BEFORE THE

LOUISIANA PUBLIC SERVICE COMMISSION

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

DIRECT TESTIMONY

OF

SEAN MEREDITH

ON BEHALF OF

ENTERGY LOUISIANA, LLC

DECEMBER 2022

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EXHIBIT LIST

I. INTRODUCTION AND PURPOSE

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

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

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

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

Q3. PLEASE DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

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

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

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

Q4. PLEASE DESCRIBE YOUR CURRENT JOB RESPONSIBILITIES.

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

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

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

Q6. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

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

II. RESILIENCE PLAN

Q7. WHAT IS THE RESILIENCE PLAN?

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

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

Q8. PLEASE DESCRIBE THE COMPONENTS OF THE RESILIENCE PLAN.

A. The Resilience Plan has four interconnected components.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

III. IMPROVING SYSTEM RESILIENCE

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

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

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

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

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

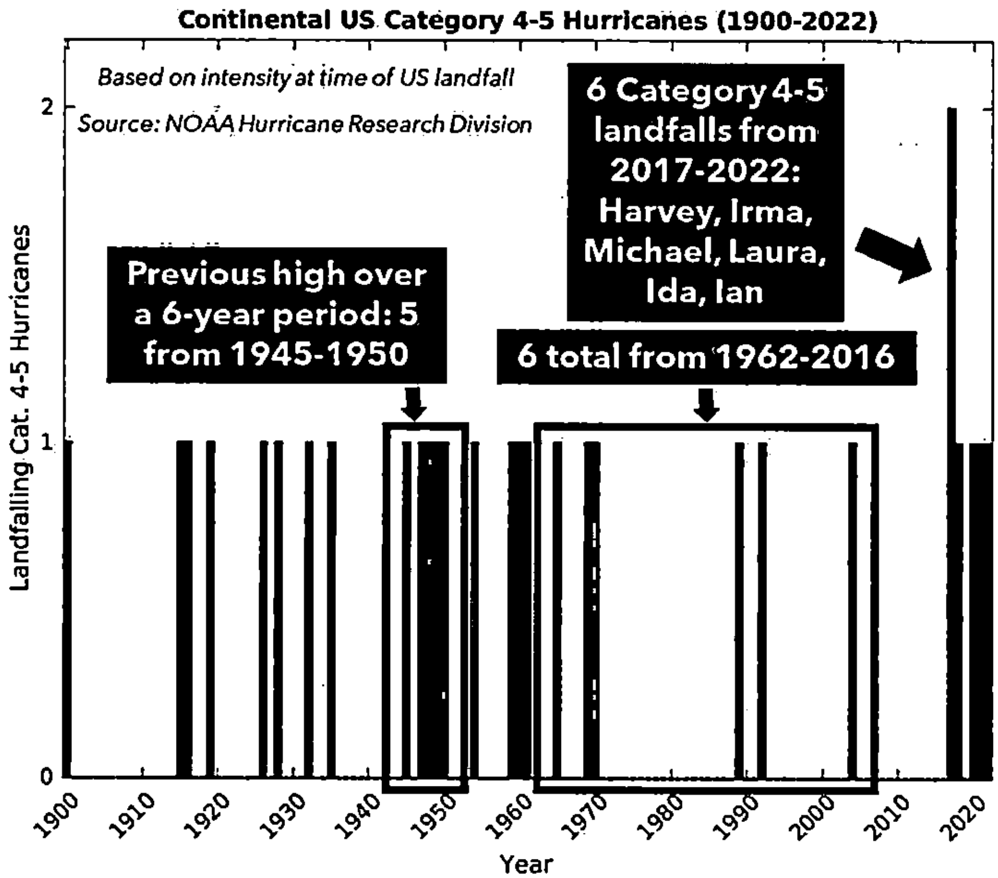
events. While such projects should be expected to have positive impacts on the day-to-day operations of the Company's utility system under normal conditions by further protecting against and mitigating outages, they are focused more particularly on preparing the electric system to withstand and recover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

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

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

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

Figure 1[6]



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

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

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

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

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

Q16. HOW DID THE COMPANY DEVELOP THE RESILIENCE PLAN?

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

IV. COMPREHENSIVE HARDENING PLAN

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

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

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

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

Q25. WHAT ASSETS DID THE SRM EVALUATE?

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

Table 1

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

Q26. HOW WERE THE POTENTIAL HARDENING PROJECTS IDENTIFIED?

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

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

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

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

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

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

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

Q27. WHAT PROGRAM ALTERNATIVES WERE CONSIDERED IN THE SRM?

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

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

Table 2

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

Q28. PLEASE EXPLAIN WHAT THE DIFFERENT PROGRAM ALTERNATIVES ENTAIL.

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

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

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

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

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

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

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

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

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

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

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

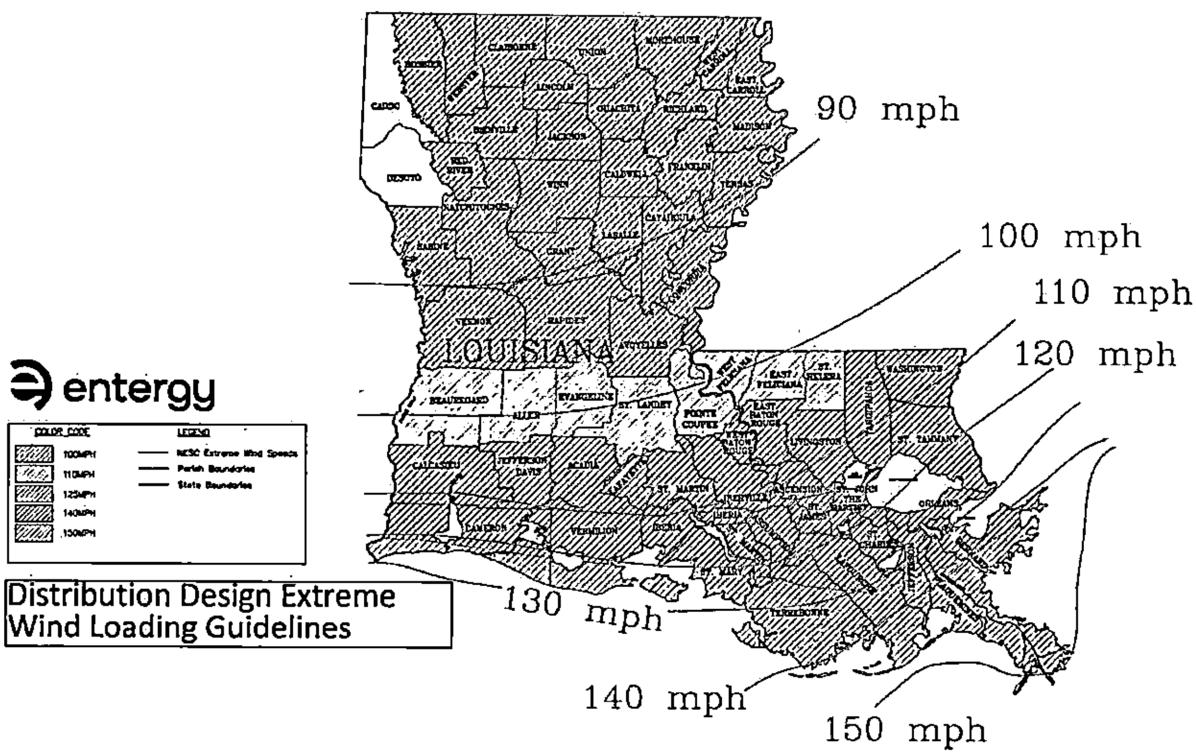
[10] Prior to the development of the EOCs' current extreme wind guidelines, the EOCs generally have designed distribution structures less than 18 meters (60 feet) above ground or water to meet or exceed the requirements of NESC 250B, which, again, provides the general combined ice and wind loading requirements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

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

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

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

Figure 2
Wind Loading Guidelines for Distribution Lines



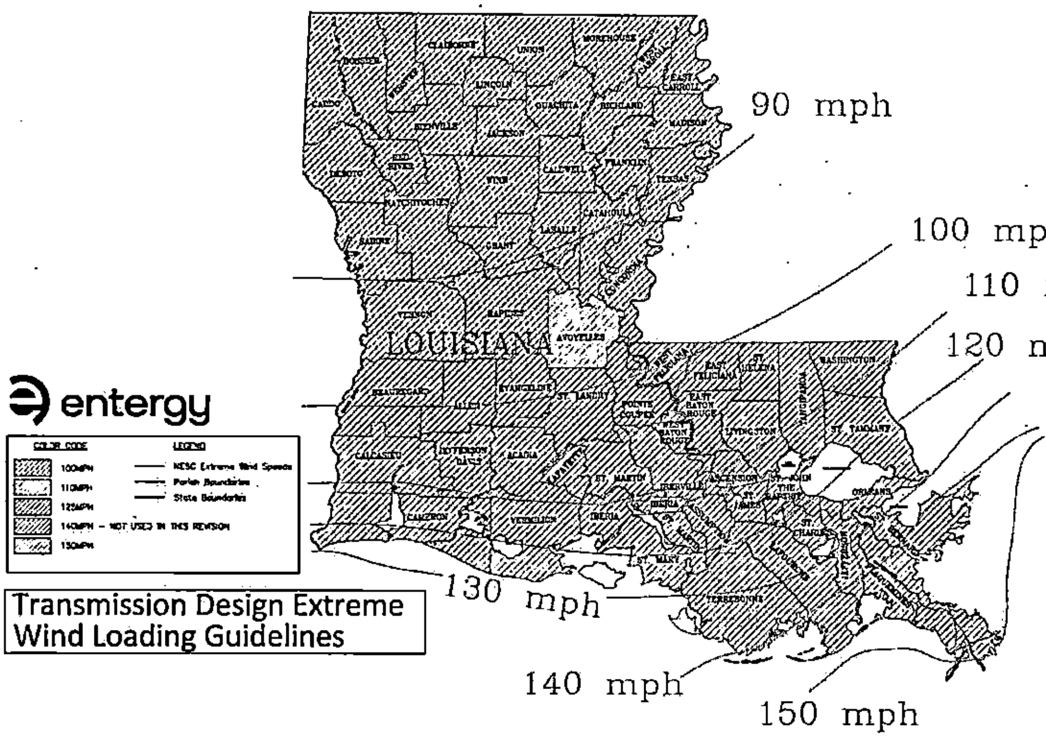
As indicated in Figure 2 and in the attached Exhibit SM-3, distribution assets and structures in portions of the following Parishes will be designed to the 150-mph extreme wind loading requirements: Cameron, Vermilion, Iberia, St. Mary, Terrebonne, Lafourche, Jefferson, Plaquemines, and St. Bernard.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

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

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

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

Figure 3
Wind Loading Guidelines for Transmission Lines



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

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

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

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

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

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

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

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

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

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

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

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

Q36. DOES ANY OTHER WITNESS DISCUSS THE SRM?

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

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

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

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

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

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

B. Storm Impact Model

Q39. PLEASE EXPLAIN THE STORM IMPACT MODEL FURTHER.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

A. Yes. Determining the value and potential benefits of any storm hardening effort is a complex task, and it requires more than a simple objective evaluation of the possibly