cost estimates, project execution timelines, and proposed cost recovery for consideration by the Council. If the Council were to approve the Project as being in the public interest, ENO would proceed from that point to procure the necessary equipment and plan for the installation. At this time, I expect that the Project would require approximately 18-24 months to complete following receipt of Council approval.

Q12. WHY IS IT REASONABLE FOR SWBNO AND ENO TO SHARE THE PROJECT COSTS THAT WOULD NOT BE COVERED BY THE HERO GRANT?

A. The Project represents a significant improvement to the resilience of critical pumping infrastructure that benefits citizens of New Orleans. By partnering on an application to pursue matching HERO grant funding for the Project, ENO and SWBNO are taking an important step towards being able to pursue the Project at a reduced cost to New Orleans ratepayers. The backup generation will provide important redundancy for critical SWBNO pumping sites while also providing a resource that could be called on to support the electric needs of its customers during times of high peak demands on the electric grid. Also, installing and interconnecting the backup generators such that they would be able to flow power to the distribution grid could provide a viable option to help serve ENO's customers depending on future resource planning requirements. A sharing of the remaining costs between SWBNO and ENO represents a reasonable approach between the two (2) utilities to serve the needs of their customers in New Orleans.

Q13. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, at this time.

AFFIDAVIT

STATE OF LOUISIANA

PARISH OF ORLEANS

NOW BEFORE ME, the undersigned authority, personally came and appeared, **KEITH D. WOOD**, 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.

Keith Wood

KEITH D. WOOD

SWORN TO AND SUBSCRIBED BEFORE ME
THIS 8th DAY OF DECEMBER 2025

Regina Bartholomew-Woods

NOTARY PUBLIC #26577

My commission expires: upon death

5668 Bancroft Drive
New Orleans, LA 70122
(504) 710-0682

Listing of Previous Testimony Filed by Keith D. Wood

DATE	TYPE	SUBJECT MATTER	REGULATORY BODY	DOCKET NO.
7/27/2012	Affidavit	Energy Smart-Algiers Expansion	CCNO	UD-08-02
4/4/2014	Direct	Electric Cooperative Net Metering Cap	LPSC	U-32913
7/14/2014	Direct	Quick Start Energy Efficiency Portfolio Plan	LPSC	R-31106
11/4/2016	Settlement	Ninemile 6 Prudence Review	LPSC	U-33633
11/27/2024	Affidavit	Super Bowl LIX Short-Term Power Sale and Purchase Agreement	CCNO	Undocketed

BEFORE THE

COUNCIL OF THE CITY OF NEW ORLEANS

IN RE: **SYSTEM RESILIENCY AND STORM HARDENING**	**))**	**DOCKET NO. UD-21-03**

DIRECT TESTIMONY

OF

ALYSSA MAURICE-ANDERSON

ON BEHALF OF

ENTERGY NEW ORLEANS, LLC

PUBLIC REDACTED VERSION

DECEMBER 2025

TABLE OF CONTENTS

EXHIBIT LIST

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 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 Council of the City of New Orleans ("Council") on behalf of Entergy New Orleans, LLC ("ENO" or the "Company").

Q3. PLEASE DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

A. I hold a Master of Business Administration (concentration in Finance) from Tulane University's Freeman School of Business, 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 filed by regulated subsidiaries of Entergy Corporation -- first for ENO, then for Legacy Entergy Louisiana, LLC ("Legacy ELL") and Legacy Entergy Gulf States Louisiana, LLC

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

("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; managing and obtaining approval of ratemaking 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 ratemaking 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. ("MISO"), 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 the Council, 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 calculations and cost of service studies, 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 ratemaking treatments, including the types that are the subject of this regulatory proceeding.

Q4. HAVE YOU PREVIOUSLY TESTIFIED BEFORE ANY REGULATORY BODIES?

A. Yes. I have submitted testimony to the Council, the Louisiana Public Service Commission ("LPSC"), and the Public Utility Commission of Texas. A list of the matters in which I have previously provided 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, respectively.

II. <u>PURPOSE OF TESTIMONY</u>

Q5. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my direct testimony is to address financial and ratemaking issues raised by the Phase 2 Resilience Plan, as described in the Application and by Company witnesses Messrs. Chris Gremillion and Arlin M. Mire. First, I discuss the potential future benefits that may arise from the Council demonstrating to the investment community its support for a continuous resilience plan. Approving the Phase 2 Resilience Plan would be an important step in rehabilitating ENO's credit ratings, which have not recovered from previous downgrades. The Council and ENO should continue to take action focused on improving ENO's credit ratings to protect customers from higher capital costs, not only as to the Phase 2 Resilience Plan, but across ENO's entire business.

Second, I explain why the continuation of the Resilience & Storm Hardening Cost Recovery Rider ("Resilience Rider" or "Rider") is necessary for ENO to undertake the proposed Phase 2 Resilience Plan. The proposed Resilience Rider with ministerial changes reflected in red-line format is attached as Exhibit AMA-2. Without the continuation of the Rider, undertaking the proposed Phase 2 Resilience Plan would compromise ENO's cash flow and credit metrics and be a step backwards in terms of improving ENO's financial health and program execution. A stable, long-term recovery mechanism for the duration of Phase 2 would allow the projects to be executed efficiently. In other words, ENO would be able to leverage economies of scale, maintain a qualified workforce, and avoid the starts and stops that would occur if timely cost recovery and Council support was uncertain. Moreover, contemporaneous cost recovery also is appropriate because as ENO completes the Phase 2 Resilience Plan projects, benefits are available to customers. Therefore, ENO respectfully urges the Council to continue the Resilience Rider so that the opportunity for recovery of the Phase 2 Resilience project costs is contemporaneous with the availability of the benefits.

Third, my testimony discusses the applicable public interest standard and explains why the Phase 2 Resilience Plan, among related requests for relief, is in the public interest. Further, my testimony supports the continuation of the ratemaking treatment for distribution plant that must be retired and replaced with new assets as part of the Phase 2 Resilience Plan and a second accounting waiver that ENO intends to request at the Federal Energy Regulatory Commission ("FERC"), which would mitigate the Phase 2 Resilience Plan's near-term bill effects on the Company's customers.

III. CREDIT RATINGS AND A CONTINUOUS RESILIENCE PLAN

Q6. ARE ENO'S CREDIT RATINGS SATISFACTORY IN YOUR OPINION?

A. No. I would characterize ENO's credit ratings as needing improvement. The Council's approval of a robust and continuous Phase 2 Resilience Plan would be an important step toward maintaining and potentially improving ENO's credits ratings, which have not recovered since the downgrade in 2020.

Q7. PLEASE BRIEFLY DESCRIBE THAT DOWNGRADE.

A. S&P Global ("S&P") downgraded ENO three times and four notches in 2020 and 2021. S&P downgraded ENO in October 2020 from 'BBB+' to 'BBB'; the basis of that downgrade was severe storm risks, a revised assessment of group support, and weaker forecasted credit metrics.[2]

[2] S&P, *Entergy New Orleans LLC*, October 8, 2020, at 1-2. Reports from S&P and Moody's cited here are included in Exhibit AMA-3, *in globo*.

In September 2021, S&P downgraded ENO's issuer rating twice, from 'BBB' to 'BB+'[3] and then from 'BB+' to 'BB.'[4] S&P based its downgrades, in large part, on "ENO's small service territory, limited diversity, and ongoing exposure to severe storms and hurricanes"[5] and weakened financial risk measures, with ENO's credit metrics being on the lower end of the 'Significant Financial Risk' benchmark range.[6]

In September 2021, Moody's Investor Service ("Moody's") changed ENO's outlook from 'Stable' to 'Negative.' Moody's based that change on "the added cost burden imposed by recent storm activity and the potential for impaired customer relations, increased political or regulatory challenges to full and timely cost recovery, and prolonged financial metric weakness."[7]

Q8. HAVE ENO'S CREDIT RATINGS AND OUTLOOK STABILIZED SINCE THEN?

A. Yes, they have, but they have not returned to the pre-downgrade level. Currently, S&P rates ENO as 'BB' with a 'Stable' outlook.[8] Moody's rates ENO as 'Ba1' with a 'Stable' outlook.[9] Although S&P and Moody's use different rating scales, ENO's two credit ratings are very similar.

---

3 S&P, *Entergy New Orleans LLC*, September 2, 2021.

4 S&P, *Entergy New Orleans LLC*, September 24, 2021.

5 S&P, *Entergy New Orleans LLC*, September 2, 2021, at 1.

6 S&P, *Entergy New Orleans LLC*, September 24, 2021, at 1.

7 Moody's, *Entergy New Orleans LLC*, September 29, 2021, at 2.

8 S&P, *Entergy New Orleans LLC*, September 9, 2025, at 1. A copy of this report is attached as Exhibit AMA-4.

9 Moody's, *Entergy New Orleans LLC*, July 23, 2025, at 1. A copy of this report is attached as Exhibit AMA-5.

Q9. DO S&P AND MOODY'S CONSIDER STORM RISK AS A MAJOR FACTOR AFFECTING ENO'S CREDIT QUALITY?

A. Yes. S&P explains that ENO's "credit quality reflects its small service territory, limited diversity, and ongoing exposure to severe storms and hurricanes."[10] Moody's states that ENO's "credit profile is constrained by its small, geographically concentrated asset footprint in a storm prone location."[11] Both credit rating agencies identify exposure to severe weather as major credit challenges.

Q10. DO S&P AND MOODY'S HAVE A VIEWPOINT ON WHETHER ENO SHOULD CONTINUE ITS EFFORTS TO IMPROVE ITS GRID'S RESILIENCE?

A. S&P does. S&P's viewpoint is unequivocal: "Investment in resiliency is necessary to reduce risk. . . . We expect that the [Council] will approve a continuous and sustained resiliency plan that will gradually reduce the company's risks of sustained outages and high damages from severe weather events."[12] Further, S&P has cautioned that it could lower ENO's credit rating if "[t]he company does not implement a resiliency plan that gradually reduces its exposure to severe storms."[13]

---

10 S&P, *Entergy New Orleans LLC*, September 9, 2025, at 1.

11 Moody's, *Entergy New Orleans LLC*, July 23, 2025, at 1.

12 S&P, *Entergy New Orleans LLC*, September 9, 2025, at 2.

13 *Id*.

Moody's mentions ENO's resilience efforts and notes that severe weather has long-term effects on population outflow and local economic conditions in its discussion of Environmental, Social, and Governance factors.[14]

Q11. HAS S&P DESCRIBED A SCENARIO IN WHICH IT COULD UPGRADE ENO'S CREDIT RATING?

A. Yes. S&P is the agency that downgraded ENO most recently. S&P has stated that (1) implementing a continuous resilience plan, (2) improving cash-flow-to-debt metrics, and (3) effectively managing regulatory risk could lead to an upgrade in the next twelve months.[15] ENO's management does not agree with S&P's assessment that ENO is nonstrategic to the Entergy group. ENO invites the Council and the Advisors to consider these factors and to work collaboratively with ENO to improve ENO's issuer credit rating from S&P.

Q12. WHY IS A CONTINUOUS RESILIENCE PLAN AN IMPORTANT CONSIDERATION WITH RESPECT TO FUTURE EFFORTS?

A. In addition to addressing external expectations, such as those expressed by S&P, recognizing that in recent times the Gulf Coast has experienced increased intensity and frequency of severe weather, it has become necessary to institute an accelerated plan to mitigate the potential effects of future events. Avoiding interruption of resilience

---

14 Moody's, *Entergy New Orleans LLC*, July 23, 2025, at 4.

15 S&P, *Entergy New Orleans LLC*, September 9, 2025, at 2.

efforts is important to the overall program execution because it translates to greater efficiency, and benefits for customers. As explained by Mr. Gremillion, an uninterrupted plan provides for consistent resource demand that facilitates continuous work, resulting in efficiencies and reduced competition for resilience resources and ultimately translates into lower costs for the program and customers.

Q13. WOULD STRENGTHENING ENO'S CREDIT RATINGS BENEFIT CUSTOMERS?

A. Yes, credit ratings directly affect ENO's cost of capital and drive overall customer rates. Improvements in credit ratings would put downward pressure on debt costs and on rates over time.[16] In contrast, downgrades would put upward pressure on debt costs and on rates over time.

Q14. BESIDES THE BENEFITS FROM A CREDIT RATINGS PERSPECTIVE, DOES A CONTINUOUS RESILIENCE PLAN YIELD OTHER BENEFITS FOR CUSTOMERS?

A. Yes. As explained by Ms. Rodriguez, a continuous resilience plan will help attract new customers to New Orleans and maintain existing ones. The proposed resilience projects address critical infrastructure and customers, such as the NASA Michoud Assembly Facility, and encompass parts of New Orleans that are ripe for economic development. Moreover, the strategic location of New Orleans at the mouth of the Mississippi River

[16] Phillips, Charles F., Jr., The Regulation of Public Utilities, Arlington, Virginia: Public Utilities Reports, Inc., 1993, at p. 250.

makes New Orleans critical for the nation's supply chain and for global trade. The Company's electric grid must be sufficiently resilient so that New Orleans can be relied upon to play its critical role in these economies.

IV. MINOR MODIFICATIONS TO THE RESILIENCE RIDER'S TERMS

Q15. PLEASE PROVIDE AN OVERVIEW OF THE CURRENT VERSION OF THE RESILIENCE RIDER AND ITS APPROVAL.

A. ENO proposed the current Resilience Rider through my Direct Testimony filed in April 2023. Ultimately, the Council approved the Resilience Rider with modifications in Resolution R-24-625, dated October 24, 2024. Briefly, the Rider accomplishes contemporaneous recovery of Resilience Plan project costs through a forward-looking rate that includes a true-up associated with completed projects after a prudence review. The Resilience Rider's procedures provide the Council and its Advisors with sufficient time to (a) review the projects placed in service in the following calendar year and (b) determine the prudence of project execution based on actual data from the previous calendar year.

The Council modified the rider ENO originally proposed in three ways, as set forth in Ordering Paragraph 7 of Resolution R-24-625. To summarize, first, the Council ordered that Rider recovery be allocated to the rate classes based on the most recently calculated Distribution Primary Demand allocator reflected in ENO's rates. Second, the Council ordered that the Rider recovery be incorporated into the annual Electric Formula Rate Plan ("FRP") Rate Adjustments. Third, the Council ordered that ENO periodically realign the Rider recovery associated with the Phase 1 Resilience

Plan project costs included in per book plant in service in a FRP Evaluation Report or base rate case class cost of service study.

Q16. PLEASE EXPLAIN THE MODIFICATIONS TO THE MECHANISM THAT ENO PROPOSES IN THE PRESENT APPLICATION SO THAT THE RESILIENCE RIDER MAY CONTINUE IN EFFECT.

A. The modifications are minor and clarify that the Council has approved the execution of additional resilience projects and has approved the recovery of their cost through the Rider. As mentioned previously, the modifications are shown in red-line in Exhibit AMA-2.[17]

ENO proposes that Section II entitled "Definitions" be amended to identify the Council resolution issued in this Phase 2 proceeding that would further authorize capital additions for the Phase 2 Resilience Plan. ENO also proposes that Section IV entitled "Term" be amended to recognize that subsequent phases of the original (Phase 1) Resilience Plan approved by the Council would extend the operation of the Rider.

Q17. WOULD THE SCOPE OF THE RSHCR REVENUE REQUIREMENT TO BE RECOVERED THROUGH THE RESILIENCE RIDER CHANGE?

A. No.

[17] Also, ENO has updated Attachment A of the Resilience Rider to include the Large Municipal rate class.

Q18. WOULD THE RESILIENCE RIDER CONTINUE TO ACCOMMODATE OTHER TYPES OF COSTS IN THE FUTURE?

A. Yes. The Resilience Rider would continue to accommodate the recovery of other types of resilience expenses and investments only if the Council ultimately authorized such recovery.

Q19. WOULD THE RESILIENCE RIDER CONTINUE TO ACCOMMODATE ENO'S RECEIPT OF OTHER FUNDS TO REDUCE THE COST OF ANY RESILIENCE PROJECTS?

A. Yes. The Resilience Rider would continue to have the flexibility to give customers, on a timely basis, the benefit of any funds that would reduce the cost of the program, such as grants that the Company may receive to offset the cost of resilience projects.

Q20. ASSUME ENO FILES A BASE RATE CASE IN THE LATTER PART OF 2026. HOW WOULD THE ASSUMED BASE RATE CASE AFFECT THE RESILIENCE RIDER FILINGS IN 2026 AND 2027?

A. If ENO files a base rate case in the latter part of 2026, one should further assume that ENO would request that new base rates be based on a period II test year ending December 31, 2026, with known and measurable changes to plant in service through December 31, 2027, as this would provide the most accurate representation of ENO's cost of service during the rate effective period. Also, one should assume that the Company would request a new FRP, which would use the twelve months ending

December 31, 2027 as its first evaluation period. Under those assumptions, ENO would proceed as follows.

With respect to the base rate case, ENO would exclude from the proposed base rate revenue requirement its Phase 1 2026 Resilience Plan capital additions and associated operating expenses and its Phase 2 2027 Resilience Plan capital additions and associated operating expenses from the *projected* financial data used in the base rate case. ENO would include in the proposed base rate revenue requirement its Phase 1 2025 Resilience Plan capital additions, which would have closed to plant in service in calendar year 2025.

With respect to the Resilience Rider filing, such filings would continue during the pendency of the rate case. On or before August 1, 2026, ENO would file its True-up Report regarding the 2025 Resilience Plan capital additions, which true-up ENO would commence to collect effective January 1, 2027. In the first billing cycle in September 2026, ENO would realign the 2025 Resilience Plan capital additions' revenue requirement from the RSHCR Revenue Requirement to the Annualized Evaluation Period EFRP Revenue. On or before October 1, 2026, ENO would file its updated RSHCR Revenue Requirement, which ENO would commence to collect effective January 1, 2027. The updated RSHCR Revenue Requirement would reflect 2026 Resilience Plan capital additions and associated operating expenses and its 2027 Phase 2 Resilience Plan capital additions and associated operating expenses. The updated RSHCR Revenue Requirement would also incorporate the true-up for the 2025 Resilience Plan capital additions filed in August.

Q21. WHAT RESILIENCE RIDER FILINGS WOULD OCCUR IN 2027?

A. On or before August 1, 2027, ENO would file its True-up Report regarding the 2026 Resilience Plan capital additions, which true-up ENO would commence to collect effective January 1, 2028. On or before October 1, 2027, ENO would file its updated RSHCR Revenue Requirement, which ENO would commence to collect effective January 1, 2028. The updated RSHCR Revenue Requirement would reflect 2026 Resilience Plan capital additions and associated operating expenses; the 2027 Phase 2 Resilience Plan capital additions and associated operating expenses; and the 2028 Phase 2 Resilience Plan capital additions and associated operating expenses. The updated RSHCR Revenue Requirement would also incorporate the true-up for the Phase 1 2026 Resilience Plan capital additions filed in August.

Q22. IN 2027, WOULD THERE BE ANY REALIGNMENT OF THE RECOVERY OF THE PHASE 1 2026 RESILIENCE PLAN CAPITAL ADDITIONS?

A. No. There would be no Electric FRP Evaluation Report filed in 2027 using per book information for calendar year 2026, and the rate change from the base rate case would not include the costs associated with the Phase 1 2026 Resilience Plan capital additions.

As a result of the Electric FRP Evaluation Report filed in 2028, assuming a new FRP is established after the rate case, in the first billing cycle in September 2028, ENO would realign both the Phase 1 2026 Resilience Plan capital additions' and the Phase 2, 2027 Resilience Plan capital additions' revenue requirement from the RSHCR Revenue Requirement to the Annualized Evaluation Period EFRP Revenue. The following table summarizes the timing of the realignments that would occur assuming ENO files a base rate case in 2026.

Table 1
Timing of Resilience Plan Capital Additions Realignments
Assuming ENO Files a Rate Case in 2026

Year	FRP Filed?	Vintage of Capital Additions to be Realigned
2026	Yes	Phase 1 2025
2027	No	Not Applicable
2028	Yes	Phase 1 2026 and Phase 2 2027

Q23. HOW WOULD THE TIMING OF REALIGNMENTS CHANGE ASSUMING ENO'S CURRENT FRP IS EXTENDED AND ENO DOES NOT FILE A RATE CASE?

A. Assuming ENO's current FRP is extended, and ENO does not file a rate case in 2026, the above table would change as shown below.

Table 2
Timing of Resilience Plan Capital Additions Realignments
Assuming FRP Extension in 2026

Year	FRP Filed?	Vintage of Capital Additions to be Realigned
2026	Yes	Phase 1 2025
2027	Yes	Phase 1 2026
2028	Yes	Phase 2 2027

V. CONTINUED NEED FOR THE RESILIENCE RIDER

Q24. WHY DOES ENO CONTINUE TO NEED THE RESILIENCE RIDER?

A. ENO continues to need the Resilience Rider so that the Company can execute the Phase 2 Resilience Plan on an accelerated basis and deliver benefits to customers as soon as practical without compromising ENO's credit metrics and cash flow while maintaining ENO's baseline operations.

Maintaining ENO's credit ratings to protect its customers from higher capital costs, not only as to the Resilience Plan but across ENO's entire business, should be an operational and regulatory priority. In this Application, ENO is requesting that the Council authorize ENO to invest approximately $400 million over the next five years (2027 through 2031) to continue infrastructure hardening of the Company's distribution systems at an accelerated pace. Given the large capital investment and time horizon involved in implementing the Phase 2 Resilience Plan and ENO's small size and risk profile, it is essential that ENO continue to have assurance that it has a reasonable opportunity to recover the costs of its accelerated resilience investment in a timely manner. The Resilience Rider provides that assurance and would serve as a constructive sign that the Council is willing to support ENO in preventing any further degradation of ENO's credit ratings. Additionally, that assurance allows ENO to leverage the economies of scale and have the work continuity to efficiently execute the Phase 2 Resilience Plan, as discussed by Mr. Gremillion.

Q25. WOULD ENO'S ELECTRIC FRP PERMIT TIMELY COST RECOVERY OF THE RESILIENCE PLAN?

A. No. ENO has a limited term FRP, and ENO cannot depend on the FRP to be in place for the duration of the Phase 2 Resilience Plan. The maximum term for which ENO's FRPs have been approved has been only three years, and ENO will file the last Evaluation Report under the current FRP in 2026. Thus, the FRP alone does not present the level of assurance needed to efficiently execute the Phase 2 Resilience Plan.

Accordingly, the FRP is not a suitable cost recovery method for the five-year Phase 2 Resilience Plan.

Also, a rate case would not provide suitable cost recovery considering the timeline for resolution of ENO's typical rate cases (i.e., 12 months). Multiple rate cases would be an expensive, inefficient, and unnecessary use of resources for periodically resetting rates. Thus, continuing the Resilience Rider is a workable solution because it provides a stable source of recovery that supports an efficient supply chain strategy over a five-year cycle, more closely times recovery with the availability of benefits to customers, and provides a level of transparency that would enable efficient regulatory oversight.

Q26. WHAT EVIDENCE DO YOU HAVE TO SUPPORT YOUR OPINION THAT UNDERTAKING THE PHASE 2 RESILIENCE PLAN WITHOUT THE RESILIENCE RIDER WOULD HARM ENO'S CREDIT METRICS AND CASH FLOW?

A. I sponsor the indicative financial model ("Financial Model") attached to my testimony as Exhibit AMA-6, which Financial Model uses simplifying assumptions to compare cash flow results assuming no contemporary cost recovery mechanism and assuming the proposed Resilience Rider is in place. The Financial Model is similar to the one that accompanied my Direct Testimony filed in April 2023.

The Financial Model shows that if assuming no contemporary cost recovery mechanism is in place in one or more years that projects are closed to plant in service, ENO's most important credit metric, cash-flow-to-debt, would experience significant downward pressure during the Phase 2 Resilience Plan, 2027 to 2031, and that downward pressure would increase the longer cost recovery is delayed. The Financial Model is simplified in that ENO has assumed no recovery occurs over the entire duration of the Phase 2 Resilience Plan. The conclusion one should draw from the results of the Financial Model is that if one year without contemporaneous cost recovery occurs, ENO's cash-flow-to-debt ratio would degrade, and that potential degradation would be concerning.

Q27. PLEASE FURTHER DESCRIBE THE FINANCIAL MODEL PRESENTED ON EXHIBIT AMA-6.

A. The Financial Model isolates the cash flows that would occur during the Phase 2 Resilience Plan. The Financial Model uses the cash flows to calculate the projected degradation of ENO's cash-flow-to-debt ratio for the Phase 2 Resilience Plan. For simplification purposes, the Financial Model does not include cash flow projections for the remainder of ENO's operations beyond the Phase 2 Resilience Plan because such projections are unnecessary to determine the effects associated with the Phase 2 Resilience Plan.

In addition to the Phase 2 Resilience Plan, ENO's baseline capital program requires significant amounts of cash. This baseline capital program will drive debt issuances just like the Phase 2 Resilience Plan and likewise will be a source of downward pressure on ENO's credit metrics if supporting ratemaking mechanisms are not in place to recover the baseline capital spending.

Q28. IS THE BASELINE CAPITAL SPENDING FOR THE PERIOD 2026 THROUGH 2030 COMPARABLE TO THE BASELINE CAPITAL SPENDING IN APRIL 2023 WHEN ENO FIRST REQUESTED APPROVAL OF THE RESILIENCE RIDER?

A. Yes, currently ENO's projected baseline capital spending for the period 2026 through 2030 is comparable to the projected baseline capital spending for the period 2024 through 2028. ENO, however, believes that it is likely that baseline capital spending for the period 2026 through 2030 will increase as ENO continues its planning process.

Q29. WHY DOES THE FINANCIAL MODEL FOCUS ON THE CASH-FLOW-TO-DEBT RATIO?

A. The funds from operations ("FFO") to debt ratio and the cash flow from operations before changes in working capital ("CFO pre-WC") to debt ratio are very important to utility credit analysts. These ratios measure the degree of financial risk (the lower the percentage, the higher the risk) experienced by a company by comparing its cash flow to the level of debt that such company requires to sustain its operating and capital investment activities. These ratios are 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.

Q30. WHAT ELEMENTS IN THE FINANCIAL MODEL ARE USED TO CALCULATE THE CASH-FLOW-TO-DEBT RATIOS?

A. The Financial Model calculates cash flow using Interest Expense from the debt supporting the Phase 2 Resilience Plan projects. The Financial Model calculates debt by assuming that approximately 49% of the Phase 2 Resilience Plan's capital expenditures are funded with new debt issuances. The Phase 2 Resilience Plan's capital expenditures,[18] which include removal costs, are set forth in the table below.

Table 3 Phase 2 Resilience Plan Projected 2026-2031 Capital Expenditures ($ millions)	
Year	**Total**
2027	$77.2*
2028	$86.6
2029	$97.9
2030	$76.2
2031	$60.6
Total	$398.6
Notes: * This balance reflects $4.8 million of spending in 2026.	

Q31. WHAT ARE THE ASSUMPTIONS ASSOCIATED WITH INTEREST PAYMENTS?

A. The Financial Model assumes that the interest paid on debt supporting the Phase 2 Resilience Plan projects is based on an assumed cost of debt of [redacted], which is the assumed cost used in ENO's financial planning processes. Debt issuances are assumed to occur mid-year for purposes of calculating interest paid in the year of issuance.

18 These expenditure amounts assume that conductor handling costs are capitalized as discussed *infra*.

Q32. WHAT ASSUMPTIONS REGARDING INCOME TAXES DOES THE FINANCIAL MODEL ASSUME?

A. The Financial Model assumes that ENO no longer has a net operating loss ("NOL") and is making cash income tax payments. On an incremental basis, no recovery decreases cash income tax payments, and contemporaneous recovery increases cash income tax payments. Should ENO experience a NOL, the decrease in cash income tax payments would cease to occur in a no-recovery scenario.

Q33. WHAT ARE THE CASH-FLOW-TO-DEBT RATIOS FOR THE PHASE 2 RESILIENCE PLAN, ASSUMING THE RESILIENCE RIDER MECHANISM IS NOT IN PLACE FOR THE RECOVERY OF THE PHASE 2 RESILIENCE PLAN'S ASSOCIATED COSTS?

A. As shown below, the cash-flow-to-debt ratios are negative and trend downwards over time. These projections demonstrate that the Phase 2 Resilience Plan, without any cost recovery mechanism in place, would decrease ENO's overall cash-flow-to-debt ratios.

Table 4
Phase 2 Resilience Plan
Cash-Flow-to-Debt Ratio Assuming No Cost Recovery Mechanism for the Years 2027 through 2031

	2027	**2028**	**2029**	**2030**	**2031**
CF to Debt – No Recovery	-2.9%	-4.3%	-4.7%	-5.1%	-5.3%

This type of degradation in ENO's credit metrics would be insufficient to support sustainable, reliable operations and the Phase 2 Resilience Plan. Thus, ENO needs to have a contemporaneous cost recovery mechanism to address the financial pressures of the Phase 2 Resilience Plan over its duration and place ENO in a position to increase system resilience in a meaningful way and maintain its financial condition. These actions both enhance the likelihood of positive outcomes for customers in the form of a more resilient system and lower rates over time.

Q34. WHAT EFFECT WOULD THE RESILIENCE RIDER HAVE ON ENO'S FINANCIAL CONDITION?

A. As shown in the table below, continuation of the Resilience Rider would protect ENO's financial condition over the duration of the Phase 2 Resilience Plan. ENO's projected cash flow would improve relative to a situation where there is no recovery of the costs associated with the Resilience Plan, and such improvement would put ENO in a better financial position to execute the Resilience Plan and meet the Council's and customers' expectations in the future. The conclusion to draw from the below ratios under the two different scenarios is that one year without contemporaneous cost recovery would result in concerning consequences from a credit metric perspective but continuation of the Resilience Rider for the duration of the Phase 2 Resilience Plan would mitigate those adverse consequences.

Table 5
Phase 2 Resilience Plan
Cash-Flow-to-Debt Ratio Comparing No Recovery Mechanism to Recovery Through the Proposed Resilience Rider for the Years 2027 through 2031

	2027	2028	2029	2030	2031
CF to Debt – No Recovery	-2.9%	-4.3%	-4.7%	-5.1%	-5.3%
CF to Debt – Rider Recovery	5.9%	10.5%	13.5%	15.8%	17.6%

Q35. FOR PURPOSES OF THE COMPARISON REFLECTED IN TABLE 5, DID ENO CHANGE ANY ASSUMPTIONS IN THE FINANCIAL MODEL BECAUSE OF THE PROPOSED RESILIENCE RIDER?

A. The only change made to the Financial Model was to reflect the cash flow from the proposed Resilience Rider. The Financial Model assumes that ENO collects the estimated RSHCR Revenue Requirement in the calendar year corresponding to the projects' placement in service.

Q36. CONSIDERING THE RESILIENCE RIDER, WHAT IS THE ESTIMATED EFFECT OF THE PROPOSED RESILIENCE PLAN ON THE BILL OF A TYPICAL RESIDENTIAL CUSTOMER?

A. The estimated bill effects for a typical residential customer using 1,000 kwh per month are $1.01 per month in 2027 and $3.28 per month in 2028 and continue to increase over the course of the Phase 2 Resilience Plan. Exhibit AMA-7 shows the estimated Total Company revenue requirements, Residential Rate Class revenue requirements, and potential bill effects for the Phase 2 Resilience Plan for a typical residential customer using 1,000 kwh per month. These amounts assume that the Council does not authorize any mitigation for these bill effects.

Q37. ARE THE ESTIMATED BILL EFFECTS FROM THE PHASE 2 RESILIENCE PLAN OUTWEIGHED BY THE PROJECTED CUSTOMER BENEFITS?

A. Yes, ENO's customers would be better off paying for the Phase 2 Resilience Plan projects, both from a financial and service disruption standpoint. The 1898 & Co.

analysis, and as discussed by Mr. Gremillion and Mr. Mire, shows that ENO customers are better off paying for the Phase 2 Resilience Plan projects, paying reduced storm restoration costs, and experiencing shorter and fewer outages, as opposed to paying greater storm restoration costs and experiencing longer and more frequent storm outages without the Phase 2 Resilience Plan projects. Moreover, the preservation of ENO's financial integrity and related credit metrics mitigates exposure to downgrades that could result from insufficient cash flows. In short, paying for the Phase 2 Resilience Plan projects buys ENO's customers a more affordable future than if the Phase 2 Resilience Plan projects do not go forward.

VI. PUBLIC INTEREST

Q38. IS THE PROPOSED PHASE 2 RESILIENCE PLAN IN THE PUBLIC INTEREST?

A. Yes, the Phase 2 Resilience Plan is in the public interest. The related requests for relief in the Application, including continuation of the Resilience Rider and monitoring plan, are also in the public interest.

Q39. 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. In a case previously relied upon by the Council,[19] 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

[19] Resolution R-18-65, dated March 8, 2018, at 14 (relying on the quoted passage in describing the public interest standard).

> 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.[20]

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 relevant 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.[21] Finally, although witnesses can provide facts and opinions that bear on this issue, the decision-maker here – the Council – must ultimately weigh all of these factors and conclude whether the particular proposed course of action is in the public interest.

---

[20] *See also* Resolution R-18-65 at 107 (A public interest determination often requires "a subjective balancing of interests by the regulator . . . .").

[21] *See Permian Basin Area Rate Cases*, 390 U.S. 747, 815 (1968).

Q40. HAVE YOU REVIEWED THE REPORT THAT IS ATTACHED TO MR. MIRE'S TESTIMONY, AND IF SO, WHAT ARE YOUR CONCLUSIONS?

A. I have reviewed that report, and I find the approach taken by 1898 & Co. to be reasonable and carefully planned in its assessment of (1) all storms that have affected ENO's service area over a long period of time and (2) virtually all of ENO's grid assets, to develop levels of investment and portfolios of hardening projects for the Company to consider. As described in the Direct Testimony and report of Mr. Mire, the approach taken by 1898 & Co. also considers a multitude of other factors in its analysis, including the strength and location of storms as well as the age and condition of ENO's assets. Importantly, the approach is customer-centric in that it quantifies benefits of hardening projects directly in relation to the effects of those projects on customers, both on the storm restoration costs they will bear after future storms and the duration of the outages that customers will experience as a result of those future storms. This information also was used to prioritize the hardening projects in the Phase 2 Resilience Plan that reflect overall customer benefits exceeding the costs of the related investments. Customers are projected to achieve significant net benefits from the investments proposed to be undertaken by ENO in this docket based on 1898 & Co.'s analysis – a plan level benefit-cost ratio of 3.97.[22] Even if ENO experiences a very low storm future, 1898 & Co.'s analysis shows that the Phase 2 Resilience Plan would result in net benefits to

[22] Exhibit AMM-2 to the Direct Testimony of Mr. Mire at 9 (second bullet).

customers.[23] In short, if ENO does not go forward with the Phase 2 Resilience Plan, customers would be worse off following severe weather events.

Q41. WHAT ARE THE REASONS THAT SUPPORT YOUR OPINION THAT THE RESILIENCE PLAN IS IN THE PUBLIC INTEREST?

A. Overall, I base this opinion on the following: the increasing frequency and intensity in storms; the observed effectiveness of other utilities' resilience investments during recent storms (which Mr. Gremillion discusses in his testimony); and 1898 & Co.'s analysis showing that customers are better off if ENO goes forward with its Phase 2 Resilience Plan. I also base this opinion on the other economic benefits to New Orleans from a continuous resilience plan, which benefits are described by Ms. Rodriguez in her testimony and which I summarized earlier in my testimony.

Q42. PLEASE ELABORATE ON WHY THE INCREASING FREQUENCY AND INTENSITY IN STORMS SUPPORT A PUBLIC INTEREST FINDING IN FAVOR OF ENO'S PROPOSED PHASE 2 RESILIENCE PLAN.

A. As discussed in detail by Messrs. Gremillion and Mire in their testimonies, ENO's recent storm experience, and an expected storm future with increasingly frequent and intense storm activity, has made clear the need to further storm harden ENO's grid as soon as practical. Indeed, the Council has stated that "the current cycle of [storm]

[23] *See* Exhibit AMM-2 to the Direct Testimony of Mr. Mire at Section 8.3. As shown in Figure 8-8 in Exhibit AMM-2, assuming the lowest level of future storm activity, the Phase 2 Resilience Plan has a benefit-cost ratio of 1.33.

damage and repair is not sustainable."[24] Similarly, as mentioned above, S&P has stated that a continuous resilience plan is necessary for ENO to maintain its credit rating, and Moody's has identified the long-term adverse effects of not addressing storm risk. Moreover, both S&P and Moody's have observed that ENO's size and its storm-prone location are credit negatives.

Q43. HOW DOES THE EFFECTIVENESS OF OTHER UTILITIES' RESILIENCE INVESTMENTS DURING STORMS SUPPORT A FINDING THAT THE COMPANY'S PROPOSED HARDENING PLAN IS IN THE PUBLIC INTEREST?

A. Examples of the effectiveness of other utilities' resilience investments support that continuing resilience investments in New Orleans is in the public interest. Most recently, as explained by Mr. Gremillion, Hurricane Francine tested resilience investments in Grand Isle made by ELL after Hurricane Ida, and ELL's new infrastructure largely withstood the Hurricane Francine's effects.

The Company expects the same types of benefits from its proposed Phase 2 Resilience Plan, as discussed by Messrs. Gremillion and Mire.

[24] Resolution R-21-401, dated October 27, 2021, at 2.

Q44. THE 1898 & CO. ANALYSIS QUANTIFIES THE REDUCTION IN STORM RESTORATION COSTS AND IN CUSTOMER MINUTES INTERRUPTED AS BENEFITS FROM THE HARDENING PROJECTS IN THE PHASE 2 RESILIENCE PLAN. DO THESE BENEFITS SERVE THE PUBLIC INTEREST?

A. Yes, they do. After Hurricane Ida, the Council opened this docket in large part because the cycle of storm restoration costs over the last few years, in particular, is not sustainable for customers or the Company itself. The expected reduction in future storm restoration costs from the Phase 2 Resilience Plan, as described by Mr. Mire in his testimony and the 1898 & Co. report, is a significant benefit to customers and serves the public interest. The 1898 & Co. report quantifies the expected reduction in future storm restoration costs from the Phase 2 Resilience Plan at approximately $83 million over the 50-year time horizon assuming an above average frequency of storms.[25] Indeed, being good stewards of customers' money, while maintaining reliable electric service, is fundamental to the public interest. With regard to the expected reduction in customer minutes interrupted, per Mr. Mire's testimony, a shortened period during which customers are without electricity from storm events is another significant benefit of the Phase 2 Resilience Plan. The 1898 & Co. report estimates a decrease in the total number of customer minutes interrupted by 3.4 billion minutes, which corresponds to an estimated reduction of over $1.3 billion in overall outage costs to customers, over the 50-year time horizon assuming an above average frequency of storms.[26]

---

[25] Exhibit AMM-2 to the Direct Testimony of Mr. Mire at Section 8.3.

[26] *Id*.

Shorter outages allow customers to get back to normal quicker, whether those customers are residents or businesses, and that is certainly in the public interest. Moreover, I find 1898 & Co.'s use of the Interruption Cost Estimate ("ICE") Calculator from the U.S. Department of Energy ("DOE") to estimate the societal benefit from reduced customer interruption minutes to be reasonable in the present circumstances.[27]

Q45. ARE THERE OTHER FACTORS THAT YOU CONSIDER RELEVANT TO A PUBLIC INTEREST DETERMINATION REGARDING THE PHASE 2 RESILIENCE PLAN?

A. Yes. The other factors include the fact that the Company considered bill impacts to customers in selecting the Phase 2 portfolio. It is in the public interest for the Company to balance costs to customers against expected benefits in making business decisions and selecting infrastructure projects. In addition, "blue sky" resilience work can be more carefully performed and cost-effective than reactive, post-storm restoration work, and customers will see the benefits of such "blue sky" work sooner than if the projects were delayed. These benefits are in the public interest. Further, as mentioned above, there are likely supportive credit implications associated with the Phase 2 Resilience Plan.

[27] As Mr. Gremillion explains in his testimony, 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 the use of the DOE's ICE calculator to help prioritize projects within the Phase 2 Resilience Plan is not an endorsement of any other use.

Q46. ARE THE RELATED REQUESTS FOR RELIEF IN THE APPLICATION, INCLUDING CONTINUATION OF THE RESILIENCE RIDER AND MONITORING PLAN, ALSO IN THE PUBLIC INTEREST?

A. Yes. Earlier in my testimony, I explained why I recommend that the Council continue the Resilience Rider. Furthermore, as Mr. Gremillion discusses, continued reporting and application of reasonable metrics will facilitate oversight of the Phase 2 Resilience Plan by the Council and its Advisors.

VII. RATEMAKING AND ACCOUNTING TREATMENTS

Q47. PLEASE DESCRIBE THE COMPANY'S REQUEST CONCERNING UNRECOVERED PLANT COSTS.

A. In Ordering Paragraph 6 of Resolution R-24-625 addressing the Phase 1 Resilience Plan, the Council authorized ENO 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 Phase 1 Resilience Plan. ENO requests that such authorization be extended to the assets that must be retired and replaced with new assets as part of the Phase 2 Resilience Plan. Pursuant to such authorization, ENO intends to include the regulatory asset in rate base in its upcoming FRP filing 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 ENO recovers its prudently incurred costs, all else being equal.

Q48. WHAT WILL THE PROCESS BE FOR CALCULATING AND AMORTIZING THE REGULATORY ASSET GIVEN THAT IT INVOLVES THE RETIREMENT AND REMOVAL OF MASS PROPERTY THAT IS NOT ACCOUNTED FOR INDIVIDUALLY ON THE BOOKS AND RECORDS OF THE COMPANY?

A. ENO intends to use a single, average amortization rate based on the pertinent distribution depreciation rates associated with the unrecovered plant to be applied to the remaining regulatory asset balance. This will facilitate ENO automating the calculation of the amortization of the regulatory asset and insuring customers will not see an incremental increase in rates from the recovery of the unrecovered plant costs.

Unlike the Advanced Metering Infrastructure ("AMI") retired meters regulatory asset previously approved by the Council, which had a definite balance and a definite amortization period, unrecovered plant costs will be continuously added to the regulatory asset over the course of the Phase 1 and Phase 2 Resilience Plans and perhaps future phases. By applying a single amortization rate, ENO would be able to transfer the unrecovered plant costs from the plant accounting system to another accounting system and avoid extensive manual processing and monitoring the detailed plant accounting transactions records tracking plant vintage, account depreciation rates, and 300-level FERC account, which are used in the plant accounting system.

Q49. PREVIOUSLY THE COMPANY SOUGHT AN ACCOUNTING WAIVER FOR DISTRIBUTION CONDUCTOR HANDLING COSTS. DOES THE COMPANY INTEND TO REQUEST EXTENSION OF THAT ACCOUNTING WAIVER FROM THE FERC FOR THE PHASE 2 RESILIENCE PLAN?

A. Yes, the Company does. The Company's estimated bill effects assume that ENO is able to capitalize distribution conductor handling costs incurred with projects in the Phase 2 Resilience Plan, which are those costs associated with transferring existing conductors and fixtures to new poles during pole replacements.

VIII. COUNCIL RULES AND REGULATIONS

Q50. IN PREPARING YOUR TESTIMONY AND OFFERING YOUR OPINIONS, DID YOU CONSIDER APPLICABLE COUNCIL RULES AND REGULATIONS?

A. Yes. I considered Section 158 of the Code of the City of New Orleans and certain resolutions applicable to ENO.

Q51. DO YOU HAVE ANY OPINIONS REGARDING ENO'S REQUESTS IN THIS APPLICATION RELATIVE TO THOSE COUNCIL RULES AND REGULATIONS?

A. Yes. For all of the Company's requests in this Application, it is my understanding that the Company has complied with, or is not in conflict with, the provisions of all applicable Council resolutions and any other laws, regulations, or requirements that may be applicable. Moreover, to the extent that ENO has not complied with any such requirements of the City Code, the Council should allow ENO a reasonable time to cure any such deficiency or grant a waiver of any applicable Council requirement to the extent that such a waiver may be required to facilitate consideration and approval of the Phase 2 Resilience Plan and associated requested relief.

IX. CONCLUSION

Q52. 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 her sworn testimony in this proceeding and that she 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, she verily believes them to be true.

ALYSSA MAURICE-ANDERSON

SWORN TO AND SUBSCRIBED BEFORE ME
THIS 15th DAY OF DECEMBER 2025

NOTARY PUBLIC

My commission expires: upon death

Testimony Presented by Alyssa Maurice-Anderson
Before Utility Regulators

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, Affiliate Costs
5	Dec 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
6	Mar 2023	In Re: Application of Entergy Louisiana, LLC for Approval of the Entergy Future Ready Resilience Plan (Phase I)	U-36625	Louisiana Public Service Commission	Direct	Ratemaking
7	April 2023	In Re: System Resilience and Storm Hardening	UD-21-03	Council of the City of New Orleans	Direct	Ratemaking
8	Mar 2023	In Re: Application of Entergy Louisiana, LLC for Approval of the Entergy Future Ready Resilience Plan (Phase I)	U-36625	Louisiana Public Service Commission	Direct	Ratemaking
	Aug 2023	Application of Entergy Louisiana, LLC for Approval of Regulatory Blueprint Necessary for Company to Strengthen the Electric Grid for State of Louisiana	U-36959	Louisiana Public Service Commission	Direct	Ratemaking, Policy (public interest)
9	Nov 2023	In Re: Application of Entergy Louisiana, LLC for Approval of the Entergy Future Ready Resilience Plan (Phase I)	U-36625	Louisiana Public Service Commission	Rebuttal	Ratemaking
10	June 2024	Delta States Utilities LA and Entergy Louisiana, LLC [sic], Ex Parte. In Re: Application for Authority to Operate as Local Distribution Company and Incur Indebtedness and Joint Application for Approval of Transfer and Acquisition of Local Distribution Company Assets and Related Relief	UD-24-01	Council of the City of New Orleans	Rebuttal	Policy, Restructuring, Ratemaking
11	Sept 2024	Delta States Utilities LA and Entergy Louisiana, LLC [sic], Ex Parte. In Re: Application for Authority to Operate as Local Distribution Company and Incur Indebtedness and Joint Application for Approval of Transfer and Acquisition of Local Distribution Company Assets and Related Relief	UD-24-01	Council of the City of New Orleans	Rejoinder	Policy, Restructuring, Ratemaking
12	Sept 2025	In Re: Application of Entergy Louisiana, LLC to Return River Bend Deregulated Asset to Rate Base and Other Associated Relief	U-37735	Louisiana Public Service Commission	Direct	Policy, Ratemaking

ENTERGY NEW ORLEANS, LLC
ELECTRIC SERVICE

RIDER SCHEDULE RSHCR

Effective: October 24, 2024
Filed: December 18, 2024
Supersedes: New Schedule
Schedule Consists of: Two Pages plus Attachments A and B

RESILIENCE & STORM HARDENING COST RECOVERY RIDER

I. PURPOSE

The purpose of the Resilience & Storm Hardening Cost Recovery Rider ("Rider RSHCR") is to establish the revenue requirement associated with the Council-approved Resilience Plan capital additions ("RSHCR Revenue Requirement"). Entergy New Orleans, LLC ("ENO" or the "Company") will recover the RSHCR Revenue Requirement through the Electric Formula Rate Plan ("EFRP") Rate Adjustment. Capital additions associated with other transmission and distribution work shall not be eligible for recovery through this Rider RSHCR. To the extent that ENO receives government grant funding for such capital additions, such funding shall be accounted for as stated below.

II. DEFINITIONS

RSHCR Revenue Requirement shall include the cost associated with the Council-approved Resilience Plan capital additions determined in Council Resolution No. R-24-625 and Council R-26-XXX in Council Docket No. UD-21-03 and any other costs that the Council finds appropriate to support the resilience of ENO's operations, including capital investments and expenses.

III. BILLING AND CALCULATION, REDETERMINATION, TRUE-UP, AND REALIGNMENT

A. **Billing and Calculation.** Attachment A shall show the estimated annual RSHCR Revenue Requirement by rate class. The estimated annual RSHCR Revenue Requirement for the following calendar year shall be calculated with the formula ("RSHCR Revenue Requirement Formula") set out in Attachment B to this Rider RSHCR. The estimated Rider RSHCR Revenue Requirement shall be included in the Rider EFRP Rate Adjustment as an Outside the Band adjustment. The RSHCR Revenue Requirement will be allocated to the Rate Classes based on the most recently calculated D1: Distribution Primary Demand allocator reflected in ENO's rates. The initial estimated annual Rider RSHCR Revenue Requirement for calendar year 2025 will be included in Rider EFRP Attachment A as part of the EFRP Rate Adjustment effective with the first billing cycle of January 2025 per Council Resolution No. R-24-625.

B. **Redetermination.** For each calendar year after 2025, the Company shall update the RSHCR Revenue Requirement. On or before October 1, 2025, and each subsequent October 1 thereafter, the Company shall file a new estimated annual revenue requirement, which will be based on forecasted information for the following calendar year, and which will be used beginning with the first billing cycle of the following January. Such estimated annual revenue requirement shall include all costs associated with Resilience Plan capital additions for the following calendar year and any RSHCR Revenue Requirements that have not been realigned into base rates.

C. **True-Up and Prudence Review.** Beginning in 2026, on or before August 1, the Company shall file a report to support the prudence of the previous calendar year's actual RSHCR Revenue Requirement. Such report shall include a variance report comparing actual capital to projected capital additions plus any other material cost differences. Such report shall also include the computation to true-up the previous calendar year's actual RSHCR Revenue Requirement with the corresponding estimated annual RSHCR Revenue Requirement ("True-Up"). The difference plus interest shall be returned to or recovered from customers over twelve months beginning in the first billing cycle of the following January, as shown in the RSHCR Revenue Requirement Formula. The interest rate to be utilized is the prime bank lending rate as published in the Wall Street Journal. Any grant funding from non-utility sources that ENO receives for Resilience Plan capital additions shall be treated as an offset to the capital additions included in the actual revenue requirement.

D. **Dispute Resolution.** The Council Advisors ("Advisors"), any intervenors allowed by the Council, and the Company (collectively, the "Parties") shall have until November 1 to file a report communicating any errors or disputes ("Correction/Error Report") with respect to the proposed Rider RSHCR Revenue Requirement, the true-up, or the prudence of any capital addition or other cost. Each such indicated dispute shall include, if available, documentation to support the proposed correction or prudence dispute. The Company shall then have thirty (30) days to review any proposed corrections or disputes, to work to resolve any disputes, and to file a revised Rider RSHCR Revenue Requirement reflecting all corrections and disputes upon which the Parties agree. The Company shall provide the Advisors with appropriate workpapers supporting any revisions.

In the event there are disputes regarding the Rider RSHCR Revenue Requirement, the true-up, or the prudence of any capital addition or other cost, the Parties shall work together in good faith to resolve such disputes. 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 thirtieth (30) day after the filing of the Correction/Error Reports, revised Rider RSHCR Revenue Requirement reflecting all revisions to the initially filed RSHCR Revenue Requirement on which the Parties agree shall be used in the EFRP Rate Adjustment effective the first billing cycle of the following January.

Any remaining disputes shall be submitted to the Council for resolution. If the Council's final ruling on any disputes requires changes to the true-up initially used pursuant to the above provisions, within sixty (60) days after receipt of the Council's final ruling on any disputes, the Company shall file a revised true-up and shall determine the amount to be refunded or surcharged to customers, if any, together with interest based on the rate set forth in Paragraph C above. Such refund/surcharge amount shall be included in the next true-up computation.

E. **Realignment.** The Company shall realign all RSHCR Revenue Requirements related to Resilience Plan capital additions included in per books plant in service in an EFRP Evaluation Report or base rate case class cost of service study contemporaneous with the rate change resulting from that rate proceeding. In the case of an EFRP, such realigned revenue requirement shall be included inside the bandwidth calculation and the associated revenues shall be realigned to Annualized Evaluation Period EFRP Revenues. The Company shall adjust the Rider RSHCR Revenue Requirement to remove the corresponding realigned revenue requirement contemporaneous with the EFRP or base rate change.

IV. TERM

The Rider RSHCR shall remain in effect until the Council replaces the Rider RSHCR with a new contemporaneous cost recovery mechanism. After the completion of the Council-approved Resilience Plan capital additions, the recovery of the Rider RSHCR Revenue Requirement shall remain in effect unless and until the last day of the month prior to the implementation of base rates recovering the RSHCR Revenue Requirement previously recovered through the EFRP Rate Adjustment.

Within six months after termination of the Rider RSHCR, there will be a true-up of any periods not previously subject to a true-up as provided for above. Any over- or under- refund/recovery, including interest, will be included in Attachment A, Page 2, Line 12 of the then-effective Rider Schedule FAC as a Prior Period Adjustment to the Cumulative (Over)/Under Collection Account.

Attachment A
Page 1 of 1

Entergy New Orleans, LLC
Resilience & Storm Hardening Cost Recovery Rider
Resilience & Storm Hardening Cost Recovery Rider Revenue Requirement Formula
Rider RSHCR Rate Formula

Rate Adjustments - January XXXX

	Col A	Col B	Col C
		Resilience & Storm Hardening Cost Recovery Rider Revenue Requirement (RSHCRRR)	
Ln No.	Rate Class (1)	Class Allocation (%) (2)	RSHCRRR ($) (3)
1	Residential		$ -
2	Small Electric		$ -
3	Municipal Buildings		$ -
4	Large Electric		$ -
5	Large Electric High Load Factor		$ -
6	Master Metered Non Residential		$ -
7	High Voltage		$ -
8	Large Interruptible		$ -
9	Large Municipal		$ -	T
10	Lighting		$ -	T
11	Total ENO	0.00%		T

Notes:
(1) Excludes schedules specifically identified on Attachment A of Rider EFRP.

(2) Requirement (RSHCRRR) shall be allocated to the retail rate classes based on the most recently used D1: Distribution Primary Demand Allocation Factor pursuant to Section III.A of this Resilience & Storm Hardening Cost Recovery Rider.

(3) See Attachment B, Page 1, Line 17 for the RSHCR Revenue Requirement. The class amount is the Class Allocation % in Col B times the RSHCRRR.

Entergy New Orleans, LLC
Resilience & Storm Hardening Cost Recovery Rider
Resilience & Storm Hardening Cost Recovery Rider Revenue Requirement Formula (1)
For the Twelve Months ended December 31, XXX

Ln No.	Description	Amount	Reference
	Rate Base:		
1	Plant in Service (2)		WP 1
2	Accumulated Depreciation & Amortization (2)		WP 2
3	**Net Utility Plant**	-	Line 1 + Line 2
4	Accumulated Deferred Income Taxes (3)		WP 2
5	**Total Rate Base**	-	Line 3 + Line 4
6	Before-Tax Rate of Return on Rate Base (4)		WP 4
7	**Return on Rate Base**	-	Line 5 * Line 6
8	**Expenses:**		
9	Operation & Maintenance Expense (6)	-	WP 3
10	Depreciation & Amortization Expense (5)		WP 2
11	Taxes Other Than Income (5)	-	WP X
12	AFUDC Equity Book Depreciation Income Tax Expense Flow Through (7)	-	WP 2
13	**Total Expenses**	-	Line 9 + Line 10 + Line 11 + Line 12
14	Revenue Related Expense Factor (8)		WP 5
15	**Total Estimated Annual Resilience & Storm Hardening Cost Recovery Rider Revenue Requirement**	-	(Line 7 + Line 13) * Line 14
16	True-up of Resilience & Storm Hardening Cost Recovery Rider Revenue Requirement	-	Att B Pg 2, L24
17	**Total Annual Resilience & Storm Hardening Cost Recovery Rider Revenue Requirement (RSHCRRR)**	$ -	Line 15 + Line 16

Notes:
(1) Pursuant to Section III.B of this Resilience & Storm Hardening Cost Recovery Rider
(2) Estimated Plant in Service and Accumulated Depreciation & Amortization balances at December 31 of the upcoming calendar year based on end of period. This amount also includes conductor handling costs.
(3) The amount is adjusted for the normalization limit per Regulation Section 1-167(l)-1(h)(6).
(4) The Before Tax Rate of Return is based on the currently approved rate proceeding using the most recently approved return on equity at December 31 of the current calendar year unless another capital structure is agreed upon for ratemaking purposes.
(5) Estimated Depreciation & Amortization Expense and Other Tax Expense for the upcoming calendar year.
(6) Operation & Maintenance Expense approved by Council for recovery through the Resiliency Rider.
(7) This amount reflects the grossed-up federal and state income tax expense resulting from the recovery of book depreciation expense attributable to previous accruals of AFUDC Equity that were not included in the income tax return and for which there is no tax basis and no accelerated tax depreciation. Recovery of this amount is consistent with Council ratemaking practice.

(8) Revenue Related Expense Factor = 1 / (1-Bad Debt Rate - Revenue Related Tax Rate). The ENO Bad Debt Rate and the Revenue Related Tax rate shall be developed consistent with the methodology used for calculating it in the most recent ENO rate filing and shall use the most recently available calendar year data at the time of filing.

Entergy New Orleans, LLC
Resilience & Storm Hardening Cost Recovery Rider
Resilience & Storm Hardening Cost Recovery Rider Revenue Requirement Formula
True-up of Resilience & Storm Hardening Cost Recovery Revenue Requirement [1]
For the Period ended December 31, XXXX

Ln No.	Description	Amount	Reference
	Rate Base:		
1	Plant in Service [2]	-	WP X
2	Accumulated Depreciation & Amortization [2]	-	WP X
3	**Net Utility Plant**	-	Line 1 + Line 2
4	Accumulated Deferred Income Taxes [2]	-	WP X
5	**Total Rate Base**	**-**	Line 3 + Line 4
6	Before-Tax Rate of Return on Rate Base [3]	0.00%	WP X
7	**Return on Rate Base**	**-**	Line 5 * Line 6
8	**Expenses:**		
9	Operation & Maintenance Expense [4]		WP X
10	Depreciation & Amortization Expense [4]	-	WP X
11	Taxes Other Than Income [4]	-	WP X
12	AFUDC Equity Book Depreciation Income Tax Expense Flow Through[5]	-	WP X
13	**Total Expenses**	**-**	Line 9 + Line 10 + Line 11 + Line 12
14	Revenue Related Expense Factor	-	Att B, Pg 1, L14 PY Filing
15	**Actual Resilience & Storm Hardening Cost Recovery Rider Revenue Requirement**	**$ -**	(Line 7 + Line 13) * Line 14
16	**Estimated Resilience & Storm Hardening Cost Recovery Rider Revenue Requirement**	**$ -**	WP X
17	**Difference in Actual Annual Rider RSHCR Revenue Requirement and Estimated Rider RSHCR Revenue Requirement**	**-**	Line 15 - Line 16
18	**Interest:**		
19	Annual Prior Year True-up of Resilience & Storm Hardening Cost Recovery Rider Revenue Requirement [6]	-	Att B Pg 2, L24 PY Filing
20	Prior Period Adjustments	-	
21	Total True-Up Adjustment Before Interest	-	Line 17 + Line 19 + Line 20
22	Interest Rate [7]	0.00%	
23	**Interest on Average Balance**	**-**	(Line 21/2) * Line 22
24	**Total True-Up of RSHCRRR with Interest**	**$ -**	Line 17 + Line 23

Notes:
(1) Pursuant to Section III.C of this Resilience & Storm Hardening Cost Recovery Rider
(2) Actual Plant in Service, Accumulated Depreciation & Amortization, and Accumulated Deferred Income Taxes balances on December 31 of the previous calendar year based on end of period. To the extent that ENO receives government funding for such capital additions, such funding shall be treated as an offset to rate base and book depreciation expense in the revenue requirement including interest calculated from the date that the funds were received. The ADIT impacts associated with taxable government funding would also be included in the adjustments to the revenue requirement.
(3) The Before Tax Rate of Return is based on the actual capital costs at December 31 of the previous calendar year.
(4) Actual Operation & Maintenance Expense, Depreciation & Amortization Expense, and Other Tax Expense for the previous calendar years balances as of December 31.
(5) This amount reflects the grossed-up federal and state income tax expense resulting from the recovery of book depreciation expense attributable to previous accruals of AFUDC Equity that were not included in the income tax return and for which there is no tax basis and no accelerated tax depreciation. Recovery of this amount is consistent with Council ratemaking practice.
(6) Prior Period True-up of Resilience & Storm Hardening Cost Recovery Rider Revenue Requirement (RSHCRRR) reflected on line 24 of Attachment B, Page 2 in the previous years Resilience & Storm Hardening Cost Recovery Rider filed August XXXX.
(7) Prime Rate on the last business day of the operations recovery period as stated in the Wall Street Journal was X.XX%.

S&P Global
Ratings

RatingsDirect®

Research Update:

Entergy New Orleans LLC Downgraded To 'BBB' From 'BBB+' On Storm Risks, Outlook Negative

October 8, 2020

PRIMARY CREDIT ANALYST

Mayur Deval
Toronto
(1) 416-507-3271
mayur.deval
@spglobal.com

SECONDARY CONTACT

Gerrit W Jepsen, CFA
New York
(1) 212-438-2529
gerrit.jepsen
@spglobal.com

Rating Action Overview

- Regulated utility Entergy New Orleans LLC's service territory is subject to the risk of severe storms and hurricanes.
- We our lowering our issuer credit rating on Entergy New Orleans LLC (ENO) to 'BBB' from 'BBB+'. The outlook is negative.
- We are revising our assessment of ENO's group support from parent company Entergy Corp. (Entergy) to moderately strategic from core given our view that group support has weakened because of the propensity and severity of storm activity along the Gulf Coast. Our stand-alone credit profile (SACP) for ENO remains 'bbb-'.
- At the same time, we are lowering our ratings on ENO's first-mortgage bonds to 'A-' from 'A'. The recovery rating remains '1+'.
- The negative outlook reflects our expectation of weaker financial measures including adjusted funds from operations (FFO) to debt in the 13%-15% range through 2022. In addition, our outlook reflects the potential that we could revise the designation of group support under our group rating methodology to nonstrategic within the next year. As such, we could lower the issuer credit rating on ENO to reflect view of a stand-alone credit profile (SACP) 'bbb-' and our assumption of no group support.

Rating Action Rationale

ENO's service territory creates severe storm and hurricane risks for the utility. Given ENO's exposure to severe storms including hurricanes, a low-lying service territory along the Gulf Coast, and relatively limited size and diversity to help absorb the impact of such storms, ENO's SACP remains 'bbb-'.

We revised our assessment of ENO's group status to parent Entergy, under our group rating methodology to moderately strategic from core. Our reassessment of ENO's group status incorporates its importance to the group's long-term strategy and being a reasonably successful utility. We have concluded that group support has weakened because of the propensity and severity of storm activity along the Gulf Coast, which is critical to a service territory that mostly encompasses a low-lying city that has been in the path of numerous hurricanes. We would however expect ENO to receive extraordinary group support in some circumstances. This could include in times of stress such as for storm repairs or large capital spending initiatives.

The outlook reflects our baseline forecast of weaker financial measures through 2022, the service territory's continued susceptibility to severe storms, and the lack of significant financial support from parent Entergy. Specifically, we expect ENO's service territory to have ongoing exposure to severe storms like the recent Hurricane Laura, and Hurricane Delta currently moving through the Gulf of Mexico, potentially leading to significant liabilities and damages to the infrastructure. Therefore our outlook reflects the potential that we could revise the designation of group support under our group rating methodology to nonstrategic within the next year. As such, we could downgrade ENO to reflect our view of ENO's SACP of 'bbb-' and our assumption of no group support. In addition, our negative outlook reflects our expectation of weaker financial measures including adjusted FFO to debt in the 13%-15% range through 2022

Environmental, social, and governance (ESG) credit factors for this credit rating change.

- Natural conditions

Outlook

The negative outlook on ENO reflects its small service territory, limited diversity, and ongoing exposure to severe storms and hurricanes and our expectation of weaker financial measures partly from higher capital spending and elevated leverage. Specifically, we forecast the company's adjusted consolidated FFO to debt to remain weak in the 13%-15% range in 2020 and 2021.

Downside scenario

We could lower our ratings on ENO if its business risk would materially weaken or financial measures decline, including adjusted FFO to debt consistently below 13%. The negative outlook reflects the weaker financial measures and the potential that we could revise the designation of group support under our group rating methodology to nonstrategic if we perceive limited to no group support for ENO during times of stress. As such, we could downgrade ENO to reflect our view of ENO's SACP of 'bbb-' and our assumption of no group support, particularly in times of stress such as for storm repairs or large capital spending initiatives. Although unlikely, we could lower our ratings on ENO if we lower our ratings on Entergy.

Upside scenario

We could revise the outlook to stable if financial measures materially strengthen and, although unlikely, we reassess and conclude that group support would be readily available to fund ENO if a severe storm resulted in material restoration costs to the utility.

Company Description

ENO is a vertically integrated electric and natural gas distribution utility operating largely in New Orleans.

Our Base-Case Scenario

- Expected EBITDA margin averaging about 22% per year;
- Annual capital spending of $160 million to $180 million through 2022;
- Dividends over $20 million after 2020;
- Negative discretionary cash flow indicating external funding needs;
- Generally constructive regulatory environments help provide prudent cost recovery; and
- All debt maturities are refinanced.

Based on our assumptions, we expect the following measures over the forecast period through 2022:

- Annual adjusted FFO to debt in the 13%-15% range;
- Annual adjusted debt to EBITDA in the 4.5x-5.5x range; and
- Annual adjusted FFO cash interest coverage in the 4x-4.5x range.

Liquidity

We assess ENO's stand-alone liquidity as adequate, because we believe its liquidity sources are likely to cover uses by more than 1.1x over the next 12 months and meet cash outflows even with a 10% decline in EBITDA. 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 $30 million;
- Estimated cash FFO of about $120 million; and
- Credit facility availability of about $25 million.

Principal liquidity uses

- Debt maturities of about $25 million;
- Capital spending of about $120 million; and
- Dividends of about $10 million.

Group Influence

We view ENO as a member of the Entergy group. We assess ENO as a moderately strategic subsidiary of Entergy because it is important to Entergy's long-term strategy and it is reasonably successful as a utility, and we expect extraordinary group support will remain limited to some circumstances. As a result, our rating on ENO is based on its SACP of 'bbb-' and one notch of group support.

Issue Ratings - Recovery Analysis

ENO'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 of two notches above the issuer credit rating.

Ratings Score Snapshot

Issuer Credit Rating: BBB/Negative/--

Business risk: Strong

- Country risk: Very low
- Industry risk: Very low
- Competitive position: Satisfactory

Financial risk: Significant

- Cash flow/leverage: Significant

Anchor: bbb

Modifiers

- 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 group: Moderately Strategic (+1 notch above SACP)

Related Criteria

- General Criteria: Group Rating Methodology, July 1, 2019
- Criteria | Corporates | General: Corporate Methodology: Ratios And Adjustments, April 1, 2019
- Criteria | Corporates | General: Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers, Dec. 16, 2014
- Criteria | Corporates | General: Corporate Methodology, Nov. 19, 2013
- Criteria | Corporates | Utilities: Key Credit Factors For The Regulated Utilities Industry, Nov. 19, 2013

- General Criteria: Methodology: Industry Risk, Nov. 19, 2013
- General Criteria: Country Risk Assessment Methodology And Assumptions, 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

Ratings List

Downgraded; Outlook

	To	From
Entergy New Orleans LLC		
Issuer Credit Rating	BBB/Negative/--	BBB+/Negative/--
Ratings Lowered; Recovery Rating Unchanged		
	To	From
Entergy New Orleans LLC		
Senior Secured	A-	A
Recovery Rating	1+	1+

Certain terms used in this report, particularly certain adjectives used to express our view on rating relevant factors, have specific meanings ascribed to them in our criteria, and should therefore be read in conjunction with such criteria. Please see Ratings Criteria at www.standardandpoors.com for further information. Complete ratings information is available to subscribers of RatingsDirect at www.capitaliq.com. All ratings affected by this rating action can be found on S&P Global Ratings' public website at www.standardandpoors.com. Use the Ratings search box located in the left column.

S&P Global
Ratings

RatingsDirect®

Research Update:

Entergy New Orleans LLC Downgraded To 'BB+' On Weather-Related Weaker Credit Metrics; Outlook Stable; Bond Rating Lowered

September 2, 2021

Rating Action Overview

- Entergy New Orleans LLC (ENO), an operating subsidiary of Entergy Corp. (Entergy), will likely have weaker financial measures than we previously expected because of higher capital spending from severe storms and hurricanes, like Hurricane Ida. We forecast ENO's adjusted funds from operations (FFO) to debt to be in the 12%-13% range through 2023.
- We lowered our issuer credit rating on ENO to 'BB+' from 'BBB'. At the same time, we lowered our ratings on ENO's first-mortgage bonds (FMBs) to 'BBB+' from 'A-'. The '1+' recovery rating on the bonds remains unchanged.
- The lower issuer credit rating reflects a change in the business risk profile to satisfactory from strong due to ongoing risks related to ENO's exposure to coastal storms. In addition, we apply the negative comparable ratings analysis modifier due to weaker financial measures within the financial risk category.
- The stable outlook reflects our view that ENO will restore operations following hurricane Ida in an orderly manner and that any additional costs will be manageable within the current financial risk profile assumptions.

PRIMARY CREDIT ANALYST

Gerrit W Jepsen, CFA
New York
+ 1 (212) 438 2529
gerrit.jepsen@spglobal.com

SECONDARY CONTACTS

William Hernandez
Farmers Branch
+ 1 (214) 765-5877
william.hernandez@spglobal.com

Daria Babitsch
New York
917-574-4573
daria.babitsch1@spglobal.com

Rating Action Rationale

The lower issuer credit rating reflects a weakening of ENO's business risk along with weakening financial measures. We changed the business risk profile to satisfactory from strong, reflecting ENO's small service territory, limited diversity, and ongoing exposure to severe storms and hurricanes. This revision reflects the smaller size of the utility, exposure to severe storms including hurricanes due to its low-lying service territory along the Gulf Coast, and expectation of more volatile profitability measures. Financial risk measures have weakened within the significant financial risk profile category to the lower end of the benchmark range. The weaker measures include adjusted FFO to debt in the 12%-13% range from severe storms such as Hurricane Ida that lead to higher capital spending, operating expenses from storm restoration, and revenue declines following power outages and load reduction.

The outlook reflects our baseline forecast of weaker financial measures through 2023, the service territory's ongoing susceptibility to severe storms, and limited financial support from parent Entergy. Specifically, we expect ENO's service territory to have ongoing exposure to severe storms like the recent Hurricane Ida, potentially leading to significant liabilities and damages to the infrastructure. The stable outlook incorporates the weaker financial measures including adjusted FFO to debt in the 12%-13% range through 2022. Our downside scenario, while not expected, includes the potential that we could revise the designation of group support under our group rating methodology to nonstrategic if we perceive limited to no group support for ENO during times of stress. As such, we could downgrade ENO to reflect our view of ENO's stand-alone credit profile (SACP) of 'bb' and our assumption of no group support, particularly in times of stress such as for storm repairs or large capital spending initiatives.

Environmental, social and governance (ESG) credit factors for this credit rating change.

- Natural conditions

Outlook

The stable outlook reflects our view that ENO will restore operations following hurricane Ida in an orderly manner and that any additional costs will be manageable within the current financial profile assumptions. The company's small service territory, limited diversity, and ongoing exposure to severe storms and hurricanes remains a risk as does the expectation of weaker financial measures partly from higher capital spending and elevated leverage. Specifically, we forecast the company's adjusted consolidated FFO to debt to remain in the 12%-13% range through 2023.

Downside scenario

We could lower the ratings on ENO if its financial measures decline, including sustained adjusted FFO to debt consistently below 11%. We could also lower the rating if we revise the designation of group support under our group rating methodology to nonstrategic if we perceive limited to no group support for ENO during times of stress. As such, we could downgrade ENO to reflect our view of ENO's SACP of 'bb' and our assumption of no group support, particularly in times of stress such as for storm repairs or large capital spending initiatives.

Upside scenario

We could upgrade ENO if financial measures remain consistently above 17% and we believe group support would be readily available to fund ENO if a severe storm resulted in material restoration costs to the utility.

Company Description

ENO is a vertically integrated electric and a natural gas distribution utility operating largely in New Orleans.

Our Base-Case Scenario

- Expected EBITDA margin averaging about 20% per year;
- Annual capital spending of $205 million through 2023;
- Dividends over $30 million through 2023;
- Negative discretionary cash flow indicating external funding needs;
- Generally constructive regulatory environments help provide prudent cost recovery; and
- All debt maturities are refinanced.

Based on our assumption, we expect the following measures over the forecast period through 2023:

- Annual adjusted FFO to debt in the 12%-13% range;
- Annual adjusted debt to EBITDA in the 5.5x-6.5x range; and
- Annual adjusted FFO cash interest coverage in the 3.5x-5x range.

Liquidity

We assess the company's stand-alone liquidity as adequate because we believe its liquidity sources are likely to cover uses by more than 1.1x over the next 12 months and meet cash outflows even with a 10% decline in EBITDA. 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 $25 million;
- Estimated cash FFO of about $130 million;
- Expected ongoing group support of $110 million; and
- $40 million of the storm reserve.

Principal liquidity uses:

- Debt maturities of about $70 million;
- Capital spending of about $205 million.

Group Influence

We view ENO as a member of the Entergy group. We assess ENO as a moderately strategic subsidiary of Entergy because it is important to Entergy's long-term strategy and it is reasonably successful as a utility, and we expect extraordinary group support will remain limited to some circumstances. As a result, our rating on ENO is based on its SACP of 'bb' and one notch of group support.

Issue Ratings - Recovery Analysis

Key analytical factors

- ENO's debt structure consists of $35.6 million in securitized bonds, $525 million in FMBs secured by mortgages on its regulated utility assets, unsecured bank debt consisting of a $25 million revolving facility, and a $70 million term loan, and a long-term payable obligation owed to an associated company.
- Our '1+' recovery rating on ENO's senior secured FMBs reflect the substantial value of its regulated utility assets, which is sufficiently larger than its secured debt and the limited amount of priority claims, and other liabilities. For our recovery analysis, we treat the securitized bonds as a priority claim due to its senior claim to the company's cash flows and the structural protections of this financing structure.
- The recovery rating indicates our highest expectation for full recovery and results in an issue-level rating three notches above our long-term issuer credit rating. It also reflects collateral coverage in excess of 150%, which is consistent with our criteria for recovery ratings on debt issued by regulated utilities and secured by key utility assets.
- A default could stem from sudden liquidity pressure amid additional severe disruptions due to unpredictable weather events, costs, or other market events outside the company's control, which is consistent with the conditions of past utility defaults.
- We expect ENO would continue to operate and reorganize after a default given the essential nature of its services. We also assume the value of the utility's assets would be preserved. We use the net value of its regulated fixed assets as a proxy for its enterprise value. The company's regulated asset value is roughly $1.458 billion.

Simulated default assumptions

- Simulated year of default: 2026
- Gross enterprise value (discrete asset valuation approach): $1.458 billion.

Simplified waterfall

- Net recovery value after administrative costs (5%): $1.385 billion
- ENO value: $1.385 billion
- Priority claims at ENO (securitization bonds, unrated): $36.1 million

- Secured debt claims at ENO (FMBs): $536.1 million
- -- Recovery expectations: 100% (coverage in excess of 150%)
- Residual value available to other ENO claimants: $812.8 million
- Unsecured debt and other estimated claims: $107.7 million

Debt amounts include six months of accrued interest that we assume will be owed at default. We also assume cash flow revolvers are 85% drawn at default. We assume any debt maturing before default is refinanced on similar terms before maturity.

Ratings Score Snapshot

Issuer Credit Rating: BB+/Stable/--

Business risk: Satisfactory

- Country risk: Very low
- Industry risk: Very low
- Competitive position: Fair

Financial risk: Significant

- Cash flow/leverage: Significant

Anchor: bb+

Modifiers

- 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: bb

Group credit profile: bb+

- Entity status within group: Moderately strategic (+1 notches above SACP)

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
- Criteria | Corporates | General: Corporate Methodology, Nov. 19, 2013
- 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 | 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

Ratings List

Downgraded; Outlook Action

	To	From
Entergy New Orleans LLC		
Issuer Credit Rating	BB+/Stable/--	BBB/Negative/--
Issue-Level Ratings Lowered; Recovery Ratings Unchanged		
Entergy New Orleans LLC		
Senior Secured	BBB+	A-
Recovery Rating	1+	1+

Certain terms used in this report, particularly certain adjectives used to express our view on rating relevant factors, have specific meanings ascribed to them in our criteria, and should therefore be read in conjunction with such criteria. Please see Ratings Criteria at www.standardandpoors.com for further information. Complete ratings information is available to subscribers of RatingsDirect at www.capitaliq.com. All ratings affected by this rating action can be found on S&P Global Ratings' public website at www.standardandpoors.com. Use the Ratings search box located in the left column.

S&P Global
Ratings

RatingsDirect®

Research Update:

Entergy New Orleans LLC Downgraded To 'BB' From 'BB+ On Group Status Revision; Outlook Developing

September 24, 2021

Rating Action Overview

- Entergy Corp. proposed multiple options regarding subsidiary Entergy New Orleans LLC (ENO) including a sale, spinoff, or municipalization of the utility following an announcement from the New Orleans City Council (NOCC) president regarding the future ownership of the utility.
- As a result, we revised our assessment of ENO's group status to nonstrategic from moderately strategic. Our stand-alone credit profile (SACP) remains 'bb'.
- With the change in group support, ENO will receive no uplift from its SACP of 'bb'. Therefore, we lowered the issuer credit rating on ENO to 'BB' from 'BB+'.
- At the same time, we lowered our ratings on ENO's first-mortgage bonds (FMB) to 'BBB' from 'BBB+'. The recovery rating on the bonds remains '1+' (150%).
- The outlook is developing to reflect the uncertainty surrounding the future ownership of ENO, which could result in our assessment of the utility's credit quality as stronger, weaker, or it may not affect credit quality at all.

PRIMARY CREDIT ANALYST

Gerrit W Jepsen, CFA
New York
+ 1 (212) 438 2529
gerrit.jepsen@spglobal.com

SECONDARY CONTACTS

Omar El Gamal
Toronto
omar.elgamal@spglobal.com

Daria Babitsch
New York
917-574-4573
daria.babitsch1@spglobal.com

Rating Action Rationale

We revised our assessment of ENO's group status to the Entergy group, under our group rating methodology to nonstrategic from moderately strategic. In the aftermath of Hurricane Ida, the NOCC announced the intention to study the future ownership of ENO after which Entergy proposed the sale, spinoff, or municipalization of ENO along with merging into affiliate Entergy Louisiana LLC. In our view, this indicates there it is unlikely that ENO would receive extraordinary support from Entergy group--particularly in times of severe stress. Therefore, we revised ENO's group status to nonstrategic from moderately strategic regarding ENO's strategic importance to Entergy.

We continue to assess our SACP on ENO as 'bb'. Our assessment of ENO's business risk is satisfactory and its financial risk is significant. Financial risk measures remain within the significant financial risk profile category but at the lower end of the benchmark range. Specifically, we forecast ENO's adjusted funds from operation (FFO) to debt to remain in the 12%-14% range through 2023.

Our developing outlook reflects uncertainty regarding the future ownership of ENO pending the conclusion of the NOCC's investigation. The developing outlook reflects the uncertainty surrounding the future ownership of ENO, which could result in our assessment of the utility's credit quality as stronger, weaker, or it may not affect credit quality at all. After NOCC reaches a decision and there is greater certainty regarding the future ownership of the utility, we will be able complete further analysis on the credit quality of ENO and reflect this in our ratings and outlook.

Outlook

The developing outlook indicates that we could take a rating action on ENO following NOCC's decision on the future ownership of the utility.

Downside scenario

We could lower the ratings on ENO if:

- Its financial measures decline, including sustained adjusted FFO to debt consistently below 10%; or
- The NOCC's review and decision on ownership of ENO will lead to fundamental deterioration of the utility's credit quality or through a potential weakening of the regulatory relationship or financial profile deterioration from storm-related costs.

Upside scenario

We could take a positive rating action on ENO if:

- The utility's financial measures remain consistently above 17%; or
- The NOCC's review and decision on ENO's ownership will lead to fundamental improvement of the utility's credit quality. Such an event could occur, for example, if ENO was to be acquired by a stronger parent that we believed would be likely to support ENO in times of severe stress.

Company Description

ENO is a vertically integrated electric and a natural gas distribution utility operating largely in New Orleans.

Our Base-Case Scenario

Elevated capital spending averaging about $235 million in 2021 and 2022 due to restoration costs from Hurricane Ida, and about $175 million in 2023.

Dividends averaging about $30 million per year through 2023.

Negative discretionary cash flow indicating external funding needs;

Generally constructive regulatory environments help provide prudent cost recovery; and

All debt maturities are refinanced.

Liquidity

We assess the company's stand-alone liquidity as adequate because we believe its liquidity sources are likely to cover uses by more than 1.1x over the next 12 months and meet cash outflows even with a 10% decline in EBITDA. 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 $25 million;
- Estimated cash FFO of about $130 million;
- Expected access to the Entergy money pool of $110 million; and
- Storm reserves of about $40 million.

Principal Liquidity Uses

- Debt maturities of about $70 million; and
- Capital spending of about $195 million.

Group Influence

We view ENO as a member of the Entergy group. We assess ENO as nonstrategic to the Entergy group, reflecting our view that the company has very limited strategic importance to the parent. We believe that Entergy will no longer provide extraordinary support to ENO. As a result, we based our rating on ENO on the utility's SACP of 'bb'.

Issue Ratings - Recovery Analysis

Key analytical factors

- ENO's debt structure consists of $35.6 million in securitized bonds, $525 million in FMBs secured by mortgages on its regulated utility assets, unsecured bank debt consisting of a $25 million revolving facility, and a $70 million term loan, and a long-term payable obligation owed to an associated company.
- Our '1+' recovery rating on ENO's senior secured FMBs reflect the substantial value of its regulated utility assets, which is sufficiently larger than its secured debt and the limited amount of priority claims, and other liabilities. For our recovery analysis, we treat the securitized bonds as a priority claim due to its senior claim to the company's cash flows and the structural protections of this financing structure.
- The recovery rating indicates our highest expectation of full recovery and results in an

issue-level rating three notches above our long-term issuer credit rating. It also reflects collateral coverage in excess of 150%, which is consistent with our criteria for recovery ratings on debt issued by regulated utilities and secured by key utility assets.

- A default could stem from sudden liquidity pressure amid additional severe disruptions due to unpredictable weather events, costs, or other market events outside the company's control, which is consistent with the conditions of past utility defaults.
- We expect ENO would continue to operate and reorganize after a default given the essential nature of its services. We also assume the value of the utility's assets would be preserved. We use the net value of its regulated fixed assets as a proxy for its enterprise value. The company's regulated asset value is roughly $1.458 billion.

Simulated default assumptions

- Simulated year of default: 2026
- Gross enterprise value (discrete asset valuation approach): $1.458 billion.

Simplified waterfall

- Net recovery value after administrative costs (5%): $1.385 billion
- ENO value: $1.385 billion
- Priority claims at ENO (securitization bonds, unrated): $36.1 million
- Secured debt claims at ENO (FMBs): $536.1 million
- -- Recovery expectations: 100% (coverage in excess of 150%)
- Residual value available to other ENO claimants: $812.8 million
- Unsecured debt and other estimated claims: $107.7 million

Debt amounts include six months of accrued interest that we assume will be owed at default. We also assume cash flow revolvers are 85% drawn at default. We assume any debt maturing before default is refinanced on similar terms before maturity.

Ratings Score Snapshot

Issuer Credit Rating: BB/Developing/--

Business risk: Satisfactory

- Country risk: Very low
- Industry risk: Very low
- Competitive position: Fair

Financial risk: Significant

- Cash flow/leverage: Significant

Anchor: bb+

Modifiers

- 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: bb

Group credit profile: bbb+

- Entity status within group: Nonstrategic (no impact)

Related Criteria

- General Criteria: Group Rating Methodology, July 1, 2019
- Criteria | Corporates | General: Corporate Methodology: Ratios And Adjustments, April 1, 2019
- 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: Country Risk Assessment Methodology And Assumptions, Nov. 19, 2013
- General Criteria: Methodology: Industry Risk, 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

Entergy New Orleans LLC Downgraded To 'BB+' On Weather-Related Weaker Credit Metrics; Outlook Stable; Bond Rating Lowered, Sept. 2, 2021

Ratings List

Downgraded; Outlook Action

	To	From
Entergy New Orleans LLC		
Issuer Credit Rating	BB/Developing/--	BB+/Stable/--
Issue-Level Ratings Lowered; Recovery Ratings Unchanged		
Entergy New Orleans LLC		
Senior Secured	BBB	BBB+
Recovery Rating	1+	1+

Certain terms used in this report, particularly certain adjectives used to express our view on rating relevant factors, have specific meanings ascribed to them in our criteria, and should therefore be read in conjunction with such criteria. Please see Ratings Criteria at www.standardandpoors.com for further information. Complete ratings information is available to subscribers of RatingsDirect at www.capitaliq.com. All ratings affected by this rating action can be found on S&P Global Ratings' public website at www.standardandpoors.com. Use the Ratings search box located in the left column.

MOODY'S
INVESTORS SERVICE

CREDIT OPINION
29 September 2021

Update

Rate this Research

RATINGS

Entergy New Orleans, LLC.

Domicile	New Orleans, Louisiana, United States
Long Term Rating	Ba1
Type	LT Issuer Rating
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.

Contacts

Ryan Wobbrock +1.212.553.7104
VP-Sr Credit Officer
ryan.wobbrock@moodys.com

Sahiba Sikand +1.212.553.5819
Associate Analyst
sahiba.sikand@moodys.com

Michael G. Haggarty +1.212.553.7172
Associate Managing Director
michael.haggarty@moodys.com

Jim Hempstead +1.212.553.4318
MD - Global Infrastructure & Cyber Risk
james.hempstead@moodys.com

CLIENT SERVICES

Americas	1-212-553-1653
Asia Pacific	852-3551-3077
Japan	81-3-5408-4100
EMEA	44-20-7772-5454

Entergy New Orleans, LLC.

Update following outlook change to negative

Summary

Entergy New Orleans, LLC.'s (ENOL, Ba1 negative) credit profile is supported by its monopoly service territory as a vertically integrated utility company and predictable financial metrics derived from a formula rate plan (FRP).

ENOL's credit profile is challenged by its small, geographically concentrated service territory in a storm-prone location. The coastal nature of the service territory is a material credit negative due to the rising risk of storm surges, more severe weather events and the impact this has on customer migration or local economic conditions. For these reasons, ENOL's credit quality is well below peer utilities with similar financial metrics.

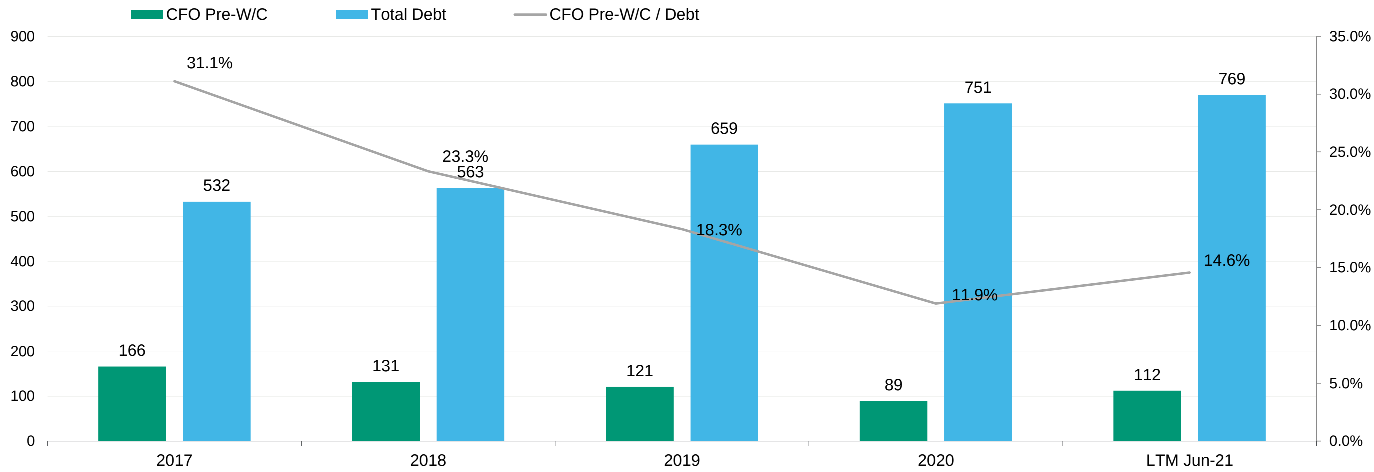
Recent storm events have also created a more contentious political and regulatory environment for ENOL, with various calls for an investigation into the utility's performance during Hurricane Ida (August 2021), a management audit, consideration of a potential sale or municipalization of the utility and market reforms introducing retail competition. These various and unique social pressures around stakeholder and customer relations could have negative financial implications for the company, if support for incremental rate increases wanes.

Recent Developments

On 23 September 2021, we changed the outlooks of ENOL, its parent company Entergy Corp. (Baa2 negative) and affiliate utility, Entergy Louisiana, LLC (ELL, Baa1 negative) to negative following a 21 September 2021 8-K filing which indicated that restoration costs for the repair and/or replacement of the electrical facilities damaged by Hurricane Ida are estimated to be in the range of $2.1 billion to $2.6 billion, enterprise-wide, which are higher than we had originally anticipated.

From a cost perspective, ENOL has been less affected by the most recent storms than ELL, with 2020 and 2021 combined storm costs expected to be under $200 million (i.e., about $40 million from Hurricane Zeta in 2020 and an estimated $120-$150 million for Hurricane Ida), which is about 20% of ENOL's total electric and gas rate base.

Exhibit 1
Historical CFO pre-WC, CFO pre-WC to Debt, Total Debt



Source: Moody's Financial Metrics

Credit strengths

» Adequate financial metrics should be sustainable given regulatory provisions and a rate base of around $900 million

» Storm cost recovery mechanisms are tested and important features given climate risks

Credit challenges

» Small and concentrated service territory in a low-lying coastal region exposed to storm surges and severe weather events

» Weaker than expected financial metrics due to recent storm activity

» Currently contentious political and regulatory environment following Hurricane Ida

Rating outlook

ENOL's negative outlook reflects a higher-risk political and regulatory environment following Hurricane Ida. Customer outages and the added cost burden caused by recent storm activity risks impaired customer relations, increased political or regulatory challenges to full and timely cost recovery, and prolonged financial metric weakness.

Factors that could lead to an upgrade

» It is unlikely that ENOL's issuer rating will be upgraded to Baa3, due to its concentrated service territory and vulnerability to storm activity.

» However, the maintenance of a financial profile that is much stronger than peer utilities and significantly improved regulatory and legislative support could lead to an upgrade

Factors that could lead to a downgrade

» A materially adverse regulatory decision

» Significant storm damage and delayed cost recovery for repairs

» A sustained decline in financial metrics, including cash flow to debt ratios remaining below the mid-teens

Key indicators

Entergy New Orleans, LLC.

	Dec-17	Dec-18	Dec-19	Dec-20	LTM Jun-21
CFO Pre-W/C + Interest / Interest	8.1x	6.3x	5.5x	3.8x	4.4x
CFO Pre-W/C / Debt	31.1%	23.3%	18.3%	11.9%	14.6%
CFO Pre-W/C – Dividends / Debt	17.0%	19.1%	18.3%	11.9%	14.6%
Debt / Capitalization	43.5%	42.6%	44.0%	44.3%	44.6%

All ratios are based on 'Adjusted' financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations.
Source: Moody's Financial Metrics

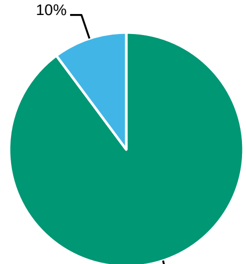
Profile

ENOL is an electric and gas utility serving the city of New Orleans, Louisiana. The company is the smallest of the Entergy Corporation (Entergy, Baa2 negative) family, which includes five utility subsidiaries and System Energy Resources, Inc. (SERI Baa3 negative, a 1,400 MW nuclear unit in Mississippi). ENOL represents well under 10% of Entergy's adjusted consolidated cash flow, debt and net PP&E. ENOL's rate base is currently split roughly 90:10 (i.e., roughly $800 million to about $100 million) between electric and gas assets.

Exhibit 3

Roughly 90% of ENOL's revenue is derived from electric operations, even amid COVID-19 challenges for electric sales

Revenue ($M) for the 3 months ended 30 June 2021



Source: Entergy Corp.

Detailed credit considerations

More contentious political and regulatory environment following Hurricane Ida

The magnitude of the damage ($120-$150 million) and customer outages (roughly 205,000 at the peak of the storm) caused by Hurricane Ida has resulted in a higher level of political and regulatory contentiousness for ENOL, with various calls for an investigation into the utility's performance during Hurricane Ida, a management audit, consideration of the potential sale or municipalization of the utility and market reforms introducing retail competition. While a negative political reaction to severe storms is not new for the utility industry, the nature and severity of the rhetoric in New Orleans is unusual, including Entergy's own press release (21 September 2021) that outlined four potential paths for the future operation and ownership of ENOL (i.e., a merger with ELL, sale of ENOL to a third party, spin off ENOL as a stand-alone company and ENOL municipalization).

Given the degree of political and stakeholder scrutiny at this time, it is possible that regulators will modify they typical nature of storm recovery, or limit other rate increases requested by the utility in annual FRP filings - a key consideration in ENOL's negative outlook. We will continue to monitor the progress with storm and FRP filings, as well as the future legal structure and ownership of the utility.

Notwithstanding the current relationship climate between Entergy and the City of New Orleans, there is a strong precedent for storm cost securitization in New Orleans and we expect that ENOL will be able to move forward on this mode of cost recovery. We view securitization to be a credit positive method of cost recovery, 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 of collections. We estimate that $150 million of storm cost securitization would translate to about a 1% increase to ENOL revenue, or about 3% of non-fuel related gross profit.

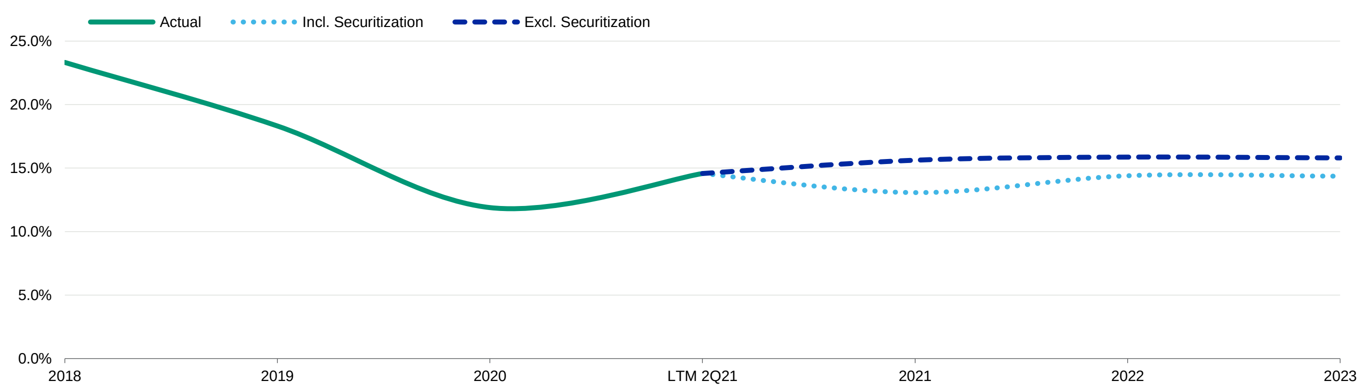
Ida occurred only 11 months after Hurricane Zeta, which also caused damage to the company's service territory in October 2020. However, the cost of Zeta was much less, at roughly $36 million, including approximately $28 million in capital costs and about $8 million in operating costs.

Financial metrics should remain steady around 16% CFO pre-WC to debt over the next two years

Based upon ENOL's regulatory rate framework, we expect the utility will generate CFO pre-WC to debt in the mid teen's percent range through 2023. Even without storm-related headwinds from lost revenue, higher costs and additional debt, this financial profile will remain below historical averages due to the ongoing impact of 2017's federal tax reform, a lower ROE and increasing debt used to fund capital expenditures.

In Exhibit 4, we show our base case financial projections (the "excluding securitization" line disregards securitized debt) for ENOL, based on its regulatory allowed rate base (approximately $900 million), capital structure (51%) and allowed ROE (9.35%). Our assumptions also include some growth attributable to around $480 million in capital expenditures made from 2021-2023 and including new generation assets in rates and a modest level of deferred tax benefits. Tax assumptions could differ materially from actual results since Entergy employs aggressive tax strategies at times, which has greatly benefitted ENOL and affiliate cash flow in the past. Exhibit 4 also shows the impact that securitizing $150 million of debt would have on ENOL's metrics ("Including securitization").

Exhibit 4
ENOL's CFO pre-WC to debt should remain steady in the mid-teen's percent range through 2023



Source: Moody's Financial Metrics and Moody's projections

Aside from storm repair and equipment replacement, ENOL's capital expenditure program will include advanced metering infrastructure, additional solar power generation resources as well as the long-term repair and replacement of 844 miles of steel and cast iron pipes that were flooded with saltwater after hurricanes Katrina and Rita. The company has estimated that the effort will cost a total of $465 million over several years, an amount that has been certified by the New Orleans City Council.

Monopoly utility operating within a formulaic rate plan framework

ENOL's credit is underpinned by its business profile as a vertically integrated utility operating in a monopoly service territory with a regulatory allowed return on equity. The underlying framework of ENOL's regulated rates is supportive, since it includes a three-year formula rate plan (FRP) for both electric and gas operations and a pilot program for full revenue decoupling. The FRP also contains some forward-looking adjustments for known and measurable costs in subsequent FRP evaluation periods and new rate constructs for renewable power offerings and electric vehicle investments.

In July 2021, ENOL submitted its FRP 2020 test year filing, which reported a 6.26% earned ROE and seeks approval for about $65 million of rate increases. The case is still being reviewed, with resulting rates to be effective in November, unless the City Council sets a procedural schedule that would extend the process into 2022.

Previously, the City Council had approved certain parameters of the FRP, which allows ENOL to: 1) use a 51% equity structure, 2) increase the depreciation rate (and annual revenue recovery) of its New Orleans Power Station to 3% from 2%, 3) retain over-recovery of $2.2 million in rider revenues, 4) recover $1.4 million of certain rate case expenses outside of the earnings band and 5) recover the costs of the New Orleans Solar Station (NOSS, a 20 MW solar plant) upon its completion. NOSS has subsequently been completed and is now in-service and reflected in rates.

These features provide a line of sight into what ENOL's cost recovery and financial position should be - absent any regulatory penalties or changes to the framework - throughout the three-year plan period, a credit positive.

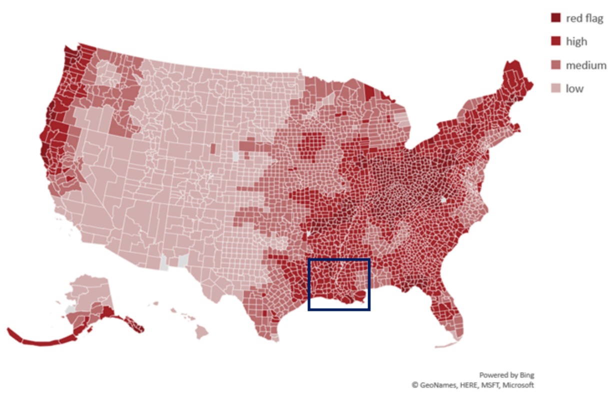
ESG considerations

Environmental - climate risks

ENOL has an ongoing vulnerability to weather events that constrains its credit profile. While New Orleans is better prepared for a major hurricane than it was pre-Katrina, the company still has a higher risk service territory because it is concentrated in a small geographic area and is located partially below sea level in a storm prone location. Therefore, potentially damaging storms, with increasing severity and higher storm surges, are the most persistent threat to the company's customers and assets.

Exhibit 5

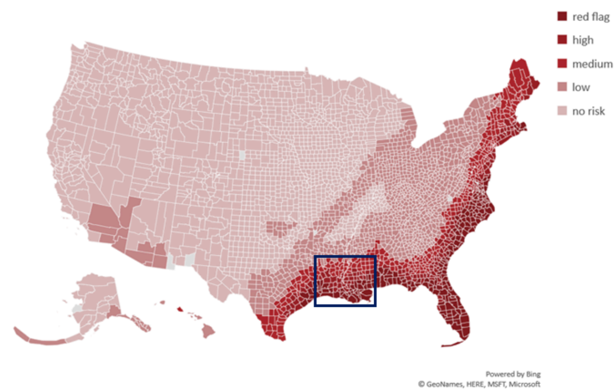
Relative projected extreme rainfall and flood stress



This metric is a combination of 3 projected components (wet days, very wet days, rainfall intensity) with annual changes from 2030-2040 vs. 1975-2005 + 2 historical components (flood frequency and flood severity, on return inundation basis).
Source: 427 (data sourced from CMIP5 models and Fathom)

Exhibit 6

Hurricane risk (historical data)



The indicator reflects the cumulative wind velocity from recorded cyclones over the period 1980-2016
Source: 427 (data sourced from IBTrACS version 3)

Historically, regulatory responses have been helpful in recovering costs of major storms - a credit positive. For example, the City Council allows ENOL to collect revenue for a storm reserve fund and has provided for the securitization of storm costs through a discrete charge to customers. We expect similar treatment to be applied following Hurricanes Zeta and Ida.

Environmental - carbon transition

ENOL's owned generation portfolio is comprised almost entirely of natural gas-fired units, which emit roughly half of the carbon, per unit of electricity generated, than coal-fueled generation. The company also acquires roughly 30% of its generation supply from an affiliate's nuclear plant, which has no carbon emissions. The company is actively pursuing the implementation of solar generation, a trend we expect to continue over the foreseeable future. Entergy as a whole exhibits strong positioning for the carbon transition with a business model that is not expected to be materially affected, as well as its plans in place to mitigate carbon transition exposure.

In May 2021, the City Council adopted a Renewable and Clean Portfolio Standard (RCPS) for the city, which requires that, by 2050, Entergy must entirely eliminate the use of fossil fuels. This legal mandate will help to improve ENOL's carbon profile, over time, and will be credit positive as long as the appropriate cost recovery provisions maintain the utility's financial profile throughout the transition.

Social

ENOL is facing significant social risk around customer, political and regulatory relationships as a result of significant customer outages due to Hurricane Ida. Given the degree of political and stakeholder scrutiny at this time, it's possible that regulators will modify the typical nature of storm recovery, or limit other rate increases requested by the utility in annual FRP filings - a key consideration in ENOL's negative outlook.

Governance

ENOL's governance is driven by that of Entergy Corp., its ultimate parent company.

Entergy's governance is broadly in-line with other utilities and does not pose particular risk. This is underpinned by our view that the company's financial strategy and risk management, management credibility and track record are generally supportive to credit, despite the above average use of aggressive tax policies that have caused some cash flow volatility and recent challenges by regulators.

Liquidity analysis

We expect ENOL to maintain adequate liquidity over the next 12-18 months, due to the availability of external borrowing sources, including external liquidity sources, and its ability to borrow from the Entergy money pool.

ENOL requires external funding since the company generates material amounts of negative free cash flow, like most utilities. For example, through LTM 30 June 2021, ENOL generated around $67 million of cash flow from operations, had $205 million in capital expenditures, but distributed no dividends due to these high capital needs. ENOL's negative free cash flow was $138 million through LTM Q2 2021 - a trend that we expect to continue.

To supplement internal liquidity needs, ENOL has a FERC authorized short-term borrowing limit of $150 million, corresponding to its ability to borrow from the Entergy money pool through July 2022. As of 30 June 2021, ENOL had a $38 million payable balance on the money pool. Additionally, ENOL has a stand-alone credit agreement in the amount of $25 million, maturing in June 2024, which was fully available at 30 June 2021. ENOL also has a $70 million unsecured term loan issued on 18 December 2019 that will mature in May 2022, which is fully outstanding. The company also has $1 million of letters of credit outstanding under an uncommitted credit facility to support its MISO obligations.

ENOL's next significant long-term debt maturity is $100 million of senior secured notes due in July 2023.

Appendix

Exhibit 7

Credit metrics and financial statistics

CF Metrics	Dec-17	Dec-18	Dec-19	Dec-20	LTM Jun-21
As Adjusted					
FFO	**164**	**133**	**127**	**116**	**115**
+/- Other	2	-2	-6	-26	-3
CFO Pre-WC	**166**	**131**	**121**	**89**	**112**
+/- ΔWC	-28	45	-6	-25	-45
CFO	**137**	**176**	**115**	**64**	**67**
- Div	75	24	0	0	0
- Capex	115	196	218	223	205
FCF	**-53**	**-44**	**-103**	**-159**	**-138**
(CFO Pre-W/C) / Debt	31.1%	23.3%	18.3%	11.9%	14.6%
(CFO Pre-W/C - Dividends) / Debt	17.0%	19.1%	18.3%	11.9%	14.6%
FFO / Debt	30.7%	23.7%	19.3%	15.4%	15.0%
RCF / Debt	16.6%	19.5%	19.3%	15.4%	15.0%
Revenue	716	717	686	634	685
Interest Expense	23	25	27	31	33
Net Income	51	58	67	48	42
Total Assets	1,508	1,584	1,731	1,936	1,906
Total Liabilities	1,101	1,149	1,245	1,331	1,295
Total Equity	407	435	486	605	611

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 8

Peer comparison

	Entergy New Orleans, LLC. Ba1 (Negative)			Mississippi Power Company Baa1 (Stable)			Duke Energy Kentucky, Inc. Baa1 (Stable)			Alaska Electric Light and Power Company(AELP) Baa3 (Stable)		
(In US millions)	FYE Dec-19	FYE Dec-20	LTM Jun-21	FYE Dec-19	FYE Dec-20	LTM Jun-21	FYE Dec-19	FYE Dec-20	LTM Jun-21	FYE Dec-20	FYE Dec-20	LTM Jun-21
Revenue	686	634	685	1,264	1,172	1,222	479	452	483	37	43	44
CFO Pre-W/C	121	89	112	419	341	345	134	125	132	15	17	17
Total Debt	659	751	769	1,614	1,506	1,995	823	885	834	133	127	124
CFO Pre-W/C + Interest / Interest	5.5x	3.8x	4.4x	6.9x	6.6x	6.9x	6.0x	5.5x	5.7x	5.1x	6.0x	5.7x
CFO Pre-W/C / Debt	18.3%	11.9%	14.6%	26.0%	22.6%	17.3%	16.3%	14.1%	15.8%	11.1%	13.8%	13.3%
CFO Pre-W/C – Dividends / Debt	18.3%	11.9%	14.6%	26.0%	17.7%	9.6%	16.3%	14.1%	15.8%	3.1%	9.4%	8.8%
Debt / Capitalization	44.0%	44.3%	44.6%	43.6%	40.8%	46.4%	48.6%	48.0%	44.3%	52.6%	51.1%	47.8%

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

Rating methodology and scorecard factors

Entergy New Orleans, LLC

Regulated Electric and Gas Utilities Industry [1][2]	Current LTM 6/30/2021		Moody's 12-18 Month Forward View As of Date Published [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	B	B	B	B
b) Generation and Fuel Diversity	B	B	B	B
Factor 4 : Financial Strength (40%)				
a) CFO pre-WC + Interest / Interest (3 Year Avg)	4.6x	A	5x - 5.5x	A
b) CFO pre-WC / Debt (3 Year Avg)	14.5%	Baa	16% - 19%	Baa
c) CFO pre-WC – Dividends / Debt (3 Year Avg)	14.0%	Baa	14% - 17%	Baa
d) Debt / Capitalization (3 Year Avg)	45.2%	Baa	49% - 50%	Baa
Rating:				
Scorecard-Indicated Outcome Before Notching Adjustment		Baa1		Baa1
HoldCo Structural Subordination Notching	0	0	0	0
a) Scorecard-Indicated Outcome		Baa1		Baa1
b) Actual Rating Assigned		Ba1		Ba1

[1] All ratios are based on 'Adjusted' financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations.
[2] As of 6/30/2021(L).
[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

Ratings

Exhibit 10

Category	Moody's Rating
ENTERGY NEW ORLEANS, LLC.	
Outlook	Negative
Issuer Rating	Ba1
First Mortgage Bonds	Baa2
PARENT: ENTERGY CORPORATION	
Outlook	Negative
Issuer Rating	Baa2
Senior Unsecured	Baa2
Commercial Paper	P-2

Source: Moody's Investors Service

REPORT NUMBER 1304186

CLIENT SERVICES

Americas	1-212-553-1653
Asia Pacific	852-3551-3077
Japan	81-3-5408-4100
EMEA	44-20-7772-5454

S&P Global
Ratings

RatingsDirect®

Entergy New Orleans LLC

September 9, 2025

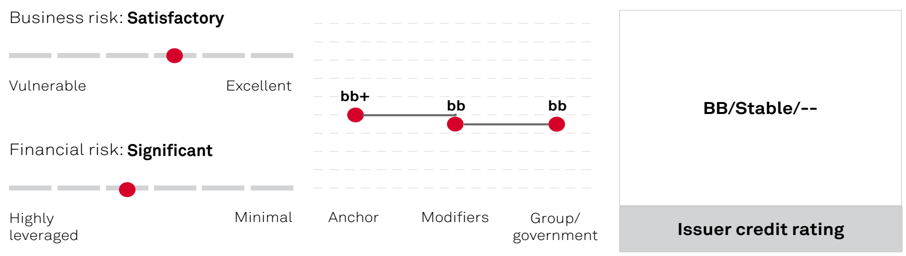
This report does not constitute a rating action.

Primary Contacts

Omar El Gamal, CFA
Toronto
1-4165072523
omar.elgamal
@spglobal.com

Matthew L O'Neill
New York
1-212-438-4295
matthew.oneill
@spglobal.com

Ratings Score Snapshot



Credit Highlights

Overview

Key strengths	Key risks
Fully rate-regulated, vertically integrated utility operations.	Exposure to severe hurricanes and storms within its service territory that requires continuous management of regulatory risk.
Relatively supportive regulatory framework with formula rate plans (FRP) that provide cash flow stability and predictability.	Lack of sufficient system hardening, which limits ability to protect against severe storms and increases business risk relative to peers.
Well-established procedure for allowing utilities to securitize storm-related costs, which we assess as credit supportive.	Small scale operations, which increases cash flow volatility.

Entergy New Orleans LLC's (ENO's) credit quality reflects its small service territory, limited diversity, and ongoing exposure to severe storms and hurricanes. ENO operates in a low-lying service territory along the Gulf Coast, increasing its susceptibility to physical risks. The company remains exposed to severe storms--such as Hurricane Ida in 2021--that can damage its infrastructure. This could result in higher capital spending and operating expenses from storm restoration and revenue declines following power outages and load reduction. Overall, this credit risk, along with the company's small scale, increases ENO's volatility of profitability measures, weakening credit quality.

Investment in resiliency is necessary to reduce risk. While the company has some tools to recover costs following a severe storm, including a limited storm reserve (about $75 million as of June 2025) and securitization, ENO needs to invest further in resiliency is needed to reduce credit risks. In October 2024, the New Orleans City Council (NOCC) approved the first-phase resilience spending of $100 million over two years that is recoverable through a rider effective January 2025. ENO originally filed an approximate $560 million resilience plan over five years. We expect that the NOCC will approve a continuous and sustained resiliency plan that will gradually reduce the company's risks of sustained outages and high damages from severe weather events.

We expect financial measures to be temporarily strong in 2025. Specifically, we expect funds from operations (FFO) to debt of 23%-25% in 2025. This reflects our expectation of a cash flow surplus from ENO's sale of its gas business for about $288 million in July 2025, as well as cash generated from its gas business for the first half of 2025. We expect ENO to utilize surplus cash by paying down its debt and distributions to its parent Entergy Corp.

However, FFO to debt will normalize in 2026 to 15%-18%. This will reflect the loss of cash flows from the sale of ENO's gas business and capital expenditure (capex) of about $200 million in 2026 and about $160 million in 2027 that will create consistent cash flow deficits, pressuring financial measures.

Outlook

The stable outlook on ENO reflects our view that the company will implement a resiliency plan that reduces the risks of sustained outages and high damages from severe storms, while financial measures improve such that stand-alone FFO to debt is consistently greater than 12%.

Downside scenario

We could lower our ratings on ENO over the next 12 months if:

- The company does not implement a resiliency plan that gradually reduces its exposure to severe storms;
- ENO's ability to consistently manage regulatory risk weakens;
- Business risk increases; or
- Stand-alone FFO to debt remains consistently below 12%, which could occur if ENO experiences a severe weather event that causes extensive damages or sustained customer outages.

Upside scenario

Although less likely, we could raise our ratings on ENO over the next 12 months if the company effectively manages regulatory risk, implements a continuous resiliency plan, and improves FFO to debt to consistently greater than 18%, without any increase to business risk.

Our Base-Case Scenario

Assumptions

- Periodic annual rate increases through annual FRPs.
- Capital spending totals about $580 million through 2027.
- Surplus cash flows in 2025 pay down debt and distributions to its parent.
- Negative discretionary cash flow in 2026 and 2027 indicates external funding needs.
- All debt maturities are refinanced.

Key metrics

Entergy New Orleans LLC--Forecast summary

Period ending	Dec-31-2021	Dec-31-2022	Dec-31-2023	Dec-31-2024	Dec-31-2025	Dec-31-2026	Dec-31-2027
	2021a	2022a	2023a	2024a	2025e	2026f	2027f
Adjusted ratios							
Debt/EBITDA (x)	6.3	4.6	5.5	6.0	3.5-4.0	4.5-5.0	4.5-5.0
FFO/debt (%)	12.6	17.4	11.3	13.2	23.0-25.0	15.0-17.0	16.0-18.0
FFO cash interest coverage (x)	4.3	5.1	3.2	3.4	5.5-6.0	4.0-4.5	4.0-4.5
a--Actual. e--Estimate. f--Forecast.							

Company Description

Entergy New Orleans LLC (ENO) is a vertically integrated electric utility operating largely in the city of New Orleans. It serves a small customer base of 209,000 electric customers. It has a generation fleet of more than 650 megawatts. About 95% of its generation portfolio is natural gas-fired generation, and the rest is solar generation.

Peer Comparison

Entergy New Orleans, LLC--Peer Comparisons

	Entergy New Orleans LLC	Cleco Power LLC	Tucson Electric Power Co.
Foreign currency issuer credit rating	BB/Stable/--	A-/Stable/NR	A-/Negative/NR
Local currency issuer credit rating	BB/Stable/--	A-/Stable/NR	A-/Negative/NR
Period	Annual	Annual	Annual
Period ending	2024-12-31	2024-12-31	2024-12-31
Mil.	$	$	$
Revenue	804	1,122	1,805
EBITDA	148	494	663
Funds from operations (FFO)	117	411	565
Interest	50	86	111

Entergy New Orleans, LLC--Peer Comparisons

Cash interest paid	49	83	98
Operating cash flow (OCF)	285	256	650
Capital expenditure	159	252	783
Free operating cash flow (FOCF)	126	4	(133)
Discretionary cash flow (DCF)	1	(91)	(218)
Cash and short-term investments	32	24	14
Gross available cash	32	24	14
Debt	890	1,617	2,738
Equity	698	2,107	3,103
EBITDA margin (%)	18.4	44.0	36.7
Return on capital (%)	3.8	6.5	7.7
EBITDA interest coverage (x)	2.9	5.7	6.0
FFO cash interest coverage (x)	3.4	6.0	6.8
Debt/EBITDA (x)	6.0	3.3	4.1
FFO/debt (%)	13.2	25.4	20.6
OCF/debt (%)	32.0	15.8	23.7
FOCF/debt (%)	14.2	0.2	(4.9)
DCF/debt (%)	0.1	(5.7)	(8.0)

Business Risk

Our assessment of ENO's business risk profile reflects its small size, limited regulatory and business diversity, and susceptibility to physical risks. Furthermore, the propensity and severity of storm activity within ENO's service territory along the Gulf Coast affects business risk, as does the utility's limited ability to protect against severe storms. Because of these risks, we assess the company at the lower half of the range of its business risk profile category, compared to peers.

Supporting its business risk profile is the NOCC's generally constructive regulatory framework. ENO operates under an FRP, providing cash flow stability, and ENO also benefits from a storm reserve and securitization laws that supports credit quality. We also view the NOCC’s approval of ENO’s resiliency spend as positive for ENO’s credit quality; a continuous and sustained resiliency plan, beyond the next two years, will gradually reduce the company's risks of sustained outages and high damages from severe weather events.

Financial Risk

Under our current base case, we expect ENO's stand-alone FFO to debt will normalize to 16%-18%. We assess ENO's financial risk profile under our medial volatility financial benchmarks, reflecting the company's regulated utility operations and generally effective management of regulatory risk. These benchmarks are more relaxed compared with those we use for a typical corporate issuer.

We expect that ENO's 2025 stand-alone FFO to debt will be temporarily strong at 23%-25%, reflecting proceeds from the sale of its gas business and cash flows generated from ENO’s gas operations creating a cash surplus that will be used partially to pay down debt. We expect ENO's future financial performance will normalize, reflecting the middle of the range for its financial risk profile category.

Debt maturities

- 2025: $80 million
- 2026: $85 million
- 2027: None
- 2028: None
- 2029: $35 million

Entergy New Orleans, LLC--Financial Summary

Period ending	Dec-31-2019	Dec-31-2020	Dec-31-2021	Dec-31-2022	Dec-31-2023	Dec-31-2024
Reporting period	2019a	2020a	2021a	2022a	2023a	2024a
Display currency (mil.)	$	$	$	$	$	$
Revenues	674	621	756	985	831	804
EBITDA	119	125	135	196	153	148
Funds from operations (FFO)	95	89	107	157	95	117
Interest expense	27	32	32	39	45	50
Cash interest paid	29	32	32	38	44	49
Operating cash flow (OCF)	103	55	71	356	195	285
Capital expenditure	227	232	221	220	166	159
Free operating cash flow (FOCF)	(124)	(177)	(149)	136	29	126
Discretionary cash flow (DCF)	(124)	(177)	(149)	136	(96)	1
Cash and short-term investments	6	0	43	4	0	32
Gross available cash	6	0	43	4	0	32
Debt	604	731	845	902	847	890
Common equity	498	607	639	703	807	698
Adjusted ratios						
EBITDA margin (%)	17.7	20.1	17.8	19.9	18.4	18.4
Return on capital (%)	7.3	5.9	4.9	8.2	4.9	3.8
EBITDA interest coverage (x)	4.4	3.9	4.2	5.0	3.4	2.9
FFO cash interest coverage (x)	4.2	3.8	4.3	5.1	3.2	3.4
Debt/EBITDA (x)	5.1	5.8	6.3	4.6	5.5	6.0
FFO/debt (%)	15.8	12.2	12.6	17.4	11.3	13.2
OCF/debt (%)	17.1	7.5	8.4	39.5	23.0	32.0
FOCF/debt (%)	(20.5)	(24.2)	(17.7)	15.1	3.4	14.2
DCF/debt (%)	(20.5)	(24.2)	(17.7)	15.1	(11.3)	0.1

Reconciliation Of Entergy New Orleans, 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-31-2024									
Company reported amounts	735	698	811	141	56	41	148	287	125	156

Reconciliation Of Entergy New Orleans, 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
Cash taxes paid	-	-	-	-	-	-	18	-	-	-
Cash interest paid	-	-	-	-	-	-	(40)	-	-	-
Lease liabilities	14	-	-	-	-	-	-	-	-	-
Operating leases	-	-	-	2	0	0	(0)	2	-	-
Accessible cash and liquid investments	(32)	-	-	-	-	-	-	-	-	-
Capitalized interest	-	-	-	-	-	1	(1)	(1)	-	(1)
Securitized stranded costs	-	-	(6)	(6)	-	-	-	(6)	-	-
Power purchase agreements	168	-	-	11	7	7	(7)	4	-	4
Asset-retirement obligations	4	-	-	0	0	0	-	-	-	-
Nonoperating income (expense)	-	-	-	-	(2)	-	-	-	-	-
Total adjustments	155	-	(6)	7	6	9	(31)	(2)	-	3
S&P Global Ratings adjusted	**Debt**	**Equity**	**Revenue**	**EBITDA**	**EBIT**	**Interest expense**	**Funds from Operations**	**Operating cash flow**	**Dividends**	**Capital expenditure**
	890	698	804	148	62	50	117	285	125	159

Liquidity

As of June 30, 2025, we assess ENO's liquidity as adequate, with sources covering uses by 1.1x over the coming 12 months, and that its sources cover uses even if forecast consolidated EBITDA declines 10%. We believe the predictable regulatory framework for ENO provides manageable cash flow stability even in times of economic stress, supporting our use of slightly lower thresholds to assess liquidity. ENO maintains $25 million in committed credit facilities through June 2027 and participates in Entergy's group money pool with a sublimit of $150 million. We believe the company can lower its capital spending during stressful periods. Overall, we believe ENO should withstand adverse market circumstances over the next 12 months with sufficient liquidity to meet its obligations. The company's next debt maturity coming due in June 2026 amounts to about $85 million. We expect the company to proactively address its debt maturities well in advance of their due dates.

Principal liquidity sources	Principal liquidity uses

- Total credit facilities availability of $155 million
- Cash FFO of about $160 million; and,
- Asset sale proceeds of about $290 million.
- Capex of about $210 million;
- Dividends of about $75 million; and
- Debt maturities of about $165 million.

Environmental, Social, And Governance

Environmental factors are a negative consideration in our credit rating analysis of ENO, namely because its service territory has severe storm and hurricane risks. The company's exposure to severe storms including hurricanes, a low-lying service territory along the Gulf Coast, and relatively limited size and diversity to help absorb the impact of such storms are negative factors in our rating analysis. We expect the service territory to have ongoing exposure to severe storms that can lead to significant liabilities and damage to the infrastructure.

Social factors are negative because of reputational damage after severe storms and hurricanes including Hurricane Katrina and Hurricane Ida.

Group Influence

We view ENO as a member of the Entergy group. We assess ENO as nonstrategic to the Entergy group, reflecting our view that the company has very limited strategic importance to the parent. We believe that Entergy will no longer provide extraordinary support to ENO. As a result, we base our rating on ENO on the utility's stand-alone credit profile (SACP) of 'bb'.

Issue Ratings--Recovery Analysis

Key analytical factors

- ENO's debt structure consists of about $657 million in first mortgage bonds (FMBs) secured by mortgages on its regulated utility assets, unsecured bank debt consisting of a $25 million revolving facility, a term loan of $80 million, and a long-term payable obligation of $7.0 million owed to an associated company.
- We conduct our recovery analysis for ENO on a consolidated basis and assume a default in 2030.
- Our recovery valuation assumes ENO's regulated asset value plan will be valued at net book value of about $1.496 billion as a proxy for the allowed regulated return of these assets.
- We expect ENO's secured debt totals about $673 million at default (including an estimated six months' accrued interest) and that it would have the highest priority claim to the value of the regulated assets (about $1.421 billion net of estimated bankruptcy costs).
- This suggests collateral coverage of nearly 211%.
- Our criteria require coverage from regulated assets of at least 150% to qualify for a '1+' recovery rating. As such, our '1+' recovery rating on this debt indicates our expectation for full recovery.

- Hence, we rate senior secured bonds at 'BBB' three notches above the issuer credit rating.

Simulated default assumptions

- Simulated year of default: 2030

Simplified waterfall

- Regulated asset value: $1.496 billion
- Net enterprise value (after 5% administrative costs): $1.421 billion
- Net value available to ENO's first-lien debt: $1.421 billion
- FMBs and other first-lien debt: $673.3 million

Rating Component Scores

Foreign currency issuer credit rating	**BB/Stable/--**
Local currency issuer credit rating	**BB/Stable/--**
Business risk	**Satisfactory**
Country risk	Very Low
Industry risk	Very Low
Competitive position	Fair
Financial risk	**Significant**
Cash flow/leverage	Significant
Anchor	**bb+**
Modifiers	
Diversification/portfolio effect	Neutral (no impact)
Capital structure	Neutral (no impact)
Financial policy	Neutral (no impact)
Liquidity	Adequate (no impact)
Management and governance	Neutral (no impact)
Comparable rating analysis	Negative (-1 notch)
Stand-alone credit profile	**bb**
Group credit profile	bbb+
Entity status within the group	Nonstrategic (0 notch from SACP)

Related Criteria

- Criteria | Corporates | General: Sector-Specific Corporate Methodology, July 7, 2025
- General Criteria: Hybrid Capital: Methodology And Assumptions, Feb. 10 2025
- Criteria | Corporates | General: Corporate Methodology, Jan. 7 2024
- Criteria | Corporates | General: Methodology: Management And Governance Credit Factors For Corporate Entities, Jan. 7 2024
- General Criteria: Environmental, Social, And Governance Principles In Credit Ratings, Oct. 10 2021
- General Criteria: Group Rating Methodology, 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. 6 2016
- Criteria | Corporates | General: Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers, Dec. 16 2014
- General Criteria: Country Risk Assessment Methodology And Assumptions, Nov. 19 2013
- General Criteria: Methodology: Industry Risk, Nov. 19 2013
- General Criteria: Principles Of Credit Ratings, Feb. 16 2011

Ratings Detail (as of September 09, 2025)*	
Entergy New Orleans LLC	
Issuer Credit Rating	BB/Stable/--
Senior Secured	BBB
Issuer Credit Ratings History	
03-Sep-2024	BB/Stable/--
24-Sep-2021	BB/Developing/--
02-Sep-2021	BB+/Stable/--
08-Oct-2020	BBB/Negative/--
02-Oct-2020	BBB+/Negative/--
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
Junior Subordinated	BBB-
Senior Unsecured	BBB
Entergy Louisiana LLC	
Issuer Credit Rating	BBB+/Stable/--
Senior Secured	A
Entergy Mississippi LLC	
Issuer Credit Rating	A-/Stable/--
Senior Secured	A
Entergy Texas Inc.	
Issuer Credit Rating	BBB+/Stable/--
Preferred Stock	BBB-
Senior Secured	A

Ratings Detail (as of September 09, 2025)*

System Energy Resources Inc.	
Issuer Credit Rating	BBB-/Stable/--
Senior Secured	BBB+

*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.

CREDIT OPINION
23 July 2025

Update

Send Your Feedback

RATINGS

Entergy New Orleans, LLC

Domicile	New Orleans, Louisiana, United States
Long Term Rating	Ba1
Type	LT Issuer Rating
Outlook	Stable

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.

Contacts

Ryan Wobbrock +1.212.553.7104
VP-Sr Credit Officer
ryan.wobbrock@moodys.com

Dean Moschitto +1.212.553.4149
Ratings Associate
dean.moschitto@moodys.com

Michael G. Haggarty +1.212.553.7172
Associate Managing Director
michael.haggarty@moodys.com

Jim Hempstead +1.212.553.4318
MD - Global Infrastructure & Cyber Risk
james.hempstead@moodys.com

» Contacts continued on last page

CLIENT SERVICES

Americas	1-212-553-1653
Asia Pacific	852-3551-3077
Japan	81-3-5408-4100
EMEA	44-20-7772-5454

Entergy New Orleans, LLC

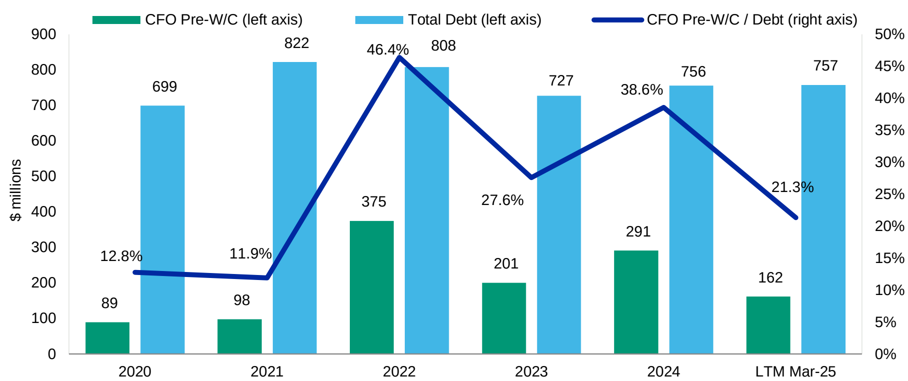
Update to credit analysis

Summary

Entergy New Orleans, LLC's (ENOL, Ba1 stable) credit profile is constrained by its small, geographically concentrated asset footprint in a storm prone location. The coastal nature of the service territory is a material credit negative due to ENOL's exposure to physical climate risk events, such as storm surges and flooding. In addition, more severe weather events can have a negative impact on customer migration patterns and local economic conditions. For these reasons, ENOL's credit rating is well below peer utilities with similar financial metrics.

ENOL's credit is supported by its monopoly service territory as a regulated vertically integrated utility company and supportive rate treatment underpinned by its annual formula rate plan (FRP) cost recovery framework.

Exhibit 1
Historical CFO Pre-WC, Total Debt and CFO Pre-WC to Debt



All figures and ratios are based on adjusted financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations.
Periods are fiscal year-end unless indicated. LTM = Last 12 months.
Source: Moody's Financial Metrics™

Recent events

On 1 July 2025, Entergy Corporation (Baa2 stable) announced the successful completion of ENOL's natural gas distribution business for roughly $200 million in sales proceeds. The transaction reduces the size and diversity of ENOL's operations, but not to a material degree, given the pre-sale rate base was roughly 85%/15% electric/gas.

Credit strengths

» Solid financial profile including a ratio of CFO pre-WC to debt above 20% that should be sustainable, given regulatory provisions and a rate base of around $1.2 billion

» Supportive storm cost recovery mechanisms that have been tested and are critical to credit quality given physical climate risks

Credit challenges

» Small and concentrated service territory

» Geographically positioned in a low-lying coastal region exposed to storm surges and severe weather events

Rating outlook

ENOL's stable outlook incorporates our view that support for storm cost recovery will continue in New Orleans and that stakeholder relationships will remain relatively supportive. Moody's expects ENOL to generate a ratio of CFO pre-WC to debt over 20% on a sustainable basis.

Factors that could lead to upgrade

It is unlikely that ENOL's issuer rating will be upgraded to Baa3, due to its concentrated service territory and vulnerability to storm activity. However, the company's ability to maintain a financial profile that is much stronger than peer utilities and significantly improved regulatory and legislative support could lead to an upgrade.

Factors that could lead to downgrade

ENOL could be downgraded if there is a combination of significant storm damage and delayed cost recovery for repairs, if regulatory and stakeholder relationships deteriorate or if its ratio of CFO pre-WC to debt declines to the mid-teen's percent range for a sustained period.

Key indicators

Exhibit 2

Entergy New Orleans, LLC

	2020	2021	2022	2023	2024	LTM Mar-25
CFO Pre-W/C + Interest / Interest	3.8x	4.3x	11.4x	6.1x	7.8x	4.5x
CFO Pre-W/C / Debt	12.8%	11.9%	46.4%	27.6%	38.6%	21.3%
CFO Pre-W/C – Dividends / Debt	12.8%	11.9%	46.4%	10.4%	22.0%	4.8%
Debt / Capitalization	42.6%	45.0%	42.6%	42.0%	45.7%	46.3%

All figures and ratios are based on adjusted financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations.
Periods are fiscal year-end unless indicated. LTM = Last 12 months.
Source: Moody's Financial Metrics™

Profile

ENOL is a vertically integrated electric utility serving the city of New Orleans, Louisiana and is regulated by the New Orleans City Council (NOCC). The company is the smallest utility in the Entergy Corporation (Entergy, Baa2 stable) corporate family, representing about 3% of Entergy's adjusted consolidated cash flow, debt and Net PP&E.

Detailed credit considerations

Monopoly utility operating within a formulaic rate plan framework

ENOL's credit is underpinned by its business profile as a vertically integrated utility operating in a monopoly service territory with a regulated cost of service model and allowed return on equity. The underlying framework of ENOL's regulated rates includes a three-year FRP for rates and full revenue decoupling. The FRP also contains some forward-looking adjustments for known and measurable costs in subsequent FRP evaluation periods and rate constructs for renewable power offerings and electric vehicle investments.

We view the FRP construct as credit supportive since it allows for annual rate increases, which is particularly helpful in an inflationary environment. The FRP proceedings are also generally less contentious than traditional general rate case filings and more predictable since there are prescribed levels for capitalization and allowed returns and the cost review is generally agreed upon.

In April 2025, ENOL submitted its FRP 2024 test year filing, which included a 10.98% earned electric ROE, compared to its 9.35% allowed ROE, which has resulted in a $9 million rate decrease requested for the company.

Regulatory scrutiny over customer outages

On 25 May 2025, the Midcontinent Independent System Operator (MISO) ordered ENOL, its larger affiliate, Entergy Louisiana, LLC (ELL, Baa1 stable) and neighboring utility Cleco Power (A3 stable) to drop roughly 600 MW of load in order to maintain reliability within the bulk transmission system. It's been reported that hot temperatures and high demand, combined with transmission and generation outages contributed to abnormal grid constraints and the rare need to shed load. For ENOL, this meant that around 209 MW had to be shed, resulting in roughly 55,000 of ENOL customers to be without power for roughly three hours.

Despite ENOL's obligation to follow MISO orders, the event is negative from a customer relations standpoint. At this time, the NOCC and Louisiana Public Service Commission are looking into the root causes of the event, including subpoenas issued to MISO officials and subsequent testimony.

While currently unrelated to this event, we note that ENOL has had instances of challenged relationships with the NOCC in the past. Any regulatory transference of blame for the MISO order, to ENOL, could be credit negative.

Run-rate financials expected to produce a ratio of CFO pre-WC to debt in the low-20% range

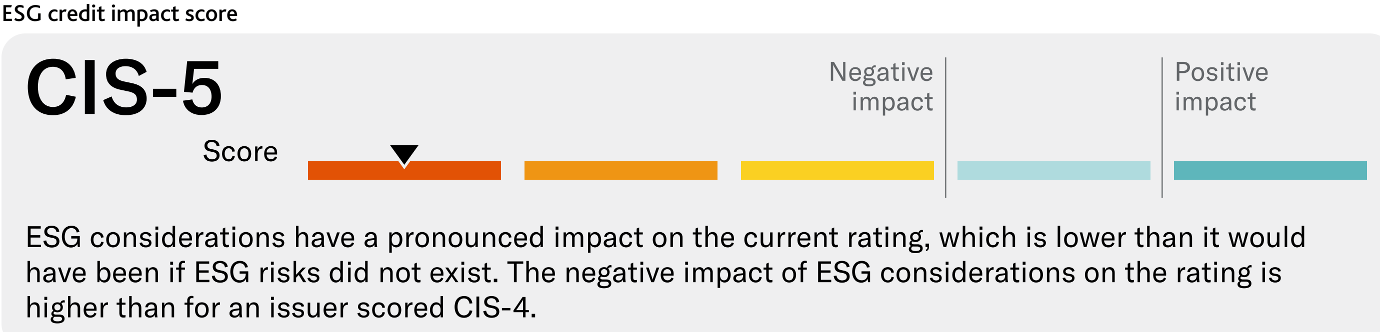
The company's 2022 and 2024 cash flow was inflated by $200 million of storm cost securitization proceeds and refunds from affiliate generator System Energy Resources, Inc. (SERI, Ba1 stable), respectively. When projecting ENOL's financial performance - based upon the company's regulatory rate framework and assumptions that include a $1.4 billion rate base, 55% equity capitalization and a 9.35% allowed ROE - we estimate that the utility will generate a ratio of CFO pre-WC to debt of over 20% for the next several years.

Our assumptions also include some growth attributable to around $450 million of capital expenditures we assume in 2025 and 2026 and ongoing benefits from deferred taxes. Tax assumptions could differ materially from actual results since Entergy employs aggressive tax strategies at times, which has greatly benefitted ENOL and affiliate cash flow in the past.

ESG considerations

Entergy New Orleans, LLC's ESG credit impact score is CIS-5

Exhibit 3
ESG credit impact score

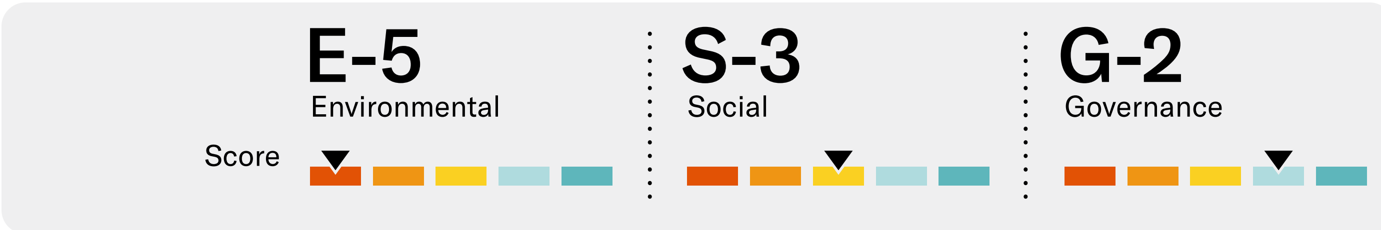


Source: Moody's Ratings

ENOL's **CIS-5** indicates that the rating is lower than it would have been if ESG risk exposures did not exist and that the negative impact is more pronounced than for issuers scored CIS-4. ENOL has significant exposure to physical climate risks given the company's small size and concentrated service territory in a storm-prone location.

Exhibit AMA-5
CNO Docket No. UD-21-03
Page 4 of 9

Exhibit 4
ESG issuer profile scores



Source: Moody's Ratings

Environmental

ENOL's **E-5** issuer profile score is driven by the concentrated nature of its customer base, located on the coast of the Gulf of Mexico. This exposes ENOL's asset base to physical climate risk events such as storms and flooding. The company is making significant investment to harden the system and improve resiliency, however, severe weather events can also have an impact on customer migration or local economic conditions that disrupt ENOL's revenue and cash collections.

Social

ENOL's **S-3** issuer profile score reflects the fundamental utility risk that demographics and societal trends could include social pressures or public concern around affordability, utility reputational or environmental concerns. In turn, these pressures could result in adverse political intervention into utility operations or regulatory changes.

Governance

ENOL's **G-2** issuer profile score is driven by that of its parent. Entergy's **G-2** issuer profile score reflects credit-supportive financial policies such as common equity issuance, using asset sales proceeds to help fund increasing capital expenditures and a lower dividend payout to retain more cash. We also note the company's use of aggressive tax policies which can cause cash flow volatility in some years or be challenged by regulators.

ESG Issuer Profile Scores and Credit Impact Scores for the rated entity/transaction are available on Moodys.com. In order to view the latest scores, please click here to go to the landing page for the entity/transaction on MDC and view the ESG Scores section.

Liquidity analysis

We expect ENOL to maintain adequate liquidity over the next 12-18 months, due to the availability of external borrowing sources, including liquidity facilities, and its ability to borrow from the Entergy money pool.

ENOL's internal liquidity is projected to consist of around $250-$300 million of cash flow from operations, compared to roughly $210 million in capital expenditures over the next 12 months. As a result, ENOL's free cash flow position will largely depend on its dividend policy and maintaining its regulated capital structure. Through 2018-2022, ENOL retained all of its internally generated cash flow, but paid $125 million of dividends to Entergy in Q4 2024.

To supplement internal liquidity needs, ENOL has a FERC authorized short-term borrowing limit of $150 million, corresponding to its ability to borrow from the Entergy System money pool through January 2026. In June 2025, Entergy amended its master credit facility, so that the $3.0 billion facility is due June 2030. We note that ENOL is excluded from cross-default language in Entergy's master credit facility; we interpret this to be an indication of ENOL's higher probability of default versus its utility affiliates.

ENOL also has a stand-alone short-term credit agreement in the amount of $25 million.

The company's next significant long term debt maturity is a term loan of $80 million due in March 2026.

Exhibit AMA-5
CNO Docket No. UD-21-03
Page 5 of 9

Exhibit 5

ENOL's various liquidity facilities as of 31 March 2025

Facility Description (in $ millions)	Capacity	Expiration	Outstanding	Available
Money Pool Payable/(Receivable)	150.0	-	-	150.0
Revolving credit facility	25.0	June 2027	-	25.0
Uncommitted, MISO LCs	1.0	-	0.5	0.5

Source: Company filings

Appendix

Exhibit 6

Peer comparison
Entergy New Orleans, LLC

	Entergy New Orleans, LLC			Duke Energy Kentucky, Inc.			Alaska Electric Light and Power Company(AELP)			Kentucky Power Company		
	Ba1 Stable			Baa1 Stable			Baa3 Stable			Baa3 Stable		
(in $ millions)	FY Dec-23	FY Dec-24	LTM Mar-25	FY Dec-23	FY Dec-24	LTM Mar-25	FY Dec-23	FY Dec-24	LTM Mar-25	FY Dec-23	FY Dec-24	LTM Mar-25
Revenue	844	811	799	586	638	664	48	49	48	615	696	721
CFO Pre-W/C	201	291	162	194	216	220	17	18	16	67	124	127
Total Debt	727	756	757	877	958	958	117	125	125	1,399	1,455	1,464
CFO Pre-W/C + Interest / Interest	6.1x	7.8x	4.5x	5.6x	6.3x	6.1x	5.8x	5.7x	5.1x	1.9x	2.8x	2.8x
CFO Pre-W/C / Debt	27.6%	38.6%	21.3%	22.1%	22.5%	23.0%	14.9%	13.9%	12.4%	4.8%	8.5%	8.7%
CFO Pre-W/C – Dividends / Debt	10.4%	22.0%	4.8%	22.1%	7.9%	8.4%	14.4%	9.5%	7.9%	4.8%	8.5%	8.7%
Debt / Capitalization	42.0%	45.7%	46.3%	37.9%	40.3%	39.8%	47.0%	48.4%	46.4%	49.6%	49.7%	49.6%

All figures and ratios are based on adjusted financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations.
LTM = Last 12 months.
Source: Moody's Financial Metrics™

Exhibit 7

Moody's-adjusted cash flow metrics
Entergy New Orleans, LLC

(in $ millions)	2020	2021	2022	2023	2024	LTM Mar-25
FFO	**115.5**	**119.4**	**161.3**	**120.5**	**114.8**	**170.6**
+/- Other	(26.2)	(21.6)	213.4	80.1	176.5	(8.9)
CFO Pre-WC	**89.3**	**97.8**	**374.6**	**200.5**	**291.4**	**161.6**
+/- ΔWC	(25.1)	(15.0)	(9.3)	4.0	0.3	123.5
CFO	**64.2**	**82.7**	**365.3**	**204.5**	**291.7**	**285.1**
- Div	0.0	0.0	0.0	125.0	125.0	125.0
- Capex	223.2	220.2	219.5	165.4	159.2	159.7
FCF	**(159.0)**	**(137.5)**	**145.8**	**(85.9)**	**7.5**	**0.4**
(CFO Pre-W/C) / Debt	12.8%	11.9%	46.4%	27.6%	38.6%	21.3%
(CFO Pre-W/C - Dividends) / Debt	12.8%	11.9%	46.4%	10.4%	22.0%	4.8%
FFO / Debt	16.5%	14.5%	20.0%	16.6%	15.2%	22.5%
RCF / Debt	16.5%	14.5%	20.0%	-0.6%	-1.3%	6.0%
Revenue	633.8	768.9	997.3	843.9	810.6	798.7
Interest Expense	31.4	29.8	35.9	39.0	42.6	46.4
Net Income	47.9	47.4	82.5	284.0	82.0	78.9
Total Assets	1,935.9	2,150.3	2,212.4	2,098.0	2,223.2	2,209.6
Total Liabilities	1,331.3	1,511.6	1,509.6	1,291.2	1,525.6	1,499.9
Total Equity	604.5	638.7	702.8	806.8	697.6	709.7

All figures and ratios are based on adjusted financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations
Periods are fiscal year-end unless indicated. LTM = Last 12 months.
Source: Moody's Financial Metrics™

Rating methodology and scorecard factors

We use our global Regulated Electric and Gas Utilities rating methodology as the primary methodology for analyzing Entergy New Orleans, LLC. ENOL's rating is five notches below the scorecard-indicated outcome of A2. Their rating is constrained from being geographically positioned in a low-lying coastal region which is exposed to storm surges and severe weather events.

Exhibit 8

Methodology scorecard factors

Entergy New Orleans, LLC

Regulated Electric and Gas Utilities Industry [1][2]	Current LTM 3/31/2025		Moody's 12-18 Month Forward View [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	B	B	B	B
b) Generation and Fuel Diversity	B	B	B	B
Factor 4 : Financial Strength (40%)				
a) CFO pre-WC + Interest / Interest (3 Year Avg)	7.7x	Aa	5.5x-6.5x	Aa
b) CFO pre-WC / Debt (3 Year Avg)	35.0%	Aa	18%-21%	Baa
c) CFO pre-WC – Dividends / Debt (3 Year Avg)	24.3%	A	13%-17%	Baa
d) Debt / Capitalization (3 Year Avg)	44.4%	A	42%-45%	A
Rating:				
Scorecard-Indicated Outcome Before Notching Adjustment		A2		A3
HoldCo Structural Subordination Notching		0		0
a) Scorecard-Indicated Outcome		A2		A3
b) Actual Rating Assigned		Ba1		Ba1

All figures and ratios are based on adjusted financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations.
LTM = Last 12 months.
Moody's forecasts are Moody's opinion and do not represent the views of the issuer
Source: Moody's Financial Metrics™ and Moody's Ratings forecasts

Ratings

Exhibit 9

Category	Moody's Rating
ENTERGY NEW ORLEANS, LLC	
Outlook	Stable
Issuer Rating	Ba1
First Mortgage Bonds	Baa2
PARENT: ENTERGY CORPORATION	
Outlook	Stable
Issuer Rating	Baa2
Senior Unsecured	Baa2
Jr Subordinate	Baa3
Commercial Paper	P-2

Source: Moody's Ratings

Exhibit AMA-5
CNO Docket No. UD-21-03
Page 7 of 9

Contacts

Ryan Wobbrock +1.212.553.7104
VP-Sr Credit Officer
ryan.wobbrock@moodys.com

Jim Hempstead +1.212.553.4318
MD - Global Infrastructure & Cyber Risk
james.hempstead@moodys.com

Dean Moschitto +1.212.553.4149
Ratings Associate
dean.moschitto@moodys.com

Michael G. Haggarty +1.212.553.7172
Associate Managing Director
michael.haggarty@moodys.com

CLIENT SERVICES

Americas	1-212-553-1653
Asia Pacific	852-3551-3077
Japan	81-3-5408-4100
EMEA	44-20-7772-5454

Exhibit AMA-6

Entergy New Orleans, LLC
Distribution Resiliency Investments
Estimated Revenue Requirement Calculations
Financial Model - simplified

		-	1	2	3	4	5
		2026	2027	2028	2029	2030	2031
Inputs							
Composite income tax rate	25.35%						
Property tax rate	0.80%						
BTWACC / Before tax RORB	9.10%						
WACC / RORB	7.35%						
Interest rate	7.70%						
Debt Ratio	49.00%						
Equity Ratio	51.00%						
Total T&D Rate base & revenue requirement calculations							
Rate Base							
Beginning rate base		$0	-	39,857,853	120,484,001	211,345,964	290,494,063
Plant in service							
Beginning plant in service		$0	-	40,528,886	124,464,502	222,588,799	312,932,932
Plant additions		$0	40,528,886	83,935,616	98,124,297	90,344,133	85,617,302
End of year plant in service		$0	40,528,886	124,464,502	222,588,799	312,932,932	398,550,234
Depreciation							
Book depreciation - single year		$0	653,692	2,661,184	5,597,634	8,637,447	11,475,535
Book depreciation - cumulative		$0	653,692	3,314,875	8,912,509	17,549,957	29,025,491
Deferred Income Tax - single year		$0	(17,341)	(648,284)	(1,664,700)	(2,558,587)	(3,143,280)
Accum. Deferred Income Tax (ADIT)		$0	(17,341)	(665,626)	(2,330,326)	(4,888,913)	(8,032,192)
End of Year Rate Base		$0	$39,857,853	$120,484,001	$211,345,964	$290,494,063	$361,492,550
Before tax return on Ending Rate Base		$0	$3,627,065	$10,964,044	$19,232,483	$26,434,960	$32,895,822
O&M Expenses		$0	-	-	-	-	-
Property Taxes		$0	-	319,002	969,197	1,709,410	2,363,064
Total revenue requirement		**$0**	**$4,280,756.3**	**$13,944,229**	**$25,799,314**	**$36,781,817**	**$46,734,421**
Revenue Expense Conversion Factor		1.00703	1.00703	1.00703	1.00703	1.00703	1.00703
Total revenue requirement		**$0**	**$4,310,860**	**$14,042,290**	**$25,980,742**	**$37,040,479**	**$47,063,072**
Cash flow simple model calculations (assume no recovery)							
Capital spending - Single year			77,167,697	86,565,536	97,924,770	76,243,786	60,648,447
Capital spending - Cumulative		-	77,167,697	163,733,233	261,658,003	337,901,789	398,550,236
Debt issuance (49% Debt/ 51% equity) - Single year		-	37,812,172	42,417,113	47,983,137	37,359,455	29,717,739
Debt issuance - Cumulative		-	37,812,172	80,229,284	128,212,421	165,571,877	195,289,616
Interest expense @ 7.7%		-	1,455,769	4,544,596	8,025,006	11,310,695	13,893,167
Revenue							
Expense		-	(2,109,460)	(7,524,781)	(14,591,837)	(21,657,553)	(27,731,766)
Incremental Pre-tax Income		-	(2,109,460)	(7,524,781)	(14,591,837)	(21,657,553)	(27,731,766)
Incremental Tax Expense (25.35%)		-	534,748	1,907,532	3,699,031	5,490,190	7,030,003
Incremental Earnings - Resilience		-	(1,574,712)	(5,617,249)	(10,892,806)	(16,167,363)	(20,701,763)
Net Cash impact							
Revenue							
Cash expense		-	(1,455,769)	(4,863,598)	(8,994,203)	(13,020,106)	(16,256,231)
Tax: (increase in payments) / reduction in payments			341,000	1,435,000	3,013,000	4,557,000	5,873,000
Operating cash flow		-	(1,114,769)	(3,428,598)	(5,981,203)	(8,463,106)	(10,383,231)
Debt issuance		-	37,812,172	42,417,113	47,983,137	37,359,455	29,717,739
Capex		-	(77,167,697)	(86,565,536)	(97,924,770)	(76,243,786)	(60,648,447)
Net Cash flow		-	(40,470,294)	(47,577,021)	(55,922,835)	(47,347,437)	(41,313,939)

OCF:Debt

Operating Cash Flow	-	(1,114,769)	(3,428,598)	(5,981,203)	(8,463,106)	(10,383,231)
Debt	-	37,812,172	80,229,284	128,212,421	165,571,877	195,289,616
OCF:Debt Ratio		-2.9%	-4.3%	-4.7%	-5.1%	-5.3%
Cash flow simple model calculations (assume resilience rider)						
Capital spending - single year	-	77,167,697	86,565,536	97,924,770	76,243,786	60,648,447
Capital spending - Cumulative	-	77,167,697	163,733,233	261,658,003	337,901,789	398,550,236
Debt issuance (49% Debt/ 51% equity) - Single year	-	37,812,172	42,417,113	47,983,137	37,359,455	29,717,739
Debt issuance - Cumulative	-	37,812,172	80,229,284	128,212,421	165,571,877	195,289,616
Interest expense @ 7.7%	-	1,455,769	4,544,596	8,025,006	11,310,695	13,893,167
Revenue	$0	$4,310,860	$14,042,290	$25,980,742	$37,040,479	$47,063,072
Expense	-	(2,109,460)	(7,524,781)	(14,591,837)	(21,657,553)	(27,731,766)
Incremental Pre-tax Income	-	2,201,400	6,517,508	11,388,906	15,382,925	19,331,306
Incremental Tax Expense (25.35%)	-	(558,055)	(1,652,188)	(2,887,088)	(3,899,572)	(4,900,486)
Incremental Earnings - Resilience	-	1,643,345	4,865,320	8,501,818	11,483,354	14,430,820
Net Cash impact						
Revenue	$0	$4,310,860	$14,042,290	$25,980,742	$37,040,479	$47,063,072
Cash expense	-	(1,455,769)	(4,863,598)	(8,994,203)	(13,020,106)	(16,256,231)
Tax: (increase in payments) / reduction in payments		(627,000)	(750,000)	332,000	2,073,000	3,621,000
Operating cash flow	-	2,228,091	8,428,692	17,318,540	26,093,373	34,427,841
Debt issuance	-	37,812,172	42,417,113	47,983,137	37,359,455	29,717,739
Capex	-	(77,167,697)	(86,565,536)	(97,924,770)	(76,243,786)	(60,648,447)
Net Cash flow	-	(37,127,434)	(35,719,731)	(32,623,093)	(12,790,958)	3,497,133
OCF:Debt						
Operating Cash Flow	-	2,228,091	8,428,692	17,318,540	26,093,373	34,427,841
Debt	-	37,812,172	80,229,284	128,212,421	165,571,877	195,289,616
OCF:Debt Ratio		5.9%	10.5%	13.5%	15.8%	17.6%
Variance (no recovery vs resilience rider)						
Revenue (no recovery)	0	0	0	0	0	0
Revenue (rider)	$0	$4,310,860	$14,042,290	$25,980,742	$37,040,479	$47,063,072
difference	$0	$4,310,860	$14,042,290	$25,980,742	$37,040,479	$47,063,072
Operating cash flow (no recovery)	-	(1,114,769)	(3,428,598)	(5,981,203)	(8,463,106)	(10,383,231)
Operating cash flow (rider)	-	2,228,091	8,428,692	17,318,540	26,093,373	34,427,841
difference	-	3,342,860	11,857,290	23,299,742	34,556,479	44,811,072
OCF: debt ratio (no recovery)	0.0%	-2.9%	-4.3%	-4.7%	-5.1%	-5.3%
OCF: debt ratio (rider)	0.0%	5.9%	10.5%	13.5%	15.8%	17.6%
difference	0.0%	8.8%	14.8%	18.2%	20.9%	22.9%

Phase 2 Resilience Plan Projected Rider Rate Impact for a Typical Residential Customer using 1,000 kWh per Month Years 2027 through 2031			
Year	Projected Total Cumulative Resilience Plan Revenue Requirement ($ in Millions)	Projected Residential Cumulative Revenue Requirement ($ in Millions)	Projected Monthly Residential Bill Impact ($/month)
2027	$4,310,860	$2,350,983	1.01
2028	$14,042,290	$7,658,142	3.28
2029	$25,980,742	$14,168,930	6.08
2030	$37,040,479	$20,200,498	8.66
2031	$47,063,072	$25,666,447	11.01

CERTIFICATE OF SERVICE
UD-21-03

I hereby certify that I have served the required number of copies of the foregoing pleading upon all other known parties of this proceeding individually and/or through their attorney of record or other duly designated individual.

Clerk of Council
Council of the City of New Orleans
City Hall, Room 1E09
1300 Perdido Street
New Orleans, LA 70112

Erin Spears
Chief of Staff, Council Utilities Regulatory Office
City of New Orleans
City Hall, Room 6E07
1300 Perdido Street
New Orleans, LA 70112

Bobbie Mason
Christopher Roberts
Byron Minor
Candace Carmouche
Jared Reese
Council Utilities Regulatory Office
City of New Orleans
City Hall, Room 6E07
1300 Perdido Street
New Orleans, LA 70112

Krystal D. Hendon
City of New Orleans
CM Morrell Chief-of-Staff
1300 Perdido St. Rm. 2W50
New Orleans, LA 70112

Andrew Tuozzolo
City of New Orleans
CM Moreno Chief of Staff
1300 Perdido Street, Rm 2W40
New Orleans, LA 70112

Justyn Hawkins
Chief of Staff
New Orleans City Council
City Hall, Room 1E06
1300 Perdido Street
New Orleans, LA 70112

Donesia D. Turner
Tanya L. Irvin
Chief Deputy City Attorney
City Attorney Office
City Hall, Room 5th Floor
1300 Perdido Street
New Orleans, LA 70112

Norman White
Department of Finance
City Hall – Room 3E06
1300 Perdido Street
New Orleans, LA 70112

Greg Nichols
Deputy Chief Resilience Officer
Office of Resilience & Sustainability
1300 Perdido Street, Ste 8E08
New Orleans, LA 70112

Sophia Winston
Energy Policy & Program Manager
Office of Resilience & Sustainability
1300 Perdido Street, Ste. 8E08
New Orleans, LA 70112

Hon. Jeffrey S. Gulin
Administrative Hearing Officer
3203 Bridle Ridge Lane
Lutherville, MD 21093

Clinton A. Vince, Esq.
Presley R. Reed, Jr., Esq.
Emma F. Hand, Esq.
Dee McGill
Dentons US LLP
1900 K Street NW
Washington, DC 20006

Basile J. Uddo
J.A. "Jay" Beatmann, Jr.
c/o Dentons US LLP
650 Poydras Street, Suite 2850
New Orleans, LA 70130

Joseph W. Rogers
Victor M. Prep
Byron S. Watson
Legend Consulting Group
6041 South Syracuse Way, Suite 105
Greenwood Village, CO 80111

Courtney Nicholson
Regina Bartholomew-Woods
Heather Silbernagel
Leslie M. LaCoste
Edward Wicker Jr.
Linda Prisuta
Entergy Services, LLC
Mail Unit L-ENT-26E
639 Loyola Avenue
New Orleans, LA 70113

Polly Rosemond
Kevin T. Boleware
Keith Wood
Derek Mills
Ross Thevenot
Entergy New Orleans, LLC
1600 Perdido Street
Mail Unit L-MAG-505B
New Orleans, LA 70112

Vincent Avocato
Entergy Services, LLC
2107 Research Forest Drive, T-LFN-4
The Woodlands, TX 77380

Joe Romano, III
Tim Rapier
Entergy Services, LLC
Mail Unit L-ENT-3k
639 Loyola Avenue
New Orleans, LA 70113

Katherine W. King
Randy Young
Air Products and Chemicals, Inc.
Kean Miller LLP
400 Convention Street, Suite 700
Post Office Box 3513
Baton Rouge, LA 70821-3513

Carrie R. Tournillon
Air Products and Chemicals, Inc.
Kean Miller LLP
900 Poydras Street, Suite 3600
New Orleans, LA 70112

Maurice Brubaker
Air Products and Chemicals, Inc.
Brubaker & Associates, Inc.
16690 Swingley Ridge Road, Suite 140
Chesterfield, MO 63017

Jesse George
Logan Atkinson Burke
Sophie Zaken
Alliance for Affordable Energy
4505 S. Claiborne Avenue
New Orleans, LA 70125

Yolanda Y. Grinstead, Esq.
Theron Levi
Sewerage and Water Board
New Orleans – Legal Dept.
625 St. Joseph Street, Room 201
New Orleans, LA 70165

Pastor Gregory Manning
President, Board of Directors of GNOICC
2021 S. Dupre Street
New Orleans, LA 70125

Jonathan Sebastian Leo
Member, Board of Directors, GNOICC
10942 Neale Fraser Drive
Baton Rouge, LA 70810

Myron Katz, PhD
Building Science Innovators
Prorate Energy, Inc.
302 Walnut Street
New Orleans, LA 70118

Broderick Bagert
Abel Thompson
Pierre Moses
Cynthia Coleman
Together New Orleans
2721 S. Broad Street
New Orleans, LA 70125

Leroy Nix
VP, Regulatory & Public Affairs
1600 Perdido Street
Mail Unit: L-MAG-505A
New Orleans, LA 70112

New Orleans, Louisiana, this 19th day of December, 2025

____
Edward R. Wicker