2019 Integrated Resource Plan

Entergy Louisiana, LLC.

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Introduction

The electric grid provides the foundation upon which a strong Louisiana economy is built. 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 the lowest total retail prices in the country[1] with Entergy Louisiana, LLC's own rates being at or near the lowest within the State. 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 Entergy Louisiana, LLC ("ELL" or the "Company") 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 customers. ELL supports continued growth in our State through its continued investment in the State which allows us to power the lives of our customers with clean, affordable, and reliable electricity. The reliability of the electric system depends on long-term resource planning and Commission oversight. This Integrated Resource Plan ("IRP") is a product of a dynamic, ongoing process and this report provides a touchstone for this process.

Since joining the Midcontinent Independent System Operator, Inc ("MISO") in December 2013, ELL, with approval from the Commission, has added or plans to add over 2.9 gigawatts ("GW") of new generation in the State. This investment of more than $2.5 billion in new generation is needed to reliably serve Louisiana customers and support $101B of new capital investment and over 16,300 new jobs in our territory, based on projects announced since 2013. This growth, in turn, leads to innumerable improvements in Louisiana communities including increased investment in our schools, streets, parks, and other resources that enhance the daily lives of Louisianans.

Participation in MISO has brought tremendous value to Louisiana customers over the last five years. ELL has estimated approximately $560 million in savings since joining MISO as a result of lower reserve margins and MISO's economic dispatch of generation through its energy market. MISO, however, has no responsibility to provide or build generating capacity, and its capacity market, which is limited-term in nature, is not structured to cover the full cost of adding new generation. The MISO annual capacity market provides a mechanism for load serving entities to purchase or sell excess capacity on a limited-term basis; it is not a source of long-term capacity. Rather, MISO relies on its load serving entities (like ELL), under the regulation of state commissions (like the LPSC), to meet customer needs and ensure a reliable system. Those load serving entities do so through prudent long-term resource planning, the type of planning ELL presents to the Commission in this report.

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[1] Based on Form EIA-861M data from the U.S Energy Information Administration ("EIA"), Louisiana had the lowest average retail rates in the country in 2016, 2017 and 2018. *See* EIA "Form EAI-861M (formerly EIA-826) detailed data," which can be accessed at https://www.eia.gov/electricity/data/eia861m/.

Executive Summary

Statement of Purpose

This IRP Report, prepared in accordance with the rules promulgated by the Louisiana Public Service Commission,[2] describes the long-term resource planning of ELL for the period 2019-2038. The IRP provides a holistic look at considerations in designing and leveraging a forward-thinking portfolio of resources to meet ELL customers' energy needs. The IRP outlines the current landscape and provides a path forward for ELL so that ELL can continue to power homes, businesses, and communities reliably and cost effectively, while preparing for the challenges and opportunities that lie ahead.

ELL takes a customer-centric approach to long-term planning. The considerations detailed in the following pages are focused on meeting the ever-changing supply needs of ELL's customers. ELL seeks to meet those needs through its IRP strategy, which ensures that it is making the necessary decisions to continue to enhance reliability and affordability while mitigating risks. This approach also provides the flexibility ELL requires to respond and adapt to a constantly shifting utility landscape.

Background and Key Considerations

Since submitting its last 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 responded to this by moving forward with adding 2.2 GW of efficient, reliable gas-fired generation within historically constrained areas of ELL's footprint. 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.

Table 1: ELL's Planned New Resource Additions

ELL'S Planned New Resource Additions	MW	COD	Planning Area
St. Charles Power Station ("SCPS")	923	2019	Amite South
Lake Charles Power Station ("LCPS")	924	2020	WOTAB
Washington Parish Energy Center ("WPEC")	363	2021	Amite South
Total	**2,210**		

Additionally, ELL has executed Purchased Power Agreements ("PPAs") on almost 1 GW of combined cycle gas turbine ("CCGT") capacity and a 50 megawatt ("MW") solar photovoltaic ("PV") resource – the largest of its kind for the Company and the state of Louisiana. These additions, along with continued investment in ELL's transmission infrastructure, have allowed ELL to make significant progress towards decreased reliance on less efficient generation. In total, ELL assumes 5.8 GW of generation is to be deactivated over the 20-year planning horizon. Of this amount, 3.1 GW is sourced from legacy gas units, which are currently over 40 years old. These resources are relied upon to support transmission reliability and to serve load within the Planning Areas shown in Figure 1, below, that have transmission import constraints.

[2] *See*, LPSC Corrected General Order No. R-30021, dated April 20, 2012 (*In re: Development and Implementation of Rule for Integrated Resource Planning for Electric Utilities*).

Within ELL's service area there is expected significant load growth from new and existing large industrial customers. Constrained areas ("Load Pockets"), such as WOTAB (West of the Atchafalaya Basin) and Amite South, continue to grow contributing to the need for reliable generation within the load pockets. Flexibility will be required in resource planning as:

1. ELL's customers' load shapes continue to change due to differing use patterns and preferences, and
2. ELL continues to see the potential for block load additions in conjunction with ongoing economic development in the region

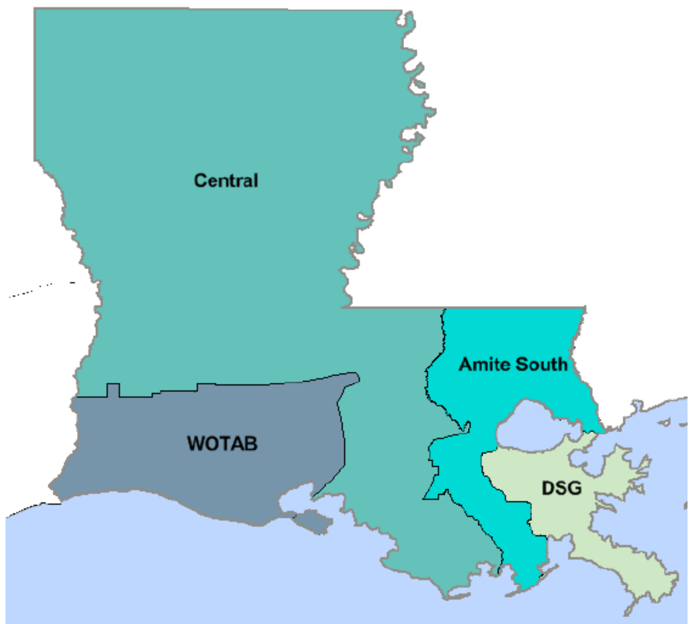

Figure 1: Outline of ELL Planning Areas

Industrial growth continues in Louisiana, and ELL sees the potential for several GW's of additional industrial demand developing in its service area beyond what is incorporated in the 2019 ELL IRP analytics. This growth is occurring at a time when most states are seeing flat to negative load growth and provides an opportunity, not just for ELL customers, but for the state as a whole. ELL is committed to helping Louisiana capitalize on these growth opportunities through responsible long-term resource planning which provides customers with clean, affordable power while improving system reliability for the benefit of all customers. ELL will continue to monitor these projects and adjust the forecast as necessary to provide a capacity and energy demand outlook based on the best available information at the time.

ELL's IRP is based on the best information available at the time of submittal; however, any insights taken from the IRP analytics must be made in light of the current load forecast, which could change with block load additions. As discussed throughout the IRP, subsequent planning flexibility is necessary to respond to changing conditions. Given the potential for legacy steam unit deactivations during the planning horizon and the potential load growth within southern portions of Louisiana, sound, proactive planning is required to address ongoing reliability requirements and needed flexibility throughout the planning horizon.

The Industry Condition

Gas-fired generation is expected to continue to be an important component of a diverse generation portfolio. However, ELL recognizes that the way its customers use and consume energy is changing, especially in the residential and commercial sectors, so the way it plans for, produces, and delivers the power they rely on must evolve as well. ELL strives to have a planning process that provides for the flexibility needed to better respond to this constantly evolving environment. Below are additional considerations, changes, and opportunities that help drive ELL's IRP strategy.

Changing Customer Preferences

The evolution and adoption of customer-centric technology and services, both in and out of the traditional utility construct, have created a shift in customer preferences and expectations – both in terms of how the power they use is generated, and the services and offerings they value from utility companies.

Today's energy customers seek 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. Increasingly, customers are becoming more interested in getting their power from cleaner, more sustainable sources of energy, including natural gas, nuclear, and renewables like wind and solar. Entergy is recognized as an industry leader for taking bold action to address climate issues. Our commitments have yielded beneficial results not only for the environment, but also for our stakeholders, including customers.

ELL is focused on achieving a better understanding of these changing customer preferences so that they can be taken into account in the IRP process. This will allow ELL to:

- ***Develop a comprehensive outlook on the future utility environment*** so it can more effectively anticipate and plan for the future energy needs of its customers and region.
- ***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.
- ***Continue to integrate and offer the innovative products and services*** its customers want and expect.

Technological Advancements

Technological advancements provide the energy industry increased alternative pathways to plan for and meet customers' energy needs. From energy production and generation, to storage and delivery, these innovations are helping strengthen reliability and increase affordability for the homes, businesses, industries, and communities 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 development of an Integrated Grid, one example of which would include ELL's Advanced Metering System ("AMS"),[3] is enabling the entire utility industry to better understand the new, changing ways in which customers are using energy. That allows energy companies to make more informed decisions and provide tailored customer solutions through enhancements to the electric infrastructure, the adoption of new products and services, and more.

Utility Actions

ELL understands that its customers' needs and expectations are changing, and these changes will help inform the IRP process as well as ELL's approach to customer service. Accordingly, ELL is evaluating and incorporating new, customer-centric technology and designing an energy portfolio that leverages a more diverse mix of energy resources – including a greater reliance on renewable and clean energy sources – to adapt to the changing needs of customers while keeping affordability

[3] *AMS can also be referred to as AMI: advanced metering infrastructure.*

and reliability top of mind for the customers ELL serves. ELL sees opportunity in providing a portfolio of efficient generation for the increased electrification of other industry sectors, including transportation and the powering of marine vessels while at port, which will add to regional sustainability.

Customer Value

Taken together, the changing customer preferences, technological advancements, and utility actions described above coalesce to provide increased value for ELL's customers. By combining a more thorough understanding of what today's energy customers want from their utility with a comprehensive, forward-thinking IRP process, ELL can deliver the services and products customers desire while maintaining reliable, cost effective service.

Primary Planning Objectives

Throughout the IRP process, and in the normal course of business, ELL is seeking to identify, deploy, and integrate the right mix of technology, resources, and products and services for its customers. While the scope and nature of the utility industry must always be evolving in response to the aforementioned factors, ELL's primary objectives in the planning process remain the same:

- ***To serve customers' power needs reliably***, helping to meet the energy needs of the homes, businesses, and communities ELL serves now and in the future.
- ***To reliably provide power at the lowest reasonable supply cost***, by pursuing a diverse mix of energy resources, new generation techniques, and customer-centric technological innovations.
- ***To mitigate exposure to risks that may affect customer cost or reliability***, keeping energy as affordably priced and reliable for ELL customers as possible.

Guiding Principles

ELL's planning process is guided by the following principles to support planning objectives:

- ***Capacity*** - Provide adequate capacity to meet customer needs.
- ***Base Load Production Cost*** - Meet base load requirements to keep costs stable.
- ***Load Following Production Cost*** - Respond to the varying needs of customers based on a number of factors.
- ***Modern Portfolio*** - Leverage ELL's modern, efficient generation while evaluating economics and reliability associated with less efficient legacy units.
- ***Price Stability*** - Mitigate exposure to price volatility.
- ***Supply Diversity*** - Diversify technology, location, capital commitments, and supply channels.
- ***In-Region Resources*** - Leverage a variety of in-region resources to meet customers' needs reliably and affordably.

Resource Adequacy and Planning Reserve Requirements

ELL is responsible for planning and maintaining a diverse energy resource portfolio that meets customers' power needs consistent with reliability, which requires maintaining the right types and amounts of generating capacity. With respect to the amount of capacity this requires, ELL takes into consideration two primary factors:

1. ***MISO Resource Adequacy requirements.*** MISO Resource Adequacy requirements are set annually and apply only to the subsequent planning year (defined as a one-year period beginning every June 1st). While this process establishes minimum requirements that must be met in the short-term and provides additional information on ELL capacity needs, it does not provide an appropriate basis for determining long-term resource needs. Also, relying solely on this near-term outlook for planning purposes unnecessarily exposes ELL's customers to reliability and

economic risk.

2. ***Long-term planning reserve margin targets.*** Because of the limited-term focus of MISO Resource Adequacy requirements, ELL plans its long-term portfolio to meet projected peak load, plus a 12 percent planning reserve margin, based on installed capacity. This approach ensures that ELL is able to maintain reliability for its customers even during unplanned events, like generating unit outages and extreme weather, over the long-term planning horizon, while still benefitting from participation in MISO's broader energy markets. This long-term planning approach (as opposed to relying heavily on MISO's capacity and energy markets) not only helps reduce unnecessary reliability and economic risk to customers but also allows ELL to be more agile in serving potential load growth and addressing resource needs as existing generation reaches the end of its useful life.

Through this two-pronged approach, ELL is able to meet its capacity needs reliably while protecting customers against extreme price fluctuations and uncertainty.

Current Fleet and Projected Needs

Current Fleet

In recent history, ELL has been successful in transforming its portfolio with reliable, efficient Combustion Turbine ("CT") and CCGT capacity to meet its supply needs. By 2021, ELL expects this type of technology to account for over 50% of owned and contracted capacity, replacing less efficient legacy gas units.

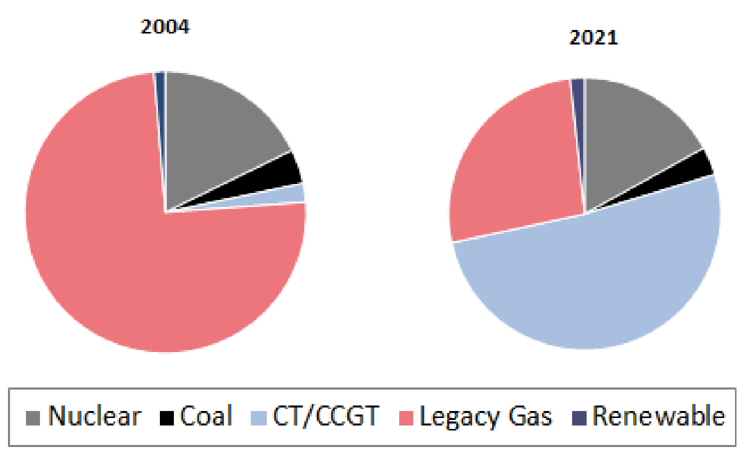

Figure 2: ELL's Evolving Portfolio

ELL's 2019 Integrated Resource Plan analytics help explore the right types of resources to replace deactivating generation and meet ELL's growing and changing load. Additionally, the economics of non-traditional supply (i.e., energy storage, renewables) and demand-side alternatives will be explored to more fully understand the benefits of a diverse mix of fuel and technology types.

Projected Needs

A number of factors have been considered and evaluated in order to understand and determine ELL's supply needs:

3. ***Long-Term Capacity Requirements*** - Given the evolving resource mix within ELL's portfolio, ELL will need new generating capacity over the course of the 20-year IRP planning period. Taking into account deactivation assumptions,

expected load growth, and units recently certified by the Commission, ELL's long-term deficit is expected to approach 7 GW[4] by the end of the planning horizon.

4. ***Energy Requirements*** - In addition to capacity requirements, ELL regularly examines its current and projected fleet to ensure it can effectively meet its energy requirements. Understanding current energy sufficiency also helps inform the future portfolio design. As resources deactivate and ELL's capacity requirements increase, ELL will look to balance energy producing and grid-balancing supply options to effectively and efficiently meet customer requirements.

5. ***Planning Region Needs*** - Amite South is a load pocket within ELL's service area that contains a high amount of existing and potential high load factor industrial load. The area regularly relies on local generation as well as imports to serve peak load and transmission requirements. Further, a large portion of ELL's generation, specifically legacy assets, is located in the area. Transmission and generation requirements will continue to be evaluated to support the reliability of the planning regions as load grows and infrastructure ages.

6. ***Environmental Regulations*** - Fossil fueled generation could be subject to future federal and state plans and regulations developed to meet the requirements of the federal Regional Haze Rule and other policies. As explained below, ELL considers future carbon emission pricing scenarios in its analysis. ELL's long-term planning process and the evaluation outlined in this IRP help inform how ELL will meet its future capacity and energy requirements.

Assumptions and Assessments

In designing ELL's 2019 IRP, a number of factors and assumptions were used to guide the portfolio design analysis and strategy, including:

- ***Analyzing the technological landscape to identify potential supply-side generation solutions*** that could help ELL serve customers' needs reliably and at the lowest reasonable cost, including existing and emerging natural gas, renewable, and energy storage technologies. ELL's technology assessment for the 2019 IRP seeks to explore in greater detail the challenges and opportunities of various generation alternatives as well as corresponding cost information to consider when designing the optimal resource portfolio to meet the capacity needs of its customers.

- ***Ever-advancing technology provides new opportunities to meet customers' needs reliably and affordably.*** Renewable energy resources are becoming increasingly economic alternatives with historically declining costs as illustrated in Figure 3 below, and these costs are expected to continue to improve throughout the planning horizon.

[4] Value does not include several GW of potential block load additions that are currently not incorporated into the 2019 ELL IRP analytics.

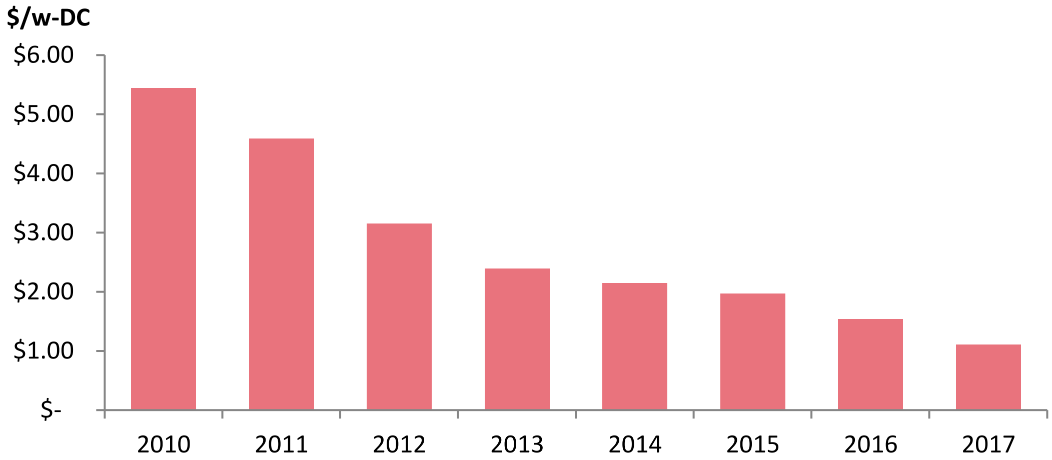

Figure 3: Utility Scale P.V., One-Axis Tracker[5]

With an increased deployment of intermittent generation, the value and necessity of flexible, diverse supply alternatives and smaller, more modular resources, such as battery storage devices, increases in order to provide opportunities to reduce risk and better address locational and site-specific reliability requirements while continuing to support overall grid reliability. Costs of energy storage resources have been observed to decline significantly in recent history, shown in the chart below, and are expected to continue to decline over the planning horizon.

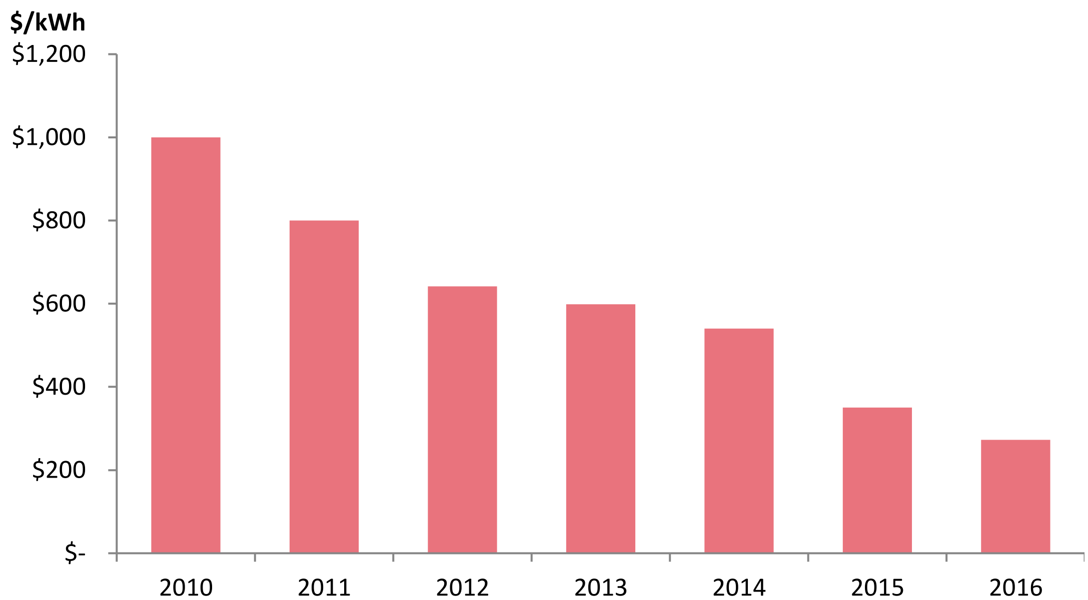

Figure 4: Lithium Ion Battery Costs[6]

[5] Data adapted from National Renewable Energy Laboratory ("NREL") U.S. Solar Photovoltaic System Cost Benchmark, Q1 2017.

[6] Source: Bloomberg New Energy Finance ("BNEF").

- ***Identifying and incorporating effects of potential cost-effective demand-side management programs.*** For the 2019 IRP, ELL engaged ICF to produce a Demand Side Management ("DSM") potential study that includes both energy efficiency ("EE") and demand response ("DR") offerings. The study considered EE programs including those administered by ELL's Quick Start Phase I Program Year 2 ("PY2") (referred to as "Current Programs"), an expansion of those programs, and new offerings. For demand response, a variety of offerings were included related to price response and load response programs. It should be noted that the ICF DSM potential study relied on Time of Use ("TOU") for DR savings, noting that the infrastructure for dynamic pricing alternatives was not in place. However, with the deployment of AMI, which commenced in 2019, ELL will be well positioned to offer dynamic pricing, which may be a better alternative for sending appropriate price signals for DR than traditional TOU rate structures, which require customers to shift consumption over long periods of time in order to avoid on-peak pricing. In fact, residential TOU options at other Entergy Operating Companies have had limited interest and very low enrollment. Overall, ELL believes that dynamic pricing alternatives better align with customers' evolving expectations because they are less invasive on an everyday basis than TOU rate structures in helping customers manage their bills.

- ***Preparing a natural gas price forecast to serve as a model for future natural gas pricing*** based on current market expectations. Due to limitations in natural gas forecasting as well as overall uncertainty in the natural gas market, ELL presents three scenarios for natural gas prices.

- ***Considering the potential for carbon regulation for the energy sector***, including identifying three potential scenarios for how the timing, design, and outcome of such regulation may result in the cost to operate carbon-emitting generation.

- ***Developing a 20-year, hour-by-hour load forecast, taking into account a wide range of factors*** including, but not limited to: economic growth and activity, developments in energy efficiency technology, changes in customer use and consumption, and the potential adoption of distributed generation technologies.

Portfolio Design and Analytics

ELL used a futures-driven scenario approach to guide the IRP process and strategy, through which it analyzed the total supply cost of four different resource portfolios under these different futures. The futures included unique attributes and assumptions in order to provide a range of market drivers and outcomes to analyze the portfolios against. This approach helps form the basis of understanding potential benefits and risk to ELL's customers derived from the attributes of each portfolio.

As a result of the portfolio analytics, ELL observed that a combination of CCGTs, peaking gas resources, and solar has the potential to meet planning objectives of cost, risk, and reliability. However, more detailed analyses will be required as ELL executes on supply alternatives. These analyses will need to account for current market conditions, availability of supply alternatives, customer preferences, feasibility and practicality of certain supply options, ELL's energy needs, local reliability criteria, potential environmental regulation and carbon emissions pricing, and transmission planning requirements.

The Path Forward (Action Plan)

ELL considers a number of factors when designing an IRP strategy that will enable the Company to continue serving customers' power needs as reliably and affordably as is reasonably possible. ELL believes that the following actions are important as it pursues a path forward to a strong energy future for ELL customers:

1. ***Legacy Generation Economic Study*** - As a part of its robust and iterative long-term planning processes, the Company continually monitors and studies the condition of units, market conditions, and economics to evaluate whether legacy units are candidates for deactivation or retirement. Consistent with the LPSC directive from the February 21, 2018

Open Session, ELL is conducting a comprehensive evaluation to assess the continued operations and role of its legacy fleet.[7] The study will consider the reliability implications of future unit deactivations and retirements and will provide additional insight into the transmission and generation support needed within the Amite South region given the current generation fleet, existing load, and potential load growth within the region. While the LPSC directive requires ELL's report to the Commission and final reports of the Staff be completed no later than six months following the commencement of generation at the new ELL power plant in Lake Charles, ELL expects to complete and file this study in the fourth quarter of 2019. This should afford Staff an appropriate amount of time to complete their report and allow both Staff and ELL to file their respective reports no later than six months following the commencement of generation at Lake Charles Power Station.

2. ***Environmental Impacts and Regulatory Requirements*** - ELL's facilities and operations are subject to regulation by various governmental authorities having jurisdiction over air quality, water quality, control of toxic substances and hazardous and solid wastes, and other environmental matters. ELL has a robust compliance assurance program and an environmental management system in place to address the compliance requirements and risks associated with these issues. ELL will continue to work with regulators and other stakeholders to implement compliance programs in the most cost-effective way. Details pertaining to ELL's management of specific environmental issues can be found in Section V, The Path Forward. Lastly, while key drivers indicate continued operation of Nelson 6 benefits ELL's customers, ELL will continue to monitor this unit and these drivers, especially as underlying assumptions change regarding fuel prices, the potential creation of a price on carbon emissions and other environmental regulations, related policies affecting the economies of coal-fired generation, and customer preferences. ELL also will consider the continued use of coal at Nelson in light of the goal set by Entergy Corporation to reduce the utility's carbon emission intensity rate to 50% below 2000 levels by 2030. In light of these factors, ELL intends to complete an analysis that contemplates the cessation of the use of coal at Nelson 6. ELL anticipates completing this analysis by 2021.

3. ***Integration of Renewable Resources and Other Diverse Supply Alternatives*** - In recognition of the improving cost-effectiveness and numerous benefits that renewable resources can provide, ELL continues to plan for increased development of renewable energy resources and generation. This includes the potential to bring more economic solar generation online in the coming years to support ELL's planning objectives. To accomplish this, ELL intends to issue a Request for Proposals ("RFP") for renewable resources no later than early 2020, which ELL anticipates would be followed by a recurring series of RFPs for renewable resources to support ongoing ELL energy needs and capitalize on the improving economics of solar and potentially other technologies relative to conventional generation resources. While the frequency and other parameters of these RFPs have not yet been determined, the strategy that ELL intends to deploy is one that systematically integrates cost-effective renewable resources over time while meeting ELL's planning objectives.

4. ***Renewable Energy Pricing Tariff*** - In conjunction with its first utility-scale solar resource, ELL is seeking Commission authorization of an Experimental Renewable Option Rate Schedule ("Schedule ERO"), which is a voluntary tariff that provides pricing tied directly to renewable generation. While Schedule ERO is ELL's first offering of this type, ELL acknowledges that it will continue to work to understand the needs of interested customers and may propose other renewable offerings for ELL's customers.

5. ***Battery Storage*** - Battery storage has the potential to provide an array of benefits, including the ability to store energy for later delivery and use, rapid construction, a smaller land footprint than some other alternatives which allows for

[7] LPSC Minutes from February 21, 2018 Open Session, Exhibit 8 at pp. 2-3.

more flexible siting, and potential portability to enable redeployment of storage in different areas as grid reliability needs change. Given the implications such technology has for the utility industry and with the expectations that costs will decline, continuing to explore opportunities to expand upon and develop this technology will be critical.

6. ***Demand Side Management*** - In February 2019, the Commission initiated rulemaking docket R-35136 through which it seeks to develop rules governing the development of DR rate schedules and programs. The Commission's notice of that proceeding does not indicate if the result of this DR rulemaking is to replace or supplement the Commission's existing DR Order.[8] Separately, in April 2019, Commission Staff issued its proposed Phase II EE and Conservation Rule ("Proposed EE Rules").[9] Staff's Proposed EE Rules note the correlation of DR with EE programs and seek utilities with IRPs to evaluate EE programs within their next IRP cycle by allowing those programs to compete with supply-side resource options. Accordingly, the DR and EE landscapes at the Commission are in a very active state of potential change. The IRP analytics indicated the value DSM may bring to ELL's customers. In conjunction with the ultimate Commission rules that will result from the current DR and EE rulemakings, ELL intends to conduct more detailed analyses of those DR and EE programs that proved to be economic in its modeled portfolio results in a way that complies with ELL's AMS Order as well as the Commission's ultimate rules to be determined in Docket Nos. R-35136 and R-31106.

   In addition to the programs shown to be economic in the IRP analysis, and in response to customer feedback during this IRP cycle, ELL is developing and plans to offer a new interruptible rider to further explore customer interest in demand response as an option for meeting the Company's capacity needs. ELL expects to file a new interruptible rider in the third quarter of 2019. In addition, with the deployment of AMI, ELL will explore new dynamic pricing alternatives which can better correlate prices with the costs of energy at different times for DR.

7. ***Growth and Reliability Study*** - ELL, like all load serving entities ("LSEs") within MISO, is responsible for planning and maintaining a resource portfolio to meet its customers' power needs. The Commission has acted as a steward of responsible system planning through various requirements, including but not limited to IRP requirements, periodic reporting on load forecasts, and resource certifications. ELL plans to undertake a study to evaluate load growth and unit deactivations not accounted for in the Commission's current long-term planning processes (i.e., entities that are not subject to LPSC Jurisdiction or electric cooperatives that have been exempted from the IRP process) in order to measure potential impact on ELL customers and system reliability, which may affect ELL's resource needs.

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8 General Order dated September 22, 2009, in Docket No. R-29213 consolidated with Docket R-29213 Sub. A (the "AMS/DR General Order"). See also LPSC Order dated August 25, 2017, in Docket No. U-34320 (Approving ELL's Application to Implement a Permanent Advanced Metering System and Request for Cost Recovery and Related Relief. ("ELL's AMS Order")), which orders ELL to conduct and complete a study investigating the implementation of demand response programs for its customers, including potential incentives, and file a report regarding its results, conclusions, and recommendations within 12 months of the completion of its AMS deployment.

9 Notice of Phase II Proposed Energy Efficiency Rule, Third Request for Comments, and Notice of Technical Conference dated April 16, 2019, in Docket No. R-31106.

The Industry Condition and ELL's Planning Framework

ELL's planning process seeks to design a portfolio of resources that reliably meets customer power needs at the lowest reasonable supply cost while considering risk. While traditional resource planning will continue, the landscape within the electric utility industry is changing and ELL is putting plans in place to provide flexibility in how to respond to the evolving environment.

Customer Preferences

- Increased desire for more options
- Interested in the use of cleaner more sustainable energy sources
- Changes to expected types of services and products

+

Advancing Technology

- Expanding list of viable supply alternatives, including an Integrated Grid, battery storage, and commercial scale solar

+

Utility Actions

- Understand changing customer needs
- Understand and seek experience with new technologies
- Design a portfolio to meet customer needs and wants
- Continue to account for affordability and reliability

=

Increased Customer Value

- Increased available services and products
- Diversity of supply alternatives
- Decreased risk to supply cost
- Increased reliability
- Modernization of the supply portfolio

Figure 5: Changes and Opportunities within the Utility Industry

Customer Preferences

With increased advancements in technology and evolving priorities both in and out of the traditional utility framework, customer expectations have and will continue to change. Customers are increasingly wanting and relying more on customer-centric technology and innovations in their daily lives. The available mix of technologies and fuels used to generate electricity used in homes, factories, and businesses has changed, impacting the way customers use and source electricity. Additionally, customers are increasingly interested in the use of cleaner, more sustainable energy sources. Entergy is recognized as an industry leader for taking bold action to address climate issues. Our commitments have yielded beneficial results not only for the environment, but also for our stakeholders, including customers. Our carbon dioxide emissions continue to be some of the lowest among our peers. This year, we are reinforcing this focus with the release of a new analysis report, Climate

Scenario Analysis and Evaluation of Risks and Opportunities. Its purpose is: (1) to build on Entergy's long history of discussing and managing climate change risk; (2) to use scenario planning to analyze potential impacts on – and opportunities for – Entergy and the regional economies in which we operate; and (3) to inform and engage stakeholders on Entergy's current and ongoing processes for managing climate risk and evaluating future opportunities – see the report at http://entergy.com/climatereport. ELL must recognize that customer preferences and needs are evolving, and ELL's planning processes seek to understand the impacts and expectations resulting from this evolution. By understanding what its customers want, ELL is able to be more comprehensive in its resource planning, ensuring it is delivering the types of services and energy solutions its customers expect and is better prepared to anticipate future energy needs.

Advancing Technology

With an expanding and changing portfolio, ELL's supply alternatives and technologies have provided increased opportunities and alternatives to address planning objectives. Ever-advancing technology (including, but not limited to, advances in generating and battery storage technology) provides new opportunities to meet customer needs reliably and affordably and enable the delivery of more sustainable energy.

Furthermore, Integrated Grids are increasingly viable and important, thanks to the increased options of grid-connected devices for energy storage. Understanding ELL's customers' needs allows ELL to make better decisions around fleet and grid upgrades, helping it meet the demands of today's and tomorrow's energy customer. ELL's use of smart technologies and advanced analytics will help it provide tailored solutions to its customers.

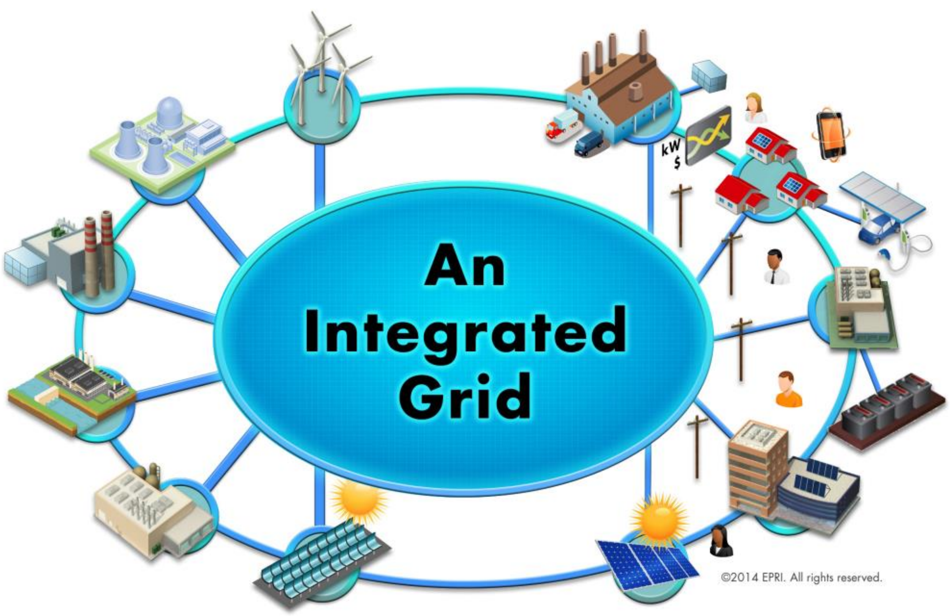

Figure 6: An Integrated Grid

Utility Actions

The scope and nature of ELL's business will and must change in response to the changing landscape. ELL's objective is to find, deploy, and integrate the right mix of technology, products, and services that provide solutions to serve the needs of its customers. ELL's planning processes and tools are evolving and will continue to evolve in order to help identify customer needs and wants, along with developing a comprehensive understanding of the various technological changes and opportunities within the utility industry. This increased understanding will enable ELL to design a portfolio of resources and services that meet customers' changing needs and wants while addressing ELL's planning objectives of serving customers reliably, at the lowest reasonable cost, while avoiding undue risk to customers. As knowledge and understanding increases, ELL strives to educate all stakeholders regarding these developments in order to make informed decisions, recognizing that financial commitments and investments are necessary to improving existing energy technologies and developing a portfolio of supply alternatives and products and services to meet customers' evolving expectations and needs.

Increased Customer Value

By combining an understanding of what its customers want with sound and comprehensive planning, ELL can better deliver the types of services and products its customers expect while continuing to address traditional planning objectives of cost, reliability, and risk. Increasing the array of alternatives provides an opportunity to better meet planning principles by providing a diverse portfolio of alternatives to meet long-term capacity, transmission, and ancillary service requirements. A diverse portfolio mitigates exposure to price volatility associated with uncertainties in fuel and purchased power costs, and risks that may occur through a concentration of portfolio attributes such as technology, location, large capital, or supply channels. Additionally, taking advantage of increased and evolving opportunities, ELL continues its effort of modernizing its supply portfolio.

Primary Planning Objectives

While the utility environment may be changing, ELL continues to plan to accomplish three broad objectives:

- ***To serve customers' power needs reliably;***
- ***To reliably provide power at the lowest reasonable supply cost; and***
- ***To mitigate exposure to risks that may affect customer cost or reliability.***

These objectives will be achieved while considering utilization of natural resources and the effect on the environment.

Objectives are measured from a customer perspective. That is, ELL's planning process seeks to design a portfolio of resources that reliably meets customer power needs at the lowest reasonable supply cost while considering risk.

In designing a portfolio to achieve the planning objectives, the planning process is guided by the following principles:

- ***Capacity*** - Provide adequate capacity to meet customer needs measured by peak load plus a long-term planning reserve margin.
- ***Base Load Production Cost*** - Provide resources to economically meet base load requirements at reasonably stable prices.
- ***Load Following Production Cost*** - Provide economically dispatchable resources capable of responding to the varying needs of customers driven by such factors as time of use, weather, and the integration of renewable generation.
- ***Modern Portfolio*** - Leverage ELL's modern, efficient generation while evaluating economics and reliability associated with less efficient legacy units.
- ***Price Stability*** - Mitigate exposure to price volatility associated with uncertainties in fuel and purchased power costs.
- ***Supply Diversity*** - Mitigate exposure to risks that that may occur through concentration of portfolio attributes such as technology, location, large capital commitments, or supply channels.
- ***In-Region Resources*** - Avoid overreliance on remote resources; provide adequate amounts and types of in-region resources to meet area needs reliably at a reasonable cost.

Participation in MISO

ELL has been a market participant in the MISO Regional Transmission Organization ("RTO") since December 19, 2013. MISO is a non-profit, member-based organization, which exists to provide an independent platform for efficient regional energy markets. MISO conducts transmission planning and manages buying and selling of wholesale electricity across 15 U.S. states and the Canadian province of Manitoba.

As shown below, ELL is located within Local Resource Zone ("LRZ") 9 of the MISO footprint.

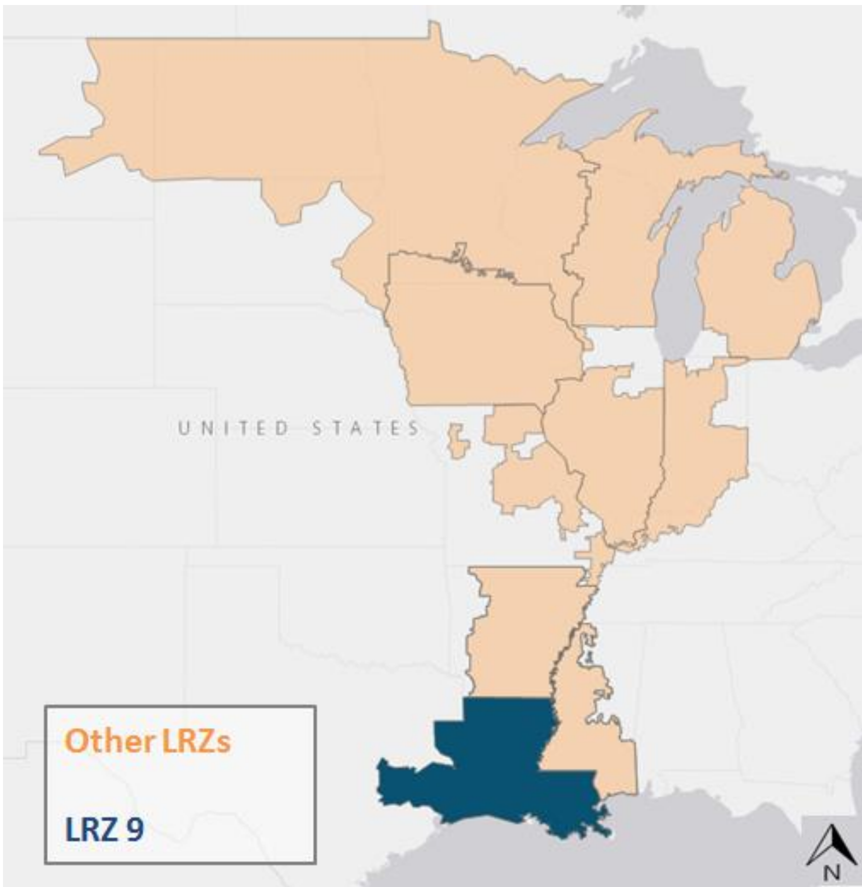

Figure 7: LRZ 9 within MISO

As a MISO member, ELL has access to a large, structured market that enhances the resource alternatives available to meet customers' near-term power needs. Over the long term, the availability and price of power in the MISO market affects ELL's resource strategy and portfolio design. Additionally, ELL retains responsibility for providing safe and reliable service to its customers. Thus, the 2019 ELL IRP is designed to help ensure development of a long-term integrated resource plan for ELL that reflects that responsibility and balances the objective of minimizing the cost of service while considering factors that affect risk and reliability.

Transmission Planning

The Company's internal transmission planning and its participation in the MISO transmission planning process ensures that the transmission system:

(1) remains compliant with applicable North American Electric Reliability Corporation ("NERC") standards and the Company's related local planning criteria, and

(2) is designed to efficiently deliver energy to end-use customers at a reasonable cost. Since joining MISO, ELL plans its transmission system in accordance with the MISO Tariff.

Expansion of, and enhancements to, transmission facilities must be planned well in advance of the need for such improvements given that regulatory approvals, right-of-way acquisition, and construction can take years to complete. Advanced planning requires that computer models be used to evaluate the transmission system in future years, taking into account the planned uses of the system, generation and load forecasts, and planned transmission facilities. On an annual basis, the Company's Transmission Planning Group performs analyses to determine the reliability and economic performance needs of ELL's portion of the interconnected transmission system. The projects developed are included in the Long-Term Transmission Plan ("LTTP") for submission to the MISO Transmission Expansion Planning ("MTEP") process as part of a bottom-up planning process for MISO's consideration and review. The LTTP consists of transmission projects planned to be in-service in an ensuing 10-year planning period. The projects included in the LTTP serve several purposes: to serve specific customer needs, to provide economic benefit to customers, to meet NERC transmission planning reliability standards, to facilitate incremental load additions, and to enable transmission service to be sold and generators to interconnect to the electric grid.

With regard to transmission planning aimed at providing economic benefit to customers, ELL has and will continue to actively engage in MISO's top-down regional economic planning process, referred to as the Market Congestion Planning Study ("MCPS"), which is a part of the MTEP process. MISO's MCPS relies on the input of transmission owners and other stakeholders, both with regard to the assumptions and scenarios utilized in the analysis and identification of proposed projects intended to reduce transmission congestion. The Company analyzes forecasted congestion patterns using MISO's models and will propose projects that the Company believes have benefits. Based on ELL's input and the input from other stakeholders, MISO evaluates the economic benefits of the submitted transmission projects while ensuring continued reliability of the system. The potential benefits include the savings associated with a more efficient commitment of resources across the MISO footprint, including potential reduction in Voltage and Local Reliability costs (previously referred to as "RMR" unit operations), the reduction in transmission system losses, and the potential to offset previously approved transmission projects. The intended result of the MCPS is a project, or set of projects, determined to be economically beneficial to customers, which is submitted to the MISO Board of Directors for approval. MISO typically recommends transmission projects found to result in economic benefits to the MISO Board for their approval in December of the MTEP year.

In each MTEP cycle, analyses are performed by the Company's Transmission Planning Group in coordination with the Company's resource planners to identify any transmission options that could economically deliver existing or planned resources located anywhere in MISO to ELL's customers. MTEP 18 concluded in December 2018 with no new economic projects being identified. However, a number of projects in previous cycles have been approved including the Louisiana Economic Transmission Project, Waterford – Churchill, and several additional smaller projects. These projects have either been completed or are planned for construction in the coming years. The current MTEP cycle, MTEP19, is currently in process but not yet complete. The analyses and results from all previous internal analyses and MTEP cycles up through and including MTEP18 were considered in the development of the IRP and in ELL's ongoing long-term planning processes. As part of and beyond the IRP, ELL looks at locational benefits of any planned incremental capacity or transmission impact of deactivating a resource. The evaluation of site-specific resource locations and deactivations takes into account planned or "Appendix A" projects to account for the reliability and economic benefits of transmission investment.

It is also important to note that while MISO's MCPS within the MTEP process generally considers capacity needs for the entire RTO, the MCPS process focuses on the delivery of energy and thus it does not attempt to develop a detailed plan to address the capacity needs of MISO or any entity within MISO. Therefore, while energy-related economic benefits may be addressed through transmission expansion, other important needs such as reactive power production, the local need for inertia in industrial areas, the ability to support the integration of inverter-based resources, etc. must be considered in developing integrated resource plans.

Details of the LTTP projects can be found in the current and past MISO MTEP reports, which are publicly available at www.misoenergy.org/planning/transmission-studies-and-reports.

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 and requirements for meeting NERC reliability standards and efficiently delivering energy to customers at a reasonable cost. 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 supply needs is critical in meeting ELL's planning objectives of cost, reliability, and risk. As part of ELL's ongoing planning process, ELL seeks to support transmission and capacity requirements through siting needed generation in locations that support and are supported by the transmission infrastructure. An example of ELL's diligence in siting generation to support the transmission system is in the planning and execution of LCPS and SCPS.

Stability of the transmission system is, in large part, correlated to the inertia of the rotors spinning within operating generation and the real and reactive power produced. In concert, these services allow the transmission system to resist changes to system frequency and maintain steady operating characteristics. This is of particular importance when serving large motors and industrial loads, a large component of ELL's customers. Although inverter-based technology such as solar PV does not inherently provide these services in the same manner as spinning generation, these resources can still provide benefits to the region's energy mix. Going forward, ELL will have to balance the need for conventional generation to provide adequate reliability for its industrial customers while pursuing transmission solutions and inverter-based technology when economic, capable of enhancing reliability, and/or when appropriate for meeting its customers' preferences.

The continued evaluation and condition of ELL's legacy gas-fired generation, which will be further discussed later in the document, must be taken into account to support integrated generation and transmission planning. ELL's aging legacy fleet has the potential and expectation of deactivating during the planning horizon, which will have an impact on transmission reliability requirements without apposite replacement generation.

ELL's Integrated Resource Planning models used in the analysis described herein does not consider transmission as an alternative to generation. Transmission does not provide generating capacity and energy needed to serve ELL's customers. ELL's resource portfolio is based primarily on meeting projected capacity and energy needs as are prescribed by ELL's guiding principles. While the implementation of a sound transmission plan is necessary to ensure reliability and can facilitate the efficient flow of energy within a system, it does not address capacity needs. 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 by applying the transmission topology. This topology will include the most up-to-date configuration of the Entergy transmission system, as well as the most current load forecasts, all approved MISO MTEP projects, and other projects targeted for MISO approval which are expected to be in service within the timeframe of the analysis.

Resource Adequacy and Planning Reserve Requirements

As an LSE within MISO, ELL is responsible for planning and maintaining a resource portfolio to meet its customers' power needs. To meet its customers' needs, ELL must maintain the right type and amount of capacity in its portfolio. With respect to the amount of capacity, two considerations are relevant: ***1) MISO Resource Adequacy Requirements***; and ***2) Long-Term Planning Reserve Margin Targets***.

MISO Resource Adequacy Requirements

Resource Adequacy is the process by which MISO obligates participating LSEs to procure sufficient capacity, through the procurement of zonal resource credits ("ZRCs") equal to their Planning Reserve Margin Requirement ("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 established by MISO annually for the MISO footprint.

Under MISO's Resource Adequacy process, the 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 annual capacity needs for a particular region or LRZ based on load requirements, capability of the existing generation, and import capability of the LRZ. Those generation needs are articulated through a Local Clearing Requirement for the LRZ for each Planning Year.

At present, the MISO Resource Adequacy process is a short-term construct. Requirements are set annually and apply only to the next year. Similarly, the cost of planning resource credits, as determined annually through the MISO auction process, apply only to the forthcoming year. The cost of capacity credits is based on an auction clearing price and does not necessarily reflect the cost to own and operate generation. Both the level of required ZRCs and the cost of those ZRCs are subject to change from year to year. In particular, the cost of ZRCs can change quickly as a result of, among other things, changes in bidding strategy of market participants, the availability of generation within MISO and a specific LRZ, and an LRZ's Local Clearing Requirement. As a result, although the MISO Resource Adequacy process establishes minimum requirements that must be met in the short term and are reviewed regularly as part of the resource planning process, it does not provide an appropriate basis for determining ELL's long-term resource needs. In other words, relying on the short-term market for ZRCs to meet customers' long-term power needs involves risk. A more stable basis for long-term planning is needed if ELL is to meet its long-term planning objectives.

Long-Term Planning Reserve Margin Targets

ELL plans its portfolio to meet its projected peak load, plus a 12 percent planning reserve margin, based on installed capacity. The long-term planning reserve margin is intended as a generation supply safety margin to maintain reliable service during unplanned events including, but not limited to, generating unit forced outages, extreme high temperatures, and load forecast deviations while still taking into account the advantages of participating in MISO's broader market. Moreover, a portfolio of long-term physical resources (versus relying heavily on MISO's capacity and energy markets) helps reduce unnecessary reliability and economic risk to customers and allows ELL to be more agile with potential load growth and aging infrastructure.

It is worth noting that ELL believes this margin to be appropriate at this time and as long as the MISO capacity market is not inappropriately used. It appears that distribution electric cooperatives that have been exempted from the IRP Order on the basis that they have a full requirement contract, are attempting to enter into new wholesale supply agreements in connection with block load additions without LPSC engagement in a resource planning effort. To the extent that distribution electric cooperatives or any other entities within the MISO market overly rely on the short-term MISO capacity market to serve load, such reliance could have unintended consequences on reliability and electricity prices in the state.

Current Fleet and Projected Needs

Current Fleet

ELL currently controls nearly 9 GW of generating capacity through either direct ownership or through life-of-unit contracts with affiliate Entergy Operating Companies. The table below shows ELL's supply resources by resource type measured in installed capacity with the percentage contribution to the overall portfolio.

Table 2: ELL's Resource Portfolio – Fuel Mix

ELL'S Resource Portfolio: Fuel Type	MW	%
Coal	392	4%
Nuclear	1,981	22%
CCGT	2,634	30%
CT	445	5%
Legacy Gas	3,115	35%
Load Modifying Resources	333	4%
Total	**8,900**	**100%**

Of this 8,900 MW, about one-third of ELL's total capacity is derived from legacy gas units, which range in age from 43 to 52 years of service and are assumed to deactivate over the course of the IRP planning horizon.

In addition to these legacy gas assets, ELL also maintains ~400 MW of coal fired generation within the supply portfolio, from ownership shares in the Nelson 6 and Big Cajun 2 facilities, in addition to affiliate Power Purchase Agreements of Independence and White Bluff. Currently, these resources provide fuel diversity and solid fuel assurance to ELL's customers. Throughout the planning period, Nelson 6 and Big Cajun 2, Unit 3 are assumed to continue to operate. These units will continue to operate as long as operating the resources is consistent with ELL's long-term planning objectives. Independence and White Bluff are assumed to deactivate during the IRP planning period.

ELL's current portfolio by unit is shown in the table below and is supplemented by a description of each unit that ELL owns and/or operates located in Appendix G.

Table 3: ELL's Resource Portfolio by Unit

Plant	Unit	MW[1]	Fuel	Resource Type	Location	ELL Ownership (%)	Purchaser of ELL MW[2]	Operation Date
Acadia	2	544	Natural Gas	CCGT	Acadia, LA	100%	ENOL (Algiers)	2002
ANO	1	22	Nuclear	PWR	Pope, AR	-	ENOL (Algiers)	1974
ANO	2	26	Nuclear	PWR	Pope, AR	-	ENOL (Algiers)	1980
Big Cajun 2	3	139	Coal	Steam	Pointe Coupee, LA	24%	-	1983
Calcasieu	1	143	Natural Gas	CT	Calcasieu, LA	100%	-	2000
Calcasieu	2	156	Natural Gas	CT	Calcasieu, LA	100%	-	2001
Grand Gulf	-	205	Nuclear	BWR	Claiborne, MS	-	ENOL (Algiers)	1985
Independence	1	7	Coal	Steam	Independence, AR	-	ENOL (Algiers)	1983
Little Gypsy	2	401	Natural Gas	Steam	Saint Charles, LA	100%	ENOL (Algiers)	1966
Little Gypsy	3	508	Natural Gas	Steam	Saint Charles, LA	100%	ENOL (Algiers)	1969
Ninemile	4	669	Natural Gas	Steam	Jefferson, LA	100%	ENOL (Algiers)	1971
Ninemile	5	740	Natural Gas	Steam	Jefferson, LA	100%	ENOL (Algiers)	1973
Ninemile	6	443	Natural Gas	CCGT	Jefferson, LA	100%	ENOL/ENOL (Algiers)	2014
Ouachita	3	249	Natural Gas	CCGT	Ouachita, LA	100%	-	2002
Perryville	1	361	Natural Gas	CCGT	Ouachita, LA	100%	ENOL (Algiers)/ETI	2002
Perryville	2	104	Natural Gas	CT	Ouachita, LA	100%	ENOL (Algiers)/ETI	2001
Riverbend 30	-	191	Nuclear	BWR	West Feliciana, LA	100%	ENOL/ENOL (Algiers)	1986
Riverbend 70	-	389	Nuclear	BWR	West Feliciana, LA	100%	ETI	1986
Roy Nelson	6	221	Coal	Steam	Calcasieu, LA	40%	-	1982
Sterlington 7 A	7A	46	Natural Gas	CT	Ouachita, LA	100%	ENOL (Algiers)	1973
Union PB	4	494	Natural Gas	CCGT	Union, AR	100%	-	2003
Union PB	3	497	Natural Gas	CCGT	Union, AR	100%	-	2003
Waterford	3	1147	Nuclear	PWR	Saint Charles, LA	100%	ENOL (Algiers)	1985
Waterford	4	32	Oil	CT	Saint Charles, LA	100%	ENOL (Algiers)	2009
Waterford	1	399	Natural Gas	Steam	Saint Charles, LA	100%	ENOL (Algiers)	1975
Waterford	2	399	Natural Gas	Steam	Saint Charles, LA	100%	ENOL (Algiers)	1975
White Bluff	1	13	Coal	Steam	Jefferson, AR	-	ENOL (Algiers)	1980
White Bluff	2	12	Coal	Steam	Jefferson, AR	-	ENOL (Algiers)	1981
LMR (Load Modifying Resource)	-	333[3]	N/A	N/A	-	-	N/A	
Total	-	**8,900**						

1. Represents ELL net share after ownership and PPAs
2. Indicates a purchaser of MW ELL either owns or receives through a PPA as described below.
3. Includes ELL's Montauk PPA (3.3 MW Total)

The majority of the resources included in Table 3 are owned by ELL, but ELL also receives energy and capacity from other Entergy affiliates through PPAs for certain resources. 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 the Federal Energy Regulatory Commission ("FERC").

In addition to purchasing the output of certain units from other Entergy affiliates, ELL also sells the output 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[10] 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. In addition to those tabulated, ELL also included "ELL Renewables RFP 1[11]", "ELL Renewables RFP 2", and the renewal of the Carville PPA as future resources in the years 2019, 2020 and 2022, respectively, as a planning assumption.

Table 4: Third Party PPAs (Power Purchase Agreements)

Resource	MW	Fuel	Contract Expiration Year
Agrilectric	9	Biomass	2033
Carville[12][13]	243	Natural Gas	2022
Montauk	3	Biomass	2024
Oxy-Taft	471	Natural Gas	2028
Rain CII	28	Waste Heat	2032
Vidalia	112	Hydro	2031

[10] "Legacy ELL" refers to the ELL entity prior to the combination of Legacy ELL and Entergy Gulf States Louisiana, L.L.C. ("EGSL") approved by the LPSC in LPSC Docket No. U-33244.

[11] ELL Renewables RFP 1 is now referred to as LA3 Solar PPA (50 MW).

[12] To be renewed upon expiration for a 10-year duration for the full output of the unit (485 MW).

[13] ETI is the buyer of the Carville PPA and subsequently sells 50% of the output to ELL.

Existing Fleet Deactivation Assumptions

The IRP includes deactivation assumptions for existing generation in order to plan for and evaluate the best options for replacement capacity over the planning horizon. Based on current planning assumptions, during the planning period, the total net reduction in ELL's generating capacity from the anticipated unit deactivations is expected to be ~6 GW. Generally, the IRP analysis reflects generic deactivation assumptions for the generation fleet: 60 years for coal and legacy gas resources, and 30 years for combustion turbine technology (CTs and CCGTs). As resources age and assumed deactivation dates near, as equipment failures occur, or as operating performance diminishes, cross-functional teams are then assembled to evaluate whether to keep a particular unit in service for a specified amount of time and level of reliability. Any resulting deviations from the generic assumptions are detailed below. These deactivation assumptions do not constitute a definitive deactivation schedule but are based upon the best available information and are used as planning tools to 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. Some of these deactivation assumptions could accelerate as these units approach the end of their design-life.

In the near term, ELL's unit deactivation assumptions for the 2019 ELL IRP are outlined below.

[redacted]

Little Gypsy 2 and 3

Deactivations currently assumed for Little Gypsy 2 and 3 are 2026 and 2029 respectively. These are generic assumptions only and do not reflect unit specific analyses or decisions. As stated above, these assumptions are reevaluated as the resources age and their conditions change.

White Bluff 1, White Bluff 2, and Independence 1

ELL currently has a life-of-unit contract with EAL for a portion of White Bluff 1, White Bluff 2, and Independence 1 coal units. ELL assumed within its modeling an accelerated deactivation date to reflect EAL's commitment to cease to burn coal at White Bluff by 2028 and its planning assumption to cease burning coal at Independence by the end of 2030.

These assumptions are summarized in the table below.

Table 5: Near-Term Deactivation Assumptions

Plant	Unit	Assumption
[redacted]		
Little Gypsy	2	2026
White Bluff	1	2027
White Bluff	2	2028
Little Gypsy	3	2029
Independence	1	2030

Consistent with the LPSC directive from the February 21, 2018 Open Session, ELL will complete a study of the economic viability of all legacy power plants. This study is required to be finalized no later than six months following the commercial operation date of Lake Charles Power Station, however ELL intends to target the completion of this study in the fourth quarter of 2019. This evaluation will support the current or a change to the deactivation assumptions for ELL's legacy generation.

Load Forecasting Methodology

A wide range of factors will affect electric load in the long term, including:

- Levels of economic activity and growth;
- The potential for technological change to affect the efficiency of electric consumption;
- Potential changes in the purposes for which customers use electricity (e.g., replacement of vehicles that operate using internal combustion engines with vehicles that operate using electric motors);
- The potential adoption of end-use (behind-the-meter) self-generation technologies (e.g., rooftop solar panels); and
- The level of energy efficiency, conservation measures, and distributed generation adopted by customers.

Such factors may affect both the levels and patterns of electricity consumption in the future. Peak loads may be higher or lower than projected levels. Similarly, industrial customer load factors may be higher or lower than currently projected. Uncertainties in load levels and patterns may affect both the amount and type of resources required to efficiently meet customer needs in the future.

The long-term load forecast is an hour-by-hour, 20-year forecast of MW consumption. The preparation of the long-term load forecast involves two distinct and sequential processes: (1) electric sales forecasting and (2) load forecasting. In the first process, the monthly sales are forecasted assuming normal weather across the forecast horizon. The second process takes the monthly sales forecast and develops monthly peaks and allocates the monthly MWh to individual hourly MW based on hourly consumption profiles or shapes. These processes are discussed in more detail below.

For the 2019 IRP, three load forecasts were produced as part of the future analytical framework:

Table 6: Load Forecasting Scenarios

Scenario	Drivers
Low	• Residential customer growth rate decreased by 15% and commercial customer growth rate decreased by 25% ○ Job growth does not materialize in the area ○ Brick and mortar retail stores continue closing in the face of online competition • Residential and Commercial Energy Efficiency increases 25% ○ Energy efficient appliance technology continues to advance ○ LED light bulbs continue to get cheaper with higher adoption ○ Commercial electricity prices increase by 10% with elasticity of -0.2 • Industrial ○ Fewer new projects come online as well as reduced output from existing customers ○ Large and Small Industrial growth rates decreased by 20% ○ Liquified natural gas ("LNG") economics do not allow new export facilities to become operational ○ Customers add more cogeneration and solar to offset power consumption
Reference	• Louisiana's natural resources and tax structure create opportunities for new large and small

	industrial sales • Increases in heating and cooling equipment efficiency as well as LED lighting becoming more affordable and common • Use per customer declines in Residential and Commercial, partially offset by growth in customer counts

High	• Residential customer count growth rate increased by 25% and commercial customer count growth rate increased by 10%
	• Residential appliance energy efficiency decreased by 25%
	  ○ LED light bulb penetration weaker than anticipated
	  ○ New administration discontinues Energy Star program used to incentivize businesses to create more efficient appliances
	• Large and small industrial sales growth rates increased by 10% and realization of speculative projects

Sales Forecasting

The sales forecast is developed using a bottom-up approach by customer class – residential, commercial, large industrial, small industrial, and governmental. The High and the Low scenarios are sensitivities based on the Reference Case, which is the same as the 2018 Business Plan Update or “BP18-U”. The Reference Case forecast was developed by customer class using historic sales volumes and customer counts, as well as historical and estimated normal weather, economic, and energy efficiency measures. In addition, the forecast includes estimates for future growth in large industrial usage as well as estimates of future growth from electric vehicles and declines due to future rooftop solar adoption.

For the Reference Case and each scenario, the monthly sales forecasts are converted to hourly load forecasts using historical hourly load shapes and specific shapes for the daytime effects of rooftop solar. The load forecasts are the sum of the hourly forecasts for legacy EGSL and ELL, which were modeled and produced separately. Because many of the drivers of the load forecast are assembled to first develop the underlying sales forecast in terms of annual MWh, many of the explanations below refer to the sales forecasts.

Overall, the compound annual growth rate (“CAGR”) for 2019-2025 for the Reference Case forecast is 0.8%/year. This growth is primarily driven by growth for the class of large industrial customers and is offset by expected declines in growth for the residential and commercial classes. Those forecasts are discussed further below.

Large Industrial Growth

Customers in the large industrial class are forecasted individually. The main growth driver in the overall forecast comes from the large industrial class. The 2019-2025 CAGR for ELL large industrial sales is 2.9%/year, with most of that growth expected to come in 2020 due to ramping of new LNG and new chemical customers mainly in the Lake Charles area. The customers expected to contribute to 2020 growth are already under construction or ramping up (low risk). Forecasts for new or prospective large industrials are based on information from the new/prospective customer and Entergy’s Economic Development team as to their expected MW size, operating profile, and ramping schedule. The forecasts are also risk-adjusted based on the status of the customer along the path of signing an electric services agreement and progress towards achieving commercial operations. Existing industrial customers are forecasted based on historical usage, planned future outages, expansions or contractions. Table 7 shows the forecasted year-over-year growth in sales due to large industrials.

Table 7: Large Industrial Growth

	2020	2021	2022	2023	2024	2025	2019 - 2025 CAGR
YoY Growth in Industrial Energy Sales	**5.5%**	0.0%	0.7%	1.3%	2.0%	0.5%	**2.9%**

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 econometric forecasting software called Metrix ND, 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 time periods and those relationships are applied going forward to estimates of normal weather, economic factors, and/or time periods to develop the forecast. Autoregressive and moving average variables are also included in the models to account for time series effects when significant. Explanatory variables are included in each model if the significance is greater than 95%.

The sales forecasts assume weather to be "normal." For this purpose, normal weather is defined as a 20-year average of temperatures by month. 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 averages are built from hourly temperatures and are allocated to each calendar month based on the billing cycles for each month to ensure that the resulting averages appropriately consider the temperatures on the days when the power was consumed.

Residential

Near-term growth in residential sales is expected to be relatively flat-to-declining with a forecast CAGR of -0.2%/yr for 2019-2025. The forecasted decline in residential sales growth is due to several factors. By 2021, residential sales are assumed to decline by 1.5% due to ELL's installation of the AMS metering and the accompanying consumption information that will be available to customers to help customers manage their usage. The 1.5% expected AMI reduction is the combination of a 1.75% reduction in sales offset by a 0.25% increase in sales related to unaccounted for energy benefit. The decrement is phased in over three years starting in 2019. In addition, the forecast assumes future levels of energy efficiency putting downward pressure on electricity consumption. The energy efficiency is expected to come primarily from cooling and lighting and is based on future consumption estimates from the EIA and is separate from company-sponsored DSM discussed further below. Overall, average annual kWh consumption per household is expected to decline by 1.1%/yr. for 2019 – 2025.

The monthly model for residential use per customer, taking into account expected efficiency is:

Residential use per customer per day =

$$\textit{Heating Degree Days}_m * \textit{Heating efficiency index}_m * \textit{Heating coefficient}_m +$$

$$\textit{Cooling Degree Days}_m * \textit{Cooling efficiency index}_m * \textit{Cooling coefficient}_m +$$

$$\textit{other use coefficient} * \textit{other use efficiency index}_m$$

Forecasting use per billing day increases the monthly forecast accuracy because the days in a billing cycle vary from month to month. Monthly heating and cooling coefficients are used in the regression because generally a degree day in August has more effect than a degree day in May. Actual historical weather is used in the regression model. The twenty-year normal weather is used for forecasting normal sales.

Offsetting declines in use per customer are expectations for customer count growth. Based on historical growth in customer counts as well as expected future growth in the population and numbers of households in Louisiana, ELL has forecasted residential customer growth of 0.9%/yr for 2019-2025. The combined impact of lower usage per customer ("UPC") (resulting from AMI, energy efficiency, etc.) and increasing customer count growth leads to a net forecasted CAGR in residential energy of -0.2%/yr for 2019-2025.

See 8 showing the year-over-year changes and CAGRs in Residential energy, customer counts, and household counts.

Table 8: YoY Growth Residential

	2020	2021	2022	2023	2024	2025	2019 - 2025 CAGR
Energy	-0.8%	-0.9%	-0.3%	0.1%	0.6%	0.0%	-0.2%
UPC	-2.0%	-2.0%	-1.2%	-0.7%	-0.1%	-0.7%	-1.1%
Customers	1.2%	1.1%	0.9%	0.8%	0.7%	0.7%	0.9%

Commercial Forecast

Commercial sales are also forecasted to decline slightly for 2019-2025 with a CAGR of -0.4%/yr. This is being driven by forecasted customer count growth of 0.7% per year offset by commercial UPC declines of 1.1%/year.

The explanations for the Commercial class are very similar to those for the Residential class in that the Commercial forecast includes a net decrement of 1.5% similar to the adjustment for Residential by 2021 (phased-in starting in 2019) for the AMI installations and related customer information that will be available to customers to help customers manage their usage. In addition, the Commercial forecast accounts for increased energy efficiency, primarily from HVAC and refrigeration, that is separate from company-sponsored DSM discussed further below.

Monthly Commercial sales are forecasted in total rather than by use per customer because of the diversity of commercial customers.

$\textit{Commercial Sales}_m =$

$\textit{Heating Degree Days * Heating efficiency index * Heating coefficient}_m +$

$\textit{Cooling Degree Days * Cooling efficiency index * Cooling coefficient}_m +$

$\textit{other use coefficient * other use efficiency index}_m$

The combined impact of lower UPC (resulting from AMI, energy efficiency, etc.) and increasing customer count growth leads to a net forecasted CAGR in residential energy of -0.4%/yr for 2019-2025.

See 9 for estimated year-over-year changes and CAGRs in commercial sales, commercial customer counts, population, and commercial energy efficiency.

Table 9: YoY Growth Commercial

YoY Growth Commercial	2020	2021	2022	2023	2024	2025	2019 - 2025 GAGR
Energy	-0.5%	-0.9%	-0.7%	-0.3%	0.0%	-0.1%	-0.4%
UPC	-1.3%	-1.6%	-1.4%	-1.0%	-0.7%	-0.8%	-1.1%
Customers	0.8%	0.7%	0.7%	0.7%	0.7%	0.7%	0.7%

DSM

The load forecast for ELL includes a separate adjustment for company-sponsored DSM programs. Historical levels of DSM are added back to historical sales to produce an initial forecast as if there had been no DSM. The estimated future levels of DSM are then subtracted based on the accumulated effects of historical programs as well as budgeted estimates for future DSM savings. For example, a program from last year to encourage conversion of incandescent lighting to LED lighting is still expected to lower consumption this year and beyond as the newer, more efficient lighting continues to operate. As such, these programs have useful lives that extend beyond the first measure year of the program. The DSM is done at the class level for Residential and Commercial sales and reduces the load forecast based on the Residential and Commercial load shapes and the expected future volumes of DSM. ELL's DSM programs are expected to reduce Residential sales by 0.2%/year and Commercial sales by 0.3-0.4%/year through 2025.

Small Industrial Forecast

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

Electric Vehicles and Solar

Forecasts for incremental electric vehicles ("EVs") and solar adjust the base residential and commercial forecast. The EV forecast is based on the estimated historical EV sales and are projected based on estimated EV use and population growth. EV adoption rates in Louisiana are expected to be lower than national average. The rooftop solar forecast is based on historical solar adoption. In the current forecasts, future levels of rooftop solar adoption are relatively low due to the low electricity prices in Louisiana and the current lack of state tax credits. The net effect of incremental EVs and solar represent a very minor (less than 1%) adjustment to the residential and commercial sales forecast.

Load Forecasting

The long-term hourly load forecast is the result of the calibration of a monthly peak forecast, the monthly sales forecast, and estimated load shapes for each customer class.

Like the process used for the sales forecast, twenty years of "normal weather" data is used to convert historical load shapes into "normal load shapes". This adjusts the historical consumption profiles by month and hour for year-over-year changes in days of the week, holiday schedules, and temperatures. For example, if the actual sales for ELL's residential customers occurred during very hot weather conditions, the normal load shape would flatten the historic load shape. If the actual weather were mild, the normal load shape would raise the historic load shape. Each customer class reacts differently to weather, so each has its own weather response function.

The peak forecast is developed using historical calendarized sales, historical peaks, and degree days to develop relationships between peaks and energy. Those relationships are applied to the forecasted energy and use normal weather for the future forecast period.

As mentioned previously, the forecasted energy, the forecasted peaks, and the forecasted hourly profiles are calibrated together to ensure that all the forecasted energy is accounted for while maintaining, as closely as possible, the forecasted peaks and shapes. Typical load shapes for incremental solar and electric vehicle consumption are used to allocate reduced or increased consumption to the appropriate month, day and hour of electricity use. The final load forecasts include transmission and distribution losses, which are computed by class and separately for EGSL and ELL. Because line losses are applied to the respective classes, changes in customer class mix are taken into account for losses.

Resource Portfolio Needs

Long-term Capacity Considerations

Consistent with planning guidelines, ELL plans to meet capacity needs based on projected peak load requirements plus a 12 percent planning resource margin using installed capacity (for conventional generation and effective for renewable) to meet this need. The requirements shown below reflect this assumption and are adjusted to account for ELL's current resource portfolio reflected in Table 2 and Table 4 above. The requirements evolve over time as forecasted energy use changes and resources are assumed to deactivate. The Low, Reference, and High load scenarios attempt to bookend the effect changes to customer use patterns could have on ELL's energy and peak requirements, absent the potential incremental industrial block load additions described later in this report.

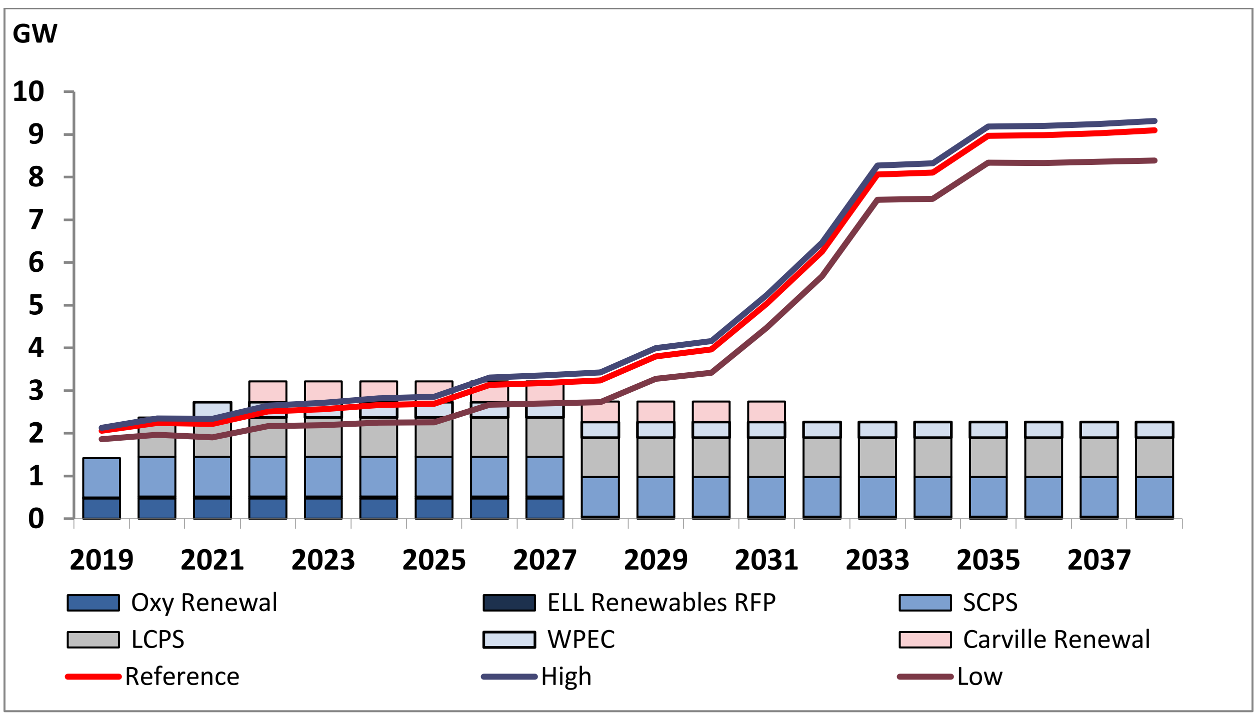

Figure 8: ELL's Projected Long-Term Resource Requirements

Given planned additions, across each load scenario ELL expects that around 6 GW of replacement capacity is necessary to account for deactivating generation, expiring PPAs, and load growth.

ELL's Expected Energy Coverage

The Company regularly assesses ELL's expected energy coverage utilizing production cost modelling to better understand the needs of ELL's customers. Illustrated below is ELL's annual projected energy generation based on its allocated share of resources based on the expected commitment and dispatch of those resources in MISO's energy market totaled. This is compared to the total amount of ELL's forecasted annual energy requirements. Any gap between generation and load on an annual basis indicates net purchases from the MISO market, and as such, is an indication of magnitude of customer energy exposure.

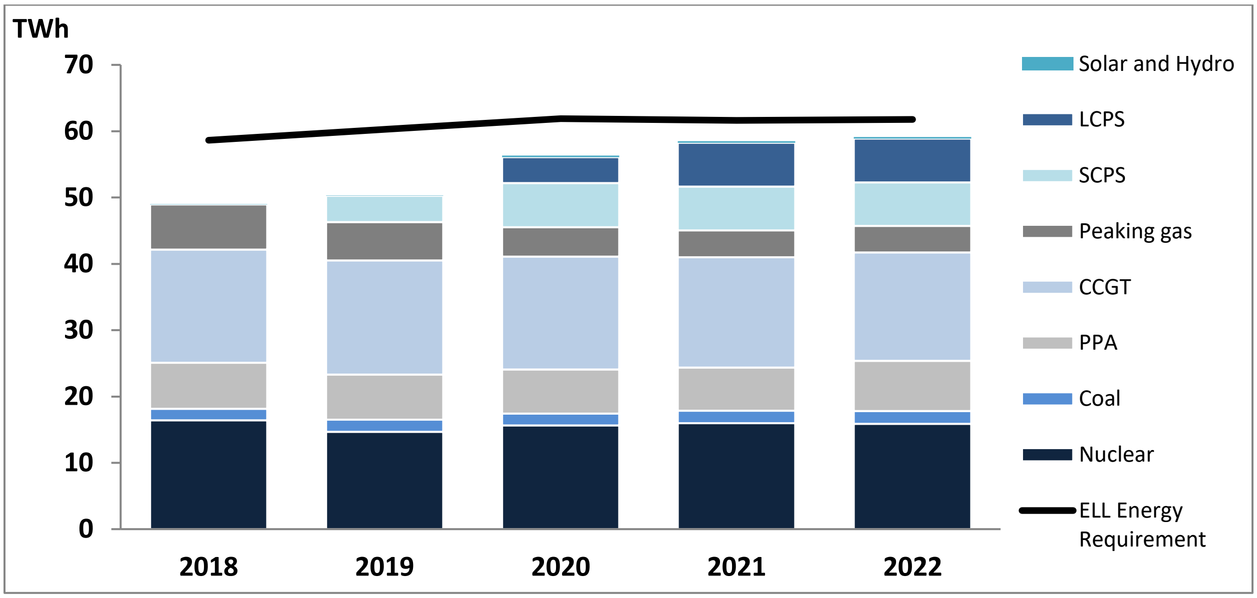

Figure 9: ELL's Expected Energy Coverage

Absent additional energy producing capacity past the SCPS and LCPS CCGT additions, ELL is expected to remain a net purchaser in MISO's energy markets. This energy position leaves ELL's customers subject to MISO's day ahead and real time energy markets for economic energy. Consistent with ELL's guiding principles of **Base Load Production Costs** and **Price Stability,** ELL seeks to meet its capacity needs through a balanced portfolio with resources that contribute to meeting its energy needs.

ELL's Planning Region Needs

Amite South is a constrained planning area in ELL's service area which contains a significant amount of high load factor industrial load. The area regularly relies on local generation as well as imports to serve peak load and transmission requirements. Further, a large fraction of ELL's legacy assets are located in the area as illustrated below.

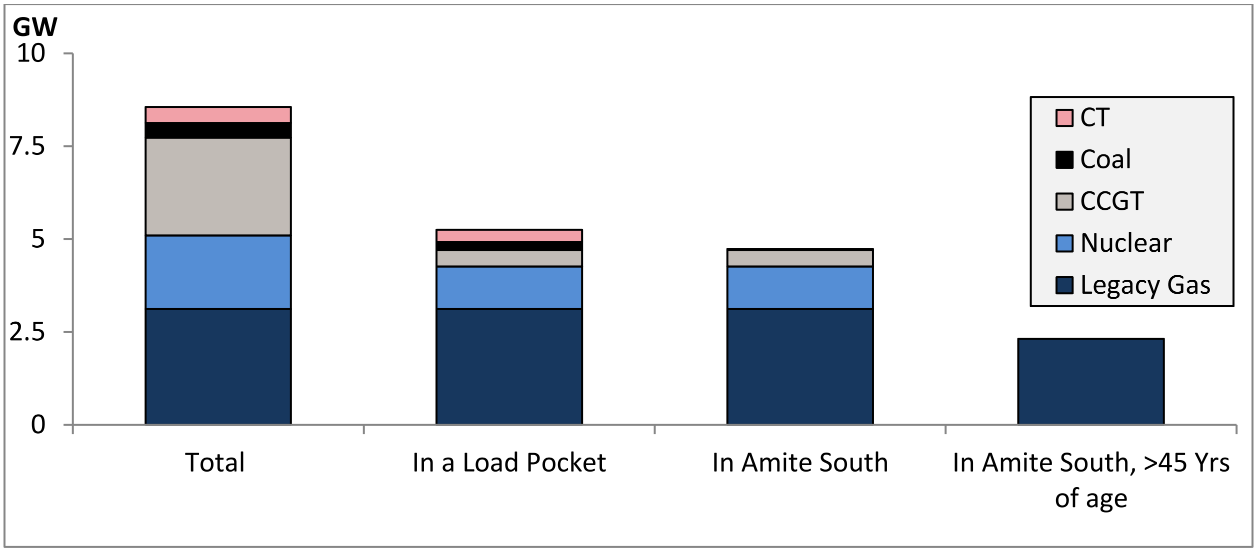

Figure 10: ELL's Generation Fleet- Amite South View

These legacy units which are critical to local reliability, such as Ninemile 4, Nimemile 5, and the Little Gypsy units, are currently greater than 45 years of age and are expected to deactivate over the planning horizon. The incremental resources of St. Charles Power Station and Washington Parish Energy Center are expected to support the local needs of the area; however, additional generation will be required in the region to replace these assets and support local requirements when legacy generation deactivates and/or load grows.

Legacy Gas Useful Life Assumptions

ELL plans its long-term generation portfolio utilizing assumptions which have been developed through expert judgement, industry experience, and research into industry trends. One such assumption is the operating life for assets within the portfolio. Deactivation assumptions must be made to reasonably plan a portfolio of resources, but as more insight is gained over time, technology progresses, and industry conditions change, a reassessment may be required.

As the assumed deactivation dates near, or as equipment failures occur, cross-functional teams are assembled to evaluate whether to keep a particular unit in service for a specified amount of time and level of reliability.

Looking to the longevity of units similar to ELL's legacy gas units, an Electric Power Research Institute ("EPRI") analysis performed in 2012 projected that the average age of natural gas steam turbine retirements as of 2016 would be 52.9 years old. A 2017 study performed by the Lawrence Berkley National Laboratory (and supported by the U.S. Department of Energy) produced similar results finding that the most common age of recently retired natural gas steam turbines was between 40 and 50 years. This is consistent with the 52.4 years average life of the Entergy Operating Companies' natural gas steam turbines either deactivated or retired since 2000. Given these trends, there is risk that ELL's legacy gas units may not be economic or feasible to operate through their assumed 60-year useful life.

Consistent with the Commission's Directive at the February 21, 2018 Open Session, ELL will complete a study of the economic viability of its legacy gas generators. While the LPSC directive requires ELL's report to the Commission and final reports of the Staff be completed no later than six months following the commencement of generation at the new ELL power plant in Lake Charles, ELL intends to complete this study in the fourth quarter of 2019.

Potential for Block Load Additions

Sales and load forecasts for prospective large industrial growth are based on information gathered from prospective or existing (in the case of expansion) customers and are risk-adjusted based on the project status and account manager expertise. Moreover, some potential load growth is not captured within the load forecast due to an assumed low probability of that load materializing. However, large block additions can materialize quickly and ELL needs to be agile to respond to the need to serve that load. Not incorporated within the load forecast (due to lower probability of occurrence and/or updated information) is [redacted]

[redacted]

As discussed previously, these industrial loads, at some level, are expected to require spinning mass generation to provide inertia to support the stability of the transmission system. Transmission needs related to industrial loads will continue to be evaluated and taken into account in the resource planning process going forward.

Combustion Turbine-Based Technology

Similar to legacy gas, ELL must make assumptions regarding the longevity of generating assets to conduct portfolio analytics. For CT and CCGT technology, consistent with the Electric Power Research Institute and unless better information is available, ELL assumes a 30-year useful life. However, considering that deployment of F-frame style combustion turbine-based resources began in the early 2000's, there is limited information available as to the disposition of the units after 30 years of continued operation. There is a potential that these units will continue to be economic to operate well into the 2030s, providing capacity and energy benefits to ELL's customers past their assumed useful lives. Shown in the figure below is the impact to ELL's long-term capacity requirement should those resources extend beyond their assumed useful life and throughout the planning horizon.

[redacted]

As with all assets ELL maintains, as the unit life assumptions near the present, or as equipment failures occur, or as operating performance diminishes, ELL evaluates whether to keep a particular unit in service for a specified amount of time and level of reliability.

Environmental Considerations of the Existing Fleet

ELL's facilities and operations are subject to regulation by various governmental authorities having jurisdiction over air quality, water quality, control of toxic substances and hazardous and solid wastes, and other environmental matters. ELL has a robust compliance assurance program and an environmental management system in place to address the compliance requirements and risks associated with these issues. Some specific compliance issues and programs are presented below – ELL will continue to work with regulators and other stakeholders to implement compliance programs in the most cost-effective way.

Regional Haze – In Louisiana, ELL worked with the Louisiana Department of Environmental Quality ("LDEQ") and the Environmental Protection Agency ("EPA") to revise the Louisiana State Implementation Plan ("SIP") for regional haze, which was disapproved in part in 2012. The LDEQ submitted a revised SIP in February 2017. In May 2017, the EPA proposed to approve a majority of the revisions to the SIP. In September 2017, the EPA issued a proposed SIP approval for the Nelson plant, requiring an emission limitation consistent with the use of low-sulfur coal, with a compliance date of January 22, 2021. The EPA's final approval was issued in December 2017 and is on appeal to the U.S. Court of Appeals for the Fifth Circuit. The Fifth Circuit tentatively has scheduled oral argument for the week of June 10, 2019. Should the EPA's final rule be upheld, ELL will need to buy and use a type (or blend of types) of coal that enables Nelson 6 to meet an emission limit that is consistent with that of low-sulfur coal. In anticipation of this ruling, ELL has adjusted its coal procurement practices so that it can be compliant with the Regional Haze rule by January 22, 2021.

Coal Combustion Residuals ("CCR") Rule – In March 2018, the EPA published its proposed revisions to the CCR rule and finalized those revisions in August 2018. This final rule extends certain deadlines in the program and creates some more flexible groundwater protection standards. The EPA intends to issue another rule in 2019 that will cover issues not addressed in the March 2018 proposal. The ultimate compliance strategy and cost will depend on the final outcome of these rulemakings. Pursuant to the current (as amended) EPA Rule, ELL operates groundwater monitoring systems surrounding its coal combustion residual landfills located at the Nelson plant. Monitoring to date has detected concentrations of certain listed constituents in the area, but has not indicated that these constituents originated at the active landfill cells. Reporting has occurred as required, and detection monitoring will continue as the rule requires.

Effluent Limitations Guidelines ("ELG") Rule – The ELG rule, as amended in 2015, covers wastewater discharges from power plants operating as utilities and is expected to apply to ELL's Nelson 6 coal and Cleco Cajun's Big Cajun. For ELL, the final 2015 rule primarily applies to bottom ash transport water ("BATW") and requires zero discharge. This could be problematic in times of heavy rainfall. The rule was challenged by multiple parties and litigation was consolidated in the 5th Circuit. Compliance dates for the BATW requirements in the 2015 rule were to be set by the permitting agency "as soon as possible beginning Nov. 1 2018, but no later than Dec. 31, 2023." However, in 2017 to allow for reconsideration of the BATW and certain other limits from the 2015 rule, the EPA issued a rulemaking changing the BATW compliance dates to "as soon as possible beginning Nov. 1, 2020 but no later than Dec. 31, 2023," effectively staying application of the 2015 BATW limits for two years. Environmental groups have challenged that stay, but the stay currently remains in effect. The EPA intends to propose revised BATW limits that could impact ELL this summer. Separately, the 5th Circuit vacated the 2015 rule's best available technology ("BAT") limits for legacy wastewater and combustion residual leachate and remanded those portions of the 2015 rule back to EPA for further rulemaking. At this point, it is unclear how the ELG rule will ultimately impact ELL.

Potential and Emerging Regulations – In addition to the specific instances described above, there are a number of legislative and regulatory initiatives concerning air emissions, as well as other media, that are under consideration at the federal, state, and local level. Because of the nature of ELL's business, the imposition of any of these initiatives could affect ELL's operations. ELL continues to monitor these initiatives and activities in order to analyze their potential operational and cost implications. These initiatives include:

- designation by the EPA and state environmental agencies of areas that are not in attainment with national ambient air quality standards;
- introduction of bills in Congress and development of regulations by the EPA proposing further limits on NOx, SO2, mercury, and carbon dioxide and other air emissions. New legislation or regulations applicable to stationary sources could take the form of market-based cap-and-trade programs, direct requirements for the installation of air emission controls onto air emission sources, or other or combined regulatory programs;
- efforts in Congress or at the EPA to establish a federal carbon dioxide emission tax, control structure or unit performance standards;
- efforts to develop more stringent state water quality standards, effluent limitations for Entergy's industry sector, stormwater runoff control regulations, and cooling water intake structure requirements;
- efforts to restrict the previously-approved continued use of oil-filled equipment containing certain levels of PCBs;
- efforts by certain external groups to encourage reporting and disclosure of carbon dioxide emissions and risk; and
- the listing of additional species as threatened or endangered, the protection of critical habitat for these species, and developments in the legal protection of eagles and migratory birds.

Additional Information and details concerning each of these and other rules is included in Entergy's consolidated 2018 10K (pages 267-278). This can be accessed at https://www.entergy.com/userfiles/content/investor_relations/pdfs/2018_Form_10K.pdf

In light of industry trends concerning the economics of such units, ELL continuously monitors the economics of coal-fired generation relative to deactivation and repowering alternatives. At this time, the key drivers indicate continued operation of such units provides benefits to ELL's customers. ELL will continue to monitor such facilities to understand the value they bring to customers, especially as underlying assumptions change regarding fuel prices, the potential creation of a price on carbon emissions and other environmental regulations, related policies affecting the economies of coal-fired generation, customer preferences, and in light of the goal set by Entergy Corporation to reduce the utility's carbon emission intensity rate to 50% below 2000 levels by 2030.. Additionally, ELL intends to complete an analysis that contemplates the cessation of the use of coal at Nelson 6, which analysis it anticipates completing by 2021.

Summary of Types of Resources Needed

In order to continue to support customer's needs at the lowest reasonable cost, ELL plans to a portfolio of generation resources that includes sufficient capacity to meet ELL's peak load and reserve margin target of 12 percent and to satisfy MISO's Resource Adequacy Requirements while providing the efficient operating flexibility required to serve evolving customer demands.

As discussed below, to address ELL's additional energy needs there are a number of supply-side and demand-side alternatives available for meeting long-term resource needs. These include incremental long-term resource additions from self-supply alternatives, acquisitions, and long-term PPAs. Demand-side alternatives including Energy Efficiency, Demand Response, and developing products and services can also provide solutions to meet long-term needs.

The portfolio design analytics outlined in more detail later within the document explore the value of renewables, dispatchable supply-side alternatives, and demand-side measures. The long-term planning horizon will likely include additions of renewable technologies such as solar. As the solar industry matures and the capital costs associated with these resources continue to decline, solar is anticipated to become increasingly feasible as a utility-scale supply solution. As intermittent resource additions increase and ELL's legacy fleet deactivates, ELL will not only continue to see value in conventional generation (e.g., CCGTs) due to needed inertia for transmission reliability, but could also see increased value in additional flexible peaking and quick-start capability more indicative of internal combustion turbine, Frame CT, and Aeroderivative CT technologies.

ELL will continue to assess the likely increasing capacity, energy, and operational flexibility required over the long-term planning horizon. This ongoing assessment of the generation supply plan against dynamic factors like capacity requirements, operating roles, and evolving technologies allows ELL to continually improve efficiencies and reliability to develop the best possible solutions to address its customers' needs with the least cost solutions.

Assumptions

Supply Alternatives to Meet ELL Resource Needs

Technology Assessment

The IRP process considers a range of alternatives available to meet the planning objectives, including the existing fleet of generating units, as well as new demand-side management and supply-side resource alternatives. As part of this process, a Technology Assessment was prepared to identify a wide range of potential supply-side resource alternatives that merit more detailed analysis due to their potential to meet ELL's planning objectives of balancing reliability, cost, and risk. Alternatives evaluated are technologically mature and could reasonably be expected to be operational in or around the ELL service area. Unless indicated directly, information provided below is specific to utility-scale generation. A visualization and list of the technologies selected for further, more detailed evaluation in the IRP included:

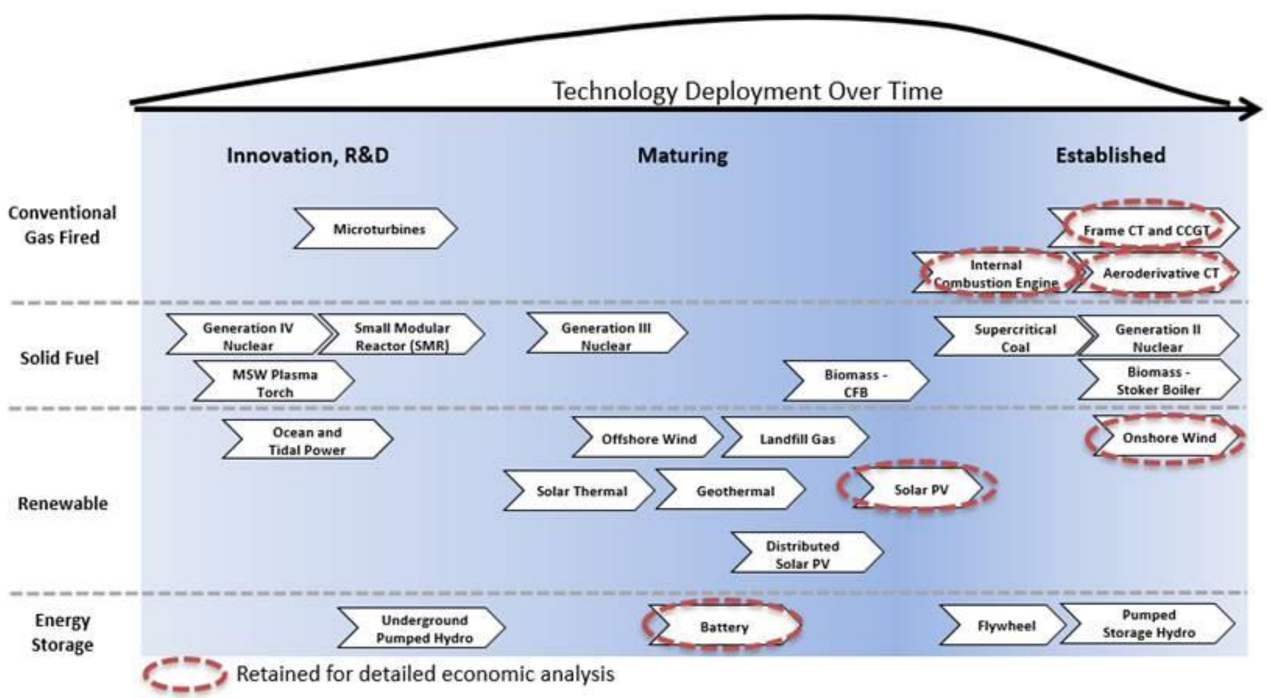

Figure 13: Technology screening curve illustration

I. Natural Gas Fired Technologies

   a. Combustion Turbine (CT)

   b. Combined Cycle Gas Turbine (CCGT)

   c. Aeroderivative CT

   d. Internal combustion engine ("ICE") or reciprocating internal combustion engine ("RICE")

II. Renewable Technologies

   a. Solar PV (Tracking)

   b. Wind (Onshore)

III. Energy Storage

   a. Battery storage technologies

Each of these technologies has advantages and disadvantages to consider when designing a resource portfolio to meet customers' capacity needs. The information below summarizes some of those various considerations and provides major inputs, which were utilized in the portfolio analyses discussed later in the document.

Table 10: Gas-Fired Technology Considerations

	CT	CCGT	Aeroderivative CT	RICE
Description	Frame CTs are a mature technology. Low gas prices and continual heat rate and capacity improvements have made CTs the industry's technology of choice for peaking applications. CTs can also help integrate renewables by providing quickstart (~10 minutes) backup power.	Modern combined cycle facilities provide efficiencies, moderate flexibility, and improved CO_2 emissions relative to coal plants, making them suitable for a variety of supply roles (baseload, load-following, limited peaking). CCGT efficiency and flexibility is expected to continue to improve.	Aeroderivative CTs trade increased cost for greater flexibility (start time, ramp times), lower heat rates, and higher reliability relative to frame CTs.	RICEs are useful for applications requiring heavy cycling and ramping, as they incur lower O&M penalties when operated in this manner relative to other conventional peaker technologies. As renewable penetration increases, this technology will likely see increased deployment in North American power markets due to its flexibility and efficiency.
Advantages	• Low capital and staffing costs • Existing operating expertise • Flexible, quick start capability	• Lowest heat rates • Moderate capital cost • Synergies with existing and planned fleet (e.g., parts, staff)	• Higher flexibility • Moderate heat rates • High reliability	• Low heat rates • Highest flexibility • No gas compression needed • Modular additions

Disadvantages	• Higher heat rates • Difficult to neatly match need (blocky additions) • High gas pressure requirements	• Increases reliance on natural gas • Blocky additions • High gas pressure requirements	• Moderate capital cost • High gas pressure requirements • Less experience with technology	• Moderate capital cost • High variable operating cost • Less experience with technology

In addition to the qualitative factors considered above, the table below summarizes the cost information from the Technology Assessment for gas-fired generation.

Table 11 : Gas-Fired Resource Assumptions

Technology		Summer Capacity [MW]	Capital Cost [2017$/kW]	Fixed O&M [2017$/kW-yr]	Variable O&M [2017$/MWh]	Heat Rate [Btu/kWh]	Expected Capacity Factor [%]
CT / CCGT	1x1 501JAC	510	$1,238	$17.02	$3.14	6,400	85%
	2x1 501JAC	1020	$1,090	$11.12	$3.15	6,400	85%
	501JAC	300	$833	$2.84	$13.35	9,400	10%
Aeroderivative CT	LMS100PA	102	$1,543	$5.86	$2.90	9,397	20%
RICE	7x Wartsila 18V50SG	128	$1,642	$31.94	$7.30	8,401	30%

Renewables (Solar PV and Wind)

In the last decade, the renewable energy industry has experienced substantial growth, driven in large part by cost declines, technological improvements, and environmental concerns. As shown in Figure 14, renewables' capital cost declines are particularly evident in utility-scale solar installations within the U.S. over the past five years. Among all technologically-feasible renewable energy options, solar and onshore wind resources are the most cost effective, commercially-available alternatives to meet ELL's capacity and energy needs.

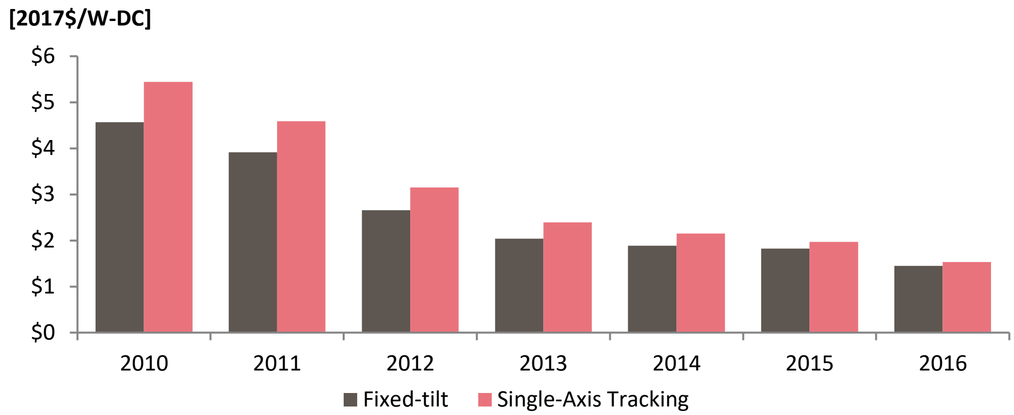

Figure 14: Historical Utility-Scale Solar Capital Costs[14]

The costs of renewable generation have declined significantly in the previous five years, and this trend is expected to continue. As visualized below, installed costs of utility-scale renewables (wind and solar) in real dollars are expected to decline throughout the planning horizon.

[redacted]

The table below expands upon the opportunities presented by solar and wind generation. In general, advantages of renewables include zero emissions and fuel costs, which decrease reliance on fuel commodities. Disadvantages are related to

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[14] Data adapted from NREL U.S. Solar Photovoltaic System Cost Benchmark, Q1 2017.

[15] [redacted]

relative land use compared with traditional alternatives as well as relative capacity contribution due to the intermittent nature of these energy sources.

Table 12: Renewable Technology Considerations

	Solar	Wind
Description	Solar capital costs have fallen dramatically in the last decade and continue to decline as the industry matures. Solar production roughly aligns with customer load patterns, but grid flexibility and quickstart backup generation are necessary to ensure reliability in the absence of large-scale, economic energy storage alternatives. The industry will continue to mature and solar energy is expected to continue to compete with gas-fired generation within the planning horizon, constrained mainly by site-specific performance and market conditions (e.g., construction cost, energy value).	The wind industry is mature relative to the solar industry. Current research focuses more on improving performance, rather than cost, through larger, taller turbines and improved control technologies (e.g., turbine alignment sensors, integrated battery storage). Wind is not likely to see extensive local deployment within the MISO South region but could play a role in the region's energy mix if storage economics improve or significant high voltage direct current ("HVDC") projects are completed.
Advantages	• Zero Emissions • No fuel cost • Capital costs continue to decline • Federal investment tax credits ("ITCs") • Predictable energy curve • Construction timeline	• Zero Emissions • No fuel cost • Federal production tax credits • Efficiency continues to increase • Construction timeline
Disadvantages	• Relative capacity value to traditional generation • Land-intensive • Integration requirements (responsive, quickstart generation is necessary to integrate large amounts of intermittent solar PV) • Site-specific performance	• Relative capacity value to traditional generation • Land-intensive • Integration requirements (responsive, quickstart generation is necessary to integrate large amounts of intermittent wind) • MISO South not ideal for wind without incurring transmission or congestion costs

Additional unique qualities associated with renewable generation are summarized below.

Table 13: Additional Benefits of Renewables

Additional Benefits of Renewables	
Diversity	Renewables add fuel diversity and provide a hedge within gas-centric resource portfolios as ELL's ability to rely on coal for fuel diversity becomes uncertain
Infrastructure	Reduced infrastructure requirements (e.g., gas pipelines, water supply) increase siting flexibility
Scalability	Deployment can be scaled up or down to meet capacity needs more easily relative to conventional alternatives
Carbon and other emissions	Renewables offer customers protection against uncertainty related to potential CO_2 costs and the increasing stringency of other emissions regulations
Customer Engagement	Gaining experience with renewables and the integration of AMI can help ELL take advantage of opportunities such as community solar and the deployment of distributed energy resources ("DERs")

The table below provides a summary of operational costs and performance assumptions for solar and wind technology used within the 2019 IRP.

Table 14: Renewable Modeling Assumptions

	Solar	Wind
Fixed O&M (2017$/kW-yr)	$15.78	$23.46
Useful Life (yr)	30	25
Capacity Factor	26%	34%
Effective Capacity Value	50%	15.6%
Tracking Type	Single Axis	N/A

Energy Storage Systems

Energy storage, particularly in the case of battery-enabled storage, provides a range of attributes that differ from traditional supply-side options discussed previously, such as:

- The ability to store energy for later commitment and dispatch,
- Ability to discharge in milliseconds and fast ramping capability,

- Rapid construction (on the order of months),
- Modular deployment,
- Portability and capability to be redeployed in different areas,
- Small footprint (typically less than an acre), allowing for flexible siting, and
- Low round-trip losses compared to other storage technologies (such as compressed air).

Battery storage system benefits lie in the attributes highlighted above and the ability to offer stacked values through multiple revenue streams to benefit customers. Battery storage effectively enables an intra-day temporal shift between energy production and energy use. Energy can be absorbed and stored during off-peak/low cost hours and discharged during on-peak/high cost hours. The spread (i.e., cost difference) between the time periods creates cost savings for customers and may produce a reduction in emissions. In addition to energy market attributes, battery storage systems qualify in some markets for various ancillary service applications such as regulation, reserves, and voltage regulation, and qualify for MISO's capacity market, given sufficient discharge duration. Lastly, energy storage may, depending on location and characteristics, offer the capability of transmission and distribution cost deferral. As the MISO market evolves in reaction to the potential increased deployment of energy storage technologies and to FERC Order 841, the market driven value streams may become more transparent and quantifiable. ELL will continue to be engaged and monitor these changes within MISO.

Given the current higher installed cost, energy storage faces challenges for high-deployment potential. The typical on-peak/off-peak spread remains low in MISO South, which may limit arbitrage potential. Additionally, MISO's ancillary services market is limited today and fully met with existing resources but continues to evolve. ELL will continue to monitor MISO's energy and ancillary market conditions to identify energy storage potential. At the time of this report, the fixed costs of energy storage today remain above a new build CT, as visualized below.

[redacted]

16 [redacted]

For storage, the key to achieving positive net benefits today is identifying the right transmission use-case. For example, battery storage can provide transmission benefits by avoiding investments required due to line overloads. In addition to these peak-shaving applications, energy storage sited in location-specific areas provide voltage support, which mitigates the effects of electrical anomalies and disturbances. However, if sited and/or operated sub-optimally, storage can increase transmission congestion and could drive otherwise unnecessary transmission improvements. Also, charge and discharge cycles must be optimized so as not to conflict with transmission reliability and/or economics. Similar concepts could be applied to a distribution system.

Similar to what has been seen in recent years within the solar industry, it is expected that battery storage costs will decline within the planning horizon. Therefore, while limited deployment may make sense today for ELL customers, this technology will continue to evolve, and additional applications could present themselves in the future.

Demand-Side Alternatives

For the 2019 IRP, ELL engaged the services of ICF International to assess the market-achievable potential for DSM programs that could be deployed over the planning horizon. These programs are then made available to the AURORA capacity expansion model, to select the least cost portfolio given a set of assumptions contained within a future time period. Information regarding the DSM programs explored, both Energy Efficiency and Demand Response programs, is summarized below.

Energy Efficiency

The International Energy Agency defines Energy Efficiency **as achieving the same services with less energy**. This ensures an opportunity for ELL to serve its customers by providing energy savings. The method utilized by ICF for determining EE is summarized below.

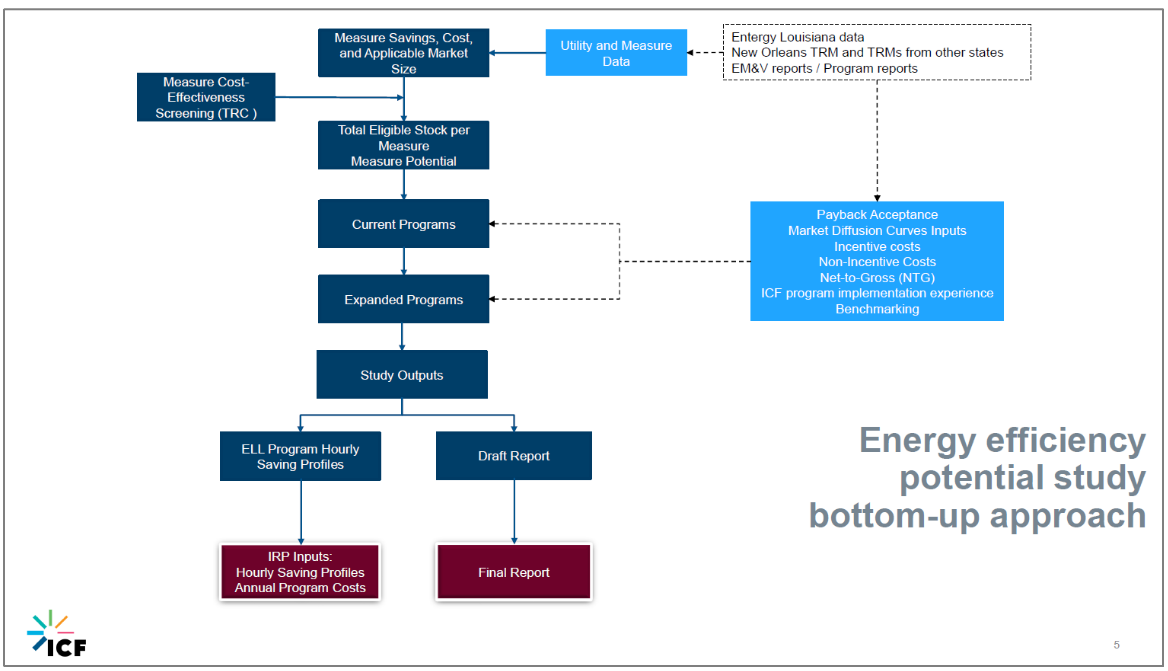

Figure 17: Energy Efficiency study approach

ICF's energy efficiency modeling included 2 potential scenarios:

- **Current Programs** based on ELL's Quick Start PY2 designs, but with expanded budgets, and
- **Expanded Programs** which included current programs and new best practice programs.

The total potential of each EE scenario is outlined in Figure 18.

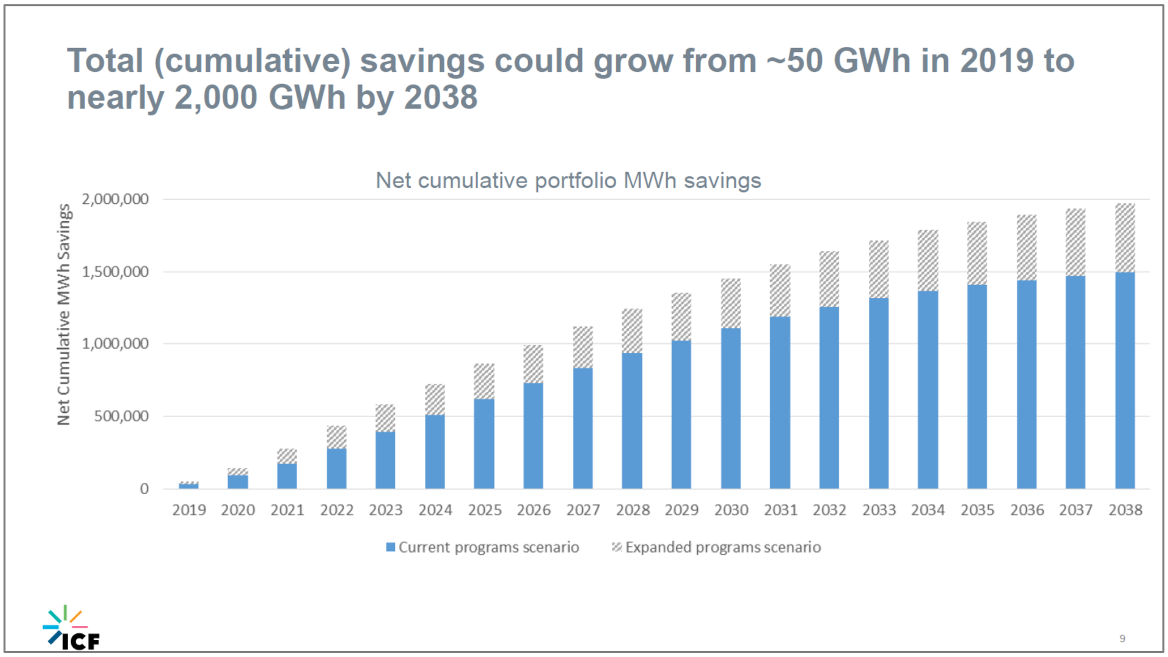

Figure 18: Current and Expanded EE Program Potential

Demand Response

Demand response provides an opportunity for consumers to play a significant role in the operation of the electric grid by reducing or shifting their electricity usage during peak periods. DR offerings which ICF found to be cost-effective using the Total Resource Cost test are shown below.

Table 15: Cost-Effective DR

Class	Measure
Residential	Room AC Switch
	Central AC Switch
	Smart Thermostat
	Water Heater Switch
Commercial	Central AC Switch
	Water Heater Switch
	Smart Thermostat

These programs were made available to the AURORA model for a reference and high case, differing in terms of pricing signals and adoption rates. The total annual MW savings made available for selection is illustrated below, representing approximately 400 MW in the reference case and 500 MW in the high case. The cost-effective DR solutions included in the model do not include rate offerings recommended by ICF, such as dynamic pricing alternatives. With the deployment of AMI, ELL is well positioned to begin making offerings for dynamic pricing alternatives that will send appropriate price signals to customers for DR purposes and may be more preferable to ELL customers than traditional time of use rate structures.

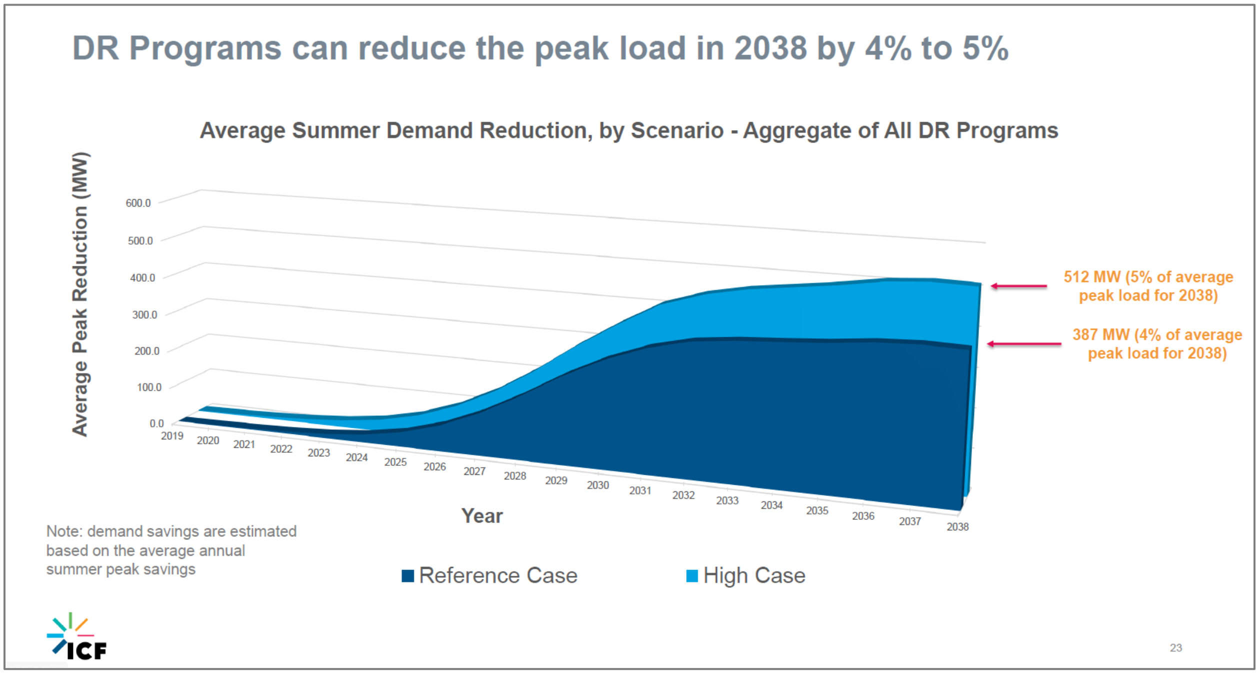

Figure 19: Achievable DR

DSM program costs utilized in the IRP include incentives paid to participants and program delivery costs such as marketing, training, and program administration. Program delivery costs were estimated to reflect average annual costs over the 20-year planning horizon of the DSM Potential Study. The costs reflect an assumption that over the planning horizon, program efficiencies will be achieved resulting in lower expected costs. That is, as experience is gained with current and future programs, actual costs may decrease over time. As such, actual near-term costs associated with current and future programs may be higher than the assumptions used to determine the optimal cost-effective level. Therefore, future DSM program goals and implementation plans should reflect this uncertainty.

Summary of Emerging Supply Trends and Implications

Expanding and changing supply alternatives and technologies have provided increased opportunities and alternatives to address planning objectives. Advancing technologies (including, but not limited to, advances in generating technology) provide new opportunities to meet customer needs reliably and affordably. ELL's planning processes strive to understand these technological changes to enable it to design a portfolio of resources and services that meet customers' needs and wants.

Renewable energy resources, especially solar, have emerged as viable economic alternatives and are expected to continue to improve throughout the planning horizon. However, increased deployment of intermittent generation has increased the value and necessity of flexible, diverse supply alternatives. Smaller, more modular resources, such as peaking generation 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.

Additionally, Integrated Grids have become increasingly viable and important, thanks to the increased options of grid-connected devices for energy storage. The development of a more complex energy system can help manage ELL customer's electrical requirements.

Natural Gas Price Forecast

The near-term portion (the first year) of the natural gas price forecast is based on NYMEX Henry Hub forward prices, which are market future prices as of January 2018. 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 average of several expert independent, third-party consultant forecasts. The long-term natural gas price forecast used in the IRP also includes cases for high and low gas prices to support analysis across a range of future scenarios. In levelized 2019 dollars per MMBtu through the IRP period (2019-2038), the reference case natural gas price forecast is $4.51, the low case is $3.07, and the high case is $6.28.

Each gas price sensitivity is illustrated below and is 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.

ELL purchases the majority of its natural gas supply in the day ahead and intraday natural gas markets. A portion of ELL's natural gas supply requirements for certain plants is procured under a long-term supply agreement. In order to minimize the risk of natural gas pipeline transportation disruptions, ELL contracts for firm pipeline transportation capacity for a significant portion of its transportation requirements.

For purposes of production cost modeling, a delivered price is used. Delivered price to ELL generating units is a long-term delivered price forecast created from the natural gas price forecast described above adjusted for sales tax, adders, and transportation costs associated with existing fuel contracts and potential future contracts.

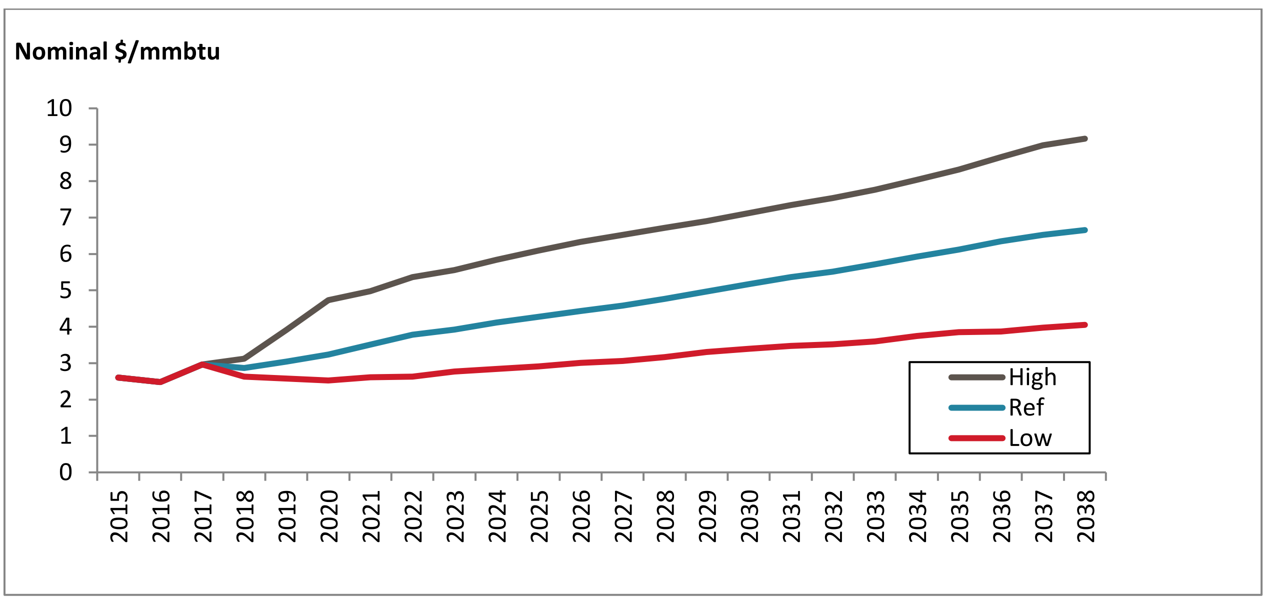

Figure 20: Natural Gas Price Forecast

[redacted]

CO_2 Price Assumptions

ELL's point of view is that national carbon regulation or pricing for the power generation sector will occur; however, the timing, design, and outcome of any carbon-control program remain uncertain.

The scenarios forecasted and utilized in ELL's evaluations are based on the following three cases:

1. ***Low Scenario*** - A $0/ton CO_2 price, representing either no program or a program that requires "inside-the-fence" measures at generating facilities, such as efficiency improvements, that do not result in a tradable CO_2 prices. This scenario is basically consistent with the Affordable Clean Energy ("ACE") rule proposed by the EPA in August 2018.

2. ***Reference Scenario*** - A "CPP Delay" case reflects a 6-year delay in the implementation of the Clean Power Plan ("CPP") or similar national regulation and represents a regional mass-based cap consistent with achieving the final CPP requirements but delayed by approximately 4-6 years due to the federal administration change in 2017 and consistent with the President's executive order in March 2017; and

3. ***High Scenario*** - A "National Cap and Trade" High Case assumes a national cap and trade program that begins in 2028 and targets an approximately 80 percent reduction from 2005 sector Emissions by 2050. This case is generally consistent with the 2030 and 2050 emission reduction targets developed by the Intergovernmental Panel on Climate Change and anticipated by the Paris Agreement.

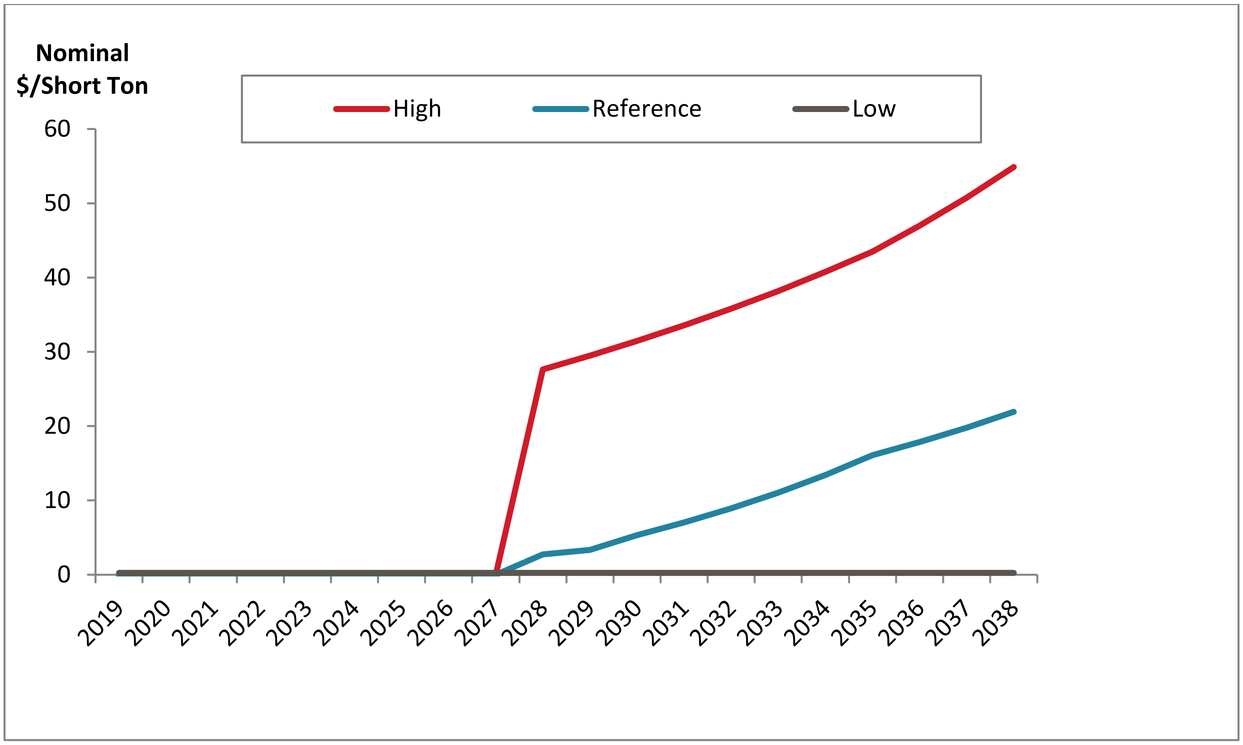

Figure 21: CO_2 Price Forecast

Section IV

Portfolio Design Analytics

Futures

The IRP analysis was performed using a scenario approach, relying on futures to assess supply portfolios across a range of economic outcomes. The various portfolios developed, some of which were based on the market value assumed under each future, were tested across each future to generate a total supply cost unique to each portfolio/future combination. Details regarding the evaluated portfolios and total supply cost results are described further below.

For the 2019 IRP, ELL utilized a set of four futures which vary based on economic, policy, and customer behavior assumptions that impact market prices, including:

- Peak load and energy growth
- Natural gas prices
- Coal and legacy gas generation deactivations
- Renewable penetration
- CO_2 prices

The four futures utilized by ELL for the 2019 IRP are given below along with major assumptions unique to each future.

Table 16: Overview of Futures

	Future 1	Future 2	Future 3	Future 4
	Progression Towards Resource Mix	Policy Reversion (Gas Centric)	Decentralized Focus (DSM & Renewables)	Economic Growth w/ Emphasis on Renewables
Peak Load & Energy Growth	*Reference*	*High*	*Low*	*High*
20-Year Levelized Natural Gas Prices (2019$)	*Reference ($4.81)*	*Low ($3.27)*	*Low ($3.27)*	*High ($6.70)*
Market Coal & Legacy Gas Deactivations	*Reference (60 years)*	*55 years*	*50 years*	*55 years*
Magnitude of Market Coal & Legacy Gas Deactivations	*12% by 2028* *54% by 2038*	*31% by 2028* *88% by 2038*	*54% by 2028* *91% by 2038*	*31% by 2028* *88% by 2038*
Incremental Market Renewables / Gas Mix (Nameplate MW)				
CO_2 Price Forecast	*Reference*	*None*	*High*	*Reference*

Each future represents a unique set of key market drivers. A summary of each future is provided below.

Future 1: Progression Towards Resource Mix

The market experiences flat to declining electric UPC in residential and commercial sectors due to increases in energy efficiency. This is partially offset by industrial growth and growth in residential and commercial customer counts. Coal economics continue to face pressure from low natural gas prices. Renewables and gas play balanced roles in replacing retiring capacity to promote fuel diversity in long-term resource planning.

Future 2: Policy Reversion

Residential and commercial customer growth rates increase due to economic development and decreased energy efficiency gains due to a shift in public policy (e.g., discontinuation of Energy Star program). This increase, combined with increased industrial sales growth due to realization of lower-probability projects, results in high peak and energy load growth. Sustained low gas prices accelerate legacy gas and coal retirements due to economic pressure. Sustained low gas pricing, a low (zero) CO_2 price, and a shift in public policy lead to gas-fired generation comprising the majority of capacity additions, complemented by some renewables.

Future 3: Decentralized Focus

Residential, commercial, and industrial growth rates decrease due to strong customer preferences for energy efficiency and distributed energy resource, resulting in a low (compared to Future 1) energy and peak load growth. Aggressive CO_2 cost and gas prices drive coal and legacy gas plants to retire much earlier than anticipated. The capacity and energy are replaced by an aggressive penetration of renewables complemented by gas-fired generation.

Future 4: Economic Growth with Emphasis on Renewables

Residential and commercial customer growth rates increase due to economic development and decreased energy efficiency gains due to a shift in public policy (e.g., discontinuation of Energy Star program). Load growth is further driven by industrial sales growth due to realization of lower-probability projects. Political and economic pressure on coal and legacy gas plants accelerates retirements. Moderate CO_2 pricing, along with political and economic factors, drive an aggressive portfolio of renewables and gas-fired technology to replace retiring capacity.

Market Modeling

The first step within the market modeling process is to utilize the AURORA[17] production cost model to develop a projection of the future market supply based on the specific characteristics of each future. The energy market simulation results in hourly energy prices for each of the four futures. This projection encompasses the power market for the entire MISO footprint (excluding ELL). The purpose of this step is to provide projected market power prices to assess potential portfolio strategies for ELL within each future. In order to achieve this, assumptions are required about the future supply of power, as outlined in the previous "Futures" section. Represented below are the projected average annual MISO South (excluding ELL) power prices under each future.

[17] The AURORA model is the primary production cost tool used to perform MISO 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.

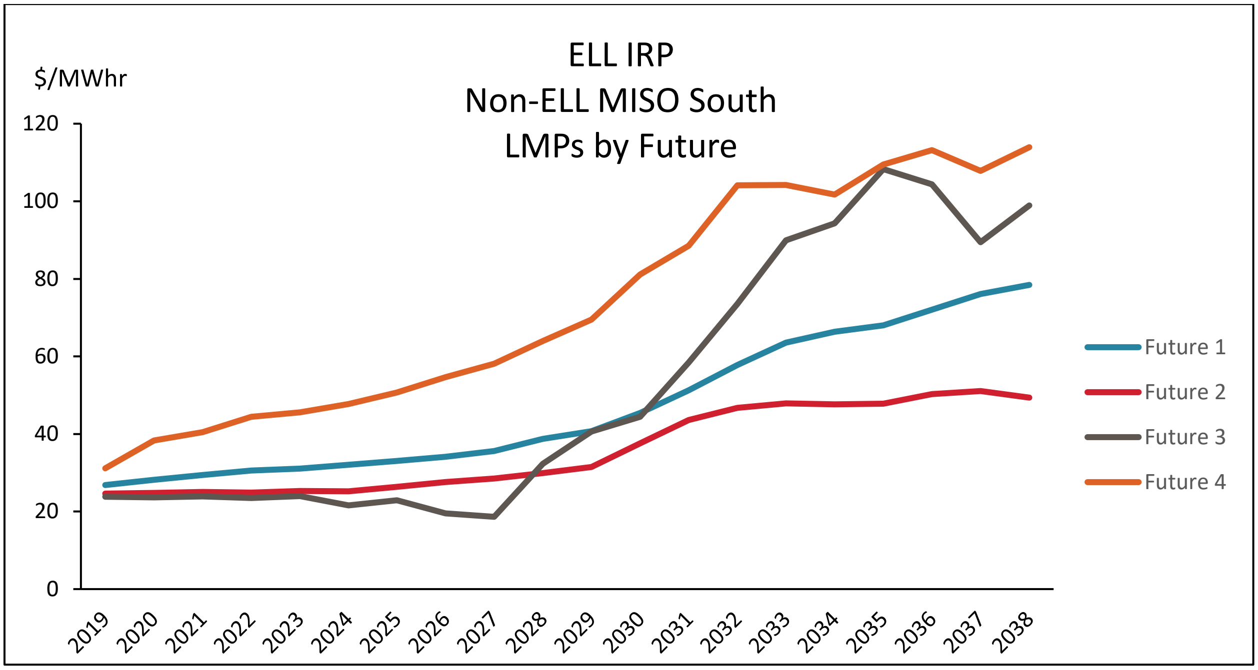

Figure 22: Average Annual MISO South Non-ELL Locational Marginal Price ("LMP")

Portfolio Design

Following the market modeling process, which results in LMPs for the MISO South non-ELL region, the AURORA Capacity Expansion Model was used to identify economic type, amount, and timing of supply-side resources needed to meet reserve margin requirements. The result of this process is a portfolio of supply-side alternatives that produces the lowest total supply cost to meet the identified need within the constraints defined in each of the four futures (the "optimized portfolio").

Solar Capacity Credit Modeling

For the 2019 IRP, ELL sought to take into account integration considerations of intermittent generation. In order to reasonably bound the amount of solar generation the capacity expansion model would include, it was assumed for modeling purposes that the capacity contribution of solar diminished as a function of the amount of incremental solar added in the ELL footprint. The concept that solar provides diminishing returns in capacity and energy value is a relatively recent notion that has been further explored in works by CAISO[18]and MISO[19] in great detail and generally is due to solar production shifting a load serving entity's net peak such that every incremental unit of solar provides less value in supporting reliability needs. For the purposes of capacity expansion within the IRP, ELL used the following accreditation of solar for AURORA when making portfolio selections. The solar capacity credit assumptions noted below were applied to nameplate capacity to determine an overall effective capacity for solar resources.

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[18] https://www.nrel.gov/docs/fy16osti/65023.pdf.

[19] https://cdn.misoenergy.org/20180605%20RIIA%20Workshop%20Presentation213125.pdf.

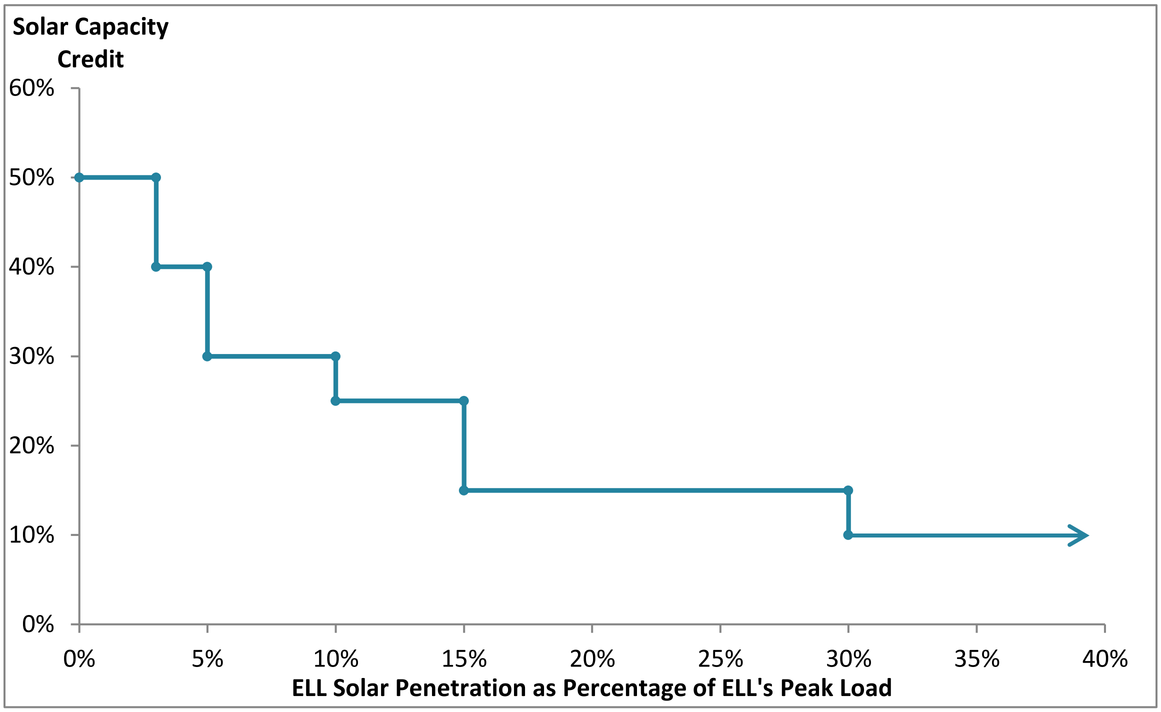


Figure 23: Solar Credit Step-Down as Penetration[20] Increases

This is a heuristic approach which, rather than rely on any specific analysis, utilizes a step-down approach from 50% credit (the current 1st year capacity credit a solar resource is granted in MISO) to attempt to capture the diminishing returns solar has within a portfolio. This assumption is limited to only the AURORA capacity expansion. For the purpose of computing a total supply cost to customers, ELL defaulted to the 50% credit consistent with current MISO practice.

Portfolio Results

The figures below demonstrate the timing of resource additions and existing capacity throughout the ELL IRP evaluation period of 2019-2038. 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.

Future 1 is defined by reference load growth and gas prices and a one-third to two-thirds split of renewables to gas for incremental market additions. Under reference assumptions, Future 1 produces a diverse portfolio of resources which includes baseload energy producing resources, grid balancing gas, renewables, energy storage, and DSM. Based on nameplate capacity, renewable additions make up nearly half of the installed capacity in ELL's portfolio or 4.4 GW, indicating the value intermittent generating resources could provide Louisiana customers. 4.1 GW of low heat rate combined cycle is added to address ELL's expected energy needs, in addition to accounting for future deactivation of energy producing resources. 1.2 GW of CT was selected to provide capacity and energy in high load / market price events. The additions are shown in the following visual.

[20] Here solar penetration is defined as nameplate capacity of installed solar as a percentage of peak demand.

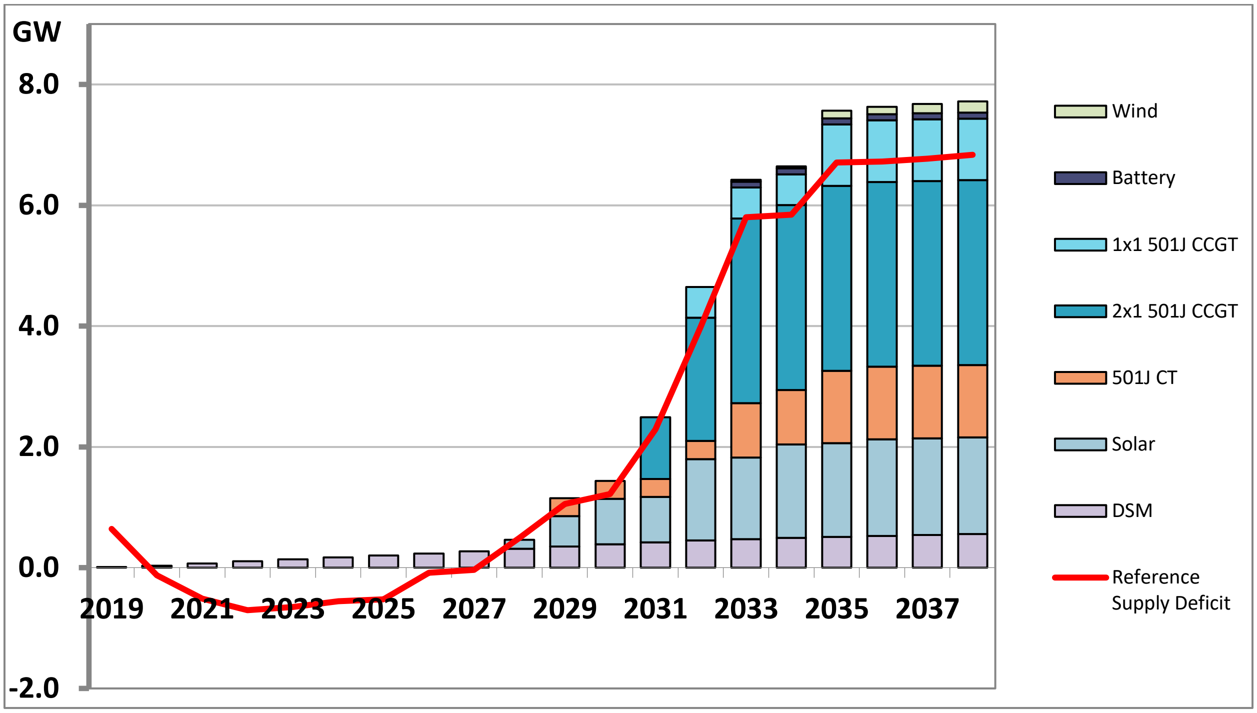


Figure 24: Capacity Expansion Portfolio Future 1[21]

[21] Reference Supply Deficit includes the impact of existing and firm planned resources.

Renewables in Figure 24 are shown as effective MW, rather than nameplate capacity.

Future 2 is defined by high load growth, low gas prices, and a one-fourth to three-fourths split of renewables to gas for incremental market additions. Zero CO_2 price and accelerated legacy gas and coal retirements, along with the replacement of these retirements with efficient generation, lead to sustained low LMPs over the planning horizon. Despite low gas and CO_2 prices, a similar magnitude of dispatchable gas resources is selected. Low LMPs may be providing downward pressure on the value of renewables. Ultimately 1 GW of solar (nameplate) is selected in this future. Energy storage and DSM appears to continue to add value in both in Future 1 and Future 2.

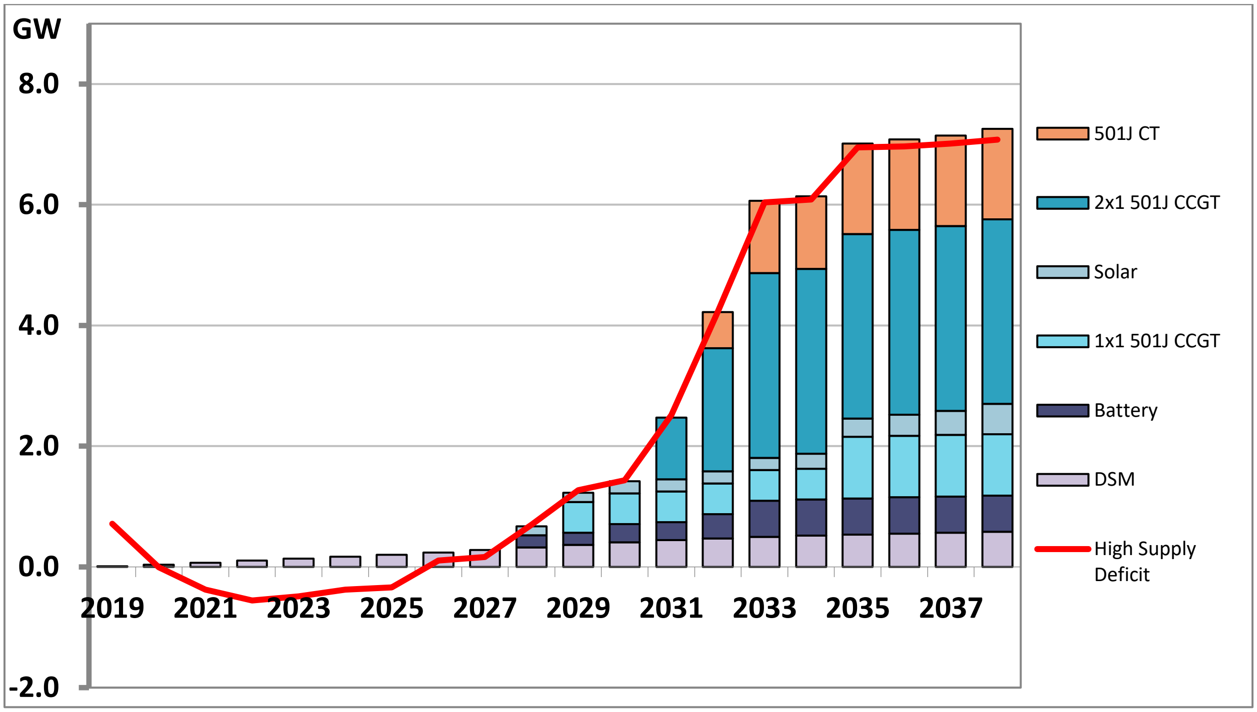


Figure 25: Capacity Expansion Portfolio Future 2[22]

[22] Reference Supply Deficit includes the impact of existing and firm planned resources.
Renewables in Figure 25 are shown as effective MW, rather than nameplate capacity.

Future 3 is defined by low load growth, low gas prices, and more accelerated (relative to Future 2) legacy gas and coal retirements. As shown in Figure 22 above, High CO_2 price and 50/50 renewables to gas incremental market additions lead to volatile LMPs over the planning horizon. Similar to Futures 1 and 2, ~4 GW of CCGT capacity adds value to ELL's portfolio. High CO_2 and low load growth dampen grid-balancing gas additions. High CO_2 may also be driving the significant deployment of renewables (~50% of installed supply-side MW, based on nameplate capacity).

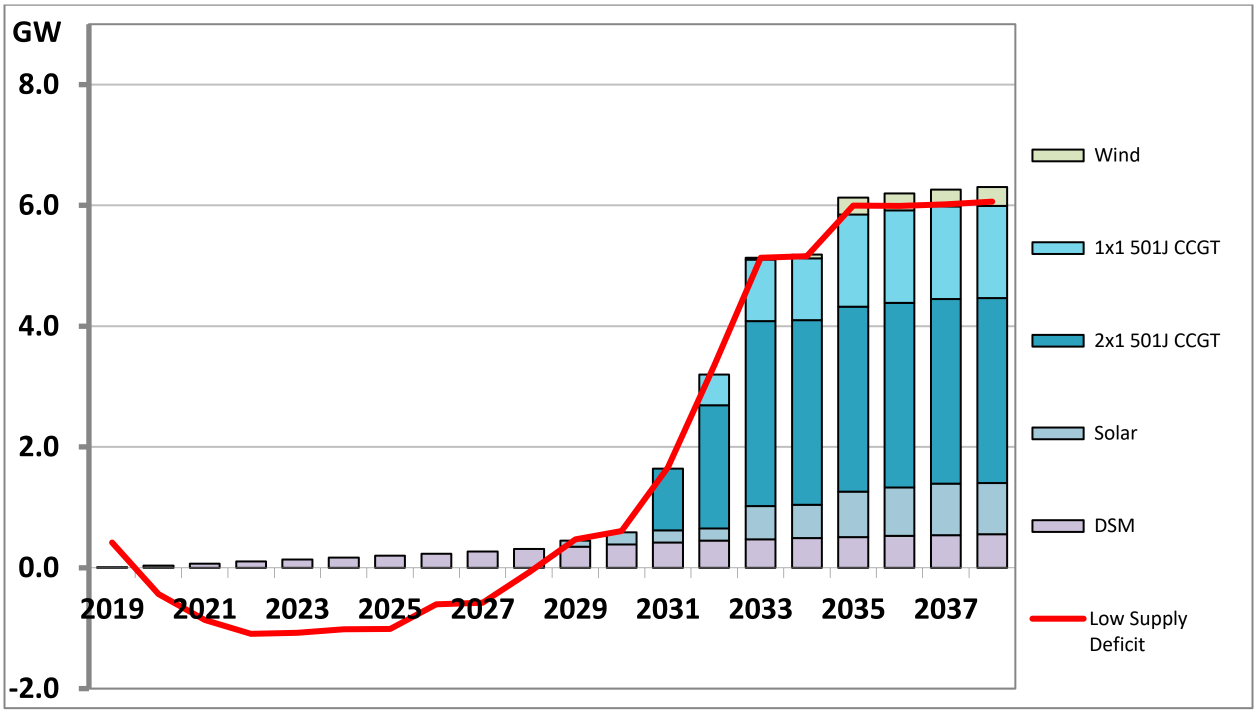


Figure 26: Capacity Expansion Portfolio Future 3[23]

[23] Reference Supply Deficit includes the impact of existing and firm planned resources.

Renewables in Figure 26 are shown as effective MW, rather than nameplate capacity.

Future 4 is defined by high load growth, high gas prices, and accelerated legacy gas and coal retirements. Reference CO_2 prices and 50/50 renewables to gas incremental market additions lead to LMPs that are generally high but volatile. Energy needs driven by high load growth assumptions and high LMPs result in the addition of ~4 GW CCGT and grid balancing dispatchable capacity in the form of peaking gas generation and energy storage. The remainder of ELL's capacity and energy needs are met through renewable deployments of 3.7 GW solar and 3.8 GW wind (nameplate capacity). High load, gas prices, and market prices, likely drive renewable deployment, yielding the most renewables added of the four futures developed.

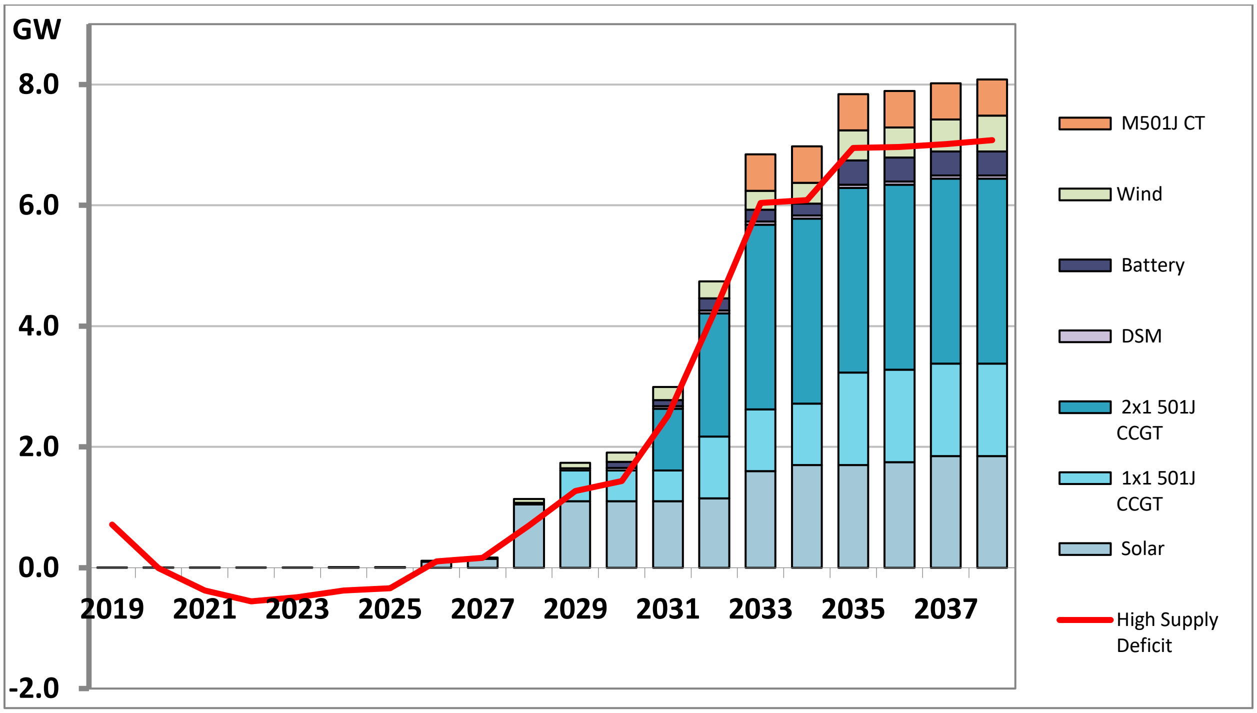


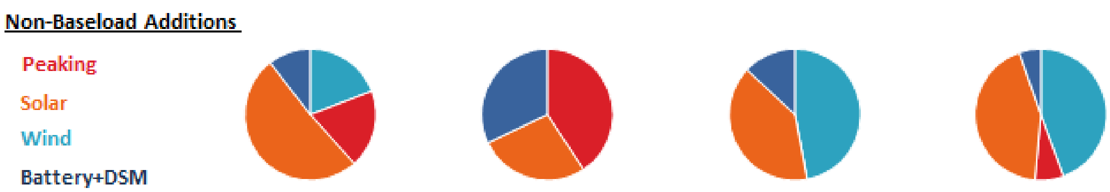
Figure 27: Capacity Expansion Portfolio Future 4[24]

[24] Reference Supply Deficit includes the impact of existing and firm planned resources.
Renewables in Figure 27 are shown as effective MW, rather than nameplate capacity.

A **summary of developed futures** is given below. Each future resulted in a diverse portfolio, indicating the value multiple technologies and fuel types bring to ELL customers. Capacity Expansion results generally indicated **CCGTs**, **renewables**, and **DSM** are economic under the futures tested in the 2019 IRP and are able to provide value under a wide array of potential market and policy outcomes.

Table 17: Overview of Capacity Expansion Outcome (Numerical Values in Table are MW's)[25]

	Builds			
Resource Type	P1	P2	P3	P4
CCGTs	4080	4080	4590	4590
J - CTs	1200	1500	0	600
Solar	3200	1000	1700	3700
Wind	1200	0	2000	3800
Batteries	100	600	0	400
DSM	554	580	554	53
Total	10,143	7,546	8,653	13,148
Effective	6,685	6,926	5,800	7,076



Referring to Figure 24 through Figure 27, **solar appears to be the preferred renewable alternative over wind initially**, as the model selects solar resources prior to wind in all futures. The capacity expansion algorithm selects at least 1 GW of solar before transitioning to **adding solar and wind in concert**. This could be due to the diminishing returns of solar capacity value, after which wind adds value to a portfolio containing solar by providing off-peak energy. This indicates that ELL should continue to monitor solar buildout within the portfolio, continue to assess the cost and performance of wind, and understand the value a combination of renewables alternatives may bring customers in the future. In the near-term, other resource alternatives are more economic than wind to meet ELLs customer needs, but a confluence of factors - a significant shift in the composition of resources, drivers of energy costs, and load profiles within ELL's footprint - as defined by some of the scenarios evaluated, may permit wind to be an economic alternative in the later years of the planning horizon for this IRP. For now and the foreseeable future, economic wind development is expected to be located in higher capacity factor regions (e.g. MISO North, Oklahoma), and delivering this energy to ELL's customers would entail congestion risk and face increased cost to utilize wind.

[25] Table reflects nameplate capacity of renewable generation other than "Effective" row which accounts for renewable effective capacity assumptions.

As indicated in the portfolios above, ELL considers DR to be a valuable resource alternative. Referring to ELL's Reference Resource Plan (Portfolio 1), 90 MW of DR was selected as economically viable when considering all potential sources of new supply under reference conditions. Though the amount and type of DR ELL may procure with any new programs will likely differ from this amount due to the LPSC's DR rulemaking docket, demand response has inherent value as an option to defer conventional generation and contribute to a well-balanced portfolio to serve customers.

Discussion of Results

The Total Relevant Supply Cost ("TRSC") for each portfolio was calculated in each of the four futures described earlier. The total relevant supply cost was 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, CO_2 emission costs, startup costs, energy revenue, and uplift revenue
- ***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
- ***Demand Side Management Costs –*** Implementation costs for incremental DSM programs selected in each portfolio
- ***Capacity Purchases/(Sales)*** - The capacity surplus (or deficit) in each portfolio multiplied by the assumed capacity price

Shown below is the present value of the total relevant supply cost for each portfolio by future. The total relevant supply cost of each portfolio is comparable across each future, thus allowing an ability to evaluate a portfolio's relative performance across futures.

Table 18: PV of Total Relevant Supply Costs by Future

PV of Total Relevant Supply Cost (MM, 2019$, 2019-2038)				
	Future 1	*Future 2*	*Future 3*	*Future 4*
Portfolio 1	$26,294	$21,816	$22,224	$35,803
Portfolio 2	$26,534	$21,460	$22,492	$36,489
Portfolio 3	$26,557	$21,787	$21,876	$35,872
Portfolio 4	$27,099	$22,647	$22,431	$35,767

The columns in the table below provide the rankings of each of the modeled portfolios within each of the futures based on the economic performance of the portfolios shown above.

Table 19: Economic Portfolio Ranking by Future

Portfolio Rankings				
	Future 1	*Future 2*	*Future 3*	*Future 4*
Portfolio 1	1	3	2	2
Portfolio 2	2	1	4	4
Portfolio 3	3	2	1	3
Portfolio 4	4	4	3	1

The relative difference between each portfolio and the least cost portfolio within each future is quantified below.

Table 20: PV of Total Relevant Supply Cost Variance to Least Cost Portfolio

PV of Total Relevant Supply Cost (MM, 2019$, 2019-2038)				
	Future 1	*Future 2*	*Future 3*	*Future 4*
Portfolio 1	$0	$355	$348	$36
Portfolio 2	$240	$0	$616	$722
Portfolio 3	$263	$327	$0	$105
Portfolio 4	$804	$1,186	$555	$0

The performance of each portfolio within Future 1, measured by total relevant supply cost, is visualized below.

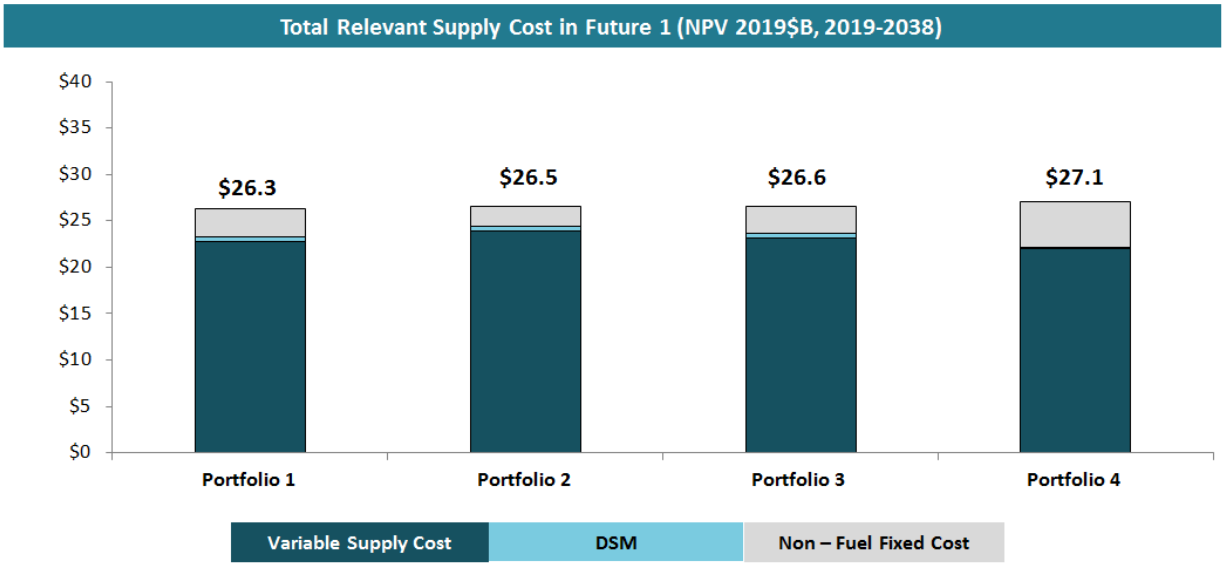


Figure 28: Total Relevant Supply Cost in Future 1

The Capacity Expansion portfolios should perform well from a total relevant supply cost perspective as the AURORA model was configured to produce optimal resource alternatives based on the inputs given. In addition to least cost planning, ELL must also balance the planning objectives of risk mitigation and reliability when determining ELL's Preferred Portfolio. Table 19, above, demonstrates that the portfolios optimized through Capacity Expansion were the lowest cost portfolios in the futures for which they were optimized, which is expected.

Assessment of Risks

The purpose of the risk assessment is to give ELL an indication of the variability of a portfolio's costs as underlying assumptions change (e.g. natural gas prices, CO_2 policy, load, market composition) using the metric of TRSC of each portfolio as it performs in the four futures developed for the 2019 IRP. This assessment, in part, quantifies the risk around price stability for each portfolio and how well each portfolio performs across a range of futures.

Cost as Measured by Expected Value

To perform an assessment of risks between portfolios generated for the 2019 IRP, ELL first computed the ***expected value (“EV”)*** of each portfolio across each of the four tested futures. Assuming that any of the given futures are equally likely to occur, the expected value for each portfolio was calculated as the simple average of total supply cost across futures. The results for each portfolio tested in each future are shown below.

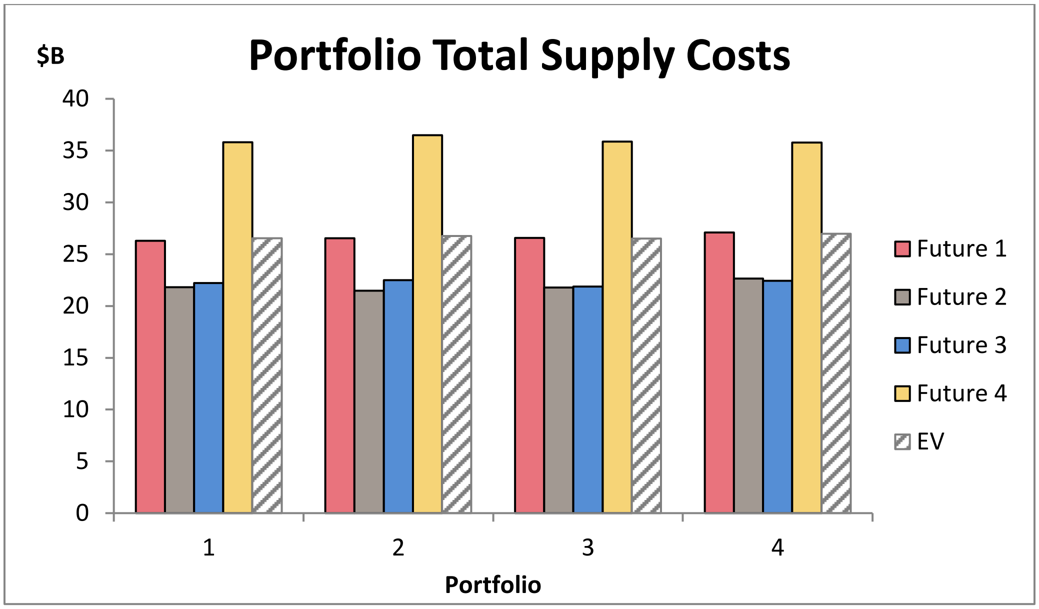


Figure 29: Determination of Portfolio Expected Value

The expected value measures the cost that can be expected of each portfolio across a range of potential outcomes.

Risk as Measured by the Risk Premium

The ***risk premium*** monetized the risks unique to each portfolio and is determined by risk weighting ELL's customers' potential ***Exposure*** (Portfolio Max Cost Future – EV). The Exposure was probability weighted by 25%, stemming from ¼ chance of the high cost future occurring. To illustrate, an example is shown below.

Table 21: Determination of Portfolio Risk Premium

Portfolio 1	Description	Value ($B)
Expected Value ("EV")	**The average TRSC for a portfolio across the four futures**	**26.5**
Exposure	Max cost future (future 4) - EV	9.3
Risk Premium	**Probability weighted (25%) of Exposure**	**2.3**

The incorporation of this metric allowed portfolios of differing risk characteristics to be compared. Ultimately, the risk premium described the impact that portfolio costs are greater than expected. Conversely, ELL also computed the **upside potential** of each portfolio. The upside potential measures the ability for total supply costs to be less than the expected value (i.e. a benefit to ELL's customers) and is calculated in a similar manner to the risk premium utilizing the least cost future for a given portfolio.

Cost/Risk Tradeoff and Conclusions

Using this framework, the costs and risk of each portfolio are visualized below.

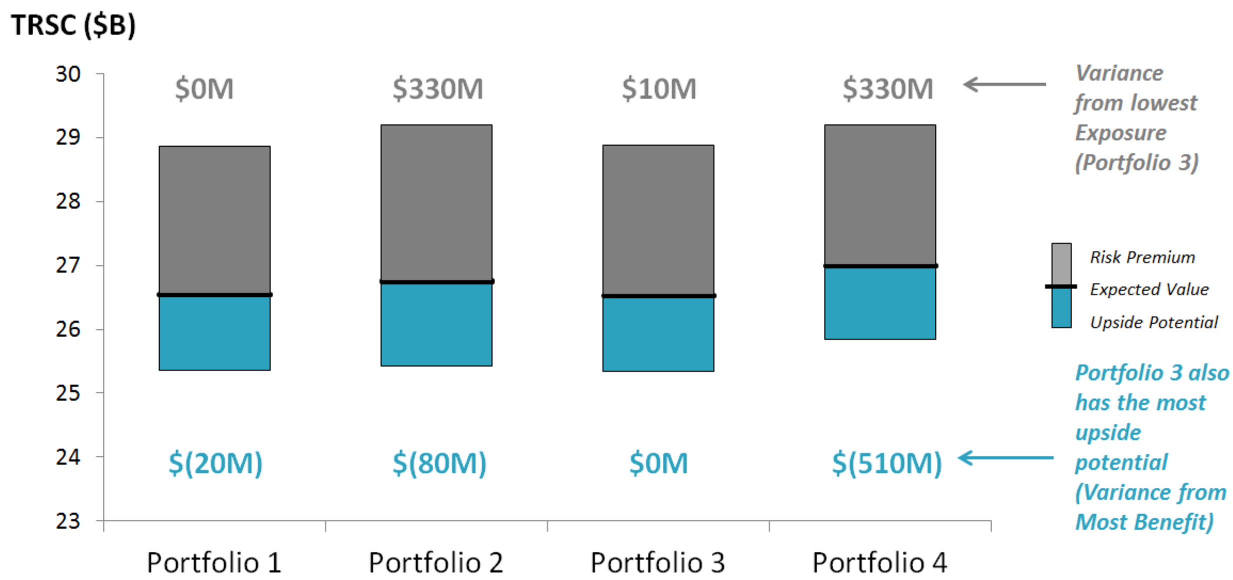


Figure 30: Cost and Risk Profiles of Each Portfolio

From an expected value standpoint, Portfolios 1 and 3 are the lowest on an expected value basis, both yielding ~$26.5B in customer costs. Portfolio 1 is the least expected cost and has the lowest Risk Premium, with Portfolio 3 approximately $10M greater in cost and risk. Considering potential benefits, Portfolio 3 has the potential to provide the most upside to ELL's customers, with a $20M Upside Potential over Portfolio 1. This analysis indicates Portfolios 1 and 3 are generally least cost across the futures tested and have similar expected costs and risk profiles.

Portfolio 1 and Portfolio 3 balance ELL's planning objectives of **Cost** and **Risk** while considering **Reliability.** Examining the composition of these portfolios, these portfolios incorporate a balance of **CCGT**, **Renewables**, and **DSM**. The reference CO_2 assumptions seen in Future 1 bring flexible, dispatchable gas alternatives (in this case CTs) into consideration, while no CO_2 is likely to result in similar conclusions.

Energy Storage was selected in small amounts in Portfolio 1 (100MW). Given policy changes, market conditions, cost declines, and performance improvements, storage may become increasingly cost-effective for ELL's customers. Results suggest continuous monitoring of storage and consideration of potential pilot projects is warranted.

ELL continues to see CCGTs, similar in type to Ninemile 6, St. Charles Power Station, and Lake Charles Power Station, provide value to customers by being selected in all futures. This technology type is unique among generation alternatives in providing economic baseload power and support to the transmission system to enable the high load factor demand that ELL serves in the industrial corridors within WOTAB and Amite South. Though intermittent and not capable of providing the inertial support to the transmission system, inverter-based resources such as wind and solar provide an opportunity for ELL to diversity its portfolio with assets not dependent on fuel prices or CO_2 prices and align with customer preferences for sustainable generation. Finally, the IRP analytics continue to show the value of efficiency and demand response as a resource by both reducing demand and enabling customers an active role in the grid.

Estimated Rate Impacts

To estimate the rate impact of ELL's studied IRP portfolios, the Total Relevant Supply Cost of each portfolio in each future is divided by the total kWh of load in the modeled futures. To estimate the base rate effect, the Non-Fuel Fixed Costs[26], DSM Costs, and Capacity Purchases/Sales, are divided by the total load. This represents the costs of the new resources in those portfolios, but existing resource fixed costs and other base rate components such as distribution and transmission costs are not included as they are assumed to remain constant across the portfolios. Fuel cost effects are estimated by dividing the Variable Supply Cost by the total load. The following charts show these estimated rate effects in 2038, which, as the final year in the study period, includes the complete resource portfolios. This information for other years is included in Appendix C.

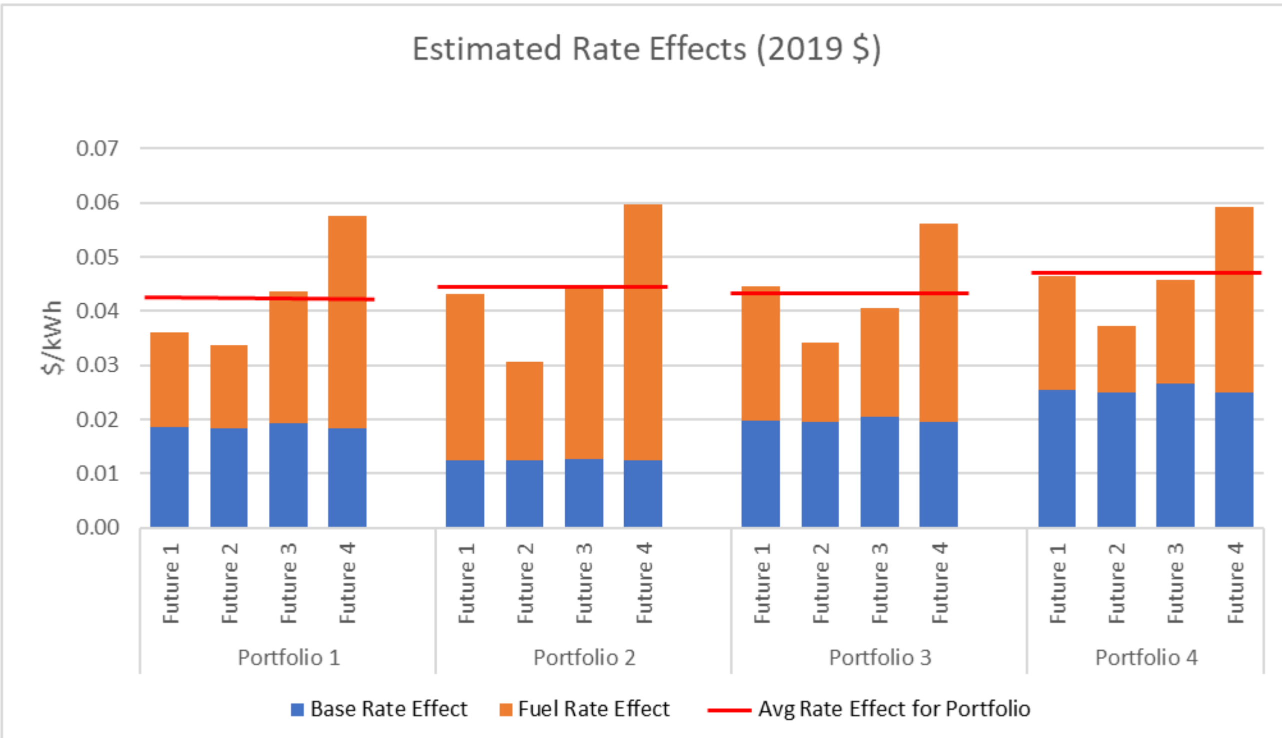


Figure 31: Estimated rate effects of ELL's IRP portfolios in each of its defined futures

Portfolio 2 has the lowest estimated base rate effects but the highest estimated fuel rate effects of the modeled portfolios, so it is the most vulnerable to increases in fuel and CO_2 price assumptions. Portfolio 4, on the other hand, has the highest base rate effect but the lowest fuel rate effect. With higher reliance on renewable resources like wind and solar, it is more insulated from changes in fuel and CO_2 price assumptions. Portfolios 1 and 3, with a more balanced mix of new gas-powered and renewable resources, have a lower base rate effect than Portfolio 4, but also provide some protection against increased fuel and CO_2 prices because of the high volume of renewable resources included in the portfolios.

[26] While the rest of ELL's IRP analysis utilizes Non-Fuel Fixed Costs that have been levelized over the resources' useful lives on a real dollar basis, this rate analysis uses the non-levelized fixed costs (i.e., the resource has a revenue requirement that decreases with time as the asset depreciates).

Reference Resource Plan

Given that Portfolios 1 and 3 balance customer expected cost and risk in similar ways (<1% difference in both categories), these portfolios can be considered essentially equivalent in these parameters. Specific to Portfolio 1, this portfolio was determined by capacity expansion to be the least cost under Future 1 that includes reference assumptions for fuel and CO_2 pricing. This portfolio also has the benefit of performing well under changing market conditions (i.e., performing well across other futures as determined by the Risk Premium and Potential Upside metrics).

In addition to considerations of cost and risk, Portfolio 1 presents a mix of renewable resources which, based on current expectations and experience, appears more executable in the MISO South region within which ELL operates. Generally, both portfolios pursue significant amounts of solar PV as the first supply-side capacity addition to meet load requirements prior to other supply-side alternatives. Given the volume of solar PV in the MISO Queue in the South region (currently over 80% of total MW, compared to Wind's ~3%) and ELL's recent resource selection from the 2016 Renewables RFP, ELL expects solar PV to be the renewable resource which will benefit customers most in the near term. ELL will continue to monitor market conditions and resource cost and performance, and in tandem with RFP evaluations update its point-of-view for supply alternatives as time goes on.

Given these factors, ELL selects Portfolio 1 as the Reference Resource Plan for this IRP. The Table below provides a summary of the selection process.

Table 22: Portfolios and Planning Guidelines

Planning Guideline	Cost	Risk	Reliability	Aligned with Planning Guidelines	2019 IRP Reference Resource Plan
2019 IRP Metric	Expected Value	Risk Premium	12% PRM		
Portfolio 1	✔	✔	✔	✔	✔
Portfolio 2			✔		
Portfolio 3	✔	✔	✔	✔	
Portfolio 4			✔		

Though analytics have provided insight into the value of a changing resource mix, more detailed analyses will be required as ELL executes on any future supply alternatives. Such analyses will need to account for current market conditions, availability of supply alternatives, customer preferences, feasibility and practicality of certain supply options, ELL's energy needs, local reliability criteria, and transmission planning requirements.

Section V

The Path Forward (Action Plan)

ELL considers several factors when designing an IRP strategy that will enable it to continue serving its customers' power needs as reliably and affordably as reasonably possible. Below are the main considerations ELL believes will be important to keep in mind as it pursues a path forward to a strong energy future for customers.

Legacy Generation Economic Study

Consistent with the Louisiana Public Service Commission's directive at the February 21, 2018 Open Session, ELL will undertake and complete a study of the economic viability of its legacy gas generators. While the LPSC directive requires ELL's report to the Commission and final reports of the Staff be completed no later than six months following the commencement of generation at the new ELL power plant in Lake Charles, ELL expects to complete this study in the fourth quarter of 2019. This should afford Staff an appropriate amount of time to complete their report and allow both Staff and ELL to file their respective reports no later than six months following the commencement of generation at Lake Charles Power Station. This study will evaluate whether any of ELL's legacy gas units should be deactivated in light of the modernization of ELL's generating portfolio which includes the Lake Charles and St. Charles Power Stations. This evaluation will also provide additional insight into the transmission and generation support needed within Amite South given the current generation fleet, existing load and potential load growth within the region. This detailed evaluation will more fully inform ELL's resource portfolio needs going forward.

Environmental Impacts and Regulatory Requirements

ELL's facilities and operations are subject to regulation by various governmental authorities having jurisdiction over air quality, water quality, control of toxic substances and hazardous and solid wastes, and other environmental matters. ELL has a robust compliance assurance program and an environmental management system in place to address the compliance requirements and risks associated with these issues and is monitoring certain proposed requirements that may trigger compliance action by ELL over the next 5 years. ELL will continue to work with regulators and other stakeholders to implement compliance programs in the most cost-effective way.

Regional Haze – The EPA issued a final approval in December 2017 of the Louisiana SIP for regional haze, but this approval is currently being appealed at the U.S. Court of Appeals for the Fifth Circuit. Should the EPA's final rule be upheld, ELL will need to buy and use a type (or blend of types) of coal that enables Nelson 6 to meet an emission limit that is consistent with that of low-sulfur coal by January 22, 2021. In anticipation of this ruling, ELL has adjusted its coal procurement practices so that it can be compliant with the Regional Haze rule by January 22, 2021.

Coal Combustion Residuals ("CCR") Rule – In March 2018, the EPA proposed revisions to the CCR rule which were finalized in August 2018. The EPA intends to issue another rule in 2019 that will cover issues not addressed in the March 2018 proposal. The ultimate compliance strategy and cost will depend on the final outcome of these rulemakings. Pursuant to the current (as amended) EPA Rule, ELL operates groundwater monitoring systems surrounding its coal combustion residual landfills located at the Nelson plant. Monitoring to date has detected concentrations of certain listed constituents in the area but has not indicated that these constituents originated at the active landfill cells. Reporting has occurred as required, and detection monitoring will continue as the rule requires.

Effluent Limitations Guidelines ("ELG") Rule - The ELG rule, as amended in 2015, covers wastewater discharges from power plants operating as utilities and is expected to apply to ELL's Nelson 6 coal and Big Cajun 2, Unit 3, which is co-owned by ELL. For ELL, the final 2015 rule primarily applies to bottom ash transport water (BATW) and requires zero discharge. This could be problematic in times of heavy rainfall. The rule was challenged by multiple parties and litigation was consolidated in the 5th Circuit. Compliance dates for the BATW requirements in the 2015 rule were to be set by the permitting agency "as soon as possible beginning Nov. 1, 2018, but no later than Dec. 31, 2023." However, in 2017, to allow for reconsideration of the BATW and certain other limits from the 2015 rule, EPA issued a rulemaking changing the BATW compliance dates to "as soon as possible beginning Nov. 1, 2020 but no later than Dec. 31, 2023," effectively staying application of the 2015 BATW limits for two years. Environmental groups have challenged that stay, but the stay currently remains in effect. The EPA intends to propose revised BATW limits that could impact ELL this summer. Separately, the 5th Circuit vacated the 2015 rule's best available technology limits for legacy wastewater and combustion residual leachate and remanded those portions of the 2015 rule back to the EPA for further rulemaking. At this point, it is unclear how the ELG rule will ultimately impact ELL.

Potential and Emerging Regulations – In addition to the specific instances described above, there are a number of legislative and regulatory initiatives concerning air emissions, as well as other media, that are under consideration at the federal, state, and local level. Because of the nature of ELL's business, the imposition of any of these initiatives could affect ELL's operations. ELL continues to monitor these initiatives and activities in order to analyze their potential operational and cost implications. These initiatives are described in detail in the Environmental Considerations of the Existing Fleet section within Section II.

Nelson 6 Analysis **–** Lastly, while key drivers indicate continued operation of Nelson 6 provides benefits to ELL's customers, ELL will continue to monitor this unit and these drivers, especially as underlying assumptions change regarding fuel prices, the potential creation of a price on carbon emissions and other environmental regulations, related policies affecting the economies of coal-fired generation, and customer preferences. ELL also will consider the continued use of coal at Nelson in light of the goal set by Entergy Corporation to reduce the utility's carbon emission intensity rate to 50% below 2000 levels by 2030. In light of these factors, ELL intends to complete an analysis that contemplates the cessation of the use of coal at Nelson 6, which analysis it anticipates completing by 2021.

Integration of Renewable Resource and Other Diverse Supply Alternatives

Going forward, as customers are increasingly interested in sustainable energy generation, ELL is considering the value that more modular additions bring such as:

- Renewable energy resources (distributed and centralized),
- Emerging technologies such as storage,
- Other grid balancing supply which is expected to be more modular in nature (e.g., RICE).

Previous resource additions by ELL include large, gas fired central station facilities such as the Union, St. Charles, and Lake Charles Power Stations, and the Washington Parish Energy Center.

In LPSC Order No. I-33014, which reviewed the Company's first IRP cycle, the Commission noted the Company's intent to conduct the 2016 Renewables RFP to determine the cost-effectiveness, viability, and performance of certain renewable technologies in Louisiana. As a result of that RFP, ELL has executed a PPA on a 50 MW solar photovoltaic resource – the largest of its kind for the Company and the state of Louisiana. The Commission certified this resource in LPSC Order No. U-34836, which was approved at its February 2019 B&E. Expanding on and building out ELL's capabilities could prove critical as it continues to meet changing consumer demands while finding new, more sustainable ways to meet its region's energy needs. Agility from both the LPSC and ELL may be needed to quickly evaluate and procure emerging technologies that provide value to customers in terms of lower cost, enhanced reliability, and the diversification of ELL's portfolio.

In recognition of the improving cost-effectiveness and numerous benefits that renewables provide, ELL intends to issue an RFP in early 2020, which ELL anticipates would be followed by a recurring series of renewables RFPs seeking renewable resources to support ongoing ELL energy needs and capitalize on the improving economics of solar and potentially other technologies relative to conventional generation resources. While the frequency and other parameters of these RFPs have not yet been determined, the strategy that ELL intends to deploy is one that systematically integrates renewable resources over time while meeting its planning objectives. For example, ELL's reference resource plan includes 300MW of solar in 2028. Rather than procure all 300MW in 2028, it may be beneficial to procure these MW's on a different time frame.

Renewable Energy Pricing Tariff

In conjunction with its first utility-scale solar resource, ELL is seeking Commission authorization of an Experimental Renewable Option Rate Schedule, which provides pricing that is tied directly to renewable generation. Certain of ELL's commercial and industrial customers have expressed a desire for a rate option that would provide them access to renewable resources. In response, ELL has proposed Schedule ERO in LPSC Docket No. U-35019, as a voluntary tariff to meet those customers' goals. The proposed Schedule ERO provides eligible ELL customers, which are defined in the tariff, with an opportunity to voluntarily match a portion of their annual energy use with renewable energy. In addition, enrolled customers will also receive the benefit of having the renewable energy credits associated with the elected amount of capacity from the renewable energy resource retired on their behalf. While Schedule ERO is ELL's first offering of this type, ELL acknowledges that it will continue to work to understand the needs of interested customers and may propose other renewable offerings for ELL's customers in the future.

Battery Storage

As outlined in greater detail in the IRP, battery storage has the potential to provide an array of benefits. Those include the ability to store energy for later delivery and use, short construction timelines, a smaller land footprint than some other alternatives which allows for more flexible siting and potential portability to enable redeployment of storage to different areas as grid reliability needs change.

Though battery storage costs are currently high relative to other alternatives, these costs are expected to decline within the planning horizon. Smaller scale deployments or pilots may provide the opportunity to gain operational experience while mitigating significant cost concerns. ELL will continue to monitor the cost and performance of storage technologies and seek opportunities for deployment within ELL's service territory. In addition to the cost and performance of storage, market constructs enabling storage are developing and require close attention to fully understand the value storage may provide to ELL's customers.

Demand Side Management

In February 2019, the Commission initiated a rulemaking proceeding (LPSC Docket No. R-35136) through which it seeks to develop rules governing the development of DR rates schedules and programs.[27] The Commission's notice of that proceeding does not indicate if the result of this impending DR rulemaking is to replace or supplement the Commission's existing DR Order. Separately in April 2019, Commission Staff issued its Proposed EE Rules. Staff's Proposed EE Rules note the correlation of DR with EE programs and seek for utilities with IRPs, such as ELL, to evaluate EE programs within their next IRP cycle by allowing those programs to compete with supply-side resource options. Accordingly, the DR and EE landscapes at the Commission are in a very active state of potential change. While the DSM Potential Study in this IRP indicates the value that DSM may bring to ELL's customers, there is considerable uncertainty at the Commission regarding the program structures and requirements that will ultimately shape ELL's potential offerings.

For example, Commission Staff's Proposed EE Rules unexpectedly do not provide for utility performance incentives. As the Company has stated in that rulemaking docket, ELL and many other stakeholders have filed comments stating that there is widespread agreement and national support for the inclusion of utility performance incentives as a critical component to an effective EE program. The Commission's ultimate decision on the inclusion of such a key program component would undoubtably affect how the Company would design its Phase II EE programs – including how it could incorporate those programs into its IRP process, another unexpected potential requirement.

ELL will be an active participant in these pending rulemakings as the Commission sets policy that will affect the Company's potential DR and EE offerings. ELL will also conduct and complete the Commission-ordered study investigating the implementation of demand response programs for its customers, including potential incentives, and file a report regarding its results, conclusions, and recommendations within 12 months of the completion of its AMS deployment. Accordingly, ELL intends to conduct more detailed analysis of those DR and EE programs that proved to be economic in its modeled portfolio results in a way that complies with ELL's AMS Order as well as the Commission's ultimate rules to be determined in Docket Nos. R-35136 and R-31106.

In addition to the programs shown to be economic in the IRP analysis, and in response to customer feedback in this IRP cycle, ELL will develop and offer a new interruptible rider to further explore commercial and industrial customer interest in supporting demand response as an option for meeting the Company's capacity needs. ELL expects to file a new interruptible rider no later than the third quarter of 2019. ELL will design and offer a new rider that will be a voluntary option generally available to non-residential customers who meet the criteria specified in the rider. Designing the pricing under such riders must carefully take into account the value of the demand response provided, so as not to unduly burden non-participating customers. Once offered, the new rider will provide ELL with real information about the viability of demand response within its footprint.

With the deployment of its Advanced Metering System, ELL will be well positioned to begin making offerings for dynamic pricing alternatives that will send appropriate price signals to customers for DR purposes and may be more preferable to ELL customers than traditional time of use rate structures.

Growth and Reliability Study

ELL, like all LSEs within MISO, is responsible for planning and maintaining a resource portfolio to meet its customers' power needs. The Commission has acted as a steward of responsible system planning through various requirements, including the

[27] Depending upon the outcome of this proceeding, ELL may propose a new DR tariff or rider to accommodate Aggregators of Retail Customers ("ARCs").

IRP requirement giving rise to this report, as well as other requirements such as periodic reporting on load forecasts and resource certifications. Distribution electric cooperatives, however, were exempted from the IRP order on the basis that they have a full requirement contract. Those full requirements contracts appear to be expiring in what would otherwise be a five-year action plan for cooperatives if they participated in transparent integrated resource planning. It now appears, however, that some cooperatives are attempting to enter into new wholesale supply agreements in connection with block load additions without LPSC engagement in that resource planning procurement effort.

To the extent that distribution electric cooperatives or any other entities within the MISO market overly rely on the short-term MISO capacity market to serve load, such reliance could have unintended consequences on reliability and electricity prices in the state. As such, ELL plans to undertake a study to evaluate load growth and unit deactivations not accounted for in the Commission's current long-term planning processes in order to measure potential impact on ELL customers and system reliability, which may affect ELL's resource needs.

Appendix A Actual Historic Load and Load Forecast

Historic Peak Demand and Energy

Table 1: Actual Historic Energy (GWh) (Includes T&D Losses)

	Residential	Commercial	Industrial	Governmental	Total
2008	14,054	11,303	22,672	707	48,737
2009	14,473	11,480	22,052	705	48,709
2010	15,836	12,018	24,454	724	53,032
2011	15,431	11,971	26,115	731	54,248
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

Table 2: Summer and Winter Historical Peaks (MW)[28]

	Summer	Winter
2008	9,347	7,970
2009	9,503	7,678
2010	9,400	8,544
2011	9,656	8,549
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

Table 3: Historic Monthly Energy (MWh)[29]

	Residential	Commercial	Industrial	Governmental	Total
1/1/2008	1,178,957	890,261	1,967,233	59,637	4,096,089
2/1/2008	1,131,146	867,275	1,875,010	61,299	3,934,730
3/1/2008	905,612	809,846	1,797,068	58,147	3,570,673
4/1/2008	883,998	830,460	1,929,429	57,222	3,701,108
5/1/2008	967,857	887,553	1,928,783	57,183	3,841,375

[28] Actuals are not available for revenue classes.

[29] Including T&D Losses to match forecasts values

6/1/2008	1,414,837	1,063,469	2,023,645	60,816	4,562,768
7/1/2008	1,579,841	1,121,010	1,960,113	62,143	4,723,107
8/1/2008	1,632,760	1,127,893	2,053,111	60,798	4,874,561
9/1/2008	1,372,973	1,037,163	1,976,185	59,011	4,445,331
10/1/2008	1,120,924	961,087	1,419,183	58,570	3,559,764
11/1/2008	883,573	876,939	1,965,539	55,726	3,781,777
12/1/2008	981,895	830,009	1,777,047	56,310	3,645,261
1/1/2009	1,139,477	893,683	1,663,868	57,436	3,754,465
2/1/2009	1,053,420	828,200	1,730,252	59,509	3,671,380
3/1/2009	946,319	838,872	1,547,639	56,516	3,389,346
4/1/2009	850,690	842,751	1,745,748	57,922	3,497,111
5/1/2009	1,023,946	892,404	1,876,409	57,455	3,850,214
6/1/2009	1,306,627	1,007,157	1,897,906	57,422	4,269,113
7/1/2009	1,753,969	1,140,663	1,830,230	59,369	4,784,231
8/1/2009	1,622,111	1,108,780	1,923,894	59,679	4,714,465
9/1/2009	1,506,026	1,123,984	2,025,297	59,364	4,714,671
10/1/2009	1,335,725	1,058,101	1,979,013	61,096	4,433,935
11/1/2009	943,871	899,659	1,952,951	59,646	3,856,127
12/1/2009	990,426	845,808	1,878,460	59,134	3,773,828
1/1/2010	1,484,586	958,904	1,853,380	67,914	4,364,784
2/1/2010	1,250,018	884,697	1,892,252	62,595	4,089,561
3/1/2010	1,168,255	870,118	1,753,612	62,224	3,854,211
4/1/2010	860,052	816,243	2,027,417	56,228	3,759,939
5/1/2010	1,021,582	916,372	2,096,060	56,866	4,090,880
6/1/2010	1,497,680	1,103,182	2,203,507	60,007	4,864,376
7/1/2010	1,738,366	1,178,746	2,109,886	61,940	5,088,939
8/1/2010	1,802,171	1,197,812	2,059,636	62,182	5,121,801
9/1/2010	1,665,666	1,178,444	2,150,916	59,280	5,054,306
10/1/2010	1,338,682	1,089,533	2,135,559	60,215	4,623,990
11/1/2010	960,443	939,443	2,157,946	57,647	4,115,479
12/1/2010	1,048,279	884,015	2,014,037	57,360	4,003,691
1/1/2011	1,381,746	943,292	1,991,009	61,360	4,377,407
2/1/2011	1,300,903	911,354	2,149,323	60,362	4,421,942
3/1/2011	992,400	894,513	1,959,829	59,756	3,906,498
4/1/2011	930,927	899,532	2,131,366	59,250	4,021,075
5/1/2011	1,088,384	928,515	2,160,145	57,421	4,234,465
6/1/2011	1,479,611	1,080,414	2,148,263	60,743	4,769,031
7/1/2011	1,753,077	1,163,121	2,249,398	61,535	5,227,131
8/1/2011	1,699,796	1,163,059	2,379,774	64,760	5,307,388
9/1/2011	1,686,830	1,192,582	2,310,619	66,724	5,256,754
10/1/2011	1,216,781	1,031,298	2,242,136	61,952	4,552,167
11/1/2011	889,899	884,048	2,181,765	57,215	4,012,927

12/1/2011	1,010,759	879,499	2,211,526	59,573	4,161,357
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
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

Prior Load Forecast Evaluation

Table 4: Energy Forecasted vs Actual

Sales (GWh)	**2015**	**2016**	**2017**
Previous IRP Sales Forecast (BP15)*	58,829	61,281	64,654
Weather Normalized Actual Sales	56,801	57,287	58,782
Deviation	2,028	3,993	5,872
% Deviation	3%	7%	9%

Table 5: Peak Forecasted vs Actual

Peaks (MW)	2015	2016	2017
Previous IRP Sales Forecast (BP15)*	9,869	10,081	10,495
Weather Normalized Actual Peaks	9,640	9,908	10,317
Deviation	229	173	178
% Deviation	2%	2%	2%

Causes of Significant Deviations Between Forecasts and Actuals

Industrials

The sales levels forecasted as part of the previous IRP were generally higher than weather normalized actuals, with the majority of the differences coming from the industrial class. At the time of the prior forecast development in 2Q2014, oil prices were high (near $100/bbl.) and there were a number of large industrial expansion projects and other new large industrial projects expressing interest in the ELL area. This was expected to have secondary effects for residential and commercial electricity consumption as well. Shortly thereafter, oil prices began a steep decline during 2014 and further into early 2016 before prices leveled off in the low $40/bbl. range through 2017. As a result, a number of the large industrial projects were either delayed or cancelled, thereby causing electricity consumption to be lower than forecasted levels.

Energy Efficiency

In addition, during this time, there were a number of advancements in energy efficiency that resulted in lower electricity consumption. These advancements include the proliferation of efficient LED bulbs at lower prices and in warmer colors than the older, blue-hued LEDs. These developments led to customers' increased usage of more energy efficient products and cut significantly into both the residential and commercial sales.

Also, new commercial refrigeration standards as well as new residential water heater standards went into effect during this time (2015-2017), resulting in lower than expected electricity consumption.

Economics

Additionally, the commercial sales forecast model used for the previous IRP included an economic variable called Gross State Product ("GSP") which is akin to a state-level Gross Domestic Product ("GDP"). The outlook for GDP was positive and optimistic; however, during 2016 and 2017, it was noted that the trending relationship between electricity consumption and economic output was breaking down, largely due to energy efficiency becoming more prevalent and due to the recent shift from an energy-intensive manufacturing economy to a less energy-intensive services-based economy.

Electrification Projects

The previous IRP forecast included a greater amount of expected sales growth from electrification projects such as conversions of diesel pumps to electric pumps and conversions of gas-powered forklifts to electric-powered forklifts. These types of conversions became less attractive as oil prices declined. The levels of conversions included in the current IRP forecast are now lower.

Peaks

All of the above factors which affected the sales forecast also had an effect on the peak forecasts; however, it is believed that the effects of energy efficiency have affected sales projections and resulting variances more than peaks.

Explanations of revisions applied to subsequent forecasts to adjust for deviations

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

- Taking a more conservative approach to adding new large industrial customers or industrial expansion projects to the sales forecast – The current forecast process uses higher thresholds for new project inclusion and risk-adjusts the expected increases in electricity volume for these projects.

- Removal of secondary effects for Residential and Commercial from new Large Industrial projects – While it is reasonable to assume that a new petrochemical facility in an area will result in more residential and commercial customers in that area, these secondary effects have been removed from the current forecast process due to the uncertainty around timing and magnitude of realizing this type of additional growth.

- Inclusion of explicit DSM decrements – The current forecast employs an add-back method for estimating the effects of DSM on future electricity consumption. This method allows ELL to better assess the levels of its DSM programs in the future and the effects on the forecasts.

- Removal of GSP as an economic variable – As mentioned previously, due to the decoupling of electricity consumption from economic output and due to the volatility in the economic forecasts, this variable has been removed from the commercial forecast models.

The current peak load forecast uses historical hourly load data settled through the MISO market as an input. In addition, as the company has more history with the Algiers load excluded from ELL's load, the historical data will better represent future load levels.

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. In the previous IRP forecast, there was no adjustment for these programs.

The sales and load forecasts are based on historical levels of electricity consumption and therefore inherently include the effects of load that was interrupted. ELL also prepares a firm load forecast that includes assumptions for interruptible load.

Load Forecast

[redacted]

Table 7: Summer Coincident Peaks (MW) Forecast

	Residential	Commercial	Industrial	Governmental	Company Use	Wholesale	Total
2019	3,574	2,386	3,877	144	22	129	10,133
2020	3,546	2,381	4,061	148	22	129	10,288
2021	3,531	2,354	4,080	150	23	129	10,267
2022	3,531	2,328	4,107	152	23	129	10,270
2023	3,540	2,317	4,155	155	23	129	10,319
2024	3,541	2,321	4,229	159	23	129	10,401
2025	3,541	2,325	4,248	162	23	129	10,428
2026	3,554	2,322	4,269	164	23	129	10,461
2027	3,575	2,313	4,289	166	23	129	10,495
2028	3,603	2,300	4,310	168	23	129	10,533
2029	3,624	2,303	4,336	171	23	129	10,586
2030	3,616	2,305	4,349	174	23	129	10,595
2031	3,618	2,310	4,369	177	23	129	10,625
2032	3,633	2,302	4,395	179	23	129	10,660

2033	3,655	2,291	4,419	180	23	129	10,696
2034	3,674	2,288	4,440	183	23	129	10,737
2035	3,699	2,291	4,468	186	23	129	10,795
2036	3,690	2,305	4,473	190	23	129	10,809
2037	3,707	2,305	4,493	192	23	129	10,849
2038	3,727	2,298	4,514	194	23	129	10,885

Table 8: Winter Coincident Peaks (MW) Forecast

	Residential	**Commercial**	**Industrial**	**Governmental**	**Company Use**	**Wholesale**	**Total**
2019	3,242	1,930	4,019	154	16	129	9,490
2020	3,072	1,943	4,148	156	17	129	9,466
2021	3,066	1,939	3,970	159	17	129	9,280
2022	2,997	1,915	4,090	164	17	129	9,312
2023	3,017	1,896	4,171	168	16	129	9,398
2024	3,194	1,888	4,335	169	16	129	9,731
2025	3,103	1,812	4,254	170	16	129	9,484
2026	3,085	1,921	4,224	174	17	129	9,551
2027	3,090	1,927	4,241	177	17	129	9,581
2028	3,050	1,900	4,328	183	16	129	9,606
2029	3,046	1,898	4,361	182	16	129	9,633
2030	3,225	1,897	4,457	186	16	129	9,911
2031	3,131	1,825	4,378	187	16	129	9,666
2032	3,104	1,936	4,350	191	17	129	9,728
2033	3,043	1,925	4,404	195	17	129	9,714
2034	3,065	1,911	4,464	200	16	129	9,785
2035	3,063	1,909	4,496	199	16	129	9,813
2036	3,159	1,838	4,485	201	16	129	9,828
2037	3,143	1,945	4,451	205	17	129	9,891
2038	3,148	1,953	4,468	208	17	129	9,923

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Table 10: Annual Load Factor Forecast

	Residential	Commercial	Industrial	Governmental	Company Use	Wholesale	Total
2019	48%	58%	93%	71%	59%	51%	68%
2020	48%	58%	94%	70%	59%	51%	69%
2021	48%	58%	93%	71%	59%	51%	69%
2022	47%	58%	93%	71%	59%	51%	69%
2023	47%	59%	93%	71%	59%	51%	69%
2024	48%	58%	93%	71%	59%	51%	69%
2025	48%	58%	94%	71%	59%	51%	69%
2026	48%	58%	94%	71%	59%	51%	69%
2027	48%	59%	94%	71%	59%	51%	69%

2028	48%	59%	94%	72%	59%	51%	69%
2029	47%	59%	94%	72%	59%	51%	69%
2030	48%	59%	94%	71%	59%	51%	70%
2031	48%	59%	94%	71%	59%	51%	70%
2032	48%	59%	94%	72%	59%	51%	70%
2033	47%	60%	94%	72%	59%	51%	70%
2034	47%	60%	94%	72%	59%	51%	70%
2035	47%	60%	94%	72%	59%	51%	70%
2036	48%	60%	95%	72%	59%	51%	70%
2037	48%	60%	95%	72%	59%	51%	70%
2038	48%	60%	95%	72%	59%	51%	70%

Appendix B Response to Stakeholder Comments Received Prior to Issuance of the Draft IRP

Comments Regarding Deactivation and Retirement Assumptions or Evaluations

Staff requests that when the Company files its Draft IRP, a confidential version of the Draft IRP that includes a detailed discussion of the assumptions behind the Company's deactivations decisions, including any subjective decisions made in the assumptions, be made available to Staff and Stakeholders who have signed confidentiality agreements in this Docket. Pages 11 and 12 of the "2018_0614 Staff Comments" document. LEUG requests that Entergy provide, in its Draft IRP Report, "expected retirement date for any resource expected to retire within the next ten years, and an explanation of the reason for the retirement". Page 9 of the "2018_0614 LEUG Comments" document. AAE noted that the Company did not identify any generating assets within its fleet that would be considered for deactivation. Page 3 of the "2018_0614 Alliance Comments" document.	Please see Section: Existing Fleet Deactivation Assumptions.
ELL's analysis should include transmission as an alternative to additional generation resources and the IRP Report should detail how this analysis was performed. Page 14 of the "2018_0614 Staff Comments" document.	The generation portfolio design included in the IRP document is based primarily on ELL's projected capacity needs. As mentioned in Section: Legacy Gas Useful Life Assumptions and ELL's Action Plan, ELL will perform an economic analysis of its legacy fleet, which will support or identify necessary changes to deactivation assumptions. The results of this detailed analysis will provide some insight regarding where new generation may need to be sited, as well as whether transmission enhancements may be a viable alternative to additional generation. Please see Section: Transmission Planning.
Sierra Club infers that an IRP process is the appropriate time for ELL to "rigorously investigate the risk that its coal-fired power plants pose to its ratepayers". Page 2 of the "2018_0614 Sierra Club Comments" document. Sierra Club recommends that ETR should present a	Throughout the planning period all ELL owned coal units (Nelson 6 and Big Cajun 2 Unit 3) are assumed to continue to operate. These units will continue to operate as long as it is in the customers' best interest to do so, while considering the long-term planning objectives of cost, reliability and risk. ELL continues to monitor key market drivers and their effects on

scenario specifically evaluating the costs and benefits of retiring ETR's coal-fired units. Page 4 of the "2018_0614 Sierra Club Comments" document. Sierra Club recommends that ETR should present a detailed financial analysis of the costs of continuing to operate each of its coal-fired units, including an analysis of each unit's total production costs compared to its operational revenues. Page 4 of the "2018_0614 Sierra Club Comments" document. Sierra Club recommends that ELL should use consistent retirement assumptions across its IRP processes in AR and LA. In particular, the Company should, as it has indicated in AR, assume in its reference case the retirement of WB and IS in 2028, 2030, respectively. The Company should include a scenario or sensitivity evaluating those retirements even earlier, in addition to the retirement of NL6 in the mid- to late-2020's. Page 6 of the "2018_0614 Sierra Club Comments" document.	ELL's generation portfolio, including the coal units. Entergy's point of view on future carbon emission pricing is included in the analysis. Additionally, within the evaluation, White Bluff and Independence (resources which ELL has a life-of-unit PPA) are assumed to deactivate in 2027 (White Bluff Unit 1), 2028 (White Bluff Unit 2) and 2030 (Independence Unit 1). These assumptions are consistent with the assumed deactivation schedule at the time the analysis was complete.
Sierra Club recommends that ELL should allow the model to determine unit retirements decisions endogenously. Page 4 of the "2018_0614 Sierra Club Comments" document. Sierra Club recommends that such retirement decisions should be made in the context of portfolio replacement options, rather than single one-off replacement assumptions (i.e., a single natural gas combined cycle ("NGCC" unit) to capture least-cost resource options. Page 6 of the "2018_0614 Sierra Club Comments" document. SWEA recommends that ELL should verify that the AURORA software and its methodologies will be used to identify potential generation units for retirement. Page 1 of the "2018_0614 SWEA Comments" document.	AURORA has the capability to assess deactivations in the capacity expansion algorithm, but there are data requirements which make this impractical within the scope of an IRP analysis. Assessments would be required for each unit and each potential deactivation date for that unit to determine the capital and O&M spending each year needed to maintain the unit from the beginning of the study period through each potential deactivation date. Furthermore, if unit availability or other attributes are dependent on the deactivation date, then estimates and assumptions would need to be developed to reflect changes in those attributes. The magnitude and timing of potential investments required to maintain a plant in excess of routine operating & maintenance expenses are uncertain and difficult to forecast, especially as units reach the end of their useful lives. Specific analyses are performed for such units when events (e.g., major component failures) trigger the need for such investments or when sustainability investments are required to operate the unit long-term. Additionally, generally it is a reasonable assumption to expect maintaining an existing operating plant will be lower cost to customers than building a new

	generating facility, unless circumstances around the cost to maintain the facility, market conditions, or policy changes dictate a more detailed evaluation.
SWEA recommends that ELL should comment on the finalized MTEP19 retirement assumptions, and unit-specific information, as it relates to its own scenario-building process. Page 1 of the "2018_0614 SWEA Comments" document. SWEA recommends that ELL should fully utilize MISO's future assumptions for its IRP, and retirement assumptions. Page 11 of the "2018_0614 SWEA Comments" document.	ELL designed the presented futures to reasonably bound possible outcomes and to provide a reasonable outlook on a range of potential market prices. ELL sees no reason to limit its IRP assumptions to those made in the MTEP process.

Comments Regarding Energy Efficiency and DSM

AEMA provided "benchmarking" analysis that suggests that MISO's DR penetration, on average, is triple that of Entergy's. Pages 12 and 13 of the "2018_0614 AEMA Comments" document. AEMA provided "benchmarking" analysis that suggests that Peer utilities, with reasonably similar C&I DR programs, have two to five times the C&I DR penetration as Entergy. Pages 13 and 14 of the "2018_0614 AEMA Comments" document. AEMA provided "benchmarking" analysis that	The purpose of the DSM study is to evaluate the potential growth of Demand Response and Energy Efficiency programs when compared to the Current Programs, as defined in the Draft IRP Report.

suggests that based on DR supply curves produced for Xcel Energy, Entergy's C&I DR potential could exceed 1 GW. Pages 14 to 16 of the "2018_0614 AEMA Comments" document.	
Staff noted that the ICF DSM Presentation explains that "current energy efficiency programs… were modeled largely based on current program designs, but with expanded budgets". Staff also notes that data supporting this statement has not been provided, "leaving Staff entirely unable to understand how, and to what extent, Existing Demand-Side Resources have been modeled". Page 13 of the "2018_0614 Staff Comments" document.	Supporting data for this is included in ICF's report for the draft IRP.
Sierra Club recommends that ETR should use energy efficiency assumptions that are consistent with its approach in AR. Pages 20 and 21 of the "2018_0614 Sierra Club Comments" document. Sierra Club recommends that all of model runs should have Entergy meet any mandated energy efficiency DSM goals. Pages 20 and 21 of the "2018_0614 Sierra Club Comments" document. AAE urged the Commission and the Company to "fully exploit this largely untapped affordable energy resource (Energy Efficiency) in the IRP. Page 4 of the "2018_0614 Alliance Comments" document.	ELL's Energy Efficiency program is conducted pursuant to the Louisiana Public Service Commission's Quick Start Energy Efficiency Rules, which were issued in LPSC General Order No. R-31106, dated September 30, 2013. In particular, Section VI of the EE Rules established a range for each participating utility's energy efficiency budget of 0.25 - 0.5% of 2012 retail revenues, adjusted for Industrial Opt-Outs and the $75 per month cap. Exceeding this cap could potentially put any expenses over 0.50% at risk for regulatory recovery. ELL continues to participate in the Commission's energy efficiency rulemaking and has filed comments in Phase II rulemaking of this docket in support of expanding the energy efficiency budget cap up to 1% of ELL's retail revenues. ELL's Draft IRP analysis included the Program Year 2 (2015-2016) energy efficiency programs at the Year 2 budgets as a starting point, an expansion of those programs, and new programs for selection in each portfolio. In total, these options add up to forecasted energy savings of up to 4x ELL's Program Year 2 savings.
Sierra Club recommends that ETR should disclose the costs of energy efficiency to be assumed for this IRP and provide the underlying assumptions. Pages 20 and 21 of the "2018_0614 Sierra Club Comments" document.	The energy efficiency costs were included in the DSM potential study stakeholder presentation posted to ELL's website. The underlying assumptions will be provided as part of the draft IRP in ICF's final report.
Sierra Club recommends that ETR should develop a supply curve for energy efficiency; the development of the supply curve should be disclosed for the	Energy efficiency supply curves were not developed by ELL because the evaluation of the potential DSM programs (energy efficiency and demand response)

Commission and stakeholders. Pages 20 and 21 of the "2018_0614 Sierra Club Comments" document.	was performed using the AURORA model including inputs from the ICF DSM study that, in addition to supply curve considerations, takes into account each DSM program's load shape, ELL's hourly load shape, and hourly energy prices.
Sierra Club recommends that ETR should model efficiency as a resource and using the utility cost method. Pages 20 and 21 of the "2018_0614 Sierra Club Comments" document.	EE is included as a resource with a 20-year load shape and levelized cost. The utility cost method was one of the four standard tests calculated and applied by ICF in its modeling approach.

Comments Regarding the Evaluation Process

AAE urges the Commission to confirm that ELL is in fact fully and accurately evaluating purchasing power from the MISO market, especially while prices are currently low. Page 2 to 3 of the "2018_0614 Alliance Comments" document. Staff requests ELL to explicitly describe how participation in the MISO marketplace may provide alternatives to ELL generation projects and whether elements of the market are included in the optimal portfolio mix. IRP requirements on this topic can be found in sections 5(d) and 6(a). Page 14 of the "2018_0614 Staff Comments" document. Staff requests ELL to ensure that all resources available to ELL through the MISO system are included and evaluated. Page 15 of the "2018_0614 Staff Comments" document.	Elements of the market are implicitly included in the 'optimal' portfolio mixes for each future by virtue of the modeling methodology laid out in the assumptions presentation. Market LMPs (Locational Marginal Prices) are calculated based on the varying fundamental and market assumptions in each future - portfolio choices are influenced by these market prices. However, while ELL recognizes the benefits of participating in MISO through its long-term planning, it is important to note that participation in MISO does not change the responsibilities of an LSE to ensure-reliable, economic electric service for its customers, which requires long-term planning. Consistent with this responsibility, ELL's long-term planning reserve margin target is consistent under each future (12% ICAP RM (Installed Capacity Reserve Margin) on NCP (Non-coincident Peak) does not vary). See Section: Resource Adequacy and Planning Reserve Requirements.
Staff requests ELL to include information detailing how excess capacity available through MISO and potential purchase power agreements were considered as available alternative resources in the Company's analysis. Pages 14 and 15 of the "2018_0614 Staff Comments" document.	Excess capacity available through MISO is not guaranteed long-term and partially a function of proactive planning actions of regulated utilities such as ELL. Accordingly, excess market capacity is not considered as an 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.
Staff requests that, should ELL exercise its option to "screen out of evaluation certain viable resource alternatives," ELL is to fully explain the basis of the exclusion from evaluation in accordance with IRP Rules. Page 16 of the "2018_0614 Staff Comments" document.	See Section III of the IRP.
AAE suggests that AURORA has "significant shortcomings" and that the Commission and ELL "acknowledge these shortcomings and ensure verifiable steps are taken to optimize for the utilization of low-cost energy from renewable and demand side resources." Page 9 of the "2018_0614 Alliance Comments" document. SWEA recommends that ELL should develop a study detailing various benefits and limitations of its current modeling software. Page 11 of the "2018_0614 SWEA Comments" document.	ELL adopted AURORA for long-term energy price forecasting and production costing in 2013 and has used AURORA for several resource certifications and IRPs that were accepted by the LPSC. ELL regularly reviews the software alternatives available to meet its long-term energy price forecasting and production costing needs and currently it has determined that AURORA best meets those needs.
SWEA noted that EAI representatives suggested that AURORA was addressing capacity shortages in the afternoon/evening by "building gas technologies rather than renewables, even if its first preference is renewables". ELL should work to identify solutions to the aforementioned problem with the AURORA dispatch model. Page 13 of the "2018_0614 SWEA Comments" document.	Please see Table 10: Renewable Modeling Assumptions and Section: Solar Capacity Credit Modeling for more information on assumptions and methodology used for solar and wind generation. The AURORA model reasonably evaluated all resource alternatives and their corresponding benefits to meeting capacity and energy requirements. The approach outlined in the IRP resulted in a wide range of the amount of renewable additions between the portfolios (1 GW (Portfolio 2) to 7.5 GW (Portfolio 4) on an installed capacity basis).
API recommends that ETR use a neutral approach regarding fuel and technology when planning for the use of more newer energy resources that would provide for more flexibility, reliability, and cleaner energy. Pages 5 and 6 of the "2018_0614 API Comments(2)" document.	ELL's approach to fuel and technology is neutral in that it seeks to identify the benefits and drawbacks of each generation technology in a non-preferential manner. Recognizing the fuel diversity benefits of zero variable cost resources is part of a neutral approach, as is recognizing the dispatchable nature/benefits of gas resources.

Comments Regarding LPSC IRP Rules and Entergy Policy

Staff and stakeholders found that it was important for	Though not officially labeled as an "IRP Update" in

ELL to update its load projections and allow the Commission the opportunity to monitor the projections. Staff encouraged ELL to file updated IRP Reports as conditions and ultimately resource plans change. Staff, however, is unaware of any updates filed the Company. Page 10 of the "2018_0614 Staff Comments" document.	ELL's IRP docket, ELL provided the Commission and Intervenors with updates to the assumptions used in the IRP and any changes to ELL's resource plan in other docketed proceedings. For example, ELL provides its current load forecasts on a quarterly basis in LPSC Docket U-32675 and also provided updated load and capability analyses in conjunction with certifications associated with LCPS, SCPS, WPEC, Oxy, Carville, etc. ELL is aware of Staff's recommendation and intends to provide updates to its IRP when/if conditions and/or plans change significantly such that an update is warranted.
Staff recommends that ELL review Sections 5(b) and 8(c) of the IRP Rules, and that the Company's Draft IRP include a detailed discussion of each Existing Supply-Side Resources topic listed in the IRP Rules. For example, these discussions should include: description of the conditions, ownership information, and location of all the Company's Existing Supply-Side Resources. Page 12 of the "2018_0614 Staff Comments" document.	See Section II of the Draft IRP report.
Staff recommends that ELL "review the IRP Rules" and that the Company's Draft IRP include a detailed Existing Resource Evaluation, including a discussion of the development and incorporation of each data assumption related to Existing Supply-Side Resources, Existing Demand-Side Resources, and Existing Transmission System topics listed in the IRP Rules. Refer to sections 3(b), 6(a) and 6(b) for a description of existing resources that are to be evaluated and provides guidelines for their evaluation. Page 15 of the "2018_0614 Staff Comments" document. Staff requests that the Company fully document and explain all data assumptions, including how and why those assumptions were developed and used to analyze viable resource alternatives in a technical appendix to the Company's Draft IRP Report. Page 16 of the "2018_0614 Staff Comments" document.	See Section II of the Draft IRP report.
LEUG requests that Entergy provide, in its Draft IRP Report, "some measure of rate impacts for the reference plan and the alternative resource planning scenarios evaluated". Page 9 of the "2018_0614 LEUG Comments" document.	See Table 14 of this Draft IRP for the present value of each portfolio's cost in each modeled future. This table is intended to provide the best available estimate of overall portfolio cost given the long-term nature of the IRP process and the fact that customer

	class bill and rate effects will be determined through certification proceedings associated with particular resources.
LEUG requests that Entergy not use the IRP to circumvent the MBMO. Pages 10 to 12 of the "2018_0614 LEUG Comments" document.	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." In its previous IRP cycle, and as required by the IRP Docket rules, ELL utilized the normal docketed resource certification process, including the requirements of the MBMO, for certification of the resources identified in the Action Plan that ELL chose to pursue. ELL intends to continue to follow the rules as outlined in the IRP Docket and comply with all relevant Commission orders.
AAE asserts that ENO and EAI provided more of an opportunity for stakeholders to develop "their own modeling inputs" with regards to DSM. Pages 3 and 4 of the "2018_0614 Alliance Comments" document.	ELL will take this feedback into consideration in planning its next IRP cycle.
Sierra Club recommends that ETR should make all underlying data and inputs available in electronic, unprotected formats, and preferably available through the Company's publicly available website or a cloud-based website. Page 23 of the "2018_0614 Sierra Club Comments" document.	ELL has posted its publicly available initial IRP data assumptions, responses to stakeholder questions, and supplemental data assumptions on its public website at http://www.entergy-louisiana.com/irp/2019_irp.aspx. ELL does not intend to make native files available on a publicly available or cloud-based website.
Sierra Club recommends that ETR should provide documentation for historical data and other data and assumptions that are enumerated in the LPSC order. Page 23 of the "2018_0614 Sierra Club Comments" document.	Please refer to Appendix A for this information.
Sierra Club recommends that ETR should also provide for an informal discovery process and make its responses to discovery requests available through its publicly accessible website. Page 23 of the "2018_0614 Sierra Club Comments" document.	Staff's report (2018_0525 Report of Stakeholder Mtg_Notice of Extension.pdf) states clearly that "As a robust IRP schedule is set forth in Section 10 of the Commission's IRP Rules and formal discovery is not part of those procedures, no formal discovery will be allowed herein." Given that, ELL asserts that the opportunities for stakeholders candid participation in

	technical conferences and offering comments to which ELL may respond is indeed an informal discovery process.
SWEA recommends that ELL should conduct a study of corporate renewable energy procurement practices by other utilities and states. This study should include best practices, estimated corporate interest within the ELL footprint, and recommendations for an action plan (reference to a Green Tariff). Pages 11 to 12 of the "2018_0614 SWEA Comments" document. AAE suggests that ELL should consider a Green Tariff, "from residential to large industrial," contemplated within its IRP. Page 5 of the "2018_0614 Alliance Comments" document.	ELL is actively engaged in studying and understanding its customers' needs including "corporate interest." On September 14, 2018, ELL filed the Experimental Renewable Option Tariff in response to its large commercial and industrial customers' interest in being powered by additional renewable energy sources to meet its corporate sustainability and renewable objectives. Furthermore, ELL intends to continue to contemplate a variety of offerings that meet its customers' needs while providing service at the lowest reasonable cost to its customers.

Comments Regarding Model Inputs and Data Assumptions

Staff requests that the Company's Draft IRP include detailed documentation on the background and reasons for how the Company developed each of its data assumptions as well as how those data assumptions were then utilized in the Company's modeling efforts, and why they were utilized in the manners selected. Pages 9 and 10 of the "2018_0614 Staff Comments" document.	See Sections II and III of the Draft IRP report for a variety of discussions regarding data assumptions.
Staff requests that ELL include a functional description of its current and projected ELL transmission network topology, MISO's planning projects for transmission, ELL operations within MISO system-wide planning, and that the transmission network topology be used in identifying needs in accordance with Section (8)(d)(iv) of the IRP Rules. Page 13 of the "2018_0614 Staff Comments" document. LEUG requests that Entergy, in its Draft IRP Report, identify whether its IRP modeling assumptions include all transmission reliability and congestion projects that have been approved by MISO, including the "DSG-6" congestion project that was approved by MISO for SE LA as part of its 2016 congestion study process as an "Other" project but which has not yet	The analysis performed for the resource portfolio design included in the IRP document is based primarily on evaluating ELL's projected capacity needs and targeted resource mix and does not consider Transmission topology at this stage in long-term resource planning. 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 will apply the Transmission topology in the AURORA Network Nodal Model, and will including approved MISO MTEP projects.

<table>
<tr><td>been submitted by Entergy to the LPSC for certification approval. Page 10 of the “2018_0614 LEUG Comments” document.</td><td></td></tr>
<tr><td>Staff requests that ELL provide additional details on the development of data assumptions related to demand and energy growth projections. Page 15 of the “2018_0614 Staff Comments” document.</td><td>See Section Load Forecasting Methodology and Appendix A of the IRP.</td></tr>
<tr><td>Oxy stated that while ELL's May 31, 2018 Data Assumptions included Oxy as a resource, the June 1, 2018 Data Assumptions Supplement excluded Oxy as a resource. Pages 1 to 3 of the “2018_0614 Oxy Comments” document.

LEUG notes that ELL "inadvertently" omitted Oxy PPA as one of its resources in the June 1, 2018 Data Assumptions Supplement filing. Page 13 of the “2018_0614 LEUG Comments” document.</td><td>Although it was inadvertently omitted from the June 1, 2018 Data Assumption Supplement, the Oxy PPA is included as an ELL resource in ELL’s IRP analysis.</td></tr>
<tr><td>LEUG requests that Entergy identify and explain the methodology and due diligence process that it uses to project industrial load growth and whether to include projected new or expansion projects in the load forecast. They go on to specify (5) specific questions that should be answered in ELL's analysis. Page 8 of the “2018_0614 LEUG Comments” document</td><td>1. The load forecast is based on the expected operating levels of existing large industrial customers as well as analysis of individual project proposals for new or expansion customers.
2. The load forecast takes into account new plants and expansion of existing plants.
3. A project typically has a signed Electric Service Agreement (ESA) in order to be included in the forecast. Further clarification can be found in the response to (4) below.
4. The projects are probability weighted based on each project’s stage of development. A probability is assigned to each project based on: the progress made toward the execution of a contract for electric service or delivery of service, customer actions such as load studies, facilities studies, project funding decisions, public announcements, permits, incentive packages, reimbursement agreements, and executed Electric Service Agreements (“ESAs”), all of which signal progress. Probability assessments are based on the informed judgement of ELL’s industrial customer representatives. The individual probabilities are used to weight each new or expansion project. For example, a project with 70% probability would enter the forecast with 70% of the MW and MWh for the full project.
5. The projects are probability weighted based on each project’s stage of development. A probability is assigned to each project based on: the progress made toward the execution of a contract for electric service or delivery of service, customer actions such as load</td></tr>
</table>

	studies, facilities studies, project funding decisions, public announcements, permits, incentive packages, reimbursement agreements, and executed Electric Service Agreements ("ESAs"), all of which signal progress. Probability assessments are based on the informed judgement of ELL's industrial customer representatives. The individual probabilities are used to weight each new or expansion project. For example, a project with 70% probability would enter the forecast with 70% of the MW and MWh for the full project.
AEMA recommends that the Commission retain an independent third-party consultant to evaluate the DR potential within ELL. Page 3 of the "2018_0614 AEMA Comments" document. AEMA recommends that Entergy use a conservative placeholder of 6% total C&I DR potential in its IRP until the Commission-led study is completed. Page 3 of the "2018_0614 AEMA Comments" document. AEMA recommends that Entergy issue a revised IRP using the results of the new potential study as inputs to its final IRP modeling. Page 3 of the "2018_0614 AEMA Comments" document. AEMA states that one of Entergy's shortcomings with data assumptions is its failure to consider additional curtailable or interruptible DR from C&I customers as a viable alternative resource to new generation. They then go on to suggest that ICF used a "flawed assumption" when they assumed that "all customers could participate in Entergy's existing interruptible tariff, and therefore, that no incremental potential existed". They then cite that Entergy's existing Interruptible Tariff, which provides the only option for C&I DR, has been closed to new customers since 1999. Pages 8 to 12 of the "2018_0614 AEMA Comments" document.	In light of the Company's proposed Action Plan in this IRP and other factors as described below, the additional DSM potential study recommended by AEMA is not necessary at this time. Although new interruptible load tariffs were not included in the ICF DSM potential study or the Draft IRP analysis, ELL has committed to develop new interruptible rate schedule options for its customers, as discussed in further detail in the Action Plan of this Draft IRP. The Company's offering of new interruptible rate schedules will give real data on customer interest in interruptible rates and therefore should eliminate the need for a study of interruptible load potential. Lastly, the Draft IRP results, even without any additional interruptible load modeled, give meaningful insight into the resource planning landscape for ELL over the study period. The Company's IRP analysis is solving for a resource need of approximately 6.5 GW by 2038, with the first new-build resources not being needed until 2028. Given AEMA's recommended assumption of an additional 400 MW of interruptible load, the addition of this demand response option in the model would not change ELL's IRP in a meaningful way. Because the Company has committed to develop new interruptible load programs, and because the Draft IRP results are useful and not likely to change substantially with the study recommended by AEMA, it is unnecessary to delay the IRP process with the additional demand response potential study and additional IRP analysis recommended by AEMA.
AAE recommends implementing reputable DR programs in the IRP, including TOU and Interruptible Load Programs. Page 4 of the "2018_0614 Alliance Comments" document.	ToU and interruptible load programs were included for residential and commercial customers. ToU was included for industrial customers. See ICF's DSM study for more detail.

AAE recommends that DR measures should "compete" with supply side options by recognizing the "option value". In other words, they recommend that ELL consider the value of DR during "extreme events" and not just under "normally modeled situations". Page 5 of the "2018_0614 Alliance Comments" document.	All resources would have different value under "extreme events" relative to "normally modeled situations."
AAE recommends that DR measures should "compete" with supply side options by recognizing the "option value". In other words, they recommend that ELL consider dispatching DR programs so that they "spread out" load reductions over a broader number of peak hours rather than utilizing them during one peak period. Page 5 of the "2018_0614 Alliance Comments" document.	DSM programs (which include Energy Efficiency and Demand Response) are available for selection within the Capacity Expansion optimization algorithm, and they compete directly with supply-side alternatives. DR programs' load reductions are consistent with the hourly MW reduction provided by ICF, and are dependent on the program type.
AAE urges ELL to consider "all benefits to the system". Specifically, AAE urges ELL to include, in its modeling, the benefits associated with voltage regulation, load following, and contingency reserves. They also recommend that ELL use a "net-cost-of capacity approach, as pioneered by Portland General Electric in its 2016 draft IRP. Page 7 of the "2018_0614 Alliance Comments" document.	Quantifying benefits associated with voltage regulation would likely require transmission modeling and even then, the economic benefit is uncertain (i.e. what is the cost of avoided voltage regulation?). Reserves value can be approximated out of model using historical ancillary market clearing prices to forecast future values. However, these values are historically small and are expected to remain so. In general, the Portland General Electric approach is doable, but these benefits are also site-specific, and the existing modeling construct is zonal in nature.
AAE infers that ELL should consider Lazard's annual analysis regarding Levelized Cost of Energy ("LCOE") and incorporate that into its IRP modeling. Pages 7 and 8 of the "2018_0614 Alliance Comments" document. SWEA recommends that ELL use Lazard's analysis as a resource for LCOE Analyses associated with renewable energy and energy storage pricing. Pages 3 to 5 of the "2018_0614 SWEA Comments" document.	Lazard produces capital cost and LCOE/LCOS estimates for generation alternatives and storage. These are roughly consistent with ELL's internal calculations and external consultant data.
AAE recommends that ELL should be required to provide a detailed accounting of changes it makes to how AURORA performs the optimization modeling to include 1) whether existing resources are fully competing against alternatives (if not, explain), 2) whether potential supply additions are competing directly against the full range of DSM resources, 3)	1. The model does not make endogenous retirement decisions. Even if it did, this would require projections of go-forward capital / O&M spend for every unit throughout the planning horizon, which doesn't exist at an accurate enough level to compete against generic supply-side resources, which are all evaluated on a comparable basis which excludes these costs (other than generic fixed and variable O&M).

any limitations on allowed market sales from ELL to MISO, 4) any limitations on market purchases from MISO to ELL, 5) any assumptions about the cost and types of new non-ELL resource additions in MISO, 6) any additional costs or constraints placed on renewables above installed cost and generation output, 7) any limitations placed on DR resources. Pages 9 and 10 of the "2018_0614 Alliance Comments" document.	2. Depends on the definition of "competing" and "full range," but yes, DSM resources are seen by the model and treated mathematically the same as supply-side resources. The difference lies in the start year relative to capacity need and the fact that DSM resources are evaluated based on net economic benefit and do not require a capacity need to be present in year 1 (2019). 3. In the capacity expansion phase the limit is 1,000 MWh per hour. In the production cost phase there is no explicit limitation. 4. In the capacity expansion phase the limit is 200 MWh per hour. In the production cost phase there is no explicit limitation. 5. Non-ELL resource additions in MISO are added to the market to meet a (16%) reserve margin and are added in the ratios listed in the future summary matrix (Table 12 of Section IV of this Draft IRP). 6. None 7. DR resource profiles are generated by ICF using avoided cost inputs from ELL and ICF internal software / algorithms.
Sierra Club states that "it appears that Entergy is likely operating…[NL6] non-economically, or at a loss". Specifically, it appears as if they are "self-scheduling" "regardless of the market price". They go on to provide "estimated losses" for WB and ISES, but not for NL6. Page 3 of the "2018_0614 Sierra Club Comments" document. Sierra Club infers that ELL is "hard-wiring" NL6 "into the model" (AURORA). Pages 5 and 6 of the "2018_0614 Sierra Club Comments" document.	In the context of IRP modeling, Nelson 6 is modeled such that it is committed and dispatched based on economics. Nelson 6 typically operates at high utilization rates, which is indicative of a highly economic resource. Nelson 6 is not modeled as a Must Run unit or forced to operate on a set schedule regardless of economics.
Sierra Club recommends that ELL should use a non-zero CO2 price in all of its scenarios. Pages 6 to 13 of the "2018_0614 Sierra Club Comments" document.	As described in Section III of this Draft IRP, ELL has decided to model a zero CO2 price in one of its futures to represent either no carbon control program or a program that does not result in tradable CO2 prices. ELL believes that some kind of national carbon regulation will occur, and has modeled programs with non-zero CO2 prices in the other three futures.
Sierra Club recommends that in modeling, CO2 cost should influence the dispatch of Entergy's units, and not be treated as a cost "after the fact". Pages 6 to 13 of the "2018_0614 Sierra Club Comments" document.	The AURORA model dispatch takes into account CO2 prices when calculating economic dispatch.
Sierra Club recommends that ETR should be sure to	ELL fully agrees and complies with this

not overly constrain the model including ensuring that it minimizes manual portfolio decisions and prescreening. Pages 13 to 16 of the "2018_0614 Sierra Club Comments" document.	recommendation.
Sierra Club recommends that ETR should ensure that it captures avoided costs that are provided by certain resources that occur outside of traditional energy planning. Ideally, this would be done through an assessment of those value streams outside of the model structure (and subsequent repricing in the model). Pages 13 to 16 of the "2018_0614 Sierra Club Comments" document.	Many avoided costs "outside of traditional energy planning' are site and/or project specific and are therefore not well suited for capacity expansion optimization.
Sierra Club recommends that ETR should ensure that the model captures the energy shifting value of storage or demand response. Pages 13 to 16 of the "2018_0614 Sierra Club Comments" document.	Energy market benefits for storage and demand response are captured through the model's dispatch logic and DR load shape inputs, respectively.
Sierra Club recommends that all data should be provided at the first step of the stakeholder engagement process and be updated promptly throughout the process. Page 23 of the "2018_0614 Sierra Club Comments" document.	ELL will take this feedback into consideration when developing data assumptions associated with its next IRP cycle.
SWEA recommends that ELL should not "self-schedule" or "hard-wire" new or existing generating units to dispatch in its model run. Page 11 of the "2018_0614 SWEA Comments" document. SWEA recommends that ELL should report the results of these non-self-scheduled model runs and the implications for each of its existing generating units. Page 11 of the "2018_0614 SWEA Comments" document.	Except for nuclear, certain hydro, and solar resources that do not permit dispatch flexibility, all resources are modeled to economically commit and dispatch consistent with their capabilities.
SWEA recommends that ELL should explicitly verify that the AURORA software and its methodologies truly prioritize least-cost resources, and not prioritize capacity resources. Page 12 of the "2018_0614 SWEA Comments" document. Sierra Club recommends that ETR should ensure AURORA model has ability to fully optimize the ETR portfolio, including retirements and demand side resources. Pages 13 to 16 of the "2018_0614 Sierra Club Comments" document.	The AURORA model developed and used to perform evaluation of resource alternatives to meet ELL's planning objectives in the IRP appropriately considers the cost and revenue of energy and capacity in the context of the MISO market.
SWEA recommends that ELL use the National Renewable Energy Lab's (NREL's) Annual	ELL considers several public and proprietary sources when developing the generating technology capital

Technology Baseline (ATB) as a resource for model inputs and future forecasts for IRP processes (this document, according to SWEA, is scheduled to be published in August, 2018). There are specific references to which data sets should be used. Pages 2 and 3 of the "2018_0614 SWEA Comments" document. SWEA recommends that ELL should use NREL's ATB values, and verify that "inflation" does not artificially cause renewable energy prices to continually increase over time. Page 13 of the "2018_0614 SWEA Comments" document.	cost estimates included in the IRP modeling. The 2018 NREL ATB capital cost forecast values for solar and wind resources are similar to the inputs used for capacity expansion modeling when compared on an even basis (e.g. nominal $/kW-AC). The treatment of cost inputs with respect to inflation has no effect on the results since all technologies are treated identically.
SWEA recommends that ELL should include PTC and ITC in near-term project procurement as cost reductions. Pages 7 and 8 of the "2018_0614 SWEA Comments" document.	The IRP is solving for a high-level indication of what types of capacity should be procured or investigated to meet ELL's long-term capacity need beginning in the mid-2020s. Accordingly, the PTC is assumed to have expired and the ITC is held constant at 10%.
SWEA recommends that ELL should evaluate low-cost energy purchases in its modeling, even if no capacity need exists. Page 12 of the "2018_0614 SWEA Comments" document. Sierra Club recommends that ETR should evaluate and incorporate low cost energy purchases and ensure its model prioritizes least-cost resources, even if no capacity is needed. Pages 17 to 20 of the "2018_0614 Sierra Club Comments" document. Sierra Club recommends that ELL should allow market-based purchases in its modeling. Pages 17 to 20 of the "2018_0614 Sierra Club Comments" document. SWEA recommends that ELL should allow market-based purchases in its modeling. Page 12 of the "2018_0614 SWEA Comments" document.	Economic market-based energy purchases and prioritization of least-cost resources are accounted for in the IRP modeling to the extent ELL requires capacity to meet its planning objectives. However, ELL is forecasted to remain a net energy purchaser in the MISO market in the near future. Accordingly, additional economic energy purchases may be evaluated outside of the context of IRP modeling to support ELL's planning objectives. Please see Section II and ELL's Action Plan.

Comments Regarding Portfolio Alternatives

Sierra Club recommends that Entergy should ensure that its model can pick partial blocks of resources wherein block size is not a barrier (such as solar and wind) and pick reasonable partial blocks of other resources where capacity can be shared between	Solar, wind, and battery storage are evaluated as alternatives in the capacity expansion process of the IRP analysis. Resource alternatives are sized in the evaluation to be appropriate for meeting ELL's needs in the context of strategic IRP analysis. Specific

utilities. Pages 13 to 16 of the "2018_0614 Sierra Club Comments" document. Sierra Club recommends that ETR should develop a reasonable range of wind and solar resources alternatives using multiple variations of various technologies of different sizes and ensure that its model optimized decision-making by allowing it to choose partial blocks of resources, or combinations of resources. Pages 17 to 20 of the "2018_0614 Sierra Club Comments" document. Sierra Club recommends that ETR should incorporate into its analysis the important co-benefits of battery storage. Pages 21 to 23 of the "2018_0614 Sierra Club Comments" document. Sierra Club recommends that ETR should expand the options available and include additional battery store alternatives, including a two-hour option. Pages 21 to 23 of the "2018_0614 Sierra Club Comments" document. Sierra Club recommends that ETR should allow its modeling to select among portfolios of options including solar or wind coupled with batteries. Pages 21 to 23 of the "2018_0614 Sierra Club Comments" document. SWEA recommends that ELL should model blended renewable resources such as solar+wind, solar+storage, wind+storage, and wind+solar+storage as independent resources for possible selection. Page 13 of the "2018_0614 SWEA Comments" document.	resource sizing decisions are properly addressed in the detailed evaluations that are performed prior to selecting a resource. Coupling these resources would not improve the economics within the IRP evaluation of these alternatives. The nuanced benefits of coupling batteries and intermittent resources will continue to be explored on a case-by-case basis.
AAE urges ELL to use "up-to-date" advanced storage cost estimates and forecasts. Page 7 of the "Alliance Comments" document.	The storage cost forecast and estimates are as of October 2017 and predict aggressive cost declines.
AAE mentioned that the Company "did not make mention of Electric Vehicles". Page 7 of the "Alliance Comments" document.	Please see the response in the "Electric Vehicle Assumptions" in the Data Assumptions Supplement filed June 1st 2018. .
Sierra Club recommends that ETR should clarify the sizing and specifications of the different resources like solar, wind, and battery options. Pages 13 to 16 of the "2018_0614 Sierra Club Comments"	Solar: 100MW Wind: 200MW Battery storage: 100MW/400MWh

document.	
Sierra Club recommends that ETR should include a cost projection for wind and solar resources that reflects current industry understanding and expectations. Pages 17 to 20 of the "2018_0614 Sierra Club Comments" document.	Cost projections included in the modeling and documented in the assumptions filing reflect current industry understanding and expectations. These have also been benchmarked against market data from RFPs and/or unsolicited offers.
Sierra Club urges ELL to adopt a transparent and robust resource planning framework that encourages the replacement of uneconomic fossil fuel resources with affordable renewable energy and energy efficiency investments. Page 2 of the "2018_0614 Sierra Club Comments" document.	See Section: Portfolio Results. The IRP reasonably evaluated all resource alternatives resulting in a wide range of the amount of renewable additions between the portfolios (1 GW (Portfolio 2) to 7.5 GW (Portfolio 4) on an installed capacity basis). Additionally, the evaluation resulted in over 550 MW of DSM in three out of the four portfolios. See response above regarding deactivation assumptions and evaluations.
SWEA recommends that ELL should conduct a utility-scale energy storage study to develop several metrics for value stacking capability, in anticipation of full implementation of FERC Order Number 841 and conduct all modeling on a sub-hourly basis. Page 11 of the "2018_0614 SWEA Comments" document.	Energy storage is considered within ELL's IRP evaluation. The evaluation indicates that further exploration of battery storage is warranted. Additional potential value steams and drivers will be considered in project-specific evaluations.
SWEA recommends that ELL should not include the modeling of tariffs on solar panels. Pages 8 and 9 of the "2018_0614 SWEA Comments" document.	The current cost assumptions do not include the solar PV module tariffs.
SWEA recommends that ELL issue an RFI regarding wind energy, solar energy, and energy storage to receive project specific pricing, performance, and locations and incorporate federal PTC and ITC for renewable energy resources, and some energy storage projects that are tied to renewable energy resources. Page 11 of the "2018_0614 SWEA Comments" document.	ELL asserts that pricing reflected in its data assumptions is reflective of market forecasts. An issuance of an RFI would be duplicative given that ELL is currently using industry standard resources to develop the data assumptions. Furthermore, ELL issued an RFP in 2016 specifically related to renewable resources. Through that effort ELL was able to obtain "project specific" information. Through the course of ELL's normal business, ELL will continue to evaluate whether or not it is appropriate to issue additional RFPs, which may include renewable resources, as business needs arise.
SWEA recommends that ELL evaluate both fixed-tilt and single-axis tracking PV. Page 10 of the "2018_0614 SWEA Comments" document.	The Technology Assessment fully addresses this.
SWEA recommends that ELL's modeling regarding renewable energy resources should reflect an	The cost inputs to the model do reflect anticipated cost declines over time for renewable resources as

anticipated decline in costs over time. Pages 6 and 7 of the "2018_0614 SWEA Comments" document.	well as energy storage.
SWEA recommends that ELL provide a comparison of capacity values for various wind energy and solar energy resources to that of ELL's peak load, MISO's peak load, and MISO's wind energy and solar energy capacity valuations. Page 10 of the "2018_0614 SWEA Comments" document.	ELL's assumed solar capacity credit and wind credit are based on the MISO Tariff. Please see Table 10: Renewable Modeling Assumptions and Section "Solar Capacity Credit Modeling" for more information on assumptions used for solar and wind generation.
To the extent that ELL will require new energy generating resources in the next five years, ELL should consider accelerating the adoption of those resources to take full advantage of the expiring PTC and ITC. Page 10 of the "2018_0614 SWEA Comments" document.	ELL intends to procure generation resources consistent with its long-term planning objectives. Please see ELL's Action Plan.
SWEA recommends that ELL should evaluate multiple energy storage configurations, using sub-hourly dispatch, with multiple revenue streams as stand-alone projects as well as coupled with generation resources. Pages 6 and 7 of the "2018_0614 SWEA Comments" document. AAE urges ELL to model battery storage on a sub-hourly basis. Page 6 of the "2018_0614 Alliance Comments" document.	While the AURORA model has the capability to simulate sub-hourly time intervals, the analysis is prohibitively time consuming considering the scope and strategic objectives of the IRP analyses.
AAE recommends that ELL use hourly and sub-hourly load shaped from NREL's WIND Toolkit and NREL's System Advisor Model (SAM). Page 9 of the "2018_0614 Alliance Comments" document.	NREL SAM is used for wind hourly profiles. As stated previously, the AURORA model is currently run using an hourly time resolution.

Comments Regarding Scenarios, Sensitivities, and Risk

Staff requests that ELL incorporate a probability weighting of the scenarios used and that the Company fully document the sensitivity and scenario analyses' data assumptions and results. This information is to be included in one or more technical appendices to the Draft IRP Report. Page 16 of the "2018_0614 Staff Comments" document.	An equal probability weighting per future is implicit within the framework of the risk assessment. See Section III: Assumptions and Section IV: Portfolio Design Analytics for more detail on the assumptions used, the analytical framework, and the results of the evaluation.
AAE recommends that ELL "evaluate multiple tranches with different performance levels and pricing assumptions [which is] similar to analysis performed for fuel-based power generation resources." To the extent possible, data should be	Current assumptions are a reasonable outlook of renewable development costs, and are based on an annual, confidential IHS forecast and market information. Meaningful sensitivities are incorporated within the futures and focus on inputs

used from the 2018 NREL ATB, when published in August. Page 9 of the "2018_0614 Alliance Comments" document.	that impact ongoing market prices. To the extent development cost assumptions change, these costs would be incorporated through subsequent planning processes, IRPs, and procurement activities.
Sierra Club recommends that ETR should decouple commodity prices, emissions prices, and other assumptions. Choose the most important sensitivities and provide reasonable corner or end members of these sensitivities. Provide more than four optimization runs. Page 16 to 17 of the "2018_0614 Sierra Club Comments" document. Sierra Club recommends that sensitivities for potential CO2 and other environmental compliance costs should be conducted independently of each other and other variables (i.e. not correlated). Page 6 to 13 of the "2018_0614 Sierra Club Comments" document.	The current futures framework is a comprehensive analysis which reasonably bookends possible outcomes including those around commodity and emissions prices. The futures were formulated with the intent that the assumptions present in each future are cohesive and logically sound.
Sierra Club recommends that ELL's reference case should model a cap reflecting the application of section 111(d) to both existing and new electric generating units. Page 6 to 13 of the "2018_0614 Sierra Club Comments" document.	Section 111(d) of the Clean Air Act applies only to existing units. A regulatory program similar to the Clean Power Plan, the current regulation interpreting 111(d), is included as the reference case of Entergy's carbon pricing point of view and is included as an input to the futures described above. Section 111(b) regulations, which apply to new units, are considered as new units are planned and developed. CO2 prices assumed within the futures are applied to both existing and new generation within the AURORA model. See Section "CO2 Price Assumptions" for a more detailed description of the CO2 assumptions used.

Other Comments

LEUG urges that the LPSC should initiate proceedings to investigate its proposals for: 1) an industrial customer market access option, 2) a new interruptible service tariff option, 3) a real-time pricing tariff options, and 4) a market-based stand-by service option. Pages 1 to 8 of the "2018_0614 LEUG Comments" document.	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. 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, refuse to continue building needed generation for which they 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 do not result in the cost shifting noted above. For example, as part of its Action Plan, the Company has committed to designing and offering a new interruptible service tariff that would be generally available to customers, including LEUG members.
LEUG requests that Entergy, in its Draft IRP Report, "identify and describe" any RMR units that it operates and discuss any actions that could be taken to eliminate the RMR units. Page 9 of the "2018_0614 LEUG Comments" document.	Please see the Transmission Planning section of this Draft IRP for an explanation of why transmission alternatives are not modeled in this stage of ELL's long-term planning. Proposed economic transmission solutions are reviewed as part of MISO's MTEP process as projects for approval when a business case can be established on the basis of benefits that are shown to exceed commensurate costs.
LEUG requests that Entergy, in its Draft IRP Report, "identify and describe" any significant transmission constraints and limitations within the system and discuss any actions that could be taken to eliminate the constraints, limitations. Page 10 of the "2018_0614 LEUG Comments" document.	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, which is posted publicly at www.misoenergy.org/planning/transmission-studies-and-reports. These constraints and mitigations are analyzed through Entergy's LTTP and MISO's MCPS MTEP processes, as described in Section I: Transmission Planning of the draft IRP. Details of the Transmission Study processes are included in "Book 1,"and details of the ELL constraints and mitigation projects are included in "Appendix D1 (South)."
Sierra Club recommends that ELL should develop estimates for decommissioning and demolishment of its units. These estimates should be open to vetting	ELL suggests that this comment is not relevant to the IRP. As is stated in LPSC General Order R-30021, the purpose of the IRP is for the utility "to develop

by the commission and stakeholders and should be presented in terms of net costs (the cost of decommissioning and demolition less the revenue generated from sale of scrap metal, salvaged equipment, and land value). Page 6 of the "2018_0614 Sierra Club Comments" document.	long-term resource plans, which include both supply and demand-side recourses, and consider transmission needs, or order to satisfy the utility's load requirements." The costs of decommissioning and demolishing units would be the same (with except to CPI-related cost changes) regardless of when a unit is decommissioned and demolished.
Sierra Club recommends that ELL should present findings from a detailed financial analysis including the costs of compliance with the Regional Haze Rule, the Clean Air Act's New Source Review Program, the NAAQS for both SO2 and ozone, the Clean Water Act's ELG rule, CCR Rule, and 316(b) rule, all proposed and emerging regulations. Pages 6 to 13of the "2018_0614 Sierra Club Comments" document. Sierra Club recommends that ELL should include in its analysis sensitivities for compliance costs and the resulting effect on the fleet's operations. Page 6 to 13 of the "2018_0614 Sierra Club Comments" document.	Information concerning each of these rules other than the Clean Water Act Effluent Guidelines ("ELG's") is included in Entergy's consolidated 2017 10K (pages 263-273). This can be accessed at http://www.entergy.com/investor_relations/2017_publications.aspx. Within the ELL fleet, the ELG regulations are expected to apply to ELL's Nelson 6 coal unit and NRG's Big Cajun. These regulations currently are under review by EPA. The cost of compliance with these regulations will depend on the final form of the rule.
API suggests that ETR look at system reliability from an attributes-oriented framework and recognizes the dynamic changes the company will encounter as energy demands and resource availability shifts. Page 2 to 5 of the "2018_0614 API Comments(2)" document.	Fuel diversity is not achieved for its own sake, but rather because it represents a reduction in commodity price risk which translates to lower production cost risk for ELL's customers. See Section: Assessment of Risks describing the risk assessment used in the IRP evaluation. See Section: Integration of Transmission and Resource Planning regarding the need to understand the requirements for inertial generation (e.g. CT, CCGT) on a high load factor system with many industrial customers.

Appendix C Total Relevant Supply Costs - Detail

Future 1 – Present Value (2019$) of Total Relevant Supply Costs

Note: Fixed costs are calculated on a levelized real basis for all futures

Portfolio 1 - Total Relevant Supply Cost		
		PV 2019$ [2019-2038]
Variable Supply Cost	[$MM]	$22,755
Resource Additions - Fixed Costs	[$MM]	$3,285
Capacity Purchases / (Sales)	[$MM]	($226)
DSM - Fixed Costs	[$MM]	$480
Total Supply Cost	[$MM]	$26,294

Portfolio 2 - Total Relevant Supply Cost		
		PV 2019$ [2019-2038]
Variable Supply Cost	[$MM]	$23,931
Resource Additions - Fixed Costs	[$MM]	$2,249
Capacity Purchases / (Sales)	[$MM]	($128)
DSM - Fixed Costs	[$MM]	$482
Total Supply Cost	[$MM]	$26,534

Portfolio 3 - Total Relevant Supply Cost		
		PV 2019$ [2019-2038]
Variable Supply Cost	[$MM]	$23,194
Resource Additions - Fixed Costs	[$MM]	$2,677
Capacity Purchases / (Sales)	[$MM]	$206
DSM - Fixed Costs	[$MM]	$480
Total Supply Cost	[$MM]	$26,557

Portfolio 4 - Total Relevant Supply Cost		
		PV 2019$ [2019-2038]
Variable Supply Cost	[$MM]	$22,043
Resource Additions - Fixed Costs	[$MM]	$5,396
Capacity Purchases / (Sales)	[$MM]	($382)
DSM - Fixed Costs	[$MM]	$42
Total Supply Cost	[$MM]	$27,099

Future 1 – Annual Total Relevant Supply Costs (Nominal $, Resource Addition Fixed Costs Levelized*)

CE Portfolio 1

		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Variable Supply Cost	[$MM]	$1,573	$1,631	$1,660	$1,723	$1,777	$1,862	$1,927	$1,967	$2,015	$2,173	$2,197	$2,277	$2,374	$2,198	$2,203	$2,348	$2,321	$2,362	$2,472	$1,707
Resource Additions - Fixed Costs	[$MM]	$0	$0	$0	$0	$0	$0	$0	$0	$0	$35	$144	$206	$347	$719	$978	$1,046	$1,311	$1,350	$1,421	$1,494
Capacity Purchases / (Sales)	[$MM]	$2	$1	($0)	($1)	($1)	($1)	($4)	($8)	($19)	($9)	($4)	($15)	($19)	($43)	($59)	($69)	($81)	($88)	($92)	($92)
DSM - Fixed Costs	[$MM]	$13	$20	$29	$36	$37	$38	$40	$43	$45	$49	$52	$54	$56	$56	$57	$57	$58	$59	$60	$61
Total Supply Cost	[$MM]	$1,589	$1,653	$1,689	$1,758	$1,813	$1,899	$1,963	$2,001	$2,041	$2,247	$2,390	$2,522	$2,758	$2,930	$3,179	$3,381	$3,609	$3,683	$3,861	$3,170

CE Portfolio 2

		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Variable Supply Cost	[$MM]	$1,585	$1,631	$1,660	$1,722	$1,777	$1,861	$1,926	$1,967	$2,014	$2,143	$2,212	$2,329	$2,420	$2,436	$2,481	$2,641	$2,708	$2,763	$2,924	$2,999
Resource Additions - Fixed Costs	[$MM]	$0	$0	$0	$0	$0	$0	$0	$0	$0	$41	$119	$137	$276	$483	$700	$726	$871	$900	$931	$967
Capacity Purchases / (Sales)	[$MM]	$2	$1	($0)	($1)	($1)	($1)	($4)	($8)	($19)	($20)	($15)	($17)	($17)	($19)	($23)	($27)	($29)	($33)	($37)	($42)
DSM - Fixed Costs	[$MM]	$13	$20	$29	$36	$37	$38	$40	$43	$46	$49	$52	$54	$56	$57	$57	$57	$58	$60	$61	$62
Total Supply Cost	[$MM]	$1,601	$1,653	$1,689	$1,757	$1,813	$1,899	$1,962	$2,001	$2,040	$2,213	$2,368	$2,503	$2,735	$2,956	$3,214	$3,397	$3,607	$3,689	$3,878	$3,986

CE Portfolio 3

		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Variable Supply Cost	[$MM]	$1,573	$1,631	$1,660	$1,723	$1,777	$1,862	$1,927	$1,967	$2,015	$2,176	$2,252	$2,374	$2,472	$2,453	$2,316	$2,441	$2,226	$2,259	$2,390	$2,436
Resource Additions - Fixed Costs	[$MM]	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$23	$47	$185	$411	$770	$827	$1,275	$1,312	$1,351	$1,423
Capacity Purchases / (Sales)	[$MM]	$2	$1	($0)	($1)	($1)	($1)	($4)	($8)	($19)	($2)	$37	$54	$58	$67	$67	$63	$59	$54	$52	$54
DSM - Fixed Costs	[$MM]	$13	$20	$29	$36	$37	$38	$40	$43	$45	$49	$52	$54	$56	$56	$57	$57	$58	$59	$60	$61
Total Supply Cost	[$MM]	$1,589	$1,653	$1,689	$1,758	$1,813	$1,899	$1,963	$2,001	$2,041	$2,223	$2,364	$2,530	$2,770	$2,988	$3,211	$3,388	$3,617	$3,684	$3,853	$3,973

CE Portfolio 4

		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Variable Supply Cost	[$MM]	$1,577	$1,639	$1,676	$1,749	$1,811	$1,907	$1,981	$2,015	$2,065	$2,019	$2,057	$2,120	$2,155	$2,046	$1,946	$2,030	$1,953	$1,981	$2,058	$2,067
Resource Additions - Fixed Costs	[$MM]	$0	$0	$0	$0	$0	$0	$0	$23	$35	$320	$453	$542	$769	$1,101	$1,472	$1,567	$1,903	$1,953	$2,060	$2,191
Capacity Purchases / (Sales)	[$MM]	$2	$1	($0)	($1)	($1)	($1)	($3)	($6)	($13)	($39)	($58)	($60)	($63)	($66)	($86)	($104)	($110)	($114)	($123)	($129)
DSM - Fixed Costs	[$MM]	$3	$3	$3	$3	$3	$3	$3	$3	$4	$4	$4	$5	$5	$5	$5	$5	$5	$5	$5	$5
Total Supply Cost	[$MM]	$1,582	$1,643	$1,678	$1,751	$1,813	$1,909	$1,981	$2,036	$2,091	$2,304	$2,458	$2,607	$2,866	$3,085	$3,338	$3,498	$3,750	$3,825	$4,000	$4,134

* Resource Addition Fixed Costs are levelized over the resources' useful lives on a real dollar basis.

Future 2 – Present Value (2019$) of Total Relevant Supply Costs

Portfolio 1 - Total Relevant Supply Cost		
		PV 2019$ [2019-2038]
Variable Supply Cost	[$MM]	$18,168
Resource Additions - Fixed Costs	[$MM]	$3,285
Capacity Purchases / (Sales)	[$MM]	($117)
DSM - Fixed Costs	[$MM]	$480
Total Supply Cost	[$MM]	$21,816

Portfolio 2 - Total Relevant Supply Cost		
		PV 2019$ [2019-2038]
Variable Supply Cost	[$MM]	$18,749
Resource Additions - Fixed Costs	[$MM]	$2,249
Capacity Purchases / (Sales)	[$MM]	($20)
DSM - Fixed Costs	[$MM]	$482
Total Supply Cost	[$MM]	$21,460

Portfolio 3 - Total Relevant Supply Cost		
		PV 2019$ [2019-2038]
Variable Supply Cost	[$MM]	$18,315
Resource Additions - Fixed Costs	[$MM]	$2,677
Capacity Purchases / (Sales)	[$MM]	$315
DSM - Fixed Costs	[$MM]	$480
Total Supply Cost	[$MM]	$21,787

Portfolio 4 - Total Relevant Supply Cost		
		PV 2019$ [2019-2038]
Variable Supply Cost	[$MM]	$17,483
Resource Additions - Fixed Costs	[$MM]	$5,396
Capacity Purchases / (Sales)	[$MM]	($273)
DSM - Fixed Costs	[$MM]	$42
Total Supply Cost	[$MM]	$22,647

Future 2 – Annual Total Relevant Supply Costs (Nominal $, Resource Addition Fixed Costs Levelized*)

CE Portfolio 1

		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Variable Supply Cost	[$MM]	$1,478	$1,474	$1,462	$1,463	$1,518	$1,575	$1,617	$1,653	$1,664	$1,720	$1,733	$1,748	$1,736	$1,490	$1,460	$1,557	$1,489	$1,455	$1,526	$1,524
Resource Additions - Fixed Costs	[$MM]	$0	$0	$0	$0	$0	$0	$0	$0	$0	$35	$144	$206	$347	$719	$978	$1,046	$1,311	$1,350	$1,421	$1,494
Capacity Purchases / (Sales)	[$MM]	$2	$2	($0)	($1)	($1)	($1)	($3)	($4)	($7)	$8	$14	$4	$1	($22)	($37)	($46)	($57)	($64)	($67)	($67)
DSM - Fixed Costs	[$MM]	$13	$20	$29	$36	$37	$38	$40	$43	$45	$49	$52	$54	$56	$56	$57	$57	$58	$59	$60	$61
Total Supply Cost	[$MM]	$1,493	$1,496	$1,491	$1,498	$1,554	$1,612	$1,654	$1,691	$1,702	$1,812	$1,944	$2,012	$2,140	$2,244	$2,458	$2,613	$2,801	$2,800	$2,939	$3,012

CE Portfolio 2

		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Variable Supply Cost	[$MM]	$1,478	$1,473	$1,462	$1,463	$1,518	$1,575	$1,618	$1,651	$1,663	$1,698	$1,730	$1,764	$1,744	$1,658	$1,657	$1,760	$1,744	$1,714	$1,811	$1,814
Resource Additions - Fixed Costs	[$MM]	$0	$0	$0	$0	$0	$0	$0	$0	$0	$41	$119	$137	$276	$483	$700	$726	$871	$900	$931	$967
Capacity Purchases / (Sales)	[$MM]	$2	$2	($0)	($1)	($1)	($1)	($3)	($4)	($7)	($3)	$3	$3	$3	$2	($1)	($4)	($6)	($9)	($13)	($17)
DSM - Fixed Costs	[$MM]	$13	$20	$29	$36	$37	$38	$40	$43	$46	$49	$52	$54	$56	$57	$57	$57	$58	$60	$61	$62
Total Supply Cost	[$MM]	$1,494	$1,495	$1,491	$1,498	$1,554	$1,613	$1,655	$1,689	$1,701	$1,785	$1,904	$1,958	$2,080	$2,200	$2,412	$2,539	$2,667	$2,664	$2,789	$2,825

CE Portfolio 3

		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Variable Supply Cost	[$MM]	$1,478	$1,474	$1,462	$1,463	$1,518	$1,575	$1,617	$1,653	$1,664	$1,723	$1,776	$1,824	$1,814	$1,701	$1,526	$1,607	$1,409	$1,381	$1,464	$1,475
Resource Additions - Fixed Costs	[$MM]	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$23	$47	$185	$411	$770	$827	$1,275	$1,312	$1,351	$1,423
Capacity Purchases / (Sales)	[$MM]	$2	$2	($0)	($1)	($1)	($1)	($3)	($4)	($7)	$16	$55	$74	$78	$89	$89	$86	$83	$78	$77	$79
DSM - Fixed Costs	[$MM]	$13	$20	$29	$36	$37	$38	$40	$43	$45	$49	$52	$54	$56	$56	$57	$57	$58	$59	$60	$61
Total Supply Cost	[$MM]	$1,493	$1,496	$1,491	$1,498	$1,554	$1,612	$1,654	$1,691	$1,702	$1,787	$1,907	$1,999	$2,133	$2,257	$2,442	$2,577	$2,824	$2,831	$2,951	$3,037

CE Portfolio 4

		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Variable Supply Cost	[$MM]	$1,480	$1,480	$1,474	$1,483	$1,548	$1,612	$1,662	$1,691	$1,705	$1,602	$1,617	$1,612	$1,553	$1,370	$1,272	$1,326	$1,230	$1,194	$1,243	$1,239
Resource Additions - Fixed Costs	[$MM]	$0	$0	$0	$0	$0	$0	$0	$23	$35	$320	$453	$542	$769	$1,101	$1,472	$1,567	$1,903	$1,953	$2,060	$2,191
Capacity Purchases / (Sales)	[$MM]	$2	$2	($0)	($0)	($1)	($1)	($2)	($1)	($0)	($22)	($39)	($41)	($43)	($45)	($64)	($81)	($86)	($90)	($99)	($104)
DSM - Fixed Costs	[$MM]	$3	$3	$3	$3	$3	$3	$3	$3	$4	$4	$4	$5	$5	$5	$5	$5	$5	$5	$5	$5
Total Supply Cost	[$MM]	$1,485	$1,485	$1,477	$1,486	$1,550	$1,614	$1,663	$1,716	$1,743	$1,904	$2,035	$2,118	$2,284	$2,431	$2,686	$2,816	$3,052	$3,062	$3,210	$3,331

* Resource Addition Fixed Costs are levelized over the resources' useful lives on a real dollar basis.

Future 3 – Present Value (2019$) of Total Relevant Supply Costs

Portfolio 1- Total Relevant Supply Cost		
		PV 2019$ [2019-2038]
Variable Supply Cost	[$MM]	$18,991
Resource Additions - Fixed Costs	[$MM]	$3,285
Capacity Purchases / (Sales)	[$MM]	($532)
DSM - Fixed Costs	[$MM]	$480
Total Supply Cost	[$MM]	$22,224

Portfolio 2 - Total Relevant Supply Cost		
		PV 2019$ [2019-2038]
Variable Supply Cost	[$MM]	$20,196
Resource Additions - Fixed Costs	[$MM]	$2,249
Capacity Purchases / (Sales)	[$MM]	($435)
DSM - Fixed Costs	[$MM]	$482
Total Supply Cost	[$MM]	$22,492

Portfolio 3 - Total Relevant Supply Cost		
		PV 2019$ [2019-2038]
Variable Supply Cost	[$MM]	$18,819
Resource Additions - Fixed Costs	[$MM]	$2,677
Capacity Purchases / (Sales)	[$MM]	($100)
DSM - Fixed Costs	[$MM]	$480
Total Supply Cost	[$MM]	$21,876

Portfolio 4 - Total Relevant Supply Cost		
		PV 2019$ [2019-2038]
Variable Supply Cost	[$MM]	$17,682
Resource Additions - Fixed Costs	[$MM]	$5,396
Capacity Purchases / (Sales)	[$MM]	($688)
DSM - Fixed Costs	[$MM]	$42
Total Supply Cost	[$MM]	$22,431

Future 3 – Annual Total Relevant Supply Costs (Nominal $, Resource Addition Fixed Costs Levelized*)

CE Portfolio 1

		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Variable Supply Cost	[$MM]	$1,411	$1,383	$1,359	$1,353	$1,383	$1,426	$1,445	$1,461	$1,456	$2,018	$2,066	$2,102	$2,109	$1,783	$1,699	$2,018	$1,813	$1,843	$2,163	$2,182
Resource Additions - Fixed Costs	[$MM]	$0	$0	$0	$0	$0	$0	$0	$0	$0	$35	$144	$206	$347	$719	$978	$1,046	$1,311	$1,350	$1,421	$1,494
Capacity Purchases / (Sales)	[$MM]	$1	$1	($1)	($1)	($2)	($2)	($7)	($19)	($52)	($56)	($54)	($68)	($74)	($101)	($121)	($134)	($149)	($159)	($167)	($171)
DSM - Fixed Costs	[$MM]	$13	$20	$29	$36	$37	$38	$40	$43	$45	$49	$52	$54	$56	$56	$57	$57	$58	$59	$60	$61
Total Supply Cost	[$MM]	$1,425	$1,404	$1,388	$1,387	$1,419	$1,462	$1,478	$1,484	$1,450	$2,045	$2,208	$2,295	$2,437	$2,457	$2,613	$2,987	$3,033	$3,093	$3,477	$3,566

CE Portfolio 2

		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Variable Supply Cost	[$MM]	$1,411	$1,383	$1,359	$1,353	$1,383	$1,426	$1,445	$1,461	$1,456	$1,989	$2,067	$2,127	$2,099	$2,042	$2,091	$2,433	$2,343	$2,451	$2,766	$2,841
Resource Additions - Fixed Costs	[$MM]	$0	$0	$0	$0	$0	$0	$0	$0	$0	$41	$119	$137	$276	$483	$700	$726	$871	$900	$931	$967
Capacity Purchases / (Sales)	[$MM]	$1	$1	($1)	($1)	($2)	($2)	($7)	($19)	($52)	($67)	($65)	($69)	($72)	($77)	($85)	($91)	($97)	($105)	($113)	($121)
DSM - Fixed Costs	[$MM]	$13	$20	$29	$36	$37	$38	$40	$43	$46	$49	$52	$54	$56	$57	$57	$57	$58	$60	$61	$62
Total Supply Cost	[$MM]	$1,425	$1,404	$1,388	$1,387	$1,419	$1,463	$1,478	$1,485	$1,449	$2,012	$2,173	$2,249	$2,359	$2,504	$2,763	$3,125	$3,174	$3,306	$3,644	$3,749

CE Portfolio 3

		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Variable Supply Cost	[$MM]	$1,411	$1,383	$1,359	$1,353	$1,383	$1,426	$1,445	$1,461	$1,456	$2,023	$2,124	$2,204	$2,224	$2,053	$1,760	$1,979	$1,467	$1,543	$1,851	$1,799
Resource Additions - Fixed Costs	[$MM]	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$23	$47	$185	$411	$770	$827	$1,275	$1,312	$1,351	$1,423
Capacity Purchases / (Sales)	[$MM]	$1	$1	($1)	($1)	($2)	($2)	($7)	($19)	($52)	($49)	($13)	$2	$2	$9	$6	($1)	($9)	($17)	($23)	($25)
DSM - Fixed Costs	[$MM]	$13	$20	$29	$36	$37	$38	$40	$43	$45	$49	$52	$54	$56	$56	$57	$57	$58	$59	$60	$61
Total Supply Cost	[$MM]	$1,425	$1,404	$1,388	$1,387	$1,419	$1,462	$1,478	$1,484	$1,450	$2,023	$2,186	$2,307	$2,467	$2,530	$2,593	$2,861	$2,791	$2,897	$3,239	$3,258

CE Portfolio 4

		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Variable Supply Cost	[$MM]	$1,413	$1,390	$1,373	$1,372	$1,411	$1,461	$1,487	$1,498	$1,497	$1,907	$1,922	$1,931	$1,824	$1,560	$1,292	$1,557	$1,181	$1,290	$1,778	$1,702
Resource Additions - Fixed Costs	[$MM]	$0	$0	$0	$0	$0	$0	$0	$23	$35	$320	$453	$542	$769	$1,101	$1,472	$1,567	$1,903	$1,953	$2,060	$2,191
Capacity Purchases / (Sales)	[$MM]	$1	$1	($1)	($1)	($1)	($2)	($6)	($16)	($45)	($86)	($107)	($113)	($118)	($125)	($147)	($169)	($178)	($186)	($198)	($208)
DSM - Fixed Costs	[$MM]	$3	$3	$3	$3	$3	$3	$3	$3	$4	$4	$4	$5	$5	$5	$5	$5	$5	$5	$5	$5
Total Supply Cost	[$MM]	$1,417	$1,393	$1,375	$1,373	$1,413	$1,462	$1,483	$1,508	$1,490	$2,144	$2,273	$2,365	$2,479	$2,541	$2,622	$2,960	$2,911	$3,063	$3,645	$3,690

* Resource Addition Fixed Costs are levelized over the resources' useful lives on a real dollar basis.

Future 4 – Present Value (2019$) of Total Relevant Supply Costs

Portfolio 1 - Total Relevant Supply Cost		
		PV 2019$ [2019-2038]
Variable Supply Cost	[$MM]	$32,156
Resource Additions - Fixed Costs	[$MM]	$3,285
Capacity Purchases / (Sales)	[$MM]	($117)
DSM - Fixed Costs	[$MM]	$480
Total Supply Cost	[$MM]	$35,803

Portfolio 2 - Total Relevant Supply Cost		
		PV 2019$ [2019-2038]
Variable Supply Cost	[$MM]	$33,778
Resource Additions - Fixed Costs	[$MM]	$2,249
Capacity Purchases / (Sales)	[$MM]	($20)
DSM - Fixed Costs	[$MM]	$482
Total Supply Cost	[$MM]	$36,489

Portfolio 3 - Total Relevant Supply Cost		
		PV 2019$ [2019-2038]
Variable Supply Cost	[$MM]	$32,400
Resource Additions - Fixed Costs	[$MM]	$2,677
Capacity Purchases / (Sales)	[$MM]	$315
DSM - Fixed Costs	[$MM]	$480
Total Supply Cost	[$MM]	$35,872

Portfolio 4 - Total Relevant Supply Cost		
		PV 2019$ [2019-2038]
Variable Supply Cost	[$MM]	$30,603
Resource Additions - Fixed Costs	[$MM]	$5,396
Capacity Purchases / (Sales)	[$MM]	($273)
DSM - Fixed Costs	[$MM]	$42
Total Supply Cost	[$MM]	$35,767

Future 4 – Annual Total Relevant Supply Costs (Nominal $, Resource Addition Fixed Costs Levelized*)

CE Portfolio 1

		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Variable Supply Cost	[$MM]	$1,819	$2,095	$2,114	$2,273	$2,359	$2,497	$2,651	$2,760	$2,882	$3,079	$3,191	$3,426	$3,564	$3,471	$3,362	$3,479	$3,390	$3,540	$3,711	$3,917
Resource Additions - Fixed Costs	[$MM]	$0	$0	$0	$0	$0	$0	$0	$0	$0	$35	$144	$206	$347	$719	$978	$1,046	$1,311	$1,350	$1,421	$1,494
Capacity Purchases / (Sales)	[$MM]	$2	$2	($0)	($1)	($1)	($1)	($3)	($4)	($7)	$8	$14	$4	$1	($22)	($37)	($46)	($57)	($64)	($67)	($67)
DSM - Fixed Costs	[$MM]	$13	$20	$29	$36	$37	$38	$40	$43	$45	$49	$52	$54	$56	$56	$57	$57	$58	$59	$60	$61
Total Supply Cost	[$MM]	$1,834	$2,117	$2,143	$2,308	$2,395	$2,534	$2,689	$2,799	$2,921	$3,170	$3,401	$3,690	$3,968	$4,225	$4,359	$4,535	$4,702	$4,885	$5,125	$5,404

CE Portfolio 2

		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Variable Supply Cost	[$MM]	$1,819	$2,095	$2,117	$2,274	$2,361	$2,504	$2,646	$2,762	$2,883	$3,085	$3,205	$3,482	$3,603	$3,854	$3,830	$4,006	$4,083	$4,283	$4,536	$4,723
Resource Additions - Fixed Costs	[$MM]	$0	$0	$0	$0	$0	$0	$0	$0	$0	$41	$119	$137	$276	$483	$700	$726	$871	$900	$931	$967
Capacity Purchases / (Sales)	[$MM]	$2	$2	($0)	($1)	($1)	($1)	($3)	($4)	($7)	($3)	$3	$3	$3	$2	($1)	($4)	($6)	($9)	($13)	($17)
DSM - Fixed Costs	[$MM]	$13	$20	$29	$36	$37	$38	$40	$43	$46	$49	$52	$54	$56	$57	$57	$57	$58	$60	$61	$62
Total Supply Cost	[$MM]	$1,835	$2,117	$2,146	$2,309	$2,397	$2,541	$2,683	$2,801	$2,922	$3,172	$3,379	$3,675	$3,938	$4,395	$4,586	$4,785	$5,006	$5,234	$5,515	$5,734

CE Portfolio 3

		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Variable Supply Cost	[$MM]	$1,819	$2,095	$2,114	$2,273	$2,359	$2,497	$2,651	$2,760	$2,882	$3,127	$3,322	$3,625	$3,777	$3,909	$3,450	$3,593	$3,128	$3,280	$3,511	$3,663
Resource Additions - Fixed Costs	[$MM]	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$23	$47	$185	$411	$770	$827	$1,275	$1,312	$1,351	$1,423
Capacity Purchases / (Sales)	[$MM]	$2	$2	($0)	($1)	($1)	($1)	($3)	($4)	($7)	$16	$55	$74	$78	$89	$89	$86	$83	$78	$77	$79
DSM - Fixed Costs	[$MM]	$13	$20	$29	$36	$37	$38	$40	$43	$45	$49	$52	$54	$56	$56	$57	$57	$58	$59	$60	$61
Total Supply Cost	[$MM]	$1,834	$2,117	$2,143	$2,308	$2,395	$2,534	$2,689	$2,799	$2,921	$3,191	$3,452	$3,800	$4,096	$4,466	$4,367	$4,563	$4,543	$4,730	$4,998	$5,226

CE Portfolio 4

		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Variable Supply Cost	[$MM]	$1,820	$2,102	$2,134	$2,310	$2,404	$2,563	$2,738	$2,834	$2,954	$2,881	$2,961	$3,144	$3,151	$3,053	$2,831	$2,993	$2,794	$2,974	$3,261	$3,423
Resource Additions - Fixed Costs	[$MM]	$0	$0	$0	$0	$0	$0	$0	$23	$35	$320	$453	$542	$769	$1,101	$1,472	$1,567	$1,903	$1,953	$2,060	$2,191
Capacity Purchases / (Sales)	[$MM]	$2	$2	($0)	($0)	($1)	($1)	($2)	($1)	($0)	($22)	($39)	($41)	($43)	($45)	($64)	($81)	($86)	($90)	($99)	($104)
DSM - Fixed Costs	[$MM]	$3	$3	$3	$3	$3	$3	$3	$3	$4	$4	$4	$5	$5	$5	$5	$5	$5	$5	$5	$5
Total Supply Cost	[$MM]	$1,825	$2,107	$2,136	$2,313	$2,406	$2,565	$2,739	$2,859	$2,992	$3,183	$3,379	$3,649	$3,882	$4,113	$4,244	$4,484	$4,615	$4,842	$5,227	$5,515

* Resource Addition Fixed Costs are levelized over the resources' useful lives on a real dollar basis.

Future 1 – Estimated Rate Impacts (Nominal $, Resource Addition Fixed Costs Not Levelized*)

CE Portfolio 1

		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Variable Supply Cost	[$MM]	$1,573	$1,631	$1,660	$1,723	$1,777	$1,862	$1,927	$1,967	$2,015	$2,173	$2,197	$2,277	$2,374	$2,198	$2,203	$2,348	$2,321	$2,362	$2,472	$1,707
Resource Additions - Fixed Costs	[$MM]	$0	$0	$0	$0	$0	$0	$0	$0	$0	$59	$240	$328	$535	$1,114	$1,483	$1,512	$1,863	$1,822	$1,831	$1,845
Capacity Purchases / (Sales)	[$MM]	$2	$1	($0)	($1)	($1)	($1)	($4)	($8)	($19)	($9)	($4)	($15)	($19)	($43)	($59)	($69)	($81)	($88)	($92)	($92)
DSM - Fixed Costs	[$MM]	$13	$20	$29	$36	$37	$38	$40	$43	$45	$49	$52	$54	$56	$56	$57	$57	$58	$59	$60	$61
Total Supply Cost	[$MM]	$1,589	$1,653	$1,689	$1,758	$1,813	$1,899	$1,963	$2,001	$2,041	$2,271	$2,485	$2,643	$2,946	$3,326	$3,684	$3,848	$4,161	$4,155	$4,271	$3,521
Load	[TWh]	60.30	61.89	61.65	61.78	62.21	62.98	63.17	63.44	63.72	64.06	64.32	64.56	64.83	65.14	65.39	65.71	66.04	66.37	66.68	67.01
Base Rate Effect	[$/kWh]	$0.00025	$0.00035	$0.00047	$0.00057	$0.00058	$0.00059	$0.00057	$0.00054	$0.00042	$0.00153	$0.00447	$0.00568	$0.00883	$0.01731	$0.02264	$0.02283	$0.02786	$0.02702	$0.02699	$0.02707
Fuel Rate Effect	[$/kWh]	$0.02609	$0.02636	$0.02693	$0.02789	$0.02857	$0.02956	$0.03050	$0.03100	$0.03162	$0.03392	$0.03416	$0.03526	$0.03662	$0.03374	$0.03369	$0.03572	$0.03514	$0.03558	$0.03706	$0.02547

CE Portfolio 2

		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Variable Supply Cost	[$MM]	$1,585	$1,631	$1,660	$1,722	$1,777	$1,861	$1,926	$1,967	$2,014	$2,143	$2,212	$2,329	$2,420	$2,436	$2,481	$2,641	$2,708	$2,763	$2,924	$2,999
Resource Additions - Fixed Costs	[$MM]	$0	$0	$0	$0	$0	$0	$0	$0	$0	$67	$189	$206	$422	$741	$1,062	$1,053	$1,234	$1,218	$1,200	$1,200
Capacity Purchases / (Sales)	[$MM]	$2	$1	($0)	($1)	($1)	($1)	($4)	($8)	($19)	($20)	($15)	($17)	($17)	($19)	($23)	($27)	($29)	($33)	($37)	($42)
DSM - Fixed Costs	[$MM]	$13	$20	$29	$36	$37	$38	$40	$43	$46	$49	$52	$54	$56	$57	$57	$57	$58	$60	$61	$62
Total Supply Cost	[$MM]	$1,601	$1,653	$1,689	$1,757	$1,813	$1,899	$1,962	$2,001	$2,040	$2,239	$2,437	$2,572	$2,881	$3,215	$3,577	$3,724	$3,970	$4,006	$4,148	$4,219
Load	[TWh]	60.30	61.89	61.65	61.78	62.21	62.98	63.17	63.44	63.72	64.06	64.32	64.56	64.83	65.14	65.39	65.71	66.04	66.37	66.68	67.01
Base Rate Effect	[$/kWh]	$0.00026	$0.00035	$0.00047	$0.00057	$0.00058	$0.00059	$0.00057	$0.00054	$0.00041	$0.00149	$0.00351	$0.00378	$0.00712	$0.01196	$0.01676	$0.01648	$0.01912	$0.01874	$0.01835	$0.01820
Fuel Rate Effect	[$/kWh]	$0.02629	$0.02636	$0.02693	$0.02788	$0.02856	$0.02955	$0.03048	$0.03100	$0.03160	$0.03346	$0.03439	$0.03607	$0.03733	$0.03740	$0.03794	$0.04019	$0.04100	$0.04163	$0.04385	$0.04476

CE Portfolio 3

		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Variable Supply Cost	[$MM]	$1,573	$1,631	$1,660	$1,723	$1,777	$1,862	$1,927	$1,967	$2,015	$2,176	$2,252	$2,374	$2,472	$2,453	$2,316	$2,441	$2,226	$2,259	$2,390	$2,436
Resource Additions - Fixed Costs	[$MM]	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$39	$77	$296	$648	$1,206	$1,239	$1,906	$1,857	$1,801	$1,809
Capacity Purchases / (Sales)	[$MM]	$2	$1	($0)	($1)	($1)	($1)	($4)	($8)	($19)	($2)	$37	$54	$58	$67	$67	$63	$59	$54	$52	$54
DSM - Fixed Costs	[$MM]	$13	$20	$29	$36	$37	$38	$40	$43	$45	$49	$52	$54	$56	$56	$57	$57	$58	$59	$60	$61
Total Supply Cost	[$MM]	$1,589	$1,653	$1,689	$1,758	$1,813	$1,899	$1,963	$2,001	$2,041	$2,223	$2,380	$2,559	$2,882	$3,225	$3,646	$3,800	$4,248	$4,229	$4,303	$4,359
Load	[TWh]	60.30	61.89	61.65	61.78	62.21	62.98	63.17	63.44	63.72	64.06	64.32	64.56	64.83	65.14	65.39	65.71	66.04	66.37	66.68	67.01
Base Rate Effect	[$/kWh]	$0.00025	$0.00035	$0.00047	$0.00057	$0.00058	$0.00059	$0.00057	$0.00054	$0.00042	$0.00073	$0.00199	$0.00287	$0.00632	$0.01185	$0.02033	$0.02068	$0.03063	$0.02969	$0.02869	$0.02870
Fuel Rate Effect	[$/kWh]	$0.02609	$0.02636	$0.02693	$0.02789	$0.02857	$0.02956	$0.03050	$0.03100	$0.03162	$0.03397	$0.03502	$0.03677	$0.03813	$0.03766	$0.03542	$0.03714	$0.03370	$0.03403	$0.03584	$0.03635

CE Portfolio 4

		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Variable Supply Cost	[$MM]	$1,577	$1,639	$1,676	$1,749	$1,811	$1,907	$1,981	$2,015	$2,065	$2,019	$2,057	$2,120	$2,155	$2,046	$1,946	$2,030	$1,953	$1,981	$2,058	$2,067
Resource Additions - Fixed Costs	[$MM]	$0	$0	$0	$0	$0	$0	$0	$39	$57	$529	$714	$808	$1,125	$1,598	$2,120	$2,155	$2,576	$2,508	$2,532	$2,597
Capacity Purchases / (Sales)	[$MM]	$2	$1	($0)	($1)	($1)	($1)	($3)	($6)	($13)	($39)	($58)	($60)	($63)	($66)	($86)	($104)	($110)	($114)	($123)	($129)
DSM - Fixed Costs	[$MM]	$3	$3	$3	$3	$3	$3	$3	$3	$4	$4	$4	$5	$5	$5	$5	$5	$5	$5	$5	$5
Total Supply Cost	[$MM]	$1,582	$1,643	$1,678	$1,751	$1,813	$1,909	$1,981	$2,052	$2,113	$2,513	$2,718	$2,873	$3,222	$3,582	$3,985	$4,086	$4,424	$4,380	$4,472	$4,540
Load	[TWh]	60.30	61.89	61.65	61.78	62.21	62.98	63.17	63.44	63.72	64.06	64.32	64.56	64.83	65.14	65.39	65.71	66.04	66.37	66.68	67.01
Base Rate Effect	[$/kWh]	$0.00009	$0.00007	$0.00004	$0.00003	$0.00003	$0.00003	($0.00001)	$0.00058	$0.00075	$0.00771	$0.01027	$0.01166	$0.01646	$0.02358	$0.03118	$0.03128	$0.03743	$0.03615	$0.03620	$0.03690
Fuel Rate Effect	[$/kWh]	$0.02615	$0.02648	$0.02719	$0.02831	$0.02912	$0.03028	$0.03136	$0.03177	$0.03241	$0.03152	$0.03199	$0.03284	$0.03324	$0.03141	$0.02976	$0.03090	$0.02957	$0.02985	$0.03086	$0.03085

* This rate analysis uses non-levelized fixed costs for resource additions (i.e., the resource has a revenue requirement that decreases with time as the asset depreciates).

Future 2 – Estimated Rate Impacts (Nominal $, Resource Addition Fixed Costs Not Levelized*)

CE Portfolio 1

		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Variable Supply Cost	[$MM]	$1,478	$1,474	$1,462	$1,463	$1,518	$1,575	$1,617	$1,653	$1,664	$1,720	$1,733	$1,748	$1,736	$1,490	$1,460	$1,557	$1,489	$1,455	$1,526	$1,524
Resource Additions - Fixed Costs	[$MM]	$0	$0	$0	$0	$0	$0	$0	$0	$0	$59	$240	$328	$535	$1,114	$1,483	$1,512	$1,863	$1,822	$1,831	$1,845
Capacity Purchases / (Sales)	[$MM]	$2	$2	($0)	($1)	($1)	($1)	($3)	($4)	($7)	$8	$14	$4	$1	($22)	($37)	($46)	($57)	($64)	($67)	($67)
DSM - Fixed Costs	[$MM]	$13	$20	$29	$36	$37	$38	$40	$43	$45	$49	$52	$54	$56	$56	$57	$57	$58	$59	$60	$61
Total Supply Cost	[$MM]	$1,493	$1,496	$1,491	$1,498	$1,554	$1,612	$1,654	$1,691	$1,702	$1,836	$2,039	$2,134	$2,328	$2,639	$2,963	$3,080	$3,352	$3,273	$3,350	$3,363
Load	[TWh]	60.84	62.72	62.58	62.80	63.32	64.20	64.45	64.77	65.11	65.49	65.79	66.08	66.39	66.74	67.03	67.37	67.71	68.05	68.36	68.70
Base Rate Effect	[$/kWh]	$0.00026	$0.00035	$0.00046	$0.00056	$0.00057	$0.00058	$0.00058	$0.00059	$0.00059	$0.00176	$0.00465	$0.00584	$0.00892	$0.01721	$0.02242	$0.02261	$0.02752	$0.02671	$0.02668	$0.02677
Fuel Rate Effect	[$/kWh]	$0.02429	$0.02350	$0.02336	$0.02330	$0.02397	$0.02453	$0.02509	$0.02552	$0.02555	$0.02627	$0.02635	$0.02646	$0.02615	$0.02233	$0.02178	$0.02310	$0.02199	$0.02138	$0.02232	$0.02218

CE Portfolio 2

		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Variable Supply Cost	[$MM]	$1,478	$1,473	$1,462	$1,463	$1,518	$1,575	$1,618	$1,651	$1,663	$1,698	$1,730	$1,764	$1,744	$1,658	$1,657	$1,760	$1,744	$1,714	$1,811	$1,814
Resource Additions - Fixed Costs	[$MM]	$0	$0	$0	$0	$0	$0	$0	$0	$0	$67	$189	$206	$422	$741	$1,062	$1,053	$1,234	$1,218	$1,200	$1,200
Capacity Purchases / (Sales)	[$MM]	$2	$2	($0)	($1)	($1)	($1)	($3)	($4)	($7)	($3)	$3	$3	$3	$2	($1)	($4)	($6)	($9)	($13)	($17)
DSM - Fixed Costs	[$MM]	$13	$20	$29	$36	$37	$38	$40	$43	$46	$49	$52	$54	$56	$57	$57	$57	$58	$60	$61	$62
Total Supply Cost	[$MM]	$1,494	$1,495	$1,491	$1,498	$1,554	$1,613	$1,655	$1,689	$1,701	$1,811	$1,974	$2,027	$2,225	$2,459	$2,775	$2,865	$3,030	$2,982	$3,059	$3,059
Load	[TWh]	60.84	62.72	62.58	62.80	63.32	64.20	64.45	64.77	65.11	65.49	65.79	66.08	66.39	66.74	67.03	67.37	67.71	68.05	68.36	68.70
Base Rate Effect	[$/kWh]	$0.00026	$0.00035	$0.00047	$0.00056	$0.00057	$0.00058	$0.00058	$0.00059	$0.00059	$0.00173	$0.00371	$0.00398	$0.00725	$0.01199	$0.01668	$0.01642	$0.01899	$0.01863	$0.01826	$0.01812
Fuel Rate Effect	[$/kWh]	$0.02429	$0.02349	$0.02336	$0.02329	$0.02397	$0.02454	$0.02510	$0.02549	$0.02554	$0.02593	$0.02630	$0.02670	$0.02627	$0.02485	$0.02472	$0.02612	$0.02576	$0.02519	$0.02649	$0.02640

CE Portfolio 3

		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Variable Supply Cost	[$MM]	$1,478	$1,474	$1,462	$1,463	$1,518	$1,575	$1,617	$1,653	$1,664	$1,723	$1,776	$1,824	$1,814	$1,701	$1,526	$1,607	$1,409	$1,381	$1,464	$1,475
Resource Additions - Fixed Costs	[$MM]	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$39	$77	$296	$648	$1,206	$1,239	$1,906	$1,857	$1,801	$1,809
Capacity Purchases / (Sales)	[$MM]	$2	$2	($0)	($1)	($1)	($1)	($3)	($4)	($7)	$16	$55	$74	$78	$89	$89	$86	$83	$78	$77	$79
DSM - Fixed Costs	[$MM]	$13	$20	$29	$36	$37	$38	$40	$43	$45	$49	$52	$54	$56	$56	$57	$57	$58	$59	$60	$61
Total Supply Cost	[$MM]	$1,493	$1,496	$1,491	$1,498	$1,554	$1,612	$1,654	$1,691	$1,702	$1,787	$1,922	$2,028	$2,244	$2,494	$2,877	$2,989	$3,455	$3,376	$3,401	$3,423
Load	[TWh]	60.84	62.72	62.58	62.80	63.32	64.20	64.45	64.77	65.11	65.49	65.79	66.08	66.39	66.74	67.03	67.37	67.71	68.05	68.36	68.70
Base Rate Effect	[$/kWh]	$0.00026	$0.00035	$0.00046	$0.00056	$0.00057	$0.00058	$0.00058	$0.00059	$0.00059	$0.00098	$0.00222	$0.00309	$0.00647	$0.01188	$0.02016	$0.02051	$0.03022	$0.02931	$0.02834	$0.02836
Fuel Rate Effect	[$/kWh]	$0.02429	$0.02350	$0.02336	$0.02330	$0.02397	$0.02453	$0.02509	$0.02552	$0.02555	$0.02631	$0.02700	$0.02761	$0.02733	$0.02549	$0.02276	$0.02385	$0.02080	$0.02029	$0.02141	$0.02146

CE Portfolio 4

		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Variable Supply Cost	[$MM]	$1,480	$1,480	$1,474	$1,483	$1,548	$1,612	$1,662	$1,691	$1,705	$1,602	$1,617	$1,612	$1,553	$1,370	$1,272	$1,326	$1,230	$1,194	$1,243	$1,239
Resource Additions - Fixed Costs	[$MM]	$0	$0	$0	$0	$0	$0	$0	$39	$57	$529	$714	$808	$1,125	$1,598	$2,120	$2,155	$2,576	$2,508	$2,532	$2,597
Capacity Purchases / (Sales)	[$MM]	$2	$2	($0)	($0)	($1)	($1)	($2)	($1)	($0)	($22)	($39)	($41)	($43)	($45)	($64)	($81)	($86)	($90)	($99)	($104)
DSM - Fixed Costs	[$MM]	$3	$3	$3	$3	$3	$3	$3	$3	$4	$4	$4	$5	$5	$5	$5	$5	$5	$5	$5	$5
Total Supply Cost	[$MM]	$1,485	$1,485	$1,477	$1,486	$1,550	$1,614	$1,663	$1,732	$1,765	$2,113	$2,296	$2,384	$2,640	$2,927	$3,333	$3,404	$3,725	$3,617	$3,682	$3,737
Load	[TWh]	60.84	62.72	62.58	62.80	63.32	64.20	64.45	64.77	65.11	65.49	65.79	66.08	66.39	66.74	67.03	67.37	67.71	68.05	68.36	68.70
Base Rate Effect	[$/kWh]	$0.00009	$0.00007	$0.00004	$0.00003	$0.00003	$0.00003	$0.00001	$0.00063	$0.00092	$0.00781	$0.01032	$0.01168	$0.01638	$0.02333	$0.03074	$0.03085	$0.03685	$0.03561	$0.03567	$0.03636
Fuel Rate Effect	[$/kWh]	$0.02432	$0.02360	$0.02356	$0.02362	$0.02444	$0.02510	$0.02579	$0.02611	$0.02619	$0.02446	$0.02458	$0.02440	$0.02339	$0.02053	$0.01898	$0.01967	$0.01817	$0.01755	$0.01819	$0.01803

* This rate analysis uses non-levelized fixed costs for resource additions (i.e., the resource has a revenue requirement that decreases with time as the asset depreciates).

Future 3 – Estimated Rate Impacts (Nominal $, Resource Addition Fixed Costs Not Levelized*)

CE Portfolio 1

		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Variable Supply Cost	[$MM]	$1,411	$1,383	$1,359	$1,353	$1,383	$1,426	$1,445	$1,461	$1,456	$2,018	$2,066	$2,102	$2,109	$1,783	$1,699	$2,018	$1,813	$1,843	$2,163	$2,182
Resource Additions - Fixed Costs	[$MM]	$0	$0	$0	$0	$0	$0	$0	$0	$0	$59	$240	$328	$535	$1,114	$1,483	$1,512	$1,863	$1,822	$1,831	$1,845
Capacity Purchases / (Sales)	[$MM]	$1	$1	($1)	($1)	($2)	($2)	($7)	($19)	($52)	($56)	($54)	($68)	($74)	($101)	($121)	($134)	($149)	($159)	($167)	($171)
DSM - Fixed Costs	[$MM]	$13	$20	$29	$36	$37	$38	$40	$43	$45	$49	$52	$54	$56	$56	$57	$57	$58	$59	$60	$61
Total Supply Cost	[$MM]	$1,425	$1,404	$1,388	$1,387	$1,419	$1,462	$1,478	$1,484	$1,450	$2,069	$2,304	$2,417	$2,625	$2,852	$3,118	$3,454	$3,584	$3,565	$3,887	$3,918
Load	[TWh]	58.76	59.72	59.23	59.11	59.29	59.79	59.82	59.91	60.02	60.20	60.32	60.43	60.57	60.75	60.88	61.05	61.23	61.42	61.58	61.58
Base Rate Effect	[$/kWh]	$0.00025	$0.00035	$0.00048	$0.00058	$0.00060	$0.00061	$0.00055	$0.00039	($0.00011)	$0.00085	$0.00394	$0.00520	$0.00853	$0.01760	$0.02331	$0.02352	$0.02894	$0.02804	$0.02800	$0.02818
Fuel Rate Effect	[$/kWh]	$0.02401	$0.02316	$0.02295	$0.02289	$0.02333	$0.02385	$0.02415	$0.02438	$0.02426	$0.03352	$0.03424	$0.03479	$0.03481	$0.02935	$0.02790	$0.03305	$0.02960	$0.03001	$0.03512	$0.03544

CE Portfolio 2

		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Variable Supply Cost	[$MM]	$1,411	$1,383	$1,359	$1,353	$1,383	$1,426	$1,445	$1,461	$1,456	$1,989	$2,067	$2,127	$2,099	$2,042	$2,091	$2,433	$2,343	$2,451	$2,766	$2,841
Resource Additions - Fixed Costs	[$MM]	$0	$0	$0	$0	$0	$0	$0	$0	$0	$67	$189	$206	$422	$741	$1,062	$1,053	$1,234	$1,218	$1,200	$1,200
Capacity Purchases / (Sales)	[$MM]	$1	$1	($1)	($1)	($2)	($2)	($7)	($19)	($52)	($67)	($65)	($69)	($72)	($77)	($85)	($91)	($97)	($105)	($113)	($121)
DSM - Fixed Costs	[$MM]	$13	$20	$29	$36	$37	$38	$40	$43	$46	$49	$52	$54	$56	$57	$57	$57	$58	$60	$61	$62
Total Supply Cost	[$MM]	$1,425	$1,404	$1,388	$1,387	$1,419	$1,463	$1,478	$1,485	$1,449	$2,038	$2,243	$2,318	$2,505	$2,763	$3,126	$3,452	$3,537	$3,623	$3,914	$3,982
Load	[TWh]	58.76	59.72	59.23	59.11	59.29	59.79	59.82	59.91	60.02	60.20	60.32	60.43	60.57	60.75	60.88	61.05	61.23	61.42	61.58	61.58
Base Rate Effect	[$/kWh]	$0.00025	$0.00035	$0.00048	$0.00059	$0.00060	$0.00061	$0.00056	$0.00039	($0.00011)	$0.00081	$0.00291	$0.00316	$0.00670	$0.01186	$0.01700	$0.01668	$0.01951	$0.01908	$0.01865	$0.01853
Fuel Rate Effect	[$/kWh]	$0.02401	$0.02316	$0.02295	$0.02288	$0.02333	$0.02385	$0.02416	$0.02439	$0.02425	$0.03304	$0.03427	$0.03520	$0.03466	$0.03361	$0.03435	$0.03985	$0.03826	$0.03991	$0.04491	$0.04614

CE Portfolio 3

		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Variable Supply Cost	[$MM]	$1,411	$1,383	$1,359	$1,353	$1,383	$1,426	$1,445	$1,461	$1,456	$2,023	$2,124	$2,204	$2,224	$2,053	$1,760	$1,979	$1,467	$1,543	$1,851	$1,799
Resource Additions - Fixed Costs	[$MM]	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$39	$77	$296	$648	$1,206	$1,239	$1,906	$1,857	$1,801	$1,809
Capacity Purchases / (Sales)	[$MM]	$1	$1	($1)	($1)	($2)	($2)	($7)	($19)	($52)	($49)	($13)	$2	$2	$9	$6	($1)	($9)	($17)	($23)	($25)
DSM - Fixed Costs	[$MM]	$13	$20	$29	$36	$37	$38	$40	$43	$45	$49	$52	$54	$56	$56	$57	$57	$58	$59	$60	$61
Total Supply Cost	[$MM]	$1,425	$1,404	$1,388	$1,387	$1,419	$1,462	$1,478	$1,484	$1,450	$2,023	$2,202	$2,337	$2,578	$2,767	$3,028	$3,273	$3,422	$3,442	$3,689	$3,644
Load	[TWh]	58.76	59.72	59.23	59.11	59.29	59.79	59.82	59.91	60.02	60.20	60.32	60.43	60.57	60.75	60.88	61.05	61.23	61.42	61.58	61.58
Base Rate Effect	[$/kWh]	$0.00025	$0.00035	$0.00048	$0.00058	$0.00060	$0.00061	$0.00055	$0.00039	($0.00011)	($0.00000)	$0.00129	$0.00219	$0.00585	$0.01174	$0.02083	$0.02120	$0.03193	$0.03092	$0.02985	$0.02996
Fuel Rate Effect	[$/kWh]	$0.02401	$0.02316	$0.02295	$0.02289	$0.02333	$0.02385	$0.02415	$0.02438	$0.02426	$0.03361	$0.03521	$0.03647	$0.03672	$0.03380	$0.02891	$0.03241	$0.02396	$0.02513	$0.03005	$0.02921

CE Portfolio 4

		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Variable Supply Cost	[$MM]	$1,413	$1,390	$1,373	$1,372	$1,411	$1,461	$1,487	$1,498	$1,497	$1,907	$1,922	$1,931	$1,824	$1,560	$1,292	$1,557	$1,181	$1,290	$1,778	$1,702
Resource Additions - Fixed Costs	[$MM]	$0	$0	$0	$0	$0	$0	$0	$39	$57	$529	$714	$808	$1,125	$1,598	$2,120	$2,155	$2,576	$2,508	$2,532	$2,597
Capacity Purchases / (Sales)	[$MM]	$1	$1	($1)	($1)	($1)	($2)	($6)	($16)	($45)	($86)	($107)	($113)	($118)	($125)	($147)	($169)	($178)	($186)	($198)	($208)
DSM - Fixed Costs	[$MM]	$3	$3	$3	$3	$3	$3	$3	$3	$4	$4	$4	$5	$5	$5	$5	$5	$5	$5	$5	$5
Total Supply Cost	[$MM]	$1,417	$1,393	$1,375	$1,373	$1,413	$1,462	$1,483	$1,524	$1,512	$2,354	$2,533	$2,631	$2,835	$3,038	$3,270	$3,548	$3,585	$3,618	$4,117	$4,096
Load	[TWh]	58.76	59.72	59.23	59.11	59.29	59.79	59.82	59.91	60.02	60.20	60.32	60.43	60.57	60.75	60.88	61.05	61.23	61.42	61.58	61.58
Base Rate Effect	[$/kWh]	$0.00007	$0.00006	$0.00003	$0.00003	$0.00002	$0.00002	($0.00005)	$0.00043	$0.00025	$0.00742	$0.01012	$0.01159	$0.01670	$0.02432	$0.03248	$0.03261	$0.03925	$0.03790	$0.03798	$0.03887
Fuel Rate Effect	[$/kWh]	$0.02404	$0.02327	$0.02318	$0.02321	$0.02381	$0.02444	$0.02485	$0.02501	$0.02494	$0.03167	$0.03187	$0.03195	$0.03011	$0.02568	$0.02123	$0.02550	$0.01930	$0.02101	$0.02887	$0.02763

* This rate analysis uses non-levelized fixed costs for resource additions (i.e., the resource has a revenue requirement that decreases with time as the asset depreciates).

Future 4 – Estimated Rate Impacts (Nominal $, Resource Addition Fixed Costs Not Levelized*)

CE Portfolio 1

		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Variable Supply Cost	[$MM]	$1,819	$2,095	$2,114	$2,273	$2,359	$2,497	$2,651	$2,760	$2,882	$3,079	$3,191	$3,426	$3,564	$3,471	$3,362	$3,479	$3,390	$3,540	$3,711	$3,917
Resource Additions - Fixed Costs	[$MM]	$0	$0	$0	$0	$0	$0	$0	$0	$0	$59	$240	$328	$535	$1,114	$1,483	$1,512	$1,863	$1,822	$1,831	$1,845
Capacity Purchases / (Sales)	[$MM]	$2	$2	($0)	($1)	($1)	($1)	($3)	($4)	($7)	$8	$14	$4	$1	($22)	($37)	($46)	($57)	($64)	($67)	($67)
DSM - Fixed Costs	[$MM]	$13	$20	$29	$36	$37	$38	$40	$43	$45	$49	$52	$54	$56	$56	$57	$57	$58	$59	$60	$61
Total Supply Cost	[$MM]	$1,834	$2,117	$2,143	$2,308	$2,395	$2,534	$2,689	$2,799	$2,921	$3,194	$3,496	$3,812	$4,156	$4,620	$4,864	$5,002	$5,253	$5,358	$5,535	$5,756
Load	[TWh]	60.84	62.72	62.58	62.80	63.32	64.20	64.45	64.77	65.11	65.49	65.79	66.08	66.39	66.74	67.03	67.37	67.71	68.05	68.36	68.70
Base Rate Effect	[$/kWh]	$0.00026	$0.00035	$0.00046	$0.00056	$0.00057	$0.00058	$0.00058	$0.00059	$0.00059	$0.00176	$0.00465	$0.00584	$0.00892	$0.01721	$0.02242	$0.02261	$0.02752	$0.02671	$0.02668	$0.02677
Fuel Rate Effect	[$/kWh]	$0.02989	$0.03341	$0.03378	$0.03619	$0.03725	$0.03889	$0.04114	$0.04262	$0.04427	$0.04701	$0.04850	$0.05184	$0.05369	$0.05201	$0.05015	$0.05163	$0.05006	$0.05203	$0.05428	$0.05701

CE Portfolio 2

		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Variable Supply Cost	[$MM]	$1,819	$2,095	$2,117	$2,274	$2,361	$2,504	$2,646	$2,762	$2,883	$3,085	$3,205	$3,482	$3,603	$3,854	$3,830	$4,006	$4,083	$4,283	$4,536	$4,723
Resource Additions - Fixed Costs	[$MM]	$0	$0	$0	$0	$0	$0	$0	$0	$0	$67	$189	$206	$422	$741	$1,062	$1,053	$1,234	$1,218	$1,200	$1,200
Capacity Purchases / (Sales)	[$MM]	$2	$2	($0)	($1)	($1)	($1)	($3)	($4)	($7)	($3)	$3	$3	$3	$2	($1)	($4)	($6)	($9)	($13)	($17)
DSM - Fixed Costs	[$MM]	$13	$20	$29	$36	$37	$38	$40	$43	$46	$49	$52	$54	$56	$57	$57	$57	$58	$60	$61	$62
Total Supply Cost	[$MM]	$1,835	$2,117	$2,146	$2,309	$2,397	$2,541	$2,683	$2,801	$2,922	$3,198	$3,449	$3,745	$4,084	$4,654	$4,948	$5,112	$5,369	$5,551	$5,785	$5,968
Load	[TWh]	60.84	62.72	62.58	62.80	63.32	64.20	64.45	64.77	65.11	65.49	65.79	66.08	66.39	66.74	67.03	67.37	67.71	68.05	68.36	68.70
Base Rate Effect	[$/kWh]	$0.00026	$0.00035	$0.00047	$0.00056	$0.00057	$0.00058	$0.00058	$0.00059	$0.00059	$0.00173	$0.00371	$0.00398	$0.00725	$0.01199	$0.01668	$0.01642	$0.01899	$0.01863	$0.01826	$0.01812
Fuel Rate Effect	[$/kWh]	$0.02989	$0.03341	$0.03383	$0.03621	$0.03728	$0.03900	$0.04106	$0.04265	$0.04429	$0.04710	$0.04872	$0.05269	$0.05427	$0.05775	$0.05714	$0.05946	$0.06030	$0.06294	$0.06636	$0.06874

CE Portfolio 3

		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Variable Supply Cost	[$MM]	$1,819	$2,095	$2,114	$2,273	$2,359	$2,497	$2,651	$2,760	$2,882	$3,127	$3,322	$3,625	$3,777	$3,909	$3,450	$3,593	$3,128	$3,280	$3,511	$3,663
Resource Additions - Fixed Costs	[$MM]	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$39	$77	$296	$648	$1,206	$1,239	$1,906	$1,857	$1,801	$1,809
Capacity Purchases / (Sales)	[$MM]	$2	$2	($0)	($1)	($1)	($1)	($3)	($4)	($7)	$16	$55	$74	$78	$89	$89	$86	$83	$78	$77	$79
DSM - Fixed Costs	[$MM]	$13	$20	$29	$36	$37	$38	$40	$43	$45	$49	$52	$54	$56	$56	$57	$57	$58	$59	$60	$61
Total Supply Cost	[$MM]	$1,834	$2,117	$2,143	$2,308	$2,395	$2,534	$2,689	$2,799	$2,921	$3,191	$3,468	$3,830	$4,207	$4,702	$4,802	$4,975	$5,175	$5,275	$5,448	$5,612
Load	[TWh]	60.84	62.72	62.58	62.80	63.32	64.20	64.45	64.77	65.11	65.49	65.79	66.08	66.39	66.74	67.03	67.37	67.71	68.05	68.36	68.70
Base Rate Effect	[$/kWh]	$0.00026	$0.00035	$0.00046	$0.00056	$0.00057	$0.00058	$0.00058	$0.00059	$0.00059	$0.00098	$0.00222	$0.00309	$0.00647	$0.01188	$0.02016	$0.02051	$0.03022	$0.02931	$0.02834	$0.02836
Fuel Rate Effect	[$/kWh]	$0.02989	$0.03341	$0.03378	$0.03619	$0.03725	$0.03889	$0.04114	$0.04262	$0.04427	$0.04775	$0.05049	$0.05486	$0.05690	$0.05858	$0.05147	$0.05333	$0.04620	$0.04821	$0.05135	$0.05332

CE Portfolio 4

		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Variable Supply Cost	[$MM]	$1,820	$2,102	$2,134	$2,310	$2,404	$2,563	$2,738	$2,834	$2,954	$2,881	$2,961	$3,144	$3,151	$3,053	$2,831	$2,993	$2,794	$2,974	$3,261	$3,423
Resource Additions - Fixed Costs	[$MM]	$0	$0	$0	$0	$0	$0	$0	$39	$57	$529	$714	$808	$1,125	$1,598	$2,120	$2,155	$2,576	$2,508	$2,532	$2,597
Capacity Purchases / (Sales)	[$MM]	$2	$2	($0)	($0)	($1)	($1)	($2)	($1)	($0)	($22)	($39)	($41)	($43)	($45)	($64)	($81)	($86)	($90)	($99)	($104)
DSM - Fixed Costs	[$MM]	$3	$3	$3	$3	$3	$3	$3	$3	$4	$4	$4	$5	$5	$5	$5	$5	$5	$5	$5	$5
Total Supply Cost	[$MM]	$1,825	$2,107	$2,136	$2,313	$2,406	$2,565	$2,739	$2,874	$3,014	$3,392	$3,639	$3,915	$4,238	$4,610	$4,891	$5,071	$5,289	$5,397	$5,699	$5,921
Load	[TWh]	60.84	62.72	62.58	62.80	63.32	64.20	64.45	64.77	65.11	65.49	65.79	66.08	66.39	66.74	67.03	67.37	67.71	68.05	68.36	68.70
Base Rate Effect	[$/kWh]	$0.00009	$0.00007	$0.00004	$0.00003	$0.00003	$0.00003	$0.00001	$0.00063	$0.00092	$0.00781	$0.01032	$0.01168	$0.01638	$0.02333	$0.03074	$0.03085	$0.03685	$0.03561	$0.03567	$0.03636
Fuel Rate Effect	[$/kWh]	$0.02991	$0.03352	$0.03410	$0.03679	$0.03796	$0.03992	$0.04248	$0.04375	$0.04536	$0.04399	$0.04500	$0.04757	$0.04746	$0.04574	$0.04223	$0.04442	$0.04126	$0.04370	$0.04769	$0.04983

* This rate analysis uses non-levelized fixed costs for resource additions (i.e., the resource has a revenue requirement that decreases with time as the asset depreciates).

BEFORE THE

LOUISIANA PUBLIC SERVICE COMMISSION

ENTERGY LOUISIANA, LLC REQUEST TO INITIATE 2017 INTEGRATED RESOURCE PLANNING PROCESS PURSUANT TO THE GENERAL ORDER NO. R-30021 (CORRECTED) DATED APRIL 20, 2012	**)))))**	**DOCKET NO. I-34694**

APPENDIX D

HIGHLY SENSITIVE
PROTECTED MATERIALS
FILED UNDER SEAL

INTENTIONALLY
OMITTED

MAY 2019

Appendix E DSM Program Selections by Portfolio

Energy Efficiency		Portfolio 1	Portfolio 2	Portfolio 3	Portfolio 4
EE Industrial Sector	Industrial Process	x	x	x	
	Industrial Prescriptive & Custom	x	x	x	x
	Industrial Strategic Energy Management				
EE Residential Sector	Appliances Recycling	x	x	x	
	ENERGY STAR New Homes2	x	x	x	
	Home Audit and Retrofit	x	x	x	
	Residential Prescriptive Non-Lighting	x	x	x	
	Residential AC Tune up	x	x	x	
	Residential HVAC Duct Sealing	x	x	x	
	Residential Lighting	x	x	x	x
	Low Income Weatherization	x	x	x	x
	Residential Unitary AC and HP	x	x	x	
	Home Energy Use Benchmarking	x	x	x	
EE Commercial Sector	Commercial Prescriptive & Custom HVAC	x	x	x	
	Commercial Prescriptive & Custom Other				
	Small Business Solutions	x	x	x	
	RetroCommissioning				
	Commercial New Construction				
	Current Commercial Prescriptive & Custom Lighting	x	x	x	
	Reduced Commercial Prescriptive & Custom Lighting				
	Midstream Commercial Lighting				
	Max Potential EE MWs*	**404**	**404**	**404**	**10**

Demand Response		Portfolio 1	Portfolio 2	Portfolio 3	Portfolio 4
Reference Case	Residential DLC (thermostat + water heater)				
	Residential ToU				
	Commercial DLC (thermostat)				
	Commercial ToU				x
	Industrial ToU				
	Max Potential MWs*	**0**	**0**	**0**	**13**
High Case	Residential DLC (thermostat + water heater)	x	x	x	
	Residential ToU				
	Commercial DLC (thermostat)	x	x	x	x
	Commercial ToU		x		
	Industrial ToU				
	Max Potential DR MWs*	**90**	**114**	**90**	**23**
Combined DR & EE	**Total Max Potential DSM MWs****	**495**	**518**	**495**	**47**

*MWs not grossed up for 12% Reserve margin
**Max Potential MW represents total MW DSM capacity in the year which DSM contributes the most capacity during the planning period. DSM capacity contribution will vary by year

Appendix F Response to Stakeholder Comments to DRAFT IRP

The information included in Appendix F provides ELL's responses to Staff and Stakeholder Comments to ELL's Draft IRP. In many instances stakeholders provided comments to the Draft IRP Report that were very similar to, or in some cases identical to, comments that were provided to in response to ELL's Data Assumptions filing and responded to by ELL in its Draft IRP Report. In reviewing these comments, ELL has determined that its responses to many of these similar/identical comments has not changed. Moreover, because ELL has already provided suitable responses to many of these comments, which have not changed, it has not repeated them in this appendix.

For example, Sierra Club recommended that ELL use "energy efficiency assumptions that are consistent with its approach in AR." ELL responded by stating that "ELL's Energy Efficiency program is conducted pursuant to the Louisiana Public Service Commission's Quick Start Energy Efficiency Rules" and that "[e]xceeding this cap could potentially put any expenses over 0.50% at risk for regulatory recovery". Sierra Club responded by repeating its comment.

In the prior example, ELL provided a comprehensive response, which outlined ELL's disagreement with Sierra Club's comment. Yet, in other cases, stakeholders repeated comments even when ELL previously confirmed its agreement with their comment. For example, Sierra Club recommended that "[i]n modeling, CO2 cost should influence the dispatch of Entergy's units, and not be treated as a cost 'after the fact'." ELL's response to this comment was "[t]he AURORA model dispatch takes into account CO2 prices when calculating economic dispatch." Sierra Club responded by repeating its comment.

Similarly, SREA noted at the November 27, 2018 Technical Conference that ELL had failed to provide Levelized Cost of Energy estimates for renewables. ELL responded that those estimates had been provided and were publicly available on ELL's IRP Website. For this round of comments, however, SREA stated "ELL continues to obfuscate the levelized cost of energy estimates for wind energy and solar power by claiming the information is highly sensitive." Again, this information has been publicly available on slide #18 of ELL's Data Assumptions presentation that is posted on ELL's IRP Website.

All new comments, or those comments that suggested additional clarifying recommendations, are addressed below.

Comments Regarding Deactivation and Retirement Assumptions or Evaluations

Sierra Club - The Company should include a scenario or sensitivity evaluating White Bluff and Independence retirements even earlier than the Company's projected cessation of coal date, in addition to the retirement of R.S. Nelson and Big Cajun II, Unit 3 in the mid- to late-2020s. (Page 12 of the "2019-01-23 Sierra Club Comments on Entergy DRAFT 2019 IRP.pdf" document)	While ELL maintains an interest in White Bluff, Independence and Big Cajun II, Unit 3, ELL is not the operator of these facilities. Given the nature of ELL's interest in these generating resources, ELL has not conducted additional scenarios/sensitivities using assumptions that differ from the guidance received by the resource owners. Furthermore, ELL believes that the Sierra Club would be better served by directing this portion of the comment to EAL and Cleco, rather than directing it to ELL. Regarding Nelson 6, as noted within the Action Plan of the IRP report, ELL intends to conduct analysis that contemplates the cessation of coal. This analysis should be completed in 2021.
Sierra Club - In its final IRP, Entergy must present a scenario specifically evaluating the costs and benefits of retiring Entergy's coal-fired units, with an emphasis on Independence, White Bluff, R.S. Nelson, and Big Cajun II, Unit 3. (Page 9 of the "2019-01-23 Sierra Club Comments on Entergy DRAFT 2019 IRP.pdf" document) Sierra Club - Entergy should present a detailed financial analysis of the costs of continuing to operate each its coal-fired units, including an analysis of each unit's total production costs compared to its operational revenues. (Page 9 of the "2019-01-23 Sierra Club Comments on Entergy	Throughout the planning period, all ELL-owned coal units (Nelson 6 and Big Cajun 2 Unit 3) are assumed to continue to operate. These units will continue to operate as long as it is determined to be in the customers' best interest, while considering the long-term planning objectives of cost, reliability and risk. ELL continues to monitor key market and policy drivers and their effects on ELL's generation portfolio, including those drivers that affect coal units. Entergy's point of view on future carbon emission pricing is included in the analysis. Additionally, as noted within the Action Plan of the IRP Report, ELL intends to conduct an analysis that contemplates the cessation of the use of coal at

DRAFT 2019 IRP.pdf" document)	Nelson 6. This analysis is expected to be complete by 2021. With respect to the White Bluff and Independence units, Entergy Arkansas, LLC, Entergy Mississippi, LLC, and Entergy Power, LLC entered into a settlement agreement with the Sierra Club and the National Parks Conservation Association. The settlement agreement memorialized certain obligations and the White Bluff cease to use coal date that already were reflected in the Arkansas Department of Environmental Equality's SIP. The settlement agreement remains pending before the federal district court, and the SIP is pending approval by the Environmental Protection Agency. ELL's IRP modeling is consistent with the timing agreed to by the Sierra Club and the National Parks Conservation Association in the settlement agreement.
SREA - Capacity-Only Planning is Deficient - Capacity-Only Planning Does Not Evaluate Retirements (Page 3 of the "2019-01-12 Southern Renewable Energy Draft IRP Comments.pdf" document)	AURORA has the capability to assess deactivations in the capacity expansion algorithm, but there are data requirements which make this impractical within the scope of an IRP analysis. Assessments would be required for each unit and each potential deactivation date for that unit to determine the capital and O&M spending each year needed to maintain the unit from the beginning of the study period through each potential deactivation date. Specific deactivation analyses are performed for units when large investments are required to

	operate the unit long-term. Additionally, generally it is a reasonable assumption to expect maintaining an existing operating plant will be lower cost to customers than building a new generating facility, unless circumstances around the cost to maintain the facility, market conditions, or policy changes dictate a more detailed evaluation.

Comments Regarding Energy Efficiency and DSM

AAE - Demand Side Management is Underutilized – Entergy should provide a qualitative discussion of how the DR capacity that will be provided under these new programs would deliver value to Entergy and reduce the need for supply-side alternatives. (Page 5 of the "2019-01-23 Alliance for Affordable Energy Comments – I-34694.pdf" document) AEMA - Entergy should provide a qualitative discussion of how the DR capacity that will be provided under these new programs would deliver value to Entergy and reduce the need for supply-side alternatives. (Page 4 of the "AEMA IRP Comments.pdf" document; see also Page 6 of the "AEMA IRP Comments.pdf" document)	See Portfolio Results Discussion within Section IV, Portfolio Design Analytics.
AEMA - Entergy's Draft IRP says nothing about when, or how, it will develop new interruptible tariffs, nor does it discuss the impact those tariffs would have on its forecasted capacity requirements. It therefore lacks necessary substance to comply with the Commission's IRP rules. (Page 3 of the "AEMA IRP Comments.pdf" document)	As stated in the Action Plan of the IRP Report, ELL intends to file a new interruptible rider in the third quarter of 2019. After the rider has been designed and implemented, ELL will better be able to report the expected impact on forecasted capacity requirements. The impact of the rider on ELL's planning requirements will be incorporated in ELL's

	next IRP cycle.
AAE - Demand Side Management is Underutilized - Entergy should therefore specify in the IRP, that new DR programs will be developed in collaboration with stakeholders, no later than 90 days after its Final IRP is approved by the Commission. (Page 5 of the "2019-01-23 Alliance for Affordable Energy Comments – I-34694.pdf" document) AEMA - Entergy should specify in its Action Plan that it will develop new DR programs, in collaboration with stakeholders, within 90 days of its Final IRP being approved by the Commission (this comment is repeated, though slightly differently, on pages 7 & 8). (Page 4 of the "AEMA IRP Comments.pdf" document)	Please see ELL's Action Plan discussion regarding DR programs. As noted there, the DR and EE landscapes at the LPSC are in a very active state of potential change. In conjunction with the ultimate Commission rules that will result from the current DR and EE rulemakings, ELL intends to conduct more detailed analysis of those DR and EE programs that proved to be economic in its modeled portfolio results in a way that complies with ELL's AMS Order as well as the Commission's ultimate rules to be determined in Docket No. R-35136 and R-31106. It is unclear at this time whether the new DR rules will replace or supplement the Commission's current DR rules with respect to stakeholder collaboration. Also as stated in the Action Plan of the IRP Report, ELL intends to file a new interruptible rider no later than the third quarter of 2019. Lastly, in accordance with the LPSC's Order approving ELL's permanent AMS deployment, ELL will conduct and complete a study investigating the implementation of demand response programs for its customers, including potential incentives, and file a report regarding its results, conclusions, and recommendations within 12 months of the completion of the deployment of AMS.
AAE - Demand Side Management is Underutilized - By modeling the existing futures and scenarios, without a detailed Energy Efficiency study, Energy Efficiency is not able to compete with traditional supply side resources. Once a more detailed report	A detailed Energy Efficiency study was provided along with ELL's Draft IRP report in October 2018 and published on ELL's IRP Website at that time. This study is provided along with ELL's IRP report as well.

on DSM is issued, the futures and scenarios should be remodeled to ensure we are planning for the lowest cost resource. (Page 5 of the "2019-01-23 Alliance for Affordable Energy Comments – I-34694.pdf" document)	
AAE - DSM is not modeled against supply side resources, in fact it doesn't appear to be included at all. This could be a result of Capacity Only Modeling or simply a lack of data on available DSM resources. Regardless, the proposed portfolios fail to take into account least cost resources. (Page 8 of the "2019-01-23 Alliance for Affordable Energy Comments – I-34694.pdf" document)	Please see the Company's response to comments in Appendix B: DSM programs (which include Energy Efficiency and Demand Response) are available for selection within the Capacity Expansion optimization algorithm, and they compete directly with supply-side alternatives. DR programs' load reductions are consistent with the hourly MW reduction provided by ICF, and are dependent on the program type. Additionally, "…the AURORA Capacity Expansion Model was used to identify economic type, amount, and timing of supply-side resources needed to meet reserve margin requirements. The result of this process is a portfolio of supply-side alternatives that produces the lowest total supply cost to meet the identified need within the constraints defined in each of the four futures . . ." The Aurora model evaluates both the capacity and energy effects of potential resource additions to identify the lowest total supply cost portfolio. Therefore, the evaluation chose all economic DSM programs and most economic supply-side resources based on their capacity and energy effects.

Comments Regarding the Evaluation Process

SREA - Capacity-Only Planning is Deficient - Aurora Software is Outdated (Page 4 of the "2019-01-12 Southern Renewable Energy Draft IRP Comments.pdf" document)	ELL adopted AURORA for long-term energy price forecasting and production costing in 2013 and has used AURORA for several resource certifications and IRPs that were accepted by the LPSC. ELL regularly reviews the software alternatives available to meet its long-term energy price forecasting and production costing needs and currently it has determined that AURORA best meets those needs.

Comments Regarding LPSC IRP Rules and Entergy Policy

Staff – The Company's Final IRP Report should include a discussion of existing fuel contracts. (Page 26 of the "2019-0222 Comments of the LPSC Staff on ELL's Draft IRP Report.pdf" document)	Please see the updated discussion contained in the Natural Gas Forecast section and Other Commodity Forecast section within Section III of the IRP Report.
Staff – The Company's Final IRP Report should contain a Five-Year Action Plan that complies with the Commission's IRP Rules. (Page 26 of the "2019-0222 Comments of the LPSC Staff on ELL's Draft IRP Report.pdf" document)	See the Action Plan of the IRP Report.
Staff – ELL's Final IRP Report should include estimates of the rate impacts of ELL's portfolios. (Page 26 of the "2019-0222 Comments of the LPSC Staff on ELL's Draft IRP Report.pdf" document) LEUG - Rate Impacts of Proposed Resources Has Not Been Provided - LEUG disagrees that Entergy's approach complies with the IRP Rule and requests that Entergy provide the required "rate impact"	See Estimated Rate Impacts section within Section IV, Portfolio Design Analytics.

information in the final IRP. (Page 9 of the "LEUG Comments on Entergy Louisiana LLC Draft Integrated Resource Plan Report I-34694.pdf" document)	
Staff – The Company's Final IRP Report should include a section discussing the development and selection of a final reference resource plan, as well as a discussion on of the specific methodological approach and decision-making process followed to select the final IRP reference resource plan. (Page 26 of the "2019-0222 Comments of the LPSC Staff on ELL's Draft IRP Report.pdf" document) LEUG - Reference Resource Plan Has Not Been Provided As A Basis For Future Requests For Proposals For New Generation Resources (Pages 11-12 of the "LEUG Comments on Entergy Louisiana LLC Draft Integrated Resource Plan Report I-34694.pdf" document)	ELL has selected a resource plan for the IRP. The discussion of the selection of a Reference Resource Plan and considerations is located at the end of Section IV of the IRP Report.
Staff – The Company's failure to address economic transmission planning in its Draft IRP Report does not address in any meaningful manner one of the stated overall objectives of the IRP Process... Staff recommends that ELL address economic transmission planning in its Final IRP Report as required by the IRP Rule. (Page 25 of the "2019-0222 Comments of the LPSC Staff on ELL's Draft IRP Report.pdf" document) LEUG - Transmission Solutions Have Not Been Considered (Page 12 of the "LEUG Comments on Entergy Louisiana LLC Draft Integrated Resource Plan Report I-34694.pdf" document)	See updated Transmission Planning discussion within Section I of the IRP Report.

SREA - Transmission Was Excluded (Pages 8-9 of the "2019-01-12 Southern Renewable Energy Draft IRP Comments.pdf" document)	
SREA - Capacity-Only Planning is Deficient - Entergy employs a "capacity-only" planning process, essentially attempting to resolve one problem: how to generate or deliver power during each annual peak. While this sort of planning is useful for reliability purposes, it is not a least-cost resource planning strategy. (Page 2 of the "2019-01-12 Southern Renewable Energy Draft IRP Comments.pdf" document) SREA - Capacity-Only Planning is Deficient - Capacity-Only Planning Ignores Low Cost Energy Resources (Pages 3-4 of the "2019-01-12 Southern Renewable Energy Draft IRP Comments.pdf" document) AAE - Capacity Modeling is Insufficient - By utilizing only capacity models, ELL's focus is on capacity, instead of cheap energy. (Page 3 of the "2019-01-23 Alliance for Affordable Energy Comments – I-34694.pdf" document)	The premise of these comments is not correct, the Aurora model used to perform the evaluations for the ELL IRP considers both the capacity and energy effects of existing resources and potential resource additions each hour of the simulation period. Please see page 48 of ELL IRP Report, which states ". . . the AURORA Capacity Expansion Model was used to identify . . . a portfolio of supply-side alternatives that produces the lowest total supply cost . . ." Also, see page 54 under Discussion of Results: "The Total Relevant Supply Cost ("TRSC") for each portfolio was calculated in each of the four futures described earlier. The total relevant supply cost was 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, CO_2 emission costs, startup costs, energy revenue, and uplift Revenue • 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 • Demand Side Management (DSM) Costs – Implementation costs for incremental DSM programs selected in each portfolio • Capacity Purchases/(Sales) - The capacity surplus (or deficit) in each portfolio multiplied by the assumed capacity price" The comparison of portfolios using the Total Relevant Supply Cost considers both the capacity

	effects in terms of its associated non-fuel fixed costs and the energy effects in terms of its associated variable supply costs. Lastly, as stated in the Action Plan provided herein, ELL intends to pursue low cost renewable generation through an RFP that is to be offered in 2020 and subsequent RFPs that will follow.

Comments Regarding Model Inputs and Data Assumptions

Staff – The chart on page 23 did not include some of the information described in Section 5 (b) of the IRP Rules, such as transactions of any type, one year or longer in duration, to any purchaser; ownership information; condition of the resource; or a discussion of any important changes to the resources that occurred since the last IRP Report was filed or expected to occur prior to when the next IRP Report will be filed. (Page 25 of the "2019-0222 Comments of the LPSC Staff on ELL's Draft IRP Report.pdf" document)	See additional and updated information within Section II of the IRP Report.
Staff – The Final IRP Report needs to confirm that the most recent long-term MTEP has been incorporated into its analysis for purposes of developing the IRP. (Page 25 of the "2019-0222 Comments of the LPSC Staff on ELL's Draft IRP Report.pdf" document)	See updated Transmission Planning discussion within Section I of the IRP Report.
Staff – The Final IRP Report must include a report of ELL's transmission network topology. (Pages 25-26 of the "2019-0222 Comments of the LPSC Staff on ELL's Draft IRP Report.pdf" document)	See updated Transmission Planning discussion within Section I of the IRP Report.

Staff – The Final IRP Report must contain sufficient detail to develop an understanding of how the Company formed data assumptions related to its demand and energy growth projections. (Page 26 of the "2019-0222 Comments of the LPSC Staff on ELL's Draft IRP Report.pdf" document)	See the updated Load Forecasting Methodology section within Section II of the IRP Report.
AAE – Capacity Modeling is Insufficient – Although there is a general understanding that the IRP Planning process should focus on in-region resources, however that should not be synonymous with ELL owned resources. ELL voiced concerns regarding the exposure risks associated with market costs without their own generation to rely on, however this risk needs to be balanced with the high cost of capital costs associated with new generation, especially considering the volatility of natural gas prices. (Page 3 of the "2019-01-23 Alliance for Affordable Energy Comments – I-34694.pdf" document) AAE - Ameren Missouri, serving the eastern side of the state, identified 300MW as a build threshold for relying on the MISO Market. If the capacity need is less than 300MW, exposure to market costs is less of a risk than the risk of exposure to capital costs associated with potentially stranded assets. (Page 3 of the "2019-01-23 Alliance for Affordable Energy Comments – I-34694.pdf" document)	An objective within ELL's IRP process is to plan to meet a specified Planning Reserve Margin Requirement. That said, as ELL transitions from planning to consideration of execution, it will take into account a variety of factors and may consider non-utility-owned resources as is evident by the recent renewals of the Carville and Occidental PPAs and by the new Toledo Bend PPA. Additionally, it will take into account its capacity position relative to the Planning Reserve Margin Requirement and determine the best course of action which may include relying on the MISO market for short-term capacity only.
AAE - Load Forecast is Inflated - The Alliance remains extremely skeptical of the Company's projected Load Forecast. In ELL's 2015 IRP, the Company's reference case projected a load of 11GW by 2019, a 15%	The selective focus on a limited number of elements of ELL's load forecast distorts the more comprehensive set of data that ELL has utilized for this analysis. To wit:

increase in load growth. In actuality, ELL's load decreased from 9.6GW to 8.9GW between 2015 and 2019. (Page 4 of the "2019-01-23 Alliance for Affordable Energy Comments – I-34694.pdf" document)	1) Data reported to EIA for the summer peak period of 2015 include the Algiers load as part of ELL's load. That load was reassigned to ENOL effective September 1, 2015. As such, any comparison back to 2015's peak load period prior to September 1 would need to be reduced by roughly 120MW to remove the Algiers load from ELL. 2) The comparison of peaks from 2015 to 2019 is a comparison of 2015 actual peaks – not weather adjusted -- to a weather-normalized estimated peak for 2019. According to NOAA, the summer period of June – August 2015 was the 12th warmest year for Louisiana in NOAA's history dating back to 1895 and was 108th in terms of precipitation. (https://www.ncdc.noaa.gov/sotc/national/201513) Said another way, 2015 was a very warm and dry year, which led to higher-than-normal electricity consumption. Comparing that year to a weather-normalized forecast year is inappropriate. A non-weather adjusted 2015 peak for ELL could be 100-500MW higher than a weather-normalized forecasted peak. 3) The load forecast used for the 2015 ELL IRP was developed in late 2013 and early 2014, when oil prices were still above $100/barrel. Related to the economic conditions at the time, that load forecast included assumptions for new, large industrial load that was expected to materialize in ELL's service area, including some load that may have been predicated on high oil prices. Since then, some of those large industrial projects have materialized and others have been delayed or cancelled. The 2019

	IRP load forecast is based on economic conditions that existed in 2018 and includes assumptions for new, large industrial customers that are now expected to come online. In addition, there are a number of potential, new, large industrial projects that ELL is pursuing and that are not included in the 2019 IRP forecast due to the uncertainty of the individual projects. 4) The peaks from the 2015 IRP are the sums of the non-coincident peaks for EGS and ELL, which were separate companies at the time. The forecasted peaks for ELL in the 2019 IRP are based on a combined EGS+ELL and will almost always be lower than the sum of two non-coincident peaks. Regarding AEE's comments about residential and commercial energy usage dropping from 2016 to 2017, while those numbers are accurate, those numbers also include the effects of weather that can skew year-over-year comparisons. The June-August period of 2017 was below average in terms of temperatures. NOAA ranks that period as the 35th coolest summer in their 122 years of recorded history. https://www.ncdc.noaa.gov/sotc/national/201713 Likewise, the summer peak season of 2016 (June – August) was the 16th warmest in NOAA's 122 years of history. https://www.ncdc.noaa.gov/sotc/national/201613 So while residential and commercial electricity consumption did decrease as AAE notes in section II, paragraph 3, the majority of that decrease was due to weather.

	ELL does agree that energy efficiency has led to a decreasing trend in residential and commercial electricity consumption on a per customer basis; however, overall residential and commercial consumption continues to grow as more customers come into ELL's service area.
AAE - The Alliance has concerns with the futures as proposed. Entergy's past load forecasts have consistently been inflated, indicating that the Low Case may be the most appropriate, yet was only modeled in one future (Future 3). Similarly, market trends indicate the cost of natural gas rising significantly over the next seven years, suggesting the Reference Case, or even the High Case may be more appropriate in regards to natural gas costs, yet those cases were each only modeled once, respectively. Furthermore, Future 2 appears simply illogical as it appears to predict the opposite of current trends. The Alliance disagrees with the futures as modeled as they do not appear to be probable, nor affordable. (Page 7 of the "2019-01-23 Alliance for Affordable Energy Comments – I-34694.pdf" document)	Please refer to section IV, Portfolio Design Analytics. The futures are intended to represent a range of possible energy market outcomes, and are not intended to opine on an ideal set of market fundamentals for ELL customers. The futures outlined resulted in a range of market prices, as seen in Figure 22, which supports the need to test the performance of portfolios given market uncertainties. It is reasonable to expect, given the current market and industry trends, that market energy prices are likely to be bounded by the range of market prices produced by the four futures.
Sierra Club - Entergy should include a cost projection for wind and solar resources that reflects current industry understanding and expectations. (Page 22 of the "2019-01-23 Sierra Club Comments on Entergy DRAFT 2019 IRP.pdf" document)	Cost projections included in the modeling and documented in the assumptions filing reflect current industry understanding and expectations. These have also been benchmarked against market data from RFPs and/or unsolicited offers.
Sierra Club - Entergy should evaluate and incorporate low cost energy purchases and ensure that its model prioritizes least-cost resources, even if no capacity is needed. (Page 22 of the "2019-01-23	Please refer to the "Market Modeling" subsection and Figure 22, which illustrates the annual average MISO-South market LMPs for each future. Within Capacity Expansion and Production Costing ELL has

Sierra Club Comments on Entergy DRAFT 2019 IRP.pdf" document) Sierra Club - EAI does not plan to allow market-based purchases of energy nor capacity to be selected as options in its modeling runs. ELL should allow market-based purchases in its modeling. (Page 22 of the "2019-01-23 Sierra Club Comments on Entergy DRAFT 2019 IRP.pdf" document)	the ability to purchase energy or sell energy at the market price to serve local demand at the lowest cost. ELL's analysis utilized assumptions specific to ELL's service area for incremental renewable generation. The timing and magnitude of any wind generation would be driven by market conditions at the time within MISO South as well as ELL's capacity and energy needs. For the 2019 IRP, ELL did not include out of region as an alternative, as it is not expected that the relatively higher performance of remote generation would be significant enough to overcome several hurdles related to congestion and transmission related service charges. For more information, refer to Appendix G of ELL's 2015 IRP.
SREA – Entergy's solar energy and wind assumptions (including installed costs as well as capacity factors) lead to LCOE's that are up to 50% higher than current market offerings and are not in any way "roughly consistent" with SREA's comments. (Page 6 of the "2019-01-12 Southern Renewable Energy Draft IRP Comments.pdf" document)	ELL is unable to directly compare the capital costs provided in the referenced Lazard document to the information used within this IRP due to the lack of details provided by Lazard (e.g. are the numbers quoted in \$/kW-AC or \$/kW-DC, what year is the data quoted in, etc). However, based on ELL's data sources and market knowledge, the assumptions used within the IRP analysis are reasonable. Given the fact that a significant amount of renewable generation was selected within each Future, the assumptions used drove the results that determined that renewables are economic. As ELL procures additional renewable generation and gains experience within the market, assumptions with renewable generation will be updated.

SREA - Multiple Renewable Energy Options Were Not Evaluated - SREA recommended that ELL evaluate multiple wind energy resources including in-state, in-region and out-of-region wind energy resources. SREA recommended ELL evaluate both fixed-tilt and single-axis tracking solar energy systems. (Pages 6-7 of the "2019-01-12 Southern Renewable Energy Draft IRP Comments.pdf" document) AAE - It is incomprehensible that SWEPCO identified 1,300 MW of wind resources in 2018 yet ELL is not considering wind until 2035. (Page 6 of the "2019-01-23 Alliance for Affordable Energy Comments – I-34694.pdf" document)	ELL's analysis utilized assumptions specific to ELL's service area for incremental renewable generation. The timing and magnitude of any wind generation would be driven by market conditions at the time within MISO south as well as ELL's capacity and energy needs. For the 2019 IRP, ELL did not include out-of-region as an alternative, as it is not expected that the relatively higher performance (as seen in MISO North or SPP) of remote generation would be significant enough to overcome several hurdles related to congestion and transmission related service charges. For more information, refer to Appendix G of ELL's 2015 IRP. Based on generic solar assumptions, the fixed cost savings associated with fix-tilt does not justify the expected lower capacity factor and associated capacity value compared to single-axis tracking. However, to the extent an offer is received from fix-tilt solar that is economically justified, then ELL would consider procuring such a resource.
SREA - Energy Storage Deficiencies - SREA recommended that ELL use multiple energy storage configurations, including various capacity/energy configurations, multiple revenue streams and as stand-alone projects as well as coupled with generation resources (such as renewable energy resources). (Pages 7-8 of the "2019-01-12 Southern Renewable Energy Draft IRP Comments.pdf" document)	In order to confine the analysis due to resource and timing constraints, ELL chose a reasonable assumption in evaluating energy storage through the capacity expansion model. The capacity/energy configuration is based on the four-hour energy requirement needed to receive capacity credit. As addressed in the Action Plan, ELL will evaluate opportunities to capture economic and reliability opportunities for Battery Storage resources.

Other Comments

LEUG - Entergy Resource Planning Should Utilize Industrial Customer Programs That Could Offset Some Of The Need To Construct Replacement Generation For Aging Fleet And Avoid Or Reduce Costs For All Ratepayers. LEUG has taken the initiative to identify to Entergy and the LPSC several demand-side resource alternatives that it believes could materially offset some of the need for Entergy to construct replacement generation for aging fleet, and thereby help avoid or significantly reduce costs for all ratepayers while also helping industrial customers maintain competitive rates in Louisiana. In particular, the alternatives that LEUG has identified are: (1) Industrial customer market access options including enhanced opportunities for Combined Heat and Power ("CHP") generation, and (2) Industrial customer demand response options for new interruptible load and real-time pricing. (Pages 3-4 of the "LEUG Comments on Entergy Louisiana LLC Draft Integrated Resource Plan Report I-34694.pdf" document) LEUG - Demand Response Analysis For Industrial Customers Is Deficient - LEUG believes that new tariffs should be implemented in the near term to allow for new Demand Response in Louisiana and urges that the LPSC initiate proceedings to investigate this as discussed above and in previous comments. (Pages 7-9 of the "LEUG Comments on Entergy Louisiana LLC Draft Integrated Resource Plan Report I-34694.pdf" document)	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. 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, refuse to continue building needed generation for which they 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 do not result in the cost shifting noted above. See the Action Plan of the IRP Report for additional information regarding demand response and a new interruptible rider for customers.

AAE - The Alliance remains concerned that the company appears to be setting the stage for a whole new gas fleet, as the older generating units are poised to retire early. (Page 3 of the "2019-01-23 Alliance for Affordable Energy Comments – I-34694.pdf" document) AAE - Entergy's plan to replace 6 out of 9GW due to early retirements is troubling. Legacy Gas units are falling short of their life expectancy as they are no longer economic, and to assume new gas generation will exceed its projected life span is quite frankly, foolish. (Page 7 of the "2019-01-23 Alliance for Affordable Energy Comments – I-34694.pdf" document) AAE - Entergy continues to 'stack the deck' in its load forecast and modeling assumptions in an apparent attempt justify a need for traditional supply side resources. (Page 3 of the "2019-01-23 Alliance for Affordable Energy Comments – I-34694.pdf" document) AAE - Despite utility trends away from natural gas resources, and market trends indicating rising gas costs, ELL continues to use this IRP process to justify a new gas fleet. (Page 7 of the "2019-01-23 Alliance for Affordable Energy Comments – I-34694.pdf" document)	As was previously stated in the IRP Report, "Throughout the IRP process, and in the normal course of business, ELL is seeking to identify, deploy, and integrate the right mix of technology, resources, and products and services for its customers". ELL anticipates load growth within its service territory and will plan accordingly to serve that load using a lowest reasonable cost approach. ELL, like AAE, recognizes the value of leveraging a diverse mix of energy resources including renewable and clean energy sources. We must not, however, force a diversity mix that would detriment reliability or affordability to ELL customers. ELL has no intention of "stack[ing] the deck" to preference any specific technology. Rather, it intends to develop an Integrated Resource Plan that serves the best interest of all ELL customers. Also, as is stated in the Company's response to comments in Appendix B, DSM programs (which include Energy Efficiency and Demand Response) are available for selection within the Capacity Expansion optimization algorithm, and they compete directly with supply-side alternatives.

AAE - Although the Alliance recognizes this draft IRP as a step in the right direction regarding clean energy sources, it is still business as usual with a heavy focus on gas-fired supply side additions. Even as costs for wind, solar, and batteries decline, DSM resources will almost always be the lowest cost resource, and without modeling them appropriately, Entergy puts rate-payers on the hook for potentially needless expenses. (Page 8 of the "2019-01-23 Alliance for Affordable Energy Comments – I-34694.pdf" document)	
Sierra Club -...while we appreciate Entergy's attempt to respond to the various stakeholders' comments and critiques of the Company's initial data assumptions, Entergy continues to rely on a series of flawed assumptions that consistently bias the Company's analysis toward its preferred result: a business-as-usual 20-year plan that continues to rely on the construction and operation of increasingly uneconomic or unnecessary fossil-fuel energy generation resources without taking a hard look at the least-cost portfolio for customers. (Page 2 of the "2019-01-23 Sierra Club Comments on Entergy DRAFT 2019 IRP.pdf" document)	Please see Figure 8 for a summary of ELL's current and forecasted capacity needs. Please see the section "Portfolio Design" on page 48 for a description of how capacity expansion was utilized to develop the least-cost portfolios for each respective future was developed.
Sierra Club - Entergy stands at a crossroads. One path is business as usual, where Entergy continues to operate one of the largest-polluting fleets in the southeast United States, even though the Company has excess generation capacity… (Page 2 of the "2019-01-23 Sierra Club Comments on Entergy DRAFT 2019 IRP.pdf" document)	Entergy operates one of the cleanest large-scale generation fleets in the country, according to the 2018 Benchmarking Air Emissions Report (which is based on 2016 data). The report provides information on the top 100 power producers, of which Entergy ranks sixth-largest, while maintaining the 26th-lowest CO2 emission rate. Entergy also ranks fifth in the production of virtually zero-

	emitting energy. For more information, please see Entergy's 2018 Integrated Report, In particular page 52. Further, please refer to the Company's Climate Report. Entergy has operated under a voluntary, tonnage-based carbon commitment for nearly two decades. However, our point-of-view on decarbonization has evolved and broadened to focus on the entire economy, not just the electric utility sector. We believe that switching to a rate-based goal acknowledges the role of an electric utility in an economy that is decarbonizing. As described in the climate report, various two degree scenarios, and the U.S. Mid-Century Strategy for Deep Decarbonization, a low and constantly improving emission rate for electrical power enables other sectors to decarbonize. We believe that as an economy, we need to pursue parallel paths, of electrifying other sectors (such as transportation, industrial, commercial, and agricultural) and continuing to transform our electrical supply to a lower-carbon generation portfolio.
LEUG - LEUG submits and requests that the final IRP should include the following data points for the past ten years so that the IRP can be viewed in relative context: 1) MWh of energy purchased from the market each year, over and above energy produced from owned and contracted resources; 2) MW of capacity satisfied from market purchases each year (unforced capacity);	This request goes beyond the scope of the IRP. ELL has provided information required by the Commission's IRP General Order.

3) MW of baseload generation capacity relative to total owned generation capacity each year (unforced capacity); 4) MW of capacity imports and exports each year (unforced capacity); and 5) MWh of energy imports and exports each year. (Page 15 of the "LEUG Comments on Entergy Louisiana LLC Draft Integrated Resource Plan Report I-34694.pdf" document)	
SREA - Capacity-Only Planning is Deficient - Entergy Planning Deficiencies - Entergy plans to ignore its IRPs. (Pages 4-5 of the "2019-01-12 Southern Renewable Energy Draft IRP Comments.pdf" document)	As has been previously stated, the Capacity Expansion optimization component of ELL's IRP seeks to add resources (either supply-side or demand-side) only when there is a projected capacity deficit. Given that a deficit is not projected within the next five years, no new resources have been identified within that period. That said, ELL recognizes the variety of benefits that renewable resources can provide its customers and, as seen in ELL's Action Plan, will seek to issue renewable RFPs within the next five years.

Appendix G – 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.

[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.

[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.

[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]

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.

[redacted]

[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.

[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.

[redacted]

[redacted]

Ninemile 6

Ninemile 6 is a 2X1 combined cycle gas turbine natural gas-fired 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 Practice.

[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.

[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.

[redacted]

[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.

[redacted]

River Bend

The River Bend nuclear facility, located in St. Francisville, LA., sits on 3,300 acres in West Feliciana Parish, approximately 30 miles from Baton Rouge. The facility has been producing safe, reliable and carbon-free power since 1986. River Bend recently received from the U.S. Nuclear Regulatory Commission a federal 20-year license renewal, enabling the plant to continue operating through 2045, two additional decades past the original licensing dates. River Bend has one boiling-water reactor with about 850 employees provides nearly 1,000 megawatts of capacity towards meeting ELL's planning reserve margin requirement, approximately 10 percent of ELL's needs. RB began its scheduled refueling and maintenance outage in April 2019.

[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.

[redacted]

Sterlington 7A

Sterlington 7A is a simple-cycle gas-fired generating unit located near Sterlington, LA. The unit entered commercial operation in 1973. 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 in fair condition, having been maintained over its long life in accordance with Good Utility Practice. At 46 years of age, it is reasonable to expect the unit would encounter growing maintenance requirements.

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.

[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.

[redacted]

Waterford 1

Waterford 1 is a steam turbine generating unit located near Killona, LA. The unit entered commercial operation in 1975. The unit is in fair condition, having been maintained over its long life in accordance with Good Utility Practice. At 44 years of age, it is reasonable to expect the unit would encounter growing maintenance requirements.

[redacted]

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 44 years of age, it is reasonable to expect the unit would encounter growing maintenance requirements.

[redacted]

Waterford 3

Entergy's Waterford 3 facility is a steam electric plant located on 3,000 acres in Killona, La., in St. Charles Parish, approximately 30 miles from New Orleans. The plant has been producing safe, reliable and carbon-free electricity since 1985. Waterford 3 recently received from the U.S. Nuclear Regulatory Commission a federal 20-year license renewal, enabling the plant to continue operating through 2044, two decades past the original licensing dates. The unit has a Combustion Engineering two-loop pressurized water reactor, about 780 employees, and provides more than 1,200 megawatts of capacity towards meeting ELL's planning reserve margin requirement, approximately 10 percent of ELL's needs. The facility recently had its scheduled refueling and maintenance outage where the team of nuclear professionals upgraded equipment, and made other investments including a new condenser.

[redacted]

Waterford 3, along with River Bend, are the largest sources of carbon-free power in Louisiana.

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.

[redacted]