Entergy Louisiana

2023 Integrated Resource Plan (Draft Report)

Submitted October 21, 2022

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Chapter 1 Executive Summary

The past three years have brought unprecedented change for the world. A global pandemic, inflation, and geopolitical conflicts have changed the trajectory of the world economy and the ripple down effect to industry is reshaping how Entergy Louisiana, LLC ("ELL" or the "Company") views its current state. These impacts, combined with the increasing threats posed by climate change, mean that the time is now to reimagine Louisiana's energy future.

Key imperatives that will drive planning for ELL include, but are not limited to:

- meeting customer demand for clean energy solutions,
- ensuring reliability and resiliency of the electric power grid while balancing affordability for all customers, and
- safeguarding the obligations of electric service providers to supply adequate generating capacity to meet electric demands.

ELL Customers are Demanding Clean Energy

The convergence of geopolitics and global energy security with a lower investment risk relative to the rest of the world puts the United States in a unique position to capitalize on opportunities to grow the economy and lead the world in the clean energy transition. In Louisiana and across the Gulf South, world-class infrastructure, favorable commodity spreads, workforce availability, and access to deep water ports put Louisiana and the region at the forefront for the U.S. to compete globally for new and expansion of its industrial customer base. A catalyst to this growth will be the Infrastructure Investment and Jobs Act and the Inflation Reduction Act, both passed by the U.S. Congress and signed into law within the last year. These laws will provide billions of dollars in federal funding to enable historic investment in clean energy production, grid resiliency, and decarbonization across all industries.

In response to the opportunities and challenges before us, ELL is imagining and creating a bold future using sustainable business practices that integrate environmental, social, and economic objectives into all it does. ELL's strategies, plans, and actions are aimed at managing risks and realizing opportunities across its full value chain, from its customers to its company operations to its suppliers.

ELL's customers are demanding carbon-free energy to meet the goals of their investors. New industries are attracted to ELL's low cost of energy and are leading the demand for clean generation. The push for net-zero Scope 2 emissions from existing and new customers, not only supports ELL's energy transition, but rather demands it.

With sustainability, reliability, and resiliency as guiding principles of its business strategy, ELL is generating positive outcomes for all its stakeholders. ELL is focused on several key customer-focused initiatives, including the following:

1. Focusing on its relentless safety objective: "Everyone safe—all day, every day."

2. Addressing its customers' goals, which align with its own, to reduce greenhouse gas emissions.
3. Fueling Louisiana's economy by capitalizing on unique growth opportunities for which ELL is geographically and operationally well positioned.
4. Strengthening its infrastructure by accelerating resilience investment and leveraging partnerships to increase the resilience of its communities.
5. Recruiting and retaining a workforce that reflects the communities ELL serves and has the skills needed to meet its objectives.

Reliability and Resiliency of the Power Grid is Essential

Vertically integrated and well-regulated utilities are essential for enabling the energy transition in an equitable manner. As the world shifts to a cleaner, greener economy, the electric grid will need to accommodate increased electrification and the increasing share of renewable generating resources. The industry has a long history of providing reliable and affordable energy and has evolved through a century of innovation. As the industry evolves yet again, vertically integrated utilities have the expertise in engineering, infrastructure, customer engagement, community connections, and energy markets to enable the transition to a cleaner energy industry.

In order to lead the transition, utilities will need to meet the growing demand for net zero generating resources, balance the intermittency of renewables, and invest in emerging technologies – all without sacrificing affordability and reliability.

Under the guidance and authority of the Louisiana Public Service Commission ("LPSC" or "Commission") and the rules that it has put in place, Louisiana has maintained amongst the lowest retail rates in the country. Attracted by Louisiana's natural resources and infrastructure, including low electricity prices and reliable power, billions of dollars of infrastructure have been invested in the State, creating thousands of jobs for Louisiana residents. Louisiana has a strong foundation, and ELL seeks to fortify and grow that foundation.

Vital to Louisiana's growing economy is the assurance that utility resources and infrastructure are in place to reliably meet the needs of existing and new commercial and industrial customers, within a regulatory paradigm that has been historically proven to maintain affordable rates and equitable outcomes for all customers. And, as discussed previously, the ability to meet customer requirements for access to clean energy resources are becoming the new table stakes for utilities.

Recent weather events have highlighted the need for continued and accelerated investments in resilience to make sure grid infrastructure can quickly recover from disruptive events and allow homes and businesses to return to normal operations. ELL supports continued growth in the State through its continued investment in Louisiana which allows ELL to power the lives of its customers with clean, affordable, and reliable electricity. This growth, in turn, leads to innumerable improvements in Louisiana communities including increased investment in its schools, streets, parks, and other resources that enhance the daily lives of Louisianans. The reliability and resilience of the electric system depends on long-term resource planning and Commission oversight of ELL and all regulated utilities in the state. This Integrated Resource Plan ("IRP") is a product of a dynamic, ongoing process and this Report provides a touchstone for that process.

The rapid rate of change in the economy and the competitive advantages inherent to Louisiana, which will contribute to rapid growth in the demand for electricity, requires ELL to evaluate needs at a much faster rate than ever before. The IRP process has always been a view of the future at a point in time, but now, more than ever, ELL must and will pivot as necessary to ensure that as a utility, it will not only enable load growth in the state, but it will be a lynchpin in the competitive advantage Louisiana offers to businesses from around the world.

Since joining the Midcontinent Independent System Operator, Inc ("MISO") in December 2013, ELL, with approval from the Commission, has added over 2.9 gigawatts ("GW") of new, dispatchable generation in the state. This investment of more than $2.5 billion in new, dispatchable generation was needed to reliably serve Louisiana customers and support approximately 120 announced economic development projects in Louisiana, totaling over $108 billion in capital investments and creating approximately 14,190 new direct jobs over the last decade. More recently, ELL has added 55 megawatts ("MW") of solar generation, obtained LPSC approval to add nearly half a GW of new solar generation, and has outstanding Requests for Proposals ("RFPs") at various stages of development seeking to add an additional 2.1 GWs of renewable generation. The Company has also gained approval of a new green tariff, the Geaux Green Option or Rider GGO, which will, among other things, allow for adding new renewable generation at a significantly reduced cost for typical customers while also ensuring all customers benefit from such resources.

In light of customer demand for clean energy resources and a desire and directive from the LSPC to facilitate the renewable transition more expeditiously,[1] ELL and the LPSC must improve the current process for vetting and approving the addition of new renewable resources. The Market Based Mechanisms Order and other relevant processes at the LPSC require a significant amount of time, in some case upwards of four to five years from beginning (i.e., issuance of a request for proposal) to end (i.e., operation of a resource). The renewable market is a rapidly evolving market and customer demand is growing at an exponential pace. To meet this demand, ELL and the LPSC must take into consideration opportunities to add renewable resources at a pace that matches it. As ELL and the LPSC continue to navigate this aspect of the clean energy transition, ELL will consider opportunities for unsolicited offers that provide benefits to customers (such as the Elizabeth Solar PPA approved by the LPSC in September 2022). Further, parties should consider alterative RFP processes that allow utilities to add resources in a timely manner while also ensuring that appropriate considerations for resource adequacy and the public interest are considered.

Prudent Utility Planning Ensures Resource Adequacy for Customers at all Times

Participation in MISO has brought value to Louisiana customers over the last eight years. ELL estimates that its customers have realized approximately $772 million in savings from ELL's participation in MISO (through 2021), primarily as a result of lower reserve margins and MISO's economic dispatch of generation through its energy market. MISO, however, has no authority

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

over, or responsibility to, provide or build generating capacity, and its planning resource auction ("PRA"), which is limited term in nature, is not structured to cover the full cost of adding new generation. The MISO annual PRA provides a mechanism for load serving entities to balance short term surpluses or deficits of zonal resource credits required to meet their planning reserve margin requirement ("PRMR"); it is not a source of long-term capacity, and as the Federal Energy Regulatory Commission ("FERC") has recognized, it was never intended to serve as the primary mechanism for LSEs to procure capacity. Rather, MISO relies on its load serving entities (like ELL), under the regulation of state commissions (like the LPSC), to build or acquire the right amount and type of physical generating capacity to ensure resource adequacy and reliability. Recent resource planning and procurements by electric cooperatives have, to varying degrees, evidenced an intent to rely on the PRA for a significant portion of their respective PRMR, instead of physical capacity. Ironically, this is occurring at a time when MISO is raising concerns about resource adequacy, and neighboring regions (SPP and ERCOT) are taking steps to increase resource adequacy requirements. The actions taken by some of the electric cooperatives do not represent prudent long-term resource planning. In addition to creating reliability risk for all load in the state, the cooperatives' continued misuse of the PRA as a primary source of capacity may call into question whether the public interest continues to be served by remaining in MISO. SPP, a neighboring RTO, does not have an organized capacity market, and pursuing membership in that RTO may be an option that ELL reasonably must consider should the cooperatives' misuse of the PRA continue.

An additional threat to resource adequacy in the state, as well as to economic development and equitable outcomes for all customers, is the recent discussion of drastically altering the heretofore successful regulatory landscape for the state of Louisiana by potentially allowing for full or partial Retail Open Access ("ROA"). Although, after a lengthy and thorough regulatory proceeding, the LPSC previously concluded that ROA is not in the public interest for any customer class, certain entities that stand to benefit financially from ROA (*e.g.*, merchant wholesale generators and a few larger industrial customers) continue to advocate for some form of ROA, which is at times referred to as "customer centered options." The latest iteration of ROA that is being pursued by these entities is a type of limited/partial ROA for industrials, which is being sold (inaccurately) as a way to avoid the need for investment in new generation assets, support private investment, shift risk away from utility customers, and allow industrials to expedite the transition to renewables at their own risk. ELL supports and advocates for new customer solutions that can provide benefits to all utility customers, like the recently approved Rider GGO. Such options must be designed in consideration of, and well-suited to address, each utility's unique customer bases and capacity and energy needs. However, the implications of full or even partial ROA could have detrimental impacts to all customers in the state of Louisiana and would be counter-intuitive to the goals of the Commission's IRP General Order and the associated planning process.

These threats to resource adequacy are made more urgent by ELL's analysis that MISO Local Resource Zone ("LRZ") 9 may reach a capacity shortfall as soon as 2025, after accounting for new resource additions that have been filed for approval before the LSPC as well as future resource deactivations and retirements. MISO itself has expressed concerns about capacity shortfalls in the near future. Specifically, MISO observed that 55 GW of capacity could retire by 2040 while an additional 4 GW of committed capacity will be needed by 2026 to meet regional requirements.[2] This situation is further exacerbated because, as MISO observes: "the majority of resources currently being retired are thermal baseload resource [sic], which generally are associated with relatively higher resource adequacy accreditation levels than the variable and/or intermittent resources with which they are being replaced."[3] When or if this potential capacity shortfall materializes, the entire LRZ 9 is at risk of clearing at the cost-of-new-entry ("CONE") prices within future MISO PRAs, significantly increasing costs and jeopardizing future reliability for all within the region. The trends observed by MISO have already materialized in other MISO LRZs, with seven LRZs clearing at CONE in the most recent MISO PRA.

Just as the past three years have been unexpected and full of change, the next several years promise to be more of the same. Opportunities for industrial expansion and development in Louisiana will drive a substantial increase in load for ELL while also creating economic development for Louisiana that has not been achieved in decades. A crucial requirement to achieve this expansion is the availability of carbon free electricity to enable companies to reduce their scope 1 and scope 2 emissions, as well as firm capacity availability and stability. As ELL lays out its Integrated Resource Plan, doing its part to ensure the economic success and environmental sustainability for Louisiana will be a key driver for its actions.

ELL Customers

ELL provides electric service to more than 1.1 million customers and has residential, commercial, industrial, and governmental customers in 58 of Louisiana's 64 parishes. It also provides natural gas service to more than 96,000 customers in Baton Rouge, Louisiana. By combining an understanding of what customers want with sound and comprehensive planning, ELL can deliver the type of service its customers expect while continuing to address the planning objectives of affordability, reliability, and environmental stewardship.

Today's customers are using energy more efficiently than ever before, due to both an increasing emphasis on social responsibility and sustainability and advances in energy efficiency ("EE") standards. Customers are also seeking more options in the generation and delivery of energy, including how they interact with, understand, and manage their own energy use, as well as the actual sources from which their energy is derived.

ELL is actively engaging its customers to obtain a better sense of those expectations and the ways in which ELL can bring offerings to the marketplace to meet those expectations. As a result of this engagement, one of ELL's goals is to develop products that will reduce its customers' scope 2 emissions. ELL's customers' needs go far beyond this, many of them have on-site equipment and processes that utilize fossil fuels and emit carbon dioxide. To achieve their decarbonization goals, these customers will need to modify their operations and processes to eliminate scope 1 emissions. They are evaluating a wide set of solutions including electrification, carbon capture and storage, clean hydrogen, biofuels, and energy efficiency. Electrification appears to be a preferred method to replace and decarbonize aging equipment such as boilers,

[2] *See,* Motion for Leave to Answer and Answer of the Midcontinent Independent System Operator, Inc., FERC Docket No. ER22-496-00.

[3] Id.

turbines, and compressors. Carbon capture and storage and clean hydrogen will also need to be powered by clean generation. Customers recognize ELL as a valued partner to help them achieve their decarbonization objectives. The solutions ELL designs today will deliver meaningful outcomes for all of ELL's stakeholders. Serving this electrification opportunity through the vertically integrated model has the added benefit of providing incremental contributions to utility fixed costs that will lower the share paid by other utility customers.

Historically, affordability and reliability have been foundational to attracting and retaining customer load. For decades, the Commission's leadership and ELL's planning efforts have made Louisiana one of the most attractive locations in the world for energy-intensive industrial and manufacturing operations, owing primarily to the low rates ELL's customers pay as well as the natural geographical advantages Louisiana offers. Increasingly, these same customers require the availability of zero-carbon emitting resources at scale as a top requirement for locating their business. While ELL's planning efforts have resulted in one of the cleanest generating fleets in the nation, to continue to remain an attractive electrical service provider to these kinds of customers and to maintain Louisiana as a preferred location for business and industry, ELL will need to facilitate these customers achieving their goals to decarbonize their operations. ELL's customers goals are being driven by their investors and their own customer bases, so ELL and the LPSC must recognize the importance of moving towards emission free generation. Providing customers with options for meeting their electricity needs with zero-carbon-emitting resources will be essential to keeping these businesses in Louisiana, as well as to pursuing opportunities to attract new businesses to the region.

Fortunately, ELL, its customers, and the Commission are currently poised to take advantage of these opportunities due to ELL's prudent long-term planning efforts, ELL's customers' investment in the existing generation portfolio, and the Commission's oversight of these efforts and investments. ELL is well positioned to continue adding zero-carbon resources to its resource mix in a way that will maintain reliability and provide net benefits to all customers, without shifting costs or burdens to customers of other utilities. Coupling those resources with customers solutions, e.g. ELL's recently approved Rider GGO in LPSC Docket No. U-36190, will further enhance ELL's ability to help these customers, and potential customers, meet their sustainability goals by allowing them to directly match portions of their electricity needs with energy from renewable resources. Additionally, by coupling new renewable resources with such customer solutions, ELL has an opportunity to mitigate the costs of these resource additions and ensure all customers benefit.

Environmental Stewardship

Entergy Corporation ("Entergy") has been an industry leader in voluntary climate action for over two decades. Building on its longtime legacy of environmental stewardship and in response to customer demand, Entergy has enhanced its climate action strategy with a near-term interim goal focused on reducing its emission rate by 50 percent of 2000 levels by 2030, and a longer-term commitment: Entergy will work over the next three decades to reduce carbon emissions from its operations to net-zero by 2050. ELL intends to contribute to meeting these goals by working with the Commission and other stakeholders to balance reliability, affordability, and environmental stewardship while transforming its portfolio and building a diverse generation fleet that maintains the grid's resilience and reliability and delivers on the shared environmental commitments among ELL and its customers. This work will be critical for helping ELL customers achieve their sustainability goals, which goals also align with those of Entergy and the State of Louisiana's goal, as laid out in the Louisiana Climate Action Plan, to achieve net-zero by 2050 for the state. As discussed above, these efforts are also needed to bolster continued economic development in the State.

In ELL's 2019 IRP, its Action Plan included ELL's intention to issue an RFP for renewable resources no later than early 2020 and anticipated that it would follow that RFP with a recurring series of RFPs for renewable resources. Since that time, ELL has issued RFPs in 2020, 2021 and again in 2022. Its 2020 RFP sought up to 300 MW of solar resources, with an option to provide battery storage, for resources located within ELL's Southeast Louisiana Planning Area ("SELPA"). ELL made selections from that RFP, negotiated with the successful bidders, and filed for certification of four new solar resources in November of 2021 that will collectively provide 475 MW of new solar resources in Louisiana. ELL received certification for these resources in September of 2022 and anticipates that these resources should be online in 2024 and 2025.

ELL's 2021 RFP sought up to 600 MW of solar resources, with an option to provide battery storage, for resources located within SELPA. It has made selections from this RFP and is currently negotiating with the selected counterparties. Finally, ELL's 2022 RFP seeks up to 1,500 MW of solar resources, with an option to provide battery storage, and additionally seeks wind resources. In this most recent RFP, ELL expanded its locational requirements beyond SELPA to include all of Louisiana for solar resources, and all of MISO South and/or SPP for wind resources. Project developers recently submitted proposals for the 2022 RFP, and the evaluation of those proposals is currently underway.

Separate from ELL's work to decarbonize its generation, another critical opportunity for decarbonization is clean electrification. Clean electrification is a longer-term option to help customers reduce their scope 1 carbon emissions. This is a unique and significant opportunity for ELL. ELL's commercial and industrial customers have decarbonization goals, and electrification is an important, cost-effective means for them to achieve their objectives.

ELL has made several recent strides to meet customer demand and resource constraints.

- The LPSC has approved ELL's 475 MW solar portfolio,
- ELL has solicited upwards of 2.1 GW of additional solar or wind,
- ELL recently announced a Memorandum of Understanding with Diamond Offshore Wind regarding the evaluation and potential early development of wind power generation in the Gulf,
- Entergy Corporation and Mitsubishi Power signed a joint development agreement to collaborate on developing hydrogen-capable gas turbine combined cycle facilities, developing green hydrogen production, storage and transportation facilities, creating nuclear-supplied electrolysis facilities with energy storage, and developing utility scale battery storage programs,

- Entergy Corporation entered into a Memorandum of Agreement with Holtec for evaluation of potential installation of one or more smaller nuclear reactors at one of its existing nuclear locations.

About This Report

This document describes ELL's long-term IRP for the study period 2023-2042 and is intended to provide stakeholders insight into the Company's long-term planning process for meeting future demand and energy needs. Similar fundamental uncertainties remain when compared to ELL's last IRP, which was filed with the LPSC on May 23, 2019, in Docket No. I-34694. These uncertainties include advances in renewable technologies and their associated costs, growing customer preferences for renewable energy, and prospective changes in environmental regulations. Based on subsequent analysis, although ELL's total generating capacity is forecasted to be nearly equal to its peak customer demand plus reserve margin target in 2023 and 2024, it is forecasted to have a capacity deficit in 2025 that is briefly resolved in 2026 due to ELL's ongoing Renewable RFPs. That deficit returns in 2027 and expands over time as forecasted customer demand increases and existing resources reach the end of their assumed useful lives.

As with the Company's last IRP, the 2023 IRP utilizes a futures-based approach by which three possible future worlds were constructed to reasonably bookend a broad range of future uncertainties. An economically optimized portfolio of both supply-side and demand-side resources was developed for each of the three futures. Summaries of the modeled portfolios are discussed further in Chapters 5 and 6.

The results of the IRP analysis reasonably support that ELL's future supply-side resource additions primarily will consist of renewable energy resources that are enabled and complemented by ELL's existing dispatchable generation resources. ELL's reference resource plan maintains the planning assumptions for existing units and continues adding renewable resources starting with solar resources followed by complementary wind resources until battery storage additions are needed to move intermittent renewable energy to hours of high customer demand net of renewable energy production. Additionally, a limited number of hydrogen capable gas CCGT units are added when existing large gas units are assumed to deactivate. The exact amount and timing of each type of resource addition will be based on market solicitations and may vary from the information included in ELL's Reference Resource Portfolio.

Since the 2019 IRP, favorable market conditions (e.g., the declining cost of utility-scale solar and recent federal legislation) are prevailing at a time of significant customer demand for clean energy solutions and a need to transform the Company's resource portfolio. This confluence of favorable market conditions and changing customer preferences supports the addition of significant amounts of new renewable resources in ELL's Reference Resource Portfolio and other assessed Portfolios that were not selected in prior IRPs, and which are now expected to result in significant variable supply cost savings for customers over the twenty-year planning horizon. These savings will be realized by all ELL customers through the fuel adjustment and are projected to almost entirely offset the base rate increases associated with new resource additions. The rate impact estimates, presented in Appendix G, notably do not account for the rate effects of future customer offerings (e.g., Rider GGO) and/or of deactivating or retiring resources, both of which may further lower net costs for all customers during the planning period.

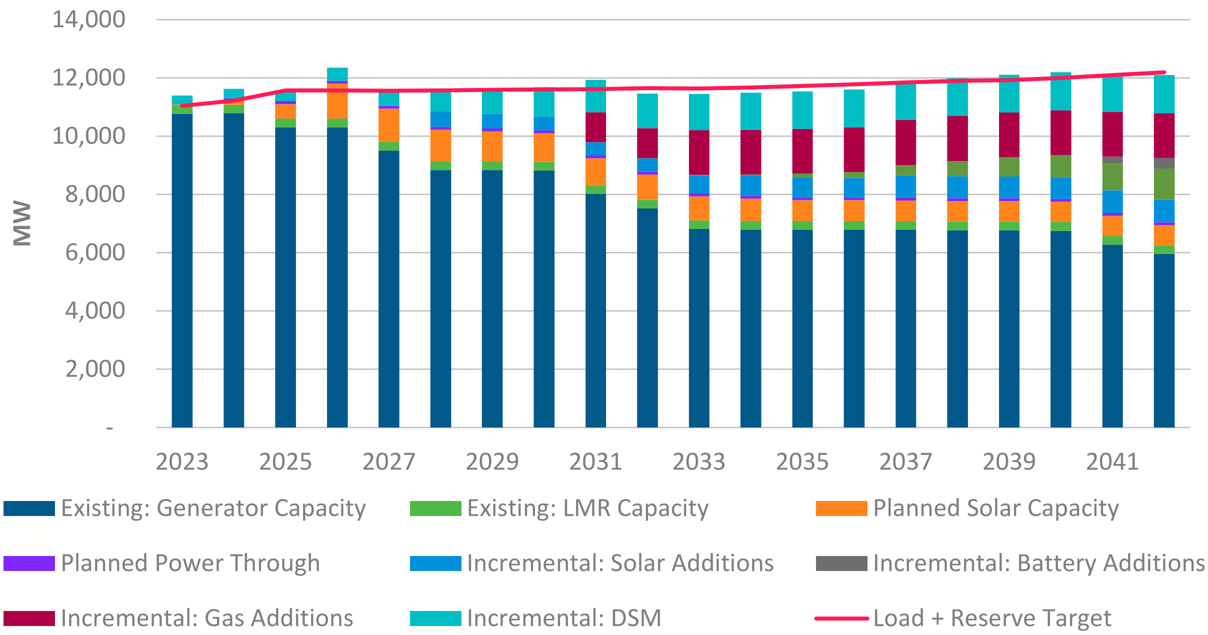

Figure 1: 2023 IRP Reference Resource Plan

The IRP's future resource portfolios are developed consistent with the Commission's Integrated Resource Planning General Order but do not represent planning decisions by ELL. Rather, the Company's specific long-term resource planning actions (e.g., capacity additions) are subject to review and approval by the Commission in future certification proceedings. In the same respect, the IRP's assumptions regarding the cost and availability of various supply-side resources do not reflect the actual cost or ownership structure for implementing those options. They are planning assumptions, with the actual costs and structures to be determined at the time of execution, likely through a market solicitation. In addition, while the IRP seeks to identify ELL's capacity needs and appropriate resources to fill those needs, this approach should not be read to foreclose the identification of a future resource which may provide significant energy value to ELL's customers or otherwise that provides value to ELL's customers and was not identified within this IRP.

ELL recognizes that creating an affordable, reliable, and sustainable future for its customers and their communities requires continued transformation of the Company's resource portfolio, and this IRP provides insights into ELL's planning process, including an illustration to show how the planning principles are applied to long-term resource planning. Looking ahead, ELL will continue to work with regulators and its key stakeholders to transform its portfolio, building a diverse generation fleet that maintains the grid's resilience and reliability and delivers on the shared environmental commitments among ELL and its customers.

While no specific approvals are sought for this IRP pursuant to the Commission's Integrated Resource Planning General Order, the Reference Resource Plan and Action Plan outlined in

Chapter 6 of the IRP reflect ELL's present expectations regarding the planning actions that can be expected over the next several years based on relevant and available information. It is important to note that these action items, as well as the Portfolios modelled herein, are consistent with Entergy's announced sustainability and emissions reductions goals and ELL's objective to provide reliable, affordable electric service to customers, which goals are driven by customers' own objectives, and this Report should be informative to stakeholders interested in the path that will lead to the accomplishment of those goals. While this Report does not represent a resource planning decision, the Company is encouraged by the fact that the least cost Portfolios identified through the IRP analyses are consistent with these objectives and, as such, the objectives do not appear to create additional incremental costs for customers beyond what would otherwise be incurred to reliably serve customers at a reasonable cost.

The 2023 IRP Action Plan consists of eight action items, which are summarized below and discussed in more detail in Chapter 6:

1. Implement ELL's Solar Portfolio & Geaux Green Tariff (2020 RFP)	Pursuant to the recently issued certification, ELL intends to add three new contracted solar resources (Vacherie, Sunlight Road & Elizabeth) and one new owned resource (St Jacques) to its generation portfolio. Additionally, ELL will implement Rider GGO, a new green tariff which will allow participants to subscribe to and receive value from these four solar resources to address their decarbonization objectives. The Company intends to expand Rider GGO and/or develop other renewable options to provide benefits to all customers (including non-participants) and address future capacity needs, where feasible.
2. Complete ELL's Two Outstanding RFPs (2021 & 2022 RFPs)	ELL's 2021 RFP sought up to 600 MWs of solar resources, with an option to provide battery storage, for resources located within SELPA. ELL's 2022 RFP seeks up to 1,500 MWs of solar resources, with an option to provide battery storage, and additionally seeks wind resources. In this most recent RFP, ELL expanded its locational requirements beyond SELPA to include all of Louisiana for solar resources, and all of MISO South and/or SPP for wind resources.
3. Continue the Issuance of Sizeable and Frequent Renewables RFPs	ELL intends to continue to issue sizeable and frequent renewable RFPs in an attempt to respond to customer preferences, diversity of ELL's generation portfolio, capitalize on the improving economics of solar and potentially other technologies relative to conventional

	generation resources, and ultimately to work toward its 2030 and 2050 sustainability goals, respectively. In response to the Commission's recent directive, ELL will also work with the Commission and other stakeholders to find ways to expedite this process. In addition, as the market continues to evolve and developers initiate projects, in accordance with LPSC guidelines, ELL will evaluate and respond to any unsolicited offer it may receive for viable resource additions.
4. Cross-State Air Pollution Rule ("CSAPR")	ELL will continue to monitor the development of the proposed revisions to the CSAPR program and seek opportunities to engage with the Environmental Protection Agency ("EPA") to advocate for a more flexible final rule which minimizes the risk of additional pollution control investment costs and/or revisions to ELL's existing resource plans. Once a final rule is issued by EPA, ELL will assess the impacts and implement a compliance strategy to meet any new or revised compliance obligations.
5. Explore Solving Some of ELL's Energy & Capacity Deficits with Distributed Generation and/or Customer Solutions	Distributed generation provides significant benefits to the grid and ELL customers through increased reliability, increased efficiency, grid balancing, peak load reduction and onsite local self-reliance for power generation needs. The LPSC's recent approval of ELL's Power Through program is a great example of a cost-effective opportunity to provide distributed generation coupled with resiliency for its customers. ELL will continue to evaluate opportunities to install distributed generation throughout its service territory as well as seek new opportunities for customer solutions that bring renewable generation to Louisiana.
6. Continue Participation in Commission Rulemakings (Resource Adequacy & Planning, Reliability)	ELL intends to monitor and participate in Commission rulemakings regarding resource planning, reliability and resource adequacy and evaluate actions that ELL should take to protect its customers from reliability and cost shifts resulting from cooperatives that plan to serve their load without appropriate long-term physical capacity, including exiting MISO.

7. Explore Additional Demand Side Management Opportunities	ELL stands ready to expand its current DSM offerings in accordance with applicable LPSC Rules[4] and Orders and where it is cost-effective to do so.
8. Pursue Power Resiliency	ELL will file its Protect Louisiana Plan highlighting its plan to accelerate the resilience of its electric system through a comprehensive set of cost-effective hardening projects.

[4] ELL notes that in the on-going rulemaking related to administration of DSM programs (Docket No. R-31106), Staff issued new draft rules on March 7, 2022. Among other things, these draft rules (if implemented as drafted) would radically change the paradigm for administration of DSM programs by removing control of the programs from utilities and seeking to hire a statewide third-party administrator to oversee programs for all utilities. It is unclear whether this model will be implemented. As ELL noted in filed comments, the Company believes the ability to achieve cost-effective savings through DSM programs would be better served by allowing utilities with existing programs to retain control over them. The discussion of DSM, and the potential benefits thereof, throughout this report and in the DSM Potential Study assumes that ELL would still be allowed to administer DSM programs once the Commission's rules are finalized and implemented.

Chapter 2 Long-Term Resource Planning

Summary

- In 2012, the LPSC issued a General Order requiring its jurisdictional utilities to file an IRP at least every four years; this is the third IRP filed by ELL since the LPSC issued its Integrated Resource Planning General Order.
- The IRP process incorporates ELL's resource planning objectives, which complement the LPSC's General Order.
- ELL has made significant progress on the action items identified in its 2019 IRP Action Plan.

Introduction

This document describes ELL's long-term IRP for the period 2023 - 2042. This is the third IRP filed by ELL since the LPSC issued its Integrated Resource Planning General Order in Docket No. R-30021. Similar to prior IRPs, ELL's 2023 IRP reflects the fact that uncertainty remains an issue that must be considered in long-term resource planning, with no outcome providing absolute certainty as to the appropriate path for the utility to take. In other words, the uncertainties that dominated ELL's 2019 IRP filed with the Commission on May 23, 2019 (e.g., advances in renewable resource technology) remain but have been expanded to include other uncertainties, such as the impact and role of more significant amounts of renewable generation in the market and the growing demand from customers, evolving customer preferences, geopolitical conflicts that shift supply chain and locational optimization for industrial processing, climate change, and policy uncertainty at the local, state and federal level. This is not an exhaustive list, but rather one that will continue to grow over time and will require the attention and action from ELL.

As indicated in Chapter 1, this IRP does not provide a fixed path for future ELL resource planning. Rather, ELL's specific long-term resource planning actions (e.g., capacity additions) typically are subject to review and approval by the Commission in separate proceedings. The Action Plan contained within this IRP reflects ELL's current expectations regarding the planning actions the Company will take over the next several years and, consistent with the IRP rules, identifies a Reference Portfolio based on information available today. As the industry pivots, ELL will address the changing economy and maintain flexibility in meeting the demands of its customers without sacrificing affordability, reliability, or environmental stewardship.

Resource Planning Objectives

ELL's resource planning efforts are driven by the fundamental goal to deliver a sustainable resource portfolio that is centered on customer outcomes. Building a sustainable portfolio requires that ELL carefully balance three key objectives: reliability, affordability, and environmental stewardship. This balance looks at both the near-term and long-term benefits and risks associated with each key objective.

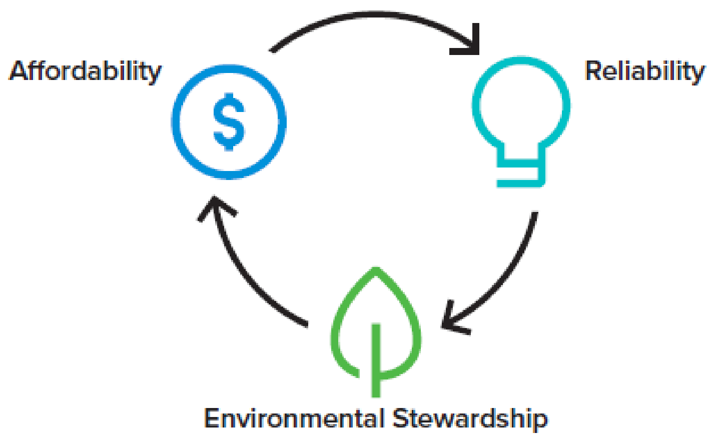

Figure 2: Key Planning Objectives

ELL's development of a sustainable portfolio places an emphasis on customer preferences. ELL recognizes that customer expectations for electric service will continue to change alongside advancements in technology and evolving market and policy considerations both in and out of the traditional utility framework. Accordingly, ELL aims to meet customers' needs for reliable, reasonably priced electric services and energy solutions both for those expected today and in the future.

Through the IRP process, ELL conducts an extensive study of customers' needs over the next 20 years based on currently available data. It does so by analyzing the costs and benefits of supply-side and demand-side alternatives to develop resource portfolio options that help meet ELL's planning objectives. The results of the IRP are not intended to represent static plans or pre-determined schedules for resource additions.

Regulatory Context for ELL's IRP

ELL's previous two IRP cycles have concluded with Staff recognizing that ELL has met the requirements of the Commission's IRP General Order, with no disputed issues requiring further resolution, and recommended that the LPSC acknowledge ELL's Final IRP report. In both instances, the Commission accepted Staff's recommendation. ELL endeavors to continue to work closely with Staff and Stakeholders throughout this process, and in accordance with the rules specified in the Commission's General Order, to achieve the same outcome in this IRP cycle.

Chapter 3 Integrated Resource Planning Process

Summary

- ELL's IRP strategy ensures that the Company is taking the necessary steps today to continue to enhance reliability, affordability, and environmental stewardship for its customers while providing flexibility to respond and adapt to a constantly shifting utility landscape.
- This strategy requires balancing many different variables, including evolution in technology and customer preferences, resource and transmission attributes, MISO resource adequacy requirements, and sustainability goals.

The IRP plays an important role in the iterative process of planning ELL's future resource portfolio by providing a comprehensive and transparent look at long-term themes and tendencies in designing and leveraging a diverse, balanced, and forward-thinking portfolio of resources to ELL planners, as well as stakeholders. While these long-term and forward-looking indicators are important guides to resource planning, the IRP fulfills a distinctly different purpose and process from near-term, specific resource decisions that typically are presented to the Commission for approval.

The considerations detailed in this report are focused on efficiently meeting all of ELL's customers' ever-changing supply needs. ELL's IRP strategy ensures it is taking the necessary steps today to continue to enhance reliability, affordability, and environmental stewardship for its customers in the future. This approach also provides the flexibility ELL requires to respond and adapt to a constantly shifting utility landscape. In response to customer demand and a business environment that is increasingly focused on sustainability and renewable energy goals, ELL received LPSC approval in early 2022 for two new renewable energy credit ("REC") based green pricing options in LPSC Docket No. U-35916. Those two new offerings, Riders GPO and LVGPO, have been

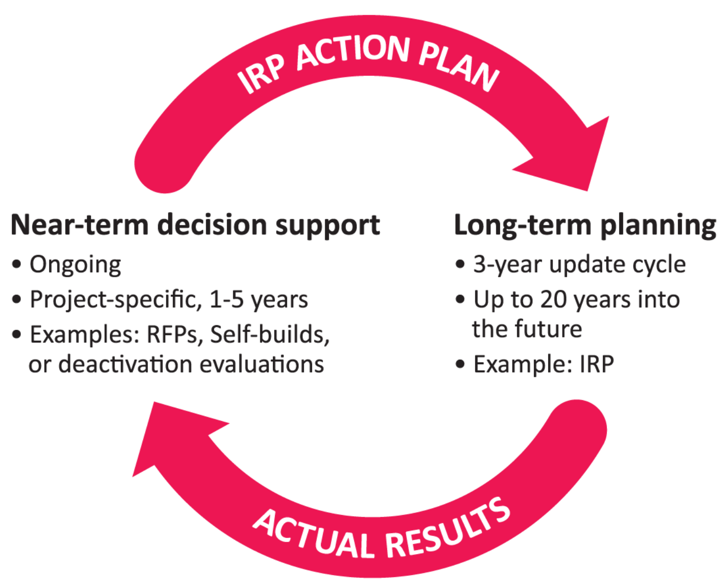

Figure 3: ELL IRP Strategy

open for customer enrollment since May 2022.[5] Also, in September of 2022, ELL received certification for a Geaux Green Option tariff in Docket No. U-36190 that offers a solution for customers to subscribe to the green tariff solution that includes RECs and value from renewable energy that is sourced from solar resources located within Louisiana. All of these voluntary renewable offerings seek to provide participating customers access to renewable energy and to support economic development in Louisiana.

The twenty-year study period for the 2023 IRP outlines the current energy landscape as well as the challenges and opportunities that lie ahead. As in ELL's previous IRPs, the 2023 IRP is guided by ELL's Resource Planning Objectives, which focus on affordability, reliability, and environmental stewardship. This IRP looks at both the near-term and long-term benefits and risks associated with each key objective.

Existing Resources

ELL provides electric service to more than 1.1 million customers and has residential, commercial, industrial, and governmental customers in 58 of Louisiana's 64 parishes. It also provides natural gas service to more than 96,000 customers in Baton Rouge, Louisiana. The Company currently controls, through ownership, Power Purchase Agreements ("PPA"), or Demand Response Resources, a diverse array of resources totaling approximately 11,842 MW of installed capacity and zonal resource credits ("ZRCs") to serve these native load customers as of 2022. The table below shows ELL's ownership share of its resources by resource type.

Of this 11,842 MW, about one-fourth of ELL's total capacity is derived from legacy gas units, which range in age from 47 to 56 years of service and are assumed to deactivate over the course of the IRP planning horizon. As is discussed in further detail in the Environmental section of this IRP, the EPA's current revision to its CSAPR may potentially accelerate some of the deactivation assumptions.

Approximately half of ELL's total capacity is derived from CT/CCGT units, which range in age from 2 to 22 years of service. Only two of ELL's CT/CCGTs are assumed to deactivate over the course of the IRP planning horizon. 2,200 MW of this fleet have been placed into service within the last 3 years.

In addition to these legacy gas assets, ELL also maintains less than 400 MW of coal fired generation within the supply portfolio, from ownership shares in the Nelson 6 and Big Cajun 2 Unit 3 facilities, in addition to affiliate Power Purchase Agreements associated with Independence and White Bluff. To date, these resources have provided fuel diversity and solid fuel assurance to ELL's customers. However, Entergy has announced plans to cease burning coal at these facilities by 2030.

[5] These offerings are being marketed to customers under the product names "Entergy Green Select" and "Entergy Green Select – Large Volume", and both products are Green-e® certified by the Center for Resource Solutions. Entergy, *Renew,* Entergy Corporation (2022), *available at* https://renew.entergy.com/.

The majority of the resources included in the table below are owned by ELL, but ELL also receives energy and capacity through PPAs for certain resources, including some from other Entergy affiliates. ELL purchases 12.6% of the output of Grand Gulf through a PPA with System Energy Resources, Inc. ("SERI"), an Entergy affiliate which owns Grand Gulf. ELL also purchases a portion of Entergy Arkansas, LLC's ("EAL's") excess baseload generation. ELL purchases 2.72% of the output of Arkansas Nuclear One ("ANO") 1, 2.71% of ANO 2, an additional 2.2% of Grand Gulf, 2.72% of EAL's owned share of Independence 1, 2.82% of EAL's owned share of White Bluff 1, and 2.6% of EAL's owned share of White Bluff 2. These PPAs are in effect for the life of the resource and are filed with and approved by FERC.

In addition to purchasing the output of certain units from other Entergy affiliates, ELL also sells the capacity and associated energy of some of its resource portfolio to other Entergy affiliates. ELL sells 20% of Ninemile 6 to Entergy New Orleans, LLC ("ENOL"), 31.88% of Perryville 1 and 2 to Entergy Texas, Inc. ("ETI"), 29.75% of River Bend 1 to ETI, and 10% of River Bend 1 to ENOL. ELL also sells to ENOL 1.84% of the generation owned by or under contract to Legacy ELL at the time of the transfer of the Algiers load to ENOL (the "Algiers PPA"). The Algiers PPA includes the output of Acadia 2, ANO 1 and 2, Grand Gulf, Independence 1, Little Gypsy 2 and 3, Montauk, Ninemile 4, 5, and 6, Oxy-Taft, Perryville 1 and 2, River Bend 1, Sterlington 7, Vidalia, Waterford 1, 2, 3, and 4, and White Bluff 1 and 2. These PPAs are also in effect for the life of the resources and are filed with and approved by FERC.

Additionally, ELL receives capacity and energy through third-party power purchase agreements. The power purchase agreements included within the assumptions for this IRP are included below.

Figure 4: Capital Region Solar

A new addition to ELL's portfolio since the 2019 IRP and a result of ELL's 2016 Request for Proposals[6], ELL executed a long-term PPA for a 50 MW solar photovoltaic ("PV") resource located near Port Allen, Louisiana named Capital Region Solar.[7] The Commission certified this resource on March 18, 2019, approving the PPA. The resource achieved commercial operation in September 2020 with ELL's PPA commencing on October 9, 2020.

As was stated in ELL's 2019 IRP, ELL has worked towards executing its action plan to support ongoing planning objectives and modernizing its fleet to support existing customers and load growth in the area served by ELL, specifically industrial growth in southern Louisiana. ELL has

[6] Entergy, Notice of the final results of the Entergy Louisiana, LLC;s 2016 Request for Proposals for Long-Term Renewable Generation Resources, Entergy Corporation (February 28, 2017), available at https://spofossil.entergy.com/ENTRFP/SEND/2016ELLRenewableRFP/Index.htm.

[7] See, Order No. U-34836 (March 18, 2019), Docket No. U-34836, In re: Application for Authorization to Participate in a Contract for the Purchase of Energy and Related Benefits from the LA3 West Baton Rouge LLC Solar Facility.

responded to this by adding 2.2 GW of efficient, reliable gas-fired generation within historically constrained areas[8] of ELL's footprint shown in Figure 5 below. The industrial sector is continuing to experience growth and is moving forward with a number of projects, including new projects and expansions of existing facilities.

Figure 5: Outline of ELL Planning Areas

In addition to these generating resources, ELL's portfolio also includes DSM resources that provide capacity value through reductions in customer load. For the 2022/2023 Planning Year, Load Modifying Resources ("LMRs") associated with legacy interruptible customer programs contributed approximately 280MW of combined capacity including values associated with reduced line losses and reserves. In 2021, ELL also received LPSC approval for new interruptible service options.[9] As customers enroll in these new tariffs, the Company's portfolio of LMRs may increase providing further demand response value to ELL's customers.

In addition to the demand response and interruptible options, ELL also manages a portfolio of EE programs that produce both energy savings for customers and a reduction in load served for the Company. These programs have reduced the Company's load behind the customer meter by an incremental 30.1 MW since 2018 and an aggregate 51.9 MW since programs were introduced in 2014. There are no prescribed energy savings targets under the current Commission EE rules, however, in 2021, the program achieved savings of 0.14% of 2012 retail sales. ELL exceeded its

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[8] The zones depicted on this map are used by Entergy Louisiana for resource planning purposes. WOTAB is the West of Atchafalaya Basin area. SELPA is the Southeastern Louisiana Planning area. Amite South is a sub-region of SELPA, and DSG is Downstream of Gypsy, which is a sub-region of Amite South.

[9] Entergy, *Interruptible Service Program,* Entergy Corporation, *available at* https://www.entergy-louisiana.com/interruptible/.

planned energy savings target with an overall achievement of 127% energy savings. EE programs offered in 2021 also exceeded cost-benefit thresholds established by the Commission in Docket No. R-31106. Gross program savings increased from 48,463 MWh for the 2020 Program Year to 56,082 MWh for the 2021 Program year. To further supplement its successful EE programs, in 2021 ELL also began offering several pilot programs including New Construction and Agricultural Solutions. Evaluated savings and overall goal achievement for the 2021 Program Year are shown in further detail in Table 1.

Table 1: EE Program Metrics

Evaluated Savings and Goal Achievement

Evaluation Metrics	2021
ELL Gross Savings (ex ante)	51,347 MWh
As adjusted by ADM Associates, Inc. for Realization Rate (ex post)	4,736 MWh
As adjusted for Net-To-Gross ("NTG") ratios	56,082 MWh
ELL MWh Target	44,003 MWh
% of Target Achievement Based on Evaluated Energy Savings	127%

ELL's current portfolio by unit is shown in Table 2 below. Additional details associated with these resources, as is required by the IRP General Order, can be found in Appendix B, and is further supplemented by a description of each unit that ELL owns and/or operates located in Appendix C.

Table 2: ELL Owned and Contracted Capacity

Power Generation Unit Name	ELL Ownership Share of GVTC [MW]	Resource Type
Acadia	526	Owned Resource/Affiliate PPA*
Arkansas Nuclear One 1*	22	Owned Resource/Affiliate PPA*
Arkansas Nuclear One 2*	26	Owned Resource/Affiliate PPA*
Big Cajun 2 Unit 3	135	Owned Resource/Affiliate PPA*
Calcasieu 1	142	Owned Resource/Affiliate PPA*
Calcasieu 2	159	Owned Resource/Affiliate PPA*
Grand Gulf*	203	Owned Resource/Affiliate PPA*
Independence 1*	7	Owned Resource/Affiliate PPA*
J. Wayne Leonard Power Station	912	Owned Resource/Affiliate PPA*
Lake Charles Power Station	913	Owned Resource/Affiliate PPA*
Little Gypsy 2	405	Owned Resource/Affiliate PPA*
Little Gypsy 3	504	Owned Resource/Affiliate PPA*
Ninemile 4	724	Owned Resource/Affiliate PPA*

Ninemile 5	728	Owned Resource/Affiliate PPA*
Ninemile 6	438	Owned Resource/Affiliate PPA*
Ouachita 3	241	Owned Resource/Affiliate PPA*
Perryville 1	355	Owned Resource/Affiliate PPA*
Perryville 2	101	Owned Resource/Affiliate PPA*
Riverbend 30	191	Owned Resource/Affiliate PPA*
Riverbend 70	389	Owned Resource/Affiliate PPA*
Roy Nelson 6	211	Owned Resource/Affiliate PPA*
Union 3	505	Owned Resource/Affiliate PPA*
Union 4	505	Owned Resource/Affiliate PPA*
Waterford 2	415	Owned Resource/Affiliate PPA*
Waterford 3	1155	Owned Resource/Affiliate PPA*
Waterford 4	32	Owned Resource/Affiliate PPA*
White Bluff 1*	13	Owned Resource/Affiliate PPA*
White Bluff 2*	12	Owned Resource/Affiliate PPA*
WPEC	370	Owned Resource/Affiliate PPA*
Agrilectric	9	Third Party PPA
Carville	485	Third Party PPA
Capital Region Solar	50	Third Party PPA
Oxy-Taft	471	Third Party PPA
Rain CII	28	Third Party PPA
Toledo Bend	48	Third Party PPA
Vidalia	133	Third Party PPA
Load Modifying Resources[10]	301	LMRs

[10] ELL's existing interruptible load contracts included in the "Load Modifying Resources" assumed to remain in place throughout the entire study period.

Figure 6 below shows the percentage, by fuel type, of energy sources serving ELL's native load in 2021.

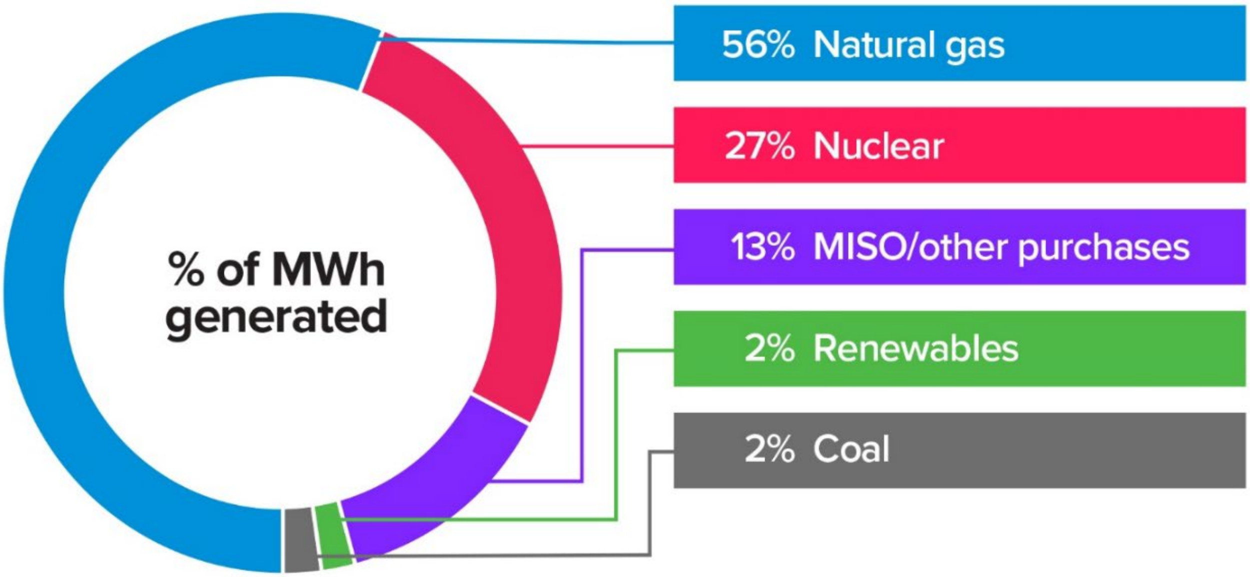

Figure 6: Entergy Louisiana 2021 Power Generation Mix

Future of Existing Resources

As indicated above, uncertainty is an ongoing issue that resource planners must consider in preparing long-term resource plans. In subsequent sections, ELL will review a number of factors that are assessed to guide and inform the portfolio design strategies and other issues facing ELL's planners.

Developing an IRP requires making assumptions about the future operating lives of existing generating units. Two key issues in this determination are the effective date of future environmental compliance requirements and whether the investments needed for ELL's older units to keep operating in compliance with those regulations are economical compared to alternative capacity resources. Another key issue in this determination is the assumed remaining useful life of a particular technology type. In ELL's 2019 IRP, it was assumed that the useful life for CTs and CCGTs was 30 years. Since that time, ELL conducted a detailed analysis on the expected remaining useful life of those resources. The result of that analysis concludes that ELL's CTs and CCGTs are generally assumed to have a remaining useful life of longer than 30 years and most are assumed to operate beyond the end of the 2023 IRP study period (2042).

The IRP includes deactivation assumptions for existing generation to plan for and evaluate the best options for replacement capacity over the planning horizon. Based on the current design life assumptions incorporated into the IRP, a number of ELL's existing generating units and PPAs are anticipated to deactivate over the IRP planning horizon (2023-2042). During this planning period, the total reduction in ELL's capacity from the assumed unit deactivations and contract expirations grows to approximately 5,200 MW (~3,400 MW in the first 10 years). The deactivations and contract expirations anticipated over the first 10 years of the planning horizon are shown in the tables below.

Table 3: Near Term Deactivations

Near Term (10 Year) Deactivations[11]	Unit	ELL Ownership Share of GVTC [MW]	Deactivation Assumption
Big Cajun 2	3	135	2025
Waterford	2	415	2025
Little Gypsy	2,3	909	2027
Roy Nelson	6	211	2028
White Bluff	1,2	25	2028
Independence	1	7	2030
Ninemile	4	724	2031

Table 4: Near Term Contract Expirations

Near Term (10 Year) Contract Expirations	MW	Fuel	Expiration Date
Montauk	2	Biomass	2024
Toledo Bend	48	Hydro	2023
Oxy-Taft	471	Natural Gas	2028
Carville	485	Natural Gas	2032

These deactivation assumptions do not constitute a definitive deactivation schedule but are used as planning tools and help to prompt cross-functional reviews and recommendations. It is not unusual for these assumptions to change over time given the dynamic use and operating characteristics of generating resources. Additionally, for ELL's nuclear fleet, the IRP reflects deactivation at the expiration of the current operating licenses. The Nuclear Regulatory Commission ("NRC") operating license for Waterford 3 and Grand Gulf will expire in 2044, and the license for River Bend will expire in 2045, all outside of the IRP planning Horizon. However, ELL's portion of Entergy Arkansas's ANO Unit 1 and ANO Unit 2 are currently assumed to become unavailable in 2034 and 2038, respectively, to align with the current operating license expirations. Entergy's Nuclear group has not yet begun its license extension review process for these nuclear units, and some degree of risk exists that an operating license extension will not be granted under the NRC's Subsequent License Renewal ("SLR") process for units requesting extended operations from 60 years to 80 years. This planning assumption results in decreased base load

[11] Following the ELL IRP Technical Conference, Sterlington 7A was deactivated. As a result, the resource has been removed from the table. It is important to note that ELL only owns a portion of Big Cajun 2 Unit 3, Roy Nelson Unit 6, White Bluff Units 1 and 2, and Independence Unit 1. The entire GVTC ratings for those respective units are currently 557 MW for Big Cajun 2 Unit 3, 524 MW for Roy Nelson Unit 6, 818 and 823 MW for White Bluff Units 1 and 2, respectively, and 822 MW for Independence Unit 1.

capacity over the planning horizon as these units reach the expected end of their licensed lives. These assumptions are discussed in greater detail in Chapter 5 of this report.

It is important to recognize that assumptions related to these uncertainties about operating lives of existing generating units do not reflect actual decisions regarding the future investment in resources or the actual dates that generating units will be removed from service. As planned deactivation dates near, a significant equipment failure occurs, or operating performance diminishes, a reassessment of assumptions may be required. Unit-specific portfolio decisions, e.g., sustainability investments, environmental compliance investments (like those contemplated in the CSAPR sub-section of the Environmental section of this IRP), or unit deactivations, will be made at the appropriate time and will be based on economic and technical evaluations considering such factors as projected forward costs, anticipated operating roles, the reliability of the system, and the cost of supply alternatives. These factors are dynamic, and as a result, actual decisions may differ from planning assumptions as greater certainty is gained regarding requirements of legislation, regulation, and relative economics. Accordingly, ELL's IRP seeks to retain the flexibility to respond to changes in circumstances up to the time that a commitment is required to be made.

Planned Resources

In its 2020 Request for Proposals for Solar Photovoltaic Resources, ELL sought up to 300 MW of solar generation to add to its resource portfolio. Out of this competitive solicitation, ELL selected three resources: Sunlight Road, a 50 MW solar resource located in Washington Parish, Vacherie, a 150 MW solar resource located in St. James Parish, and St. Jacques, a 150 MW solar resource located in St. James Parish. Additionally, ELL received an unsolicited offer for, and selected, Elizabeth, a 125 MW solar resource located in Allen Parish. ELL filed for certification of these resources at the LPSC in Docket No. U-36190 in November of 2021, they were approved by the LPSC in September of 2022, and are expected to be online in the 2024-25 timeframe.

Additionally, in its 2021 Request for Proposals for Solar Photovoltaic Resources, ELL sought up to 600 MW of solar generation to add to its resource portfolio. Out of this competitive solicitation, ELL has made selections, is currently negotiating with counterparties, and intends to file for the certification of these resources in early 2023. Furthermore, ELL has an ongoing 2022 Request for Proposal for Renewable Resources which is seeking up to 1,500 MWs of solar generation, and additional wind generation. Following the current schedule for this solicitation, ELL is expected to make selections in late 2022 or early 2023.

In July 2021, ELL filed an application in LPSC Docket No. U-36105 seeking approval for Power Through, a turnkey backup generation product offering of natural gas-fired distributed energy resources ("DER") to be deployed across the Company's service area. The Power Through offering will provide up to 150 MW of distributed generation, including 30 MW reserved for a pilot program consisting of solar and battery installations. Power Through would offer energy resiliency as a service for commercial and industrial customers via 100 kW - 10 MW DERs installed in front of a host customer's meter. These DERs will serve the dual functions of 1) meeting a portion of ELL's capacity and energy needs by delivering power to the grid when favorable market conditions exist, and 2) meeting the backup power needs of host customers during grid outages (e.g. in the aftermath of a hurricane or other weather event). The ELL Power Through program was approved by the LPSC in September of 2022, and the DERs are expected to be operational over the next several years.

While ELL's Updated Data Assumptions filing included a planned resource identified as the "2027 ELL CT", ELL has since modified this assumption and did not include it as a planned resource in the analysis provided in this Report.

Under the assumption that the planned resources described above proceed as planned, the 2023 IRP reflects a total of approximately 11,901 MW of resources in ELL's portfolio by 2026 on an effective capacity basis.[12] The diversity of ELL's currently planned resource portfolio in 2026 is shown in Figure 7 below.

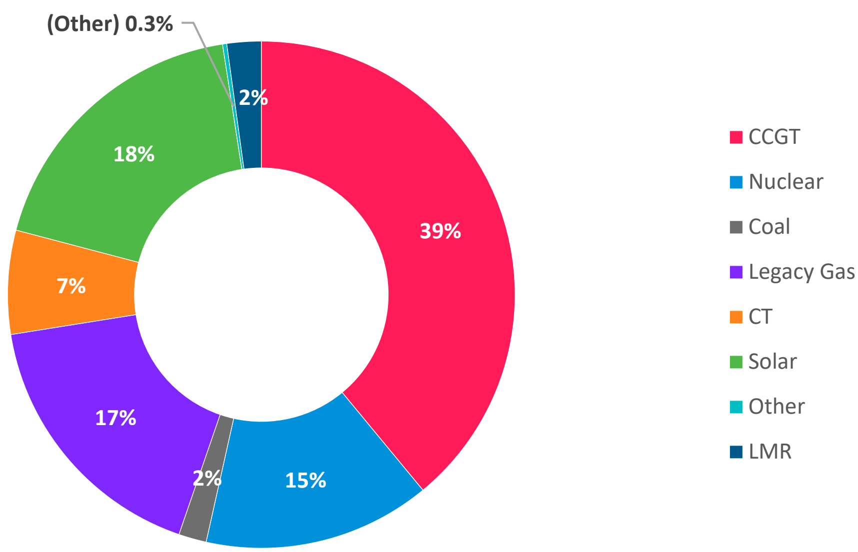

Figure 7: Entergy Louisiana 2026 Capacity Mix

Environmental Considerations

Entergy (along with its subsidiaries such as ELL) aspires to be an industry leader in protecting the environment. Environmental laws, regulations, and orders affect many areas of the Company's business, including restrictions on hazardous and toxic materials, air and water emissions, and waste disposal. ELL is committed to meeting or surpassing compliance with environmental and all applicable regulatory requirements and enhancing the communities it serves.

[12] In alignment with MISO's MTEP 21 Future report, an effective capacity for solar resources of 48% of installed capacity in 2026 is used. A 16.3% capacity credit for wind resources is used, which algins with MISO's 2021-2022 Wind Capacity Credit report. For conventional resources, a 100% capacity credit is used. LMRs receive peak hour capability plus reserve margin and transmission losses. See Chapter 5 for more in-depth discussion on effective capacity.

ELL strives to minimize any potential adverse effects of its activities on the local communities it serves, including the communities of its low-income customers. ELL considers environmental impacts in its policies and planning to minimize adverse environmental effects and to sustain its communities. ELL maintains open communication and seeks opportunities to partner with its stakeholders on environmental concerns.

To that end, the following provides an example of measures that ELL has taken regarding potential public health impacts and environmental considerations. In developing new generation, ELL identifies candidate sites and then conducts an evaluation of environmental factors and land use considerations for each site and its surroundings. This evaluation considers the presence of wetland areas, existing water quality in nearby water bodies, the potential presence of threatened or endangered species, and ambient air quality. Many of these factors are similar to the environmental indicators considered by the EPA EJSCREEN tool.[13] In addition, ELL conducts environmental due diligence reviews to identify any existing environmental conditions at or near a proposed site for generation development. ELL continues to review and analyze best practices related to potential public health impacts and environmental considerations, including the use of EJSCREEN and other beneficial tools in planning for the future.

Customer Preferences and Long-term Planning

With advancements in technology and evolving priorities, both within and outside of the traditional utility framework, customer expectations will continue to change. Today's customers are using energy more efficiently than ever before, due to both an increasing emphasis on social responsibility and sustainability and advances in EE standards. ELL approaches EE with the broader goal of enhancing the generation, delivery, and use of energy, recognizing that a well-designed electric system, with the proper mix of generating resources, is just as important to reducing customer costs and bills as are programs aimed at educating customers on how to efficiently manage their usage.

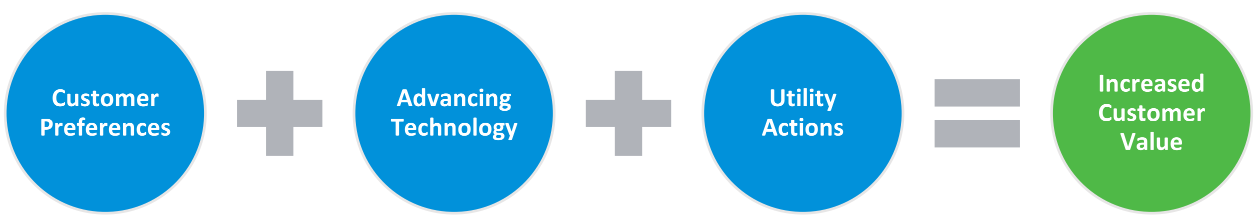

Figure 8: Changes and Opportunities Within the Utility Industry

Customers are also seeking more options in the generation and delivery of energy, including how they interact with, understand, and manage their own energy use, as well as the actual sources from which their energy is derived. As reflected in ELL's AMI proceeding in Docket No. U-34320, ELL's deployment of AMI is in response to ever-evolving customer expectations regarding the provision of electric service and technological innovation that is changing the way energy is

[13] It should be noted that the EPA's EJSCREEN tool is used only to evaluate resources to be located at a specific, known location. The IRP optimized portfolios do not contain locational-specific assumptions such that use of the EJSCREEN tool is appropriate as part of the IRP.

supplied and distributed. ELL's interest is in actively engaging its customers to obtain a better sense of those expectations and the ways in which ELL can bring offerings to the marketplace to meet those expectations.

Increasingly, ELL customers are becoming more interested in sourcing their power from cleaner, more sustainable sources of energy, with a clear preference for renewable resources like solar. As mentioned earlier, ELL's green pricing and green tariff offerings provide participating customers the ability to subscribe directly to output from renewable sources, which have been, or will be, acquired to serve and benefit all customers consistent with ELL and the LPSC's long-term planning objectives, while avoiding the financial and operational risks associated with building or contracting for their own facilities.

ELL is focused on achieving a better understanding of these evolving customer preferences, and the IRP is one set of input information ELL can leverage to help accomplish that goal. That understanding will allow ELL to:

1. Develop a comprehensive outlook on the future utility environment so ELL can more effectively anticipate, and plan for, the future energy needs of its customers and region.
2. Incorporate new, smart technologies and advanced analytics to better assess where expanding resource alternatives can be leveraged, and plan for improvements and enhancements to the electrical grid.
3. Continue to seek cost-effective renewable resource additions to ELL's portfolio to support and expand offerings of renewable energy to interested customers.

Advancing Technology - Technological advancements provide the energy industry increased opportunities and alternative pathways to plan for and efficiently meet customers' energy needs and to partner with customers to accomplish those shared objectives. From improving the reliability and efficiency of energy production and delivery of that energy to customers, to more customer facing opportunities, like storage, conservation, and AMI-enabled options, these innovations can strengthen reliability and increase affordability for the homes, businesses, industries, and communities that ELL serves. These new technologies also support the continued development and expansion of sustainability efforts while addressing ELL's long-term planning objectives, outlined in further detail below.

The deployment of advanced meters and development of smart energy grids, for example, are enabling the entire utility industry to better understand the new and changing ways in which customers are using energy. This allows energy companies to make more informed decisions and provide tailored customer solutions through enhancements to electric infrastructure and the adoption of new products and services.

Increased Customer Value - By combining an understanding of what customers want with sound and comprehensive planning, ELL can deliver the type of service customers expect while continuing to address the utility-wide planning objectives of cost, reliability, risk, and sustainability. Increasing the array of alternatives provides an opportunity to better meet ELL's planning principles by providing a diverse portfolio of resources to meet long-term service requirements. A diverse portfolio mitigates customer exposure to price volatility associated with uncertainties in fuel and power purchase costs and risks that may occur through a concentration of portfolio attributes such as technology, location, or supply channels. Additionally, by taking advantage of increased and evolving opportunities, ELL continues its effort of modernizing its supply portfolio.

Innovation

ELL strives to solve critical customer frictions for residential, commercial, and industrial customers by building new products and services. Every customer is an integral part of ELL's success. ELL collaborates with its customers, partners, and colleagues to build a more robust, sustainable power network for today and future generations.

For example, with the growing opportunity and challenges that will come with electrification of transportation in the coming years, ELL expects its customers to increasingly electrify as more vehicle models become available and their prices reach parity with, or become less expensive than, internal combustion engine alternatives. Specific to the commercial space, ELL also sees a growing number of organizations exploring electric vehicle alternatives in order to help them reach their internal sustainability goals. ELL's forecasting processes include assumptions around increased energy usage tied to electrification, which is discussed in greater detail in Chapter 4.

ELL looks to enable opportunities in this space and expects to remain customer centric with its approach. Accordingly, ELL will be exploring solutions in the future relating to fleet electrification, public charging, and workplace and residential charging. In parallel, ELL is committed to having the resources and infrastructure in place to support these initiatives.

Another example of ELL's efforts includes being one of the founding members of The Electric Highway Coalition. The collective group of utilities announced a plan in March 2021 to enable electric vehicle drivers seamless travel across major regions of the country through a network of direct current fast chargers for electric vehicles. The companies are each taking steps to provide EV charging solutions within their respective service territories. Since the March announcement, the coalition already has doubled in size with commitments from other utility partners.

MISO Resource Adequacy (“RA”) & Planning Reserve Requirements

MISO RA Requirements - As a load serving entity (“LSE”) within MISO since 2013, ELL is responsible for planning and maintaining a resource portfolio to reliably meet its customers’ power needs. To this end, ELL must maintain the proper type, location, level of control, and amount of capacity in its portfolio. With respect to the amount of capacity, two considerations are relevant:

1. MISO Resource Adequacy Requirements
2. Long-Term Planning Reserve Margin Targets

Resource Adequacy is the process by which MISO obligates participating LSEs to procure sufficient short-term capacity, through the procurement of ZRCs equal to their PRMR, in order to ensure regional reliability. ZRCs are provided by both supply-side generation and demand-side alternatives. An LSE’s PRMR is based on its forecasted peak load coincident with MISO’s forecasted peak load, plus a planning reserve margin, which is established by MISO annually, for the MISO footprint.

Contrary to the apparent belief of several Louisiana electric cooperatives, MISO's annual planning resource auction is not and should not be relied upon as a long-term source of capacity. MISO is not authorized to build or procure generating capacity to ensure there is an ample supply; MISO relies on LSEs and retail regulators like the LPSC to ensure each LSE has an appropriate amount of long-term physical capacity to support resource adequacy. If ZRCs available in the planning auction are less than the PRMR, the planning auction will value available ZRCs at cost of new entry and MISO will manage subsequent operational generation shortfalls induced by resource inadequacy through controlled load sheds as needed. For this reason, responsible resource planning requires a long-term plan for physical resources and plans to rely on the MISO annual auction as a source of that capacity are misguided.

Under MISO's Resource Adequacy process, the MISO-wide planning reserve margin is determined annually by November 1st prior to the upcoming planning year (June - May). Additionally, through MISO's annual Resource Adequacy process, MISO determines the amount of physical capacity needed within a particular region or LRZ based on load requirements, capability of existing generation, and import capability of the LRZ. Those capacity requirements are referred to as the Local Clearing Requirement ("LCR") for the LRZ for the Planning Year. Through MISO's proposed changes to the methodology for setting each LRZ's LCR, MISO has sent signals emphasizing the need for in-zone resources to contribute to LRZ resource adequacy.

At present, the MISO Resource Adequacy process is a short-term construct. Requirements are set annually and apply only to the upcoming year. Similarly, the value of ZRCs, as determined annually through the MISO auction process, apply only to the upcoming year. Both the level of required ZRCs and the value of those ZRCs are subject to change from year to year. In particular, the value of ZRCs can change quickly as a result of variables such as changes in forecasted load, transmission import/export constraints, market participant bidding strategies, the availability of generation within MISO and a specific LRZ, or an LRZ's LCR. For example, if existing LRZ 9 generation is deactivated and replaced with generation outside of LRZ 9, there will be an increased risk of higher ZRC values due to potentially insufficient in-zone generation to meet the LRZ 9 Local Clearing Requirement. ELL forecasts that absent planned physical generating resource additions that have not yet been proposed and/or certified by the LPSC, the current LRZ 9 generation surplus above its LCR is expected to erode by the 2025/2026 planning year, largely due to load growth and existing unit deactivations driven by age, economics, contract expirations, and environmental regulations, which, as previously stated, would put the entirety of LRZ 9 at risk of clearing at the CONE prices within future MISO PRAs, significantly increasing costs and jeopardizing future reliability for all within the region. The projected capacity deficits shown in the chart below could be even greater due to load growth, the seasonal construct for resource adequacy that may be implemented by MISO as soon as the 2023/2024 Planning Year[14], and/or if CSAPR or other environmental regulations trigger earlier unit deactivations. By contrast, the projected capacity deficit could be mitigated if the LPSC requires all LPSC-jurisdictional LSEs to support new or existing load with physical capacity and ensure resource adequacy.

[14] The Entergy Operating Companies, along with other MISO participating Utilities, have requested rehearing of FERC's order accepting MISO's Seasonal Accredited Capacity filing.

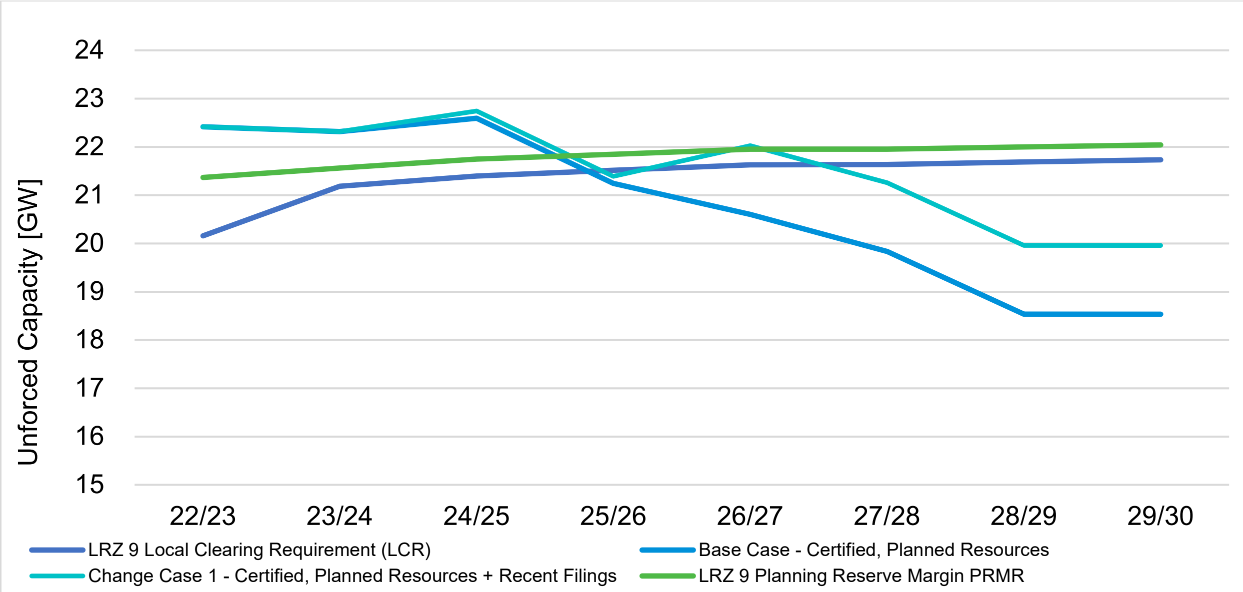

Figure 9: LRZ 9 Forecasted Unforced Capacity Position

MISO market constructs, rules, and methodologies continue to evolve, including items that impact Resource Adequacy requirements and capacity accreditation. In November of 2021, MISO filed a proposal at the FERC that would shift the current annual Resource Adequacy construct to a seasonal construct including modification to the way requirements and accreditation are derived. FERC accepted MISO's proposed tariff changes in August of 2022, and they will be implemented for the 2023/2024 PY. Given that these tariff changes were accepted late in the ELL IRP process, ELL's 2023 IRP will continue to be based on an annual construct, including the information contained throughout this report. Notwithstanding, it is important to note that ELL's current annual solar and battery capacity credit assumptions do account for the reliability contribution of these resources across all times of the year, not just the summer peak period.

In light of the recent tariff changes, ELL's planning approach is currently being re-evaluated to determine what updates are needed to align with MISO's new resource adequacy construct. Additionally, as capacity accreditation for non-thermal resources, such as solar, wind, and battery, is updated by MISO and approved by FERC, ELL will align its long-term planning strategies with these updates as well. With anticipated increases in renewable penetration, MISO[15] and ELL anticipate that the capacity value contribution of solar and wind will evolve.

As an LSE within MISO, ELL is responsible for planning and maintaining a resource portfolio to reliably meet its customers' power needs. Among other things, the resource portfolio must include the appropriate amount and type of generation to reliably support ELL's load. While the focus of resource additions will be on renewable resources, utilities must ensure they obtain or maintain an appropriate amount of dispatchable generation to support needs created by intermittent renewable resources. Moreover, the development of new capacity resources is a multi-year

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[15] MISO, *MISO's Renewable Integration Impact Assessment (RIIA),* MISO Energy (February 2021), *available at* https://cdn.misoenergy.org/RIIA Summary Report520051.pdf.

process, and load forecasts increase in their degree of uncertainty the further out into the future the forecast applies. Therefore, ELL plans beyond the immediate year requirements outlined by MISO's Resource Adequacy process. However, as discussed below, ELL's long-term reserve margin target is informed by MISO's Resource Adequacy construct.

Long-Term PRM Targets - Although the MISO Resource Adequacy process establishes minimum requirements that must be met in the prompt-year and are updated annually, it does not provide an appropriate basis for determining ELL's long-term resource needs. Moreover, relying on the MISO Planning Resource Auction as a source of generation capacity to meet customers' long-term power needs would unnecessarily expose customers to cost and reliability risk. For these reasons, ELL employs a more stable approach that is better suited for long-term planning to meet its long-term planning objectives. ELL's planning reserve margin reflects a long-term point of view that is intended, in part, to provide a buffer, or margin, above peak load to maintain reliable service during unplanned events such as higher than expected peak loads and unplanned outages of units committed to supply energy into the MISO market.

ELL's long-term planning construct is informed by a Loss of Load Expectation analysis which draws upon ELL's experience participating in MISO. The result of that analysis was a decision, in 2020, to change from the prior 12% reserve margin based on installed capacity ratings and forecasted non-coincident peak to a 12.69% reserve margin based on unforced capacity ratings and forecasted peak coincident to MISO. The changes in the planning reserve margin are intended to maintain the 1-day-in-10-year loss of load expectation level of reliability in the MISO region over the long-term planning horizon while considering long-term uncertainty related to load forecast, weather impacts, and available supply. Load forecast uncertainty was assessed by modeling a distribution based on economic uncertainty and corresponding forecast error associated with a four-year period, which was the assumed minimum lead time required to plan and install new capacity. Weather uncertainty was captured through application of historical weather shapes to forecasted peak demand and energy volumes. Supply-side resource forced outage rates for Entergy units was based on unit level historical operating data. For non-Entergy resources, MISO class average forced outage rates were used. ELL's current long-term planning construct is based on an annual target derived using the 12.69% reserve margin applied to ELL's summer peak load coincident with MISO. As discussed above, FERC recently approved MISO moving from its current annual PRA construct to a seasonal construct. With FERC having approved this change, ELL will continue to evaluate what changes, if any, are needed to the long-term planning construct.

Resource Needs

A number of factors are considered and evaluated in order to understand and determine ELL's resource needs:

Long-Term Capacity Requirements - ELL is projected to need new generating capacity over the course of the 20-year IRP period in order to reliably serve customers. Taking deactivation assumptions and load growth into account, the long-term deficit is expected to exceed 510 MW by 2027. This need may grow to over 5,100 MW by the end of the planning horizon. The below figure shows ELL's portfolio of existing resources, including both generating units and demand-side capacity, and planned resources, as described above, compared to ELL's peak load-plus-reserve-margin target. An assumption for future energy savings due to continued and expanded EE programs is included in the peak load. The deficit expands over time as expected loads increase and older generating units reach an assumed end of useful life.

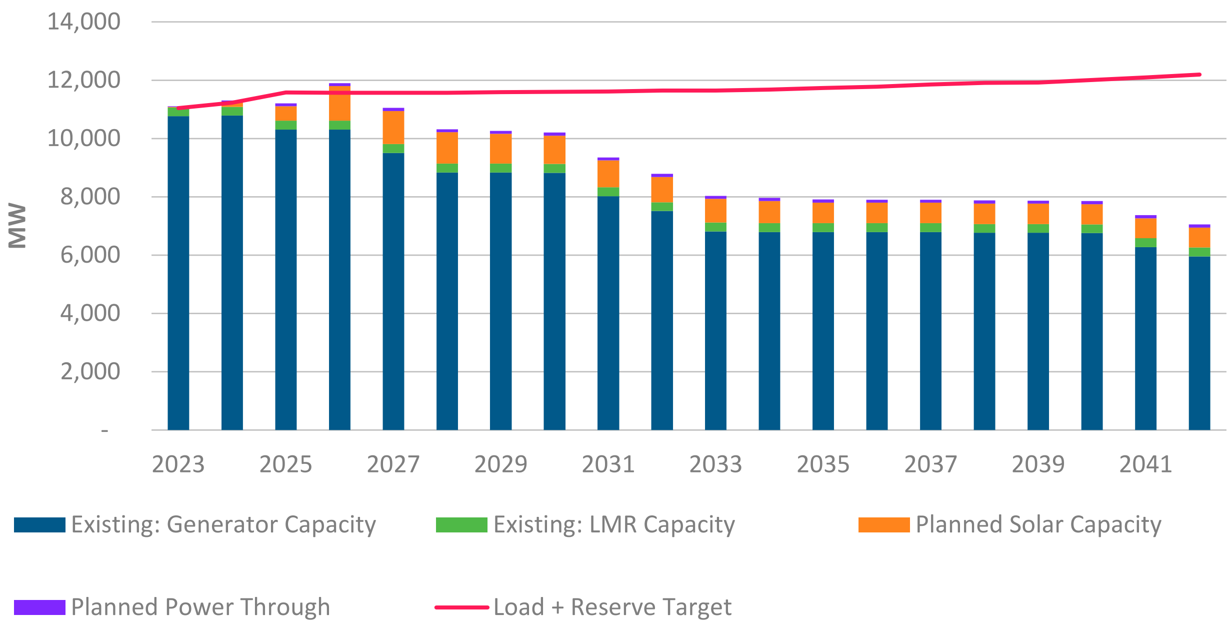


Figure 10: ELL Capacity Position

Energy Requirements - In addition to addressing long-term capacity requirements, ELL regularly assesses how its generating fleet is expected to align with its long-term energy requirements. Based on the current planning model projections and absent any changes to deactivation assumptions, approved resource additions, and renewable resources solicited in ELL’s 2021 and 2022 Solar and Renewable RFPs (identified as “Planned Solar Capacity” in Figure 10 above),[16] ELL is expected to fall short of effectively meeting its long-term energy requirements without significantly relying on other Entergy operating companies and the MISO market. However, the amount of energy produced by owned generation is subject to change based on fuel prices, market conditions, and unit operations.

[16] It is important to note that it is possible that planned additions may not come to fruition to provide the level of capacity solicited from RFPs. RFP solicitations identify a targeted amount of capacity. It is possible that selections from RFPs may not yield the solicited level of capacity, or that proposals selected do not ultimately come to fruition due to a variety of factors, several of which are beyond ELL’s control.

Through the technology assessment and the IRP analytics, ELL evaluates energy-producing resources like renewable energy and dispatchable natural gas resources to meet both capacity and energy requirements over the long-term planning horizon. As resources deactivate and capacity requirements increase, ELL will look to balance energy producing and peaking generation to meet customer requirements effectively and efficiently.

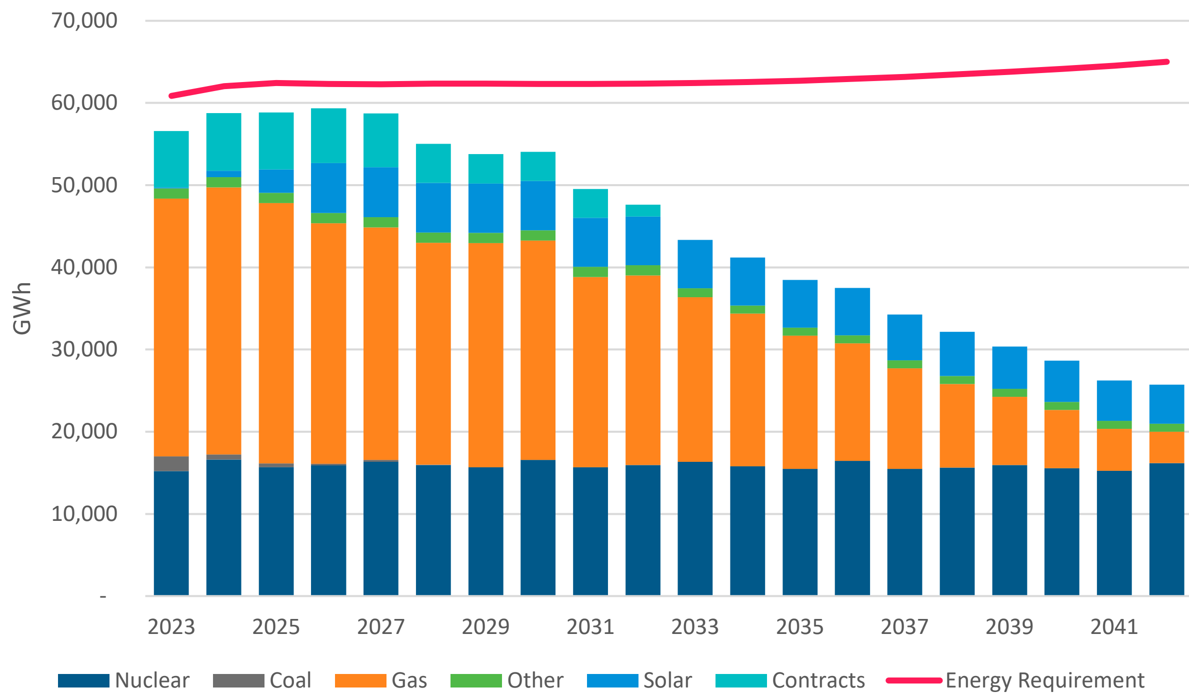


Figure 11: ELL Energy Requirements

Customer Usage - Of course, both capacity and energy resource needs are driven by customers' consumption and preferences. The type, size, and timing of future resource needs may be affected as customers gain additional resources to manage consumption, such as those that will be enhanced by AMI or those affected by increased accessibility to rooftop solar or battery storage technology.

ELL's long-term planning process and the evaluation outlined in this IRP helps inform how ELL can meet its future capacity and energy requirements needed to continue reliably serving its customers. Consistent with the resource planning objectives outlined in Chapter 2, ELL's planning approach is to employ a diverse portfolio of energy generation resource alternatives, located in relatively close proximity to customer load with flexible attributes to help provide sufficient capacity during peak demand periods as well as adequate reserves. Given the primary objective of risk mitigation, these practices ensure that ELL is able to continue providing safe and reliable service at a just and reasonable cost for its customers.

Supply Role Needs - As discussed previously in the existing resource section, ELL's CCGT generation fleet provides customers base load and load-following energy supply**.** In ELL’s 2019 IRP, it was assumed that the useful life for CTs and CCGTs was 30 years. Since that time, ELL conducted a detailed analysis on the expected remaining useful life of those resources. The result of that analysis concludes that ELL’s CTs and CCGTs are generally assumed to have a remaining useful life of longer than 30 years and most are assumed to operate beyond the end of the 2023 IRP study period (2042). ELL’s 2023 IRP reflects the useful life assumptions noted above. These deactivation assumptions result in less than a 1GW decrease in base load and load following capacity within the planning horizon. As noted previously, ELL is continually assessing these units in order to refine the useful life assumptions based on historical operations and current conditions of the facilities.

ELL’s current generating fleet also includes Coal, Legacy Gas, CT, Nuclear, and PPAs of varying technologies that reliability serves ELL’s customer demand over seasonal peaks. However, roughly 40% of this capacity will deactivate at varying times over the planning horizon. ELL has publicly announced its commitment to cease burning coal at all of its plants by 2030. Additionally, ELL has announced the planned deactivations of White Bluff 1&2 in 2028, Independence 1 in 2030, and Ninemile 4 in 2031.

Locational Considerations - The location of resources can have a significant impact on the electric grid. Resources, both supply-side and demand-side, can have an impact on the pattern of power flowing on the transmission system and on the voltage at the substations in the vicinity of the resource. The addition of a generating resource injects power into the electric grid; this additional power might help alleviate congestion on the electric grid, but the incremental power might also result in thermal constraints that may have to be alleviated with transmission upgrades. The addition of resources may also add reactive power into the system which can provide voltage regulation. This effect on the electric grid is particularly beneficial for large industrial loads and other similar loads that impose reactive power demands. Deactivations of resources can similarly change the power flows through the electric grid and may result in overloads or voltage constraints, and any resource additions or replacements in lieu of resource deactivations may be strategically located on the electric grid to minimize any detrimental impacts. Finally, the location of resources also has a broader impact on the MISO capacity auction. A location within a LRZ allows a resource to contribute to the local clearing requirement of a LRZ in the MISO PRA.

Flexibility Considerations - The portfolio design analytics explore the value of renewable energy projects, energy storage, peaking, and CCGT capacity. Based on these analyses, the long-term planning horizon will include additions of renewable and possibly energy storage and other technologies to ELL's portfolio. As intermittent additions increase, as high capacity factor loads increase, and as ELL's legacy fleet deactivates, ELL also may see increased value in additional flexible peaking and quick-response capability more indicative of spinning technologies, such as Reciprocating Internal Combustion Engines (“RICE”), Aero-derivative CT technologies, and CCGTs as well. ELL continues to be committed to exploring clean, alternative fuel sources to ensure longevity of these resources.

ELL will continue to assess the likely increasing capacity, energy and operational flexibility required over the long-term planning horizon. This on-going assessment of the generation supply plan against dynamic factors like capacity requirements, operational requirements, grid reliability and evolving technologies will enable ELL to continually improve efficiencies to develop solutions to address its customers' needs while mitigating risk.

Transmission Planning

Transmission planning ensures that the transmission system: (1) remains compliant with applicable North American Electric Reliability Corporation ("NERC") reliability standards, and related Southeastern Electric Reliability Council ("SERC") and ELL's local planning criteria, and (2) is designed to efficiently deliver energy to end-use customers at a reasonable cost. Since December 2013, ELL has been a Transmission Owning member of MISO, a Regional Transmission Organization ("RTO"). MISO was approved as the nation's first RTO in 2001 and is an independent nonprofit member-based organization that supports the delivery of wholesale electricity and operates energy and capacity markets in 15 U.S. states and the Canadian province of Manitoba. In cooperation with stakeholders, MISO manages 65,800 miles of high voltage transmission and 189,421 megawatts of power generating resources across its footprint. Since joining MISO, ELL has planned its transmission system in accordance with the MISO Tariff.

A key responsibility of MISO is the development of the annual MISO Transmission Expansion Plan ("MTEP"). ELL is an active participant in the MISO MTEP development process, which is currently in development of the MTEP 22 cycle. Participation in the MISO MTEP process is the method by which ELL's transmission plan is incorporated into the annual MTEP document. The overall planning process can be described as a combination of "Bottom–Up" projects identified in the individual MISO Transmission Owner's transmission plans which address issues more local in nature and are driven by the need to provide service safely and reliably to customers, and projects identified during MISO's "Top-Down" studies, which address issues more regional in nature and provide economic benefits or address public policy mandates or goals.

Through these MTEP related activities, ELL works with MISO, other MISO Transmission Owners, and stakeholders to promote a robust and beneficial transmission system throughout the MISO region. ELL's participation helps ensure that opportunities for system expansion that would provide benefits to ELL customers are thoroughly examined. This combination of Bottom-Up and Top-Down planning helps ensure all issues are addressed in an effective and efficient manner.

ELL's transmission strategy is centered upon meeting the evolving needs of its customers for safe and reliable energy. Each year the ELL transmission system is thoroughly studied to verify that it will continue to provide customers with reliable and safe service through compliance with all applicable NERC reliability standards as well as ELL's local planning criteria and guidelines.

These studies identify potential system conditions where reduced reliability may occur in the future. Additional studies are then performed to develop projects and determine what, where, and when system upgrades are required to address any future reliability concerns. This annual review identifies any transmission system reinforcements necessary to provide reliable and safe service in response to changing system conditions. These studies consider the effects of overall system load growth, retirements of existing generation resources, implementation of new generating resources, the adequacy of new and existing substations to meet local load, the expected power flows on the bulk electric system, and the resulting impacts on the reliability of the ELL transmission system.

These reliability studies result in projects which are presented annually to the ELL Operating Committee and ultimately must be approved by ELL's President and CEO. Once approved, these reliability projects are submitted to MISO for regional study, to 1) verify that the reliability need exists, 2) verify that the proposed solutions solve the reliability need, and 3) provide stakeholders the opportunity to propose alternatives. Additionally, MISO performs other studies each year to consider planning issues including Market Efficiency Projects, Multi-Value Projects, and customer driven projects, such as those driven by generator interconnection requests, and opportunities for interregional projects with neighboring planning regions.

The result of the MISO MTEP process is a compilation of transmission projects that are needed to address system reliability requirements, improve market efficiency, and/or provide specific system benefits as delineated in the MISO Tariff. The MTEP identifies solutions to meet regional transmission needs and to create value opportunities through the implementation of a comprehensive planning approach.

Each MTEP document is identified by the year in which it was completed. Appendix A of each MTEP cycle lists and briefly describes the transmission projects that have been evaluated, determined to be needed and subsequently approved by the MISO Board of Directors. Since joining MISO in 2013, ELL has submitted projects into MTEP 14 through MTEP 23. The ELL projects that were approved for inclusion in Appendix A of MISO's MTEP 16 thru MTEP 21 cycles are provided in Appendix D - Table 22 through Table 27, respectively. Also, submitted Target Appendix A projects for MTEP 22 and MTEP 23 are in Appendix C - Table 28 and Table 29. These future transmission projects and other transmission plans developed during the next three years will be important inputs to consideration of future resource needs.

Integration of Transmission and Resource Planning - The availability and location of current and future generation on the transmission system can have a significant impact on the long-term transmission plan, requirements for meeting NERC reliability standards, and efficiently delivering energy to customers at a reasonable cost. Optimal construction of generating resource and transmission facilities, both in terms of location and timing, and the continued maintenance of this integrated electric network is crucial to the functioning of an efficient and reliable electric network capable of delivering value to customers. Generating resources and the transmission grid serve complementary roles: while the transmission system conveys power to customers, the generating resources help meet the energy and capacity requirements of the grid. Moreover, like transmission, new generation must be planned well in advance, and due to the interrelationship of generation and transmission planning, looking far enough into the future and addressing potential generation needs is critical in meeting ELL's planning objectives of low cost, improved reliability, and reduced risk.

The continued evaluation and condition of ELL's generation fleet must be considered for integrated generation and transmission planning. ELL's planning assumption includes deactivation of existing generation resources during the planning horizon, which could have an impact on transmission reliability without proper siting of replacement generation. Likewise, the location of planned transmission facilities on the bulk electric system, particularly those at higher operating voltages, can have a significant impact on the siting, timing, size, and type of planned resources to address the generation needs of a particular area.

Distribution Planning & Grid Modernization - Through its distribution planning process, ELL's efforts will continue to maintain and improve the reliability of its distribution lines and its distribution line infrastructure, while aiming to minimize customer outages. Customers directly benefit from improvements in line maintenance, infrastructure, vegetation management, and substation reliability through reduced outages and outage duration. Customers also benefit from the reduction in costs from extending the life of distribution assets and minimizing maintenance costs with respect to those assets.

Additionally, ELL's grid modernization efforts are aimed at continually upgrading and redesigning grid infrastructure to facilitate adding new technologies and intelligent devices that facilitate safe multi-directional energy flows, automate operations, enable remote control, increase operational efficiency, improve quality of service, increase reliability and resiliency, and expand options for customers.

This modernized grid infrastructure, including enhanced communications networks that incorporate radio mesh networks, cellular and fiber optic links, is not only critical for day-to-day utility reliability needs but also to support the greater deployment of advanced meters and related infrastructure, DERs, and other technologies. ELL's objective is to achieve a modernized distribution system over time that also improves reliability to meet customers' evolving needs and expectations.

Integration of Transmission and Distribution Planning - While MISO operates an energy and ancillary services market, administers a Transmission Planning process and a resource adequacy process through an annual PRA, ELL, in its role as an LSE, must integrate resource, transmission, and distribution planning to ensure that energy can be supplied to customers in a manner that is reliable, affordable, and environmentally responsible.

As discussed above, distribution investment will enable the interconnection of DERs and impact the reliability of the system. Additionally, driven by customer specific sustainability goals, or economically offsetting wire investments, distributed generation may be deployed across the ELL service area. These investments impact the need for other transmission and generation investment.

Due to the interdependencies of the resource, transmission, and distribution long-term planning processes, coordinating and harmonizing these three planning processes is crucial to ensure that ELL's planning objectives of affordable cost, high reliability, and environmental stewardship are met.

Sustainability Goals

Entergy has been an industry leader in voluntary climate action for over two decades. In 2001, Entergy was the first U.S. utility to voluntarily limit its carbon dioxide emissions. After beating this target by more than twenty percent, Entergy renewed and strengthened this commitment twice and outperformed by eight percent its 2020 commitment to maintain carbon emissions from Entergy-owned facilities and controllable power purchases through 2020 at twenty percent below year 2000 levels.

Building on its longtime legacy of environmental stewardship, Entergy has enhanced its climate action strategy with a near-term goal to reduce the utility emission rate by 50 percent by 2030 in comparison to Entergy's emission rate from its baseline year of 2000, and a longer-term commitment: Entergy will work over the next three decades to reduce carbon emissions from its operations to net-zero by 2050. ELL intends to contribute to the company accomplishing these goals by working with its regulators and other stakeholders to balance reliability, affordability, and sustainability.

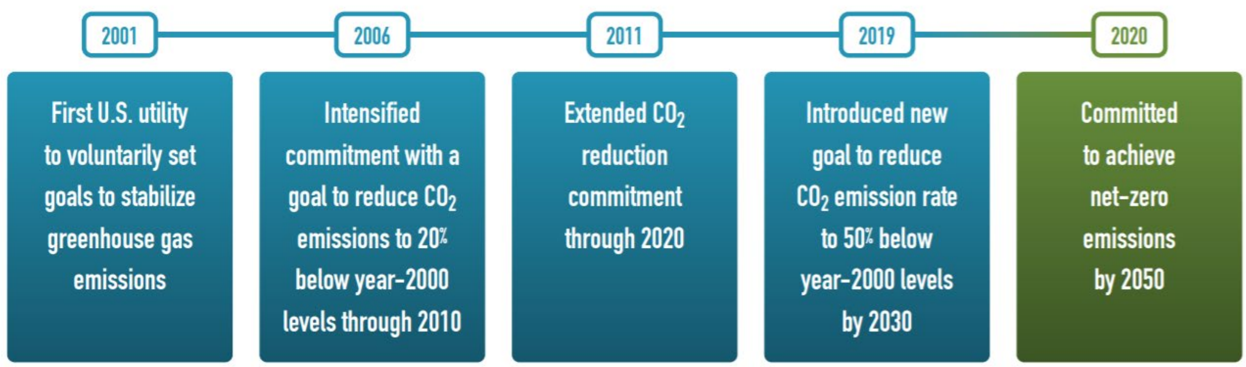


Figure 12: Entergy Climate Action Strategy

Entergy is taking action now toward a carbon-free future and expects to achieve its net-zero 2050 commitment by enhancing its portfolio transformation strategy with emerging technology options, working with customers, key suppliers and partners to advance new technologies necessary to reduce emissions, continuing to engage with partners and gain experience on enhancing natural systems like forests and wetlands that absorb carbon, and partnering with customers to electrify other sectors like transportation and industry for net emissions reductions and community benefits.

Additional details are available in ***Entergy's 2021 Integrated Report.***[17]

[17] Entergy, *The Future is On,* Entergy Corporation (2021), *available at* https://integratedreport.entergy.com/.

Chapter 4 Model Inputs and Assumptions

Summary

- ELL's reference forecast projects nearly flat growth in electricity consumption, with total energy growth of 0.1% annually and peak demand to growth of about 0.1% over the forecast horizon.
- ELL's technology assessment and fuel price forecasts have been updated.
- A third-party consultant was engaged to conduct an independent forecast of the achievable potential of DR and EE program types and DER technologies on the Company's system. The resulting forecasts were incorporated into the IRP's modeling process.

Resource Planning Considerations

Guided by its Resource Planning Objectives, ELL's resource planning process seeks to maintain a portfolio of resources that reliably meets customer power needs at a just and reasonable supply cost while minimizing risk exposure. The landscape within the electric utility industry is changing, and this IRP offers early insight for opportunities to respond to this evolving environment.

ELL recognizes the way customers consume energy and the type of energy they prefer is changing, therefore, the way the Company plans for, produces, and delivers the power on which customers rely must continue to change as well. ELL strives to have a planning process that provides for the flexibility needed to better respond to this constantly evolving environment.

Load Forecasting Methodology

Each year, ELL develops a forecast that is used for financial and resource planning. That forecast is often used as the Base Case or Reference Case for scenario analysis such as the IRP process. The Reference Case is developed sequentially starting with a forecast of monthly billed sales, which is then converted to a calendar month view, which is then converted into hourly loads across each month. Future forecasts are then developed in a similar manner starting with monthly energy and then converting those levels to hourly loads. ELL developed two future forecasts in addition to the Reference Case forecast for the 2022 IRP. These are discussed in further detail below.

Load Forecast Uncertainty - Electric load in the long term will be affected by a range of factors, including:

1. Increases in EE, brought about by:
   a) Technological changes – lighting, heating, ventilation, and air conditioning ("HVAC"), appliance efficiency

   b) Structural changes – changes in building codes or state/national requirements[18]
   c) Other conservation measures – changes in personal behavior
2. Increased participation in DR and/or interruptible programs
3. Increased adoption of Electric Vehicles (EVs) in place of vehicles using internal combustion engines
4. Other electrification opportunities brought about by customers' reductions in natural gas usage in favor of electric end-use equipment
5. Levels of economic activity and growth, including expansion or contraction with large industrial load, as well as changes in population affecting residential and commercial classes
6. Potential adoption of behind-the-meter self-generation technologies (e.g., rooftop solar)
7. Changes in temperature and weather patterns over time.

Such factors may affect the levels of electricity consumption over the term of a study period as well as the hourly patterns of consumption across individual days. Annual peak loads could be higher or lower, and daily peaks could shift to later hours in the day. Uncertainties in these load levels and patterns may affect both the amount and type of resources required to efficiently meet customer needs in the future.

Reference Case Energy Forecast - In accordance with the LPSC IRP Rules and the timeline provided by ELL at the start of this IRP cycle, the Reference Case forecast was developed in 2021 using a bottom-up approach by customer class: residential, commercial, industrial, and governmental. The forecast was developed using historical sales volumes, customer counts, and temperature inputs from January 2010 through December 2020, as well as future estimates for normal weather and EE. In addition, the forecast includes estimates for changes in customer counts, future growth in large industrial usage, and estimates of future consumption growth from EVs and declines due to future rooftop solar adoption.

Regression Models for Non-Large Industrial Forecasts - The sales forecasts for the residential, commercial, small industrial, and governmental classes are developed individually using statistical regression software and a mix of historical data and forward-looking data. The historical data primarily includes monthly sales volumes by class and temperature data expressed as cooling degree days ("CDDs") and heating degree days ("HDDs"). Some of the forecasts also use historical indices for elements such as population, employment, and levels of end-use consumption for things such as heating/cooling, refrigeration, and lighting. These historical data are used in the Metrix ND® forecasting software, which is licensed from Itron. This software is used to develop statistical relationships between historical consumption levels and explanatory variables such as weather, economic factors, and/or month-of-year, and those relationships are applied going forward to estimates of normal weather, economic factors, and/or month-of-year to develop the forecast. Explanatory variables are typically included in each class-level forecast model if the statistical significance is greater than 95%.

[18] State requirements may include future policies and rules adopted in LPSC rulemakings such as the ongoing LPSC Docket No. R-31106.

Residential Forecasts - Long-term residential forecast projects a slight increase in electricity consumption with 0.5%/yr. CAGR over the planning period. This forecasted increase is largely due to increasing customer counts due to household formation growth in ELL's service area as well as slightly positive average Use Per Customer ("UPC") growth.

Population projections come from IHS Markit[19] parish level data for ELL's service area. Overall, average annual kWh consumption per household is expected to grow slightly by 0.1%/yr. This UPC growth is driven mostly by increased electric vehicle adoption in the latter years of the forecast period, partially offset by increases in energy efficiency due to both organic adoption of newer, more efficient, technologies as well as from company sponsored EE programs.

The monthly model for residential UPC, taking into account expected efficiency is:

Residential UPC per day =

Heating Degree Days * Heating efficiency index * Heating coefficient +

Cooling Degree Days * Cooling efficiency index * Cooling coefficient +

other use coefficient * other use efficiency index

The residential forecasts use variables for individual months rather than using heating or cooling indices with monthly values across a year, allowing for greater precision with each monthly result. The regression uses actual historical weather, and the resulting coefficients are applied to estimates for normal weather levels in the future.

Trended Normal Weather - Analysis of historical data reveals that trends in average temperatures, expressed as CDDs and HDDs, have not been flat over the last few decades, and there is no evidence at this time to support an assumption of future temperatures remaining flat versus current (2020/2021) levels. As such, ELL has calculated a "trended normal" assumption for long-term energy planning using trends in 20-year rolling averages of monthly temperatures from 2001-2020, which are used in the Reference Case forecast. The use of 20 years strikes a reasonable balance between longer periods (30 years), which may take longer to pick up changing weather trends and shorter periods (10 years), which may not provide enough data points to smooth out volatility. The 20-year trended normal temperatures are built from hourly temperatures and are allocated to each calendar month. By 2042, the effect of the trended normal temperature assumption increases summer (July - September) residential and commercial energy consumption by 116 GWh (1.5%) and decreases winter (January, February, December) energy consumption by 46 GWh (-0.8%).

[19] *See,* IHS Markit Ltd. - www.ihsmarkit.com.

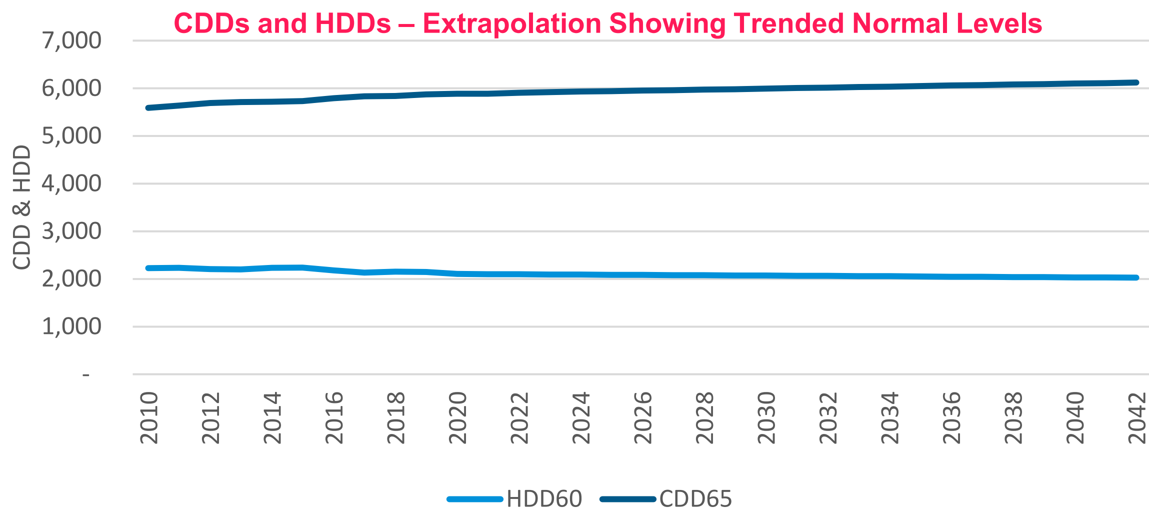


Figure 13: Changes and Opportunities Within the Utility Industry

Table 5: YoY Growth Residential

Year	Energy	Customers	UPC
2024	-0.1%	0.7%	-0.8%
2027	0.0%	0.6%	-0.6%
2030	-0.3%	0.4%	-0.7%
2033	0.3%	0.4%	-0.1%
2036	0.8%	0.3%	0.5%
2039	1.2%	0.2%	1.0%
2042	2.0%	0.2%	1.8%
2023-2042 CAGR	**0.5%**	**0.4%**	**0.1%**

Residential Forecast - ELL is expecting slightly positive residential customer count growth throughout the study period, with slight UPC declines in the near-term offsetting some of the MWh growth from increasing customer counts. Based on expected future growth in average residential UPC in ELL's service area, ELL is expected to have positive average residential UPC growth starting in the mid-2030s as increased adoption of electric vehicles begins to offset declining UPC from energy efficiency. For the period overall, the forecast is relatively flat with residential UPC growth of 0.1%/yr. for 2023-2042. The combined effect of slightly positive UPC growth and positive customer count growth leads to a net forecasted CAGR in residential energy of 0.5%/yr. The sales forecast includes a net 1.5% decrement to the residential sales, phased-in between 2020 and early 2022. The phase-in for these effects was based on the latest AMI deployment schedule available at the time of the forecast development plus a time allowance for the AMI-related customer information programs to show an effect.

See Table 5 showing the year-over-year changes and CAGRs in residential energy, customer counts, and UPC.

Commercial Forecast - Commercial use of electricity is forecasted to decrease slightly for 2023-2042 with a CAGR of -0.2%/yr. This decrease is driven by forecasted UPC decreases of -0.4%/yr. offset by slightly positive customer count growth of 0.2%/yr.

Table 6: YoY Growth Commercial

Year	Energy	Customers	UPC
2024	-0.1%	0.3%	-0.4%
2027	-0.5%	0.2%	-0.8%
2030	-0.5%	0.2%	-0.7%
2033	-0.3%	0.2%	-0.5%
2036	-0.2%	0.1%	-0.3%
2039	0.1%	0.0%	0.0%
2042	0.5%	0.0%	0.4%
2023-2042 CAGR	**-0.2%**	**0.2%**	**-0.4%**

The commercial sales forecast is developed using a similar methodology to the residential forecast with the exception that commercial sales are forecasted in total rather than by UPC because of the diversity of commercial customers, such as a large hospital versus a small office. Otherwise, the commercial forecast accounts for organic EE, primarily from HVAC and refrigeration, as well as Company-sponsored DSM programs discussed further below. The commercial forecast also includes the same type of AMI-related decrement phased-in from 2020-22 and then at the full 1.5% for the remainder of the study period.

Commercial $Sales_m$=

Heating Degree Days * Heating efficiency index * Heating $coefficient_m$ +

Cooling Degree Days * Cooling efficiency index * Cooling $coefficient_m$ +

other use coefficient * other use efficiency $index_m$

See Table 6 for estimated year-over-year changes and CAGRs for commercial sales, commercial customer counts, and UCP.

Governmental Forecast - Governmental energy usage is forecasted to be relatively flat with only a slight increase for 2023-2042 with a CAGR of 0.2%/yr. This is due to a slight increase in customer counts and in UPC.

Small Industrial Forecast - The small industrial forecast includes industrial sales that are not forecasted individually in the large industrial forecast, described below. Forecasts are based on historical trends and IHS economic indices such as for labor force, refining, and chemicals. Small industrial sales can be volatile and are generally not temperature related.

Table 7: YoY Large Ind Growth

Year	Energy
2024	4.2%
2027	0.0%
2030	0.3%
2033	0.4%
2036	0.4%
2039	0.4%
2042	0.4%
2023-2042 CAGR	**0.62%**

Large Industrial Growth - The 2023-2042 CAGR for ELL's large industrial sales is 0.6%/yr. Due to their size, customers in the large industrial class are forecasted individually. Existing large industrial customers are forecasted based on historical usage, known or expected future outages, and information about expansions or contractions. Forecasts for new or prospective large industrial customers are based on information from the customer and from ELL's Economic Development team as to each customer's expected MW size, operating profile, and ramping schedule. The forecasts for new large customers are also risk-adjusted based on the customer's progress towards achieving commercial operation.

Table 7 shows the forecasted year-over-year growth in sales attributable to large industrial customers.

Energy Consumption by Class - ELL's energy consumption comes mostly from the industrial and residential customer classes who account for 56% and 24%, respectfully, of the forecasted sales for 2023. Commercial customers consume 19% of the energy with governmental customers consuming the remaining 1%.

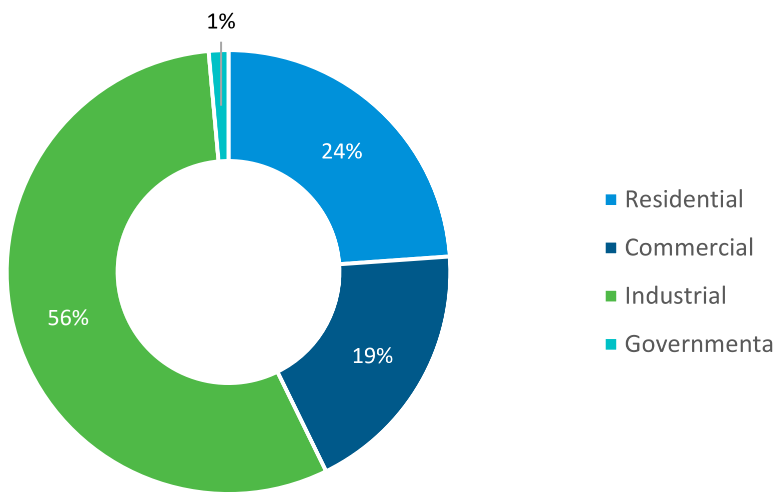


Figure 14: 2023 Energy Class Mix

This consumption mix by class is expected to remain largely unchanged throughout the study period. See Figure 15 below for the projected 2042 energy mix by customer class.

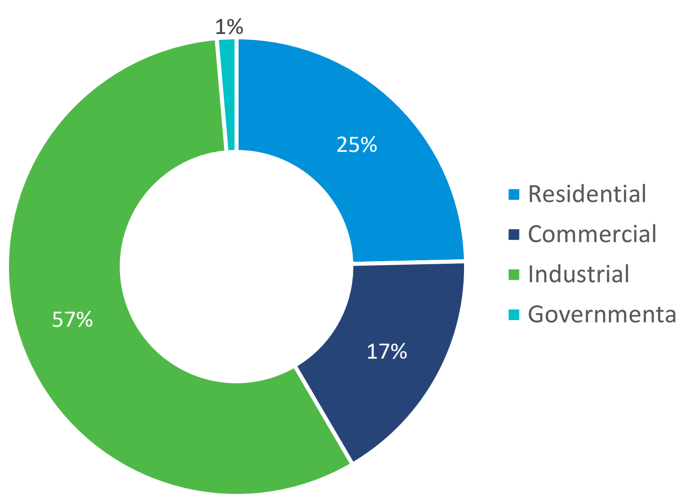


Figure 15: 2042 Energy Class Mix

Demand Side Management - ELL has had company-sponsored EE programs since late 2014, such as ones targeted for lighting, appliances, and HVAC efficiency.

DSM programs from one year have effects that carry forward into future years. For example, a program to encourage customers to switch from using incandescent lighting to LED lighting in one year will result in lower electricity consumption for years to come. As such, to develop an estimate of the DSM effects on the forecast, ELL starts with the historical (by year) DSM levels and develops an estimate of the cumulative effects of each year's programs on future years. See Figure 16 below.

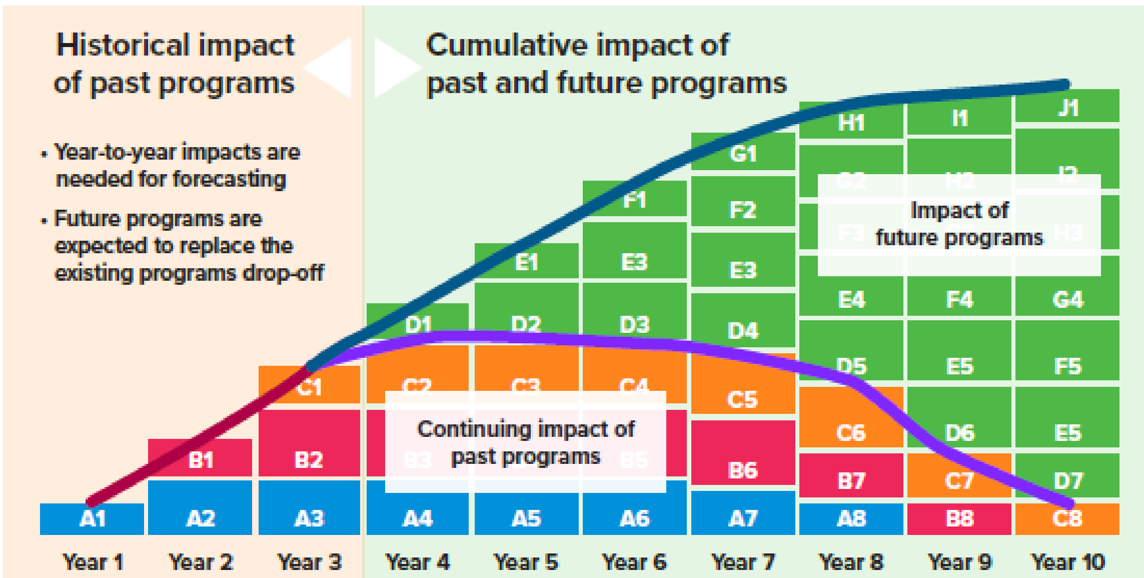


Figure 16: Chronological DSM Impacts

An add-back method was employed to develop the load forecast. See Figure 17 below. The add-back method takes the estimated cumulative historical volume of DSM savings in kWh and adds those amounts back to monthly billed-sales to develop a forecast as if there had never been DSM programs. From that forecast, the expected future levels of DSM are subtracted from the No-DSM forecast to arrive at the net forecast levels. This method was used for the Residential, Commercial and Small Industrial forecasts.

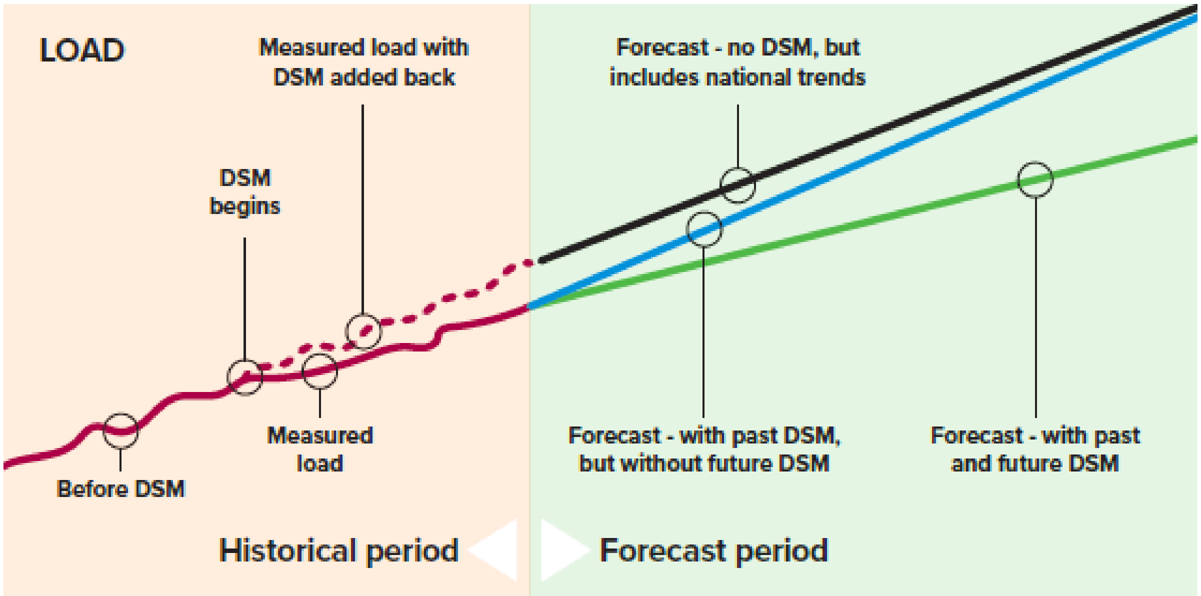


Figure 17: Add-Back Method

Using this methodology, new programs in future years are expected to reduce 0.1% of the total annual sales for ELL by 2023 in the IRP Reference Case forecast. Table 8 below shows ELL's expected incremental savings from pre-approved programs in the IRP Reference Case forecast. After 2023, there are assumptions around potential Phase II rules, with incremental savings levels increasing through 2031.

Table 8: Annual MWh Savings[20] (Incremental Assumptions)

	2023
Home Performance w/Energy Star	5,264
Retail Lighting & Appliances	13,464
Income Qualified Solutions	1,257
High Efficiency AC Tune-Up	4,007
Manufactured Homes Pilot	2,190
Multifamily Solutions	3,923
School Kits & Education	1,354
Small Commercial Solutions	7,890
Large Commercial & Industrial Solutions	19,291

Figure 18 below shows the estimated levels of cumulative annual energy savings included in the Reference Case forecast as a result of ELL's historically implemented DSM programs as well as savings from future DSM programs based on the incremental levels laid out in Table 8 above.

[20] Aligns with what was included in BP22.

DSM levels are expected to increase gradually through early 2030s, and then level off by mid-2030s and beyond.

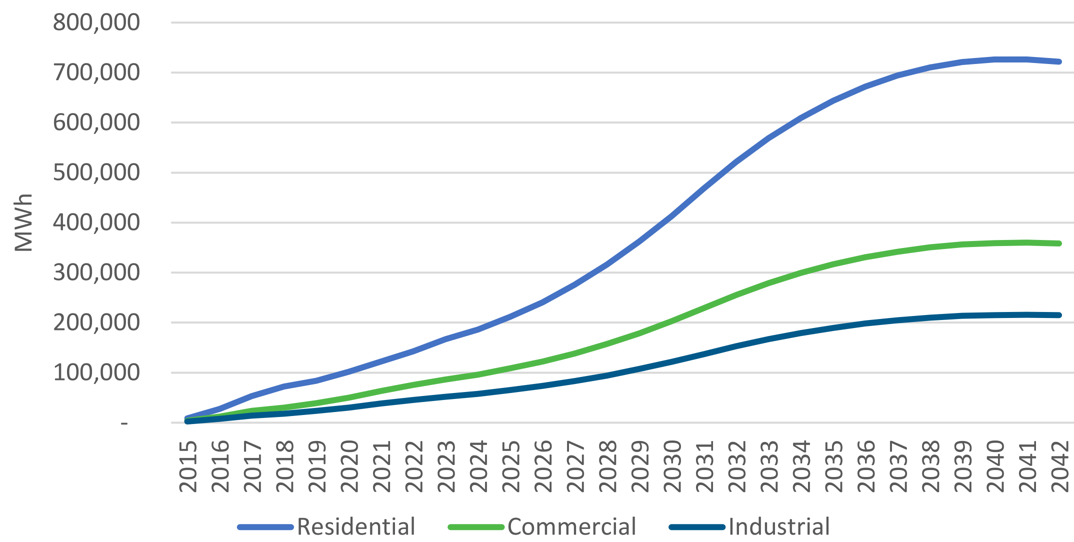


Figure 18: ELL Annual Energy Savings

Electrification and Conversions - The Reference Case forecast includes an assumption for sales growth as a result of programs sponsored by ELL to encourage electrification. The programs include electric forklifts, electric billboards, electricity-consuming services at truck stops, and agricultural irrigation pumps. Based on estimates from May 2021, these projects are expected to add nearly 335 GWh to commercial sales by 2042.

Hourly Load Forecast

Methodology - The load forecast is the result of combining three elements: the volumes from the monthly sales forecasts described above, the estimated monthly peak loads, and the hourly consumption profiles or shapes. These elements are developed using Itron's Metrix ND® software.

The forecasted monthly sales provide the monthly MWh volume for the load forecasts and reflect the expected effects of a few elements such as customer growth or declines, new large industrial customers, and EE. The monthly volumes are also used to develop the peak forecasts, which are estimated based on the historical relationship of peaks to energy while also considering the effects of weather. Hourly load shapes are developed from historical hourly load by customer class and in total. Those historical shapes are used along with historical weather data (HDD and CDD), calendar data to account for differences in usage on weekends or holidays, and other data to develop "typical load shapes" by customer class to be used for the forecast period.

The final step in producing the hourly load forecasts is to combine – or calibrate – the monthly energy, monthly peak, and the hourly shapes described above. Using Itron's Metrix LT® software, the energy volumes, the estimated peaks, and the typical hourly shapes are calibrated such that the three elements fit together in a way that the final result preserves the volume of energy while fitting it to the hourly profiles while maintaining, as closely as possible, the relationship of peak MW to monthly MWh. This process also reallocates the forecasted solar and EV energy using specific profile hours for each product technology. The result is a set of hourly load values, by class, for the forecast period from which a peak level can be determined. These hourly values are grossed up for Transmission and Distribution losses, which are calculated based on historical line losses. The Transmission and Distribution losses used in the IRP forecast are shown below.

Table 9: Transmission and Distribution Losses

	Legacy EGSL	Legacy ELL
Total Company T&D	3.8758%	3.9461%
Total Company Distribution	2.0199%	2.2219%

Reference Case Peak Comparison to Previous IRP - Since ELL's 2019 IRP cycle there have been decreases in the peak load forecast levels. This decrease is due to decreases in forecasted sales volumes across all customer classes between the two forecasts.

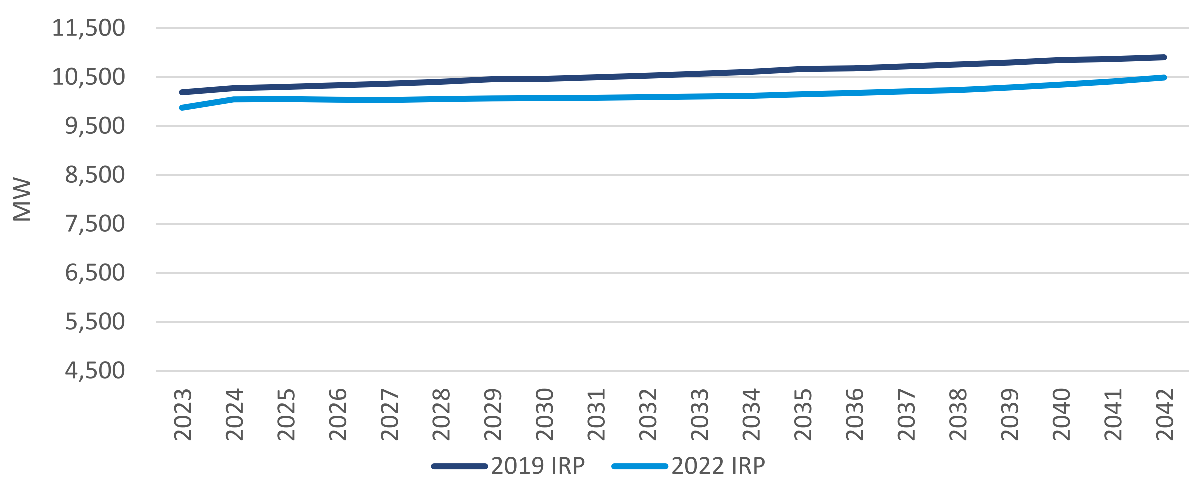


Figure 19: ELL IRP Reference Case Peaks by Version

IRP Scenarios - In previous IRP iterations, ELL would create "High" and "Low" sensitivity forecasts by adjusting the Reference Case forecasts up or down by a certain percentage to reflect a range of load possibilities. For this IRP iteration, a different approach was used in the development of the sensitivity forecasts for each Future by discerning the likely levers present based on the characteristics of each Future. Future 1 is the Reference Case forecast described above. See Table 10 below for a list of the levers and load effect in each Future scenario. Additional information for each Future used within the IRP analytics is described in Chapter 5.

Table 10: Load Levers by Future

	Item	Future 1: Reference Case	Future 2:	Future 3:
Narrative		Future 1 aligns with ELL's Reference Case Business Plan ("BP22") Uses ICF's Reference case BTM solar forecast instead of the BP22 solar forecast	Future 2 is a high growth scenario driven by growth in all customer classes, the main driver being transportation electrification and industrial growth related to process electrification. This growth is partially offset by increased BTM solar adoption.	Future 3 is a growth scenario driven by passenger vehicle electrification and industrial growth related to process electrification. This growth is partially offset by increased BTM solar adoption.
Res	Peaks Energy	Reference	Highest	Between Reference and Highest
Inputs	BTM Solar	ICF Reference	ICF High Solar + High Batteries	ICF High Solar + Reference Batteries
	Electric Vehicles (EVs)	Reference (2055)	Highest EV (2045 Passenger and Commercial Fleet)	High EV (2045 Passenger EV)
	Res. & Com. Growth	BP22	High Growth	Between Reference and High
	Refinery Utilization from EVs	BP22	Lowest	Between Reference and Lowest
	Industrial Growth	BP22	High	Between Reference and High

In Future 2, ELL sees strong growth from transportation electrification in both the passenger vehicle and commercial fleet space, whereby it's expected that ~100% of new passenger vehicle sales will be electric by 2045. Additionally, there is significant industrial growth from various types of process electrification driven by customers' desire to reduce their emissions at their facilities in ELL's footprint. This growth is partially offset by lower refinery utilization due to the prevalence of electric vehicles as well as an increased behind-the-meter (BTM) solar + battery forecast. The Demand Response (DR) and EE programs provided by ICF were not included in the Future 2 load forecast, but rather selected based on positive net benefits or selected during capacity expansions, respectively. The methodology to select DR and EE programs in future 2 will be discussed in Chapter 5.

In Future 3, ELL sees growth from transportation electrification only in the passenger vehicle space, whereby ~100% of new passenger vehicle sales will be electric by 2045. Additionally, there is industrial growth from process electrification driven by the customers' desire to reduce emissions at their facilities, however that growth is not as strong as the growth seen in Future 2. The reduction due to lower refinery utilization from EV growth is not as strong as Future 2. The BTM solar forecast is in line with Future 2 but the battery forecast is lower. In alignment with Future 2, Future 3 DR and EE programs provided by ICF were not included in the Future 2 load forecast, and followed the same methodology laid out in future 2 above and further explained in chapter 5.

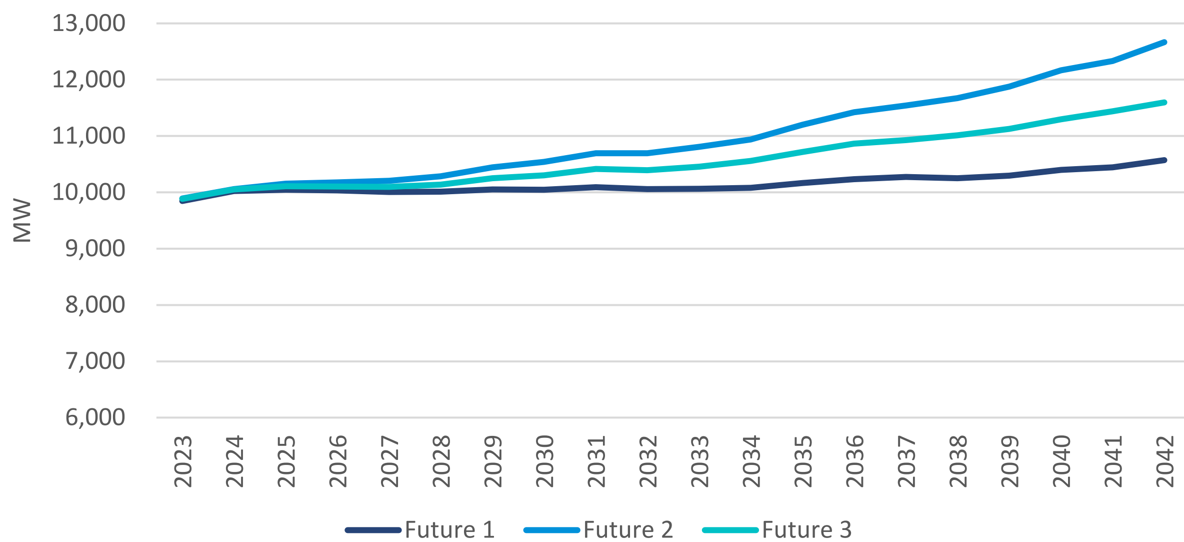


Figure 20: ELL IRP Peak Load Forecast by Future

Behind-the-meter Solar Generation - For all of the Futures scenarios, ICF produced behind-the-meter solar or solar plus battery impact estimates including a Reference Case level for Future 1, a High Solar + High Battery Case for Future 2, and a High Solar + Reference Battery for Future 3. Discussion of the methodology and assumptions for those can be found in Appendix G which contains the report produced by ICF.

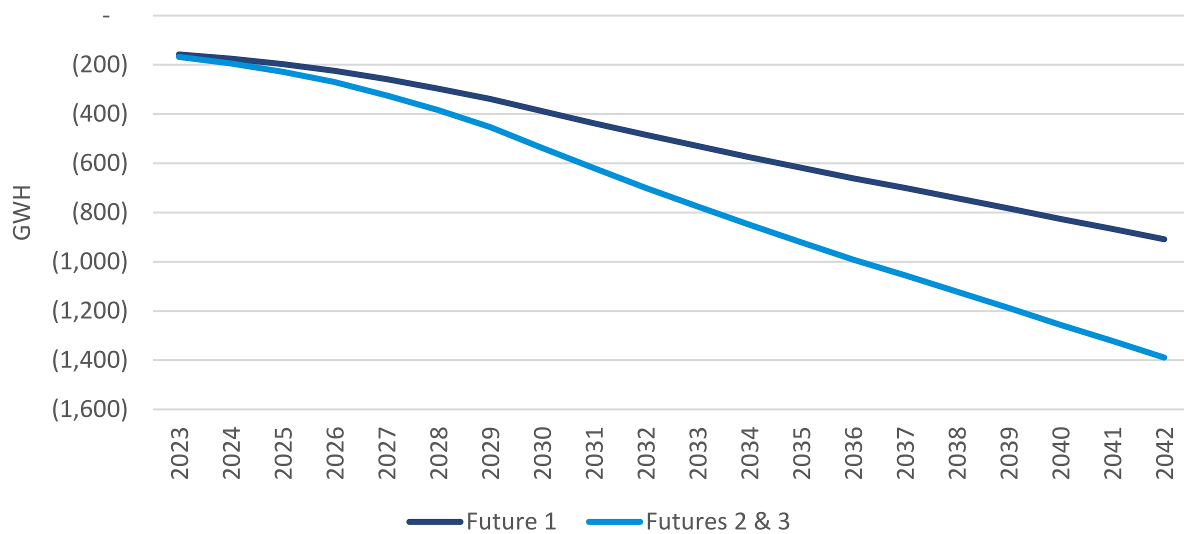


Figure 21: Residential & Commercial Solar Levels

Electric Vehicles - The Reference Case forecast includes an assumed level of additional energy consumption resulting from the adoption of EVs as well as growth in the numbers of total on-road vehicles over time as overall population is expected to continue to increase. The adoption over time is gradual based on an S-curve that assumes 99% of all passenger vehicle sales will be EVs by 2055. The effects for ELL are based on the estimated proportional numbers of vehicles in each jurisdiction within Entergy's footprint.

Overall, the additional GWh volumes from the EV forecast in the Reference Case are minimal in the near term with growth to the residential and commercial consumption volume estimated to start increasing more in the mid-2030s. These levels were used for the EV forecast inputs for Future 1.

Futures 2 and 3 used more aggressive forecasts in which 100% of new passenger vehicle sales are expected to be EVs by 2045 while taking into account expected population growth and vehicle per capita increases. Additionally, Future 2 considers EV adoption for commercial. EV market share growth in new vehicle sales is based on an S-curve. Overall, the additional GWh volumes for the 2045 EV forecast is accelerating higher in the near-term compared to the Reference Case estimate and are adding 30% and 80% to ELL's sales totals by 2042, respectively.

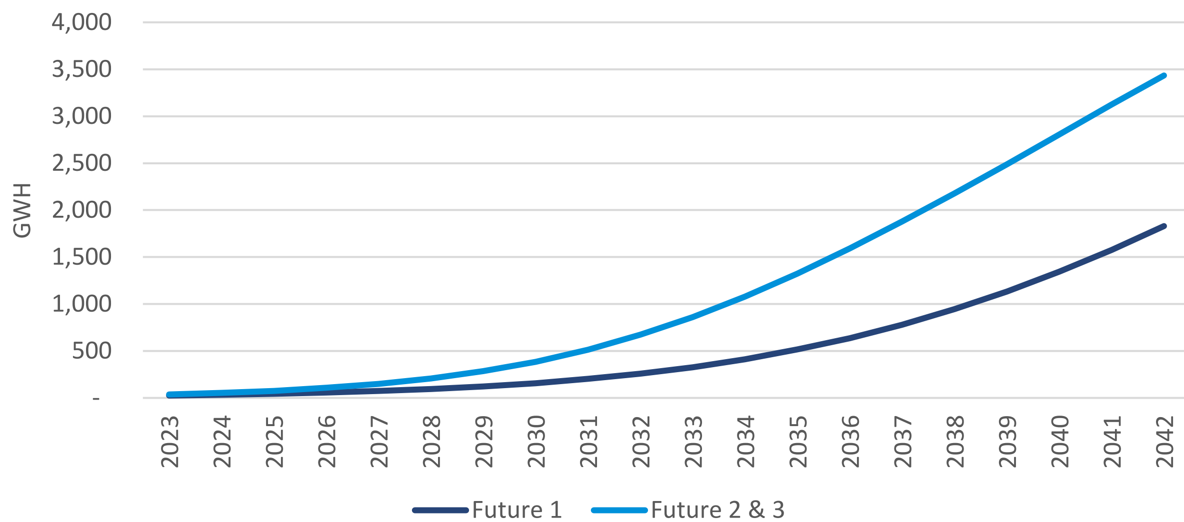


Figure 22: Residential EV Levels

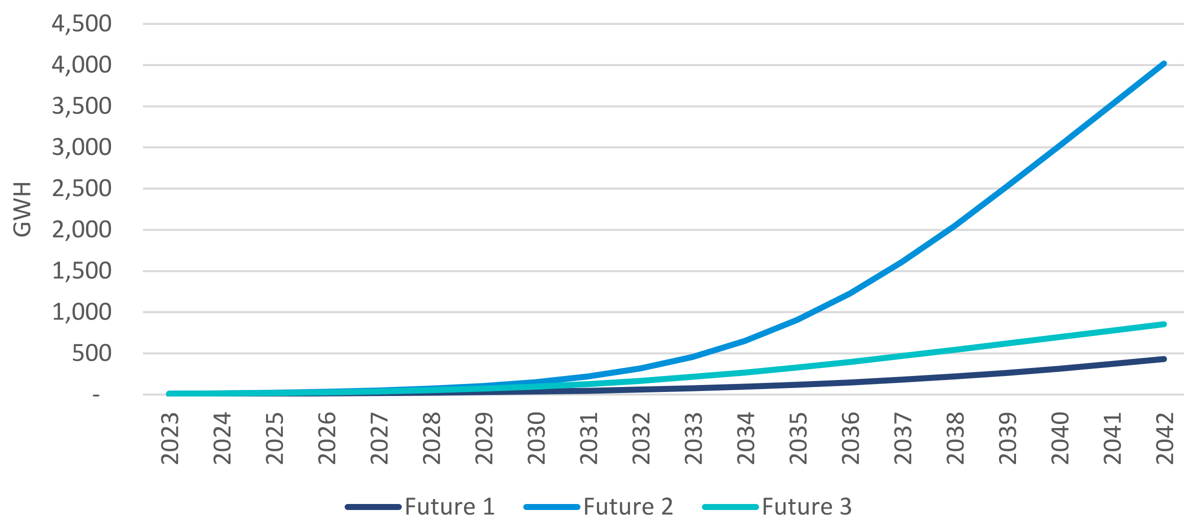


Figure 23: Commercial EV Levels

DSM (EE and DR) Measures - Discussion of the methodology and assumptions for EE and DR Measures can be found in Appendix G which contains the report produced by ICF.

Industrial Growth - Regarding industrial growth, Futures 2 and 3 have higher levels of growth than the Reference Case. The growth in Futures 2 and 3 are based on an analysis to determine the potential for Industrial process electrification in ELL's service area. Future 2 has roughly double the amount of process electrification compared to Future 3, however, both are well below the estimated potential for the service area.

Capacity Resource Options

Generation Technology Assessment - As part of its long-standing environmental stewardship and as the operator of one of the cleanest generation fleets in the nation, the commitment by Entergy to reduce utility emissions by 50% below 2000 levels by 2030 and achieve net-zero emissions by 2050, requires a continued transformation of its generation portfolio. The IRP process evaluates available supply-side resource alternatives to meet customer energy needs in accordance with ELL's planning objectives of balancing reliability, affordability, and environmental stewardship, including the existing generation fleet, DSM programs, and supply-side resources. As part of this process, the Generation Technology Assessment was prepared to identify a range of potential supply-side resource alternatives that merit more detailed analysis due to their potential to meet ELL's planning objectives.

Technology Evaluation and Selection - As illustrated in Figure 24, ELL conducted an evaluation of the cost-effectiveness and feasibility of deployment for more than 30 potential supply-side resources. The three-phased (i.e., Technical, Economic, Technology Selection) process to select generation alternatives, consider qualitative and quantitative criteria, and results in a final selection of supply-side resources that are best positioned to meet customer energy needs in accordance with ELL's planning objectives.

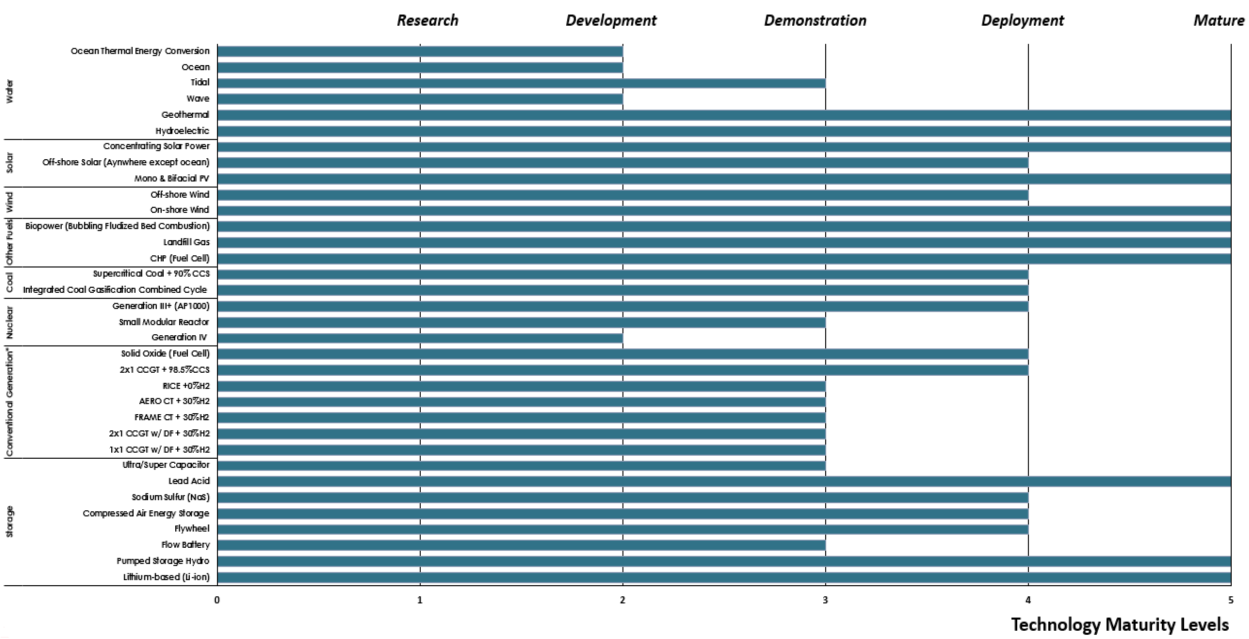
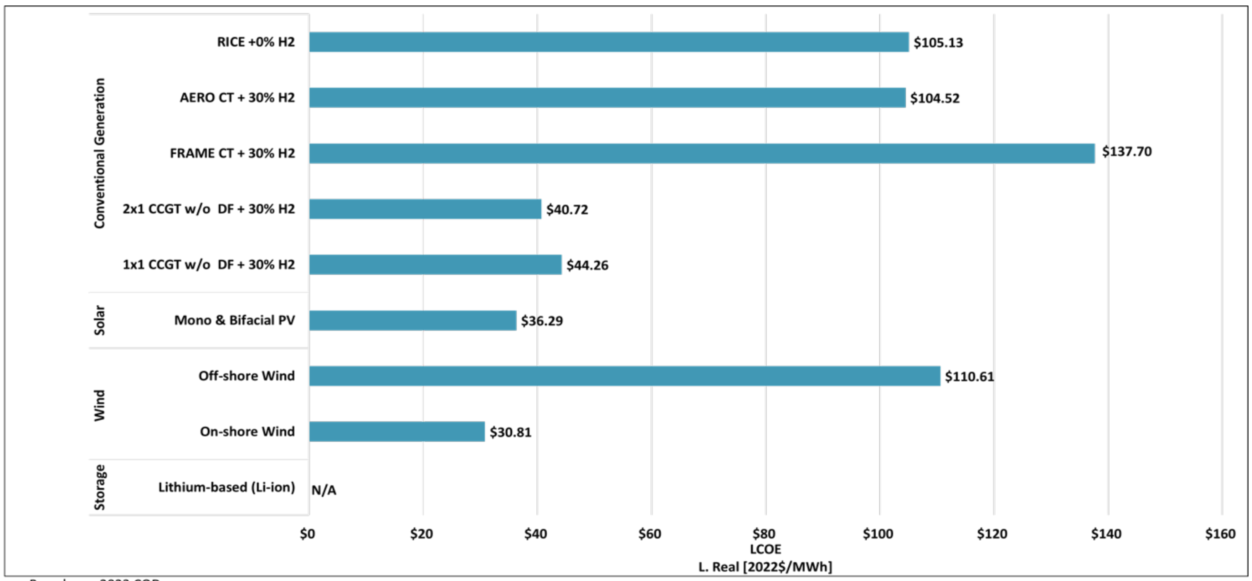


Figure 24: Technology Maturity Level

In the technical evaluation, potential supply-side resources were evaluated relative to technology maturity, environmental impact, fuel availability, and feasibility of deployment to serve ELL's service area. In the economic evaluation, ELL developed and compared technology alternatives relative to Levelized Cost of Electricity ("LCOE") and key performance indicators, including multiple renewable, energy storage, and hydrogen-capable conventional generation, as well as consideration for off-system solar and wind resources. Following the economic screening, the supply-side resources selected for inclusion in the capacity expansion models are those deemed to be the most feasible to serve ELL's generation needs based on comparative LCOE and performance parameters, deployment risks (cost/schedule certainty), and emerging commercial, technical, and policy trends. Notwithstanding the technologies specifically discussed in this IRP and included in the capacity expansion models, ELL continually evaluates existing, new, and emerging technologies to inform deployment decisions and building a balanced generation portfolio that optimizes its planning objectives. Figure *25* illustrates the LCOE results for the supply-side alternative selected for inclusion in the capacity expansion models.



- Based on a 2023 COD resource.
- LCOE is calculated as levelized total cost over the book life divided by the levelized energy output over the book life.
- LCOE for storage is not shown because as storage just moves MWh from one time to another there is no actual 'output' of energy therefore it's undefined.

Figure 25: Levelized Cost of Electricity of Selected Technologies

In the sections that follow, the selected technologies are discussed in more detail as well as the key emerging supply trends and implications that will shape the future of ELL's resource portfolio.

Conventional Generation w/ Hydrogen Capability - Natural gas-powered generation technologies are a competitive supply-side resource alternative due to historically relatively lower natural gas prices in ELL's service area and suitability to serve a variety of supply roles (baseload, load-following, limited peaking). These technologies offer synergies with the existing ELL fleet, including supply chain economies of scale and deep-rooted operational expertise.

The long-term suitability of dual fuel natural gas and hydrogen powered generation technologies to meet ELL's planning and sustainability objectives is largely dependent on natural gas prices and technology improvements, specifically, development of hydrogen co-firing capabilities, from 30% co-blending today to approaching 100% hydrogen. For wider deployment of this technology, necessary advancements that need to be made, include, but are not limited to, building hydrogen production and delivery infrastructure, combustor systems, and emission reduction technologies for Nitrogen Oxide (“NO_x”). As Original Equipment Manufacturers (“OEMs”) make advancements, ELL continues to track the development of hydrogen fueled power generation technology.

Table 11 below summarizes the natural gas-powered w/hydrogen capability generation alternatives resource assumptions, followed by a comparison of relative benefits of each alternative along with a description of each technology.

Table 11: Conventional generation with H2 capable-powered resource assumptions[21]

Technology	Net Max Summer Capacity [MW-ac]	Installed Capital Cost [2022$/KW]	Fixed O&M [2022$/KW]	Variable O&M [2022$/MWh]	Full HHV Summer Heat Rate[22] [Btu/kWh]	H2 (%)
CT (M501JAC)	365	$925	$6.66	$14.74	9,165	30%
CCGT (1x1 M501JAC)[23] w/o Duct Firing	525	$1,156	$18.43	$3.47	6,375	30%
CCGT (2x1, M501JAC)[24] w/o Duct Firing	1,055	$894	$12.07	$3.48	6,355	30%
Aero-CT (LMS100PA)	100	$1,438	$6.47	$3.21	9,015	30%
RICE (7x Wartsila 18V50SG)	129	$1,688	$23.35	$8.06	8,464	0%

Combined Cycle Gas Turbines (CCGT) with 30% Hydrogen Firing Capability - Driven by economies of scale and historically relatively low gas prices, CCGT fleet operators have remained competitive, from a $/MWh perspective, when compared to solar and wind resources. CCGTs are suitable to efficiently serve as baseload, load-following, and offer plant flexibility. In this analysis, CCGT units included are comprised of either one or two frame Combustion Turbines (CT) and a steam turbine that recovers thermal energy from the CTs, which provides an efficient heat rate and moderate flexibility. Achieving greater volumes for hydrogen co-firing will be dependent on the technology development of hydrogen fired CTs. Depending on the relative hydrogen co-firing

[21] Natural gas-powered resources shown are hydrogen capable, except for RICE resources. Assumptions do not include costs associated with firing hydrogen.

[22] Heat Rate in Full HHV Summer Condition. CCGT heat rate is reflective of the base capacity without duct firing.

[23] CCGT units without duct firing.

[24] Ibid.

volume, system modifications would be required in the CT and steam system of the plant. In addition to advancements in CT technology, potential modifications for a future hydrogen fueled CCGT plant could include, but is not limited to, modifications to the heat recovery steam generator system and post-combustion NO_x control systems.[25]

Frame Combustion Turbine (CT) with 30% Hydrogen Firing Capability - Historically, CTs have functioned as the technology of choice to support peaking application, resulting from consistent technological improvements, supported by relatively lower natural gas prices. Over time, renewable resources, particularly solar, have become an economically competitive source of peaking capacity to mitigate summer season reliability risk. While renewable resources are expected to play a larger share of the role for peaking applications, CTs can support integrating renewables and build a balanced, reliable, portfolio by offering quick-start (~30 minutes) backup power when renewables cannot meet peak demands.

Most dry, low-NO_x designs can accommodate hydrogen blends in the range of 20%-30% with advanced dry, low-NO_x technologies under development to enable higher blend rates up to 100% hydrogen fired systems.[26] Achieving higher hydrogen firing rates will be dependent on combustor designs as well as other system modifications, for example, fuel management systems/compression, CT enclosures, and control system updates.

Aeroderivative Combustion Turbine (AERO CT) with 30% Hydrogen Firing Capability - AERO CTs have gained market share in applications to serve peak and intermittent power, offering inherent flexibility as a product of applications from the aviation to power industry. Traditionally, AERO CTs provide higher flexibility than frame CTs due to their hot start time (10 minute), minimum up/down time (5/5 minute), and ramp rate (100 MW/minute).

AERO CT OEMs are continuing to develop combustion systems to enable higher hydrogen blend rates. Current dry, low-NO_x systems utilized within AERO CTs enable blending of hydrogen in the range of 30% with ongoing development of advanced combustor systems to enable higher blending rates, up to 100%.

Reciprocating Internal Combustion Engine (RICE) with 0% Hydrogen Firing Capability - As renewable penetration increases, RICE units may be leveraged to support the integration of renewable generation. RICE units can support increased demand for reliability through dispatchable power that can be placed online rapidly with the ability to frequently start/stop in response to changing load conditions. RICE units can ramp up to a full load in less than 5 minutes and operate at about 33% of nominal rating without compromising heat rate, a unique capability versus CTs, which generally ramp at a slightly slower rate (10 – 15 minutes), and while they can turn down to approximately 40% of their rated output, heat rate is compromised. RICE units,

[25] Dr. Jeffrey Goldmeer, *Gas Turbines: Hydrogen Capability and Experience,* The Department of Energy (March 9, 2020), ***available at*** https://www.hydrogen.energy.gov/pdfs/06-Goldmeer-Hydrogen%20Gas%20Turbines.pdf.

[26] Electric Power Research Institute Innovation Scouts, *Hydrogen-Capable Gas Turbines for Deep Decarbonization,* Electric Power Research Institute (November 14, 2019), ***available at*** https://www.epri.com/research/products/000000003002017544.

however, tend to have higher actual forced outage rate versus expected forced outage rate, but as more units are deployed more broadly, this factor is likely to improve.

RICE OEMs have claimed that existing models are able to accompany blends of hydrogen up to 25%, however, they have yet to demonstrate this in the field. Technology advancements and the necessary plant modifications required to increase the hydrogen blend capability above 25% remains uncertain.[27] RICE OEMs are also working to develop models compatible with other potential low-carbon fuels.

Renewable and Energy Storage Systems - Over the past decade, driven by technology improvements resulting in lower costs and improved performance, renewable and energy storage technologies have been increasingly deployed around the world, particularly utility-scale solar, followed by onshore wind and battery energy storage systems ("BESS"). Renewable energy resources add fuel diversity and play a core role in building a balanced resource portfolio.

Renewable energy resources add fuel diversity and will play a core role in building a balanced and diverse resource portfolio, and when paired, renewable energy projects and energy storage technologies have zero net emissions. Due to the intermittent nature of renewable generation, a balanced portfolio must maintain the ability to meet the changing instantaneous nature of customer usage and renewable production curves (e.g., on-peak production versus off-peak production).

Table 12 below summarizes the renewable and energy storage resource assumptions used in this IRP followed by a discussion on each technology.

Table 12: Renewable and Energy Storage Resource Assumptions[28]

Technology[29]	Net Max Summer Capacity [MW-ac]	Installed Capital Cost [2022$/KW]	Fixed O&M [2022$/KW-yr.]	Capacity Factor [%]	Useful Life [yr.]
Utility-scale Solar[30] (Single-axis tracking)	100	$1,063	$10.52	26.75% (MISO South)	30
Onshore Wind	200	$1,505	$37.72	36.8% (MISO South)	30
Offshore Wind	600	$3,620	$76.95	38.3% (Gulf of Mexico)	25

[27] Wartsila, *Energy Solutions,* Wartsila (2021), *available at* https://www.wartsila.com/docs/default-source/power-plants-documents/pps-catalogue.pdf.

[28] Source: IHS 2020: All rights reserved. The use of this content was authorized in advance. Any further use or redistribution of this content is strictly prohibited without prior written permission by IHS Markit.

[29] Solar, wind, and BESS fixed O&M excludes property tax and insurance. Solar includes inverter replacement in year 16.

[30] Solar capacity value is representative of year 1. Further explanation of solar capacity value as evaluated in the 2021 ELL IRP is summarized in the "Portfolio Design Analytics" section.

BESS[31] (Li-ion, 4hr)	50MW/ 200MWh	$1,171	$13.39	N/A	20
Solar + BESS	100 MW Solar 50 MW/ 200 MWh Battery	$1,612	$10.52	25.6%	30-year Solar 20-year Battery

Solar - Across the U.S., deployment of solar energy resources has continued to grow rapidly and as its economics improved, have become a central resource in building a balanced portfolio. From 2014 to 2020, utility-scale solar capital costs declined by more than 50%, resulting from declines in global PV module prices and economies of scale from larger project capacities. Beyond 2030, project costs are expected to continue to decline, albeit at a slower pace than in the prior decade as the industry continues to mature. In addition to cost impacts from the industry maturing, new module designs and configurations continue to be developed to improve efficiency and reduce overall costs. Over the next 30 years, costs are expected to decrease with solar resources expected to become a larger share of the generation portfolio mix. However, because solar energy production is variable in nature, grid flexibility and quick start backup generation are necessary to ensure reliability. Additionally, as part of the planning considerations for utility-scale facilities, land size requirements and site-specific needs must be evaluated.

Onshore Wind - Onshore wind resources have gained momentum in the US and international markets, driven by technology improvements that reduced capital costs. Between 2014 to 2020, capital costs decreased by approximately 18%, resulting primarily from reductions in turbine costs due to economies of scale created from larger turbines with higher capacity projects. Further cost reductions are expected to be incremental as developers improve efficiency and as larger turbine model market penetration increases. Larger wind turbine blade diameters have rapidly entered the market, and while in 2010, no onshore wind project utilized blades 115 meter or larger, as of 2020, 91% met or exceeded that length.[32] ELL is considering the reliability, cost, and executability tradeoffs between the potential deployment of onshore and offshore wind resources located in its service area and imported from neighboring markets.

ELL is actively evaluating cost effective ways to integrate wind resources into its portfolio. However, some aspects of wind energy that is local to the area served by ELL is currently challenging compared to wind energy that serves some nearby regions. For example, wind energy in MISO South has an estimated capacity factor of ~37%, compared to those in MISO North (~47%) and SPP (~49%). However, ELL's wind resource options may include some local wind, and wind energy imports from nearby regions with a stronger wind resource.

Offshore Wind - In the U.S., the offshore wind industry has been developing with its first commercial offshore wind farm becoming operational in Rhode Island in 2016 (30 MW Block

[31] BESS round-trip efficiency is assumed as 86%. BESS Installed Capital Cost includes 10% initial oversizing in year 1 to account for Depth of Discharge (DoD), followed by replacement of 10% of battery modules every five years (year 6, 11, & 16) to allow for a 20-year life.

[32] Berkeley Lab, *Land-Based Wind Market Report,* U.S. Department of Energy (2022), ***available at*** https://emp.lbl.gov/wind-technologies-market-report/.

Island Wind Farm). At this time, while most of the U.S. industry is concentrated in the northeastern United States, potential projects have been developing across the U.S. with more widespread maturity having been achieved in Europe. Offshore wind technologies are comprised of both fixed and floating foundations, and in recent years, turbine capacity has increased significantly with OEMs offering larger diameter systems in the range of 14 MW per turbine. In 2022, the U.S. Bureau of Ocean Energy Management identified potential wind energy areas and proposed to hold the first federal lease auction in the Gulf of Mexico. Since ELL's service area is prone to frequent hurricanes, development of offshore wind resources in the Gulf of Mexico will depend, in part, on advancing the capability of wind energy generation equipment to withstand sustained hurricane force winds. Assuming technology improvements are achieved, conditions in the Gulf of Mexico and current economics, however, position fixed turbines are more suitable for deployment, particularly in areas with relatively shallower depths. Additional development of offshore wind projects in the northeast may positively impact costs, but for offshore wind resources in the Gulf of Mexico to be included in the longer- term transmission and supply planning efforts, technology improvements suited for ELL service areas along with reduction in resource cost projections, relative to alternative, will need to show a positive impact for its key stakeholders.

An important advancement in the development of offshore wind in the Gulf of Mexico is an action laid out in Louisiana's Climate Action Plan that includes a goal of adding 5 gigawatts of offshore wind generation by 2035. Further, the LPSC has asked utilities to evaluate the costs and benefits of offshore wind in order to ensure every available technology is analyzed in long term resource planning initiatives. To advance this opportunity, in September 2022, ELL announced a Memorandum of Understanding ("MOU") with Diamond Offshore Wind regarding the evaluation and potential early development of wind power generation in the Gulf. The MOU provides the framework toward future development of potential demonstration projects and in the near term will focus on the evaluation of grid interconnection to determine the optimal size and locations of future projects. This will be ELL's first step in understanding feasibility of projects. As part of this work, ELL will grow internal knowledge and build partnerships with external experts to understand costs in order to fully undertake a cost benefit analysis.

Battery Energy Storage Systems (BESS) - From 2015 to 2020, utility-scale BESS capital cost declined by 180% with battery modules contributing to two-thirds of the decline (ATB NREL), a trend that is expected to continue. Current use cases of battery technology are applied to discharge times that are four-hours or less to provide peak shaving capabilities. When strategically and efficiently integrated into the electric grid, BESS have the potential to provide transmission and distribution grid benefits by avoiding investments required due to line overloads that occur under peak conditions. In addition to these peak shaving applications, BESS can provide voltage support, which mitigates the effects of electrical anomalies and disturbances. If paired together, BESS have the potential to deliver solar energy production into late afternoon hours, mitigating the ramping requirement created by the daily decline in solar energy production.

In addition to the above, BESS have the potential to offer additional values through MISO markets to benefit customers by effectively enabling an intra-day temporal shift between energy production and energy use. Through this process, energy can be absorbed and stored during off-peak/low-cost hours and discharged during on-peak/high-cost hours. When dispatched advantageously, the spread (i.e., cost difference) between the time periods can create cost savings for customers. BESS qualify in some markets for various ancillary service applications such as frequency regulation, reserves, voltage regulation, and given enough discharge duration, can qualify for MISO's capacity market. As the industry learns more and further deploys this technology, safety considerations and practices are becoming clearer, including fire prevention.

Hydrogen - ELL is well-positioned to play a key role in the opportunities presented by hydrogen technology due to the Company's proximity to the existing US hydrogen infrastructure. Low-to zero-carbon hydrogen appears to represent one of the key technology evolutions that can potentially support continued transformation of ELL's resource portfolio. Hydrogen has the potential to provide diverse reliability and sustainability benefits through its applications as a dual fuel paired with natural gas and providing long duration energy storage. It also provides a potential pathway to ensure that highly flexible, load following power generation resources with the capability for spinning reserves have a line of sight into operations. Hydrogen investments by customers in or near ELL's territory, recently accelerated by the tax credits provided in the Inflation Reduction Act, support this value proposition. While hydrogen remains one of several emerging technologies the Company is monitoring as an option for meeting resource needs, it appears to have the potential to play an important role in a balanced resource portfolio.

Carbon capture, utilization, and sequestration - ELL is monitoring the development of carbon capture, utilization, and sequestration ("CCUS") technology for potential deployment for its existing and future fleet to support resource planning objectives. CCUS can potentially serve as a decarbonization solution in ELL's existing natural gas fleet and as a complement to its low-to zero-carbon hydrogen strategy for traditional hydrogen production using steam methane reforming. The geology and infrastructure in south Louisiana are well-suited to deployment of CCUS technology and support incurring reduce costs associated with CO2 transportation and storage.

Newer generation of fossil fueled technologies coupled with carbon capture and storage may present the opportunity to generate cost-effective low to zero carbon electricity in the future. The Company will continue to monitor the development of this technology.

Advanced Nuclear Technology and Small Modular Reactors - Nuclear energy is a key component for meeting ELL's long-term resource planning objectives. As ELL continues to operate its existing nuclear fleet, it continues to observe industry developments in Advanced Nuclear Technology and Small Modular Reactors (SMRs) to meet customer needs. SMRs may potentially offer several benefits, including being physically smaller, reduced capital investments and opportunities for incremental power additions, as well as supplying base load electricity including system "inertia" that is lacking in inverter-based resources. In addition, SMRs generally rely on passive safety systems, requiring no manual intervention or externally applied forces to safely shut down. Pairing SMRs with renewable resources would provide complementary technology that does not depend on climate and time of day. The Company will continue to monitor the development of this technology.

Summary of Emerging Supply Trends and Implications - Advancement in generation technologies provides new opportunities to meet customer needs reliably and affordably, increasingly rendering new supply-side generation alternatives as viable options to address planning objectives. ELL's planning processes strive to understand these technological changes to enable the Company to design a portfolio of resources and services that meet customers' needs and wants, while maintaining a reliable grid.

Renewable and energy storage system technologies have emerged as viable economic alternatives and are expected to continue to improve through the planning horizon. Increased deployment of intermittent generation will need to be balanced with flexible, dispatchable and diverse supply alternatives. Smaller, more modular resources, such as Aero-CT, RICE, and battery storage, provide an opportunity to reduce risk and better address locational, site-specific reliability requirements while continuing to support overall grid reliability. Combining these trends provides additional opportunities to meet ELL's planning objectives.

Looking ahead, ELL will endeavor to maximize clean energy options while balancing reliability, affordability, and environmental stewardship. Efforts will include renewable energy as well as modern resources with optionality to be powered with hydrogen and/or retrofitted with carbon capture and sequestration technology.

DSM Potential Resource Assessment

As part of the development of ELL's 2023 IRP, ELL engaged a third-party consultant, ICF International, Inc., ("ICF") to conduct an independent forecast of the achievable potential of EE and DR program types and DER technologies on the utility's system. EE and DR programs and DER technologies were selected for analysis based on their relevance to utility planning practices nationwide and their specific relevance to ELL's customers and planning processes.

The resulting ICF forecast was used by ELL to provide hourly inputs for its IRP modeling process over the period 2023 through 2042. ICF produced forecasts for two scenarios: high levels of program or technology adoption and reference levels of adoption.

The starting point of ICF's forecasts for ELL was the selection of relevant EE and DR programs and DER technologies. Among EE, ICF analyzed existing programs offered through Entergy Louisiana's Quick Start EE programs as well as additional measures that ICF determined could be cost-effective to deploy for ELL customers. Among DR, ICF analyzed event-based program types, separated for residential, commercial, industrial, and agricultural customers, as well as existing and new rate-based DR programs. For DER, PV and battery storage technologies were separated by residential and C&I adoption.

For each selected EE program, DR program and DER technology, ICF produced hourly ELL net load forecasts covering 20 years for each of two scenarios: reference (expected) adoption and high adoption. The reference scenario reflects ICF's judgment as to the level of adoption that is most likely to occur given ELL and external market information available at the time of the study.

As described in detail later in this IRP, the incremental EE portfolios were included in Aurora's Capacity Expansion Tool for economic selection along with supply-side resource options for Futures 2 and 3. The DR programs were evaluated based on each program's benefit to cost ratio where DR with ratio higher than 1 were selected. Each portfolio included an assumed start date, program measure life, hourly demand profile, and annual program costs.

Environmental

Another key driver to changes in future resource needs is the various environmental regulations that have the potential to affect the long-term viability of ELL's existing generating units. Five key areas of regulations are discussed here: Regional Haze Rule, Cross-State Air Pollution Rule, Coal Combustion Residuals Rule, Effluent Limitation Guideline Rule, and Potential Greenhouse Gas Regulation. The uncertainty associated with each area varies. For example, the Regional Haze requirements have been in place for some time and are far more developed, with greater certainty as to the compliance requirements and timing. Even so, the specifics that will be required for compliance with Regional Haze are not known fully at this time.

Regional Haze Rule - The current Regional Haze Program was established as part of the 1990 amendments to the Clean Air Act. This program is designed to protect visibility at certain federally designated Class I areas and to return visibility conditions at those areas to natural background visibility conditions by the year 2064. This is to be accomplished via a series of 10-year planning periods where each state is charged with surveying contributions from air emissions sources in that state and developing a Regional Haze State Implementation Plan ("SIP") to ensure that sufficient emission reductions occur during each planning period to remain on course to achieve natural background conditions in all Class I areas by 2064. During each planning period, the State of Louisiana must evaluate contributions from sources within the state for potential impacts to visibility conditions at various Class I areas. During the first planning period, Louisiana finalized a SIP which imposed a lower emission limitation, corresponding to the use of lower-sulfur coal, for emissions of sulfur dioxide (SO_2) from Nelson Unit 6. This limit went into effect in January 2021 and the Unit has operated in compliance with this regional haze SIP limit since this time. Compliance is achieved via management of the sulfur content of the fuel supply to the unit.

For all states, a SIP for the regional haze second planning period, which spans from 2018 to 2028, was to be submitted to the EPA by July 31, 2021. Many states, including Louisiana, continue to prepare their second planning period SIP for submittal to the EPA. On July 8, 2021, the EPA issued a memorandum to provide states with additional information and feedback to consider for supporting their SIP development. In that same memorandum, EPA recognizes that while some states have already submitted final SIPs, others are at different stages of the SIP development process. Subsequently, in April of 2022, the EPA announced that it would issue a formal Finding of Failure to Submit to any state which did not submit a final SIP for the Regional Haze second planning period by August 15, 2022.

As part of their SIP development process for the second planning period, the Louisiana Department of Environmental Quality (LDEQ) issued Information Collection Requests (ICRs) to ELL which requested that certain air pollution control retrofit analyses be conducted for emissions of SO_2 and oxides of nitrogen (NO_x) from Unit 6 and the Nelson Station and emissions of NO_x from Units 4 and 5 at the Ninemile Point Station.

LDEQ issued a draft regional haze SIP for public review and comment in April of 2021, and this draft SIP did not propose to require any additional pollution control requirements for any ELL units. LDEQ received significant public comment on this draft SIP and continues to work towards the development of a final SIP. As a result, the state did not meet the August 15, 2022, deadline for submittal of a final SIP and EPA formally published a Finding of Failure to Submit for Louisiana on August 30, 2022. This finding will be effective on September 29, 2022 and triggers an obligation for EPA to either approve a final SIP submitted by Louisiana or to issue a final Federal Implementation Plan (FIP) for Louisiana within two years, by September 28, 2024.

Final determinations of whether any additional air pollution control retrofits are necessary at ELL generating units will be made once EPA either approves a SIP or issues a final FIP for Louisiana. This is expected to occur in 2023 or 2024.

Cross-State Air Pollution Rule (CSAPR) - The EPA finalized the CSAPR in 2011 under the "good neighbor" provision of the Clean Air Act to reduce transported pollution that significantly affects downwind non-attainment and maintenance problems for the 2008 ozone National Ambient Air Quality Standard ("NAAQS"). The rule was vacated and stayed December 30, 2011, but in late 2014 the stay was lifted following a Supreme Court reversal of the lower court decision. Louisiana is subject to CSAPR for ozone-season (May 1 – September 30) emissions of NO_x. Affected entities must hold one allowance for every ton of NO_X and SO_2 generated, depending on which programs their respective state is required to participate.

Phase I of CSAPR went into effect in May 2015 and Phase II went into effect in May of 2017. On September 7, 2016, the EPA issued a CSAPR update rule which revised the CSAPR program. This 2016 update rule revised the total allowance pool for Louisiana sources.

In March of 2021, the EPA issued the revised CSAPR update rule, which was published in the Federal Register on April 30, 2021. This rule establishes a new CSAPR Group 3 which is comprised of 12 of the 21 CSAPR Group 2 states. Louisiana was one of the 12 states moved to CSAPR Group 3 and the state-wide CSAPR NOx allowance budget for Louisiana was reduced by approximately 20% by this 2021 rule. Due to the more limited number of NOx emission allowances budgeted to states subject to the Group 3 program, allowance costs increased for Group 3 allowances from historical values of $100-500 per allowance under the Group 3 program to approximately $6,000 per allowance by February 2022.

On April 6, 2022, the EPA issued a new regulatory proposal to again revise the CSAPR to move additional states to the Group 3 allowance program and to further reduce state NOx emission budgets for Louisiana and 23 other states, including Arkansas, Mississippi, and Texas. These further revisions to the CSAPR program were proposed in order to address interstate transport requirements of the Clean Air Act with respect to the 2015 National Ambient Air Quality Standard ("NAAQS") for ozone. This regulatory proposal, if finalized, would significantly reduce the statewide NOx emission allowance budget for Louisiana with a further decrease of approximately 37% (from the 2022 budget) in 2023 and a cumulative decrease of approximately 75% (from the 2022 budget) in 2026. EPA proposes to establish the stringent 2026 state budget via a proposed dynamic budgeting approach to be conducted in 2025, based on prior-year actual unit operating and emissions data and presumed pollution control retrofits to install Selective Catalytic Reduction (SCR) NOx emission control systems on most coal-fired and certain large gas-fired generating units prior to the 2026 ozone season.

ELL-owned (or co-owned) units identified by EPA for such SCR retrofits, under this proposal include: Nelson 6, Big Cajun II Unit 3, Little Gypsy 2, Little Gypsy 3, Ninemile 4, and Ninemile 5. While the EPA proposal would not explicitly require SCR retrofits for any units, it would significantly reduce state NOx emission budgets and corresponding unit-level emission allocations as if these SCR retrofits had occurred, resulting in a likely significant NOx emission allowance shortfall, in the 2026 and subsequent ozone seasons, for any unit which continues to operate but does not conduct a SCR retrofit or otherwise significantly reduce NOx emissions.

EPA's April 2022 proposal would also more quickly modify state emission budgets to remove deactivated units and would impose additional restrictions on the maximum number of allowances which can be "banked" in one year for use in a future ozone season. These changes, along with the significant proposed emission budget reductions, would create a far more constrained NOx emission allowance market than has existed to date under the CSAPR Program.

Since EPA's proposal was issued in April 2022, significant price volatility has been reported for current Group 3 NOx emission allowances. Reported pricing for current (2022) Group 3 allowance transactions has increased from approximately $6,000/allowance prior to the EPA proposal to the range of $15,000 to $47,000 per allowance during the third quarter of 2022.

EPA is expected to finalize revisions to the CSAPR program in early 2023 with initial changes going into effect for the 2023 ozone season. Should EPA finalize revisions substantially similar to the April 2022 proposal, then ELL may be required to conduct costly pollution control retrofits on some units, revise unit deactivation assumptions, and/or incur potentially significant NO_x emission allowance costs to allow for continued operation of units as necessary to meet system capacity needs until such time as adequate replacement generation can be placed into service.

Coal Combustion Residuals Rule - ELL operates a coal ash landfill which is regulated as a Coal Combustion Residuals ("CCR") unit at Nelson Unit 6, which is subject to the CCR rule. In April 2015 the EPA published the final CCR rule regulating coal ash from coal-fired generating units as non-hazardous wastes under RCRA Subtitle D. The final regulations became effective on October 19, 2015, and created new compliance requirements for CCR management including modified storage, new notification and reporting practices, product disposal considerations, ongoing monitoring requirements and CCR unit closure criteria. In December 2016, the Water Infrastructure Improvements for the Nation Act ("WIIN Act") was signed into law, which authorizes the EPA to enforce the CCR rule rather than leaving primary enforcement to citizen suit actions.

On August 21, 2018, the D.C. Circuit Court vacated and remanded several provisions of the CCR rule that relate to inactive and unlined surface impoundments. On August 28, 2020, the EPA issued a final rule with a revised date of April 11, 2021, that unlined surface impoundments and units that failed the aquifer location restriction must cease receiving waste and initiate closure.

The Nelson 6 facility operates a coal ash landfill which is regulated under the CCR rule. The Nelson 6 facility does not operate any surface impoundments regulated by the CCR rule.

The CCR rule allows states to seek approval from EPA for state CCR permit programs. Louisiana is working toward submission of a state CCR permit program for EPA approval but has not completed development of this program.

Effluent Limitation Guideline Rule - Updates to the Effluent Limitation Guideline rule ("ELG") were finalized by the EPA on November 3, 2015. These revisions apply to ELL's coal-fired generating asset, Nelson 6, and require that coal-fired electric generating units achieve zero discharge of bottom ash transport water (BATW). The requirement was originally scheduled to become effective between November 1, 2018, and December 31, 2023, with the exact date to be determined by the permitting authority (LDEQ). On September 17, 2017, the EPA finalized a revision to the ELG rule which modified the earliest possible compliance date from November 1, 2018, to November 1, 2020. In this action, the EPA also indicated its intent to reconsider other aspects of the 2015 ELG rule, including the requirements for bottom ash transport water. On October 13, 2020, EPA issued a further revision to the final rule which would allow for limited discharges of bottom ash transport purge water under certain defined circumstances.

The Nelson 6 unit utilizes a dry ash handling system to manage fly ash generated by operation of the unit. However, the site utilizes a wet sluicing system to manage bottom ash. This system utilizes BATW and may generate a BATW discharge under certain circumstances. ELL is currently pursuing a modified and renewed Louisiana Pollutant Discharge Elimination System (LPDES) permit from the LDEQ which would allow for such limited discharges of BATW in accordance with the provisions of the October 2020 revisions to the ELG rule. In April 2022, LDEQ issued a draft permit decision which would allow for such limited discharges of BATW, and ELL is currently awaiting issuance of a final revised LPDES permit.

316(b) Cooling Water Intake Rule - Section 316(b) of the Clean Water Act requires the EPA to issue regulations on the design and operation of water intake structures to minimize adverse impacts on aquatic organisms. On August 15, 2014, the EPA issued the final 316(b) rule for existing electric generating facilities which use one or more cooling water intake structures to withdraw water from waters of the US and have a cumulative design intake flow of greater than 2 million gallons per day (MGD).

Implementation of the 316(b) rule is ongoing at ELL's generating facilities, with technology evaluations expected to occur at the Ninemile Point and Waterford 2 generating stations in 2025-2026, and at the Little Gypsy generating station in 2027-2028. The results of these technology evaluations will inform the selection of appropriate water intake technology to install at each facility to reduce the impingement and entrainment of aquatic organisms in the water intake at each site.

Potential GHG Regulation - ELL's Point of View ("POV") is that national carbon regulation for the power generation sector will occur; however, the timing, design, and outcome of any carbon control program are highly uncertain.

Under both the Obama and Trump administrations, EPA developed regulations for emissions of greenhouse gas (GHG) emissions from existing electric generating units ("EGUs") under Section 111(d) of the Clean Air Act. The Clean Power Plan ("CPP") was developed by the Obama Administration and the Affordable Clean Energy ("ACE") rule was developed by the Trump Administration. Both rules were stayed, vacated, and/or remanded by federal courts and neither was fully implemented.

EPA's authority to regulate GHG emissions from existing EGUs was again reviewed by the US Supreme Court in 2022, and in June 2022 the court issued a decision in *West Virginia v EPA* which held that that Section 111(d) of the Clean Air Act ("CAA") does not provide EPA with the authority to establish GHG emission standards based primarily upon generation shifting from coal to natural gas-fired generating units. The court held that such generation shifting would constitute a "major question" that is, an agency action that would result in "…vast economic and political significance." For such a "major question," the court held that EPA would require clear authorization from the U.S. Congress providing the regulatory authority asserted by the agency, and that Section 111(d) of the CAA does not provide the authority cited by EPA to justify the use of generation shifting to craft the CPP.

At this time, ELL expects that the current administration will propose some form of nation-wide greenhouse gas regulation for emissions from existing electric generating units, pursuant to Section 111(d) of the CAA and subject to the constraints articulated by the Supreme Court in the *West Virginia* decision. Based on the most recent unified agenda filed with the White House Office of Management and Budget, EPA is projecting to release this proposed regulation in Q1 of 2023. ELL will continue to evaluate the potential effects of this regulation in subsequent IRPs.

CO_2 Price Forecasts - ELL's CO_2 point of view is based on the following four cases:

- A "No CO_2 Policy/Clean Energy" in which, the power sector does not face a CO_2 price due to preference for clean energy standards, lack of federal action, or other factors.
- A "Regulatory" in which, Low prices representative of action under Clean Air Act (similar to Clean Power Plan) are utilized.
- A "50% Reduction" in which, Mid prices representative of price needed to reach national target of 50% reduction from 2020 levels by 2050 are utilized.
- A "Legislative" in which, High prices consistent with Climate Leadership Council proposal and other proposals from the 116th Congress are utilized.

After deriving projections of CO_2 allowance prices for each of these four cases, the following probability weightings were applied to each to arrive at the ELL's point of view assumption:

Table 13: CO_2 Probability Weightings

Reference CO_2 Case Probability	2022	2023	2024	2025	2026	2027	2028	2029	2030	2035	2040	2045
No CO_2 Policy/ Clean Energy	100%	90%	70%	60%	55%	50%	45%	40%	35%	30%	20%	10%
Regulatory	0%	10%	20%	25%	27%	29%	31%	33%	35%	30%	25%	20%
50% Reduction	0%	0%	10%	15%	18%	21%	24%	27%	30%	35%	40%	45%
Legislative	0%	0%	0%	0%	0%	0%	0%	0%	0%	5%	15%	25%

The low case assumes no CO_2 price, the reference case assumes the ELL's point of view CO_2 price, and the high case assumes the CO_2 Price High Tax case as shown below:

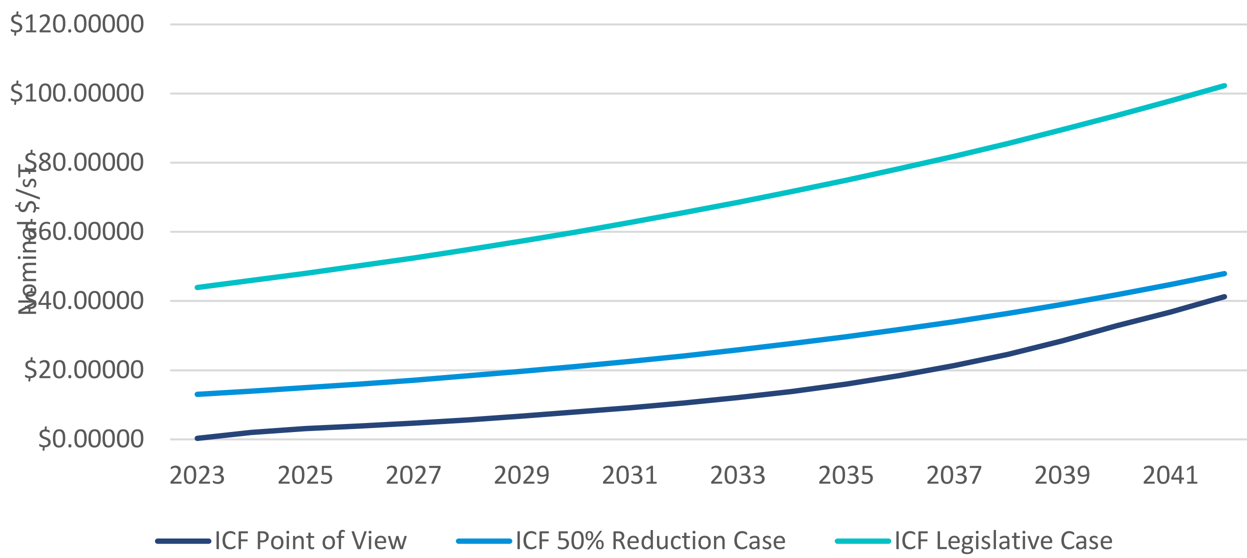


Figure 26: CO2 Price Forecast Scenarios

Fuel Price Forecasts

Natural Gas Price Forecasts - Three natural gas price forecasts were used in the development of the 2023 IRP. The near-term portion (year one) of the natural gas price forecast is based on NYMEX Henry Hub forward prices, which are market future prices as of November 2021. Because the NYMEX futures market becomes increasingly illiquid as the time horizon increases, NYMEX forward prices are not a reliable predictor of future prices in the long term. Due to this limitation, the long-term point of view regarding future natural gas prices utilizes a consensus across several independent, third-party consultant forecasts. Gas markets are influenced by a number of complex forces; consequently, long-term natural gas prices are highly uncertain and become increasingly uncertain as the time horizon increases. Therefore, ELL presents and uses three alternatives for natural gas prices to address this uncertainty. In levelized 2023 dollars per MMBtu throughout the IRP period, the reference case natural gas price forecast is $3.73, the low case is $2.92, and the high case is $5.00.

Described in more detail later in this section, each of the IRP Futures assumes the natural gas price forecast sensitivity appropriate for the future world envisioned.

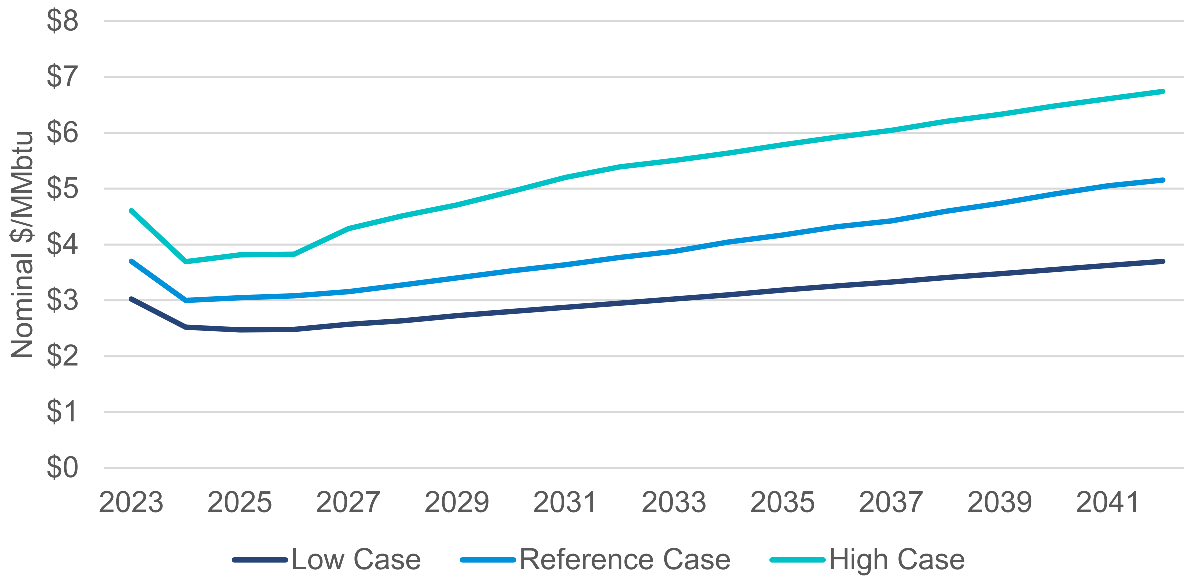


Figure 27: Annual Natural Gas Price Forecast

Coal Price Forecasts - The delivered to plant coal price forecast for Nelson 6, is based on a weighted average price of coal commodity and coal transportation commitments under contract, as well as third-party consultant forecasts of Powder River Basin coal prices for any open coal commodity position. In addition, railcar expenses and appropriate plant specific coal handling cost adders are included. The current transportation rate for Nelson 6 is escalated by 2% annually and current fuel surcharges are escalated by the On-Highway Diesel fuel price index. The current transportation rate for White Bluff and Independence is calculated monthly based on the average daily futures price of natural gas reported for "Contract 1" by the EIA and current fuel surcharges are escalated by the On-Highway Diesel fuel price index." Current plant specific delivery component costs are escalated based on an appropriate index to forecast the future year component cost. In levelized 2023 dollars per MMBtu throughout the IRP period, the delivered coal price for Nelson 6 is $2.10. The delivered coal price forecast for non-Entergy plants comes directly from the Aurora default input database provided by Energy Exemplar and prices vary by plant.

Coal Price Forecasts - The delivered to plant coal price forecast for Nelson 6 is based on a weighted average price of coal commodity and coal transportation commitments under contract, as well as third-party consultant forecasts of Powder River Basin coal prices for any open coal commodity position. In addition, railcar expenses and appropriate plant specific coal handling cost adders are included. The current transportation rate for Nelson 6 is escalated by 2% annually and current fuel surcharges are escalated by the On-Highway Diesel fuel price index. Current plant specific delivery component costs are escalated based on an appropriate index to forecast the future year component cost. In levelized 2023 dollars per MMBtu throughout the IRP period, the delivered coal price for Nelson 6 is $2.06. The delivered coal price forecast for non-Entergy plants comes directly from the Aurora default input database provided by Energy Exemplar and prices vary by plant.

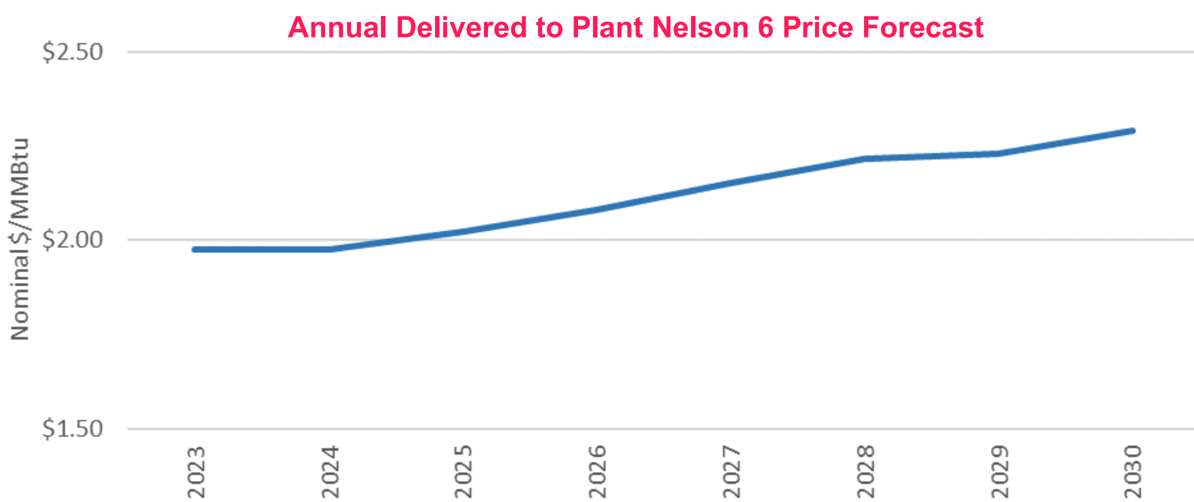


Figure 28: Coal Price Forecast

Chapter 5 Modeling Framework

Summary

- As with the 2019 IRP, a futures-based approach was employed for the 2023 IRP. Three futures were modeled to bookend a broad range of uncertainties.
- Renewable capacity accreditation was aligned with MISO MTEP methodology.

Futures-Based Approach

Instead of analyzing and planning for one set of outcomes, ELL's IRP uses a futures-based approach to evaluate portfolios across a broad range of potential future conditions. This is done because long-term outcomes are uncertain for many input assumptions. Futures are described as different combinations of assumptions that could plausibly coexist together resulting in a range of market outcomes. The 2023 IRP considers the following three Futures:

Table 14: IRP Futures Assumptions

	Future 1	Future 2	Future 3
Peak Load & Energy Growth	Reference	Highest	Between Reference and Highest
Natural Gas Prices	Reference	High	Low
MISO Coal Deactivations[33]	All ETR coal by 2030 All MISO coal aligns with MTEP Future 1 (46 year life)	All ETR coal by 2030 All MISO coal aligns with MTEP Future 3 (30 year life)	All ETR coal by 2030 All MISO coal aligns with MTEP Future 2 (36 year life)
MISO legacy gas deactivations	55 year life	45 year life	50 year life
Carbon tax scenario ICF 2020 post-election	ICF Point of View	ICF Legislative Case (High)	ICF 50% Reduction Case (Mid)
ITC/PTC Assumptions	Current methodology	HR 5376	Current Methodology
DSM Potential Study	ELL EE embedded in BP22 Load Forecast + for DR: option to select ICF up to High Case	Option to select ICF DR & EE up to High Case	Option to select ICF DR & EE up to High Case
Allow Future Emitting Resource	Yes	No	Yes

[33] Deactivation assumptions will be consistent with current planning assumptions for ELL owned or contracted generation.

Narrative	Aligns with Point of View CO2 price consistent with expected probability weighted CO2 price. Point of View CO2 leads to electrification decisions driven by sustainability efforts rather than CO2 prices. Point of View CO2 leads to relatively constant consumption of natural Gas and constant pricing. Coal is not economic to operate past 46 years of life and Legacy Gas is not economic to operate to full life assumption.	Aligns with high CO2 price consistent with aggressive decarbonization mandate scenarios. High CO2 price increases natural gas extraction and export leading to high gas prices. Coal is not economic to operate past 30 years of life and Legacy Gas is not economic to operate to full life assumption.	Aligns with mid CO2 price representative consistent with ICF 50% Reduction Case Mid price CO2 lowers consumption of Natural Gas thus decreasing prices on a global scale. Coal is not economic to operate past 36 years of life and Legacy Gas is not economic to operate to full life assumption

Renewables Capacity Credit - The solar capacity credit assumption used in the IRP aligns with the solar assumption detailed in the 2021 MISO Futures Report. Under this assumption, all solar units have a 50% capacity credit at the beginning of the study period and then decreases by 2% starting in year 2026, until the capacity credit reaches a minimum of 30%.

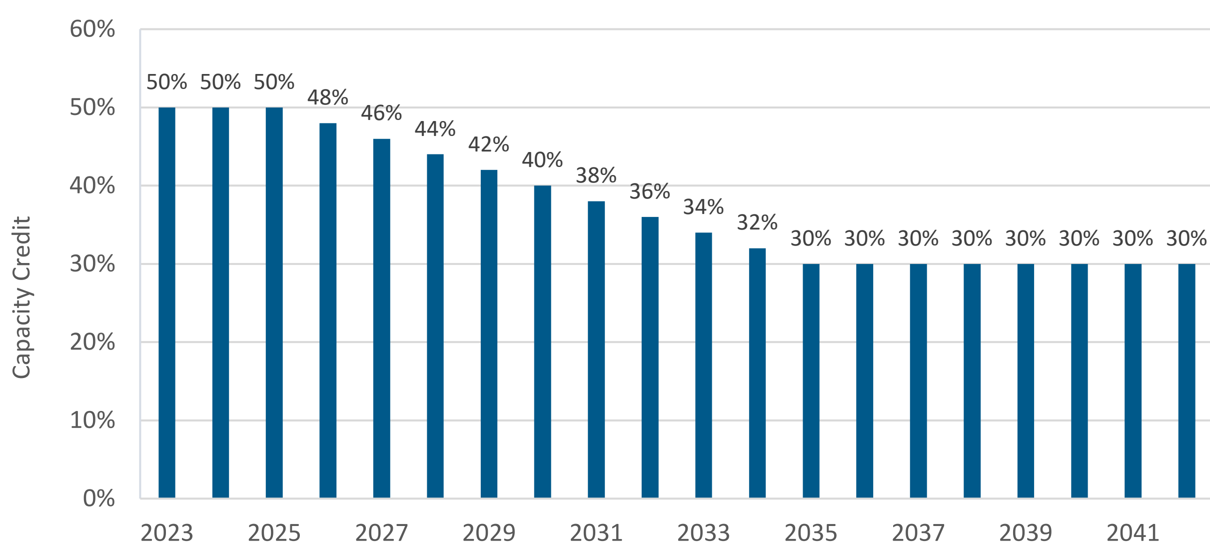


Figure 29: MTEP21 Solar Capacity Credit Approach

The 16.3% wind capacity credit assumption used in the IRP is sourced from MISO's 2021/2022 PY Wind & Solar Capacity Credit Report. The MISO system-wide wind capacity credit is calculated using a probabilistic approach to find the Effective Load Carrying Capability ("ELCC") value for all wind resources in the MISO footprint.

Market Modeling

The development of the 2023 IRP relied on the Aurora[34] Energy Market Model to develop optimized portfolios and generate Locational Marginal Prices ("LMPs") for the MISO energy market and for ELL under a range of possible futures. Aurora is a production cost and capacity expansion optimization tool that simulates energy market operations using hourly demand and individual resource operating characteristics in a chronological dispatch algorithm and uses projected market economics to determine the optimal long-term resource portfolio under varying future conditions including fuel prices, available generation technologies, available DSM program alternatives, environmental constraints, and future demand forecasts. Aurora's optimization process identifies the set of future resources that most economically meets the identified requirements given the defined constraints.

The first step within the market modeling process is to utilize Aurora to perform capacity expansion to develop a projection of the future market supply based on the specific characteristics of each future. Once the market supply resources are determined for each future, energy market simulations are performed, which results in hourly energy prices for each of the three futures. This projection encompasses the power market for the entire MISO footprint (excluding ELL). MISO (excluding ELL) projected power prices are extracted from the energy market simulations to assess potential portfolio strategies for ELL within each future. Figure 30 - Figure 35 below show the projected market supply for each of the three futures. Figure 36 represents projected annual MISO (excluding ELL) power prices for each future.

[34] The Aurora model is the primary production cost tool used to perform MISO energy market modeling and long-term variable supply cost planning for ELL. Aurora supports a variety of resource planning activities and is well suited for scenario modeling and risk assessment modeling through hourly simulation of the MISO market. It is widely used by a range of organizations, including large investor-owned utilities, small publicly owned utilities, regulators, planning authorities, independent power producers and developers, research institutions, and electric industry consultants.

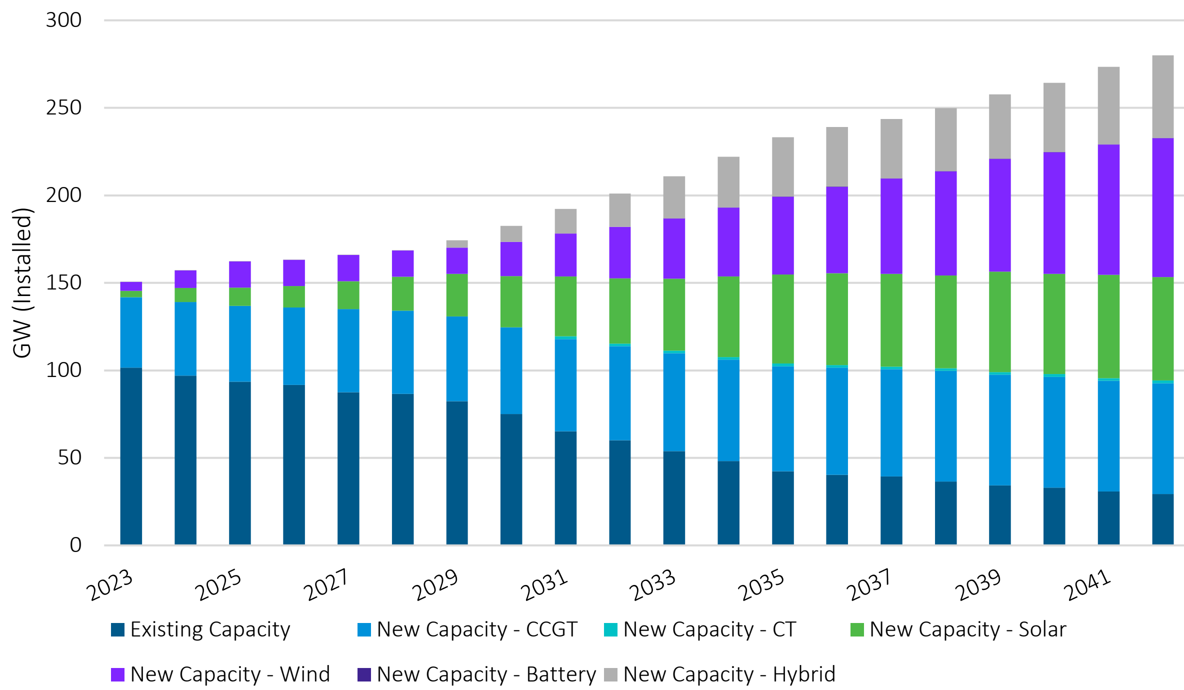


Figure 30: Future 1 Annual Projected Future MISO Market Non- ELL Installed Capacity

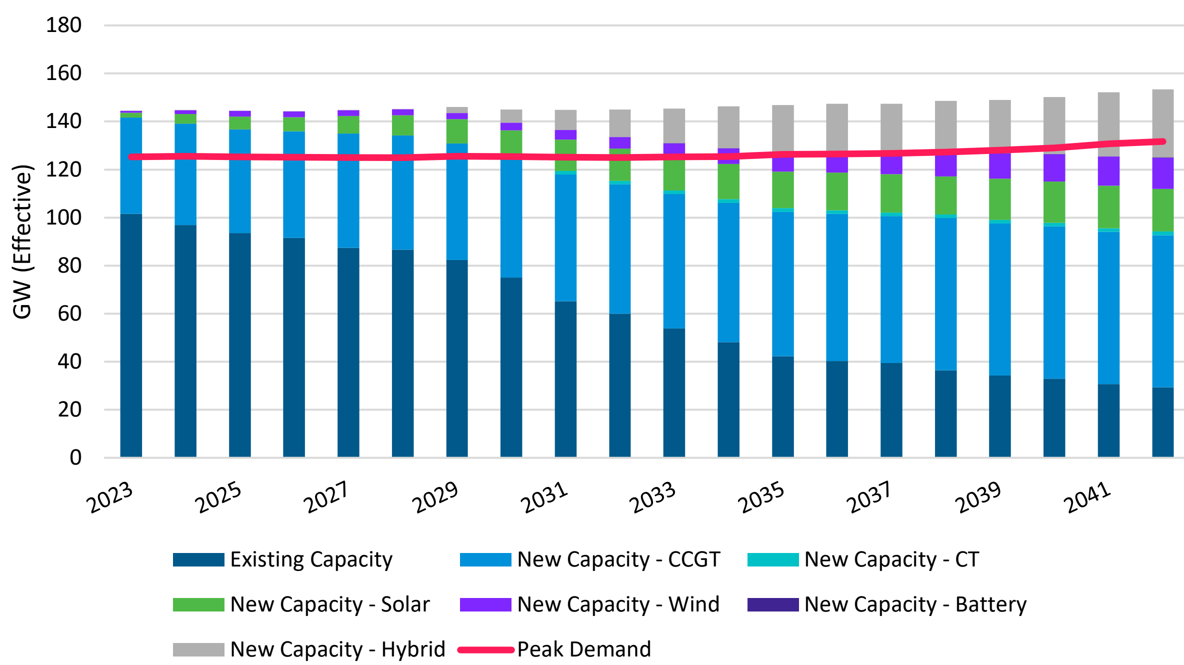


Figure 31: Future 1 Annual Projected Future MISO Market Non-ELL Effective Capacity

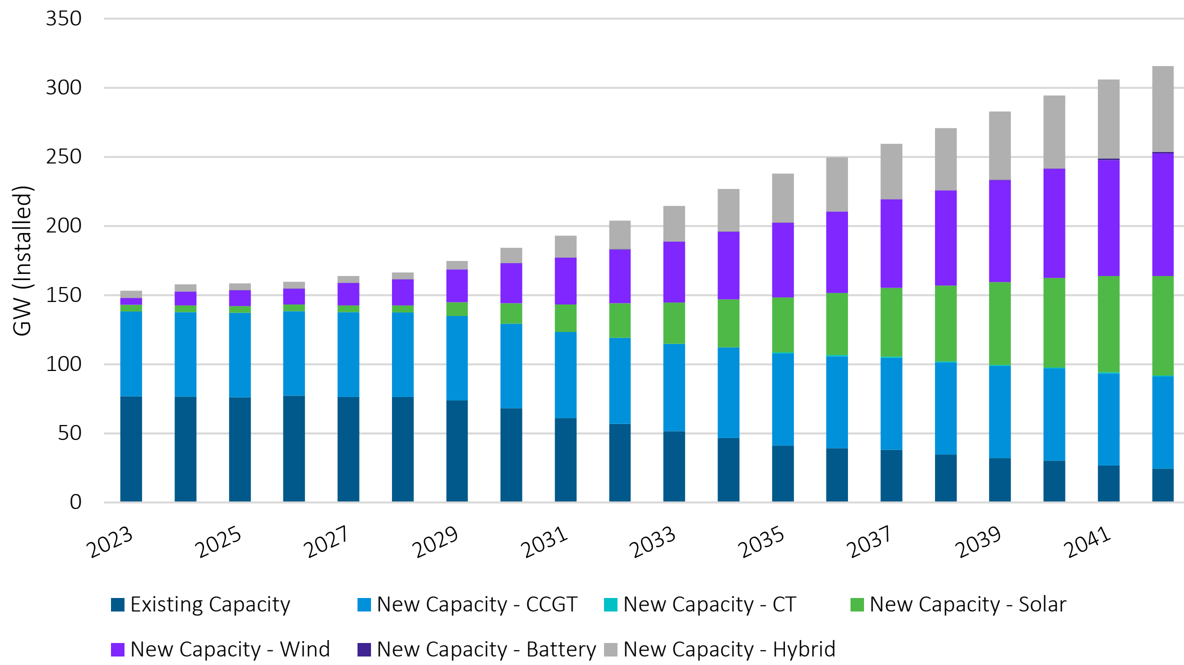


Figure 32: Future 2 Annual Projected Future MISO Market Non- ELL Installed Capacity

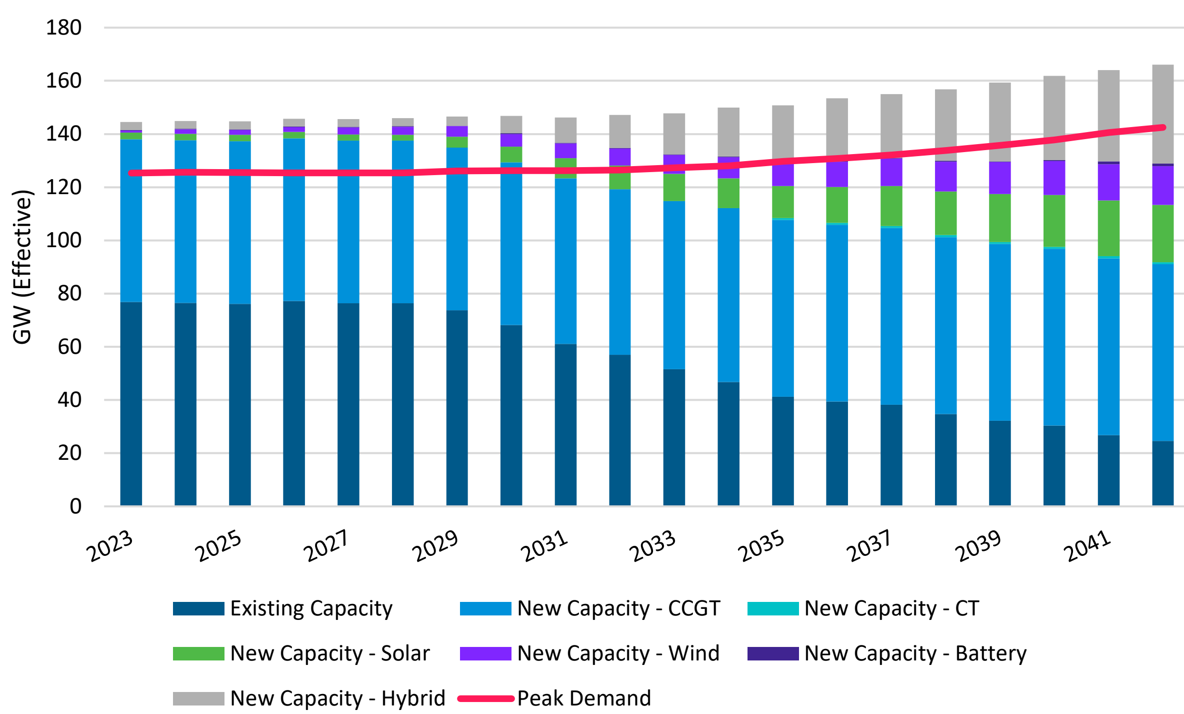


Figure 33: Future 2 Annual Projected Future MISO Market Non-ELL Effective Capacity

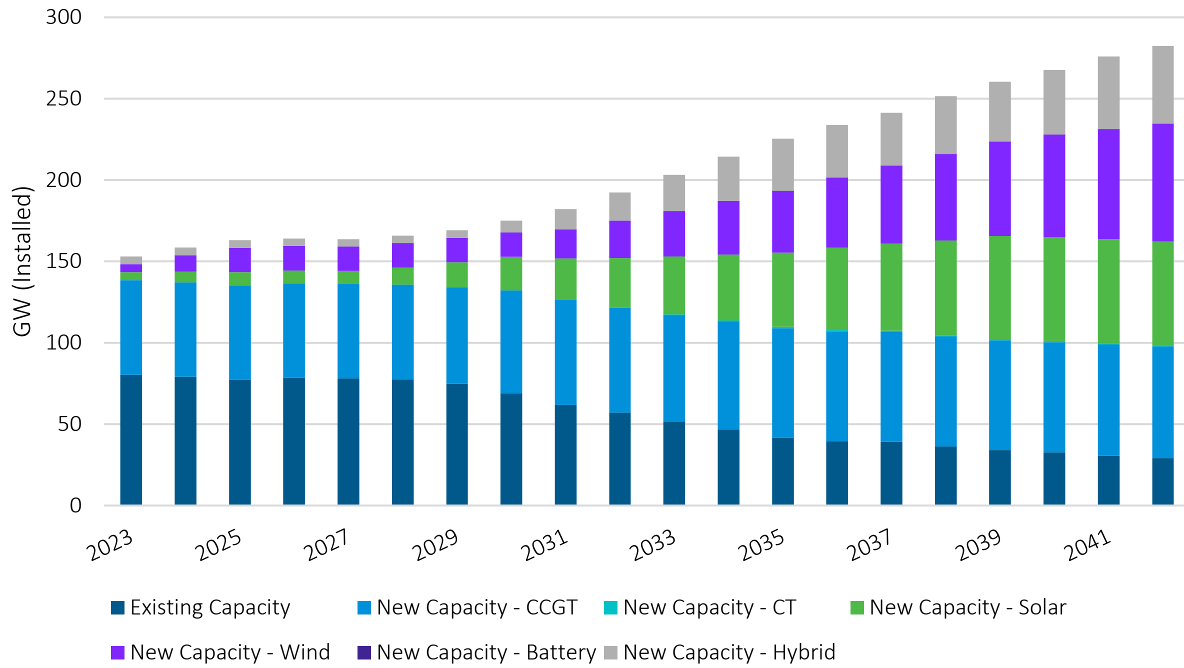


Figure 34: Future 3 Annual Projected Future MISO Market Non- ELL Installed Capacity

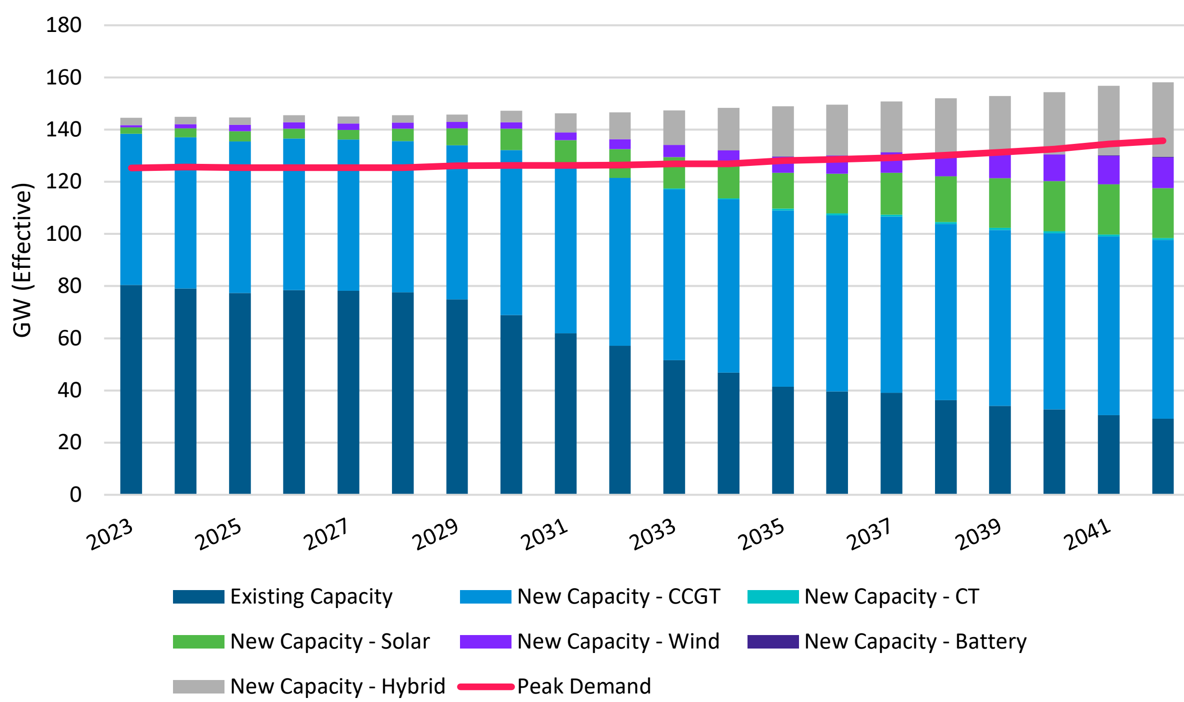


Figure 35: Future 3 Annual Projected Future MISO Market Non-ELL Effective Capacity

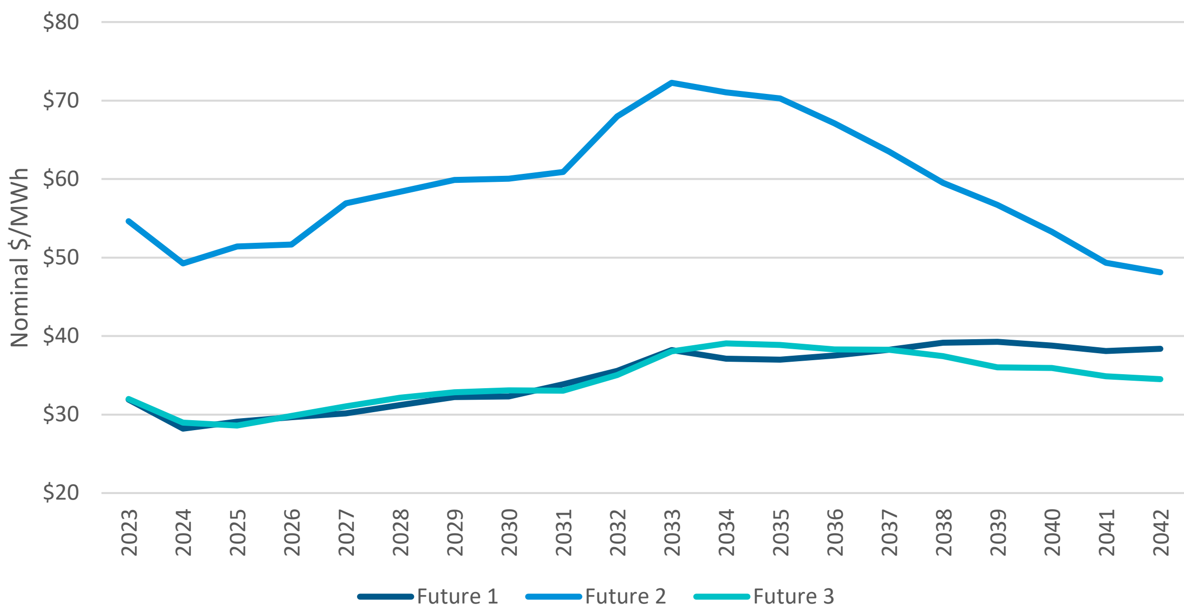


Figure 36: Average Annual MISO Market Non-ELL LMP

ELL Portfolio Optimization

Following the market modeling process, which results in LMPs for the non-ELL MISO region, the Aurora long-term capacity expansion logic was used to identify economic type, amount, and timing of demand-side resources and supply-side resources needed to meet ELL's future capacity needs. The result of this process is a portfolio of demand-side resources and supply-side resources that produces the lowest total supply cost to meet the identified need within the constraints defined in each of the three futures (the "optimized portfolio").

DSM Modeling - DSM Potential Programs were evaluated as resource alternatives to identify the most economic programs to be included in ELL's portfolio. Potential DR and EE programs were developed and evaluated by ICF based on the characteristics and attributes described in Chapter 4. ICF's reference and high DR programs were evaluated using ELL and ICF data to estimate the net benefits of each program. DR programs with benefit to cost ratios higher than 1 were selected and used to reduce the peak load. Since the high and reference programs are mutually exclusive, only one tier of each program was allowed to be selected.

EE programs were selected using Aurora. In Future 1, no ICF EE programs were allowed since EE was already embedded in the base BP22 load forecast[35]. In Future 2 and Future 3 EE was not included in the load forecast, hence, both high and reference ICF EE programs were offered for economic selection. Similarly, since the high and reference programs are mutually exclusive, only one tier of each program was allowed to be selected.

[35] The amount of embedded EE within the BP22 load forecast included in Future 1 is similar to the ICF High EE scenario.

Aurora considers the cost and revenue of energy and capacity in the context of the MISO market for each EE program alternative. Due to the nature of the forecasted EE programs that gain adoption by customers over time, each program was designed to start in 2023 and continue through the end of the technical life of the technology, if applicable, or through the end of planning horizon. Because ELL is not projected to have a need for incremental capacity in 2023, the selection of the EE programs in the model was based strictly on economics, and not capacity position. The capacity credit of selected EE programs is counted toward meeting ELL's capacity needs through reduction of peak load.

Table 15: High ICF DSM Programs Selected by Aurora by Future

ICF High DSM Programs	Type	Sector	Future 1	Future 2	Future 3
Agricultural	DR	Com	✓	✓	✓
DLC Water	DR	Com	×	×	×
Interruptible	DR	Com	✓	✓	✓
Smart Thermostat	DR	Com	✓	✓	✓
Interruptible Existing	DR	Ind	✓	✓	✓
Interruptible New	DR	Ind	✓	✓	✓
DLC Water	DR	Res	×	×	×
Smart Thermostat	DR	Res	✓	✓	✓
Agricultural	EE	Com	-	✓	✓
Large Commercial Solutions	EE	Com	-	✓	✓
Midstream Lighting	EE	Com	-	✓	✓
Retro-commissioning	EE	Com	-	✓	✓
Small Business Direct Install	EE	Com	-	✓	✓
Small Commercial Solutions	EE	Com	-	✓	✓
Industrial SEM	EE	Ind	-	✓	✓
Large Industrial Solutions	EE	Ind	-	✓	✓
AC Solutions	EE	Res	-	✓	✓
Appliance Recycling	EE	Res	-	✓	✓
Behavioral Home Energy	EE	Res	-	✓	✓
Home Performance	EE	Res	-	✓	✓
Income Qualified Solutions	EE	Res	-	✓	✓
Manufactured Homes	EE	Res	-	✓	✓
Midstream HVAC	EE	Res	-	✓	✓
Multifamily Solutions	EE	Res	-	✓	✓
Prepay	EE	Res	-	✓	✓
Retail Lighting	EE	Res	-	✓	✓
School Kits	EE	Res	-	✓	✓

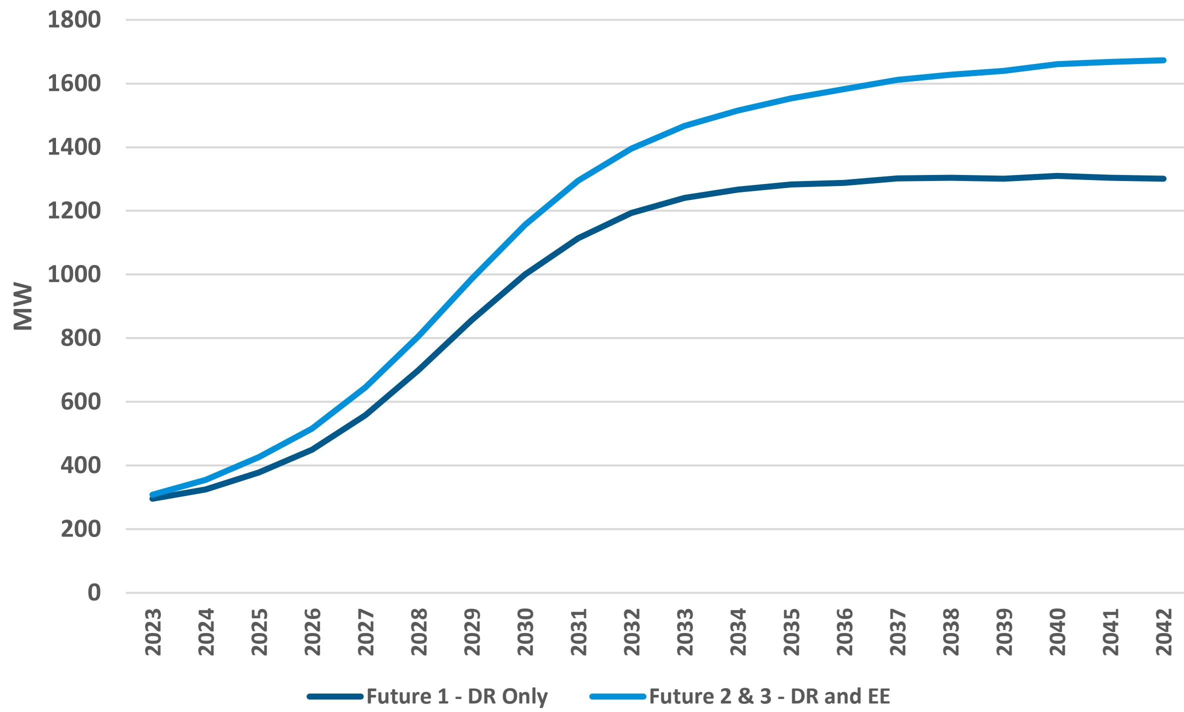


Figure 37: Selected Gross DR and EE Programs[36,37]

Results - Capacity Expansion & Total Relevant Supply Cost Metric

The following figures show the timing of incremental resource additions throughout the ELL IRP evaluation period of 2023-2042. All existing and planned capacity for ELL, as described in the Existing Resources section of Chapter 3, was included in the AURORA model to determine timing and need for incremental resources. These existing and planned resources, however, are not shown in the figures below. For each optimized portfolio, the load requirement is reflective of the future for which the portfolio is optimized (e.g., Portfolio 1 is optimized in Future 1), and includes the assumed effects of incremental DSM on the peak load requirement.

Each ELL portfolio is simulated with the Aurora production cost model for the relevant future and combined with other spreadsheet-based cost components to produce the total relevant supply cost. As previously noted, all three portfolios are consistent with and make progress towards Entergy Corporation's announced sustainability and emissions reductions goals. The results of the analysis are summarized below.

Portfolio 1

Future 1 is defined by reference load growth, reference gas price, high DR addition, and the ICF Point of View CO_2 price. The capacity under the reference assumptions is optimized to include a

[36] Future 1 shows the DR Selected through the Capacity Expansion Evaluation. EE was embedded in the Load Forecast; therefore, EE is not included in the table, however, it was included in Future 1.

[37] DSM grossed up for reserve margin and transmission loss.

diverse mix of baseload energy producing resources, renewable energy projects, energy storage, and DSM.

In Portfolio 1, 1.6 GW of thermal capacity and 9.3 GW of renewable capacity were added within the 20-year planning horizon. The optimized Portfolio 1 also includes 450 MW of additional BESS capacity which could be paired with a renewable resource or utilized as standalone resources. Most of the ICF high DR programs were economic in Portfolio 1 and included to help reduce the peak load. In the optimized Portfolio 1, solar was added first to meet the capacity need from load growth and assumed existing unit deactivations, and then CCGTs were added when large legacy dispatchable gas units are assumed to deactivate. Solar was added until the daylight hour's energy demand became saturated and then wind was added as an economic compliment to serve the load in non-daylight hours. BESS was added near the end of the study period when it is needed to move intermittent renewable energy to hours of high customer demand net of renewable energy production. These resources and DR programs together address ELL's energy needs as well as account for the future deactivation of dispatchable units. More detail on the total relevant supply cost estimate and projected rate impacts for each future can be found in Appendix G.

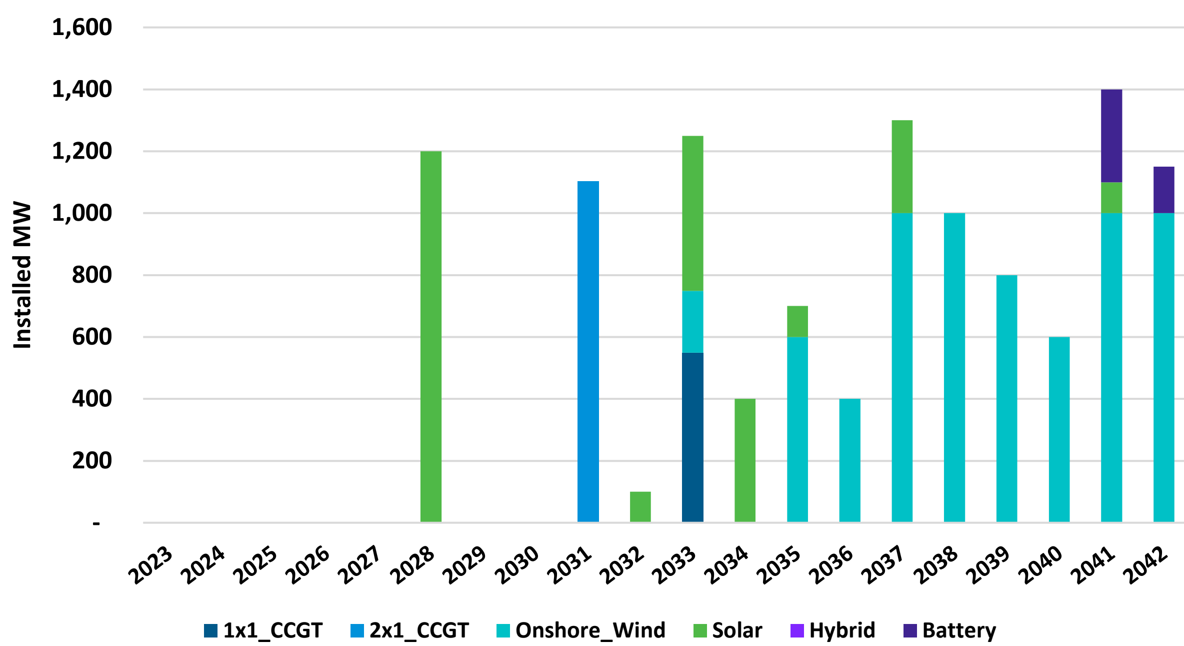


Figure 38: Annual Capacity Expansion Additions Portfolio 1

Table 16: Capacity Expansion Optimized Portfolio 1

Technology[38]	Portfolio 1 Installed MW (ICAP)	Portfolio 1 Effective MW (UCAP)
2x1 CCGT	1,102	1,102
1x1 CCGT	549	549
Aeroderivative CT	0	0
Single Axis Solar	2,700	810
Hybrid (Solar + Battery)	0	0
Lithium-Ion Battery	450	450
On-shore Wind	6,600	1,076
Total Supply Side Additions	11,401	3,987
Gross DR Programs (2042)[39]	1,301	1,301

Portfolio 2

Future 2 is defined by high load growth, high gas price, high DSM addition, and the ICF Legislative Case CO_2 price. Because Future 2 assumes an environment which would be favorable for the economics of renewable resources, emitting resource additions were not allowed to be built. Due to the high load and low peak credit of renewables, more incremental capacity was required in Portfolio 2 compared to Portfolio 1.

In Portfolio 2, 8.8 GW of installed capacity additions are sourced from solar resources and another 1.5 GW are sourced from solar resources with BESS. Portfolio 2 also includes 16 GW of additional wind resources. As shown in Table 15 above, most of the DR and all the EE offered in the ICF high programs were included resulting in 1,673 MW of gross DR and EE netted against the peak. Future 2 produced an environment where ELL would be reliant on wind resources and solar resources to meet the peak and energy requirements. Portfolio 2 also relies on the MISO energy market to a larger extent than portfolios 1 and 2 to balance ELL's generation and demand due to the level of intermittent resources added to ELL's portfolio. For the reasons described throughout this document, over-reliance on the MISO markets can pose risks to customers and reliability. Solar with BESS was added towards the end of the study to move intermittent renewable energy to hours of high customer demand net of renewable energy production.

[38] Reciprocating Internal Combustion Engine, Combustion Turbine, and Offshore Wind were included as resource alternatives for ELL but were not selected by the Aurora model in any Future during the optimization process.

[39] DSM value represented in Table 16 is the max capacity of the selected program in 2042 grossed up for reserve margin and transmission losses.

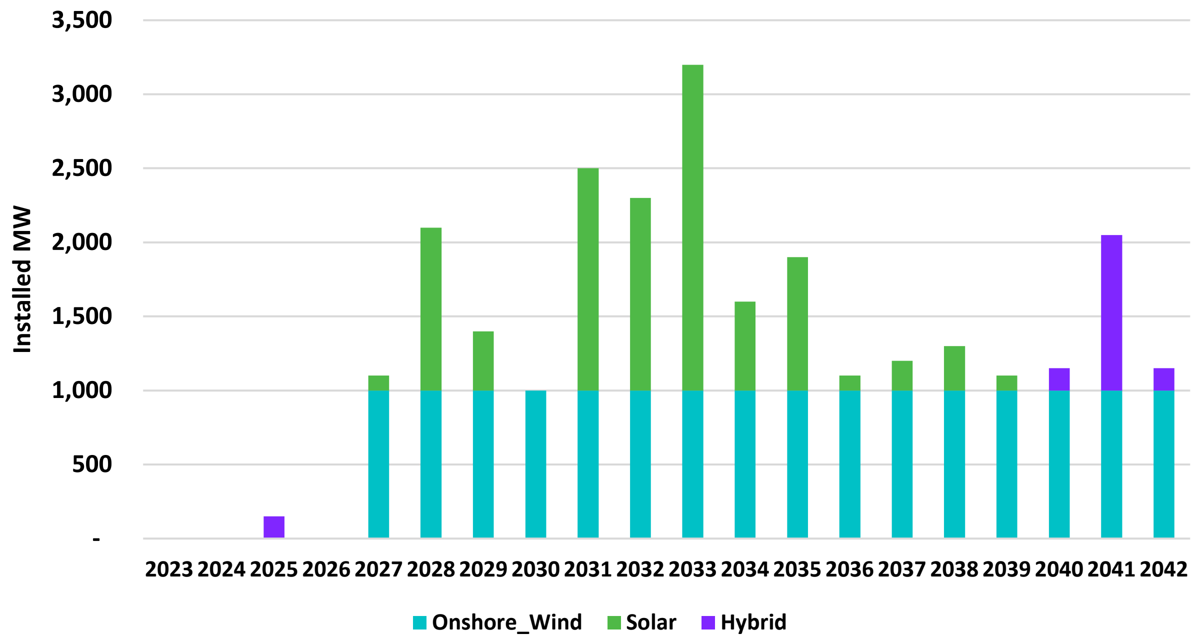


Figure 39: Annual Capacity Expansion Additions Portfolio 2

Table 17: Capacity Expansion Optimized Portfolio 2

Technology[40]	Portfolio 2 Installed MW (ICAP)	Portfolio 2 Effective MW (UCAP)
2x1 CCGT	-	-
1x1 CCGT	-	-
CT	-	-
Single Axis Solar	8,800	2,640
Hybrid	1,500	900
Lithium-Ion Battery	0	0
On-shore Wind	16,000	2,608
Total Supply Side Additions	26,300	6,148
Gross DR and EE Programs (2042)[41]	1,673	1,673

[40] Reciprocating Internal Combustion Engine, Aeroderivative CT, and Offshore Wind were included as resource alternatives for ELL but were not selected by the Aurora model in any Future during the optimization process.

[41] DSM value represented in

Table 17is the max capacity of the selected program in 2042 grossed up for reserve margin and transmission losses.

Portfolio 3

Future 3 is defined by load growth that is between reference and high, low gas price, high DSM addition, and the ICF 50% Reduction Case CO_2 price. Economically, this environment favors gas based dispatchable resources. The optimized capacity selected to best fit this environment includes a greater supply of gas resources with renewable energy, energy storage, and DSM resources providing a substantial amount of capacity.

In Portfolio 3, 3.2 GW of installed capacity additions are sourced from solar resources and another 450 MW are sourced from solar resources with BESS. The optimized Portfolio 3 also includes 400 MW of additional BESS capacity which could also be paired with a solar resource or utilized as standalone resources. Also, an additional 2.8 GW are sourced from combined cycle resources. Like Portfolio 2, most of the DR and all the EE offered in the ICF high programs were included, shown in Table 15 above, which resulted in 1,673 MW of gross DR and EE netted against the peak. First solar was added for capacity and energy needs, and then CCGTs were added to when large legacy gas units are assumed to deactivate. Solar was added until the daylight hour's energy demand was saturated and then wind was added to serve the load in non-daylight hours. Finally, BESS was added near the end of the study to move intermittent renewable energy to hours of high customer demand net of renewable energy production.

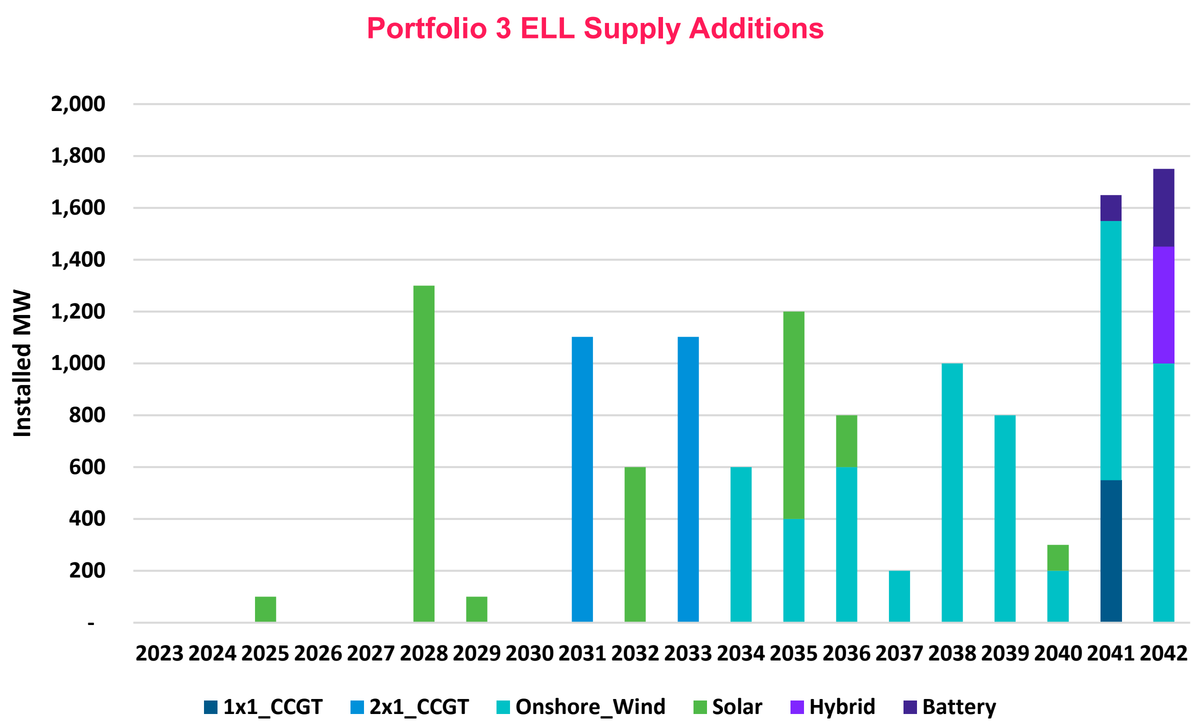


Figure 40: Annual Capacity Expansion Additions Portfolio 3

Table 18: Capacity Expansion Optimized Portfolio 3

Technology[42]	Portfolio 3 Installed MW (ICAP)	Portfolio 3 Effective MW (UCAP)
2x1 CCGT	2,204	2,204
1x1 CCGT	549	549
CT	-	-
Single Axis Solar	3,200	960
Hybrid	450	270
Lithium-Ion Battery	400	400
On-shore Wind	5,800	945
Total Supply Side Additions	12,603	5,328
Gross DR and EE Programs (2042)[43]	1,673	1,673

Qualitative Risk Characteristics

The results of the ELL IRP are not intended as static plans or pre-determined schedules for resource additions and deactivations. As ELL nears execution decisions regarding its resource portfolios, it will be important to understand the relative risk that contemplated portfolios may bring. The following factors are intended to give ELL an indication of the qualitative risk characteristics that may contribute to future portfolio decisions:

Market Factors - Reviewing market relative energy coverage within the MISO market metrics allows ELL to assess the level of exposure to market prices for a portfolio. A portfolio that is forecasted to generate less or more energy relative to their demand relies on the MISO energy market to make up its need, resulting in a higher energy price risk if LMPs are higher than anticipated, or higher fixed-cost risk if LMPs are lower than anticipated.

Reliability - Performing a reliability analysis provides ELL the ability to understand the relative reliability attributes of a portfolio for reasonably balancing regional requirements related to capacity, transmission, and reliability.

Economic, reliability, and risk evaluation - The analysis of total relevant supply cost, which represents the incremental fixed costs and total variable supply costs to serve customers' resource needs reliably under the assumptions of a particular Portfolio through the planning horizon, used cross-testing to identify a 20-year revenue requirement for each of the 3 optimized

[42] Reciprocating Internal Combustion Engine, Aeroderivative CT, and Offshore Wind were included as resource alternatives for ELL but were not selected by the Aurora model in any Future during the optimization process.

[43] DSM value represented in Table 18 is the max capacity of the selected program in 2042 grossed up for reserve margin and transmission losses.

Portfolios in all three Futures. Information on the total relevant supply cost and risk analysis can be found in Appendix G.

Modernization of Fleet - Understanding technology based useful life assumptions coupled with the average age of generating resources helps to inform an assessment of potential risks associated with maintaining and operating a portfolio of assets.

Executability - Assessing the executability of a portfolio allows ELL to evaluate the relative risks associated with the procurement of single or multiple resources within the timeframe needed. This assessment aims to highlight the potential time and cost risks associated with procuring a potential portfolio of resources such as: Interconnection/Deliverability, MISO queue process, RFP process and negotiations, construction, etc.

Optionality - Optionality considers the adaptability of a portfolio which enables ELL to adjust to various market conditions, such as how soon resources must be procured within the portfolio, the portfolio's capability to use hydrogen, or the portfolio's ability to adapt its supply role.

Fuel Supply Diversity - Fuel supply diversity assesses the level of exposure to fuel supply concerns, such as commodity constraints.

Environmental - Analyzing the relative CO_2 emissions impact of a portfolio allows ELL to understand the risks associated with changing laws, regulations, and environmental market pressures.

Chapter 6 Action Plan

Summary

- Increasing the amount of renewables capacity in ELL's portfolio is supported under a broad range of future conditions.
- The next driver for a large capacity deficit will be the timing of deactivation of legacy resources and load growth. Incremental additions of renewables continue to be a cost-effective approach to address that need.
- Potential may exist for incremental cost-effective demand response in ELL's portfolio.

Findings & Conclusions

As discussed above, the Aurora capacity expansion process resulted in three distinct resource portfolios, each of which is economically optimal for the combinations of assumptions for the respective future. Comparison across the futures provides insight on the supply additions that are robust under a wide range of uncertain future outcomes over the 20-year planning horizon.

Findings Across Futures - When reviewing the results of the resource portfolios across the futures, the many varying inputs across the futures must be taken into consideration. The portfolios that are developed based on this broad range of uncertainties reflected in the IRP Futures may provide insight into the types of resources that can be cost effective over this range of possible outcomes; however, caution must be taken when comparing results between the futures. Table 19 below summarizes key results for each future:

Table 19: Modeling Results Summary

2023-42 Modeling Results (MW)	Portfolio 1	Portfolio 2	Portfolio 3
Total Incremental Installed Capacity:	12,640	27,973	14,158
Natural Gas Capacity Additions:	1,580	0	2,635
Renewable Capacity Additions:	9,300	25,800	9,300
Battery Capacity Additions:	450	500	550
DSM Capacity Additions:	1,310	1,673	1,673

Renewable Resources are Even More Cost-effective than was Shown in ELL's Prior IRP - Renewables account for the majority of incremental supply additions across all three of the futures. In comparison to the 2019 IRP, incremental gas-powered capacity additions have decreased significantly. Table 20 below shows the proportion that renewable additions make of the future portfolios. These percentages ranged from 13% to 57% in the 2019 IRP. By contrast, dispatchable gas-powered and BESS resource additions are primarily made to provide flexible capacity to allow integration of solar and wind resource additions, though the amount and timing varies across futures because of different market conditions and amount of renewable resources added.

This result supports the conclusion that adding renewables to ELL's portfolio is a cost-effective approach across a broad range of future assumptions. This means that the Company is well poised to take actions that further the sustainability goals of its customers and of Entergy Corporation while still following the principles of least-cost resource planning.

Table 20: Renewable Capacity Additions (%)

Future	Renewable[44] resource capacity additions as percent of total incremental supply additions
Portfolio 1	74%
Portfolio 2	92%
Portfolio 3	66%

DSM is Cost-effective in all Futures - A significant amount of DSM (EE and DR) programs are cost-effective and included in the results for all three futures. The amount selected varies from a somewhat lower level in Future 1 of 1,310 MW of capacity contribution to the highest level in Futures 2 and 3 of 1,673 MW of capacity contribution by 2042. This result indicates that opportunity may exist for ELL to explore growth of existing or potentially new, cost-effective DSM programs as part of its future portfolio of resources. In addition to being an alternative to supply side generation, DSM resources may also address unique customer preferences, as well as reliability needs.

Timing of First Addition - Excluding the planned resources where procurement efforts are already underway and/or the LPSC has already approved the additions,[45] the year in which the first incremental resource addition is needed to meet the reserve margin target is 2028 for Future 1, and 2025 for Futures 2 and 3. Futures 1 and 3 assume lower load growth than Future 2. Therefore, a 2025 supply need may result should higher load growth occur or the timing of legacy resource deactivations occur earlier than assumed or both. Given the uncertainty around both of these drivers, a plan to continue methodically adding generation between 2025 and 2029 is needed.

2023 IRP Reference Resource Plan

Based on the modeling, analysis and findings discussed above, the 2023 IRP supports the conclusion that ELL's future supply-side resources will be focused primarily on renewable energy resources with additions continuing in 2025. The near-term addition of renewables enhances the adaptability of ELL's portfolio to changes, such as rapidly evolving customer demand. It also increases fuel supply diversity, lowers environmental cost risk, and responds to customers' preferences for renewable energy, while also making progress toward meeting the Company's announced sustainability goals. Based on the work conducted as part of the 2023 IRP analysis, it is also reasonable to conclude that demand-side resources will continue to be a component of

[44] Renewable resources include solar, solar with storage, wind, and BESS technologies.

[45] *See,* discussion of Planned Resources, *Id. at* p. 26-28. The Planned Resources include new solar additions approved by the LPSC in Docket No. U-36190, new renewable resources from the 2021 and 2022 ongoing RFPs, and the DER resources approved as part of ELL's Power Through program in Docket No. U-36105.

the capacity portfolio. In the near term, renewable resource additions will be made based on specific project proposals. Over the long-term, the amount of total capacity that will be needed and exactly when that capacity will be needed are uncertain. ELL's reference resource plan maintains the planning assumptions for existing units and continues adding renewable resources starting in 2025 consistent with Portfolio 1 though the exact amount of each type of renewable resource will be based on a market solicitation and may vary from the amounts identified in this analysis.

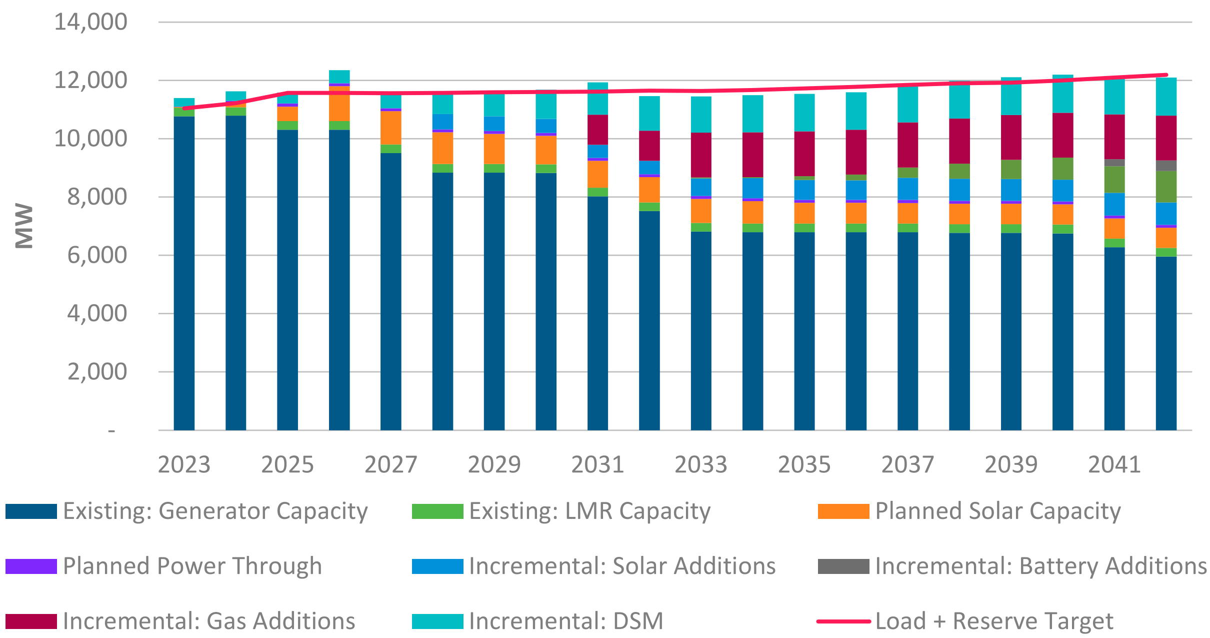


Figure 41: 2023 IRP Preferred Resource Plan

2023 IRP Action Plan

The action items below represent a pragmatic approach to ELL's integrated planning over the coming five years. By necessity, the integrated planning process is subdivided into work streams, each with its own process and timeline.

1. Implement ELL's Solar Portfolio & Geaux Green Tariff (2020 RFP)	Pursuant to the recently issued certification, ELL intends to add three new contracted solar resources (Vacherie, Sunlight Road & Elizabeth) and one new owned resource (St Jacques) to its generation portfolio. Additionally, ELL will implement Rider GGO, a new green tariff which will allow participants to subscribe to and receive value from these four solar resources to address their decarbonization objectives. The Company intends to expand Rider GGO and/or develop other renewable options to provide benefits to all customers (including non-participants) and address future capacity needs, where feasible.

2. Complete ELL's Two Outstanding RFPs (2021 & 2022 RFPs)	ELL's 2021 RFP sought up to 600 MWs of solar resources, with an option to provide battery storage, for resources located within SELPA. ELL's 2022 RFP seeks up to 1,500 MWs of solar resources, with an option to provide battery storage, and additionally seeks wind resources. In this most recent RFP, ELL expanded its locational requirements beyond SELPA to include all of Louisiana for solar resources, and all of MISO South and/or SPP for wind resources.
3. Continue the Issuance of Sizeable and Frequent Renewables RFPs	ELL intends to continue to issue sizeable and frequent renewable RFPs in an attempt to respond to customer preferences, diversity of ELL's generation portfolio, capitalize on the improving economics of solar and potentially other technologies relative to conventional generation resources, and ultimately to work toward its 2030 and 2050 sustainability goals, respectively. In response to the Commission's recent directive, ELL will also work with the Commission and other stakeholders to find ways to expedite this process. In addition, as the market continues to evolve and developers initiate projects, in accordance with LPSC guidelines, ELL will evaluate and respond to any unsolicited offer it may receive for viable resource additions.
4. Cross-State Air Pollution Rule ("CSAPR")	ELL will continue to monitor the development of the proposed revisions to the CSAPR program and seek opportunities to engage with EPA to advocate for a more flexible final rule which minimizes the risk of additional pollution control investment costs and/or revisions to ELL's existing resource plans. Once a final rule is issued by EPA, ELL will assess the impacts and implement a compliance strategy to meet any new or revised compliance obligations.
5. Explore Solving Some of ELL's Energy & Capacity Deficits with Distributed Generation and/or Customer Solutions	Distributed generation provides significant benefits to the grid and ELL customers through increased reliability, increased efficiency, grid balancing, peak load reduction and onsite local self-reliance for power generation needs. The LPSC's recent approval of ELL's Power Through program is a great example of a cost-effective opportunity to provide distributed generation coupled with resiliency for its customers. ELL will continue to evaluate opportunities to install distributed generation throughout its service territory as well as seek new opportunities for customer solutions that bring renewable generation to Louisiana.
6. Continue Participation in Commission Rulemakings	ELL intends to monitor and participate in Commission rulemakings regarding resource planning, reliability and resource adequacy and evaluate actions that ELL should

(Resource Adequacy & Planning, Reliability)	take to protect its customers from reliability and cost shifts resulting from cooperatives that plan to serve their load without appropriate long-term physical capacity, including exiting MISO.
7. Explore Additional Demand Side Management Opportunities	ELL stands ready to expand its current DSM offerings in accordance with applicable LPSC Rules[46] and Orders and where it is cost-effective to do so.
8. Pursue Power Resiliency	ELL will file its Protect Louisiana Plan highlighting its plan to accelerate the resilience of its electric system through a comprehensive set of cost-effective hardening projects.

[46] ELL notes that in the on-going rulemaking related to administration of DSM programs (Docket No. R-31106), Staff issued new draft rules on March 7, 2022. Among other things, these draft rules (if implemented as drafted) would radically change the paradigm for administration of DSM programs by removing control of the programs from utilities and seeking to hire a statewide third-party administrator to oversee programs for all utilities. It is unclear whether this model will be implemented. As ELL noted in filed comments, the Company believes the ability to achieve cost-effective savings through DSM programs would be better served by allowing utilities with existing programs to retain control over them. The discussion of DSM, and the potential benefits thereof, throughout this report and in the DSM Potential Study assumes that ELL would still be allowed to administer DSM programs once the Commission's rules are finalized and implemented.

Chapter 7 Stakeholder Engagement

Summary

- Based on feedback received from stakeholders, ELL has worked to enhance the Stakeholder engagement process for this IRP
- Due to the COVID-19 pandemic, all Stakeholder meetings were hosted virtually
- ELL hosted a stakeholder meeting, addressed Q&A, and accommodated multiple stakeholder requests

Pursuant to the LPSC Integrated Resource Plan General Order (Docket No. R-30021 - "Integrated Resource Planning Rules for Electric Utilities in Louisiana"), one component of the development of the IRP is to work collaboratively with stakeholders in ELL's long-term planning process. Stakeholders have the opportunity to ask clarifying questions during a Technical Conference and provide written comments at various stages throughout the IRP process.

The stakeholder engagement process began in November 2021 with a public Data Assumptions Posting to ELL's IRP website.[47] The Stakeholder Kickoff Meeting was held in January 2022 and included a broad amount of information regarding ELL's planning processes and objectives, including preliminary assumptions and inputs for the IRP's modeling. The meeting was well-attended with participation from numerous parties of varied educational and professional backgrounds, representing a wide range of industry experience and expertise. ELL presented extensive information designed to educate stakeholders about resource planning and responded to clarifying questions during its first Technical Conference. Following this meeting, in February of 2022 ELL posted a Q&A document that responded to questions received both during and after the Stakeholder Kickoff Meeting. ELL also provided an updated set of assumptions and inputs in response to feedback provided by stakeholders at ELL's Technical Conference. Responses to written comments provided by stakeholders after ELL's first Technical Conference are provided within (see Appendix A).

[47] *See,* https://www.entergy-louisiana.com/irp/2023_irp/for the information and documents provided by ELL to stakeholders during this IRP cycle.

Appendix A – ELL Responses to Stakeholder Comments

Comments Regarding Deactivation and Retirement Assumptions or Evaluations:

Stakeholder Comment	ELL Response
Staff: ELL should provide, in its Draft IRP, an explanation of why some deactivations are designated as confidential.	After considering stakeholder input, ELL has no longer designated any of its deactivation assumptions over the next 10 years in this Draft IRP as confidential. See Table 3 (within Chapter 3) for these assumptions.
Sierra Club: ELL should evaluate earlier retirement options for White Bluff, Independence, Nelson, and Big Cajun II, perhaps as a sensitivity, as was done in EAL's IRP.	ELL does not have majority ownership interest in White Bluff, Independence, or Big Cajun II. Therefore, it is not appropriate or meaningful to the IRP analysis to speculate on or analyze alternate deactivation assumptions for those units. Table 3 in the IRP main body documents the deactivation assumptions for these units. Regarding Nelson 6, the purpose of the IRP analysis is not to analyze or optimize near-term deactivation assumptions for individual units, but rather to identify long-term resource portfolios and strategies that are economic for ELL customers under a range of market conditions, as confirmed in the current IRP Rules.

Comments Regarding Energy Efficiency and DSM:

Stakeholder Comment	ELL Response
AAE: Pre-pay is a "predatory program" that allows utilities to avoid consumer protections related to disconnections and should not be approved as a DSM program. It can also harm LIHEAP benefits.	ELL disagrees with AAE's characterization of pre-pay programs. ELL further notes that for purposes of this IRP, pre-pay is one of many EE/DSM measures that were evaluated by ICF within the DSM Potential Study contained in Appendix I. If ELL elects to propose a pre-pay program at a later date, any such proposal will be subject to LSPC approval.
AAE: Entergy's Final Integrated Resource Plan should fully address robust and equitable energy efficiency programs to reduce bills and protect health and safety.	See the discussion of DSM resources throughout this Draft IRP Report and in ICF's DSM Potential Study contained in Appendix I.
AAE: ELL should evaluate the savings identified in the DSM Potential study against the supply-side resources proposed in its data assumptions. This includes EE, DR and DER.	ELL did conduct such an evaluation of savings in this Draft IRP Report. Please see the DSM Potential Resource Assessment section of Chapter 4 and the DSM Modeling section of Chapter 5 for additional information about the Draft IRP analysis.

AEMA: EV resources should include participation beyond smart chargers.	ICF modeled the EV program with the chargers as the primary operating device since the other program delivery modes (e.g., using telematics) are still nascent. However, to account for the fact that there might be growth in these additional program delivery options, the steady state/max market share in the reference and high cases were set to capture the range of possible levels over which participation could vary with current and further implementation designs. Regarding the cost-effectiveness difference in EV programs with telematics, a significant portion of the savings comes from not having to purchase chargers to participate in DR programs. ICF modeled program TRC with and without the cost of chargers, and in both scenarios the program doesn't clear the TRC test.
AEMA: More explanation should be given as to why residential battery storage did not pass the TRC test	The battery storage program evaluated within ICF's report (in Appendix I) reflects the high upfront costs for the customer due to the cost of the battery and the installation. Due to slower adoption of batteries, compared to more prevalent technologies like smart thermostats, the high upfront costs are not offset by the capacity benefits thus resulting in a TRC ratio significantly less than 1.
AEMA: Battery storage should include additional value streams beyond demand charges.	ICF considered demand charge reduction as the sole customer savings (or revenue creation) stream in its analysis. It did so for two reasons. First, ICF anchored its analysis of commercial and industrial ("C&I") standalone battery storage in ELL's most common present rate structures and present market opportunities. As a principle, ICF did not model different rate structures for battery storage than currently exist to avoid inconsistency with modeling across other parts of ICF's potential study and with broader elements of the utility's integrated resource planning process. Regarding wholesale price arbitrage that may become available when MISO provides market access under FERC Order 841, ICF felt that any rules and valuation for that revenue stream would be too speculative to include in the potential study at this time. The second reason that ICF concentrated on the demand charge reduction use case is that it has been the most prevalent one for C&I battery storage in many markets.[48][49] Moreover, the size (power capacity) and duration of the prototype standalone C&I battery system in ICF's analysis was established to maximize economic use for batteries under the utility's C&I rate schedules with relatively high monthly peak demand charges.
AEMA: Cost-effectiveness assumptions for residential batteries should be made more transparent.	See the discussion of residential battery resources within the DER portion of ICF's Potential Study contained in Appendix I.

[48] Galen Barbose, Salma Elmallah, and Will Gorman, Behind-the-Meter Solar + Storage, Lawrence Berkeley National Laboratory (July 2021), available at https://eta-publications.lbl.gov/sites/default/files/btm_solarstorage_trends_final.pdf.

[49] National Renewable Energy Laboratory, *Identifying Potential Markets for Behind-the-Meter Battery Energy Storage: A Survey of U.S. Demand Charges,* U.S. Department of Energy (August 2017), *available at* https://www.nrel.gov/docs/fy17osti/68963.pdf.

AEMA: DR aggregation should be more fully considered for C&I and residential customers.	DR aggregation was considered and modeled by ICF. See the discussion of DR aggregation (for the C&I interruptible program) within the DR portion of ICF's Potential Study contained in Appendix I.
AEMA: DER applications should include aggregation of resources. **AEMA: Order 2222 should be considered as one of ELL's futures in MISO that could have a significant impact on the IRP.** **SEES: ELL should develop and include at least two model implementations of Distributed Energy Resource Aggregations (DERAs) in ELL territory to illustrate inclusion of resources allowed by FERC Order 2222**	Aggregation of DER resources was not included in the DER potential study. Uncertainties in how FERC Order 2222-related tariffs will be defined and implemented in the MISO territory are still significant and create challenges in estimating potential outcomes on the level and timing of system loads. While AEMA correctly notes that ELL is actively involved in the MISO process around Order 2222, the extended timetable for final MISO action on Order 2222 maintains a high degree of uncertainty.
AEMA: Additional DER technologies such as community solar and microgrids should be included.	For microgrids and community solar, there are three reasons that they were not modeled in the draft IRP analysis. First, many of the underlying technologies in both microgrids and community solar (e.g., solar PV, battery storage, demand side management) are already accounted for within the DSM and DER forecasts in ICF's Potential Study. Therefore, an independent microgrid or community solar forecast would need to exclude the customary impacts of those technologies to avoid double-counting. Second, to estimate the incremental impacts of microgrids would require detailed data on their expected hourly operation, which is not readily available. Third, microgrids and community solar are not standardized. They tend to be deployed at vastly different scales, with different underlying amounts of distributed generation. Furthermore, microgrids can be deployed with various load control technologies and with different operating rules and economic, environmental, and resilience objectives. Therefore, making annual growth assumptions about the number, scale, and impacts of microgrids and/or community solar is not likely to be accurate.
AEMA: Additional DERs should be addressed for resilience (e.g., winter Storm Uri) and net zero carbon benefits.	While the DER potential studies did not include distinct value streams for resilience and net zero carbon benefits, their methodologies rely on market acceptance curves that implicitly include various customer motivations for adopting clean energy measures. Those motivations often include energy bill savings, energy cost certainty, environmental improvement, resilience against power outages, and grid independence. The high scenarios in the DER modeling, in particular, can be thought to more highly value factors like environmental improvement and resilience because their market acceptance curves are heavily influenced by higher DER penetration markets with relatively low carbon grids and more pairings of solar and battery storage that offer resilience

Comments Regarding the Evaluation Process:

Stakeholder Comment	ELL Response
LEUG: Entergy shall identify and describe significant transmission constraints and limitations within its system and discuss any actions that could be taken to eliminate the constraints and/or limitations.	Specific transmission constraints on the ELL system, both reliability and economic, along with proposed projects to mitigate them, are described in MISO's annual MTEP report.[50]. These constraints and mitigations are analyzed through Entergy's Long-Term Transmission Planning and MISO's MTEP processes, as described in the Transmission Planning section within Chapter 3 of this Draft IRP Report. Details of the Transmission Study processes are included in Chapter 1 of the annual MTEP Report, and details of the ELL constraints and mitigation projects are included in the South Region discussion portion of the MTEP report.
LEUG: Entergy should provide some measure of rate impacts for the reference resource plan and the alternative resource planning scenarios evaluated.	Please refer to Appendix G.
LEUG: Entergy should identify and describe any Reliability Must Run units that it operates and discuss any actions that could be taken to eliminate the RMR units.	"Reliability Must Run" is a legacy term that predates ELL's participation in MISO. In MISO, out-of-market unit commitment for reliability reasons is classified based on the reasons for such commitment – e.g., Voltage and Local Reliability. ELL interprets this question and its reference to "Reliability Must Run units" (as well as the reference to this term in the IRP General Order, which order also predates ELL's participation in MISO) as addressing out-of-market unit commitment that may occur for a variety of reliability-related reasons. The Amite South, DSG and WOTAB operating guides each provide a list of generation units which may be committed for thermal and/or voltage support (which is comparable to a list of potential "RMR" units in the areas served by ELL). The constraints described in these operating guides are the primary drivers of these "RMR" commitments. RMR commitment procedures are dependent on regional characteristics which change over time. These characteristics include (without limitation) load growth, resource start up times, and resource availability. There are several transmission projects in the MISO planning processes that are expected to help mitigate the constraints listed in the Amite South and DSG Operating Procedures.

[50] *See,* www.misoenergy.org/planning/planning.

SEES: ELL's IRP should look beyond planning for capacity needs only, when executing lowest reasonable cost planning. **SEES: ELL should run manual portfolios rather than the traditional IRP model runs that seem to only add capacity when there is a capacity need. This can allow for zero-marginal-fuel resources to be added and provide benefits sooner than capacity only modeling**	ELL agrees and ELL's optimized portfolios do this by identifying the lowest cost resources that meet ELL's planning reserve margin and customers' energy needs, subject to constraints. In the event that ELL receives opportunities to add cost-effective resources that meet customers' energy needs and provide benefits to customers, it will evaluate and consider such opportunities. The Company acted accordingly in the case of the Elizabeth Solar PPA, which was approved by the LPSC in September 2022. However, ELL notes that adding resources beyond ELL's customers' needs for capacity and/or energy may expose ELL's customers to inappropriate and unnecessary market price risk. Zero-marginal-fuel-cost resources, such as solar and wind are considered and included in the optimized portfolios when appropriate; however, these resources have fixed costs that must and are also considered in the evaluation.
SEES: ELL's IRP methodology leads to a siloed approach to resource planning.	ELL follows the rules of the IRP as laid out in the Commission order. The IRP is a planning tool developed at a point in time and is used to develop solutions for ELL resource planning but is not the only consideration when planning for long-term resources.
SEES: ELL's IRP modeling appears to be siloed from planning in the MISO market. Further, ELL should take advantage of MISO's LRTP and provide analysis on what benefits these projects could bring to the region, it should model an expansion of the North / South constraint, and it should include a market congestion study that alleviates load pockets throughout ELL territory.	The ELL IRP modeling is based on a planning reserve margin target that was determined by a study that modeled the entire MISO system. For this reason, the IRP does account for the reserve margin benefits of participating in the MISO market. Please see the Transmission Planning Section in Chapter 3 for more information.
LEUG: Entergy should identify whether its IRP modeling assumptions include all transmission reliability and congestion projects that have been approved by MISO. **SREA: ELL should incorporate local, intraregional, and interregional transmission planning.** **Staff: ELL does not consider transmission options as a viable alternative to generation, as required by the IRP rules. ELL should provide transmission topology assumptions, the cost of a selection of transmission alternatives, and future MISO projects**	Transmission is not a viable alternative to generation. Transmission facilities do not possess the ability to generate electricity. Please also refer to ELL's discussion of the transmission planning process conducted in coordination with MISO in the Transmission Planning section of Chapter 3 within this Draft IRP Report. As is discussed therein, ELL must coordinate transmission planning within that process. Please see Appendix D – MISO MTEP Submissions for a description of the transmission projects approved or submitted through MISOs MTEP process. The analysis performed for the resource portfolio design included in the IRP document is based on evaluating ELL's projected capacity and energy needs. Transmission plans are only approved for the next 5 years; whereas, this long-term IRP assessment is performed for the next 20 years. Relying on a transmission system that is unchanged after five years is insufficient when performing a 20-year IRP assessment. Other analyses which are part of ongoing planning processes, such as for the siting of specific future generation resources, will take into account transmission planning, and may apply the transmission topology in the AURORA Nodal Model construct, including approved MISO MTEP projects.

Comments Regarding LPSC IRP Rules and ELL Policy:

Stakeholder Comment	ELL Response
AEMA: There should be additional opportunities for stakeholders to engage and provide data based on deployment experience.	Please see Chapter 7 of this Draft IRP Report.
SEES: The staggered nature in which ELL provides data leads to a stakeholder process that is out of sync with opportunities for comment. Specifically, if more data was presented to parties in advance of the meeting about underlying assumptions around demand side resources, load growth, capacity additions, electrification tech adoption, generation resource types, federal tax incentives and renewables assumptions, there may have been a better grounding for next steps in the IRP process.	ELL provided its Data Assumptions, per the schedule established in the LPSC's IRP General Order (Docket No. R-30021) in November of 2021. ELL held its Technical Conference in January 2022 and filed Updated Data Assumptions, in part due to feedback received at the Technical Conference, in February 2022. Due to the filing of this Updated set of Data Assumptions, and also due to the timing of the Commission's hiring its outside consultant in the matter, ELL noted its openness to delaying the date by which stakeholders were to provide comments on ELL's data assumptions. As a result, Staff subsequently extended the deadline for comments by three weeks in a Notice of Revised IRP Dates, issued on February 16, 2022.
Sierra Club: The Commission should change the IRP Process to incorporate additional stakeholder feedback (i.e., "while modeling is being conducted") and that ELL should hold two interim stakeholder meetings between now and the draft IRP filing with the understanding that the input from stakeholders will be considered throughout the modeling process leading up to the draft IRP filing.	Please see Chapter 7 of this Draft IRP Report. In addition, the Company has followed the schedule established in the LPSC's IRP General Order (Docket No. R-30021) and has provided opportunities for additional time and feedback from stakeholders as noted above.
SREA: A docket should be opened to begin reforming the Louisiana IRP process.	The Commission has already opened a rulemaking to consider a change to the IRP rules (Docket No. R-36362), in which SREA intervened on February 18, 2022.

Comments Regarding Model Inputs and Data Assumptions:

Stakeholder Comment	ELL Response
AAE: Entergy's Final Integrated Resource Plan should fully address realistic resource costs, including gas, hydrogen, renewable, and battery storage assumptions, and further encourages Entergy to use NREL Annual Technology Baseline as a transparent and up to date reference material for these cost assumptions. **AAE: AAE noted that it is concerned that ELL's data assumptions lack clarity as to the derivation and costs of hydrogen.** **Sierra Club: ELL should include costs for converting existing units to hydrogen, necessary infrastructure and all variable costs associated with hydrogen including the fuel itself.**	Within the context of the IRP and for the purposes of long-term resource planning, ELL finds that the costs assumed for "Gas and Hydrogen" and "Renewables and Energy Storage" resources are both realistic and comparable to multiple industry resources, including NREL ATB. Gas and Hydrogen costs are derived from an engineering consultant with extensive industry experience, including development of natural gas with hydrogen capability plants. When comparing the total installed costs estimated by NREL ATB with ELL's assumption for solar, wind, and battery resources, the costs adopted by ELL is lower than or comparable to costs assumed by NREL ATB across all resources. Additionally, within the purpose of the IRP, it is not relevant to evaluate costs for converting existing natural gas units to enable hydrogen firing capabilities, rather it is appropriate to estimate the costs to incorporate hydrogen optionality into new, future units. ELL's estimated costs for "Gas + Hydrogen" resources include costs to incorporated hydrogen-capability in natural gas units, but not costs required to burn hydrogen.
AAE: ELL's assumptions for natural gas costs are not aligned with the reality of international gas markets, especially as Louisiana LNG terminals continue to gain customers.	Natural gas price forecasts are based on the consensus of independent, third-party consultant forecasts that take into account fundamental factors such as those described, along with others that may affect the supply and demand for natural gas. In addition to using multiple consultant forecasts, a range of natural gas price forecasts are used in the evaluation to provide information on the sensitivity of results relative to natural gas price assumptions. Future gas price forecasts are expected to reflect higher near-term prices consistent with current market conditions, while long-term prices will remain a function of the fundamentals included in the consultant forecasts.
LEUG: Entergy asked to address in the IRP the effect on its future resource planning from known significant generation additions being pursued by third parties within or near its service region, including Magnolia Power CCGT and several solar projects included in the approved future power supply for 1803 and reserves the right to further address Entergy's resource planning including consideration of Entergy analysis of such generation additions to the region.	Capacity Expansion in ELL's IRP seeks to identify the resource plans and strategies that are available to and controllable by ELL to serve ELL's customers in a way that balances affordability, reliability, risk, and environmental stewardship. Within the context of the IRP, it is not appropriate to consider specific incremental resources that are owned and controlled by others as potential additions to ELL's portfolio. However, all MISO market resources are appropriately considered in the context of their participation in the MISO energy and capacity markets and their effect on ELL's long-term resource planning.

LEUG: LEUG asserts that Entergy assumes acquisition of a second BOT of 600 MW to be in service in 2025. **LEUG further approximates the cost of BOTs on an installed $/kW basis and asserts that solar resources will cost more than new CCGTs on a $/kW basis.**	The resource additions identified on slide #10 of ELL's Updated Data Assumptions presentation were intended to reflect: 1) approved resource additions (Carville Renewal), 2) resources that ELL was seeking certification for at the time of the Updated Data Assumptions filing (ELL Power Through, Sunlight Road PPA, Vacherie PPA, and St. Jacques Solar BOT), 3) resources sought in ELL's 2021 Solar RFP, and 4) the 2027 ELL CT. However, following the technical conference ELL furthered negotiations on selections out of the 2021 Solar RFP and announced the ELL 2022 RFP, as a result ELL has elected to include the resources in negotiations from the 2021 Solar RFP as well as the 1,500MWs sought in the 2022 Renewable RFP. As a placeholder and until further information is known, all 1,500MWs are assumed to be solar resources and the ownership is assumed to be 50% PPA resources and 50% BOT resource. Additionally, regarding the 2027 ELL CT, that resource has been removed as a "planned resource" and ELL has elected to allow for its IRP process to solve for capacity that might be needed within the time frame that the CT was originally assumed to provide that capacity. The decision to remove this resource as a "planned resource" was made, in part, due to the recognition that the Magnolia CCGT would be located within ELL's SELPA and would provide some of the benefits to the SELPA transmission system that the 2027 ELL CT had intended to provide. Lastly, the comments here in compare an assumed cost of solar resources to the historical cost of CCGTs. While that cost comparison may provide an interesting data point, it only compares the fixed costs of the resources and ignores the variable cost, capacity value, energy value, and potential effect on load payments. Only though the evaluation of each of these factors and their effect on ELL's total relevant supply cost can the lowest cost resource be determined.

SEES: ELL's IRP should use up-to-date inputs from NREL's Annual Technology Baseline (ATB), appropriate to the resource zone where ELL is located. **SEES: NREL data should be used to inform the IRP, as it contains "up-to-date capital cost assumptions"** **Sierra Club: ELL should use NREL 2021 ATB data when modeling on-shore wind and that it should model higher quality wind, relative to wind in MISO South, like a PPA for wind in SPP.** **SREA: ELL use the National Renewable Energy Lab Annual Technology Baseline data for solar, solar+storage/hybrid, onshore and offshore wind, and battery resources.** **- Use multiple configurations of these technologies, including self-build options and PPA options** **- When modeling PPA options, use the NREL ATB LCOE values as $/MWh inputs**	The point in time from which data inputs are sourced by ELL for the IRP is dependent on the timing requirements set forth by the Commission for the IRP process to finalize data assumptions, which may differ from ELL's annual Business Plan process and release of new data by industry sources, including NREL ATB. When comparing the total installed costs estimated by NREL ATB on a nominal basis with ELL's assumption for solar, wind, and battery resources on a nominal basis, the costs adopted by ELL are lower or comparable across all resources than those assumed by NREL ATB. ELLs IRP seeks to identify the resource plans and strategies to serve ELL's customers in a way that balances affordability, reliability, risk, and environmental stewardship. Within the context of the IRP, it is not appropriate to evaluate alternative resource structures, such as PPAs. Instead, resource structure is appropriately determined through the procurement process, which is based on fair and consistent comparison of alternative proposals and proposal structures.
Sierra Club: ELL over estimates the cost of renewables and should evaluate model PPAs, as opposed to self-builds only, in its IRP. PPAs are lower cost due to ITC treatment and other reasons. Achieving the lowest reasonable cost is only possible when PPAs are considered.	ELLs IRP seeks to identify the resource plans and strategies to serve ELL's customers in a way that balances affordability, reliability, risk, and environmental stewardship. Within the context of the IRP, it is not appropriate to evaluate alternative resource structures, such as PPAs. Instead, resource structure is appropriately determined through the procurement process, which is based on fair and consistent comparison of alternative proposals and proposal structures.
SREA: ELL should manually build the MISO market using the MISO MTEP Futures 1, 2 and 3, and/or use MISO's own LMP data.	ELLs IRP considers a range of possible future scenarios that are intended to identify and evaluate a range of portfolios and portfolio strategies to meet ELLs customers' needs across a range of possible future outcomes. There is no basis to believe that MISO Transmission Expansion Plan Futures or any other possible future scenario would provide better information than the future scenarios used for ELLs IRP.
SREA: ELL should improve capacity value accreditation methodologies for all resources.	ELL aligns capacity accreditation methodology with MISO. Solar portfolio capacity accreditations aligns with MISO MTEP21 Methodology. ELL is closely monitoring MISO's non-thermal accreditation reform proposal for implementation in future planning efforts.

SREA: ELL should improve natural gas accreditation, fuels costs, and hydrogen assumptions	ELL develops natural gas price forecasts based on the consensus of independent, third-party consultant forecasts that consider fundamental factors that may affect the supply and demand for natural gas. In addition to using multiple consultant forecasts, a range of natural gas price forecasts are used in the evaluation to provide information on the sensitivity of results relative to natural gas price assumptions. Coal price forecasts are developed based on a weighted average price of coal commodity and coal transportation commitments under contract, as well as third-party consultant forecasts of Powder River Basin coal prices for any open coal commodity position. In addition, railcar expenses and appropriate plant specific coal handling cost adders are included. Hydrogen capability is included for all new, large-scale generators that can utilize hydrogen for fuel. It is currently premature and unnecessary to forecast hydrogen fuel prices and model burning hydrogen to generate energy.
SREA: ELL should appropriately evaluate transmission interconnection costs for all generation resources. **Staff: For solar resources, ELL arbitrarily includes a $100/kW transmission adder for solar; this should be supported by data or removed.** **LEUG: Entergy asked to perform a sensitivity study or run analysis with reasonable ranges of potential transmission costs associated with its data assumptions for solar and wind resources.**	ELL includes interconnection costs for all generation technologies included in the IRP. For solar resources, ELL uses reasonable assumptions based on feedback from consultants and data and inputs to the Company's technology assessment as well as information from its Transmission organization. Specifically, the $100/kW interconnection cost for solar assumes a switch yard, a small generator step-up transformer located next to the point of interconnection, and a tie-line to facilitate a 115kV, 138kV, or 230kV interconnection.
Staff: Staff requests ELL clarify its response regarding the use of solar PPAs as a "starting point" for costs in the IRP	ELLs IRP seeks to identify the long-term resource plans and strategies to serve ELL's customers in a way that balances affordability, reliability, risk, and environmental stewardship. Within the context of the IRP, it is not appropriate to evaluate alternative resource structures, such as PPAs. Instead, resource structure is appropriately determined through the procurement process, which is based on fair and consistent comparison of alternative proposals and proposal structures.
Staff: ELL should include, in its Draft IRP, support for the assumption of why environmental allowances declined in 2024 and remained flat throughout the rest of the outlook.	NOx emission allowances are limited based on the revised CSAPR update rule that was issued by the EPA in March of 2021 and a new regulatory proposal to revise CSAPR issued by the EPA on April 6, 2022. These changes are described in the Draft IRP section on CSAPR.

Staff: ELL should provide an example of how capacity value forecasts are used in IRPs	ELL's long-term capacity value is used to estimate the cost or benefit associated with normalizing the amount of capacity represented in each portfolio optimized for ELL. Differences in portfolio capacity can arise due to the discrete size of the resources selected by Aurora's capacity expansion algorithm to meet the required reserve margin. Cross testing the optimized portfolios in the alternative Futures results in surplus or deficit capacity positions relative to the required reserve margin because the peak load forecasts are designed to vary across the Futures. Capacity value is used to normalize the surplus or deficit capacity positions relative to the required reserve margin when the Total Relevant Supply Cost is determined to mitigate the effect of the surplus or deficit capacity positions and allow comparison of the portfolios on a consistent basis.
Staff: ELL needs to provide capacity factor assumptions for gas units	As a result of this comment the capacity factor assumptions for gas units were included in the "Updated Data Assumptions" file provided February 11th, 2022. Please note the capacity factor assumptions for non-renewable resources are not inputs into Aurora, but rather used to calculate indicative LCOE and, instead, are an output of the AURORA modeling.

Comments Regarding Portfolio Alternatives:

Stakeholder Comment	ELL Response
LEUG: ETR resource planning should utilize Industrial customer programs that could offset some of the need for Entergy to construct new generation and thus avoid costs for all ratepayers. LEUG: LEUG: Entergy should include 1) Industrial customer market access options, 2) enhanced CHP opportunities, and 3) PPAs by industrial customers with third-party renewable developers, as viable resource planning resource alternatives.	Some of LEUG's requests go beyond the scope of this IRP process and in fact run contrary to a primary purpose of this process, maintaining a reliable electric system for Louisiana customers. The Commission is presently examining (or re-examining) some of the issues and ideas LEUG raises in several concurrent dockets, where ELL has provided extensive data and commentary. As discussed herein, the MISO capacity market is not designed to provide compensation for the full cost of generation resources. Rather, MISO relies on utilities within its market to provide the resources needed to ensure reliability through long-term resource planning under the regulation of state commissions. Therefore, allowing a select set of customers access to the pricing of the MISO market, rather than paying full retail rates, would allow those customers to avoid the full cost of the generation needed to reliably serve all Louisiana customers. The customers not offered that option would then be forced to pay for the total cost of generation or, alternatively, the utility would refuse to continue building generation needed for reliability and for which its customers would receive an undue share of the costs. The result of the latter option is a lack of local generation needed to serve customers. This IRP process is intended to achieve the opposite result. That being said, the Company is willing to explore tariff options that provide access to renewable resources and do not result in the cost shifting noted above.

SEES: ELL should include PPA pricing data for the MISO market to establish a 'Market Resource' type for inclusion under the types of generation resources being considered for analysis in the IRP.	Excess capacity available through MISO is not guaranteed from year to year much less in the long-term and exists, partially, as a function of proactive planning actions of regulated utilities such as ELL. Accordingly, excess market capacity is not considered to be a viable option for meeting long-term planning objectives such as the reserve margin. Resource alternative inputs to the model are developed from a financial perspective assuming utility ownership. However, the type and timing of capacity is what the model is solving for, not the optimal ratio of PPA/ownership. The portfolios are indicative of what types of resources would be preferred under certain conditions. The decision to procure said resources would occur through competitive solicitations consistent with the Market Based Mechanisms Order ("MBMO") and may include self-build alternatives as well as PPAs.

Comments Regarding Scenarios, Sensitivities, and Risk:

Stakeholder Comment	ELL Response
AAE: Entergy to create at least one scenario or manual portfolio to guide the swift retirement of expensive and emitting resources in order to reach state and its own corporate climate goals.	Each optimized resource portfolio modeled in connection with the Draft IRP Report maintains consistency with the referenced goals. While assessing early deactivation of resources is not within the scope of the Commission's current IRP rules (deactivations are considered in individually docketed proceedings, such as Docket No. X-35643, which assessed the economics of early deactivation for certain legacy units), it should be noted that each Future assumes deactivation of all coal units by 2030.
SEES: ELL's IRP should Include indicative LRTP transmission lines in in ELL territory, in the IRP as a sensitivity, using the resulting Adjusted Production Cost (APC) as the cost data for existing generation versus capital cost for new generation with the LRTP lines included.	The approved MISO LRTP transmission projects do not benefit MISO-S and ELL is located in MISO-S. MISO's LRTP and APC planning processes are designed to identify transmission expansion projects and would not be appropriate for use in developing ELL's IRP that seeks to identify the resource plans and strategies to serve ELL's customers.
SEES: As a scenario, ELL's IRP should include MISO MTEP Future 3 for the purposes of helping to align with Entergy's Net Zero by 2050 corporate goal. The modeling of the MISO market through the MTEP Futures is the closest modeling to net zero by 2050 that has been produced so far for the region, and ELL should use it.	ELL's IRP considers a range of possible future scenarios that are intended to identify and evaluate a range of portfolios and portfolio strategies to meet ELL's customers' needs across a range of possible future outcomes. There is no basis to believe that MISO Transmission Expansion Plan Future 3 or any other possible future scenario would provide better information than the future scenarios used for ELL's IRP.

SREA: ELL should create several "manual portfolios" for ELL to respond to the MISO MTEP Futures - Manual portfolios should add more renewable energy sooner, rather than later - At least one manual portfolio should achieve Entergy's net zero carbon emission goal	ELL did not see a need for manual portfolios for the IRP. Further ELL notes, Future 2, described in detail in Chapter 5, only allows for non-emitting resources to be selected through capacity expansion. The first resource selected in this portfolio is in 2025. In addition, all three portfolios are consistent with and make progress towards Entergy Corporation's announced sustainability and emissions reductions goals.

Other Comments:

Stakeholder Comment	ELL Response
AAE: Entergy's Final Integrated Resource Plan should fully address Alignment with other Entergy planning efforts, including transmission, distribution, resilience/reliability, retirements, and any others that the company undertakes outside the Integrated Resource Planning process.	Please see the discussion of the coordination between these functions throughout this Draft IRP Report.
AAE: AAE would like to see, fully addressed in Entergy's Final Integrated Resource Plan, IRP alignment with climate/greenhouse gas goals, including Entergy Corporation's own carbon emissions goals and the goals outlined by the Climate Initiatives Task Force SEES: ELL's IRP is not coordinated with announced corporate sustainability goals by Entergy Corporation and is "run in a way that limits its ability to align" with these goals.	Please see the above responses and the discussion in Chapter 5 in this Draft IRP Report. The work conducted through this process (including the results of all three portfolios) align with the Company's stated goals.
Business Network for Offshore Wind provided a variety of comments supporting the continued development of offshore wind. Notably, they stated that offshore wind provides utility-scale renewable and cost-competitive energy that can help a state achieve its net-zero emission goals while growing the economy and creating jobs	Please see ELL's discussion of offshore wind in the Technology Evaluation and Selection section of this IRP and also the discussing of partnerships ELL is currently pursuing related to offshore wind.

LEUG: IRP modeling should not be used as a basis to circumvent analysis of resources available in the market.	The LPSC Corrected General Order for Docket No. R-30021: In Re: Development and Implementation of Rule for Integrated Resource Planning for Electric Utilities ("IRP Docket") states beginning on page 2, "The goal of the IRP is to develop a defined resource plan, and the Action Plan is intended to specify implementing actions that the utility should take, however Staff recognizes that these rules are not intended to replace or modify the normal docketed resource certification process, and a statement to this effect is included in the Action Plan section." ELL utilizes a separate docketed resource certification process, in accordance with the requirements of the MBM Order, for certification of the resources identified in the Action Plan that ELL chose to pursue.
LEUG: The IRP process is not a substitute for LPSC certification process and procedure and that it reserves all rights to conduct discovery and fully evaluate Entergy data assumptions and resource plans in individual resource certification proceedings and/or any other future proceedings that address Entergy resources and plans and whether such plans are prudent and in the public interest.	ELL has not proposed that the IRP be utilized as a substitute for the current Commission certification requirements outlined in the 1983 General Order or the Market Based Mechanisms Order.
LEUG: LEUG notes that it reserves the right to further address Entergy's resource planning based on the outcome of the LPSC rulemaking on minimum physical capacity thresholds, docket R-36263.	ELL's IRP and the planning conducted herein is based on rules currently in effect at the time the analyzes underpinning the IRP are performed. To the extent the Commission adopts new rules during the pendency, or following the completion, of ELL's IRP, it would be inappropriate to assess ELL's IRP Report under rules that did not exist when this process commenced.
SEES: The degree to which ELL was unable to answer questions from stakeholders raises concerns about the IRP process.	ELL conducted a stakeholder meeting that lasted over eight hours and answered a multitude of questions from stakeholders during this time as well as in writing following the meeting.
SEES: ELL's stakeholder meeting seemed to drag through some sections, and be rushed toward the end.	ELL will endeavor to be more mindful as to the flow of future stakeholder meetings.
Sierra Club: ELL should analyze the public health impacts within its IRP, especially in environmental justice communities. ELL can use the EPA's EJSCREEN tool to evaluate "a particular power plant."	The EPA's EJSCREEN tool is utilized to evaluate specific resources with known locations. The IRP does not consider or attempt to identify specific locations for the resource types included in the optimized portfolios.

Sierra Club: ELL should issue an all-source RFP or RFI for the purpose of gathering up-do-date market intelligence to inform the costs of new resources (i.e., the bids could "inform Entergy's modeling in the 2023 IRP") and "allow for effective competition" in its IRP.	A key objective of adequate and prudent resource planning for any utility is long term resource planning. ELL actively monitors and assess the needs of its system, age and type of resources, and balances this against reliability, affordability, and environmental stewardship. Every 4 years, as ordered by the LPSC, ELL produces a voluminous IRP describing this process, provide analytics for resources available to meet load needs and associated costs. These processes, which rely on multiple industry sources for technology costs, inform the technologies that best match the load need from a locational, economic, and technology perspective. As resources are needed and proposed for deployment, ELL issues an RFP to solicit market-based proposals for the type of resources that meet its supply need(s). ELL does not rely on all-source RFPs to replace prudent utility planning and decision making and instead solicits resources that are adequately suited to meet the needs of its customers.
Staff: Staff noted that it asked ELL if it had performed or provided analysis of the economics of historical and continued operations of each of its plants, and whether the going forward analysis accounted for the cost to comply with future environmental regulations. Further, Staff recommended that ELL should provide this information in its Draft IRP.	ELL does perform analysis of the economics of the continued operations of its plants including any necessary environmental compliance investments; however, these analyses are not performed within the context of the IRP (deactivations are considered in individually docketed proceedings, such as Docket No. X-35643, which assessed the economics of early deactivation for certain legacy units). As planned deactivation dates near, a significant equipment failure occurs, or operating performance diminishes, a reassessment of deactivation assumptions may be required. Unit-specific portfolio decisions, e.g., sustainability investments, environmental compliance investments, or unit deactivations, will be made at the appropriate time and will be based on economic and technical evaluations considering such factors as projected forward costs, anticipated operating roles, the reliability of the system, and the cost of supply alternatives.
Staff: ELL should provide, in its Draft IRP, a historical representation of its load served so that it might be compared to its load forecast.	Please see Appendix H.
Staff: ELL should provide, in its Draft IRP, its historical cumulative average percentage growth rate ("CAGR") for the past 10 years.	Please see Appendix H.

Appendix B – ELL Portfolio of Owned Resources

Table 21: ELL Portfolio of Owned Resources

Plant	Unit	ELL Ownership Share of GVTC [MW]	Fuel	Location	Operation Date
Acadia	2	526	Natural Gas	Acadia, LA	2002
ANO	1	22	Nuclear	Pope, AR	1974
ANO	2	26	Nuclear	Pope, AR	1980
Big Cajun 2	3	135	Coal	Pointe Coupee, LA	1983
Calcasieu	1	142	Natural Gas	Calcasieu, LA	2000
Calcasieu	2	159	Natural Gas	Calcasieu, LA	2001
Grand Gulf	-	203	Nuclear	Claiborne, MS	1985
Independence	1	7	Coal	Independence, AR	1983
J. Wayne Leonard Power Station	-	912	Natural Gas	Montz, LA	2019
Lake Charles Power Station	-	913	Natural Gas	Westlake, LA	2020
Little Gypsy	2	405	Natural Gas	Saint Charles, LA	1970
Little Gypsy	3	504	Natural Gas	Saint Charles, LA	1971
Ninemile	4	724	Natural Gas	Jefferson, LA	1971
Ninemile	5	728	Natural Gas	Jefferson, LA	1973
Ninemile	6	438	Natural Gas	Jefferson, LA	2014
Ouachita	3	241	Natural Gas	Ouachita, LA	2002
Perryville	1	355	Natural Gas	Ouachita, LA	2002
Perryville	2	101	Natural Gas	Ouachita, LA	2001
Riverbend 30	-	191	Nuclear	West Feliciana, LA	1986
Riverbend 70	-	389	Nuclear	West Feliciana, LA	1986
Roy Nelson	6	211	Coal	Calcasieu, LA	1982
Union PB	3	505	Natural Gas	Union, AR	2003
Union PB	4	505	Natural Gas	Union, AR	2003
Waterford	2	415	Natural Gas	Saint Charles, LA	1975
Waterford	3	1,155	Nuclear	Saint Charles, LA	1975
Waterford	4	32	Natural Gas	Saint Charles, LA	2009
White Bluff	1	13	Coal	Jefferson, AR	1980
White Bluff	2	12	Coal	Jefferson, AR	1981
Washington Parish Energy Center	-	370	Natural Gas	Bogalusa, LA	2020
LMR (Load Modifying Resource)	-	301	N/A	-	-
Total	-	10,640			

Notes:

- Estimates above are 2021 reductions.
- Demand Response includes Residential Direct Load Control and Agricultural Irrigation Load Control (“AILC”) programs.
- Demand Response and Interruptible capacity is grossed up to account for reserve margin and line loss value in the Load & Capability analysis.

Appendix C – Existing Resource Discussion

Acadia 2:

Acadia 2 is a 2X1 combined cycle gas turbine natural gas-fired facility located near Eunice, LA. The facility entered commercial operation in 2002 and was acquired by ELL in 2011. It is one of two CCGTs located onsite, with the other facility (Acadia 1) being owned by Cleco Power. ELL also owns 50% of the Common Facilities on site. Cleco Power operates and maintains Acadia 2. The facility is currently in good overall condition, having been maintained over time in accordance with Good Utility Practice. The facility is expected to experience good reliability and availability for the foreseeable future.
Major Maintenance activities undertaken at the facility in recent years include:

[redacted]

Big Cajun 2, Unit 3:

Big Cajun II Unit 3 is a 588 MW coal unit, located on the Big Cajun II facility, in New Roads, Louisiana. The facility entered commercial operation in April of 1983. NRG transferred ownership of the facility to Cleco in February of 2019. There are 3 units located on the Big Cajun II facility, 2 coal and 1 natural gas; Entergy Louisiana owns a non-controlling interest of 24.15% of Unit 3 and is responsible for associated costs. Entergy Louisiana is also responsible for 8.05% of the common facility costs.

Calcasieu 1:

Calcasieu 1 is a simple-cycle gas-fired generating unit located near the city of Sulphur, LA. The unit entered commercial operation in 2000 and was acquired by ELL in 2008. The unit is currently in good overall condition, having been maintained over time in accordance with Good Utility Practice. The unit should continue to experience good reliability and availability for the foreseeable future.

Major Maintenance activities undertaken at the facility in recent years include:

[redacted]

Calcasieu 2:

Calcasieu 2 is a simple-cycle gas-fired generating unit located near the city of Sulphur, LA. The unit entered commercial operation in 2001 and was acquired by ELL in 2008. The unit is currently in good overall condition, having been maintained over time in accordance with Good Utility Practice. The unit should continue to experience good reliability and availability for the foreseeable future.

Major Maintenance activities undertaken at the facility in recent years include:

[redacted]

J. Wayne Leonard Power Station:

The J. Wayne Leonard Power Station is a 2X1 combined cycle gas turbine facility located near Montz, LA. The facility entered commercial operation in 2019 and is in very good overall condition, having been maintained over its brief life in accordance with good utility practices.

Major Maintenance activities undertaken at the facility in recent years include:

[redacted]

Lake Charles Power Station:

The Lake Charles Power Station is a 2X1 combined cycle gas turbine facility located near Westlake, LA. The facility entered commercial operation in 2020 and is in very good overall condition, having been maintained over its brief life in accordance with good utility practices.

Major Maintenance activities undertaken at the facility in recent years include:

[redacted]

Little Gypsy 2:

Little Gypsy 2 is a steam turbine generating unit located near Montz, LA. The unit entered commercial operation in 1966. The unit is in fair condition, having been maintained over its long life in accordance with Good Utility Practice. At 54 years of age, it is reasonable to expect the unit would encounter growing maintenance requirements.

[redacted]

[redacted]

Little Gypsy 3:

Little Gypsy 3 is a steam turbine generating unit located near Montz, LA. The unit entered commercial operation in 1969. The unit is in generally good condition, having been maintained over time in accordance with Good Utility Practice. At 50 years of age, it is reasonable to expect the unit would encounter growing maintenance requirements.

Major Maintenance activities undertaken at the facility in recent years include:

[redacted]

Ninemile 4:

Ninemile 4 is a steam turbine generating unit located near Westwego, LA. The unit entered commercial operation in 1971. The unit is in good overall condition, having been maintained over time in accordance with Good Utility Practice. The unit has been the focus of a significant maintenance/repair program in recent years.

Major Maintenance activities undertaken at the facility in recent years include:

[redacted]

[redacted]

Ninemile 5:

Ninemile 5 is a steam turbine generating unit located near Westwego, LA. The unit entered commercial operation in 1973. The unit is in good overall condition, having been maintained over time in accordance with Good Utility Practice. The unit has been the focus of a significant maintenance / repair program in recent years.

Major Maintenance activities undertaken at the facility in recent years include:

[redacted]

Ninemile 6:

Ninemile 6 is a 2X1 combined cycle gas turbine dual fueled (natural gas and liquid fuel) facility located near Westwego, LA. The facility entered commercial operation in 2014 and is in very good overall condition, having been maintained over its brief life in accordance with good utility practices.

[redacted]

[redacted]

Nelson 6:

Nelson 6 is a coal fired generating unit located near Westlake, LA. The unit entered commercial operation in 1982. The unit is jointly owned by four co-owners. The unit is currently in good overall condition, having been maintained over time in accordance with Good Utility Practice.

Major Maintenance activities undertaken at the facility in recent years include:

[redacted]

Ouachita 3:

Ouachita 3 is one of three 1X1 combined cycle gas turbine natural gas-fired facilities located on a site near Sterlington, LA. The facility entered commercial operation in 2002 and was acquired by Entergy in 2008. The facility is currently in good overall condition, having been maintained over time in accordance with Good Utility Practice.

Major Maintenance activities undertaken at the facility in recent years include:

[redacted]

Perryville 1:

Perryville 1 is a 2X1 combined cycle gas turbine natural gas-fired facility located near Sterlington, LA. The facility entered commercial operation in 2002 and was acquired by ELL in 2005. The facility is currently in good overall condition, having been maintained over time in accordance with Good Utility Practice.

Major Maintenance activities undertaken at the facility in recent years include:

[redacted]

Perryville 2:

Perryville 2 is a simple-cycle gas-fired generating unit located near Sterlington, LA. The unit entered commercial operation in 2001 and was acquired by ELL in 2005. The unit is currently in good overall condition, having been maintained over time in accordance with Good Utility Practice.

Major Maintenance activities undertaken at the facility in recent years include:

[redacted]

Perryville BESS:

The Perryville Battery Energy Storage Station is a 7.4 MW / 7.4 MWh energy storage station near Sterlington, LA. This BESS is paired with Perryville 2 as the regional blackstart resource for ELL. When commissioned it was the first GE 7FA.03 BESS blackstart resource in the industry.

River Bend:

River Bend Station is a nuclear facility, located in St. Francisville, LA. The station sits on 3,300 acres in West Feliciana Parish, approximately 30 miles from Baton Rouge. Since June 1986, River Bend has safely and efficiently provided clean, reliable and sustainable nuclear energy. In 2018, the U.S. Nuclear Regulatory Commission granted a federal 20-year license renewal, enabling the plant to continue operating through 2045.

River Bend has one boiling water reactor with about 800 employees providing nearly 1,000 megawatts of capacity towards meeting ELL's planning reserve margin requirement, which is approximately 10 percent of ELL's needs. [redacted]

Major Maintenance activities undertaken at the facility in recent years include:

[redacted]

Sterlington 7A:

Sterlington 7A was deactivated in 2022.

Union 3:

Union 3 is one of four 2X1 natural gas-fired combined cycle gas turbines located on a plant site near El Dorado, AR. The facility entered commercial operation in 2003 and was acquired by ELL in 2016. The facility is currently in good overall condition, having been maintained over time in accordance with Good Utility Practice.

Major Maintenance activities undertaken at the facility in recent years include:

[redacted]

[redacted]

Union 4:

Union 4 is one of four 2X1 natural gas-fired combined cycle gas turbines located on a plant site near El Dorado, AR. The facility entered commercial operation in 2003 and was acquired by ELL in 2016. The facility is currently in good overall condition, having been maintained over time in accordance with Good Utility Practice.

Major Maintenance activities undertaken at the facility in recent years include:

[redacted]

Washington Parish Energy Center 1:

Washington Parish Energy Center 1 is one of two simple-cycle gas fired generating units located in Bogalusa, LA. The unit entered commercial operation in 2020 and is in very good overall condition, having been maintained over its brief life in accordance with good utility practices.

Major Maintenance activities undertaken at the facility in recent years include:

[redacted]

Washington Parish Energy Center 2:

Washington Parish Energy Center 2 is one of two simple-cycle gas fired generating units located in Bogalusa, LA. The unit entered commercial operation in 2020 and is in very good overall condition, having been maintained over its brief life in accordance with good utility practices.

Major Maintenance activities undertaken at the facility in recent years include:

- Silencer Replacement. Completed 2021

Waterford 1:

Waterford was deactivated in 2021.

Waterford 2:

Waterford 2 is a steam turbine generating unit located near Killona, LA. The unit entered commercial operation in 1975. The unit is in generally good condition, having been maintained over time in accordance with Good Utility Practice. The unit has been the focus of certain notable repairs in recent years, as detailed below. At 47 years of age, it is reasonable to expect the unit would encounter growing maintenance requirements.

Major Maintenance activities undertaken at the facility in recent years include:

[redacted]

Waterford 3:

Waterford 3 is a nuclear facility, located on the west bank of the Mississippi River in St. Charles Parish, near the town of Taft, LA, located approximately 25 miles east-southeast from New Orleans. It consists of over 3,000 acres of flat land extending from the Mississippi River to the St. Charles Drainage Canal. The Waterford 3 Facility Operating License was issued on March 16, 1985, and has since safely and efficiently provided clean, reliable, and sustainable carbon free nuclear energy.

Waterford 3 is a pressurized water reactor designed by Combustion Engineering Incorporated with approximately 700 employees. The station generates approximately 1,200 megawatts of capacity towards meeting ELL's planning reserve margin requirement, which is approximately 11.8% of ELL's needs. [redacted]

Major maintenance activities undertaken at the unit in 2022 to improve unit reliability include:

[redacted]

Waterford 4:

Waterford 4 is a simple-cycle, diesel-fired generating unit located near Killona, LA. The unit was originally commissioned in the northeastern United States in the early 1990s. It was later acquired by ELL and relocated to Louisiana in 2009. The unit entered commercial operation for ELL in 2009, following an extensive refurbishment. In addition to its role as a quick start peaking resource, the unit currently serves as a regional blackstart resource for ELL.

The unit is currently in good overall condition, having been maintained over time in accordance with Good Utility Practice.

Major Maintenance activities undertaken at the facility in recent years include:

[redacted]

Appendix D - MISO MTEP Submissions

Table 22: ELL Projects Approved in Appendix A of MTEP16

Project Driver	Project Name	Current Projected ISD
Load Growth	Thompson Road 230 kV: Construct New Substation	5/1/2023
Load Growth	Big Lake 230 kV: Construct New Substation	5/30/2023
Baseline Reliability	East Broad to Ford 69 kV line: Reconductor line	6/30/2023
Load Growth	Lake Providence 115 kV: New station	6/1/2024

Table 23: ELL Projects Approved in Appendix A of MTEP17

Project Driver	Project Name	Current Projected ISD
Baseline Reliability	Avenue C to Paris Tap 115 kV: Reconductor Line	12/30/2022
Other Reliability	Pecue 230 kV: Install transmission breakers	12/31/2022
Baseline Reliability	Jennings to Lawtag 69 kV L-13/L-19 and L-14 Reconductor	2/28/2023
Baseline Reliability	Five Points to Line 281 Tap to Line 247 Tap - Upgrade 69 kV line	3/30/2023
Baseline Reliability	Mud Lake to Big Lake 230 kV: New Line	5/30/2023
Baseline Reliability	Gypsy to Claytonia 115 kV: Reconductor Line	6/1/2024
Asset Management	Culicchia 230 kV: New Substation	12/1/2025

Table 24: ELL Projects Approved as Appendix A of MTEP18

Project Driver	Project Name	Current Projected ISD
Baseline Reliability	Mossville to Lockmoor 69 kV: Rebuild/Reconductor Line	12/31/2022
Load Growth	Goosport 138 kV: Convert Sub from 69 kV	6/1/2026

Table 25: ELL Projects Approved as Appendix A of MTEP19

Project Driver	Project Name	Current Projected ISD
Baseline Reliability	Sellers Leblanc Project (SLP): New Conrad to Sellers Road 138kV line	12/1/2022
Generation Interconnection	Galion 115 kV: Install Transmission Line Bay and Breakers (J544 Interconnection)	12/15/2022
Baseline Reliability	Jefferson Parish Area Reliability Plan Phase 2: Munster 230 kV	6/1/2023
Other Reliability	Ninemile S2015: Close Normally Open Breaker	6/1/2023
Baseline Reliability	Coly to DEMCO Coly 69 kV Upgrades	12/31/2023
Other Reliability	Ponchatoula 230 kV: Add Breakers and Transfer Bus	12/31/2024

Table 26: ELL Projects Approved as Appendix A of MTEP20

Project Driver	Project Name	Current Projected ISD
Baseline Reliability	Nelson 138 kV Substation: Install Breakers	12/31/2022
Generator Interconnection	J697/J1436 Interconnection: Expand Oak Ridge 115 kV Substation	7/1/2023
Generator Interconnection	J909 Interconnection: Amite 115kV Substation	10/15/2023
Generator Interconnection	J639 Interconnection: Construct Bueche 230kV Substation	12/31/2023

Table 27: ELL Projects Approved as Appendix A of MTEP21

Project Driver	Project Name	Current Projected ISD
Baseline Reliability	Frisco to Tezcuco 230 kV: Upgrade Circuit 1 and 2	12/30/2022
Baseline Reliability	Lake Arthur 69 kV Switch Upgrade	12/31/2022
Asset Management	2022 ELL Asset Renewal Program	12/31/2022
Baseline Reliability	Nelson 230 kV SPOF	12/1/2023
Generator Interconnection	J1158 Generator Interconnection at Vacherie 230 kV	7/1/2024
Baseline Reliability	Nelson 138 kV SPOF	1/1/2026
Load Growth	Northline 230 kV: New Substation	6/1/2026

Table 28: ELL Projects Submitted as Target Appendix A in MTEP22

Project Driver	Project Name	Current Projected ISD
Generator Interconnection	J1368/J1372 Interconnection: Ventress 230 kV Station	4/21/2023
Baseline Reliability	Drusilla to Jefferson 69 kV: Upgrade Switches	6/1/2023
Asset Management	Hartburg to Rhodes 500 kV River Crossing Tower Replacement	8/31/2023
Asset Management	2023 ELL Asset Renewal Program	12/31/2023
Network Upgrade	MPFCA J1281, J1294, J1458 Adams Creek 230 kV and Bogalusa 500-230 kV Upgrades	4/4/2024
Baseline Reliability	Dowmeter to Tiger 230 kV Re-termination	6/1/2024
Generator Interconnection	J1246 Bayou Labutte 500 kV Interconnection	6/1/2024
Network Upgrade	Point Pleasant 230 kV Breaker upgrades (tied to J1246)	4/9/2025
Generator Interconnection	J1219/J1257 Hickory 115 kV	9/24/2024
Generator Interconnection	Rilla 115 kV: Expand Station (J1239)	10/15/2024
Other Reliability	Kaiser 230-115 kV Autotransformer	12/1/2024
Baseline Reliability	Richard 500-138 kV AT1 Relay Improvement SPOF	12/31/2024
Load Growth	Calhoun 230 kV: Construct New Substation	6/1/2026

Table 29: ELL Projects Submitted as Target Appendix A in MTEP23

Project Driver	Project Name	Current Projected ISD
Baseline Reliability	Dixie Baker to Baker 69 kV: Reconductor Line	6/1/2026
Baseline Reliability	Delmont to Hazel 230 kV: Upgrade Line	6/1/2026
Baseline Reliability	Delhi - Tallulah 115 kV Rebuild	12/1/2026
Baseline Reliability	Winnsboro to Gilbert 115 kV Rebuild	12/1/2026
Baseline Reliability	Gilbert to Wisner 115 kV Rebuild	12/1/2026
Baseline Reliability	Dixie Baker to Zachary 69 kV: Upgrade Line	6/1/2027
Asset Management	McKnight 500 kV GIS Replacement	TBD
Asset Management	Webre 500 kV GIS Replacement	TBD
Asset Management	Holiday to Lafayette 69 kV: Reterminate into Elks	TBD
Asset Management	Barnett Oil Mill 69 kV Relocation	TBD
Baseline Reliability	Mossville 69 kV Upgrade Breaker 17955	TBD
Asset Management	2024 ELL Asset Renewal Program	TBD
Other Reliability	DSG Reliability & Resiliency Upgrade	TBD
Baseline Reliability	Willow Glen 138 kV Reconnect Bus	TBD
Baseline Reliability	Port Hudson - Jackson 69 kV: Switch Upgrades	TBD
Baseline Reliability	Blount to Devil Swamp New 69 kV line	TBD
Baseline Reliability	Tiger 69 kV: Bus Upgrades	TBD
Asset Management	MTEP23 ELL Capacitor Bank Retirements	TBD
Other Reliability	Amite South Reliability Project - Phase 1	TBD
Other Reliability	Amite South Reliability Project - Phase 2	TBD
Other Reliability	Amite South Reliability Project - Phase 3	TBD
Asset Management	Coly 500 kV GIS Replacement	TBD
Asset Management	Jaguar 230 kV GIS Replacement	TBD

Appendix E – Scope of Aurora Market Model

The shaded areas shown on the map below are modeled in Aurora. These areas include MISO-South, and the remainder of MISO (MISO-Central, and MISO-North).

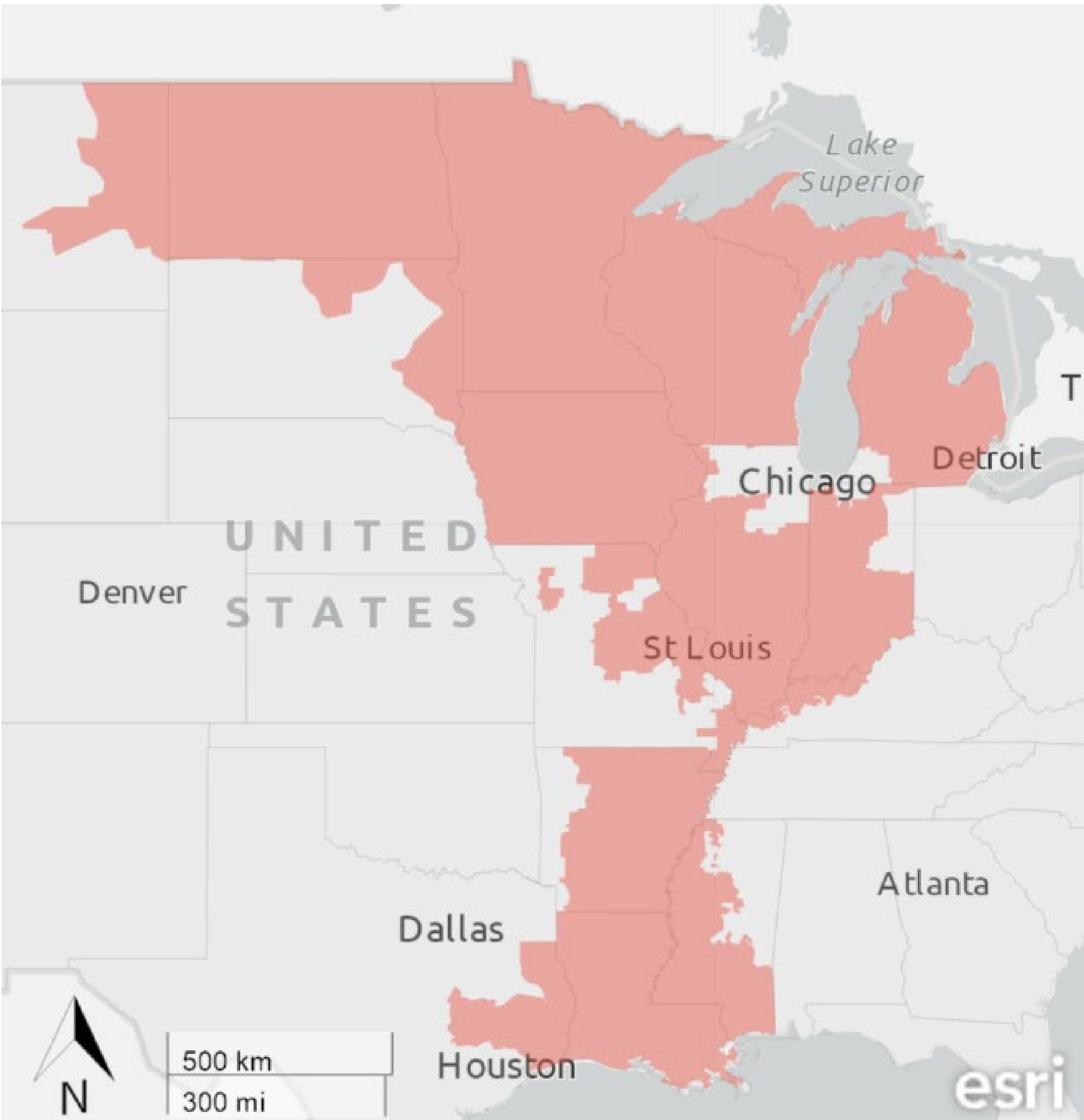


Figure 42: Map of MISO North and South

Appendix F – Portfolio Capacity Mix Figures

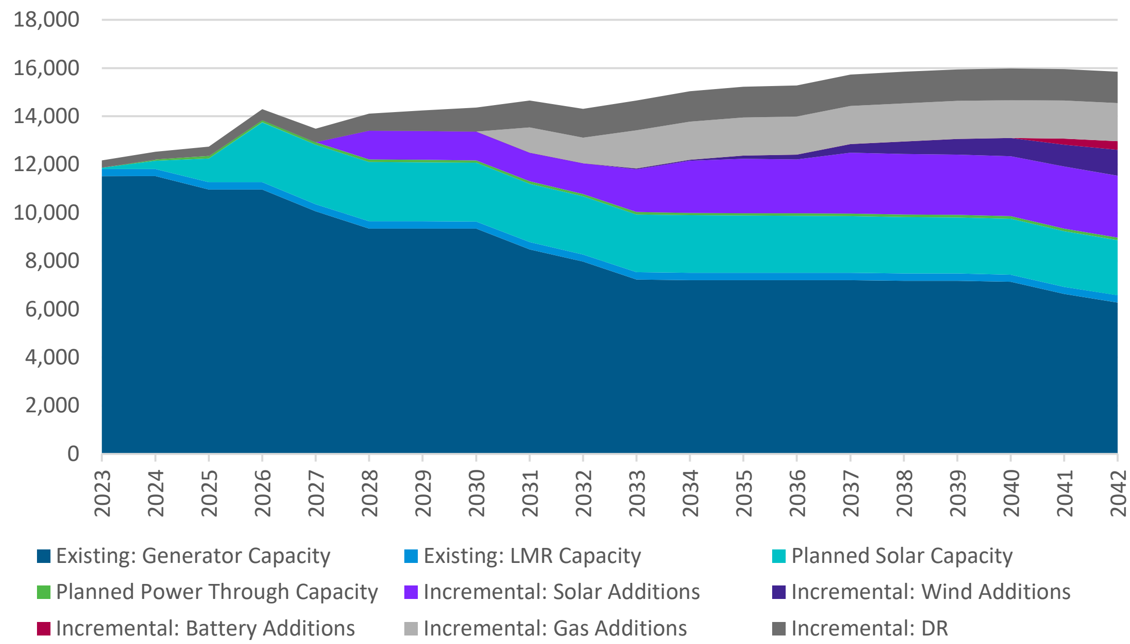


Figure 43: Portfolio 1 ELL Capacity Mix (Installed MW)

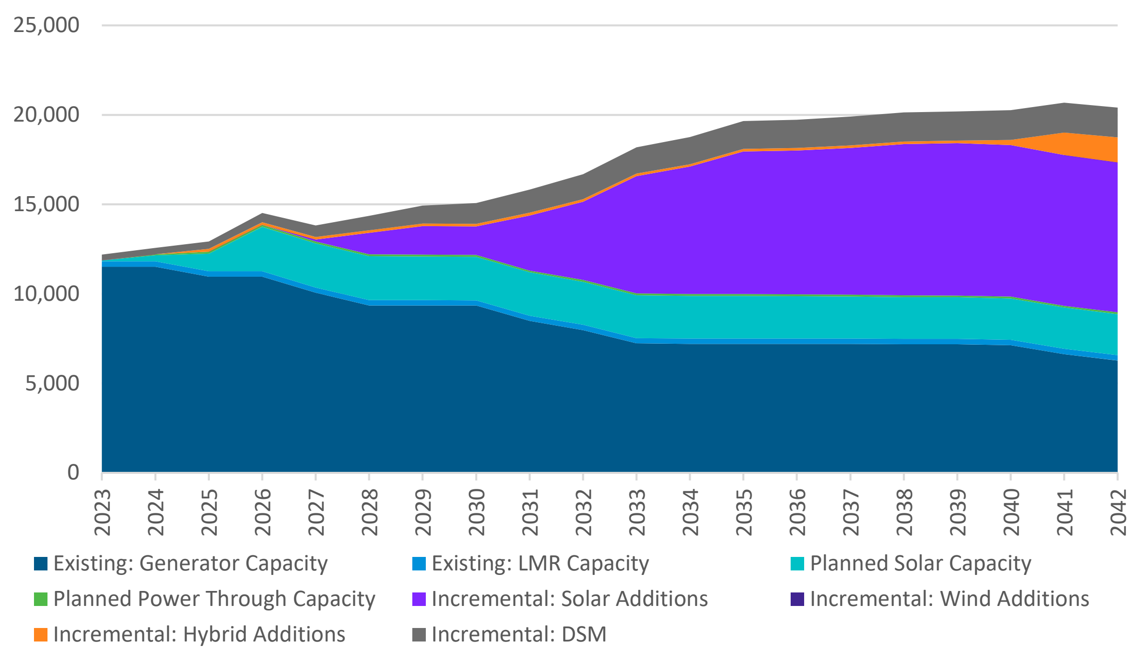


Figure 44: Portfolio 2 ELL Capacity Mix (Installed MW)

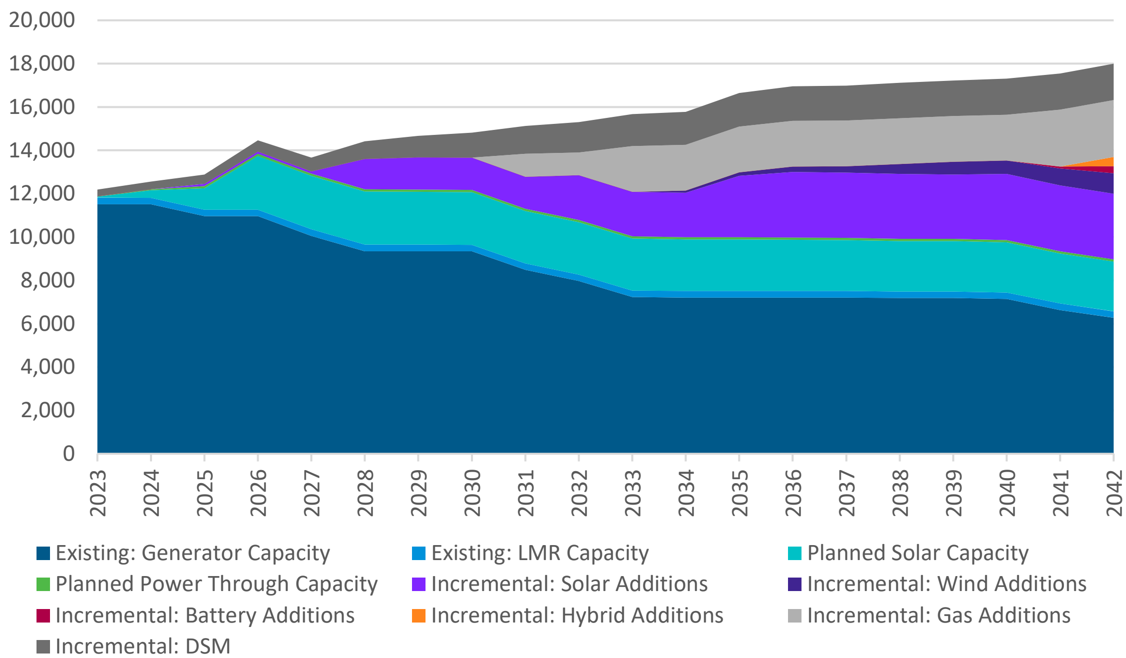


Figure 45: Portfolio 3 ELL Capacity Mix (Installed MW)

Appendix G – Total Relevant Supply Cost Analysis Results

Total Relevant Supply Cost Analysis Results

The Total Relevant Supply Cost ("TRSC") for each portfolio was calculated for the future for which it was developed. The total relevant supply cost is calculated using:

Variable Supply Cost - The variable output from the Aurora model for each portfolio in each of the futures, which includes fuel costs, variable O&M costs, emission costs, startup costs, energy revenue, make-whole payments, and uplift charges.

Levelized Real Non-Fuel Fixed Costs - Return of and on capital investment, fixed O&M, and property tax for the incremental resource additions in each portfolio, calculated on a levelized real basis.

DSM Costs - Costs associated with DSM programs less capacity value associated with the program.

Capacity Purchases/(Sales) - The capacity surplus (or deficit) in each portfolio multiplied by the assumed capacity value.

The TRSC metric measures the present value of the portion of ELL's total supply cost that is relevant to the portfolio analysis within the IRP. Accordingly, it excludes embedded fixed costs associated with generation, transmission, and distribution that currently exist in ELL's rate base and the impact of resource deactivations that are currently included in base rates. The non-fuel fixed costs included in the TRSC calculation are an estimate of the incremental fixed costs of the relevant resource portfolio (e.g. Portfolios 1, 2, and 3). Green Tariff products such as the recently approved Rider GGO or other similar customer offerings may allow customers to subscribe to and receive value from a share of renewable resources in ELL's future resource portfolio, reducing or eliminating the cost and risk allocated to all ELL customers.

Table 30: Portfolio 1 in Future 1 TRSC

	Cost [$MM, 2022$ NPV]
Variable Supply Cost	$17,963
Resource Additions Fixed Costs	$3,603
DSM Net Fixed Costs	($232)
Capacity Purchases / (Benefit)	($104)
Total Relevant Supply Cost	$21,229

Table 31: Portfolio 2 in Future 2 TRSC

	Cost [$MM, 2022$ NPV]
Variable Supply Cost	$20,301
Resource Additions Fixed Costs	$6,713
DSM Net Fixed Costs	($135)
Capacity Purchases / (Benefit)	($483)
Total Relevant Supply Cost	$26,395

Table 32: Portfolio 3 in Future 3 TRSC

	Cost [$MM, 2022$ NPV]
Variable Supply Cost	$21,843
Resource Additions Fixed Costs	$3,920
DSM Net Fixed Costs	($135)
Capacity Purchases / (Benefit)	($411)
Total Relevant Supply Cost	$21,843

Figure 46 below summarizes the TRSC results for Portfolio 1, 2, and 3 under each future.

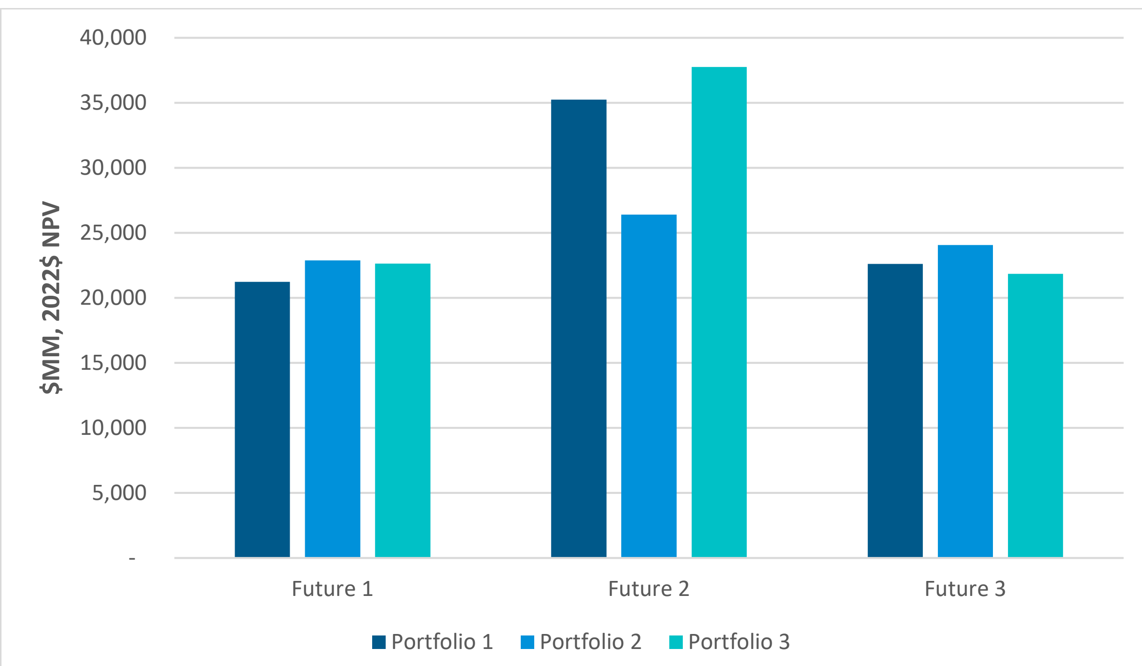


Figure 46: Portfolio Total Relevent Supply Cost by Future

To estimate the rate effects of each optimized portfolio, the incremental non-fuel fixed costs are calculated on a levelized nominal basis in terms of dollars per MWh. ELL also quantified an estimated amount of variable supply cost, or fuel, savings calculated on a levelized nominal basis by measuring the reduction in annual variable supply costs relative to the first-year cost per MWh for each portfolio. The results of this analysis presented below indicate an estimate rate effect of (¢1.20)/kWh in Portfolio 2 to ¢0.15/kWh in Portfolio 1. As noted in Chapter 5, Portfolio 2 is comprised of a significant amount of intermittent resources and relies more on the MISO energy markets than other portfolios. For the reasons described throughout this document, over-reliance on the MISO markets can pose risks to customers and reliability.

These rate impact estimates do not account for the rate effects of future customer offerings and/or the rate effects of deactivating or retiring resources, both of which may lower costs for all customers during the planning period.

Table 33: Potential Rate Impact of Portfolios

	(A) Fixed Cost [NPV $/MWh]	(B) Fuel Savings [NPV $/MWh]	(A+B=C) TRSC Cost or (Savings) [NPV $/MWh]
Portfolio 1	$3.39-$4.98	($3.72)-($2.38)	($0.33)-$2.61
Portfolio 2	$8.13-$16.56	($20.14)-($12.60)	($12.01)-$3.97
Portfolio 3	$3.19-$4.67	($3.92)- ($0.17)	$0.75- $3.56

Overall, the net effect of this analysis across all portfolios has a minimal estimated net rate impact. The figure below shows the range on a ¢/kWh basis on a 2022$ NPV basis.

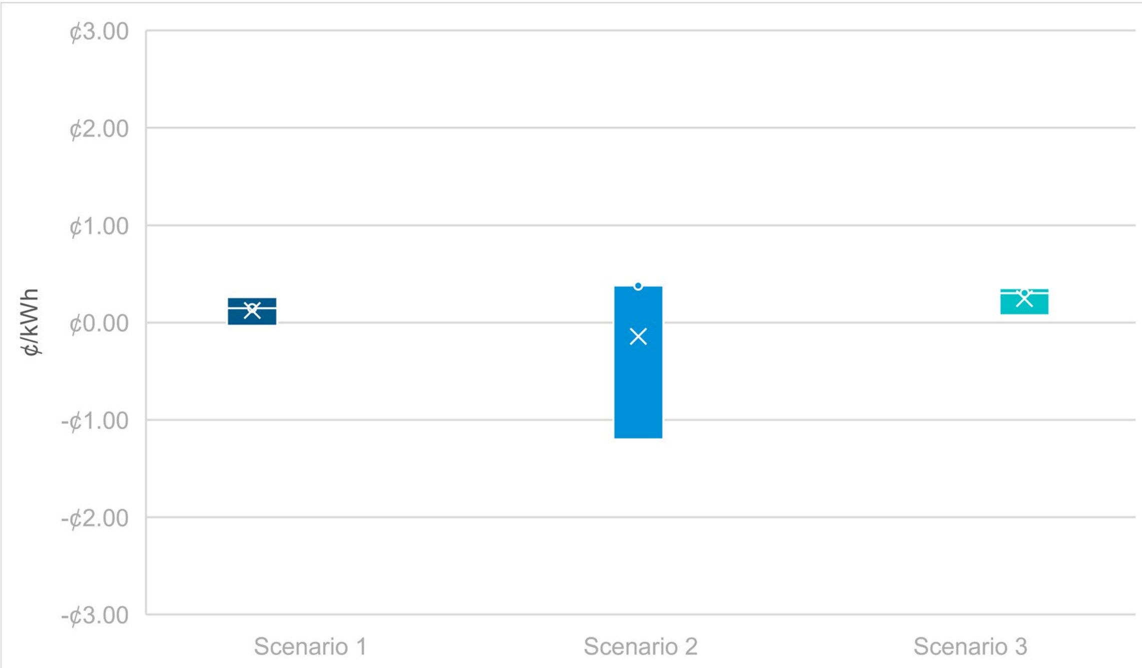


Figure 47: Estimated Net Rate Impact of Portfolios

Appendix H – Actual Historic Load and Load Forecast

Historic Peak Demand and Energy

Table 34: Actual Historic Energy (GWh) (Includes T&D Losses)

	Residential	Commercial	Industrial	Governmental	Total
2012	14,583	11,977	26,590	743	53,894
2013	14,737	11,980	27,039	759	54,516
2014	15,147	12,141	28,396	769	56,453
2015	15,129	12,294	29,120	793	57,336
2016	14,511	12,060	29,964	834	57,369
2017	14,035	11,917	31,264	830	58,046
2018	15,062	12,031	30,402	855	58,350
2019	14,596	11,798	30,969	860	58,222
2020	14,311	10,875	30,012	810	56,008
2021	14,120	10,791	31,039	823	56,772

Table 35: Summer and Winter Historical Peaks (MW)[51]

	Summer	Winter
2012	9,607	7,602
2013	9,763	7,958
2014	9,493	9,073
2015	10,358	8,824
2016	9,857	7,978
2017	9,968	8,634
2018	9,870	9,243
2019	9,929	8,394
2020	9,535	8,219
2021	10,145	8,671

Table 36: Historic Monthly Energy (MWh)[52]

	Residential	Commercial	Industrial	Governmental	Total
1/1/2012	1,184,341	916,312	2,221,892	62,767	4,385,312
2/1/2012	976,468	865,796	2,191,311	61,202	4,094,778
3/1/2012	937,649	885,876	2,208,271	60,419	4,092,216
4/1/2012	947,266	910,348	2,254,453	60,488	4,172,556
5/1/2012	1,068,155	964,145	2,225,076	59,246	4,316,622
6/1/2012	1,483,468	1,124,001	2,371,260	63,465	5,042,195

[51] Actuals are not available for revenue classes.

[52] Including T&D Losses to match forecasts values.

7/1/2012	1,653,125	1,165,556	2,276,747	64,187	5,159,616
8/1/2012	1,644,084	1,164,169	2,282,967	66,309	5,157,528
9/1/2012	1,519,527	1,122,289	2,130,745	65,144	4,837,704
10/1/2012	1,247,115	1,046,879	2,081,486	64,127	4,439,606
11/1/2012	951,378	929,933	2,210,211	58,119	4,149,641
12/1/2012	970,793	881,961	2,135,383	57,659	4,045,796
1/1/2013	1,239,178	934,099	2,287,472	64,109	4,524,858
2/1/2013	1,037,088	868,703	2,194,945	65,150	4,165,886
3/1/2013	995,157	869,926	2,094,173	63,078	4,022,334
4/1/2013	905,808	859,908	2,231,557	60,230	4,057,503
5/1/2013	914,217	897,051	2,304,183	62,540	4,177,989
6/1/2013	1,343,257	1,064,993	2,384,889	63,964	4,857,103
7/1/2013	1,639,042	1,171,257	2,278,176	64,380	5,152,855
8/1/2013	1,617,130	1,144,833	2,274,144	63,429	5,099,537
9/1/2013	1,603,942	1,187,187	2,396,925	65,511	5,253,565
10/1/2013	1,373,950	1,113,313	2,211,120	64,016	4,762,399
11/1/2013	947,443	941,621	2,173,176	60,360	4,122,600
12/1/2013	1,121,259	927,562	2,208,618	61,890	4,319,328
1/1/2014	1,456,184	988,020	2,233,409	66,637	4,744,251
2/1/2014	1,436,993	968,116	2,240,145	64,724	4,709,977
3/1/2014	1,094,468	902,740	2,076,529	63,859	4,137,596
4/1/2014	898,370	882,745	2,349,036	63,522	4,193,673
5/1/2014	979,025	933,056	2,343,315	61,853	4,317,250
6/1/2014	1,298,794	1,062,598	2,388,029	65,675	4,815,096
7/1/2014	1,567,099	1,153,136	2,467,752	65,207	5,253,194
8/1/2014	1,556,573	1,141,209	2,511,980	64,727	5,274,489
9/1/2014	1,553,712	1,159,052	2,506,819	65,986	5,285,570
10/1/2014	1,255,691	1,069,587	2,465,828	60,728	4,851,834
11/1/2014	1,008,273	976,516	2,413,650	62,116	4,460,555
12/1/2014	1,041,890	904,408	2,399,251	63,733	4,409,282
1/1/2015	1,258,340	942,169	2,426,296	65,842	4,692,647
2/1/2015	1,230,047	924,813	2,356,571	65,734	4,577,166
3/1/2015	1,196,963	941,589	2,117,129	67,880	4,323,562
4/1/2015	917,579	901,724	2,253,131	64,313	4,136,747
5/1/2015	1,014,654	952,547	2,350,362	62,790	4,380,354
6/1/2015	1,342,555	1,070,967	2,486,836	68,691	4,969,050
7/1/2015	1,646,112	1,186,064	2,526,341	67,560	5,426,077
8/1/2015	1,854,193	1,271,242	2,664,070	70,444	5,859,948
9/1/2015	1,547,044	1,183,825	2,629,681	65,945	5,426,495
10/1/2015	1,227,186	1,062,426	2,378,126	63,962	4,731,700

11/1/2015	958,111	960,782	2,394,040	64,773	4,377,707
12/1/2015	935,912	895,950	2,536,953	65,455	4,434,270
1/1/2016	1,166,831	925,874	2,510,626	67,394	4,670,725
2/1/2016	1,130,914	890,826	2,445,341	74,080	4,541,161
3/1/2016	910,786	879,537	2,423,271	67,107	4,280,701
4/1/2016	822,582	858,217	2,579,768	66,065	4,326,632
5/1/2016	947,137	927,137	2,438,960	67,859	4,381,093
6/1/2016	1,297,706	1,044,764	2,645,768	70,638	5,058,877
7/1/2016	1,672,041	1,187,467	2,569,486	72,000	5,500,994
8/1/2016	1,622,890	1,176,235	2,648,915	71,982	5,520,022
9/1/2016	1,575,457	1,169,899	2,498,810	74,626	5,318,791
10/1/2016	1,375,286	1,114,239	2,506,127	70,304	5,065,956
11/1/2016	1,023,780	984,284	2,463,271	65,818	4,537,153
12/1/2016	965,286	901,610	2,233,601	66,345	4,166,842
1/1/2017	1,167,867	925,152	2,578,889	69,888	4,741,795
2/1/2017	935,695	864,103	2,438,688	66,086	4,304,572
3/1/2017	892,749	879,445	2,296,454	67,190	4,135,838
4/1/2017	919,111	899,876	2,713,117	66,937	4,599,041
5/1/2017	1,003,096	938,864	2,626,494	66,049	4,634,502
6/1/2017	1,230,741	1,028,881	2,734,606	70,301	5,064,530
7/1/2017	1,505,955	1,117,721	2,600,064	74,814	5,298,554
8/1/2017	1,539,948	1,134,881	2,696,478	71,495	5,442,801
9/1/2017	1,473,406	1,139,257	2,717,022	71,875	5,401,560
10/1/2017	1,333,600	1,101,053	2,659,150	70,535	5,164,339
11/1/2017	1,018,878	979,619	2,558,466	67,441	4,624,404
12/1/2017	1,013,617	908,593	2,644,273	67,504	4,633,987
1/1/2018	1,462,435	970,457	2,581,091	69,843	5,083,825
2/1/2018	1,238,790	920,165	2,427,996	71,074	4,658,025
3/1/2018	893,283	874,720	2,316,175	67,613	4,151,792
4/1/2018	832,753	859,822	2,608,956	66,322	4,367,853
5/1/2018	947,526	883,992	2,518,538	66,292	4,416,348
6/1/2018	1,445,497	1,100,892	2,658,378	71,208	5,275,974
7/1/2018	1,630,434	1,159,516	2,583,825	74,527	5,448,303
8/1/2018	1,620,020	1,159,611	2,640,441	74,622	5,494,692
9/1/2018	1,589,782	1,194,934	2,692,924	75,585	5,553,225
10/1/2018	1,361,650	1,113,596	2,622,481	76,017	5,173,744
11/1/2018	974,420	930,094	2,290,520	70,879	4,265,912
12/1/2018	1,065,088	863,149	2,460,409	71,398	4,460,043
1/1/2019	1,155,826	899,071	2,634,003	73,428	4,762,329
2/1/2019	1,089,931	858,047	2,612,832	69,308	4,630,118

3/1/2019	955,119	860,901	2,383,649	68,482	4,268,152
4/1/2019	872,747	859,754	2,571,589	69,241	4,373,331
5/1/2019	978,599	902,929	2,511,625	70,721	4,463,874
6/1/2019	1,391,972	1,063,359	2,704,107	72,624	5,232,062
7/1/2019	1,597,458	1,140,243	2,636,673	72,570	5,446,944
8/1/2019	1,547,320	1,133,015	2,668,632	73,677	5,422,644
9/1/2019	1,649,749	1,181,946	2,738,324	77,174	5,647,193
10/1/2019	1,408,916	1,128,575	2,631,700	75,435	5,244,626
11/1/2019	959,721	912,112	2,406,034	69,650	4,347,517
12/1/2019	988,598	857,596	2,469,811	67,336	4,383,341
1/1/2020	1,106,879	847,359	2,636,863	69,191	4,660,292
2/1/2020	1,007,891	818,603	2,675,430	68,794	4,570,718
3/1/2020	976,473	888,953	2,429,869	68,843	4,364,138
4/1/2020	986,401	803,356	2,728,529	64,815	4,583,101
5/1/2020	1,022,840	777,759	2,423,009	63,945	4,287,553
6/1/2020	1,357,139	969,894	2,566,414	67,730	4,961,178
7/1/2020	1,586,191	1,048,490	2,420,744	71,180	5,126,605
8/1/2020	1,612,971	1,072,437	2,516,508	71,737	5,273,653
9/1/2020	1,536,036	1,031,395	2,470,514	66,846	5,104,790
10/1/2020	1,143,404	948,656	2,238,927	66,776	4,397,763
11/1/2020	975,860	837,353	2,373,110	64,289	4,250,612
12/1/2020	998,801	830,343	2,532,214	65,809	4,427,167
1/1/2021	1,301,206	854,993	2,483,030	70,206	4,709,436
2/1/2021	1,088,745	823,133	2,494,870	67,656	4,474,405
3/1/2021	1,247,771	825,552	2,306,420	66,644	4,446,387
4/1/2021	846,728	790,960	2,789,237	65,584	4,492,509
5/1/2021	951,952	827,784	2,607,529	69,293	4,456,558
6/1/2021	1,286,203	979,768	2,639,884	74,722	4,980,578
7/1/2021	1,506,050	1,052,871	2,652,945	72,885	5,284,752
8/1/2021	1,573,918	1,068,341	2,836,874	71,798	5,550,932
9/1/2021	1,345,557	944,670	2,498,419	65,099	4,853,745
10/1/2021	1,099,455	900,552	2,226,838	64,230	4,291,075
11/1/2021	959,069	854,372	2,631,428	66,108	4,510,978
12/1/2021	913,489	867,854	2,871,226	68,388	4,720,956

Prior Load Forecast Evaluation

Table 37: Energy Forecasted vs Actual

Sales (GWh)	2018	2019	2020	2021
Previous IRP Sales Forecast (BP18U)*	54,961	56,509	57,967	57,780
Weather Normalized Actual Sales	55,332	55,428	54,112	54,655
Deviation	371	-1,081	-3,855	-3,125
% Deviation	1%	-2%	-7%	-5%

Table 38: Peak Forecasted vs Actual

Peaks (MW)	2018	2019	2020	2021
Previous IRP Load Forecast (BP18U)*	9,872	10,004	10,159	10,138
Weather Normalized Actual Peaks	9,654	9,850	9,530	10,112
Deviation	-218	-154	-629	-26
% Deviation	-2%	-2%	-6%	0%

Causes of Significant Deviations Between Forecasts and Actuals

COVID-19 Pandemic
The COVID-19 pandemic resulted in many behavioral changes in 2020 and 2021 which influenced actual sales for those years being different than forecasted levels from BP18U. Business closures, work-from-home, and social distancing measures caused commercial sales to be significantly lower than forecasted levels, which assumed normal behavior. Additionally, there were negative impacts to industrial load from the pandemic including lower sales to petroleum refining customers due to lower demand when travel was diminished. Off-setting some of these lower sales effects were higher sales to residential customers, as many office employees began working from home and some school-aged children began learning from home.

Industrials
ELL's forecast includes assumptions for expected levels of electricity consumption by existing large industrial customers, including assumptions about planned maintenance outages and expansions. Differences in the planned maintenance schedule vs actual maintenance schedule can cause significant deviations between forecasts and actuals. Additionally, ELL's forecast includes new and expansion industrial projects from its Economic Development pipeline on a probability-weighted basis. If a large industrial project comes online differently than what is expected in the forecast – whether that is related to a different MW size, operating level, ramp schedule, or timing – that can cause significant deviations between forecasts and actuals.

Hurricanes
Major hurricanes affecting ELL's service territory can cause deviations between forecasted sales and actual sales. Louisiana experienced the effects of multiple, significant hurricanes during 2020 and 2021 (Laura, Delta, Zeta, Ida), causing less electricity consumption across all customer classes, with some service areas of the state still seeing negative impacts from these storms.

Energy Efficiency

The sales forecast considers the historical and future effects of energy efficiency in both residential and commercial sales. This energy efficiency can come from both company-sponsored DSM programs as well as from organic energy efficiency. Differences in the actual rate of adoption of newer, more efficient technologies relative to the forecast can cause deviations between the forecast and actuals.

Peaks

All of the above factors which affected the monthly volumes of actual consumption relative to the monthly forecasts also affected comparisons of actual peak levels compared to the peak forecasts.

Explanations of revisions applied to subsequent forecasts to adjust for deviations

As a result of the factors noted above, there have been several modifications to the sales forecast models since the previous IRP forecast to adjust for previous forecast deviations. Those adjustments include:

- Estimates of the effects of the COVID-19 pandemic in historical and future sales for residential and commercial customers
- Refining the way ELL estimates its peak forecast to account for expected changes in the mix of energy between customer classes

Explanation of the effects of DSM programs, interruptible loads, or other factors on the prior load forecast

ELL's DSM programs started in 2014 and were relatively small at the time however, ELL's DSM programs have increased since the last IRP cycle, and those effects are reflected in the sales forecast which feeds into the hourly load forecast. Additionally, the current IRP forecast includes placeholder assumptions regarding the proposed Phase II DSM savings programs. These effects are roughly in-line with the high DSM scenario prepared by ICF for the IRP futures and have a larger effect in the latter years of the forecast rather than in the near-term.

The sales and load forecasts are based on historical levels of electricity consumption and therefore inherently include the effects of load that was interrupted.

Load Forecast

Table 39: Annual Energy Forecasts (GWh) (Includes T&D Losses)

[redacted]

Table 40: Summer Coincident Peaks (MW) Forecast

	Residential	Commercial	Industrial	Governmental	Company Use	Wholesale	Total
2023	3,398	2,252	4,065	139	19	152	10,025
2024	3,387	2,254	4,242	140	19	152	10,194
2025	3,381	2,261	4,248	140	20	152	10,201
2026	3,379	2,258	4,242	140	20	152	10,190
2027	3,381	2,247	4,246	140	20	152	10,185
2028	3,386	2,234	4,271	139	20	152	10,201
2029	3,387	2,235	4,284	139	20	152	10,217
2030	3,371	2,239	4,301	140	21	152	10,224
2031	3,364	2,245	4,306	141	21	152	10,228
2032	3,370	2,235	4,321	140	21	152	10,239
2033	3,382	2,222	4,338	140	21	152	10,255
2034	3,390	2,214	4,353	140	21	152	10,270
2035	3,406	2,213	4,369	140	21	152	10,301
2036	3,406	2,226	4,379	141	21	152	10,325
2037	3,425	2,224	4,393	141	21	152	10,357
2038	3,447	2,215	4,411	141	21	152	10,387
2039	3,642	2,098	4,391	132	20	151	10,435
2040	3,688	2,101	4,404	132	20	151	10,497
2041	3,727	2,112	4,422	133	20	151	10,565
2042	3,779	2,128	4,430	134	20	151	10,642

Table 41: Winter Coincident Peaks (MW) Forecast

	Residential	Commercial	Industrial	Governmental	Company Use	Wholesale	Total
2023	3,315	1,562	3,974	118	13	111	9,094
2024	3,318	1,552	4,042	118	13	111	9,154
2025	3,312	1,545	4,229	118	13	111	9,328
2026	3,289	1,550	4,246	119	13	111	9,328
2027	3,295	1,550	4,235	119	13	111	9,323
2028	3,285	1,545	4,267	120	13	111	9,340
2029	3,304	1,529	4,276	119	13	111	9,353
2030	3,030	1,813	4,260	143	16	104	9,367
2031	3,294	1,522	4,309	120	13	111	9,368
2032	3,272	1,526	4,332	121	13	111	9,375
2033	3,279	1,526	4,343	121	13	111	9,392
2034	3,306	1,516	4,353	121	13	111	9,421

2035	3,331	1,505	4,371	121	14	111	9,452
2036	3,365	1,497	4,360	119	13	111	9,465
2037	3,366	1,509	4,411	122	13	111	9,532
2038	3,409	1,511	4,412	122	13	111	9,579
2039	3,446	1,510	4,434	122	13	111	9,637
2040	3,509	1,503	4,443	122	13	111	9,702
2041	3,580	1,490	4,433	120	13	111	9,747
2042	3,641	1,496	4,474	122	13	111	9,857

Table 42: Monthly Energy (GWh) Forecast

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

Table 43: Annual Load Factor Forecast

	Residential	Commercial	Industrial	Governmental	Company Use	Wholesale	Total
2023	46%	58%	88%	68%	58%	50%	70%
2024	46%	57%	86%	68%	58%	50%	70%
2025	46%	57%	90%	68%	58%	50%	70%
2026	46%	57%	90%	68%	57%	50%	70%
2027	46%	57%	90%	69%	57%	50%	70%
2028	46%	57%	87%	69%	56%	50%	70%
2029	46%	57%	87%	70%	55%	50%	70%
2030	46%	56%	87%	70%	55%	50%	70%
2031	45%	56%	89%	69%	55%	50%	70%
2032	45%	56%	89%	70%	54%	50%	70%
2033	45%	56%	86%	70%	54%	50%	70%
2034	45%	56%	86%	70%	54%	50%	70%
2035	45%	56%	86%	70%	54%	50%	70%
2036	45%	56%	88%	70%	54%	50%	70%
2037	45%	56%	88%	70%	54%	50%	70%
2038	45%	56%	88%	70%	54%	50%	70%
2039	44%	56%	86%	71%	54%	50%	70%
2040	44%	56%	85%	70%	54%	50%	70%
2041	44%	56%	86%	70%	54%	50%	70%
2042	44%	56%	88%	70%	54%	50%	70%

Appendix I – ICF DR & DER Achievable Potential Study

[Attachment]

PUBLIC VERSION

Entergy Louisiana: Energy Efficiency, Demand Response and Distributed Energy Resources Achievable Potential Study

Final Report

October 2022

Submitted to:
Entergy Louisiana, LLC

Submitted by:
ICF Resources, LLC
9300 Lee Highway
Fairfax, Virginia 22031

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1 EXECUTIVE SUMMARY

Entergy Louisiana, LLC (ELL) engaged consulting firm ICF Resources, LLC (ICF) to conduct an independent forecast of the achievable potential of selected energy efficiency (EE) programs, demand response (DR) programs, and distributed energy resources (DER) technologies on the utility's system. The programs and technologies were selected for analysis based on their relevance to utility planning practices nationwide and their specific relevance to ELL's customers and planning processes.

The resulting ICF forecast is being utilized by ELL to provide hourly inputs for its integrated resource planning (IRP) process over the period 2023 through 2042. ICF produced forecasts for two scenarios: reference case and high case. Doing so both allows the forecasts to be aligned with ELL's futures planning scenarios and recognizes the inherent uncertainty in forecasting over a 20-year horizon.

Key methodologies and outcomes from ICF's analysis are summarized below.

1.1 Energy Efficiency

Estimates for potential energy and demand savings were prepared for two cases, reference case and high case. The reference case included all existing programs performing at levels consistent with historic performance, with the addition of some new measures within those programs. The high case included both the expansion of the existing program to levels achieved by similar utilities as well as the addition of the new programs. New programs include appliance recycling, behavioral, HVAC midstream, and prepaid billing for residential; agricultural, industrial strategic energy management, lighting midstream, retro-commissioning, and small business direct install for commercial and industrial.

All new programs were modeled to start in 2024 with the new program planning cycle based on the presumption that the Louisiana PSC adopts comprehensive rules for permanent energy efficiency programs to begin when the latest extension to the current QuickStart phase ends. ICF used a combination of measure-level cost-effectiveness, historic program performance, benchmarking, and industry research to produce bottom-up, ELL systemwide forecasts for each program.

The key findings from the EE potential study are as follows:

- **The full portfolio has the potential to save almost 1.5 TWh by 2042.** In the reference case, the potential savings are just under 0.7 TWh in the same period.

- **Total incremental (annual) savings increase by two- to three-fold in the long term.** In the high case scenario, annual savings achieved by ELL programs grow by a factor of 2.7 above average savings achieved by ELL's QuickStart programs in Program Year 5 and 6, in 2019–2020. The growth in annual savings is due to increased budgets for existing ELL programs and to savings achieved by new and expanded programs, which contribute an additional 113% to savings above the current programs scenario level in 2042.

- **Residential and commercial programs account for over 90% of cumulative savings.** Cumulative program savings impacts in the residential sector reach 4.2% of residential electric sales in 2042 in the high case; cumulative program savings impacts in the commercial sector reach 6.2% of commercial electric sales in 2042. Industrial has the smallest potential by far, with cumulative savings impacts in 2042 only reaching 0.5% of sector sales in the high case. Since the savings impacts in the industrial sector are comparatively low, and because the share of the load that is industrial is high (51%), the total savings potential is 2.7% of total ELL system sales in 2042. If industrial programs and industrial load were removed from the equation, the total savings potential would increase to 5.1% of system sales in 2042 in the high case scenario. In the reference case, the total savings potential is 1.3% if industrial is included and 2.5% if industrial is excluded.

- **In the reference case, retail lighting and appliances remain the largest residential savings opportunity.** In the high case, the expansion of the of smart thermostats helping offset the reductions in lighting savings[1] opportunities given the transition to LED lighting. New programs could increase residential sector savings by close to 45% in the mid-term, driven largely by the expansion of existing programs.

- **Midstream lighting and the expanded existing programs drive increased program savings in the commercial and industrial (C&I) sectors.** Expanded programs could increase C&I savings by a third above the reference case.

- **The combined portfolio of residential, commercial, and industrial programs has a Total Resource Cost test ratio of 3.0 in the reference case and 2.5 in the high case.**

1.2 Demand Response

ICF took a systematic approach, as discussed in the following sections, to assess the potential for a variety of DR programs and ultimately provided forecasts for those programs which proved cost-effective. These cost-effective programs included:

- Direct load control (DLC):
  - Water Heaters and Pool Pumps (*within "DLC–water end uses" program*)
- Smart thermostat-enabled DR
- Interruptible load[2] *(Existing program associated with legacy interruptible riders – CS-L, EECS-L, Rider 2 to LIS-L, IS-G, EIS-I-G. New customers are modeled within the two new LPSC-approved, interruptible riders – IES and EIO, as well as with an 'aggregation' version wherein the flexible load from small C&I customers is aggregated to be part of the interruptible program)*
- Agricultural irrigation load control

The following programs were evaluated but did not pass the cost-effectiveness test (i.e., a Total Resource Cost [TRC] benefit-cost ratio test) in any of the scenarios modeled and thus were not included in the forecasts:

- Direct load control:
  - Room air conditioner
  - Battery storage
  - Electric vehicle smart charger
- Thermal storage

Two scenarios, reference and high cases, were modeled for this study with participation rate as the primary variable. All the programs in both scenarios were modeled to start in 2023.

Key findings on potential dispatch of DR from the study analysis are:

- **Interruptible & smart thermostat programs are the high-performing programs for DR potential.** In 2042, About 60% savings are achieved from the interruptible program, 26% savings are achieved from the smart thermostat program followed by DLC–water end uses & agricultural DLC programs contributing to 8% & 6% savings, respectively.
- **Interruptible program has a maximum contribution for savings in the C&I sector.** In 2042, in the reference case, the interruptible program contributes to 75% savings in the commercial sector, whereas in the high case the contribution increases to 79%. Since the interruptible program is the only program for the industrial sector, it accounts for 100% of industrial savings across both cases

[1] The reduction in lighting savings is based on the Energy Independence and Security Act of 2007 (EISA) backstop provision with an adjusted timeline. The topic is discussed further in section 3.3.3.1

[2] Interruptible load program is also referred to as interruptible program through the rest of the document, for brevity; and unless explicitly tagged, it refers to both existing and new programs (including the aggregation component) combined

in all years. Of this 37% in 2042 comes from the new program in the reference case, and this contribution increases to 50% in the high case.

- **Smart thermostats contribute two-thirds of the overall residential savings.** In the reference case, smart thermostat program contributes to 77% of the total savings while 23% of the contribution is by DLC-water end uses the program. However, in the high case, the savings contribution for the smart thermostat program is 69% and DLC-water end uses program contributes to 31% savings. Due to the formation of new peaks in the snapback hours, the high case for the smart thermostat program was mapped to the reference case.
- **The portfolio level cost-effectiveness i.e., TRC is greater than 1 across both the cases.** In all sectors, all programs except the existing industrial interruptible program have TRC benefit-cost ratios greater than 1 in both cases.

1.3 Distributed Energy Resources

Forecasts were prepared for five DER technologies: residential solar photovoltaic (PV); C&I PV; residential battery storage paired with PV; C&I battery storage paired with PV; and large C&I battery storage in a standalone configuration (without PV). The C&I technology forecasts were divided into separate commercial and industrial estimates.

ICF used a combination of project-level economics and individual DER market acceptance curves drawn from experience in other U.S. markets to produce top-down, ELL systemwide forecasts for each technology through a five-step analytic process.

Key findings from the DER forecasts are:

- **All five DER technologies have moderate to low levels of incremental adoption in the first five years of the forecast period** due to somewhat challenging economics (investment payback periods typically greater than 10 years and up to 20 years or more).

- Due to consistently improving economics from the combination of expected declines in PV system capital costs and rising retail electricity prices, **PV adoption increases significantly in the last 15 years of the forecast period**. By 2042, ICF estimates that 683 alternating-current megawatts (MW_{AC}) of residential PV capacity, 107 MW_{AC} of commercial PV capacity, and 9 MW_{AC} of industrial PV capacity will be installed cumulatively by ELL customers in its *high scenario*.
  - Those volumes of installed capacity translate into the equivalent of about 1,190,000 megawatt-hours (MWh) of residential PV output, 185,000 MWh of commercial PV output, and 15,000 MWh of industrial PV output annually at ELL's central station plant level by 2042 in the *high scenario*.
  - Those annual PV output levels in 2042 represent 7.9%, 1.4%, and 0.05% of ELL's historic (2019) consumption loads for residential, commercial, and industrial customers, respectively.

- However, **there are large differences in outcomes across scenarios**, with *reference scenario* cumulative installed capacity by 2042 across all customer types combined being about 275 MW_{AC} less than the *high scenario* level. That outcome largely reflects differing assumptions across scenarios about how fast PV capital and operating costs will decline in the future.

- **Residential PV is forecasted to reach much higher levels of deployment by 2042 than C&I PV,** partly because residential PV capital costs are estimated to decline at a greater rate than C&I capital costs and to reach near-parity on a per-kilowatt (kW) basis as the PV industry continues to mature. Other reasons for higher residential PV deployment than C&I include much higher existing levels of residential PV than C&I PV in ELL territory, generally higher energy (per-kWh) rates offset by PV systems for residential customers than for C&I customers, and higher market acceptance rates for residential PV in comparable utility PV markets (i.e., higher proportions of customers in these markets adopt residential PV than C&I PV).

- Though battery storage systems have not been deployed at a material level by ELL customers to date, the combination of significant decreases in storage system capital costs, increases in retail electricity prices, and the relatively large peak demand components of some ELL rate schedules for large C&I customers is expected to result in greater levels of deployment by the end of the forecast period. In the *high scenario*, 5 MW_{AC} of C&I battery power is estimated to be installed by 2042 for standalone battery systems. **Due to generally unfavorable economics and payback periods relative to the capital and operating costs of battery storage among most of ELL's C&I customer population, minimal adoption of C&I battery storage is forecasted for the study period**

- However, **additional customers are forecast to deploy battery storage along with their PV installations, motivated by non-economic factors.** That outcome occurs in other markets and is forecasted to result in an additional 50 MW_{AC} of residential battery power capacity and 7 MW_{AC} of C&I battery power capacity in the *reference scenario*, and 169 MW_{AC} (residential) and 17 MW_{AC} (C&I) in the *high scenario*.

- **On an aggregate annual energy (MWh) basis, battery storage technologies are expected to have low impacts on the ELL system.** For example, the total forecasted impact is only an increase of 2,301 MWh in utility annual net load by 2042 in the *reference scenario* for residential battery storage systems. C&I battery storage systems are forecasted with even smaller impacts at 136 MWh in aggregate by 2042 in the *reference scenario*. These low annual impacts are not only because battery systems tend to be used infrequently (to their full potential less than 5% of hours during a year), but also because their aggregate annual impacts on the grid are only the difference between their charging and discharging cycles. Since battery systems are net consumers of utility power, they increase ELL loads on an annual basis, unlike PV systems that decrease net utility loads.
  - In any given hour, however, battery systems can increase or decrease net loads on the ELL grid, depending on the aggregate battery charging and discharging behavior of customers during that hour, which is determined by customers' motivation for using the battery storage system at that time.

Benefit-cost ratios and related metrics were not calculated for DER technologies because ELL has not yet planned DER-specific programs during the forecast period.

2 INTRODUCTION

2.1 Purposes and Uses of Forecasts

ICF was retained by ELL to conduct a comprehensive potential study and to develop inputs for the company's 2023 IRP. This report covers the EE, DR, and DER potential analysis that was conducted by ICF.

The starting point of ICF's forecasts for ELL was the selection of relevant EE, DR, and DER programs and technologies. For EE, we analyzed programs separately for residential versus commercial and industrial. Among DR, we analyzed event-based program types, separated for residential, commercial, and industrial, as well as one existing rate-based DR program. For DER, PV and battery storage technologies were also separated by residential, commercial, and industrial adoption.

For each selected EE program, DR program, and DER technology, ICF produced hourly net load forecasts covering 20 years for two scenarios, reference and high cases.

ICF's residential, commercial, and industrial DER forecasted hourly load impacts for 2023 through 2042 were added to ELL's forecasted customer class consumption loads for that period as the baseline for ICF's DR analysis.

The results of ICF's analysis for all scenarios can both inform ELL's planning and be utilized as direct inputs into the utility's IRP. Though ICF's analysis is intended for the utility's internal planning purposes, ELL can publish this report at its discretion as regulatory or business circumstances warrant.

2.2 Organization of the Report

The balance of the report contains explanations of the data inputs and analytic methodologies used to forecast results from applying those inputs and methodologies and key findings. The EE program potential is described first, followed by the DR program potential, with the DER technology potential described last. The descriptions are divided into these main sections:

- Overview
- Program (EE & DR) or Technology (DER) Types and Definition
- Data Collection
- Program (EE & DR) or Technology (DER) Modeling

The modeling section also contains EE, DR, and DER achievable potential results and key findings, as well as benefit/cost analysis for ELL EE and DR programs.

The report concludes with brief descriptions of the hourly inputs and other information that ICF provided to ELL for its IRP process.

3 ENERGY EFFICIENCY (EE) POTENTIAL

3.1 Overview

Figure 1 shows our bottom-up approach to this study.

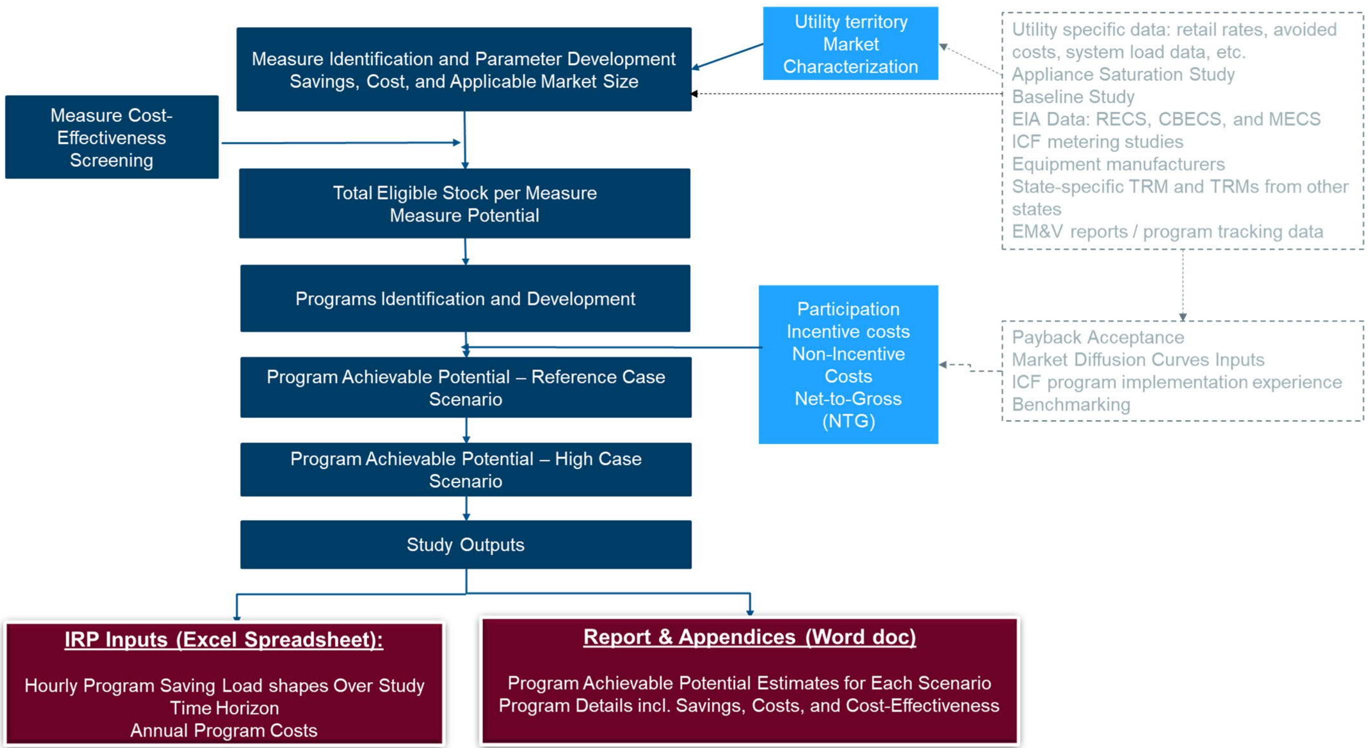

Figure 1: Overview of Bottom-up Approach to Potential Study

This bottom-up analysis began with collecting data on all relevant inputs, including baseline data, measure data, and program data, followed by estimating the eligible stock of energy efficiency measures. The eligible stock is the size of the market for efficiency measures, in measure units, such as bulbs, tons of cooling, or the number of homes. ICF estimated the eligible stock for measures within each end-use and sector. This task required data on the number of customer types in ELL's service area, the number and types of buildings, the types of energy-using equipment that are in each building type, and the current saturation of efficient equipment. We then screened measures for cost-effectiveness using the TRC test. In most cases, measures with a TRC test result of 1.0 or better passed to the next stage of the analysis.

With the eligible stock and cost-effective measures defined, ICF then conducted the achievable potential analysis, which required developing savings forecasts for demand-side management (DSM) programs for the 2023–2042 period under two scenarios: (1) a **reference case scenario** where ELL programs were modeled based on program designs implemented by ELL in Program Years four through six, 2018 to 2020, but with additional measures at similar adoption to those currently implemented; and (2) a **high case scenario**, which includes the programs in the current programs scenario with expanded budgets plus new best practice programs. Other assumptions that varied between these cases included participation rates, program marketing costs, and net-to-gross (NTG) ratios.[3] We maintained the same utility input assumptions such as retail rates, avoided costs, and discount rates in both scenarios.

Finally, ICF provided ELL with the data inputs required for its IRP. These included hourly load shapes for each program, which reflect savings forecasted for every hour of every year of the analysis, annual program costs, and program benefit-cost results.

3.2 EE Program Types and Definitions

ICF modeled 18 program types for this study, as described briefly below, by sector. These included ten existing programs and eight new program types.

3.2.1 Residential Programs

- **A/C Solutions** – Promotes investment in long-term savings by providing rebates for the purchase and installation of high-efficiency home HVAC equipment. Also conducts A/C tune-ups for customers with functioning A/Cs and duct sealing.
- **Home Performance with Energy Star** – This program includes two components: an existing home component that includes home audit and retrofits and a new home component. The home audit and retrofit consists of audits of single-family homes to identify opportunities to save energy and money. Direct install measures, including light-emitting diode (LED) bulbs and faucet aerators, are installed for free. Participants receive incentives for more comprehensive measures installed that are identified during the audit, such as air sealing, duct sealing, and ceiling insulation. The new homes component focuses on increasing awareness and understanding among home builders of the benefits of energy-efficient building practices, with a focus on capturing energy efficiency opportunities available during the design and construction of new single-family homes. Incentives are similarly provided for individual measures to the rest of the program.
- **Income-Qualified Weatherization** – Conducts free energy audits and installs free weatherization measures, such as air sealing, duct sealing, and home insulation, in homes occupied by income-qualified customers.
- **Multifamily Solutions** – Like the home audit and retrofit component of the home performance with Energy Star program but conducts audits of multi-family buildings to identify opportunities to save energy and money. Direct install measures, including light-emitting diode (LED) bulbs and faucet aerators, are installed for free. Participants receive incentives for more comprehensive measures installed that are identified during the audit, such as air sealing, duct sealing, and ceiling insulation.
- **Manufactured Homes Solutions** – Like the home audit and retrofit component of the home performance with Energy Star and the multifamily solutions programs but conducts audits of manufactured homes to identify opportunities to save energy and money. Direct install measures, including light-emitting diode (LED) bulbs and faucet aerators, are installed for free. Participants receive incentives for more comprehensive measures installed that are identified during the audit, such as duct sealing and ceiling insulation.
- **Retail Lighting and Appliances** – Provides rebates for qualifying ENERGY STAR® lighting and appliances sold through retail channels and an online marketplace, as well as information to increase customer awareness of energy efficiency appliances.
- **School Kits and Education** – Provides educational plans and materials for middle school classes as well as take-home kits with LED lighting, low-flow fixtures, and smart power strips. Designed to promote awareness of energy efficiency in students.
- **Appliance Recycling** – Promotes the retirement and recycling of inefficient, working refrigerators and freezers, as well as room ACs, from households by offering incentives and free pick-up of the equipment.

[3] NTG ratios were only varied for the midstream lighting program due to the expected increase in free-riderships due to the midstream program design.

- **Behavioral/Home Energy Report** – Provides individualized reports that detail the customer's energy use and suggests small changes that can result in energy and demand savings without significantly impacting the customer's lifestyle. The reports also include information comparing the customer's usage with that of others to spur reductions in energy use in both high- and low-usage households.
- **Midstream HVAC** – Transitions the existing HVAC measures to a midstream debate model instead of the current downstream model. The midstream model targets distributors and other trade-allies farther up the supply chain instead of the consumer directly. This increases the impact of each point of contact from the individual end-consumer to the entire set of customers serviced by the trade-ally as well as streamlining the process by taking the load for the participation of the end-consumer. The transitioned program includes a significant increase in the focus on HVAC replacement measures.
- **Prepay** – Requires included customers to pay for their electricity in advance of receiving service.4 Differences from existing billing methods include changes to payment arrangements, added energy use feedback, limited automatic disconnection, and total costs.5 On average, prepaid programs have been shown to save around 8% of a customer's energy use, with more conservative estimates putting the savings at 6%. These savings are attributed to better information and more attention paid to energy use due to the timely feedback on usage, active payment, and advanced planning. Traditional billing methods have a significant delay between energy use, billing, and payment, which prepaid billing addresses.

3.2.2 Commercial & Industrial (C&I) Programs

- **Large Commercial and Industrial Solutions** – This program includes prescriptive and custom for commercial and industrial as well as a new construction component. The prescriptive element of the program provides incentives to commercial and industrial customers on a "deemed" per-unit basis. The custom element identifies and implements site-specific and unique cost-effective energy efficiency opportunities that are not available via the prescriptive element. Customized incentives, based on calculated savings for specific customer projects, are offered. The new construction element provides technical assistance and incentives for efficient designs and measure implementation to influence building design practices during the design and construction of new buildings, major renovations of existing buildings, and tenant build-outs in the commercial sector.
- **Small Commercial Solutions** – Implements energy efficiency projects for customers under 100-kW peak demand. These customers include convenience stores, offices, garages, warehouses, restaurants, and other smaller businesses. Prescriptive and custom measures are offered, however the primary measures include lighting, refrigeration, and hot water upgrades.
- **Agricultural Pilot** – A pilot program to test out the market for agricultural energy efficiency improvements. Measures include ventilation and lighting for poultry, dairy pumps and refrigeration, and general-purpose exterior lighting and pumps.
- **Industrial Strategic Energy Management** – Helps businesses reduce their energy costs with tools, coaching, and technical resources to support energy goals through a year-long series of workshops and one-on-one coaching. Draws on the principles of continuous improvement and organizational change and integrates cost savings and operational excellence initiatives. The offering helps implement organizational structures, behavior changes, and systematic practices that can lead to significant energy and cost savings.

[4] These programs do stand to reduce electric consumption while empowering customers' decision-making. Evidence also shows they increase customer satisfaction (see "Examining Potential for Prepay as an EE Program").
[5] Some of these features could reduce energy consumption on their own with current payment methods or be removed from prepaid plans to protect customers, but the impacts to savings are not yet known. Early estimates for a pared back version of a prepaid program show a reduction in savings to only 2% of energy use.

- **Midstream Commercial Lighting** – Provides instant incentives to customers purchasing pre-qualified efficient lighting technologies. The midstream model targets distributors and other trade-allies farther up the supply chain instead of the consumer directly. This increases the impact of each point of contact from the individual end-consumer to the entire set of customers serviced by the trade-ally as well as streamlining the process by taking the load for the participation of the end-consumer.
- **Retro-Commissioning (RCx)** – Provides detailed engineering analysis of building operations designed to identify energy-savings operational improvements. Incentives are provided to customers who commit to implementing agreed-upon energy savings improvements. Common measures include equipment scheduling, optimization of economizer operations, and adjustment of HVAC set points.
- **Small Business Direct Install** – Direct install measures, including light-emitting diode (LED) bulbs, LED exit signs, and faucet aerators, are installed free of charge for small commercial customers.

3.3 Data Collection

This section details the data that was used in developing the potential for the EE programs modeled for ELL. ICF relied on a mix of confidential data provided directly by ELL in response to ICF requests and public data from government and electricity industry sources. The categories of data used in our analysis are described in the two sections below, and Section 3.3.3 describes how the data was used to create specific input assumptions tailored for this analysis.

3.3.1 ELL-Provided Data

ELL provided the following types of data that were used in the EE forecasts, as well as additional information that was requested by ICF but not directly used in our forecasts.

- Annual and hourly system energy usage forecasts, by customer class
- Annual customer count forecasts, by customer class
- Annual avoided cost forecasts—energy and capacity
- Retail rates forecast by customer class through 2025
- Historical Industrial sales by segment
- Transmission and distribution losses by customer class
- Reserve margin
- Weighted-average cost of capital (WACC)
- General price inflation estimates through 2042

In addition to data sent by ELL, ICF collected information on customer gas retail rates in ELL's territory from gas utilities' published tariffs.

3.3.2 External Program and Measure Data

ICF estimated the technical feasibility of the programs selected using:

- U.S. Department of Energy Residential Energy Consumption Survey (RECS, 2015)
- U.S. Department of Energy Commercial Buildings Energy Consumption Survey (CBECS, 2016)
- U.S. Department of Energy Manufacturing Energy Consumption Survey (MECS, 2018)

3.3.3 Development of ELL-Specific Inputs

ELL-specific inputs for the EE measures use various sources as references, including the following:

- Arkansas TRM Version 8.1, Volume 2
- New Orleans Energy Smart Technical Reference Manual: Version 3.0
- 2021 Illinois Statewide Technical Reference Manual for Energy Efficiency Version 9.0, Volume 2 and Volume 3
- ENERGY STAR® Unit Shipment and Market Penetration Report Calendar Year 2020 Summary

- Evaluation of the Program Year 4 2018 (PY4), Program Year 5 2019 (PY5), Program Year 6 2020 (PY6), Energy Efficiency Programs Portfolio for the legacy Entergy Louisiana, LLC (ELL) Service Area
- Evaluation of the Program Year 4 2018 (PY4), Program Year 5 2019 (PY5), Program Year 6 2020 (PY6), Energy Efficiency Programs Portfolio for the legacy Entergy Gulf States Louisiana (EGSL)) Service Area

These are used to populate the two primary components that feed into the bottom-up modeling. These are the measure level details and the eligible stock for each of those measures that may be replaced. The details of each are discussed in the following sections.

3.3.3.1 Measure Development

ICF developed a comprehensive measure database for this study, including commercially available measures covering each relevant savings opportunity within each end use and sector. The database includes prescriptive or "deemed" type measures, whole building options (e.g., commercial custom and new construction projects), and behavioral measures (e.g., residential home energy use benchmarking and retro-commissioning measures). Measure end uses covered include:

- Residential
- Appliances
- Consumer electronics
- Envelope (building shell)
- Hot water
- Heating, ventilation, and air conditioning (HVAC)
- Lighting
- Other (e.g., benchmarking)
- Commercial
    - Envelope (building shell)
    - Food services equipment
    - Hot water
    - HVAC
    - Lighting
    - Miscellaneous
    - Refrigeration
- Industrial
    - Machine drive
    - Compressors
    - Fans
    - Pumps
    - Motor, other applications
    - Facility HVAC
    - Facility lighting
    - Process cooling and refrigeration
    - Process heating
    - Other non-process uses
    - Other process and non-process uses

Table 1 shows the illustrative characteristics of each measure modeled with full details in the appendix section 7.1.

Table 1 Illustrative Characteristics of Measures

Line #	Measure Characteristic	Value
1	Applicable sector	Commercial
2	Applicable subsector	Grocery
3	Building type	All grocery
4	End use	Refrigeration
5	Measure name	Night covers for open refrigerated display cases
6	Measure definition	Curtains or covers on top of open refrigerated or freezer display cases
7	Baseline definition	No night cover, an average of vertical, semi-vertical, and horizontal units from Arkansas (AR) TRM definitions
8	Measure unit	Per linear foot of display case
9	Measure delivery type	Retrofit
10	Incremental cost	$42
11	Baseline unit effective useful life	N/A
12	Efficient unit effective useful life (years)	5
13	Incremental (annual) kilowatt-hour (kWh) savings	145
14	Incremental kW savings	0

In total, ICF analyzed 338 measure types and 1,338 measure permutations for this study. An example of a measure type is residential central air conditioners (CACs). Many measures required permutations for different applications, such as different building types, lamp wattages, efficiency levels, and decision types. For example, there are permutations of CACs by seasonal energy efficiency ratio (SEER) level, subsector, and building type. Descriptions of each measure type and permutation appear in the Appendix as well as in the measure cost-effectiveness results.

There was one measure baseline change accounted for in this study which was for standard light bulbs. This was included as an Energy Independence and Security Act of 2007 (EISA) backstop provisions timeline adjustments. It appears likely that the new administration will take action to reinstate the standard; however, there are significant uncertainties regarding the strategy (whether through a rulemaking process or the existing litigation process), the length of time required to execute the change, and the likely challenges and lawsuits that will follow. For the modeling in this study, current lighting saving levels are preserved for the initial years of the study (2023 – 2026) but an increase to the baseline, reducing savings, occurs in the year 2027: the assumed date for the Tier 2 baseline taking effect.

3.3.3.2 Eligible Stock

The eligible stock is the size of the market for efficiency measures, in measure units, such as bulbs, tons of cooling, or homes. ICF estimated the eligible stock for each measure within each end use and sector. Key data from the baseline sources noted previously include items such as:

- Percentage of homes with an equipment type (e.g., light bulbs, central A/C, refrigerator)
- Equipment counts (e.g., number of bulbs per home, tons of cooling per home, refrigerators per home)

- Equipment efficiency level (e.g., bulb type, SEER rating, ENERGY STAR® rating)
- Equipment age

A simple example of an eligible stock calculation for residential AC tune-ups is shown in Table 2. This example shows that there are 199,560 ACs eligible for tune-ups (row h). Because this is a retrofit measure, the eligible stock does not account for stock turnover. Stock turnover is the rate at which existing equipment expires and requires replacement. It is the inverse of the equipment age or 1 divided by the equipment's effective useful life (EUL). If this were a replace-on-burnout AC measure, the eligible stock would equal 1/10 years (1/a) times row h, which equals 19,900 ACs burning out every year and eligible for replacement.

Table 2: Illustrative Measure Eligible Stock Calculation

	Variable	Value	Source or Calculation
	Efficient unit	Central AC tune-up (5% improvement in the efficiency of the existing unit)	AR TRM
	Baseline unit	System with demonstrated imbalances of refrigerant charge	AR TRM
a	Baseline unit EUL (years)	10	AR TRM
b	Single-family homes	783,121	ELL
c	Homes with central AC (%)	78%	ELL RASS Survey, 2006
d	Number of measure units per home	1	1 central AC unit per home
e	Applicability (% of homes with AC units older than 8 years)	33%	RECS 2015, West South-Central region data
f	Efficient unit saturation	1.1%	Assuming all units older than 8 years have lost at least 5% charge since EUL of measure is 10 years
g	Not yet adopted rate	98.9%	1 – f
h	Total eligible stock in 2017 (number of potential AC tune-ups)	199,560	b × c × d × e × g

Payback acceptance curves were used in determining the split of eligible stock between measures replacing the same baseline measure. This means the measure with a shorter payback period was assigned more of the eligible stock but not all the eligible stock.

3.4 Program Modeling

This section provides an overview of how the ELL-specific inputs were turned into program-level economic analysis of the EE programs and forecasts of adoption and energy savings.

3.4.1 Elements of Analysis

The assumptions with respect to the elements of the analysis and the reporting methodology that were made in the study are listed in this section:

- **Peak demand**: Peak summer months were determined by reviewing ELL system load shapes. From this data, it was clear that peak times occurred in June through September based on high summer temperature and humidity being primary drivers. Additionally, peaks generally occur in late afternoon on weekdays when residential, commercial, and industrial consumption patterns coincide to produce the highest demand.

- **Economic screening**: All measures were screened for cost-effectiveness with a primary cost-effectiveness test of the TRC test. Measures were included in the achievable potential if they passed the TRC test.
- **Level of savings**: Savings reported for EE are all at the generator.
- **Low income/income-eligible**: Defined for the purposes of the study consistent with ELL's income-eligible program requirements.[6]
- **Achievable potential** is the amount of energy savings that can realistically be achievable by energy efficiency programs.
- **Program applicability to sub-sectors**:
  - For the residential programs, programs that specify a sub-sector, such as the Income-Qualified Weatherization and the Multifamily Solutions, are the only ones able to participate in such a program. These sub-sector programs do not exclude customers from participating in the broader programs, but since the sub-sector specific programs could offer higher incentives, we assume the customers participate in those for all measures they can.
    - The only program that fully overlaps with other programs is the School Kits and Education program. This program is prioritized since the measures are delivered for free and the delivery mechanism is school-age children.
    - Behavioral participants and prepaid billing participants are assumed to be exclusive.
    - Midstream HVAC replaces the new unit measures in the A/C solutions program when it is introduced in the high case scenario but not the tune-up and duct sealing measures.
  - For the commercial and industrial programs, like the residential programs, any sub-sector customer is assumed to prioritize participating in sub-sector specific programs but are not excluded from participating in broader programs.
    - The midstream lighting program replaces the lighting measures in other programs when it is introduced in the high case scenario.
- Levelized Cost ($/kWh): The Levelized cost is the net present value of the cost of unit energy saved over its lifetime. The costs include all the incentive and non-incentive costs from the UCT test.
- Fallback: It was assumed that customers implementing energy efficiency measures as a result of ELL programs would implement the same measures in the future once the existing measures expire but without help from ELL programs.

3.4.2 Measure Screening and Benefit/Cost Analysis

The TRC, UCT, and RIM benefit-cost ratios were calculated for the measures, programs, and portfolio. However, the measure-level screening was done using the TRC test.[7] All measures that have a TRC < 1.0 were included in the achievable potential for at least one scenario. A measure with a TRC result of 1.0 or greater indicates that the measure is cost-effective on a stand-alone basis (before consideration of program costs or NTG ratios). This cost-effectiveness screening was performed on all measures, even existing measures. If new measures fit within an existing program, then they were included as a part of the current program scenario but were otherwise included in the new programs.

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[6] The income qualification for ELL programs is 200% of the federal poverty level.

[7] Measure TRC benefits include avoided energy and avoided capacity costs due to the measure over the measure lifetime. Measure TRC costs are measure incremental costs; these include the difference in equipment and labor costs between the efficient and baseline units.

Table 3 shows the number of measures evaluated for cost-effectiveness and the number that were economic. About 80% of the measures evaluated were found to be economic and were therefore included in energy efficiency programs.

Table 3: Number of Measures Tested for Cost-effectiveness and Included in the Analysis

Subsector	Measure Types Tested for Cost-effectiveness	Total Measure Permutations Tested for Cost-effectiveness	Number of Measure Types Passing Cost-effectiveness Screening Included in the Analysis	Number of Measure Permutations Passing Cost-effectiveness Screening Included in the Analysis
Residential	78	416	63	307
Commercial	145	595	132	521
Industrial	117	327	93	248
Total	338	1,338	288	1,076

3.4.3 Scenario Definition and Development

ICF forecasted achievable energy efficiency potential for the above programs under two scenarios, which are defined in the points that follow. ICF first developed the current programs estimates by measuring for each program using the approaches described previously; then we developed the estimates for the expanded programs.

- **Reference case (current programs)** – Where ELL programs were modeled based on program designs implemented by ELL in program years four through six, but with some additional measures.
- **High case (expanded programs)** – Includes programs in the current programs scenario plus new best practice programs. In addition, all programs were expanded based on the benchmarking of similar programs in the southeast.

The names of the current programs (included in both scenarios) and new best practice programs (included only in the high case scenario) are shown in **Figure 2.**

Current Programs (Based on ELL programs implemented in PY4-PY6)	Expanded (New) Programs
•Residential •A/C Solutions •Home Performance with Energy Star •Income-Qualified Weatherization •Multifamily Solutions •Manufactured Homes •Retail Lighting & Appliances •School Kits and Education •Commercial & Industrial •Large C&I Solutions •Small Commercial Solutions	•Residential •Appliance Recycling •Behavioral / Home Energy Report •Midstream HVAC •Prepay •Commercial & Industrial •Agricultural Pilot •Industrial SEM •Midstream Lighting •Retro-commissioning •Small Business Direct Install

Figure 2: Programs included for potential study across scenarios

While the agricultural pilot began being offered by ELL in 2021, it was not in the data for this study so was included only in the high scenario. Assumptions about customer preferences and decision-making criteria, utility assumptions (e.g., avoided costs, discount rates), and exogenous economic factors (e.g., growth, inflation) were all held constant for both scenarios.[8]

3.4.4 Potential Assessment Approach

This section describes how ICF developed key assumptions for programs, including program costs and participation rates.

3.4.4.1 Program Costs

ICF estimated program costs to reflect average annual costs over the long run; incentive and non-incentive program cost estimates were developed. Incentives are program payments to customers, contractors, retailers, or manufacturers that lower the cost of efficient products and services. Non-incentive costs include administration, marketing, education and training, and evaluation costs. ICF did not estimate individual non-incentive cost categories for this study. The primary source for the program costs was current program spending. In developing new programs, we consider ICF program experience and program costs in other territories. Cost estimates by program are presented in the results section, 3.5, as well as the appendix section 7.2.2.

3.4.4.2 Participation

A participation rate is the percentage of eligible stock or applicable customer population predicted to install an efficiency measure each year.

For all existing programs and measures, historic data was used to determine the initial participation levels. These participation rates were also used as proxies for new measures within existing programs as well as new programs. In the high case scenario, benchmarking data was used to determine the potential expansion of the programs in future years to a new maximum market acceptance rate. The ramp-up followed an s-shaped adoption curve aligning with program planning cycles. Third-party research was used to determine the impact of altered program design, such as the transition to midstream for commercial lighting measures.[9]

In developing the program expansions, benchmarking data from other utilities in the Southeast was used. ICF accounted for mandatory energy efficiency resource standards, service area size, customer base, and weather in the benchmarking analysis. In addition, the analysis included controls for the difference in utility size and weather. By focusing on the Southeast, the analysis was better able to compare similarly in housing stock, economics, and other external factors that impact program performance.

Once the potential maximum annual participation rate was determined via the benchmarking analysis, a ramp-up shape was developed based on numerous factors. Factors considered included the program planning cycles, which did not coincide with the start of the study, the nature of the measure, and the timeline of the study. This shape was used for both the expansion of existing programs as well as the ramping up of new programs. Because such a wide variety of measures is included in this study, we could not apply just one formulaic approach to estimating program participation for all measures. Each measure was put in a group[10] with similar measures for assigning participation trends.

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[8] One reason that these factors are held constant in ICF's model is that ICF's DSM forecasts are used as inputs to ELL's integrated resource planning model, which is a dynamic model that varies utility, macroeconomic, and other assumptions.
[9] The shift in incentive targeting from down-stream customers to midstream distributors or installers has the potential to significantly expand the program reach and effectiveness due to the distributors becoming a built-in education network for the program (see EPA: Distributor-Focused Midstream Programs).
[10] Most programs have multiple measure groupings, or bundles. Some, such as Behavioral/Home Energy Report, only have one group.

3.5 Achievable Potential Results

This section will first cover the total portfolio-level potential results followed by sub-sections covering the residential and C&I individually. The savings values shown in the charts are at-generator values and all the charts and tables include information on the reference case and high case scenarios. Further detailed results are shown in appendix section 7.2.

The full portfolio has the potential to save almost 1.5 TWh by 2042 in the high scenario. In the reference scenario, the potential savings are just under 0.7 TWh in the same period. This means that the high scenario contributes an additional 113% to savings above the reference scenario level in 2042. The annual values for these savings can be seen in **Figure 3**. Additionally, the figure calls out the percentage of 2019 sales the energy savings represent for the first and last year of the program years modeled.

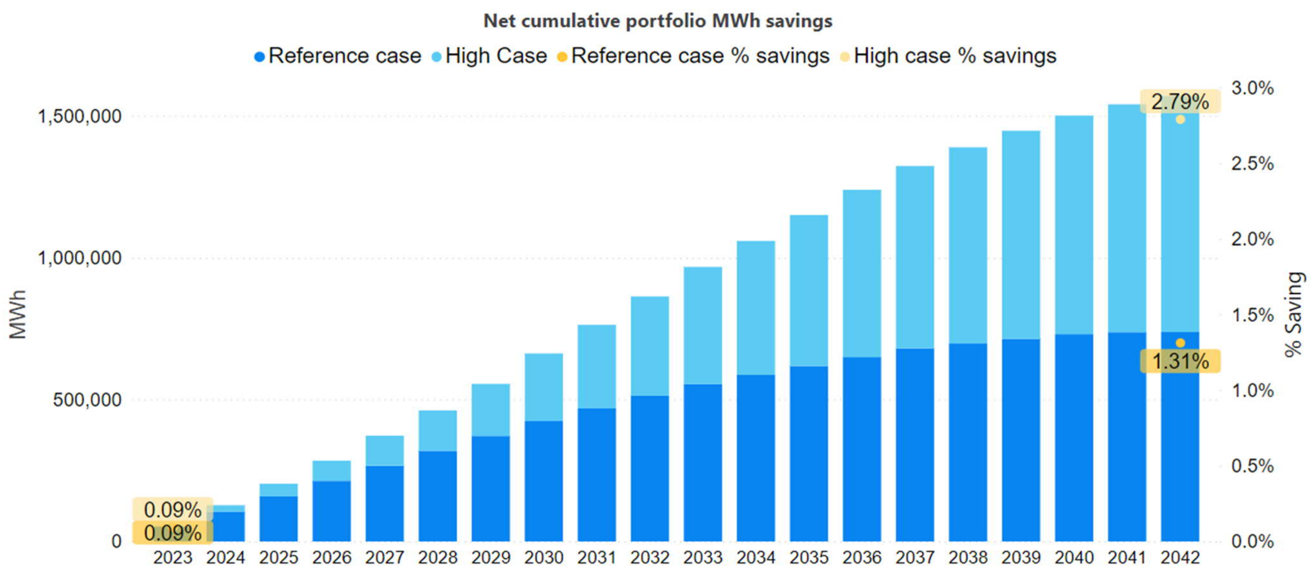

Figure 3: Net Cumulative Portfolio MWh Savings

The incremental annual savings increase only slightly in the reference scenario above-average savings achieved by ELL QuickStart programs in Program Year 5 and 6, in 2019–2020. This slight increase is primarily due to the addition of new measures. In the high scenario, annual savings achieved by ELL programs grow by a factor of 2.7. This much larger growth in annual savings is due to increased budgets for existing ELL programs and new programs. A snapshot of these savings can be seen for 2027 and 2032 in **Figure 4**.

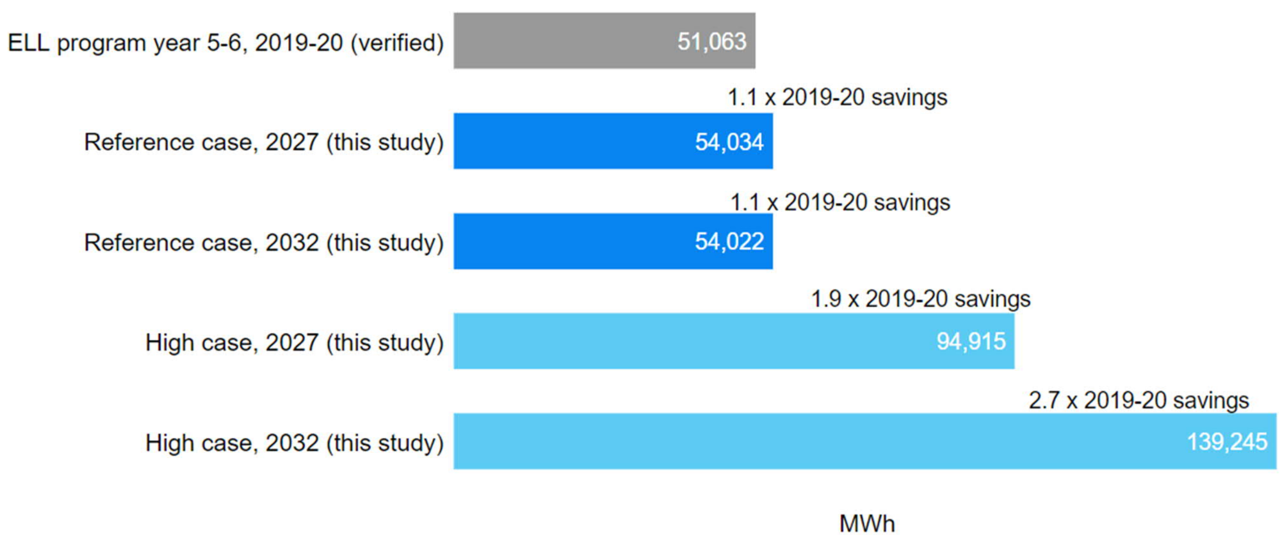

Figure 4: Total Portfolio Incremental (Annual MWh Savings, Average of PY 5 & 6 Compared to 2027 and 2032 Study Forecasts

As for the breakdown of savings between sectors, residential and commercial programs account for over 90% of cumulative savings. In the current program scenario, residential 2042 savings reach 2.3% of 2019 sales but rise as high as 4.2% of 2019 sales in the high case. The increase from the high case is larger for commercial, with the current programs scenario reaching 2.7% of 2019 sales while the high case scenario reached 6.2% of commercial electric sales. Industrial has the smallest potential by far, with cumulative savings impacts in 2042 only reaching 0.2% of sales in the current program scenario and 0.5% of sector sales in the high case scenario.

Figure 5 shows the baseline split of the forecasted electricity consumption for 2042. The residential sector contributes to 27% of the electricity consumption, while the commercial and industrial sectors contribute 23% and 50%, respectively. The savings pie chart in **Figure 5** shows the contribution of electricity savings, in 2042, from each sector. While the least savings come from the industrial sector at 6%, the residential contribution is 46% and the remaining 47% comes from the commercial sector. The low industrial potential is common across utilities as there is very limited adoption in the sector from EE programs. Industrial customers are simply less influenced by incentive-based programs and are thus often allowed to opt out of participation in such utility-provided EE programs, which is true for programs in Louisiana. Based on the ELL data, 50% of the industrial customer sales is from customers who have opted-out of their programs and is considered for this study.

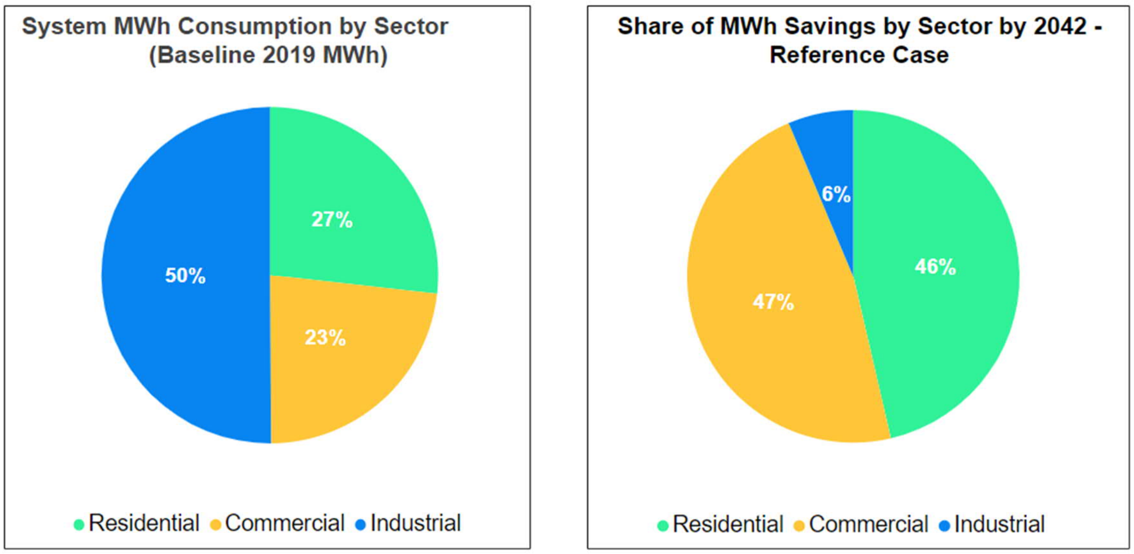

Figure 5: Electricity Consumption Baseline and Savings Split by Sector in 2042 for the Current Programs Scenario

Since the savings impacts in the industrial sector are comparatively low, and because the share of the load that is industrial is high (51%), total savings potential is only 1.3% of total ELL system sales in 2042 for the current programs scenario and 2.7% of total ELL system sales for the high case scenario. If industrial programs and industrial load were removed from the equation, the total savings potential would increase to 5.1% of system sales in 2042 in the high case scenario and 2.5% for the current programs scenario. These values are shown in **Figure 6**.

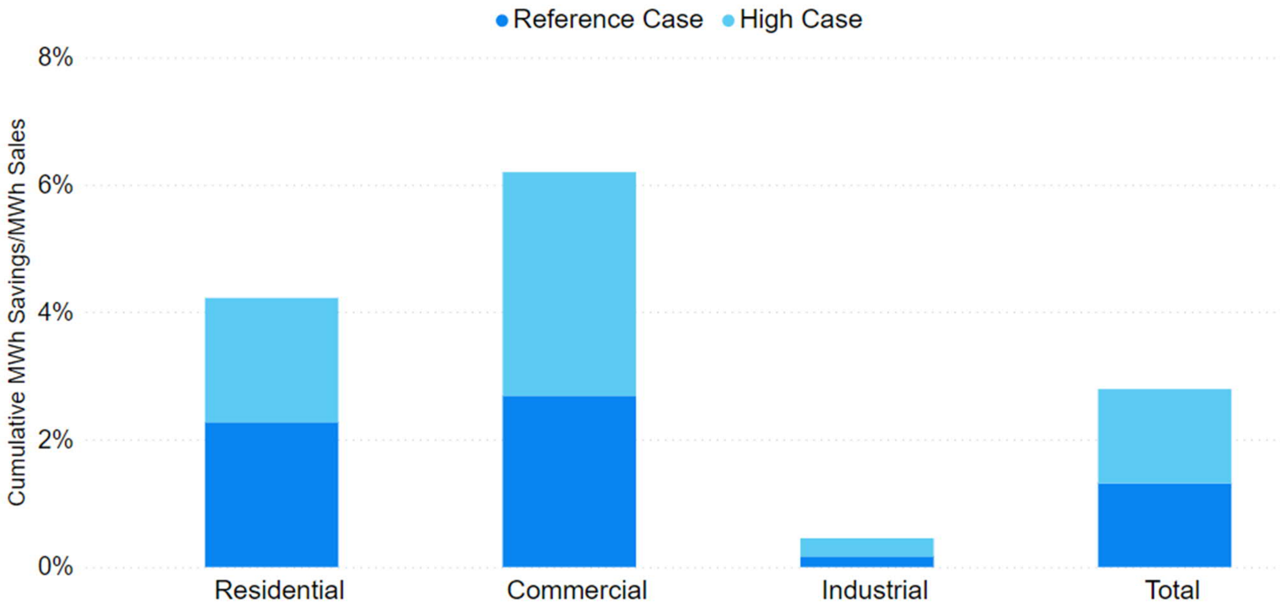

Figure 6: New Cumulative 2042 Savings as a % of 2019 Sales, by Sector

Figure 7 shows the absolute MWh savings by scenario, broken down by sector, and illustrates much of what has already been discussed individually including the dominance of the residential and commercial sector savings, the significant increase in savings in the high case scenario, and significantly larger growth of the commercial sector as compared to residential or industrial.

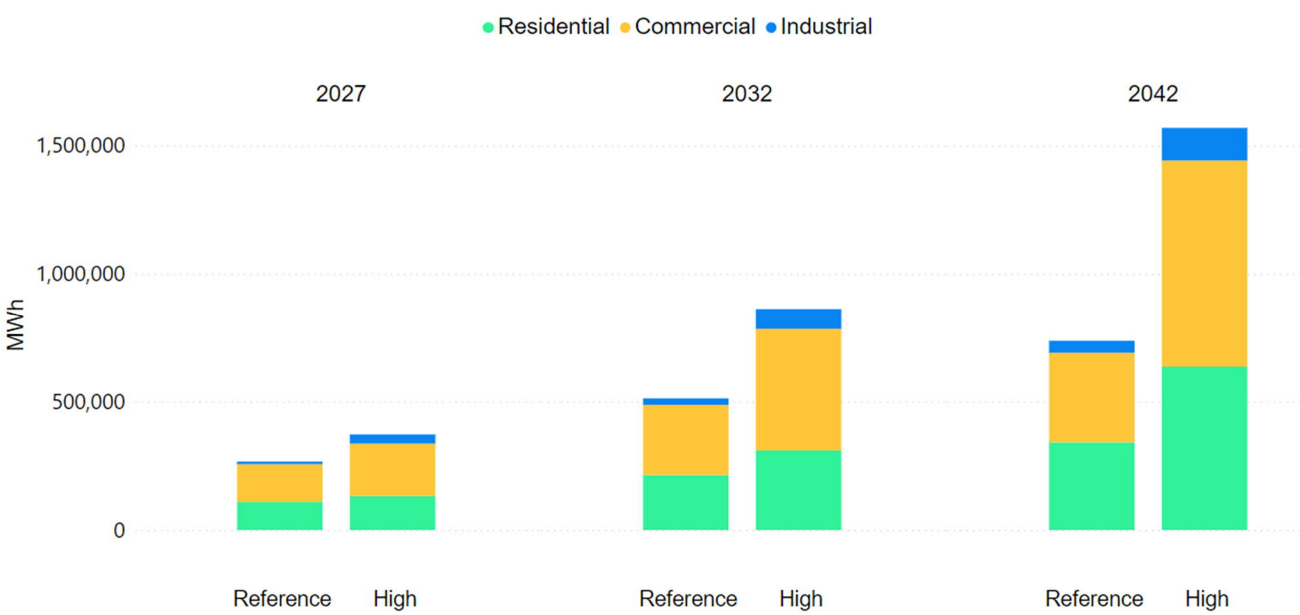

Figure 7: Net Cumulative Savings by Sector in 2027, 2032, & 2042

The following sections break down details on the residential and C&I forecast individually.

3.5.1 Residential Results

In the reference case scenario, retail lighting and appliances remains the largest residential savings opportunity. While the lighting savings are reduced starting in 2027 as discussed in section 3.3.3.1, Measure Development, the significant increase in smart thermostat adoption from the program expansion helps offset this and reinforce the program.

New programs could increase residential sector savings by close to 45% in the mid-term, driven largely by the expansion of existing programs. As the largest program in the current programs scenario, the retail lighting and appliance program see the greatest expansion. Additional details can be seen below in **Figure 8**.

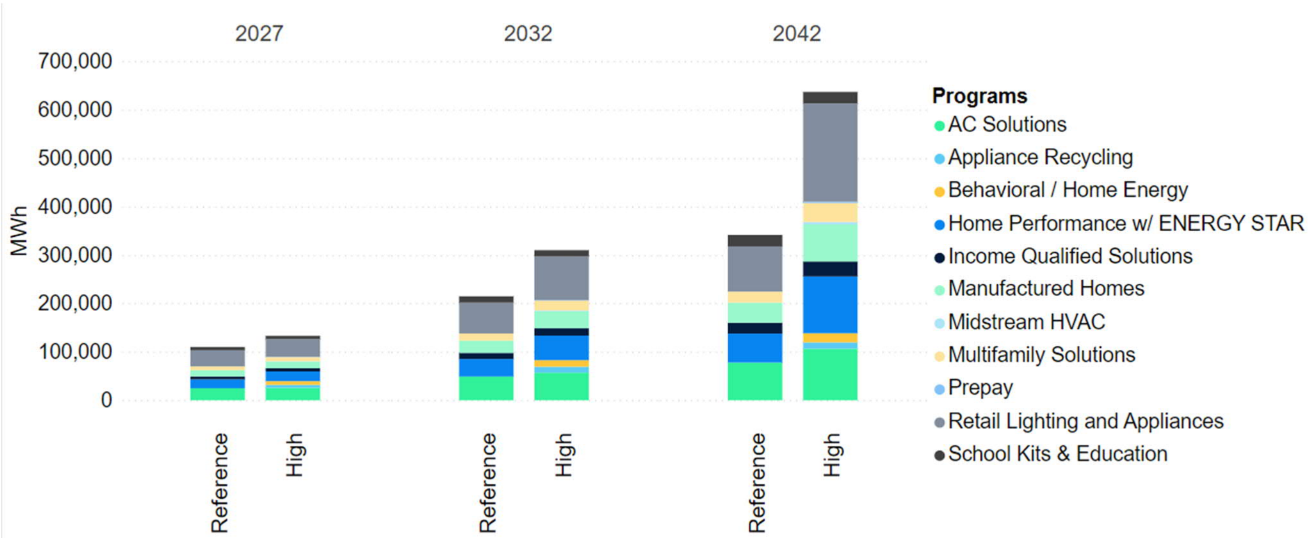

Figure 8: Net Cumulative Residential Savings by Program in 2027, 2032, & 2042

The average annual program costs drop slightly in the current programs scenario while the high case scenario has a large increase in the annual program costs. By 2037, the programs have reached their full expansion and the residential program costs have increased to be twice their program costs from the reference years. The expanded existing programs account for 79% of the growth with the other 25% increase coming from the new programs.

The Total Resource Cost (TRC) test ratio for the entire residential sector portfolio of programs drops by almost 0.2 but remains well above the cutoff point for being beneficial of 1.0. All the existing programs remain stable in their TRC ratios. All but the behavioral program are individually cost effective though the new programs generally have lower TRC ratios than the existing programs. The behavioral program is not cost-effective as a program despite the measures being individually cost-effective. This drop-in cost-effectiveness in the aggregation to a program is due to the addition of non-incentive costs. However, the potential use of the home energy reports being used as an educational tool as well as being used as a method to drive participation in the other programs, values that are harder to quantify, warrants including the program in the residential portfolio.

Details of these values can be seen in **Table 4**.

Table 4: Residential Program Cost and Cost-Effectiveness

Reference Case	Actual Cost ($ mil)	Annual Program Costs (2022 $ mil)				CE Metrics	
Program	**PY6**	**2027**	**2032**	**2037**	**2042**	**TRC**	**Levelized Cost ($/kWh)**
AC Solutions	$0.9	$0.8	$0.8	$0.8	$0.8	3.59	$0.01
Home Performance w/ ENERGY STAR	$1.0	$1.0	$1.0	$1.0	$1.0	2.70	$0.02
Income Qualified Solutions	$0.6	$0.6	$0.7	$0.7	$0.7	2.01	$0.04
Manufactured Homes	$0.8	$0.6	$0.6	$0.6	$0.6	3.62	$0.02
Multifamily Solutions	$0.4	$0.6	$0.5	$0.5	$0.5	1.76	$0.04
Retail Lighting and Appliances	$1.0	$0.7	$0.7	$0.7	$0.7	3.20	$0.01
School Kits & Education	$0.3	$0.3	$0.3	$0.3	$0.3	3.20	$0.02
Total	**$4.9**	**$4.7**	**$4.5**	**$4.5**	**$4.5**	**2.93**	**$0.02**

High Case	Actual Cost ($ mil)	Annual Program Costs (2022 $ mil)				CE Metrics	
Program	**PY6**	**2027**	**2032**	**2037**	**2042**	**TRC**	**Levelized Cost ($/kWh)**
AC Solutions	$0.9	$0.9	$1.1	$1.2	$1.2	3.62	$0.01
Appliance Recycling	NA	$0.3	$0.6	$0.6	$0.6	1.51	$0.05
Behavioral / Home Energy	NA	$0.3	$0.4	$0.6	$0.6	1.83	$0.03
Home Performance w/ ENERGY STAR	$1.0	$1.2	$2.0	$2.3	$2.3	2.73	$0.02
Income Qualified Solutions	$0.6	$0.7	$0.9	$1.0	$1.1	1.99	$0.04
Manufactured Homes	$0.8	$0.8	$1.2	$1.3	$1.2	3.65	$0.02
Midstream HVAC	NA	$0.0	$0.0	$0.1	$0.1	1.47	$0.01
Multifamily Solutions	$0.4	$0.7	$1.1	$1.0	$0.9	1.79	$0.04
Prepay	NA	$0.0	$0.0	$0.1	$0.1	2.13	$0.03
Retail Lighting and Appliances	$1.0	$0.8	$1.5	$1.7	$1.7	3.22	$0.01
School Kits & Education	$0.3	$0.3	$0.3	$0.3	$0.3	3.20	$0.02
Total	**$4.9**	**$6.1**	**$9.2**	**$10.1**	**$9.9**	**2.82**	**$0.02**

3.5.2 C&I Results

With the reduced number of programs in the C&I sector, their relative scale remains unchanged in the current programs scenario. The slight growth in the large C&I program is due to the introduction of new measures.

In the high case, midstream lighting and the expanded existing programs drive increased program savings for the sectors. Just the expansion of the existing programs could increase C&I savings by a third above the savings levels in the reference case scenario. Further details of the C&I program performance can be seen in **Figure 9**.

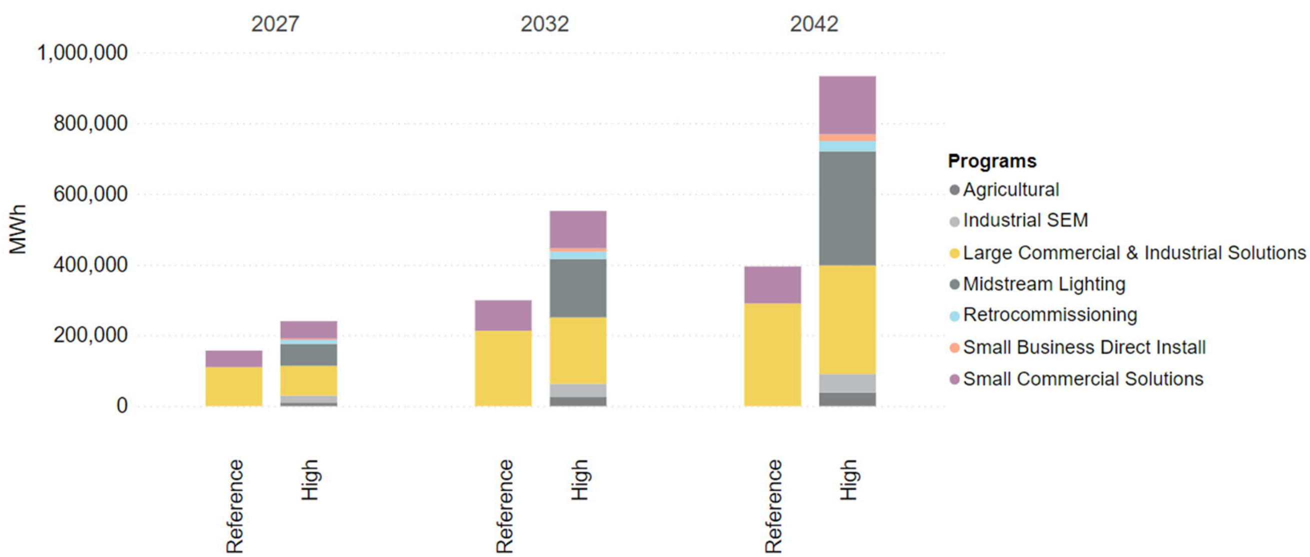

Figure 9: Net Cumulative C&I Savings by Program in 2027, 2032, & 2042

The average annual program costs increase roughly 15% in the current programs scenario due to the addition of new measures and are concentrated in the large C&I program. The high case scenario has a much larger increase in the annual program costs due to expanding existing programs and the addition of new programs. The expanded existing programs roughly account for one-third of the growth while the other two-third increase coming from the new programs.

Details of the C&I program costs and cost-effectiveness can be seen below in **Table 5**.

Table 5: C&I Program Cost and Cost-Effectiveness

Reference Case	Actual Cost ($ mil)	Annual Program Costs (2022 $ mil)				CE Metrics	
Program	PY6	2027	2032	2037	2042	TRC	Levelized Cost ($/kWh)
Large Commercial & Industrial Solutions	$2.3	$2.8	$2.9	$3.0	$3.0	3.55	$0.01
Small Commercial Solutions	$1.6	$1.7	$1.6	$1.6	$1.6	2.38	$0.02
Total	**$3.9**	**$4.5**	**$4.6**	**$4.5**	**$4.6**	**3.12**	**$0.02**

High Case	Actual Cost ($ mil)	Annual Program Costs (2022 $ mil)				CE Metrics	
Program	PY6	2027	2032	2037	2042	TRC	Levelized Cost ($/kWh)
Agriculture	NA	$0.3	$0.3	$0.3	$0.4	1.90	$0.01
Industrial SEM	NA	$1.3	$1.4	$1.4	$1.4	2.57	$0.03
Large Commercial & Industrial Solutions	$2.3	$2.3	$3.6	$4.0	$4.0	2.77	$0.02
Midstream Lighting	NA	$2.3	$3.4	$3.8	$3.7	2.95	$0.01
Retrocommissioning	NA	$0.4	$0.7	$0.8	$0.8	1.15	$0.03
Small Business Direct Install	NA	$0.1	$0.2	$0.2	$0.2	1.48	$0.01
Small Commercial Solutions	$1.6	$1.9	$2.5	$2.5	$2.5	2.40	$0.02
Total	**$3.9**	**$8.7**	**$12.1**	**$13.0**	**$13.0**	**2.54**	**$0.02**

The Total Resource Cost (TRC) test ratio for the entire sector's portfolio of programs drops by almost 0.6 but remains well above the cutoff point for being beneficial of 1.0. While the small commercial program remains stable in its TRC ratio at 2.4, the Large C&I Program TRC ratio drops significantly from 3.5 in the current programs scenario to 2.8 in the high case The drop in the TRC ratio for the Large C&I Program is due to the lighting measures being removed and shifted into the midstream lighting program. All the programs are individually cost-effective though most of the new programs have lower TRC ratios than the existing programs.

3.6 Key Findings

The key EE results are:

- **The full portfolio has the potential to save almost 1.5 TWh by 2042.** In the reference case, the potential savings are just under 0.7 TWh in the same period.

- **Total incremental (annual) savings increase by two- to three-fold in the long term.** In the high case scenario, annual savings achieved by ELL programs grow by a factor of 2.7 above average savings achieved by ELL programs in Program Year 5 and 6, in 2019–2020. The growth in annual savings is due to increased budgets for existing ELL programs and to savings achieved by new and expanded programs, which contribute an additional 113% to savings above the current programs scenario level in 2042.

- **Residential and commercial programs account for over 90% of cumulative savings.** Cumulative program savings impacts in the residential sector reach 4.2% of residential electric sales in 2042 in the high case; cumulative program savings impacts in the commercial sector reach 6.2% of commercial electric sales. Industrial has the smallest potential by far, with cumulative savings impacts in 2042 only reaching 0.5% of sector sales in the high case. Since the savings impacts in the industrial sector are comparatively low, and because the share of the load that is industrial is high (51%), the total savings potential is 2.7% of total ELL system sales in 2042. If industrial programs and industrial load were removed from the equation, the total savings potential would increase to 5.1% of system sales in 2042 in the high case scenario. In the reference case, the total savings potential is 1.3% and 2.5% if industrial is excluded.

- **In the reference case, retail lighting and appliances remain the largest residential savings opportunity, with a large increase in smart thermostat adoption helping offset the reductions in lighting savings.** New programs could increase residential sector savings by close to 45% in the mid-term, driven largely by the expansion of existing programs.

- **Midstream lighting and the expanded existing programs drive increased program savings in the commercial and industrial (C&I) sectors.** Expanded programs could increase C&I savings by a third above the reference case.

- **The combined portfolio of residential, commercial, and industrial programs has a Total Resource Cost test ratio of 3.0 in the reference case, and 2.5 in the high case.**

4 DEMAND RESPONSE (DR) POTENTIAL

4.1 Overview

A high-level process flow of ICF's bottom-up approach for DR potential evaluation, which includes calculation of program participation, savings impacts, and costs for various DR programs, is shown in **Figure 10**. Details of the process are discussed in Section 4.4.3.

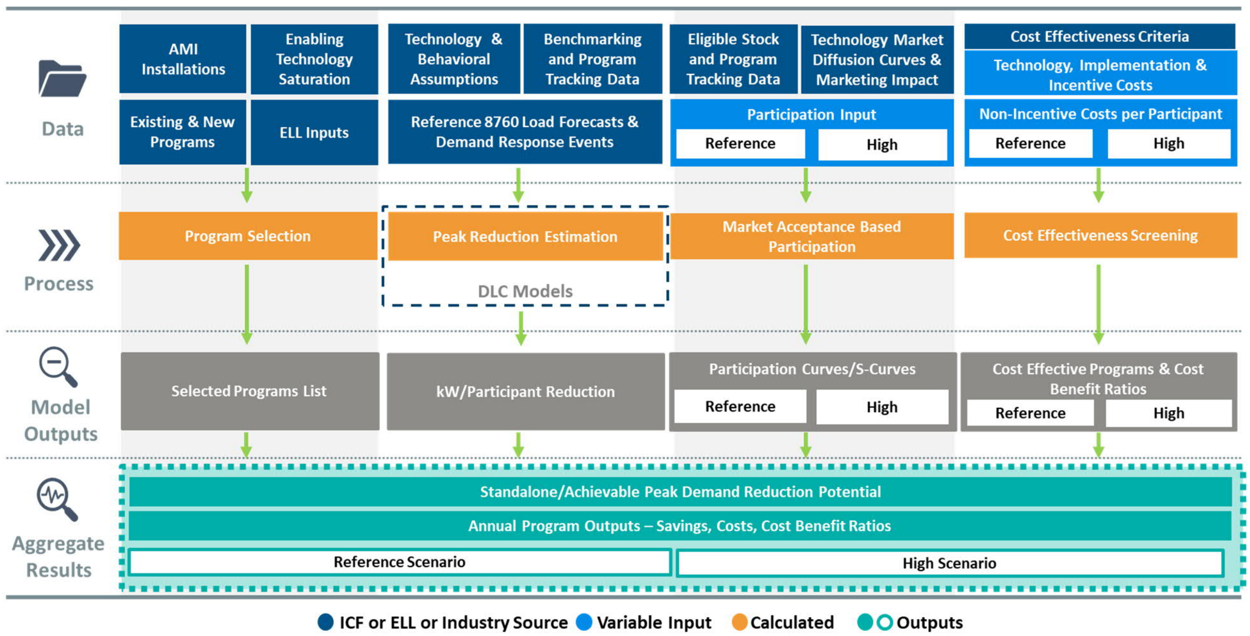

Figure 10: Summary of ICF's Approach to DR Achievable Potential Modeling

4.2 DR Program Types and Definition

Table 6 shows the list of programs and measures ICF selected, in consultation with ELL, to assess in this potential study. All the programs included are event-based programs that rely on events called by the utility[11] to invoke a response either from the customer or directly controlled by the utility to reduce demand.

All programs included, except interruptible load, are assumed to be dispatchable and controlled by the utility. A dispatchable program provides greater control to the utility to reduce the peak demand at the time of system need, as compared to other types of DR programs that rely on price responsiveness and behavioral modifications that may have greater uncertainty. A brief description of the existing interruptible program and the selected programs that cleared the cost-effectiveness test in the high scenario, as modeled in this study, is provided below.

- **Direct Load Control (DLC) – Water End Uses -** Direct load control is a program wherein the utility sends a signal to the customer's end use device to either completely turn off the device or reduce the power usage of the device. Customers are given the option to override the event when they choose to, and event notifications can be set up via electronic/mobile communication.
- **Water Heaters and Pool Pumps -** The DLC switch, in the case of these measures, is assumed to disconnect the heating or filtration process. There are additional options available such as pre-

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[11] For all programs, (1) there are no restrictions to participation (except interruptible load, where an aggregation component for small C&I customers has been added), (2) ICF models a reference and high level to capture a range of participation scenarios.

heating of water, and optimization of the daily schedules along with remote ability to control or override events like smart thermostats.

Table 6: List of Programs and Measures

Sector	Program	Measure	Program Type
Residential	Direct Load Control	Direct Load Control – Water End Uses	New
Residential	Smart Thermostat	Smart Thermostat	New
Residential	Battery Storage	Battery Storage	New
Residential	Direct Load Control	Direct Load Control – Room ACs	New
Residential	EV Chargers	EV Chargers	New
Commercial	Direct Load Control	Direct Load Control – Water End Uses	New
Commercial	Smart Thermostat	Smart Thermostat	New
Commercial	Agricultural Irrigation Load Control	Agricultural Irrigation Load Control	New
Commercial	Interruptible	Interruptible - New	New
Commercial	Thermal Storage	Thermal Storage	New
Industrial	Interruptible	Interruptible – New	New
Industrial	Interruptible	Interruptible – Existing	Existing

- **Smart Thermostats -** Smart thermostat program for residential HVAC systems operates through a remotely controllable programmable or smart thermostat. During the event, the utility sends a signal to the thermostat which in turn increases the setpoint by a few degrees. Additionally, there is a 2-hour pre-cooling to ensure maximum comfort for the participants. Thermostats return to the original setpoint after the event. Customers are given the option to override the event when they choose to. Event notifications can be set up via electronic/mobile communication (email or phone) or via a display on the thermostat for supporting devices.

  For this potential study, this program is assumed to be delivered via two options - direct install and bring your own thermostat (BYOT), however, results are reported at the program level. While the utility pays for all costs for direct install, it pays an incentive for enrollment into the program in the case of bring your own thermostat. As for the program implementation, the event calls were assumed to call a 6-hour event split into two overlapping 4-hour blocks with 50% of participating customers in each block. This avoids the possibility of creating a new peak due to snapback.

- **Interruptible Load -** Interruptible load is a program for C&I customers that involves customers identifying load that constitutes the flexible component for the customer and can be curtailed during peak events.

  For this potential study, the industrial customers on existing legacy interruptible tariffs – CS-L, EECS-L, Rider 2 to LIS-L, IS-G, EIS-I-G – are assumed to continue with those tariffs.[12] Additional customers are allowed to enroll in the new, LPSC-approved, interruptible riders – IES and EIO – within two modes of implementation:
  - Commercial and industrial customers eligible for the new riders are modeled as eligible stock for the program

[12] These five existing interruptible tariffs are closed to new business.

  - Smaller C&I customers and customers on rates not eligible for the IES and EIO riders, but with a flexible component to their load, are assumed to be eligible to participate in a separate, new interruptible program

  While the term of contract for customers enrolling in Riders IES and EIO varies from 5 to 10 years based on the tariff option chosen, the models assume that the customers renew the contracts at the end of the terms. The result is that any customer that enters interruptible service, remains available for load interruption through the end of the study period i.e., 2042.

- **Agricultural Irrigation Load Control -** This is a new program wherein ELL installs the hardware required for controlling the irrigation during DR events. The wells are powered off during the event. A notification is provided to the customer at least a couple of hours prior to the event.

4.3 Data Collection

This section details the data that was used in developing the potential for the DR programs modeled for ELL.

4.3.1 ELL-Provided Data

The following utility data was provided by ELL:

- Annual and hourly system energy usage forecasts, by customer class
- Annual avoided cost forecasts—energy and capacity
- Annual customer count forecasts, by customer class
- Retail rates forecast by customer class through 2025
- Historical industrial sales by segment
- Transmission and distribution losses by customer class
- Reserve margin
- Weighted-average cost of capital (WACC)
- Interruptible program tracking data for C&I customers

4.3.2 External Program and Measure Data

ICF estimated the technical feasibility of the programs selected using:

- U.S. Department of Energy Residential Energy Consumption Survey (RECS, 2015)
- U.S. Department of Energy Commercial Buildings Energy Consumption Survey (CBECS, 2016)

For the electric vehicle charging direct load control program, program development inputs also use the following sources:

- Residential hourly electric vehicle forecast provided by ELL
- ELL EV Forecast - # of EVs in Service Territory

4.3.3 Development of ELL-Specific Inputs for the Selected Programs

ELL specific inputs for the selected DR programs use various sources as references:

- Potential studies conducted across the country for various utilities
- Program data from ESource
- ICF program implementation data and experience

The two primary inputs that are needed to model and estimate the long-term potential are:

- **Impact Estimation**
  DR programs use kilowatt (kW) per participant reduction or a percentage of customer peak reduction, to determine the peak reduction potential of a program. The estimates developed and used in this potential study for the various programs selected are provided in Appendix 7.4. These

have been calibrated to ELL historic program tracking data for the existing programs, and they are obtained from research of other programs, pilots, and potential studies coupled with inputs from ICF implementation teams, for the new programs.

- **Participation Modeling**
Participation for DR is modeled using the Bass diffusion curve, which results in cumulative participation across years. The ramping parameters for the curve are determined based on ICF program implementation experience and potential study modeling data, while the maximum market share (i.e., the steady-state participation achieved towards the end of the study period) is determined from the sources specified above in this section. The maximum market shares used for various scenarios in this potential study are shown in Appendix 7.4 as well.

  For the existing interruptible program, the participation curve was calibrated to the historic program tracking participation data provided by ELL.

4.4 Program Modeling

4.4.1 Elements of Analysis

The assumptions with respect to the elements of the analysis and the reporting methodology that were made in the study are listed in this section:

- **Peak months and events**: Peak summer months were June through September. A maximum of 15 4-hour events are called during the highest average 4-hour load during summer months for any program, with exception of the residential smart thermostat[13].
- **Baseline peak**: The peak month was assumed to be August. The event four-hour blocks in August are used to determine the baseline peak load and the reported savings.
- **Economic screening**: All programs were screened for cost-effectiveness with a primary cost-effectiveness test of the TRC test. Programs were included in the achievable potential if it passed the TRC test.
- **Mode of program delivery**: It was assumed that all programs were opt-in.
- **Level of savings used in the analysis**: Savings reported for DR are all at the central station generator.
- **Program applicability to sub-sectors**:
  - For the residential programs, all programs were assumed to be applicable to all sub-sectors and building types.
  - For the commercial programs, the smart thermostat applies to small and medium commercial customers. DLC–water end uses programs are assumed to be applicable to all sub-sectors and building types within the commercial and government sector. The interruptible program was applicable to all sub-sectors as well, due to the possibility of demand savings from smaller customers.
  - For the industrial sector, the interruptible program applies to all industrial customers.

  Note that the smart thermostat program for commercial is merged into the residential program
- **Non-Incentive Costs for Programs**: Non-incentive costs for programs that apply to multiple sectors are assumed to have a split of costs between the sectors. For example, the DLC–water end uses program is assumed to be primarily residential, which takes up the bulk of the setup costs, and the commercial programs are assumed to leverage the setup, while adding the lower amount of additional setup, for program administration and implementation.

[13] Smart thermostat program, with high participation, runs into issues of creating a new peak due to pre-cooling or snapback. This warranted the events for smart thermostat program to be called over a 5-hour period instead of the standard 4-hour period, as in the case of other programs

- **Levelized Cost ($/kW)**: The Levelized cost is the net present value of the cost of unit demand reduction over its lifetime. The costs include all the incentive and non-incentive costs from the UCT test.
- **Program hierarchy**: The program hierarchy shown in Error! Reference source not found. was assumed for eligible stock accounting, wherein if a customer can't participate in two programs simultaneously (such as interruptible and smart thermostat), the eligible stock for the second program in the hierarchy assumes that the participants in the first program are excluded.

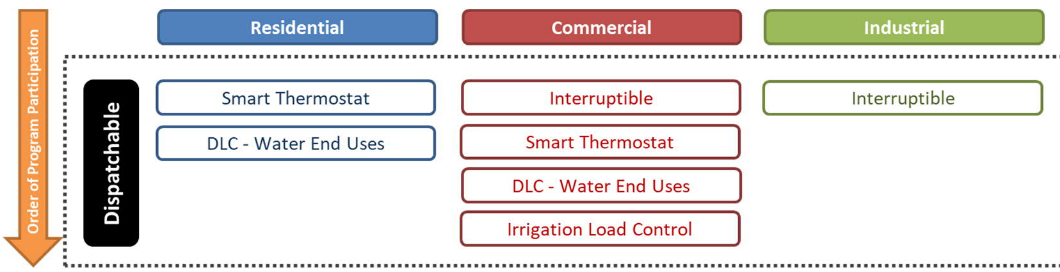

Figure 11: Program Hierarchy Assumption

Note that only the programs that cleared the TRC test in the high case are included in the study and shown in the hierarchy in Error! Reference source not found..

4.4.2 Scenario Definition and Development

ICF modeled two scenarios (reference & high) for this potential study, and the primary differentiating input between the two scenarios is the participation achieved. The varying participation also results in the savings and the costs being different for the two scenarios, thus representing a range for the achievable potential from DR programs. Sample cumulative participation curves showing different levels of maximum market share being achieved over the study period is shown in **Figure 12**.

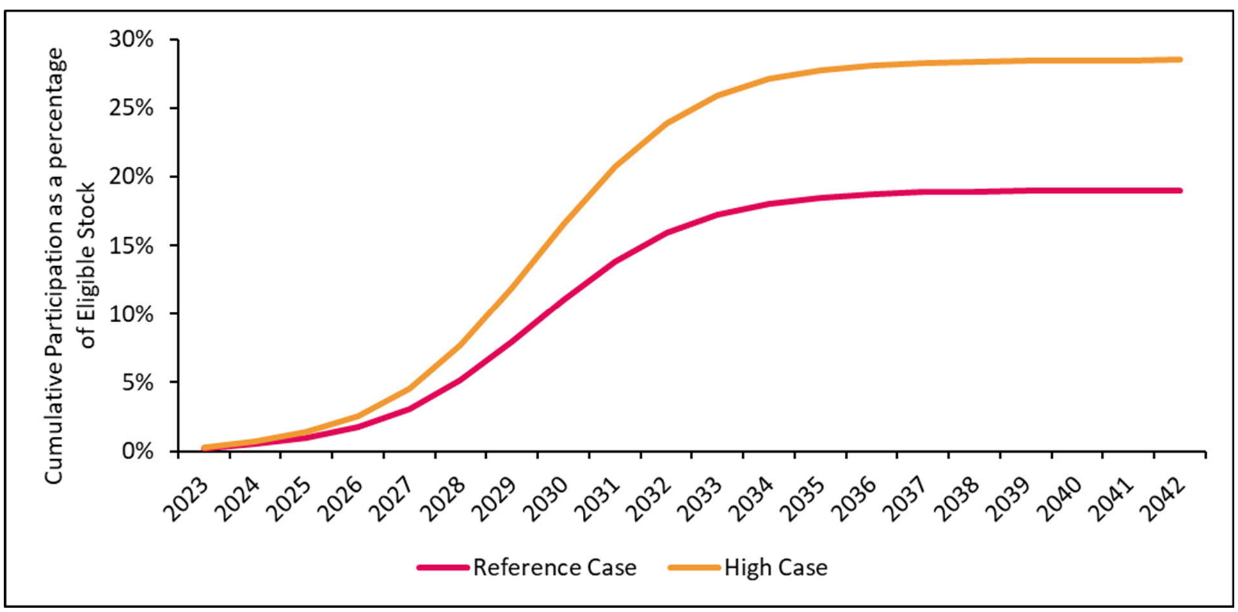

Figure 12: Sample Participation Curves by Case

- **Reference Case**

This case represents the realistic level of participation and cost-effective savings that could be achieved by utility programs.

- **High Case**
  High case represents an aggressive level of potential achievement when compared to the reference level. It was modeled by changing the maximum market share of the participation curves to usually 1.5 times the reference case levels with exceptions for particular programs[14]. Note that this also changes the adoption across the entire study period, since the rate of adoption varies across years to achieve the different levels of maximum market share set for each scenario.

4.4.3 Potential Assessment Approach

This potential study involved a four-step process: program selection, peak reduction estimation by program, application of market acceptance-based participation, and then cost-effectiveness screening to result in the achievable potential (**Figure 13**).

Figure 13: Potential Assessment Process Flow

- **Program Selection**
  Program selection is a critical task in determining the potential of demand-side management (DSM) resources. There are a myriad of demand response pilots and implementations underway in the United States, but it is important to determine which ones are applicable to the service territory of ELL taking into consideration the eligible technological stock, the load profile characteristics, feasibility of implementation of programs as well as utility and/or stakeholder preference for programs. The programs selected for this study, after discussion with ELL, are listed in Table 6.

- **Peak Reduction Estimation**
  ICF used a bottom-up approach to estimate the demand savings from DR programs and their measures, as applicable. The savings of measures were then aggregated into programs, and the program savings rolled up into the complete DR portfolio savings. For the event-based programs modeled in this study, ICF used a direct load control module, a high-level schematic of which is shown in **Figure 14**.

Figure 14: ICF Direct Load Control Module

[14] For example, a program such as agricultural, which has limited data available due to a small number of such programs being run in the country, was assumed to have same adoption rates for reference and high cases.

- **Market Acceptance based Participation**
  This step involved estimating eligible stock, technology market diffusion curves, and marketing impacts. Program participation is estimated once the size of the eligible stock is determined for each program. The maximum achievable participation levels for programs were determined from research and applied to the program using the Bass diffusion curves discussed in Section 4.4.1

- **Cost-Effectiveness Screening**
  ICF estimated the implementation and technology costs classified into incentive and non-incentive costs. The overarching assumption was 1 full-time equivalent employee each for the administrative component of the costs and program development, with additional marketing, implementation, and incentive costs layered in. To come up with these costs, ICF leveraged the database of costs it has built over time from various program implementations and resources such as filings and potential studies for new programs. The costs for programs that are common to the residential and commercial sectors are assumed to be split with the residential program starting up first and taking the bulk of the information technology infrastructure setup. The benefits, on the other hand, were estimated using the avoided capacity and energy costs provided by ELL.

  Once the programs were modeled and the corresponding costs determined, the following cost-effectiveness ratios were also estimated for the study - TRC, UCT, Ratepayer Impact Measure (RIM), and Levelized costs ($/kW). The benefits and costs were evaluated over 20 years.

After estimating the achievable potential for all screened programs, the hourly load shapes were built. Except for interruptible programs - all other programs assume 100% snapback pre- and/or post- the DR event, and the load shapes consequently are energy neutral.

After the potential assessment is completed using the 4-step approach, ICF created the 8,760 hourly loadshapes for DR programs and checked if any of the programs, individually, ran into the issue of creating new peaks due to the snapback effect. If such a scenario is encountered, the program design was altered to see if a wider event-calling period was better suited to reduce the peaks. If a modified program design also does not avoid the creation of new peaks, the participation is altered, and the potential analysis is repeated. This iterative approach was employed for the DR assessment. For example, the residential smart thermostat program in the high case encountered the issue of potentially creating new peaks, and after analyzing various options, the high case participation was mapped back to the reference case participation for just this program.

4.4.4 Program Screening and Benefit/Cost Analysis

As mentioned in the previous section, the TRC, UCT, and RIM benefit-cost ratios were calculated for the programs and portfolios. The program screening however was done using the TRC test. All programs that have a TRC > 1 at least for one of the scenarios (usually high scenario), and existing program(s) (irrespective of their cost-effectiveness), were included in the final achievable potential for all scenarios. The list of programs that cleared the TRC test as well as the existing industrial interruptible program for ELL are listed in **Table 7**.

Table 7: TRC Screened Cost-Effective Programs (and the Existing Industrial Interruptible Program)

Sector	Program	Measure	Program Type
Residential	Direct Load Control	Direct Load Control – Water End Uses	New
Residential	Smart Thermostat	Smart Thermostat	New
Commercial	Direct Load Control	Direct Load Control – Water End Uses	New
Commercial	Smart Thermostat	Smart Thermostat	New
Commercial	Agricultural Irrigation Load Control	Agricultural Irrigation Load Control	New
Commercial	Interruptible	Interruptible - New	New
Industrial	Interruptible	Interruptible – New	New
Industrial	Interruptible	Interruptible – Existing	Existing

The cost-effectiveness metrics – TRC benefit cost ratio as well as the levelized capacity costs – for the screened-out programs i.e., the ones that do not pass a program screening cost-effectiveness test, are shown in **Table 8**. The savings results for these programs do not show up in the achievable potential results.

Table 8: Cost-Effectiveness Results for Screened-Out Programs[15] for Reference and High Cases

Reference Case

		CE Metrics	
Sector	**Program**	**TRC**	**Levelized Cost ($/kW)**
Residential	Battery Storage	0.19	$264.70
	Direct Load Control - Room AC	0.63	$241.18
	EV Smart Charger	0.26	$371.15
Commercial	Direct Load Control - Room AC	0.46	$290.62
	Thermal Storage	0.61	$133.20

High Case

		CE Metrics	
Sector	**Program**	**TRC**	**Levelized Cost ($/kW)**
Residential	Battery Storage	0.19	$256.11
	Direct Load Control - Room AC	0.81	$210.58
	EV Smart Charger	0.33	$296.34
Commercial	Direct Load Control - Room AC	0.56	$257.70
	Thermal Storage	0.72	$110.71

[15] Battery storage program is associated with high upfront costs for the customer due to the cost of the battery and the installation. Due to slower adoption of batteries, compared to more prevalent technologies like smart thermostats, the high upfront costs are not offset by the capacity benefits thus resulting in a TRC ratio significantly less than 1.
The EV program's low TRC is mainly due to 'not enough' adoption and participation to offset the costs of running the program, even with the steady-state/max market share in the reference and high cases set to capture the range of possible levels over which participation could vary with current and further implementation designs. While ICF modeled the program with the chargers as the primary operating device since the other program delivery modes (e.g., using telematics) are still nascent, a sensitivity check was done with and without the cost of chargers, and in both scenarios the program doesn't clear the TRC test.
Direct load control for room AC also does not clear the TRC, due to relatively lower saturation numbers of room ACs and their corresponding participation not resulting in enough benefits to offset the costs.
Thermal storage suffers due to high upfront costs for setup, inspection etc. of storage devices and very less adoption.

4.5 Achievable Potential Results

The achievable potential results shown in this section are the DR dispatched annually – calculated as the average reduction from the events in the peak month; i.e., August. As noted in Section 4.4.4., this section includes only the programs that cleared the cost-effectiveness screening i.e., TRC >1, as well as the existing industrial interruptible program.

In the reference case, DR programs have the potential to reduce load at the time of the forecasted summer peak demand by 9% by the year 2042, which amounts to 925 MW. **Figure 15** shows the trend of savings across the study period for the two scenarios.

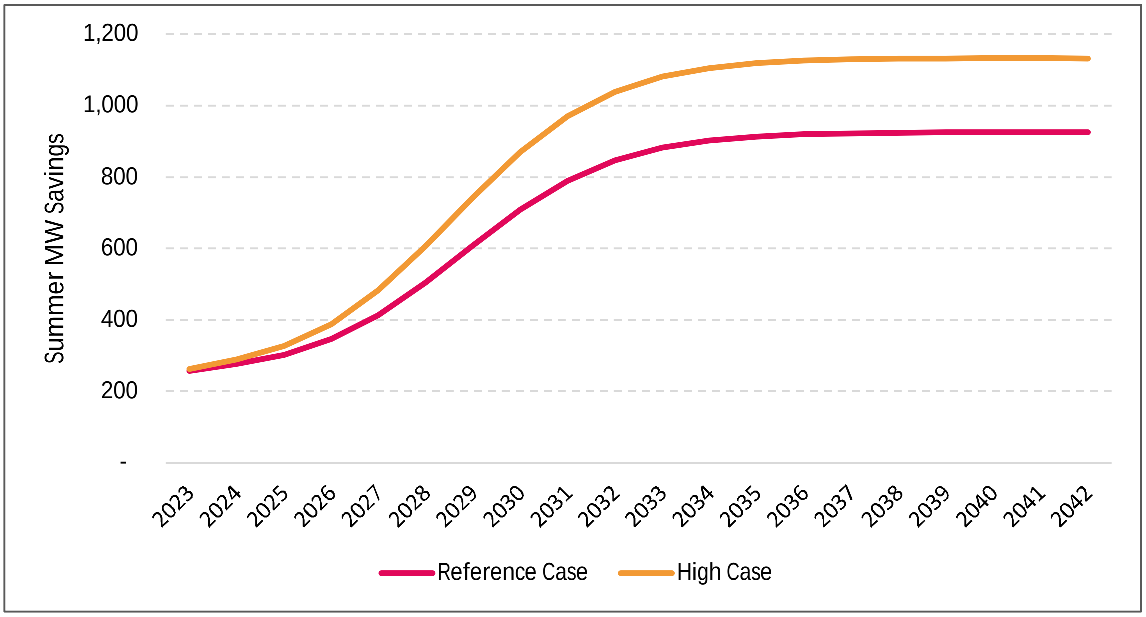

Figure 15: Savings Across the Study Period, by Scenario

Figure 16 shows the percentage savings by scenario and sector of peak demand that can be reduced.

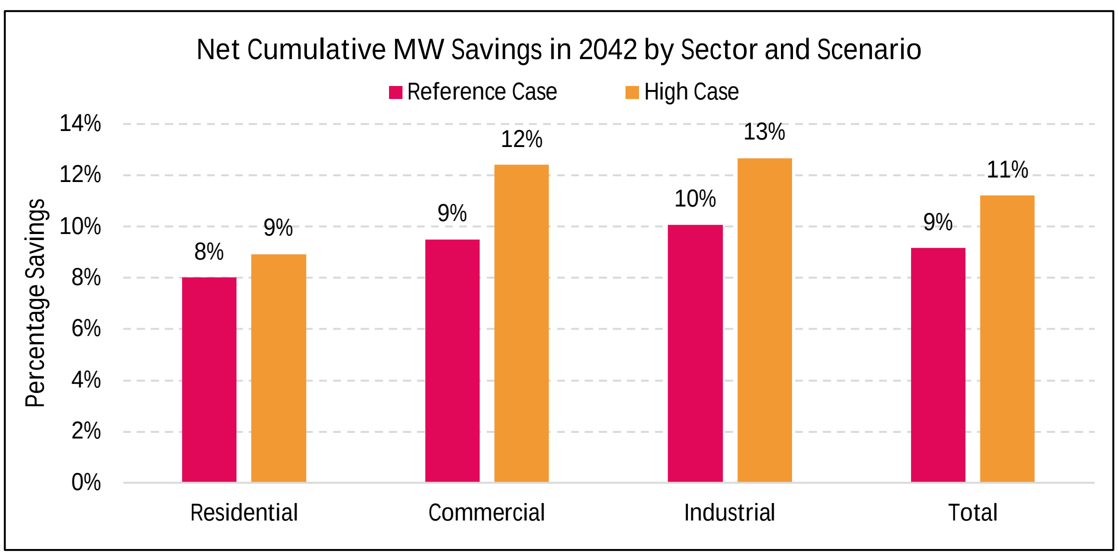

Figure 16: Percentage Summer MW Peak Savings Split by Sector & Scenario for 2042

Figure 17 shows the baseline split of the peak load for 2042. The residential sector contributes to 38% of the peak load, while the commercial & industrial sectors contribute 24% & 37% respectively. The savings pie chart in **Figure 17** shows the contribution of demand savings, in 2042, from each sector. While a majority of savings comes from the industrial sector that contributes to 42% of the savings, the residential contribution is 33% and the rest i.e., 25% comes from the commercial sector.

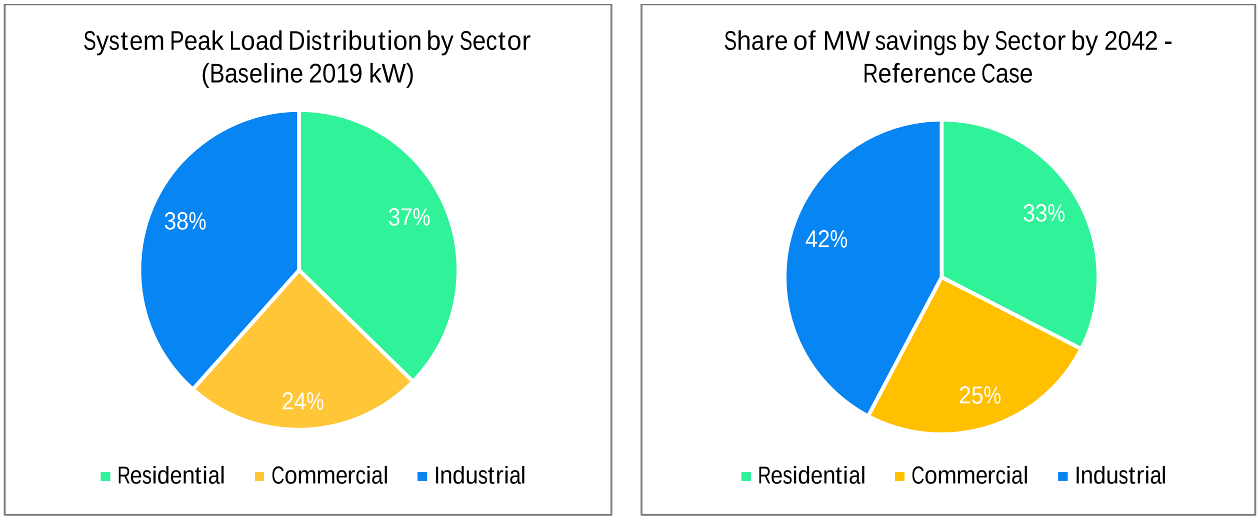

Figure 17: Baseline and Savings Split by Sector & Scenario for 2042

Figure 18 shows the real costs that will be incurred for running the programs in the reference scenario in each year. The real costs are expected to rise until 2030 and then drop till 2034 around when the participation rates for all programs start to saturate. The replacement costs of enabling devices and re-participation costs (including marketing) for existing customers whose enabling devices expire, results in the curve for the second half mimicking the first half of the study period, albeit at a higher level due to incentives for the larger participant base. The share of costs is the highest for the industrial sector, due to the higher share of participant count and relatively higher cost of running the interruptible program.

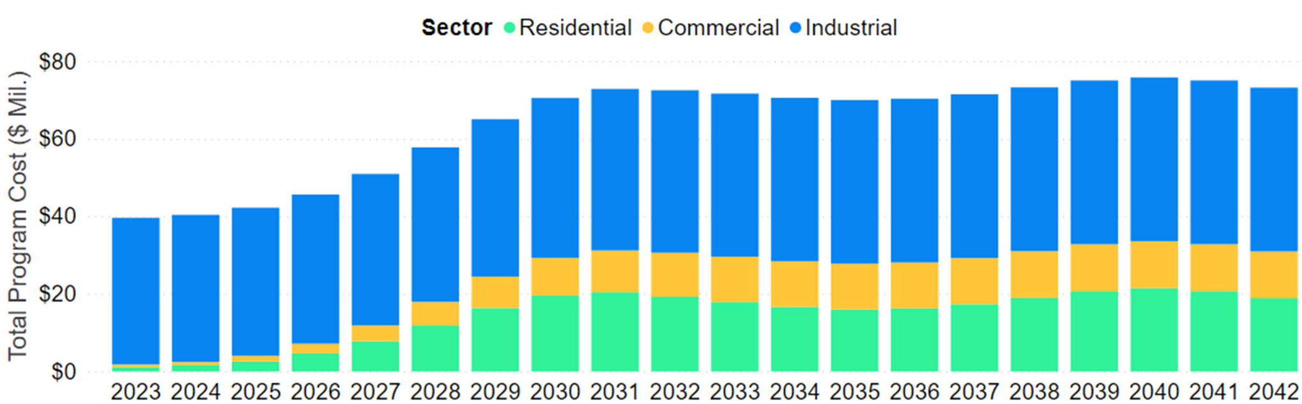

Figure 18: Annual Program Costs Split by Sector for Achievable Reference Scenario

4.5.1 Residential Results

Figure 19 shows the residential savings potential for select years, by program, for reference and high cases. Savings are estimated to reach 302 MW in reference case and 336 MW in the high case by 2042. In 2042, smart thermostats contribute to the bulk of the savings at 77% of the total for reference case followed by 23% savings contribution by DLC–water end uses.

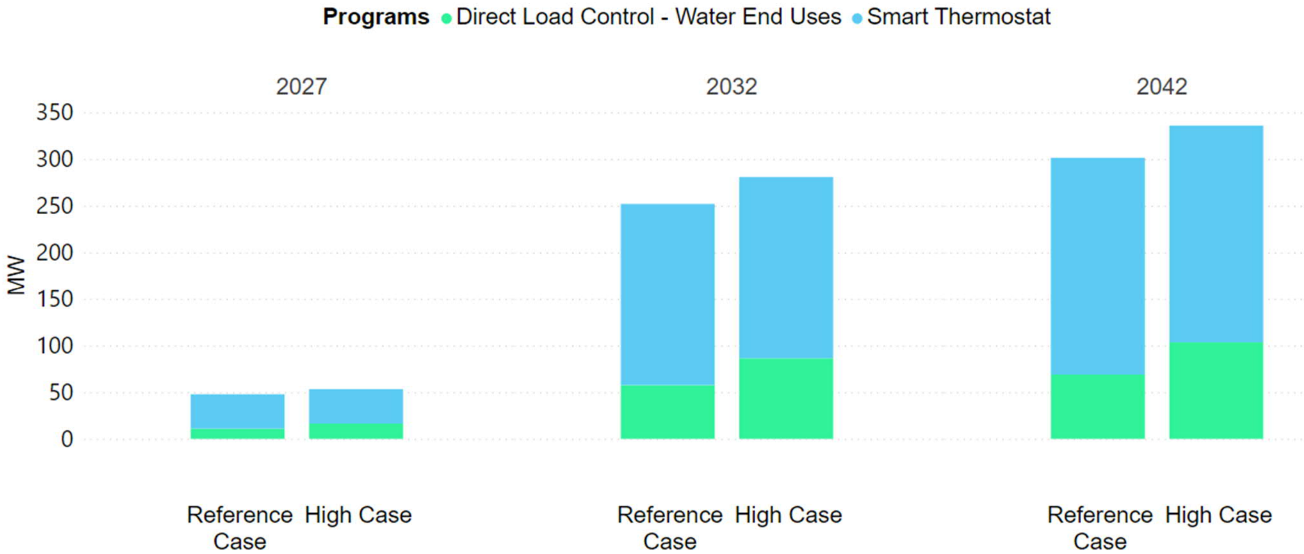

Figure 19: Residential Summer MW Peak Savings for selected years, by Program and Scenario

Table 9 shows the real costs & cost-effectiveness for selected years for the residential programs. In the reference case, the smart thermostat program has a TRC of 4.5 followed by DLC–water end uses TRC at 1.2. The overall portfolio clears TRC at 2.8. Note that the smart thermostat program for the high case was mapped back to the reference case to avoid new peak formation due to high snapback resulting from high participation, as mentioned in Section 4.4.3.

Table 9: Residential Achievable Reference Case Annual Costs & Cost-Effectiveness Ratio

Reference Case		Annual Program Costs (2022 $ Mil.)				Cost Effective (CE) Metrics		
Sector	Program	2027	2032	2037	2042	Applicable Ratio	Benefit-Cost Ratio	Levelized Cost ($/kW)
Residential	Direct Load Control – Water End Uses	$ 3.7	$ 8.4	$ 7.1	$ 7.9	TRC	1.2	$ 149.2
	Smart Thermostat	$ 4.1	$ 10.8	$ 10.2	$ 11.0	TRC	4.5	$ 56.6
	Residential Sector Total	**$ 7.8**	**$ 19.2**	**$ 17.3**	**$ 18.9**	**TRC**	**2.8**	**$ 77.7**

High Case		Annual Program Costs (2022 $ Mil.)				Cost Effective (CE) Metrics		
Sector	Program	2027	2032	2037	2042	Applicable Ratio	Benefit-Cost Ratio	Levelized Cost ($/kW)
Residential	Direct Load Control – Water End Uses	$ 5.5	$ 12.5	$ 10.5	$ 11.8	TRC	1.3	$ 147.9
	Smart Thermostat	$ 4.1	$ 10.8	$ 10.2	$ 11.0	TRC	4.5	$ 56.6
	Residential Sector Total	**$ 9.6**	**$ 23.4**	**$ 20.7**	**$ 22.8**	**TRC**	**2.5**	**$ 84.7**

4.5.2 C&I Results

Figure 20 shows the C&I savings potential by program, for specific years, for the reference & high cases. Savings are estimated to reach 623 MW in the reference case and 795 MW in the high case by 2042. In the 2042 commercial sector, about 75% savings are estimated from the interruptible program followed by agricultural irrigation load control at 22%. Savings contributions of 1.7% and 2.1% are realized from DLC–water end uses and smart thermostat, respectively. Since the interruptible program is the only program in the industrial sector, albeit with existing and new components, it constitutes 100% savings.

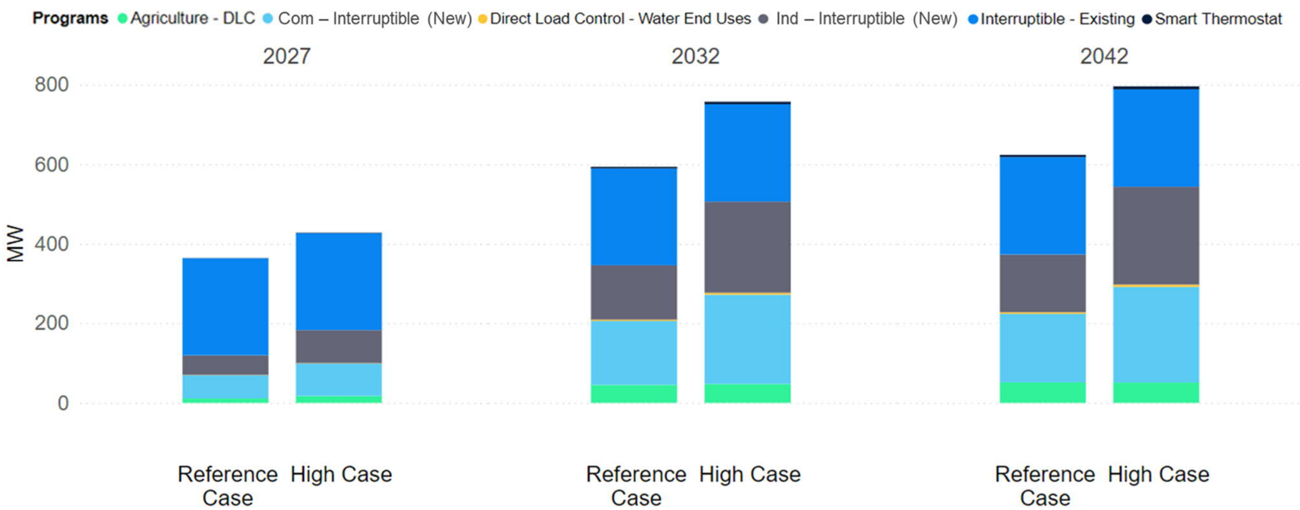

Figure 20: Commercial and Industrial Summer MW Peak Savings for selected years, by Program and Scenario

Note that the results for the 'aggregation' feature of the C&I Interruptible program, which models the smaller C&I customers who are not eligible for current tariff riders, are included within the 'Com - Interruptible (New)' and 'Ind – Interruptible (New) portion of the chart. The aggregation portion contributes to about 47% of the total potential of the interruptible (New) program.

Table 10 shows the real costs for selected years & cost-effectiveness, for the C&I sectors. In the commercial reference case, the new interruptible program has a UCT[16] of 1.6, while the smart thermostat program has a TRC of 2.6 followed by DLC–water end uses TRC at 1.2. The agricultural irrigation load control program has a TRC of 3.6. The overall portfolio clears TRC at 3.3 and UCT at 1.6. In the industrial sector, the new interruptible program has a UCT of 2.6 in the reference case and 4.0 in the high case. The existing industrial interruptible program does not clear the UCT test and has a benefit-cost ratio of 0.5, bringing down the UCT of the industrial portfolio to be below 1 for both reference and high cases. The levelized costs for all programs and portfolios are also shown in **Table 10**.

Table 10: C&I Achievable Reference Case Annual Costs & Cost-Effectiveness Ratio

Reference Case — Annual Program Costs (2022 $ Mil.) — Cost Effective (CE) Metrics

Sector	Program	2027	2032	2037	2042	Applicable Ratio	Benefit-Cost Ratio	Levelized Cost ($/kW)
Commercial	Agriculture - DLC	$ 0.6	$ 1.9	$ 2.0	$ 2.0	TRC	3.6	$ 42.7
	Direct Load Control – Water End Uses	$ 0.2	$ 0.5	$ 0.4	$ 0.4	TRC	1.2	$ 140.5
	Interruptible - New	$ 3.2	$ 8.6	$ 9.2	$ 9.3	UCT	1.6	$ 54.1
	Smart Thermostat	$ 0.1	$ 0.3	$ 0.3	$ 0.3	TRC	2.6	$ 70.5
	Commercial Sector Total	**$ 4.1**	**$ 11.3**	**$ 11.9**	**$ 12.0**	**UCT**	**1.6**	**$ 53.4**
Industrial	Interruptible - New	$ 1.6	$ 4.4	$ 4.8	$ 4.8	UCT	2.6	$ 32.7
	Interruptible - Existing	$ 37.5	$ 37.5	$ 37.5	$ 37.5	UCT	0.5	$ 153.3
	Industrial Sector Total	**$ 39.1**	**$ 41.9**	**$ 42.3**	**$ 42.3**	**UCT**	**0.7**	**$ 119.8**

High Case — Annual Program Costs (2022 $ Mil.) — Cost Effective (CE) Metrics

Sector	Program	2027	2032	2037	2042	Applicable Ratio	Benefit-Cost Ratio	Levelized Cost ($/kW)
Commercial	Agriculture - DLC	$ 0.8	$ 1.9	$ 2.0	$ 2.0	TRC	3.9	$ 40.9
	Direct Load Control – Water End Uses	$ 0.3	$ 0.6	$ 0.5	$ 0.6	TRC	1.3	$ 133.9
	Interruptible - New	$ 3.8	$ 10.4	$ 11.1	$ 11.1	UCT	1.9	$ 46.6
	Smart Thermostat	$ 0.1	$ 0.4	$ 0.4	$ 0.4	TRC	3.2	$ 64.4
	Commercial Sector Total	**$ 5.0**	**$ 13.3**	**$ 14.0**	**$ 14.1**	**UCT**	**1.8**	**$ 47.5**
Industrial	Interruptible - New	$ 1.8	$ 5.0	$ 5.3	$ 5.3	UCT	4.0	$ 21.6
	Interruptible - Existing	$ 37.5	$ 37.5	$ 37.5	$ 37.5	UCT	0.5	$ 153.3
	Industrial Sector Total	**$ 39.3**	**$ 42.5**	**$ 42.8**	**$42.8**	**UCT**	**0.9**	**$ 101.4**

[16] Note that TRC is not considered as the primary test for Interruptible program, since the incentive cost which is the bulk of the cost of the program doesn't figure into the TRC test. UCT is considered a more appropriate cost-effectiveness criteria and hence, for the Interruptible programs in both sectors – commercial and industrial, as well as for the corresponding sector level portfolios in which Interruptible is the majority contributor, UCT is reported.

4.6 Key Findings

- **Interruptible & smart thermostat programs are the high-performing programs for DR potential.** In 2042, About 60% savings are achieved from the interruptible program, 26% savings are achieved from the smart thermostat program followed by DLC–water end uses & agricultural DLC programs contributing to 8% & 6% savings, respectively.
- **Interruptible program has a maximum contribution for savings in the C&I sector.** In 2042, in the reference case, the interruptible program contributes to 75% savings in the commercial sector, whereas in the high case the contribution increases to 79%. Since the interruptible program is the only program for the industrial sector, it accounts for 100% of industrial savings across both cases in all years. Within the industrial savings, 37% in 2042 comes from the new program in the reference case, and this contribution increases to 50% in the high case.
- **Smart thermostats contribute two-thirds of the overall residential savings.** In the reference case, smart thermostat program contributes to 77% of the total savings while 23% of the contribution is by DLC-water end uses the program. However, in the high case, the savings contribution for the smart thermostat program is 69% and DLC-water end uses program contributes to 31% savings. Due to the formation of new peaks in the snapback hours, the high case for the smart thermostat program was mapped to the reference case.
- **The portfolio level cost-effectiveness i.e., TRC is greater than 1 across both the cases.** In all sectors, all programs except the existing industrial interruptible program have TRC benefit-cost ratios greater than 1 in both cases.[17]

[17] As noted above, this estimate does not include the existing interruptible program.

5 DISTRIBUTED ENERGY RESOURCES (DER) POTENTIAL

5.1 Overview

ICF's approach to DER modeling relies on the same type of project-level economics used in our forecasting of DR. ICF applied these project economics via a top-down (utility-wide) correlation between project economics and DER adoption in other U.S. markets. Doing so creates analytic efficiencies while allowing strong comparability of results between ELL and other utility markets.

ICF's analysis followed the five-step process described below and pictured in **Figure 21**:

1. Establish baseline conditions and customer project-level economics for each DER technology in ELL territory. This included:

    a. Collecting relevant DER cost, performance, and adoption data from ELL, national sources, and other state and utility markets.

    b. Drafting input assumptions for reference and high scenarios, reviewing assumptions with ELL, and mutually agreeing on assumptions to be used.

    c. Populating assumptions into 25-year Pro-forma (cash flow) models of project-level DER economics from the customer perspective.

    d. Calculating the investment payback period from the Pro-forma models for the 240 combinations of customer type and DER technology, scenario, and forecast year listed below.[18]

        i. Residential PV; C&I PV; and standalone C&I battery storage[19] (3 customer/technology combinations).

        ii. Two utility sub-territories[20] (2 territories)

        iii. Reference and high scenarios (2 scenarios)

        iv. Annual forecasts for 2023 through 2042 (20 years).

[18] ICF used an "attachment rate" model (with high and reference scenario rates) based on precedents in other U.S. markets in lieu of calculating investment payback periods for fourth and fifth DER customer technologies: residential battery storage when paired with PV and C&I battery storage when paired with PV. This is because there is not an economically-viable use case for this technology in ELL's territory given the rate structures of the utility's most common tariff rate schedules for residential and small to mid-sized C&I customers. ICF observes customers adopting battery storage when they install PV systems even in markets without present economic uses, whether to offer back-up power, in expectation of future electricity rate changes, or for other reasons. In contrast, there can be an economic use case for certain large C&I customerswith rates that have relatively high peak demand ($/kW) costs that can be shaved through well-timed battery discharge and low energy ($/kWh) costs that must be paid to recharge the batteries. That is why an economic payback-based methodology, as opposed to an attachment rate methodology, was used for battery storage for large C&I customers. Because large C&I rates typically offer minimal economic returns for on-site PV, a standalone battery configuration (not paired with PV) was used for large C&I customers.

[19] Standalone residential battery storage was not included as a DER technology in ICF's analysis because there is not economic use case for this technology in ELL's territory.

[20] ICF conducted its DER analysis at the sub-territory level before summing results at the ELL utility-wide level for presentation in this report. The two sub-territories are legacy Entergy Louisiana (labeled as "ELL") and Entergy Gulf States Louisiana (labeled as "EGSL"). The reasons for conducting sub-territory analysis were (i) rate structures differ between the sub-territories in ways that affect projected DER economic returns and technology adoption, and (ii) current levels of PV adoption differ between the two sub-territories.

2. Utilize the historical adoption experience of other U.S. markets with customer PV and battery storage systems to inform market acceptance curves.[21] ICF linked these curves to the forecasted investment payback periods for DER technologies in ELL's territory and secular growth trends to estimate adoption (i.e., the achievable potential) of the technologies by ELL customers.
3. Produce annual achievable potential forecasts of customer DER installed capacity and net electricity generation for 2023 through 2042 period. Results calculated for the ELL and EGSL sub-territories are summed at this step to obtain utility-wide results.
4. Allocate the annual forecasts performed at the C&I level into separate commercial and industrial customer results.
5. Convert the annual generation forecasts into ELL net hourly load impacts, including gross charge and discharge data for battery storage, through the use of well-grounded data on DER technology use patterns.

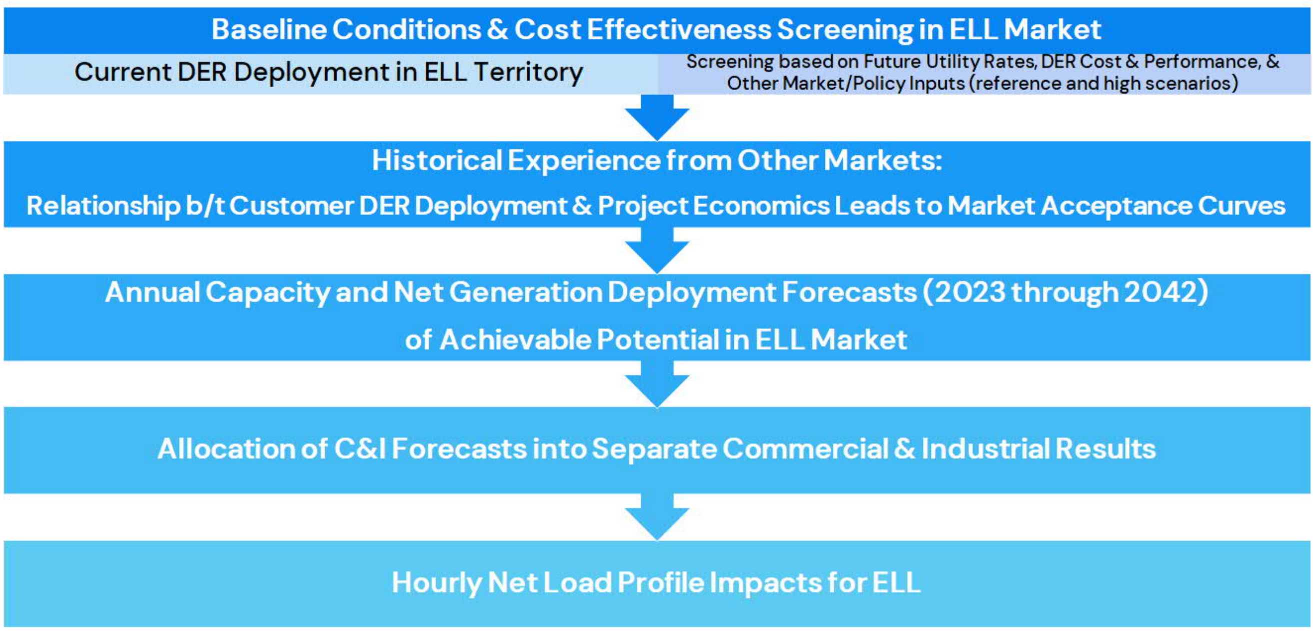

Figure 21: Summary of ICF's Approach to DER Achievable Potential Modeling

5.2 DER Technology Types and Definition

ICF analyzed five combinations of customer type and DER technologies (hereafter abbreviated as "DER technologies"), as shown in **Table 11**. We selected these as the DER technologies based on their current

[21] While this DER potential study did not include distinct value streams for resilience and net zero carbon benefits, our methodologies rely on market acceptance curves that implicitly include various customer motivations for adopting clean energy measures. Those motivations often include energy bill savings, energy cost certainty, environmental improvement, resilience against power outages, and grid independence. The high scenarios in the DER modeling, in particular, can be thought to more highly value factors like environmental improvement and resilience because their market acceptance curves are heavily influenced by higher DER penetration markets with relatively low carbon grids and more pairings of PV and battery storage that offer resilience.

deployment levels, prevalence in other markets, and suitability for long-range forecasting.[22],[23] We used a prototype size for each of the five combinations of technology and customer type to assess annual, project-level economic returns or attachment rates and to produce net load shapes of forecasted ELL customer adoption of the technology.

System sizes for PV technologies are listed in direct current (DC), while battery storage technology sizes are listed in alternating current (AC) measures of power (kilowatt, or kW) and energy (kilowatt-hour, or kWh). The former denotes the maximum amount of power that can flow into or out of the battery system at any one time subject to technical limitations (its instantaneous capacity), while the latter describes the amount of energy that can be stored in total in the battery system.[24] The ratio of energy (kWh) to power (kW) in a battery storage system is called its "duration" and is expressed in hours.

Table 11: List of DER Technologies Analyzed

Sector	Technology	Prototype Individual Project Size
Residential	PV	7 kW_{DC}
C&I	PV	40 kW_{DC}
Residential	PV + Battery Storage	PV: 7 kW_{DC} Battery: 5 kW_{AC}/12 kWh
C&I	PV + Battery Storage	PV: 40 kW_{DC} Battery: 35 kW_{AC}/70 kWh
C&I	Standalone Battery Storage	Battery: 200 kW_{AC}/800 kWh

The prototype size for residential and C&I PV reflects average national system sizes, as does the size of the residential battery storage system, as further described in Section 5.3.3 below.

[22] Specifically, there is a substantial volume of customer PV already installed in ELL territory, with 63.3 MW_{AC} of residential PV and 4.6 MW_{AC} of C&I PV as of June 2021. Across other utility markets, customers are increasingly installing battery storage with PV and in standalone configurations, which is why those technology types were included.

[23] ICF considered, but did not include, additional DER supply-side and control technologies such as community solar and microgrids in this potential study. Community solar was not included because ELL's Optional Community Distributed Generation Rider did have not substantial enough capacity to be independently modeled. We did not model any additional community solar programs to avoid speculating on how utility programs and rate structures might change in the future. For microgrids, there are three reasons that they were not included in this potential study. First, many of the underlying technologies in microgrids (e.g., PV, battery storage, EE) are already included in this study. Therefore, an independent microgrid forecast would need to exclude the customary impacts of those technologies to avoid double-counting. Second, to estimate the incremental impacts of microgrids would require detailed data on their expected hourly operation, which is not readily available. Third, microgrids are not standardized. They tend to be deployed at vastly different scales, with different underlying distributed generation and load control technologies, and with different operating rules and economic, environmental, and resilience objectives. Therefore, making annual growth assumptions about the number, scale, and impacts of microgrids is not likely to be accurate.

[24] For more information on battery metrics, see National Renewable Energy Laboratory (NREL), *Batteries 101 Series: How to Talk About Batteries and Power-To-Energy Ratios*, 2016, at: https://www.nrel.gov/state-local-tribal/blog/posts/batteries-101-series-how-to-talk-about-batteries-and-power-to-energy-ratios.html.

The size of the C&I battery storage system paired with PV was selected to have AC power approximately equal to the PV system's AC-equivalent capacity and a two-hour battery duration, as is common among C&I battery storage systems nationally when they are paired with PV. The size and duration of the standalone C&I battery system were established to maximize economic use for batteries under ELL's C&I rate schedules with relatively high monthly peak demand charges. That economic use case involves charging the battery system during times of low customer demand and discharging the battery during times of high customer demand to reduce average demand on a monthly basis.

5.3 Data Collection

ICF relied on a mix of public data from credible government and electricity industry sources and confidential data provided directly by ELL in response to ICF requests. The categories of data used in our analysis are described in the two sections below and then, the use of that data to create specific input assumptions tailored for this analysis is described in Section 5.3.3.

5.3.1 ELL-Provided Data

ELL provided the following types of data that were used in the DER forecasts, as well as additional information that was requested by ICF but not directly used in our forecasts.

- Capacity and year achieving commercial operation of interconnected customer PV systems.[25]
- Guidance on the portion of solar electricity that is typically consumed on-site by customers of Entergy utilities versus exported to the utility.
- Guidance on any current and planned utility DER programs.
- Aggregate hourly consumption load shapes by customer class.
- Customer counts by class and tariff rate.
- Forecasted future retail electricity prices by customer class.
- General price inflation estimates through 2042.
- Transmission and distribution (T&D) loss factors by customer class.

The non-PV specific information provided by ELL was also used in the DR and EE forecasts.

In addition to data sent by ELL, ICF collected information on ELL customer residential and C&I electricity rates and compensation rates and requirements for PV power exported back to the utility from the utility's published tariffs.

5.3.2 External Technology and Market Data

ICF collected data on PV and battery storage technology capital costs, operations and maintenance (O&M) costs, and performance factors from a combination of U.S. Department (DOE) and DOE-sponsored laboratory sources, as well as state public utility commission-funded, grid operator-funded, and DER

[25] No interconnected customer (behind-the-meter) battery storage systems for residential or C&I customers were included in the ELL data provided to ICF. However, to be clear, this does not preclude the possibility that such systems exist as ELL would only be aware of these behind-the-meter resources if the battery storage system was clearly noted in the customer's interconnection request.

industry reports. Data were distinguished between residential and C&I systems and sized in relation to the prototype systems used for this ELL analysis.

In addition to technology cost and performance data, ICF collected and evaluated detailed data on annual adoption patterns for behind-the-meter PV and battery storage systems across all states from DOE and DER industry sources to inform the market acceptance curves used in these forecasts.

5.3.3 Development of ELL-Specific Inputs for the Selected Technologies

Key assumptions for the project-level DER Pro-forma models are listed in **Table 12**. Values in the table correspond to residential, commercial, and industrial DER systems and to the high and reference forecast scenarios unless otherwise noted.

Assumptions were reviewed with ELL and reflect the mutual agreement between ELL and ICF that the values are appropriate for the purposes and within the limitations, of this analysis. The data sources chosen were affected by those publicly available at the time associated analyses were performed by ICF. Decimal digits have been rounded in some cases.

Table 12: Key Input Assumptions for DER Technologies Analyzed

Input	Value	Source
Individual System PV Capacity	7 kW_{DC} (residential and small commercial & industrial in EGSL sub-territory)[26] 40 kW_{DC} (all other commercial & industrial)	Rounded up from the median value of 6.5 kW_{DC} for residential systems and used the median value of 40 kW_{DC} for non-residential systems, both from Lawrence Berkeley National Laboratory (LBNL), Tracking the Sun: 2020 Distributed Solar Data Update, 2020, p. 6, https://emp.lbl.gov/sites/default/files/distributed_solar_2020_data_update.pdf.[27]
Individual Residential Battery Storage Size	5 kW_{AC} (power) 12 kWh (energy)	Approximate mean values from the most prevalent residential battery storage products paired with PV in LBNL, Behind-the-Meter Solar + Storage: Market Data and Trends, 2021, p. 14, https://eta-publications.lbl.gov/sites/default/files/btm_solarstorage_trends_final.pdf.
Individual Commercial & Industrial Battery Storage Size for Small and Medium-Sized Customers	35 kW_{AC} 70 kWh	Approximately matched battery power to the PV power of the prototype C&I system used in this forecast on an AC basis and used

[26] The most common non-residential rate class in the EGSL sub-territory is SGS-G, the customers of which have annual electricity consumption equivalent to average-sized residential customers. Therefore, ICF used a residential-scale PV system for its forecast of SGS-G customers. All residential PV system cost and performance parameters described below were applied for the SGS-G customers, except it was assumed that only 10% of PV power was exported back to the utility consistent with other non-residential customers. Because SGS-G customers are businesses, however, this study's investment tax credit, depreciation, and income tax assumptions were applied to the analysis of PV systems on their premises.

[27] Historically (between 2004 and mid-2021), the average (mean) size of residential PV systems in ELL territory has been 6.2 kW_{DC}. More recently, between 2019 and mid-2021, the average size of residential PV systems has risen to 7.4 kW_{DC} in ELL's territory. This is consistent with national trends towards larger residential systems. The average size of non-residential PV systems in ELL territory has been 10.2 kW_{DC} historically (2004 to mid-2021), while their average size has also risen between 2019 to mid-2021 to 21.3 kW_{DC}.

Input	Value	Source
		a 2-hour duration for energy-based non-residential battery storage systems paired with PV in LBNL, Behind-the-Meter Solar + Storage: Market Data and Trends, 2021, p. 15.[28]
Individual Commercial & Industrial Battery Storage Size for Large Customers	200 kW_{AC} 800 kWh	ICF modeling to optimize peak demand savings under ELL's demand-based rate structures for large C&I customers. The four-hour battery storage duration is the longest commonly seen for C&I customers.
Inverter Loading Ratio (DC to AC capacity ratio)	1.13 (residential) 1.17 (C&I)	Median values from LBNL, Tracking the Sun: 2020 Distributed Solar Data Update, 2020, p. 11, for residential and "small non-residential" systems. The "small non-residential" value was used because it corresponds to the system size analyzed in this report for C&I customers.
Annual PV Capacity $Factors_{DC}$ (in year 1 of operation)	17.3% (residential) 16.7% (C&I)	ICF calculations using National Renewable Energy Laboratory (NREL) PV Watts® for fixed roof mount systems, averaged from the locations of Baton Rouge and West Monroe, Louisiana.[29,30]
Annual PV Capacity $Factors_{AC}$ (in year 1 of operation)	19.5% (residential) 19.5% (C&I)	AC capacity factors are obtained by multiplying the DC capacity factors above by the respective customer class inverter loading ratios above.
Annual PV System Performance Degradation (after year 1 of operation)	0.5%	Median value from NREL, Solar Technical Assistance Team (STAT) FAQs Part 2: Lifetime of PV Panels, 2018. https://www.nrel.gov/state-local-tribal/blog/posts/stat-faqs-part2-lifetime-of-pv-panels.html.
Annual Battery Storage System Performance Degradation (after year 1 of operation)	1%	BTM lithium-ion battery storage values from California Public Utilities Commission (CPUC), Proposed Inputs & Assumptions: 2019-2020 Integrated Resource Planning, 2019, p. 18, https://www.cpuc.ca.gov/uploadedFiles/CP

[28] The AC capacity of the prototype C&I PV system is 34.2 kW_{AC}. That is calculated by dividing the 40 kW_{DC} system capacity by the assumed inverter loading ratio of 1.17.

[29] PV Watts® default values were utilized by ICF, except the following values used as substitutes: inverter loading ratios listed on the prior row of this table; premium modules; 97% inverter efficiency; 13% system losses for residential PV; and 16% system losses for C&I PV.

[30] PV Watts® data are publicly-available at: https://pvwatts.nrel.gov/. PV capacity factor data were obtained for this analysis in the summer of 2021 and reflect NREL's application of PV technology performance at that time. NREL periodically updates PV Watts® assumptions and, therefore, capacity factors calculated from this source may change in the future.

Input	Value	Source
		UCWebsite/Content/UtilitiesIndustries/Energy/EnergyPrograms/ElectPowerProcurementGeneration/irp/2018/Prelim_Results_Proposed_Inputs_and_Assumptions_2019-2020_10-4-19.pdf.
Portion of PV Annual Output Exported Back to Utility	30% (residential) 10% (C&I)	Residential: Based on utility analysis of data from customers with PV systems in multiple Entergy operating companies. C&I: Based on ICF's hourly PV production modeling, ELL's average commercial customer load profile, and an ICF assumption on the capacity sizing of commercial PV systems vis-à-vis load.
Consumption Load Shapes (applied to all years of analysis)	Hourly, systemwide residential, commercial, and industrial load shapes for 2023[31]	ELL.
PV System Capital Cost	Annual residential and commercial values from NREL, 2021 Annual Technology Baseline, https://atb.nrel.gov/electricity/2021/data. Used NREL's advanced and moderate cases for the high and reference scenarios, respectively, in this forecast.[32]	
Commercial & Industrial Battery Storage System Capital Cost in 2023[33]	BTM lithium-ion battery storage values	CPUC, Proposed Inputs & Assumptions: 2019-2020 Integrated Resource Planning, 2019, p. 61. Low (meaning "low cost") and mid values from the CPUC source correspond to the high and reference scenarios, respectively, in the ELL analysis.[34]
Commercial & Industrial Battery Storage System Capital Costs after 2023	Annual percentage decline rates for battery storage	NREL, 2020 Annual Technology Baseline (ATB), https://atb-archive.nrel.gov/electricity/2020/data.php.

[31] The 2023 consumption load shapes provided by ELL were applied to all DER forecast years. That method also implies that the energy efficiency of customers will not change over time for the purposes of the DER forecast.

[32] ICF converted NREL's cost projections for each year between 2023 and 2042 from its *2021 Annual Technology Baseline*, which are expressed in 2019 dollars, to nominal dollars by using the U.S. Bureau of Labor Statistics (BLS), CPI Inflation Calculator (https://www.bls.gov/data/inflation_calculator.htm) to determine the total inflation rate of 1% from December 2019 to December 2020; using the Federal Reserve Bank of Cleveland (Cleveland Fed), *Inflation Expectations* (https://www.clevelandfed.org/en/our-research/indicators-and-data/inflation-expectations.aspx) as of July 2021 to establish the average annual value of 1.7% for price inflation in 2021 and in 2022; and, then, applied ELL's annual inflation rate forecast of 2% for 2023 and beyond. C&I system costs were adjusted upward based on size-specific capital cost data in LBNL, *Tracking the Sun: 2020 Distributed Solar Data Update*, p. 28, to reflect the 40 kW_{DC} representative system size in this forecast. These adjusted C&I system capital costs were capped at no more than residential capital costs on a per-kW basis.

[33] Because ICF's analysis of residential battery storage paired with PV was accomplished via attachment rates, instead of cash flows, residential battery system cost assumptions were not required.

[34] CPUC costs assumed for 2022 were adjusted to be 2023 costs by applying one-half of CPUC's 2020 to 2022 decline rate for BTM lithium-ion battery systems.

Input	Value	Source
	system from the NREL source at right were applied to the 2023 values listed above	Used NREL's advanced and moderate case decline rates for the high and reference scenarios, respectively, in this forecast.[35]
Federal Investment Tax Credit (ITC)[36]	0% (C&I standalone battery storage) 22% in 2023 and 0% in 2024 and thereafter (residential PV) 22% in 2023 and 10% in 2024 and thereafter (C&I PV)	DOE, Homeowner's Guide to the Federal Tax Credit for Solar Photovoltaics, 2021, https://www.energy.gov/sites/default/files/2021/02/f82/Guide%20to%20Federal%20Tax%20Credit%20for%20Residential%20Solar%20PV%20-%202021.pdf; DOE, Guide to the Federal Investment Tax Credit for Commercial Solar Photovoltaics, 2021, https://www.energy.gov/sites/prod/files/2021/02/f82/Guide%20to%20the%20Federal%20Investment%20Tax%20Credit%20for%20Commercial%20Solar%20PV%20-%202021.pdf; and NREL, Federal Tax Incentives for Energy Storage Systems, 2018, https://www.nrel.gov/docs/fy18osti/70384.pdf.
Federal Accelerated Depreciation	Not applied (residential) 200% Declining Balance Schedule with half-year convention (C&I)[37,38]	Internal Revenue Service.
Annual PV Fixed O&M Cost in first project year ($\$/kW_{DC}$)	Annual residential and commercial values from NREL, 2021 Annual Technology Baseline. Used NREL's advanced and moderate cases for the high and reference scenarios, respectively, in this forecast.[39]	

[35] ICF converted NREL's decline rates to nominal dollars with ELL-provided general price inflation rates. The *2020 ATB*, rather than the *2021 ATB*, was used for these data both to assure continuity with the CPUC source used for initial battery storage capital costs and to avoid cost allocation complexities with the combined PV and battery storage systems used in the *2021 ATB*.

[36] These forecasts use ITC values in law as of the date the forecasts were conducted.

[37] For C&I PV systems, the 5-year depreciation schedule was used, while the 7-year schedule was used for C&I battery storage systems. See Internal Revenue Service, *Publication 946: How To Depreciate Property*, 2020, Table A-1, p. 71, https://www.irs.gov/pub/irs-pdf/p946.pdf.

[38] There is an option for PV system owners to take bonus depreciation in lieu of the 5-year accelerated depreciation schedule for systems placed in service through 2026. The allowable bonus depreciation declines each year; e.g., systems placed in service in 2024 are eligible for less bonus depreciation than those placed in service in 2023 (see DOE, *Guide to the Federal Investment Tax Credit for Commercial Solar Photovoltaics*, 2021). Because not all system owners take the bonus depreciation, this analysis used the accelerated depreciation schedule for consistency.

[39] ICF converted NREL's costs from the *2021 Annual Technology Baseline* in 2019 dollars to nominal dollars with BLS historical inflation data for 2020, Cleveland Fed-calculated inflation expectations as of July 2021 for

Input	Value	Source
Annual Commercial & Industrial Battery Storage Fixed O&M and Warranty Costs	1.5% of capital cost for the first three years of system operation, then 2.5% per year thereafter	Lithium-ion battery storage system values from Electric Power Research Institute (EPRI), Energy Storage Technology and Cost Assessment: Executive Summary, 2018, p. 15, https://www.epri.com/research/products/3002013958. The warranty cost component starts after three years.
Annual Escalation in PV Fixed O&M Costs (after first project year) and Battery Storage Fixed O&M Costs (after fourth project year)[40]	2%	ELL-provided general inflation rate for 2023 and beyond.
PV Inverter Replacement Cost (in year 15 of system operation)	8% of original capital cost (residential PV) 4% of original capital cost (C&I PV)	Residential value from ICF report for ISO New England, Economic Drivers of PV, p. 21, https://www.iso-ne.com/static-assets/documents/2015/02/icf_economic_drivers_of_pv_report_for_iso_ne_2_27_15.pdf. C&I value was provided by ELL.
Commercial & Industrial Battery Pack Replacement Cost (in year 10 of system operation)	\$200/kWh	The low end of the range for lithium-ion technologies from EPRI, Energy Storage Technology, and Cost Assessment: Executive Summary, 2018, p. 15.[41]
Battery Storage Roundtrip Efficiency (RTE)[42]	86%	Lithium-ion battery storage system value from DOE, Energy Storage Technology and Cost Characterization Report, 2019, p. viii, https://www.energy.gov/sites/prod/files/2019/07/f65/Storage%20Cost%20and%20Performance%20Characterization%20Report_Final.pdf.
Battery Storage Maximum Depth of Discharge	90%	ICF industry judgment.[43]
Retail Electricity Prices (applicable to PV power consumed on-site and costs for charging battery storage)	ELL-provided rates for residential, commercial, and industrial customers for the ELL and EGSL sub-territories. The utility's customer	

2021-2022, and ELL-provided general price inflation rates of 2% per year for 2023 and afterwards. NREL's commercial values were applied to C&I systems in this analysis.

[40] Due to the structure of the EPRI battery storage O&M assumption on the prior row of this table, the escalation for price inflation is not applied until the fifth project year.

[41] ICF also capped this value at no more than 25% of pre-ITC battery system capital costs for all forecast years.

[42] RTE measures the percentage of power injected into a battery storage system that is dischargeable over a full cycle of charging and discharging the battery system. One minus RTE reflects roundtrip power losses.

[43] For reference, the maximum depth of discharge is 95% in Lazard, *Lazard's Levelized Cost of Storage Analysis – Version 6.0*, 2020, p. 4, https://www.lazard.com/media/451566/lazards-levelized-cost-of-storage-version-60-vf2.pdf. The default maximum depth of discharge for battery storage is 80% in NREL, *REopt: A Platform for Energy System Integration and Optimization*, 2017, p. 40, https://www.nrel.gov/docs/fy17osti/70022.pdf. Maximum depth of discharge is equal to 1 minus "minimum charge" in the NREL publication.

Input	Value	Source
	class-specific rate forecasts extended through 2025, after which ELL's general price inflation rate of 2% per year was applied.[44,45]	
Compensation Rate for PV Power Exports in 2023	Based on ELL Distribution Generation Rider (Schedule DG).[46]	
Compensation Rate for PV Power Exports after 2023	Escalated at ELL-provided general price inflation rates.	
Renewable Energy Certificate (REC) Price	$0	Because there is no special market or tariff provision for RECs from new PV systems in ELL territory, and the value to customers of monetizing voluntary RECs is low, this was excluded from the analysis.
Federal Corporate Income Tax Rate	21% (applicable to C&I technologies only)	Internal Revenue Service.
State Corporate Income Tax Rate	8% (applicable to C&I technologies only)[47]	Tax Foundation, State Corporate Income Tax Rates, and Brackets for 2021, https://taxfoundation.org/state-corporate-tax-rates-2021/.

[44] For the PV analysis, ICF adjusted the utility-provided commercial customer prices so they would pertain more directly to the GS-L (ELL sub-territory) and SGS-G and GS-G (EGSL sub-territory) rate classes that are the most common among the utility's non-residential customer base. Those rate classes were used for prototype PV systems.

[45] For calculating the value of PV power consumed on-site by customers, ICF adjusted the residential rate downward to account for the per-kWh equivalent of customers' fixed monthly charges (and riders associated with those fixed monthly charges). That was done because deployment of PV systems by customers does not reduce their fixed monthly charges. ICF performed the same adjustment (e.g., removal of fixed monthly charges from the value of PV power consumed on-site) for C&I rates. For C&I customers with demand charges, ICF further assumed that PV power only reduced demand charges by about one-sixth of the PV system's AC capacity. That value was established from ICF's industry experience. It is a low value because there are often intervals during each month when customer electricity demand is high (at or near monthly peak values) but PV production is low or zero (e.g., during a cloudy or evening period).

[46] Rates for PV exports ("power delivered to the grid" as recorded by Channel 2 on the customer meter) were obtained from Schedule DG effective as of April 1, 2021, https://cdn.entergy-louisiana.com/userfiles/content/price/tariffs/ell_elec_dg.pdf. These rates were escalated from 2021 to 2023 values based on Cleveland Fed-calculated inflation expectations as of July 2021 for 2021-2022 and ELL's annual inflation assumption for 2022-2023. As with other DER inputs, ICF used Schedule DG data available at the time of its analysis. Since that time, ELL updated the avoided cost rate in Schedule DG effective March 31, 2022, increasing it by approximately $0.016/kWh compared to the April 1, 2021, value. Had ICF used the current avoided cost rate and changed no other inputs, forecasted cumulative capacity in 2042 would have been about 5% to 6% higher for residential PV and about 1% higher for C&I PV in both scenarios. A main reason that the forecasted impact was modest is that ICF assumed only a small portion (30% for residential PV and 10% for C&I PV) of solar power output is exported annually back to the grid and, therefore, applicable to Schedule DG.

[47] Utilized the highest marginal tax rate in the state as of the date at which ICF performed its analysis. The highest corporate tax rate has since been reduced to 7.5% in Louisiana. That change would have minimal effects (e.g., increasing cumulative C&I PV capacity by approximately one-half of 1% by 2042 in the *reference scenario*) on DER deployment levels and has not been incorporated into ICF's analysis.

5.3.4 Limitations of Analysis

There are many credible approaches to estimating future levels of customer PV and battery storage adoption, each with its own strengths and limitations. In all instances, uncertainties about future technology capital costs and performance, government policies, and utility rate structures (both for system output consumed on-site and exported to the utility grid) are important to note and can lead to substantial differences in outcomes.

Additionally, important limitations particular to this forecast include that it was conducted: (i) at the aggregated utility sub-territory level (as opposed to at a more localized level), (ii) without customer demographic data; (iii) with annual average electricity rates for PV (as opposed to analyzing the full rate structures on hourly or sub-hourly interval bases); (iv) without scenarios speculating on possible future changes in government policy or regulation, and (v) without distinctions between competing financing/contract structures and the extent of debt financing on DER economics.

5.4 Technology Modeling

This section provides an overview of how the ELL-specific inputs were turned into project-level economic analysis of the DER technologies and then, forecasts of adoption and energy generation. It also highlights the results of the adoption forecasts and key findings from our analysis.

5.4.1 Elements of Analysis

Using a standard DER project cash flow model for a 25-year investment period and the inputs described in Section 5.3.3, ICF calculated the investment payback period on an unlevered basis (without debt) in nominal dollars for potential DER projects becoming operational each year between 2023 and 2042.[48] The cash flows included appropriate replacement of major equipment (inverter for PV and battery pack for storage technologies) within the investment period.

In the project-level economic analysis of PV, sources of customer cost savings were distinguished between electricity consumed on-site versus exported to the utility (and thereby compensated at ELL Schedule DG rates). Possible incremental revenues from aggregation of PV and battery storage were not included in ICF's economic analysis due to the still-substantial uncertainties in how customers will participate in DER market aggregation.[49]

PV cost categories include net capital costs (after federal incentives and depreciation benefits, where applicable), annual O&M costs, major equipment replacement, and income taxes (for C&I customers).

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[48] As noted earlier, ICF applied an attachment rate methodology, instead of cash flow analysis, to estimate residential battery storage and C&I battery storage paired with PV that will be adopted in ELL's service territory.

[49] Federal Energy Regulatory Commission (FERC) Order 2222 "enables [distributed energy resources] to participate alongside traditional resources in the regional organized wholesale markets through aggregations, opening U.S. organized wholesale markets to new sources of energy and grid services." See FERC, *Fact Sheet, FERC Order No. 2222: A New Day for Distributed Energy Resources*, 2020, https://ferc.gov/media/ferc-order-no-2222-fact-sheet#. However, Order 2222-related tariff requirements and compensation details have not yet been established in ELL's service territory, and there may be a multi-year process involved in defining and finalizing them. The substantial uncertainty around Order 2222 tariff rules and compensation is compounded by the lack of current evidence on how PV and battery storage owners in various customer classes (residential, commercial, and industrial) will elect to utilize these tariffs once they are published and their approximate net gains from doing so. Without that information and without other existing aggregation programs within the utility for PV and battery storage, ICF could not at the time of this study's publication credibly estimate potential outcomes from aggregation of these technologies on the level and timing of ELL system loads.

For large C&I battery storage, there is an additional layer of potential cost savings from peak demand charge reductions netted against the cost of electricity lost in roundtrip battery use cycles.[50] ICF developed dispatch algorithms based on battery storage technology performance and ELL retail demand-based rate structures to maximize potential savings from battery system operation, within reasonable technology use constraints. These algorithms then established the number, scale, and timing of peak shaving events annually.[51] Battery storage capital costs, O&M costs, major equipment replacement, and income taxes were applied in the same manner as in the PV project economic analysis.

The project-level economic outcomes for residential PV, C&I PV, and C&I standalone battery storage technologies were converted to forecasted systemwide AC capacity additions using a three-part formula with components accounting for:

- The number of customers eligible for the technology,[52]
- The economically-viable portion of the customer population, determined by projected economic returns for a DER technology in a forecast year, and
- The portion of the economically-eligible population that adopts the technology annually; this is the market acceptance formula.

For PV technologies, ICF established the market acceptance formula based on DOE data on the annual growth of behind-the-meter residential and C&I PV systems, distinguished at the individual utility level. The formula ensured that forecasted PV growth rates for ELL would not be below reasonable lower bounds nor

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[50] ICF utilized demand charge reduction as the sole customer savings stream in its C&I standalone battery storage analysis. It did so for two reasons. First, ICF anchored its analysis in ELL's most common present rate structures and market opportunities. As a principle, ICF did not model different rate structures for battery storage than currently exist to avoid inconsistency with modeling across other parts of ICF's potential study and with broader elements of the utility's integrated resource planning process. Regarding wholesale price arbitrage that may become available when MISO provides market access under FERC Order 841, ICF felt that any rules and valuation for that revenue stream would be too speculative to include in the DER potential study at this time. The second reason that ICF concentrated on the demand charge reduction use case is that it has been the most prevalent one for C&I battery storage in many markets. See, for example, LBNL, *Behind-the-Meter Solar + Storage: Market Data and Trends*, 2021, https://eta-publications.lbl.gov/sites/default/files/btm_solarstorage_trends_final.pdf and NREL, *Identifying Potential Markets for Behind-the-Meter Battery Energy Storage: A Survey of U.S. Demand Charges*, 2017, https://www.nrel.gov/docs/fy17osti/68963.pdf. The size (power capacity) and duration of the prototype standalone C&I battery system in ICF's analysis was established to maximize economic use for batteries under the utility's C&I rate schedules with relatively high monthly peak demand charges.

[51] The peak shaving events assumed that the customer or battery control system can predict, based on historical norms, when its times of low and high demand would occur each month. The customer would then charge the battery system at times of low demand (making sure not to create new monthly peaks during those intervals) and discharge the battery system (thus lowering billed demand) at times of high demand. Peak shaving savings are the sole customer revenue source in ICF's economic model. The costs in ICF's model include battery storage capital costs, annual O&M costs, battery pack replacement costs, and the energy (per-kWh) costs from charging and discharging the battery system. Those energy costs are the result of roundtrip efficiency losses on each cycle of charging and discharging the battery system. ICF instituted constraints in its disptach algorithm including maximum depth of battery discharge, maximum battery utilization, maximum peak prediction accuracy, maximum speed of charging, roundtrip efficiency, and annual system performance degradation.

[52] This is defined as the projected number of customers in a relevant customer class or tariff rate schedule in a given year, minus those customers that are already adopted the technology. ICF used ELL's forecasts of total customer counts in this calculation.

above reasonable upper bounds of observed U.S. customer PV growth rates from utilities with comparable levels of PV deployment.

For residential and C&I battery storage paired with PV, attachment rates were used that denoted the percentage of new PV capacity installed in a year that would be paired with battery systems. The attachment rates applied in each scenario are described below.

- Residential reference scenario: ratable annual growth of approximately 1.5%, beginning at 1% in 2023 and terminating at a 30% attachment rate in 2042.[53,54]
- Residential high scenario: ratable annual growth of approximately 3%, beginning at 2% in 2023 and terminating at a 60% attachment rate in 2042.[55]
- C&I reference scenario: ratable annual growth of 0.65%, beginning at 0.65% in 2023 and terminating at a 13% attachment rate in 2042.[56]
- C&I high scenario: ratable annual growth of 1.3%, beginning at 1.3% in 2023 and terminating at a 26% attachment rate in 2042.[57]

Annual generation for each DER technology was obtained by multiplying the installed capacity, accounting for technology-specific annual degradation, for each forecast year by a DER technology-specific capacity factor.

Annual generation was then converted into hourly load impacts through the use of:

- For PV: NREL PV Watts® output profiles for residential and C&I systems from the Louisiana locations listed in Section 5.3.3.

[53] Among 12 states in a recent report on battery storage, residential attachment rates began at 1% (LBNL, *Tracking the Sun*, 2021, p. 14, https://emp.lbl.gov/sites/default/files/2_tracking_the_sun_2021_report.pdf). That value was used as the starting (2023) value in this ELL analysis. The annual rate of increase after 2023 in this analysis is consistent with historical national average data from the 2021 LBNL report and LBNL, *Distributed Solar 2020 Data Update*, 2020, Summary Data Tables: Storage Trends.

[54] This terminal value attachment rate for the reference scenario was established at one-half the high scenario rate.

[55] The starting value (in 2023) was set at 2%, which is an approximate median value for residential attachment rates among the 12 states reviewed in LBNL, *Tracking the Sun*, 2021, p. 14. The terminal value attachment rate of 60% reflects a highly-developed battery storage market. For example, this value approximates the attachment rate in Oahu, Hawaii in 2018 where system economics and utility regulations incentivize high levels of battery storage attachment to PV systems (LBNL, *Tracking the Sun*, 2019, p. 16, https://emp.lbl.gov/sites/default/files/tracking_the_sun_2019_report.pdf). It is also approximately ¾ as large as the 2020 residential attachment rate in Hawaii (LBNL, *Tracking the Sun*, 2021, p. 12).

[56] The annual rate of increase applied in this analysis is the average national rate of increase from 2015 through 2019 for small non-residential customers from LBNL, *Tracking the Sun*, 2021, Summary Data Tables: Storage Trends. That is also used as a starting value, assuming that non-residential battery storage deployment begins in ELL's territory in 2023. The terminal value attachment rate in 2042 is simply the result of applying the average rate of increase for the 20-year forecast horizon.

[57] High scenario values were established at double reference scenario values. Those values are consistent with data from LBNL, *Tracking the Sun*, 2021 showing that attachment rates of states with higher penetration of non-residential battery storage, apart from Hawaii, are roughly double those of lower penetration states. The terminal value attachment rate in 2042 is approximately ¾ as large as the 2020 value in the most highly-developed U.S. battery storage market of Hawaii (LBNL, *Tracking the Sun*, 2021, p. 12).

- For residential battery storage: charge and discharge patterns from a fleet of residential battery storage systems on non-time-of-use rates.[58]

- For C&I battery storage systems: ICF's project-level dispatch algorithms applied to customer load profiles.

5.4.2 Scenario Definition and Development

ICF produced high and reference scenario results for each of the five DER technologies (i.e., residential PV, C&I PV, residential battery storage when paired with PV, C&I battery storage when paired with PV, and large C&I battery storage in a standalone configuration). The reference scenario reflects ICF's best estimate of future outcomes based on available information, while the high scenario is associated with more favorable DER market trends. ICF views outcomes above the high scenario to be unlikely absent policy changes at the federal, state, or local government or utility levels.

For example, the high scenarios have lower system capital and O&M costs than the reference scenarios, reflecting rapid DER industry growth and economies of scale. Specific differences in inputs between scenarios are listed in Section 5.3.3 above.

5.4.3 Potential Assessment Approach

ICF's analysis of DER is top-down and does <u>not</u> proceed through bottom-up, iterative technical potential and economic potential stages at the individual customer site level before arriving at the achievable potential. Instead, ICF uses project-level economic analysis, combined with the relationship between project economics and DER adoption in other U.S. markets, to arrive at its DER achievable potential forecasts for ELL. Doing so allowed ICF to efficiently produce results grounded in DER market experience and to avoid creating technical and economic potential outputs that would not be used in the utility's IRP process.

5.4.4 Program Screening and Benefit/Cost Analysis

ELL informed ICF that it, like several other utilities, has no specific incentive programs now directed at customer PV or battery storage technologies. Therefore, ICF did not conduct a program benefit/cost analysis of DER technologies.

However, ICF did calculate the net energy production for each DER technology on an hourly basis. Annual summaries of that energy production are provided in the next subsection of the report.

5.5 Achievable Potential Results

This section presents results for customer installed capacity and annual energy production for each DER technology studied. These results arise from the economic, market acceptance curve, and attachment rate analysis conducted by ICF.

For residential PV, estimated investment payback periods varied in the *reference scenario* from approximately eight to 20 years across forecast years, with forecasted technology adoption accelerating when as payback periods decline. The eight-year payback period occurs in 2042, the last year of the

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[58] Data were based on CPUC, *2018 SGIP Advanced Energy Storage Impact Evaluation*, 2020, pp. 4-34 and 4-35, https://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/Utilities_and_Industries/Energy/Energy_Programs/Demand_Side_Management/Customer_Gen_and_Storage/SGIP%20Advanced%20Energy%20Storage%20Impact%20Evaluation.pdf. Data were adjusted to reflect the 86% roundtrip efficiency assumption in this analysis. They also reflect the observation that, in a fleet of residential battery storage systems across a utility service territory, one can expect that customers will be charging and discharging their systems at various times due to various use cases and the timing of their household electricity consumption and PV production.

analysis, due to the combined effects of declining PV capital and O&M costs and rising retail electricity rates.

C&I PV estimated payback periods range in the *reference scenario* from six to 22 years. The payback period declines to six years by 2042 due to the cumulative effects of declining PV capital and O&M costs and rising retail electricity rates over the 20-year forecast horizon. The six-year payback period is for the smallest C&I customers, who have the highest per-kWh retail electricity rates.

The wider range of payback periods among C&I customers than residential customers is due to the wider range of energy ($/kWh) charges among C&I customers and the presence of demand-related charges for most C&I customers. Payback periods are shorter for some customers than others. The longer payback periods on certain rate schedules are due to lower energy charges and the presence of demand-related charges on other rate schedules, which reduce the value of utility power offset by solar production.

For all customer types, payback periods decline over time as the combination of declining estimated PV capital and O&M costs and increasing retail electricity rates improve project economics.[59]

For standalone C&I battery storage, payback periods in the *reference scenario* ranged from more than 44 years at the start of the 20-year forecast period to less than 11 years in the end, with the improvements due to estimated capital cost declines combined with increases in retail electricity prices. Payback periods for this technology were as low as five to six years in the *high scenario*.

These project-level economics of DER technologies were converted into annual ELL systemwide forecasts of DER capacity using the market acceptance curves and attachment rates described in Section 5.4.1. The forecasts of installed DER capacity (at the customer meter) are in **Table 13** and **Table 14** for PV technologies. **Table 14** breaks out the C&I PV capacity from the prior table into separate commercial and industrial components according to the percentage of customers in the ELL and EGSL sub-territories that are commercial (including governmental) and industrial customers in the utility's reference case.[60]

Table 13: Forecasted Cumulative Installed Capacity of Residential and C&I PV Systems at Meter (MW_{AC})

Forecast Year	Residential PV: Reference Scenario	Residential PV: High Scenario	C&I PV: Reference Scenario	C&I PV: High Scenario
2023	80	85	8	8
2024	87	96	10	11
2025	96	112	13	15
2026	109	132	16	18
2027	125	158	19	23
2028	143	187	23	27
2029	163	221	27	33
2030	187	262	32	39

[59] As noted above, project-level economics were not calculated for residential and C&I battery storage paired with PV, and attachment rate methodologies were used due to the lack of economic use cases for those customer/technology combinations in ELL territory.

[60] Specifically, 92% of C&I customers in the ELL sub-territory are assigned to the "commercial" class and 8% to the "industrial" class. In the EGSL sub-territory, 94% of C&I customers are classified as commercial and 6% as industrial.

Forecast Year	Residential PV: Reference Scenario	Residential PV: High Scenario	C&I PV: Reference Scenario	C&I PV: High Scenario
2031	209	302	36	45
2032	232	341	41	51
2033	253	379	46	57
2034	275	415	51	64
2035	295	450	56	70
2036	315	484	60	76
2037	334	516	65	83
2038	353	549	70	89
2039	373	582	75	96
2040	393	615	80	102
2041	413	649	86	109
2042	433	683	91	115

Of the residential PV capacity in **Table 13**Error! Reference source not found., 63.3 MW_{AC} for all scenarios was existing (already interconnected with ELL) as of June 2021. Another 6.0 MW_{AC} of residential PV capacity is assumed to be interconnected between July 2021 and December 2022 in all scenarios. That projection is based on year-to-date 2021 deployment trends continuing through the end of 2021, and 2022 annual deployment being at the 2021 level.

Of the combined C&I PV capacity in **Table 13**, 4.6 MW_{AC} for all scenarios was existing as of June 2021.[61] Between that time and December 2022, ICF assumed that an additional 0.5 MW_{AC} of C&I will be interconnected in all scenarios. The C&I calculation used the same method to estimate capacity for the rest of 2021 and for 2022 as described in the prior paragraph for the residential PV calculation.

Table 14: Forecasted Cumulative Installed Capacity: Breakout of Commercial and Industrial PV Systems at Meter (MWAC)

Forecast Year	Commercial PV: Reference Scenario	Commercial PV: High Scenario	Industrial PV: Reference Scenario	Industrial PV: High Scenario
2023	8	8	0	0
2024	10	11	1	1
2025	12	14	1	1

[61] Existing C&I PV capacity was divided between commercial and industrial customers based on customer type and rate schedule information provided by ELL with its interconnection data.

Forecast Year	Commercial PV: Reference Scenario	Commercial PV: High Scenario	Industrial PV: Reference Scenario	Industrial PV: High Scenario
2026	15	17	1	1
2027	18	21	1	1
2028	21	26	1	2
2029	25	30	2	2
2030	29	36	2	3
2031	34	42	2	3
2032	38	47	3	4
2033	43	53	3	4
2034	47	59	4	5
2035	52	65	4	5
2036	56	71	4	6
2037	61	77	5	6
2038	65	83	5	7
2039	70	89	5	7
2040	75	95	6	8
2041	79	101	6	8
2042	84	107	7	9

Figure 22 illustrates the percentage of the projected ELL residential customer population forecasted to have on-site PV systems each year in the *reference scenario*. By 2042, just under 7% of the more than one million ELL residential customers served by the utility at that time are forecasted to have PV systems in the *reference scenario*.[62]

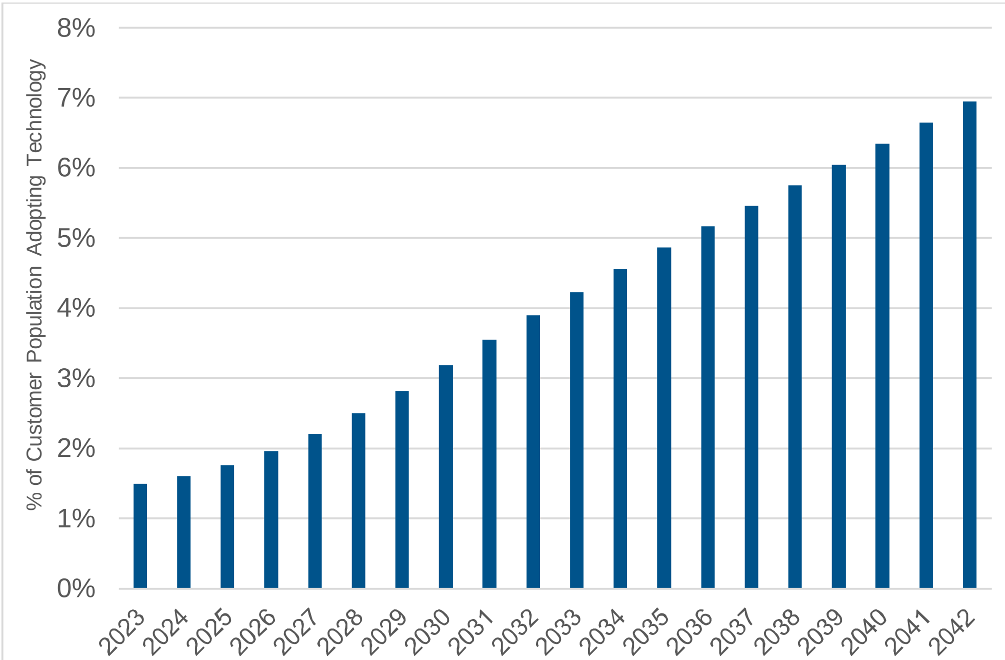

Figure 22: Forecasted Share of Residential Customers Adopting PV: Reference Scenario

[62] In the high scenario, approximately 11% of residential customers are forecast with PV by 2042.

As summarized in **Figure 23** and **Figure 24**, forecasted residential PV capacity by 2042 is about five to six times larger than C&I PV capacity in the *reference scenario* and *high scenario*, respectively.[63] This prevalence of residential PV is largely because (i) historical PV deployment in ELL's territory is dominated by residential customers, (ii) PV economics are less attractive for a segment of C&I customers (e.g., those on rates with demand charges) than for residential customers on average, (iii) PV capital costs are forecast by NREL to decline more quickly for residential customers than for C&I customers, and (iv) the market acceptance curve for C&I customers is lower than for residential customers.[64]

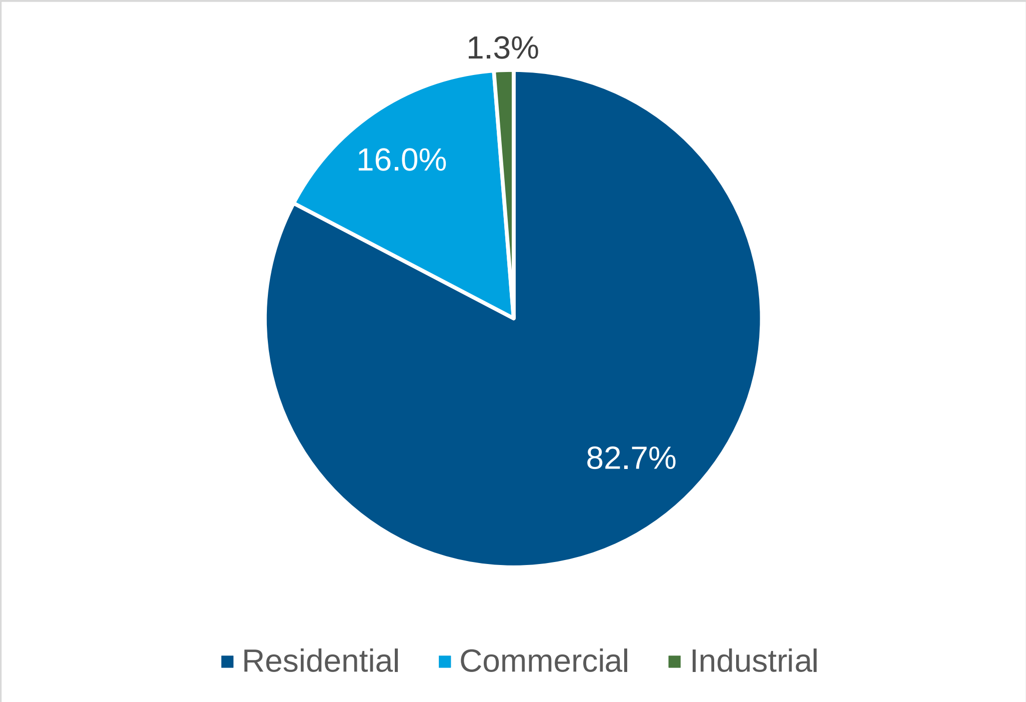

Figure 23: Forecasted PV Cumulative Capacity in 2042 by Customer Class: Reference Scenario

[63] The cumulative PV capacity (across all customer types) in 2042 represented in these pie charts is 524 MW_{AC} in the *reference scenario* and 798 MW_{AC} in the *high scenario*.

[64] Market acceptance of PV is lower for C&I customers in general in the U.S., due to reasons including: ownership complexities (many non-residential customers do not own their properties), uncertainties in how long businesses will remain at a given location, and the inability of PV systems to materially reduce electric bills for many C&I customers (for technical reasons like lack of unshaded roof space and economic reasons like rate structures and high power consumption relative to available solar electricity production).

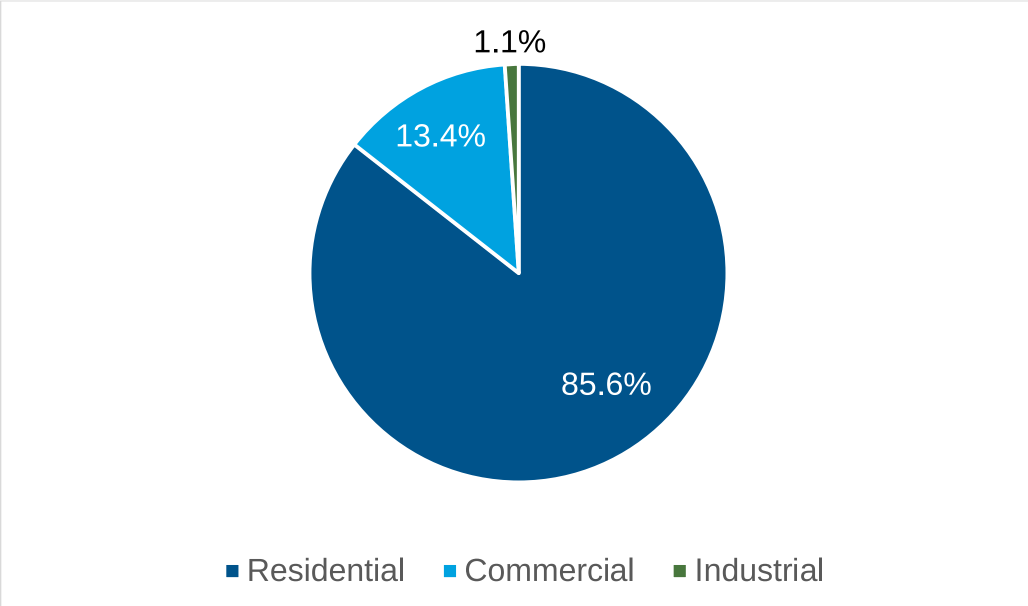

Figure 24: Forecasted PV Cumulative Capacity in 2042 by Customer Class: High Scenario

Capacity forecasts are in **Table 15, Table 16, Table 17** & **Table 18** for battery storage technologies. In ICF's forecasts, the total capacity calculated for C&I battery storage systems paired with PV is assigned between commercial and industrial customers according to customer counts in the utility's reference case projections.[65,66] The battery storage tables show results for both battery power (MW) and battery energy (MWh), with totals rounded to the nearest MW and MWh.[67,68,69] The forecasted adoption of standalone C&I battery storage in **Table 18** was modest not because the demand charge use case (described in Section 5.4.1) did not create enough customer savings, but because the relevant customer population is limited in ELL territory. In addition, the great majority of the utility's C&I customers are presently on rate structures with relatively low to no per-kW peak demand charges such as smaller commercial customers on the Small

[65] The same commercial versus industrial break-out is used for battery storage paired with PV as for PV itself. Specifically, 92% of C&I customers in the ELL sub-territory are assigned to the "commercial" class and 8% to the "industrial" class. In the EGSL sub-territory, 94% of C&I customers are classified as commercial and 6% as industrial.

[66] For standalone battery storage, all C&I systems were assigned to the industrial category because a much larger portion of the relevant customer population is industrial than commercial and the small number of total deployments of this technology (typically no more than one new build per year per utility sub-territory) made allocating between industrial and commercial categories problematic.

[67] Estimated residential battery storage capacity in the *high scenario* is much higher than in the *reference scenario* due to the combined effects of (i) greater PV capacity forecasted in the *high scenario* and (ii) higher attachment rates of battery storage to PV in the *high scenario*.

[68] For large C&I battery storage, *high scenario* outcomes are much greater than *reference scenario* outcomes. That is primarily because the *high scenario* assumes faster decreases in battery storage capital costs, leading to better economics (faster investment payback) and increased technology adoption.

[69] Due to rounding, there are entries of zero for battery power in these tables in the same year as above-zero values for battery energy. That is because the battery power is less than 0.5 MW in the year, but battery energy (at an assumed 2.4-hour duration for residential battery systems, an assumed two-hour duration for C&I battery systems paired with PV, and an assumed four-hour duration for standalone battery systems) is above 0.5 MWh in the year.

General Service rate and, therefore, are not economically-viable candidates for standalone battery storage systems.

No interconnected customer (behind-the-meter) battery storage systems for residential or C&I customers were included in the ELL data provided to ICF. However, to be clear, this does not preclude the possibility that such systems exist as ELL would only be aware of these behind-the-meter resources if the battery storage system was clearly noted in the customer's interconnection request. No new deployments of customer battery storage were assumed in this analysis between July 2021 and December 2022. Therefore, all customer battery storage results in ICF's analysis are assumed to occur within the 2023-2042 forecast period.

Table 15: Forecasted Cumulative Installed Capacity of Residential Battery Storage Systems Paired with PV at Meter (in MW_{AC} for Battery Power and MWh for Battery Energy)

Forecast Year	Battery Power: Reference Scenario	Battery Power: High Scenario	Battery Energy: Reference Scenario	Battery Energy: High Scenario
2023	0	0	0	1
2024	0	1	1	2
2025	1	2	1	4
2026	1	4	3	9
2027	2	7	5	16
2028	3	10	8	25
2029	5	16	12	39
2030	7	24	17	57
2031	10	32	23	78
2032	12	42	29	100
2033	15	52	36	124
2034	18	62	43	149
2035	21	73	51	175
2036	25	84	59	202
2037	28	96	67	231
2038	32	109	76	261
2039	36	122	86	293
2040	40	137	96	328
2041	45	152	107	365
2042	50	169	119	405

Table 16: Forecasted Cumulative Installed Capacity of C&I Battery Storage Systems Paired with PV at Meter (in MW_{AC} for Battery Power and MWh for Battery Energy)

Forecast Year	Battery Power: Reference Scenario	Battery Power: High Scenario	Battery Energy: Reference Scenario	Battery Energy: High Scenario
2023	0	0	0	0
2024	0	0	0	0
2025	0	0	0	1
2026	0	0	0	1
2027	0	1	1	1
2028	0	1	1	2
2029	1	2	1	3
2030	1	2	2	5
2031	1	3	2	6
2032	1	4	3	8
2033	2	5	4	9
2034	2	6	4	11
2035	3	7	5	14
2036	3	8	6	16
2037	4	9	7	19
2038	4	11	8	21
2039	5	12	9	24
2040	5	14	11	27
2041	6	15	12	31
2042	7	17	13	34

Table 17: Forecasted Cumulative Installed Capacity: Breakout of Commercial and Industrial Battery Storage Systems Paired with PV at Meter (in MW_{AC} for Battery Power and MWh for Battery Energy)

Forecast Year	Commercial Battery Power: Reference Scenario	Commercial Battery Power: High Scenario	Industrial Battery Power: Reference Scenario	Industrial Battery Power: High Scenario	Commercial Battery Energy: Reference Scenario	Commercial Battery Energy: High Scenario	Industrial Battery Energy: Reference Scenario	Industrial Battery Energy: High Scenario
2023	0	0	0	0	0	0	0	0
2024	0	0	0	0	0	0	0	0
2025	0	0	0	0	0	0	0	0
2026	0	0	0	0	0	1	0	0
2027	0	1	0	0	1	1	0	0
2028	0	1	0	0	1	2	0	0
2029	1	1	0	0	1	3	0	0
2030	1	2	0	0	2	4	0	0
2031	1	3	0	0	2	6	0	0
2032	1	4	0	0	3	7	0	1
2033	2	4	0	0	3	9	0	1
2034	2	5	0	0	4	11	0	1
2035	2	6	0	1	5	13	0	1
2036	3	7	0	1	6	15	0	1
2037	3	9	0	1	7	17	1	1
2038	4	10	0	1	8	20	1	2
2039	4	11	0	1	9	22	1	2
2040	5	13	0	1	10	25	1	2
2041	5	14	0	1	11	28	1	2
2042	6	16	1	1	12	32	1	3

Table 18: Forecasted Cumulative Installed Capacity of Standalone C&I Battery Storage Systems at Meter (in MW_{AC} for Battery Power and MWh for Battery Energy)

Forecast Year	Battery Power: Reference Scenario	Battery Power: High Scenario	Battery Energy: Reference Scenario	Battery Energy: High Scenario
2023	0	0	0	0
2024	0	0	0	0
2025	0	0	0	0
2026	0	0	0	0
2027	0	0	0	1
2028	0	0	0	2
2029	0	1	0	2
2030	0	1	0	3
2031	0	1	0	4
2032	0	1	0	6
2033	0	2	0	7
2034	0	2	0	9
2035	0	3	0	10
2036	0	3	0	12
2037	0	3	1	14
2038	0	4	2	15
2039	1	4	2	17
2040	1	5	3	18
2041	1	5	4	19
2042	1	5	5	20

ICF converted its forecasts of capacity for each DER technology into annual energy generation forecasts by multiplying the installed capacity for each forecast year by the technology capacity factor, further multiplying by 8,760 hours (or 8,784 hours for leap years), applying technology-specific performance degradation assumptions, and adding customer class-specific T&D loss factors to produce generation (MWh) totals at the central station generation plant level.

For PV, these energy production forecasts do not just denote power exported back to ELL, but all PV power generated by the customer systems. The resulting net energy production forecasts for the *reference scenario* and *high scenario* are shown in **Figure 25, Figure 26 & Figure 27** for residential PV, commercial PV, and industrial PV technologies, respectively. **Table 19 & Table 20** display the data from these three graphs in tabular form.

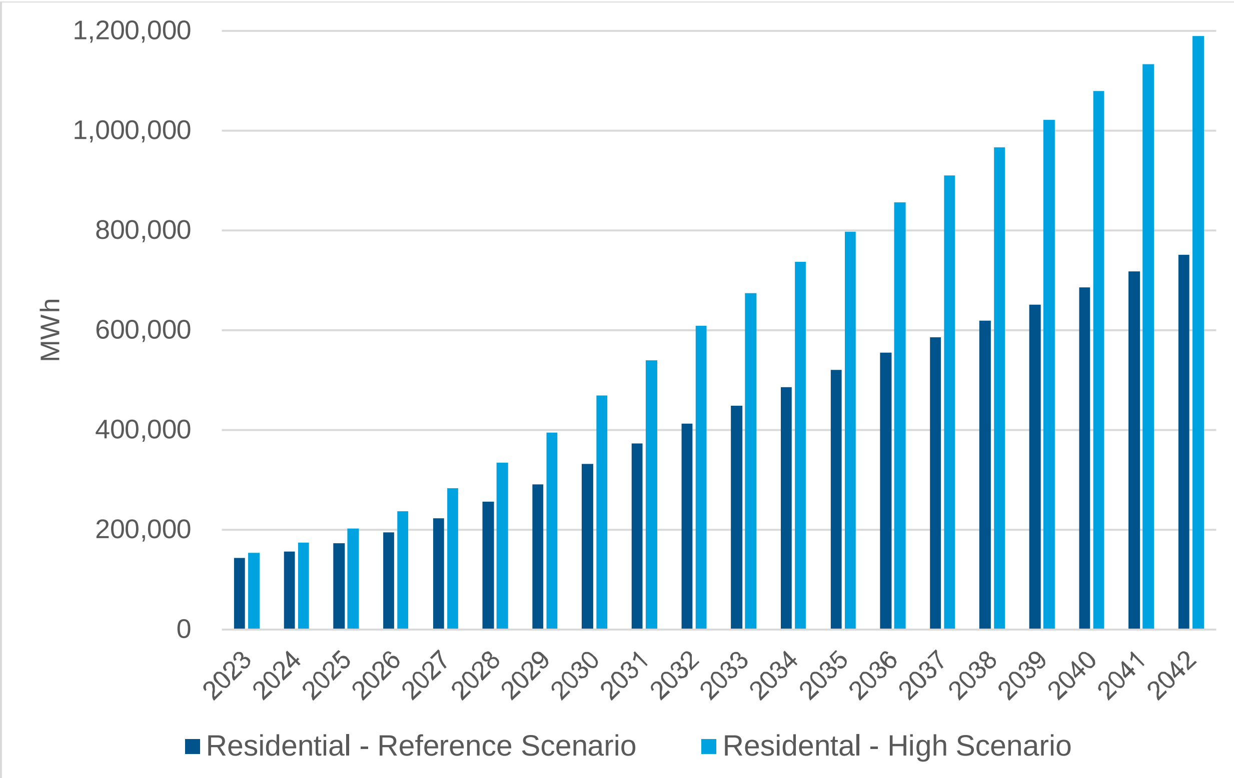

Figure 25: Forecasted Annual Residential PV Production at the Central Station Plant Level (in MWh)

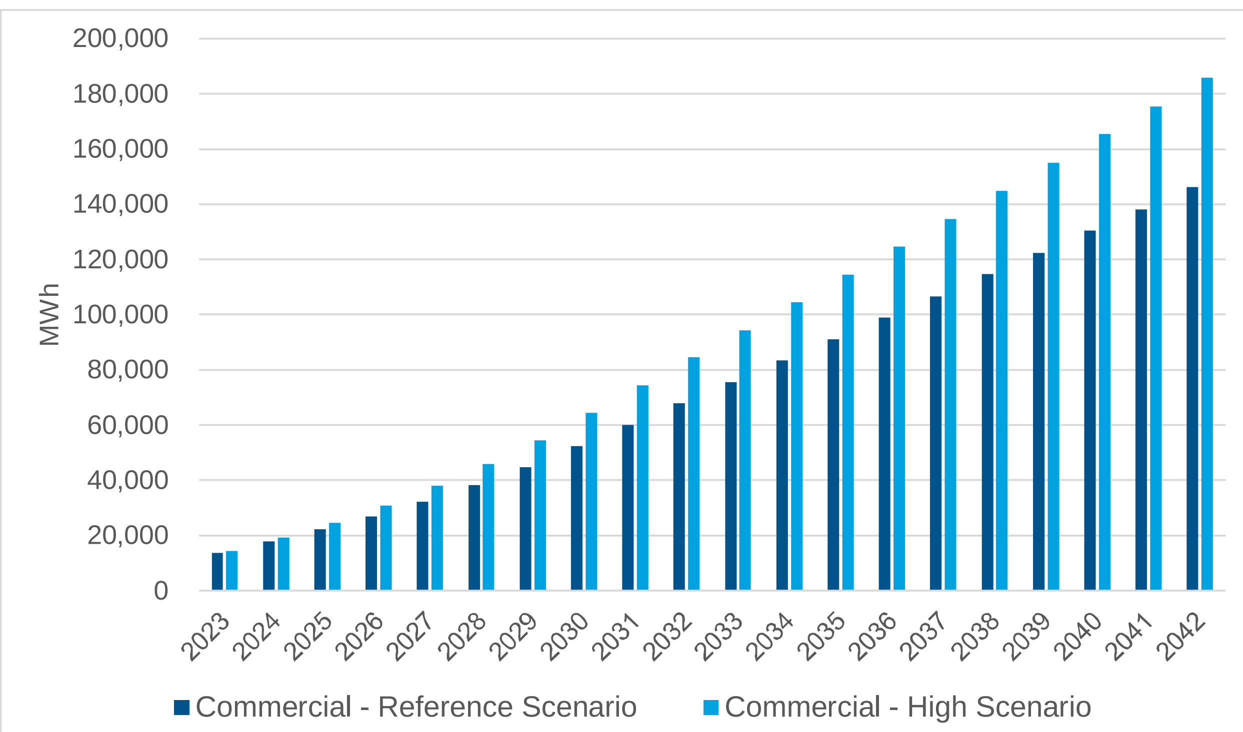

Figure 26: Forecasted Annual Commercial PV Production at the Central Station Plant Level (in MWh)

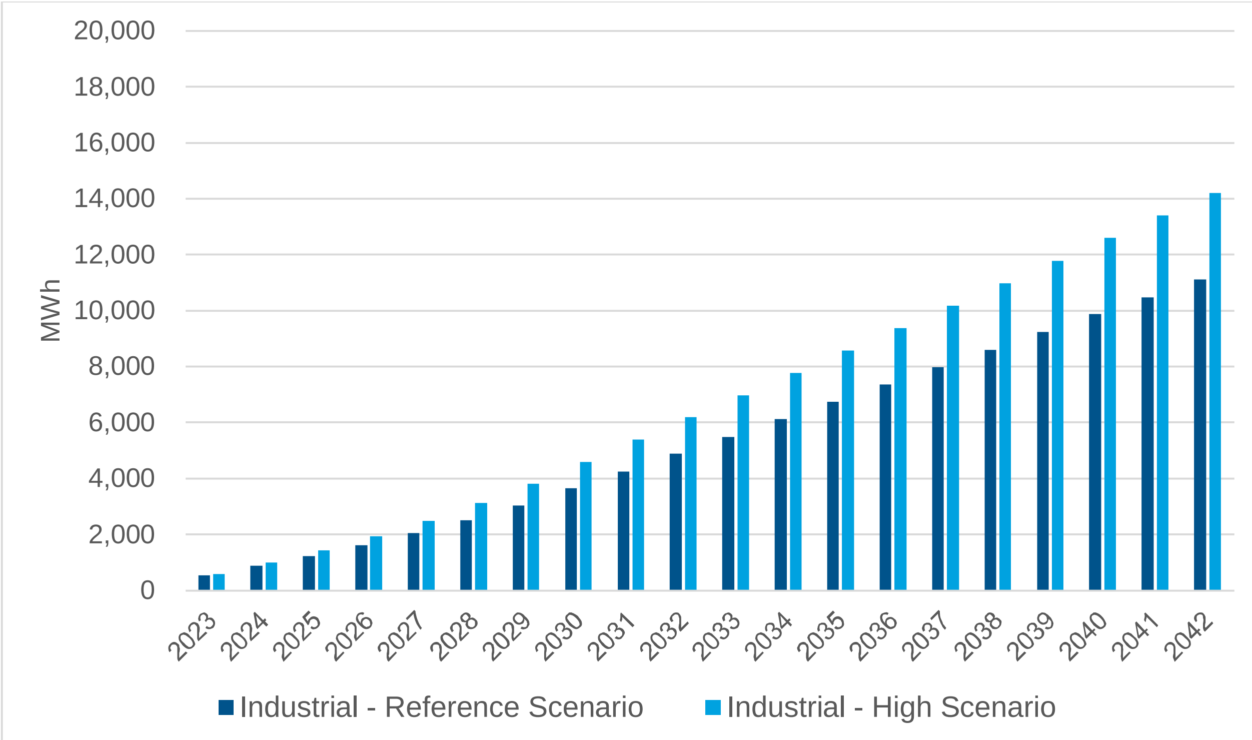

Figure 27: Forecasted Annual Industrial PV Production at the Central Station Plant Level (in MWh)

Table 19: Forecasted Annual Residential PV Production at the Central Station Plant Level (in MWh)

Forecast Year	Residential PV: Reference Scenario	Residential PV: High Scenario
2023	143,673	153,045
2024	156,195	174,169
2025	173,235	201,983
2026	195,168	237,415
2027	223,360	283,345
2028	256,191	334,616
2029	291,084	395,296
2030	332,428	468,878
2031	372,568	539,883
2032	412,046	609,138
2033	449,102	674,054
2034	485,407	737,155

Forecast Year	Residential PV: Reference Scenario	Residential PV: High Scenario
2035	520,351	797,549
2036	554,680	856,664
2037	585,995	910,566
2038	618,544	965,844
2039	651,373	1,021,288
2040	685,435	1,078,770
2041	717,828	1,133,346
2042	751,440	1,189,573

Table 20: Forecasted Annual Commercial and Industrial PV Production at the Central Station Plant Level (in MWh)

Forecast Year	Commercial PV: Reference Scenario	Commercial PV: High Scenario	Industrial PV: Reference Scenario	Industrial PV: High Scenario	Combined C&I: Reference Scenario	Combined C&I: High Scenario
2023	13,607	14,339	530	587	14,137	14,926
2024	17,772	19,291	869	988	18,641	20,279
2025	22,187	24,657	1,227	1,422	23,414	26,079
2026	26,913	30,870	1,609	1,921	28,522	32,791
2027	32,222	37,931	2,035	2,486	34,258	40,417
2028	38,196	45,841	2,514	3,117	40,710	48,958
2029	44,728	54,471	3,037	3,805	47,765	58,276
2030	52,379	64,404	3,647	4,594	56,026	68,997
2031	60,001	74,402	4,255	5,387	64,256	79,789
2032	67,855	84,527	4,879	6,190	72,734	90,717
2033	75,535	94,374	5,491	6,972	81,026	101,346
2034	83,340	104,417	6,113	7,768	89,453	112,185
2035	91,106	114,513	6,731	8,568	97,837	123,082
2036	99,030	124,747	7,362	9,378	106,392	134,125
2037	106,704	134,703	7,974	10,167	114,678	144,870
2038	114,593	144,890	8,602	10,973	123,195	155,863

Forecast Year	Commercial PV: Reference Scenario	Commercial PV: High Scenario	Industrial PV: Reference Scenario	Industrial PV: High Scenario	Combined C&I: Reference Scenario	Combined C&I: High Scenario
2039	122,444	155,094	9,226	11,780	131,670	166,874
2040	130,507	165,539	9,867	12,605	140,374	178,144
2041	138,220	175,522	10,481	13,395	148,701	188,917
2042	146,135	185,756	11,111	14,204	157,246	199,960

For battery storage technologies, charging and discharging from existing systems degrades by 1% annually, and hourly charging and discharging activities are netted to calculate annual net generation impacts. These impacts are negative (i.e., increased utility loads) because battery storage technologies are net consumers of electricity due to their RTE losses.

On an annual basis, the net increases in utility loads from battery storage technologies are very modest. For example, *reference scenario* annual net loads are forecasted to increase by only 2,301 MWh, 94 MWh, and 42 MWh in 2042 from the residential battery (paired with PV), C&I battery (paired with PV), and large C&I (standalone) battery systems, respectively. In the *high scenario*, the equivalent annual utility net load increases in 2042 are 7,803 MWh, 242 MWh, and 172 MWh for residential (paired with PV), C&I (paired with PV), and large C&I (standalone) battery systems, respectively.[70] The utility load increases are even lower than those levels in earlier forecast years (i.e., before 2042). For example, they are approximately 75% lower in 2032 than in 2042 for residential battery storage in the *reference scenario*.

Table 21 shows the annual net energy production from residential battery storage systems, while **Table 22** displays equivalent data from C&I battery storage systems. The values in these tables are negative to denote negative net energy production from the battery storage technology (i.e., increases in utility loads).

Table 21: Forecasted Net Annual Energy Production from Residential Battery Storage Systems at the Central Station Plant Level (in MWh)

Forecast Year	Reference Scenario	High Scenario
2023	(4)	(12)
2024	(11)	(36)
2025	(27)	(86)
2026	(54)	(174)
2027	(99)	(317)
2028	(161)	(511)
2029	(239)	(781)
2030	(346)	(1,156)
2031	(462)	(1,565)

[70] These utility load increases from C&I battery storage systems are the sum of totals from commercial battery storage systems and industrial battery storage systems.

Forecast Year	Reference Scenario	High Scenario
2032	(589)	(2,009)
2033	(722)	(2,470)
2034	(863)	(2,958)
2035	(1,011)	(3,465)
2036	(1,167)	(3,999)
2037	(1,322)	(4,527)
2038	(1,493)	(5,102)
2039	(1,676)	(5,715)
2040	(1,876)	(6,386)
2041	(2,080)	(7,068)
2042	(2,301)	(7,803)

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Table 22: Forecasted Net Annual Energy Production from Commercial and Industrial Battery Storage Systems at the Central Station Plant Level (in MWh)

Forecast Year	Commercial Battery Storage Paired with PV: Reference Scenario	Commercial Battery Storage Paired with PV: High Scenario	Industrial Battery Storage Paired with PV: Reference Scenario	Industrial Battery Storage Paired with PV: High Scenario	Standalone C&I Battery Storage: Reference Scenario	Standalone C&I Battery Storage: High Scenario
2023	(0)	(1)	(0)	(0)	0	0
2024	(1)	(2)	(0)	(0)	0	0
2025	(1)	(3)	(0)	(0)	0	0
2026	(3)	(6)	(0)	(0)	0	0
2027	(4)	(10)	(0)	(1)	0	(7)
2028	(6)	(15)	(0)	(1)	0	(14)
2029	(8)	(22)	(1)	(2)	0	(21)
2030	(12)	(31)	(1)	(2)	0	(28)
2031	(16)	(41)	(1)	(3)	0	(35)
2032	(20)	(52)	(2)	(4)	0	(49)
2033	(25)	(64)	(2)	(5)	0	(63)
2034	(30)	(77)	(2)	(6)	0	(77)

Forecast Year	Commercial Battery Storage Paired with PV: Reference Scenario	Commercial Battery Storage Paired with PV: High Scenario	Industrial Battery Storage Paired with PV: Reference Scenario	Industrial Battery Storage Paired with PV: High Scenario	Standalone C&I Battery Storage: Reference Scenario	Standalone C&I Battery Storage: High Scenario
2035	(35)	(91)	(3)	(7)	0	(90)
2036	(41)	(107)	(3)	(8)	0	(104)
2037	(48)	(124)	(4)	(10)	(7)	(118)
2038	(55)	(141)	(4)	(11)	(14)	(132)
2039	(62)	(160)	(5)	(13)	(21)	(145)
2040	(70)	(181)	(6)	(14)	(28)	(159)
2041	(78)	(202)	(6)	(16)	(35)	(166)
2042	(87)	(224)	(7)	(18)	(42)	(172)

5.6 Key Findings

There are six key findings from the DER forecasts:

1. Residential, commercial, and industrial PV installed capacity is expected to increase to much greater levels in the later forecast years in the reference and high scenarios, largely due to the cumulative effects of PV capital cost declines and higher retail electricity prices.
    - By 2042, total customer PV capacity (across residential, commercial, and industrial customers) is forecasted to be 524 MW_{AC} in the *reference scenario* and 798 MW_{AC} in the *high scenario*.

2. ELL's residential PV market is noteworthy among regional peers for the relatively large volume of residential PV capacity already deployed (63 MW_{AC} as of mid-2021), which was driven in large part by prior state incentives.

3. Long-term, forecasted C&I PV adoption (and energy generation) significantly trails residential PV adoption for ELL, as it has done historically in many U.S. markets. By 2042, residential PV is estimated to comprise 83% (*reference scenario*) to 86% (*high scenario*) of all customer PV adoption in ELL's territory. The same pattern has occurred historically in ELL's territory, with cumulative residential PV capacity through mid-2021 representing more than 90% of the total customer PV market.

4. C&I battery storage for large C&I customers is expected to become an attractive investment (with payback periods below 12 years) by 2024 in the *high scenario* and by 2034 in the *reference scenario*. The ability of this technology to peak shave demand charges exceeding $10/kW (on certain large C&I rates) throughout the 20-year forecast period, combined with declining system capital costs throughout that period, lead to these favorable economics. Peak shaving occurs when the customer charges the battery system at times of low demand (without increasing monthly demand) and discharges at times of high demand.
    - However, there is a small number of customers in ELL territory on rate schedules conducive to economic peak shaving.

5. For residential customers and small to mid-sized C&I customers, an attachment rate methodology was used to estimate the deployment of battery storage when paired with PV. This covers instances of customers adopting battery storage when they install solar even when not justified alone by economic factors.
    - In total, 50 MW_{AC} of residential and 7 MW_{AC} of battery storage power capacity of this type is forecasted by 2042 in the *reference scenario*.

6. Battery storage systems are not expected to have large aggregate impacts on ELL's net energy loads or capacity.
    - On the energy side, that is because customer battery systems are not expected to be as common as PV systems, they tend to operate infrequently (a small percentage of hours during the year), and battery charges and discharges are netted out in aggregate calculations. On a net basis, battery storage increases utility loads due to efficiency losses that occur during charge and discharge cycles.
    - On the capacity side, these factors are relevant, as well as the fact that C&I customers are likely to dispatch their batteries to reduce their facility peak demand, not in response to systemwide peak demand signals as in some DR programs.
    - In any given hour, the net impact of battery storage on ELL's loads can be positive or negative, depending on the aggregate battery charging and discharging behavior of ELL customers during that hour.

Taken together, these findings imply that customer PV systems are likely to be significant contributors to energy load reductions, especially towards the end of the forecast period. By 2042, residential, commercial, and industrial PV systems combined are forecasted to reduce ELL's annual loads by about 900,000 MWh in the *reference scenario* and 1,400,000 MWh in the *high scenario*. Those annual PV output levels in 2042 represent 2.5% (*high scenario*) and 1.6% (*reference scenario*) of ELL's historic (2019) consumption loads for all customer classes combined. Given their weather-derived energy production patterns that can vary from minute to minute, this creates challenges and opportunities on the ELL distribution system as other demand- and supply-side resources, including battery storage, will increasingly be used to accommodate PV production while assuring sufficient system reserves and performance.

6 IRP INPUTS

6.1 Energy Efficiency

Using the outputs of this study, ICF developed the EE hourly load shapes for ELL's IRP, which reflect savings forecasted for every hour of every year of the forecast period, 2023-2042. ICF aggregated measure level load shapes to the program level and used these program-level load shapes in the IRP analysis. These load shapes were generated for both high and reference scenarios for all cost-effective programs in each of the sectors - residential, commercial, and industrial.

6.2 Demand Response

Similar to EE, ICF developed the DR hourly load shapes for ELL's IRP, which reflect savings forecasted for every hour of every year of the forecast period, 2023-2042. ICF aggregated measure level load shapes to the program level and used these program-level load shapes in the IRP analysis. These load shapes were generated for the reference and high scenarios for all cost-effective programs in each of the sectors - residential, commercial, and industrial.

6.3 Distributed Energy Resources

Using the outputs of the analytic approaches described in this report, ICF produced hourly net load inputs that can be used in ELL's IRP process over the 2023 to 2042 forecast period for five DER technologies: residential PV, C&I PV, residential battery storage (systems paired with PV), C&I battery storage (systems paired with PV), and large C&I battery storage (standalone systems). These IRP inputs were produced for high and reference scenarios. ICF further separated C&I hourly IRP inputs into commercial and industrial sectors. For PV technologies, the IRP inputs consist of one net load per hour. For battery storage technologies, both hourly charge and discharge data were provided to offer more granularity. The sum of each hour's battery storage charge (increase in utility load) and discharge (decrease in utility load) is the net load impact.

7 APPENDICES

7.1 Measure Assumptions

Residential Assumptions

Residential_Measure Assumption.xlsx

Commercial Assumptions

Commercial_Measure Assumption.xlsx

Industrial Assumptions

Industrial_Measure Assumption.xlsx

7.2 Annual Achievable Potential Results

7.2.1 Annual Program Savings

ELL EE DR Program Savings 07-26-2022.xl

7.2.2 Annual Program Costs

ELL EE DR Program costs 07-26-2022.xlsx

7.3 Avoided Costs

HIGHLY SENSITIVE PROTECTED MATERIAL

Table 23: Avoided Energy & Capacity Costs in Real $'s

Year	Avoided Costs	
	Energy	Capacity
	$/MWh	$/kW
2023	[redacted]	[redacted]
2024	[redacted]	[redacted]
2025	[redacted]	[redacted]
2026	[redacted]	[redacted]
2027	[redacted]	[redacted]
2028	[redacted]	[redacted]
2029	[redacted]	[redacted]
2030	[redacted]	[redacted]
2031	[redacted]	[redacted]
2032	[redacted]	[redacted]
2033	[redacted]	[redacted]
2034	[redacted]	[redacted]
2035	[redacted]	[redacted]
2036	[redacted]	[redacted]
2037	[redacted]	[redacted]
2038	[redacted]	[redacted]
2039	[redacted]	[redacted]
2040	[redacted]	[redacted]

Year	Avoided Costs	
	Energy	Capacity
	$/MWh	$/kW
2041	[redacted]	[redacted]
2042	[redacted]	[redacted]

7.4 Demand Response Data and Assumptions

Table 24: Peak Reduction Assumptions

Sector	Program	Measure	Summer Savings (kW/participant)
Residential	Direct Load Control - Water	Water Heater	0.39
Residential	Direct Load Control - Water	Pool Pumps	1.52
Residential	Smart Thermostat	Smart Thermostat BYOT (74%)	1.09
Residential	Smart Thermostat	Smart Thermostat DI (26%)	1.09
Commercial	Direct Load Control - Water	Water Heater	0.69
Commercial	Direct Load Control - Water	Pool Pumps	1.85
Commercial	Smart Thermostat	Smart Thermostat BYOT (74%)	1.09
Commercial	Smart Thermostat	Smart Thermostat DI (26%)	1.09
Commercial	Interruptible	Interruptible	22%*
Industrial	Interruptible	Interruptible	22%*
Agricultural	Irrigation Load Control	Irrigation Load Control	49%**

* % of flexible load of the participant; ** % of participant irrigation peak load

Table 25: Scenario Participation Assumptions

Sector	Program	Measure	Ref	High
Residential	Direct Load Control - Water	Water Heater	20%	30%
Residential	Direct Load Control - Water	Pool Pumps		
Residential	Smart Thermostat	Smart Thermostat BYOT (74%)	25%	38%
Residential	Smart Thermostat	Smart Thermostat DI (26%)		
Commercial	Direct Load Control - Water	Water Heater	10%	15%
Commercial	Direct Load Control - Water	Pool Pumps		
Commercial	Smart Thermostat	Smart Thermostat BYOT (74%)	5%	8%
Commercial	Smart Thermostat	Smart Thermostat DI (26%)		
Commercial	Interruptible	Interruptible	20%	28%
Industrial	Interruptible	Interruptible	40%	50%
Agricultural	Irrigation Load Control	Irrigation Load Control	50%	50%

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