Entergy Louisiana, LLC

An Integrated Resource Plan (2009 – 2028)

Scope and Structure

This document describes Entergy Louisiana, LLC's ("ELL") long-term integrated resource plan ("IRP")[1] for the period 2009 – 2028. The IRP represents a component of the Entergy System's Strategic Resource Plan ("SRP") for the same period. The SRP for the Entergy System as a whole is described in a separate document; the underlying modeling constructs and assumptions are presented in the documentation associated with the SRP.

For well over the past half century, ELL has planned and operated as part of a larger integrated system – the Entergy System.[2] Entergy Arkansas Inc. ("EAI") and Entergy Mississippi Inc. ("EMI") have provided notice that as of December 2013 and November 2015, respectively, they will withdraw from the Entergy System Agreement. That means that, for the time being, ELL will be planned and operated under the terms of a 5-company System Agreement as of 2014 (excluding EAI), and a 4-company System Agreement as of 2016 (excluding EMI). The future is uncertain. The future Entergy System may or may not include EAI and EMI, depending on whether a successor System Agreement is realized. Excluding EAI and EMI from the larger integrated system will result in higher resource requirements for the remaining four Operating Companies, including ELL. The IRP assumes, as a base planning assumption, that EAI and EMI will terminate participation in the System Agreement by December 2013 and November 2015, respectively. Accordingly, the IRP results in a plan that positions ELL for reliable and

[1] Throughout this document, unless otherwise noted, the term "IRP" refers to the IRP for ELL which is a component of the Strategic Resource Plan for the Entergy System and the Entergy Operating Companies.

[2] The Entergy Operating Companies are planned and operated as a single, integrated electric system, pursuant to the Entergy System Agreement. The six Entergy Operating Companies include Entergy Arkansas, Inc. ("EAI"), Entergy Gulf States Louisiana, LLC ("EGSL"), Entergy Louisiana, LLC ("ELL"), Entergy Mississippi, Inc. ("EMI"), Entergy New Orleans, Inc. ("ENO"), and Entergy Texas, Inc. ("ETI"). The electric generation and bulk transmission facilities of these Operating Companies are planned and operated on an integrated, coordinated basis as a single electric system pursuant to the terms and conditions of the Entergy System Agreement and are referred to collectively as the "Entergy System" or the "System."

economic operations as part of the 5-company and eventually 4-company Entergy System.

With the exit of EAI and EMI from the Entergy System Agreement, the 4-company System will face new resource planning challenges. In addition to the challenges posed by potential national and state initiatives to address greenhouse gas emissions (including renewable portfolio standards ("RPS"), demand-side management ("DSM") and smart grid evolution, and new cap and trade programs limiting CO_2 emissions), unprecedented volatility in natural gas prices, and the aging generating fleet, the 4-company System also must address replacement capacity once EAI and EMI withdraw from the Entergy System Agreement.

The IRP assumes, as a base planning assumption, that EAI and EMI will exit the Entergy System Agreement and the four remaining Operating Companies will be planned and operated as an integrated 4-company System. The IRP includes capacity expansion scenarios that provide guidance regarding future resource needs and additions. It is not possible at this time to predict the outcome of uncertainties surrounding load growth, new nuclear resources, solid fuel resources, renewable portfolio standards, and the aging generating fleet. However, this plan results in adequate resources to meet the 4-company System needs under the current assumptions.

With that background, this IRP presents ELL's perspective on its:

- resource requirements over the next 20 years;
- current resource portfolio;
- Reference Planning Scenario for meeting long-term needs with a combination of Demand-Side Management and traditional and renewable generating units; and
- plans for addressing uncertainties including several alternative planning scenarios.

Regulatory Context for ELL's Integrated Resource Planning

The Louisiana Public Service Commission ("LPSC") has opened a docket investigating the potential for implementing an IRP process. However, the docket is currently inactive pending resolution of a separate re-evaluation of a new RPS for Louisiana.

ELL's Future Resource Requirements

The foundation for the IRP is an estimate of the future energy and capacity needs of ELL's customers. This estimate requires estimates of the amount of capacity and energy that ELL's customers will use, and an estimate of the amount of "reserves" that should be included in the IRP to provide reliable service.

Load Forecast

The load forecast is developed using statistical and economic modeling techniques that are described in the SRP.[3] The application of those modeling techniques to ELL results in the reference, high load growth, and low load growth cases shown in the following Figure ELL-1.

Figure ELL-1: Entergy Louisiana, LLC. Firm Non-coincident Peak Load (Load Sensitivity Cases 2009-2028) (MW)

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Reference	5,109	5,334	5,539	5,494	5,559	5,641	5,679	5,687	5,694	5,708
High Growth	5,160	5,387	5,595	5,651	5,707	5,764	5,822	5,880	5,939	5,998
Low Growth	5,099	5,109	5,119	5,129	5,139	5,150	5,160	5,170	5,181	5,191

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Reference	5,717	5,565	5,732	5,735	5,746	5,586	5,599	5,605	5,609	5,461
High Growth	6,058	6,119	6,180	6,242	6,304	6,367	6,431	6,495	6,560	6,626
Low Growth	5,201	5,212	5,222	5,233	5,243	5,254	5,264	5,275	5,285	5,296

Reserve Margins

The IRP describes ELL's requirements as part of the larger integrated Entergy System. The 4-company Operating System must have adequate resources to reliably meet customer needs. The plan does not assume that ELL will maintain sufficient generating capacity to reliably meet its own requirements as a standalone Operating Company, but as part of a larger integrated system.

[3] Chapter 3 of the SRP provides additional details regarding the load forecasting process.

This ability is measured in terms of peak load plus an adequate provision for planning reserves. Peak load (shown in Figure ELL-1) refers to the level of highest customer demand during the year. If resources are sufficient to meet peak demand, resources should be sufficient to meet demand throughout the remainder of the year.

Both customer demand and the availability of resources within the portfolio to meet demand are matters of uncertainty. Unknown events such as an unusually hot summer or an unplanned outage of a generating unit can create situations in which the System's ability to meet the experienced peak load is challenged. To protect against the consequences of such unknown events the IRP – consistent with good utility practice – provides for an additional amount of resources above projected peak demand, referred to as the planning reserve margin. The planning reserve margin may be expressed as a MW amount or as a percentage of the peak load.

A number of factors influence the level of planning reserves that are required to provide reliability. One of the most important variables is the size of the generating units within the portfolio in relation to peak load. Relying on large generating stations involves greater risk because an outage at a single unit has more significant consequences. Therefore, the larger the generating units within the portfolio in relation to peak load the greater the planning reserve margin that is required.

This relationship has consequences for the level of planning reserves that will be required in light of EAI and EMI exiting the System Agreement. In recent years the System has planned for about a 17% reserve margin. This target was developed using a technique known as a Loss of Load Probability ("LOLP") assessment. The LOLP technique is widely used throughout the industry for determining reserve margins. LOLP assesses the probability that resources will be adequate to meet load in light of uncertainties regarding customer load variability and of unit outages. Results of the LOLP assessment indicated that a 17% reserve margin provided sufficient capacity to serve load for all but one day in ten years, also a traditional measure of reliability used within the industry.

However, the loss of EAI and EMI would result in a smaller electric system. At the same time, the size of the four remaining Operating Companies' generating units would not change. Because the size of the generating units as compared to the peak load increases, the LOLP assessment indicates a need for additional planning reserves for the 4-company System to achieve the same level of reliability. The results of the LOLP calculations indicate much higher reserve requirements for a 4-company System.

In determining the target planning reserve margins, the IRP considered the following:

- The actual operating configuration of the 5-company System and 4-company System, after EAI and EMI exit the System Agreement, is uncertain.
- A number of actions may be available to mitigate risk and lower required reserve margins after the exit of EAI and EMI including possible reserve sharing arrangements.

In recognition of these factors, the IRP sought to determine a level of target planning reserves that balanced the objective of providing adequate resources to maintain reliability while avoiding commitment to long-term resources that may ultimately prove to be unnecessary. Accordingly, the IRP established the planning reserve margins for the 5-company System and the 4-company System based on the loss of the single largest generating unit. This analysis yields a planning reserve margin of 18% for the 5-company System (2014 – 2015) and 20% for the 4-company System (2016 and beyond).

For operating companies planned and dispatched within the integrated system, a 10% reserve margin is used for each company. The 10% planning reserve margin ensures that each Operating Company provides a proportionate share of the resources that are expected to be used for overall System reliability and coordinated dispatch. The 10% reserve margin represents a guideline used solely for the purposes of Operating Company Portfolio Planning within the context of operation within the System.

Other Uncertainties

In addition to load, a number of uncertainties will affect long-term resource requirements and the alternatives available to meet those needs.

Carbon

The issue of potential climate change associated with atmospheric greenhouse gases has received growing attention among the scientific community, in the media, and with governmental policy makers. A number of bills proposing to regulate carbon emissions have been proposed in the United States Congress. It is not possible to predict whether CO_2 legislation will eventually be enacted, and if so, when it would become effective or what form it would take. However, any form of CO_2 legislation would likely result in higher cost of electric generation because emissions from power plants are a major source of carbon, primarily in the form of CO_2. Moreover, because alternative technologies emit different levels of CO_2 per MWh of generation, CO_2 legislation would likely have an effect on the relative economics of supply alternatives. Consequently, assumptions regarding potential CO_2 cost represent a key input in the 2009 SRP Update.

In order to consider the effects of carbon uncertainty on resource choice and portfolio design, the 2009 SRP Update relies on a range of projected CO_2 cost outcomes. The Reference Case assumes a 2013 nominal CO_2 emission price target of $15 per ton with straight line interpolation to a 2020 nominal CO_2 emission price target of $50 per ton. By 2028, under the Reference Case, the nominal CO_2 emission price target may be $58.58 per ton.

Renewable Portfolio Standards

There is growing discussion regarding the potential implementation of a Renewable Portfolio Standard ("RPS") (also sometimes known as a "Renewable Energy Standard") either at the federal or state level. Several bills have been proposed in the U.S. Congress that would establish various targets for renewable generation and differing levels of compliance cost. If enacted, a federal RPS likely will result in higher cost for customers. Renewable generation alternatives generally are more costly than conventional generation alternatives.

Fuel

Long-term natural gas price levels remain uncertain. A wide range of factors may affect natural gas price levels and volatility in the future. Natural gas prices are expected to vary between $6.04 in 2009 (nominal $/MMBtu) to $10.06 in 2020 (nominal $/MMBtu), based on the Reference Case.

Current Resource Portfolio

The ultimate objective of an IRP is to inform the decisions that must be made in the course of the development of a future resource portfolio. The need to acquire future resources is not determined just by an estimate of future resource requirements. After there is an estimate of the level of resources that will be needed in the future, the next step in the development of an IRP is an assessment of the current portfolio of resources. This assessment should consider the amount, type, and age of the existing fleet. Then, current resources can be compared to future requirements to develop expectations regarding the need for additional resource acquisitions in the future.

Figure ELL-2 lists the resources in ELL's current resource portfolio. Figures ELL-3 and ELL-4 characterize the portfolio mix based on the attributes of fuel and resource age. These figures illustrate a few key points:

- ELL's existing portfolio of generating units has a total combined capability of 6,370 MW including 20 units at 12 sites.

- The resource mix includes a significant amount element of nuclear capacity (1,600 MW) representing 25% on a capacity basis.

- The portfolio includes only 259 MW of modern gas-fired combined cycle combustion turbine ("CCGT") capacity, including ELL's allocation of the Perryville facility (134 MW) and a long-term PPA with Occidental Chemical associated with the output of Occidental's Taft facility (125 MW).[4]

[4] The Taft-Occidental contract is divided into three components: 295 MW is considered baseload capacity, 125 MW is considered CCGT capacity, and 60 MW is considered peaking

Figure ELL-2: Entergy Louisiana, LLC. Current Owned & Long Term Resources

Unit	Supply Role	Fuel	Age	2008 Summer Capacity (MW)
Buras 8	Peaking	Gas	38	12
Grand Gulf	Baseload	Nuclear	24	159
Little Gypsy 1	Seasonal Load Following	Gas	48	238
Little Gypsy 2	Seasonal Load Following	Gas	43	415
Little Gypsy 3	Seasonal Load Following	Gas	40	525
ISES (EPI)	Baseload	Coal	25	51
Ninemile 3	Seasonal Load Following	Gas	54	125
Ninemile 4	Seasonal Load Following	Gas	38	710
Ninemile 5	Seasonal Load Following	Gas	36	711
Oxy Taft	Core Load Following	Gas	7	480
Perryville 1	Core Load Following	Gas	7	134
Perryville 2	Peaking	Gas	8	39
River Bend 30	Baseload	Nuclear	23	194
Sterlington 6	Peaking	Gas	51	212
Sterlington 7	Peaking	Gas	35	180
Toledo Bend	Peaking	Hydro	n/a	23
Waterford 1	Seasonal Load Following	Gas	35	411
Waterford 2	Seasonal Load Following	Gas	34	405
Waterford 3	Baseload	Nuclear	24	1,169
Vidalia	Peaking	Hydro	n/a	66
WBL[5]	Baseload	Nuclear & Coal		110
TOTAL				6,370

[5] The ELL Wholesale Base Load (WBL) transaction, totaling 110 MW, purchases a portion of ANO 1, ANO 2, Grand Gulf 1, Independence 1, White Bluff 1 and White Bluff 2 from EAI on a life-of-unit basis.

Figure ELL-3: Entergy Louisiana, LLC. Portfolio Fuel Mix (2009)

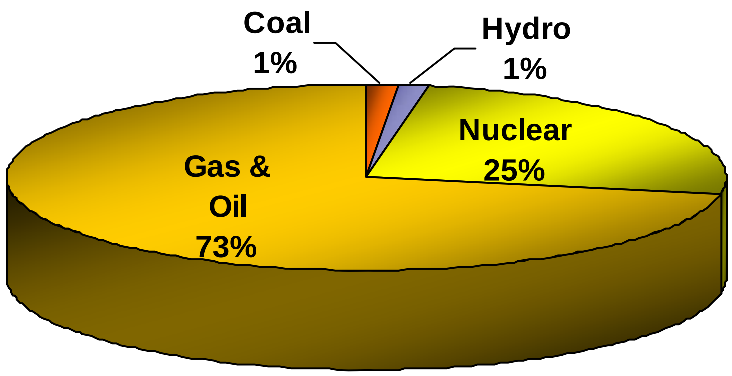
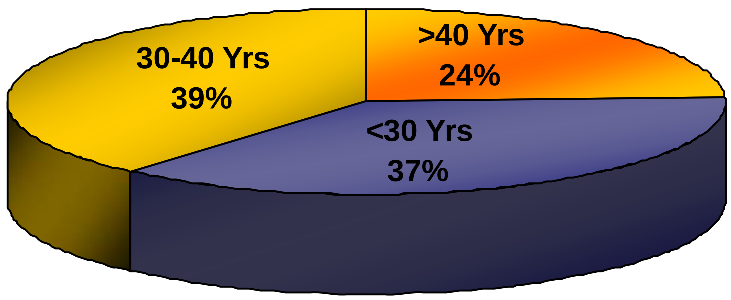


Figure ELL-4: Entergy Louisiana, LLC. Portfolio Age (2009)



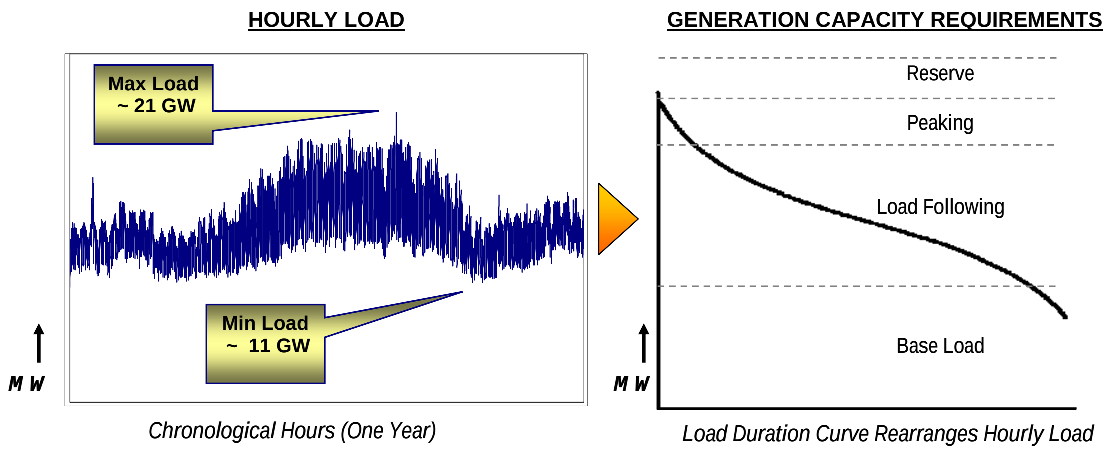
Load Shape Analysis

In the long run, the principle of matching resources to customer load shape results in a portfolio of resources that meet customer needs at the lowest reasonable cost. A cost-effective portfolio recognizes that the time-varying nature of customer demand calls for a mix of generating resources to meet differing operating roles. Determining portfolio needs therefore requires consideration of customer load shape requirements. Load shape determines functional requirements.

Figure ELL-5 illustrates a common construct for assessing and explaining the mix of resources that will be needed within a portfolio. This construct, known as a load duration curve, provides a simple way of assessing and describing the overall type of resources needed to meet customer needs. In the chart on the right, load levels are shown on the vertical axis. The curve represents load over the period of a year sorted from the highest load level to the lowest.

Points along the curve indicate the MW levels of capacity needed to meet generalized supply roles.

Figure ELL-5: Illustrative Load Duration Curve Analysis



The results of the load duration curve analysis are used throughout this report to describe the resource needs for the Entergy Operating Companies and for assessing how well resources are matched to load shape requirements. However, while a valuable tool, a load duration curve analysis also has limitations. The results of load shape analysis are intended as general guidelines for portfolio planning purposes without consideration of practical operational requirements. As described later in this chapter, the System must have sufficient flexible capacity to meet and respond to changing load conditions in order to maintain a stable electric grid. The load duration curve analysis does not explain this requirement. Moreover, in assessing existing resources relative to load shape requirements, each unit has been assigned within a specific supply role. In actuality, the distinction between supply roles is neither sharp nor static.

Supply Roles

This SRP update considered a number of generalized supply roles in assessing long-term resource needs. The supply role requirements, which are intended as general guidelines for portfolio planning purposes without consideration of practical operational requirements, are described as follows:

Baseload

The aggregate customer demand for electricity that persists most hours of the year is the baseload requirement. As a guideline, baseload requirements are determined by the level of firm load that is expected to be exceeded during 85% of the hours in a year.

Core Load Following

The aggregate customer demand for electricity that is greater than baseload requirement, but less than seasonal load following requirement. As a guideline, core load following requirements are determined by the level of firm load expected to be exceeded during 30% of the hours in a year.

Seasonal Load Following

The aggregate customer demand for electricity that is greater than core load following requirement, but less than peaking requirement. As a guideline, seasonal dispatch requirements are determined to be the level of firm load that is expected to be exceeded during 15% of the hours in a year.

Peaking

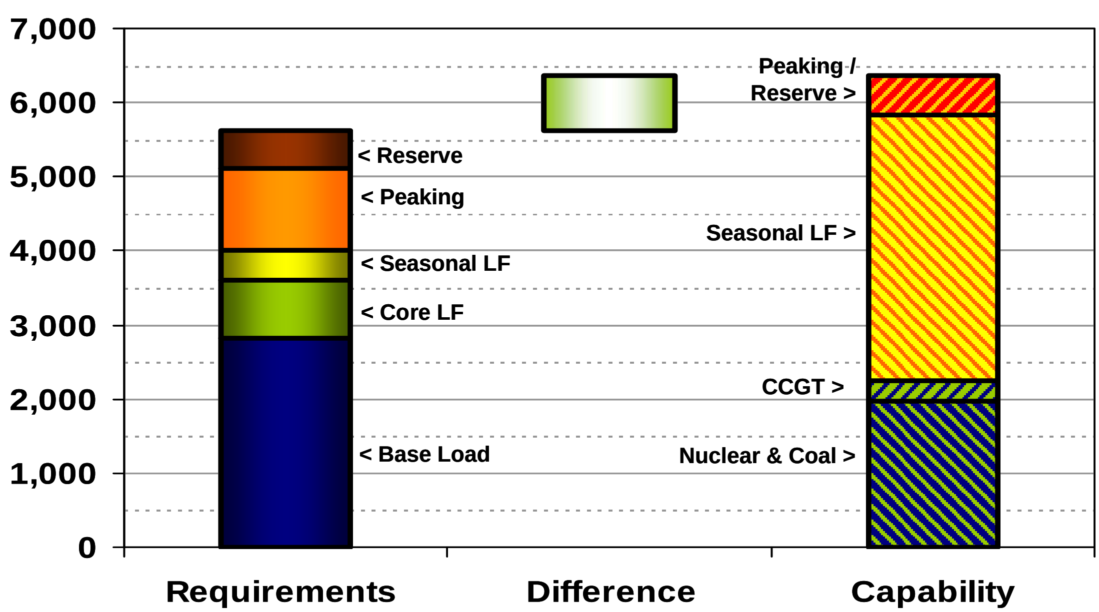
The aggregate customer demand for electricity that is greater than seasonal load following requirement, but less than reserve requirement.

Reserve

The target reserve margin, as described earlier, to maintain reliability by protecting against the consequence of potential unknown events.

Consistent with the identified supply role requirements, resource alternatives appropriate for serving each supply role can be identified. Each resource alternative has its own unique cost and performance characteristics that allow it to be functionally and economically suited to serving certain supply roles.

Figure ELL-6: Entergy Louisiana, LLC. 2009 Summary of Capacity Position by Supply Role (MW)



The results of the analysis presented in Figure ELL-6 comparing ELL's resource needs with its current portfolio of long-term resources indicate the following key points:

- ELL's current portfolio of nuclear and coal capacity is "short" of its base load requirements by 838 MW.
- ELL's current portfolio includes only 259 MW of modern gas-fired combined cycle combustion turbine ("CCGT") capacity, Perryville (134 MW) and Oxy-Taft (125 MW)[6]. Modern gas-fired CCGT resources are the technology of choice to meet incremental load following needs.[7] Consequently, incremental long-term resource additions can be expected to be weighted toward gas-fired CCGT resources.
- ELL's current portfolio is heavily weighted toward seasonal load following resources. The amount of gas fired capacity in the portfolio exceeds current seasonal load following needs.
- ELL's current portfolio of long-term resources currently meets planning reserve margin, and, in fact is "long" by about 750 MW, based on a 10% reserve margin.[8] This surplus, however, will decrease due to load growth and potential unit deactivations.

Challenges

ELL's resource portfolio faces a number of challenges.

Potential Unit Deactivations

ELL's current portfolio of long-term resources may potentially have 1,040 MW of resources deactivate over the planning horizon. Additional capacity must be added to replace the attrition of existing capacity.

Age of Existing Resources

The existing portfolio of long-term resources includes a number of gas-fired resources that are in excess of 35 years of age. In and of itself, the age of a generating unit is not the determinant as to whether any specific unit should be deactivated or retired. The ability of a generating unit to continue to

[6] The Taft-Occidental contract is divided into three components: 295 MW is considered baseload capacity, 125 MW is considered CCGT capacity, and 60 MW is considered peaking

[7] This is explained in detail in Chapter 10 (Generation Technologies) of the SRP.

[8] The 10% reserve margin represents a guideline used solely for the purposes of Operating Company Portfolio Planning within the context of operation within the System. This guideline does not represent the reserve margin requirements for the System and standalone Operating Companies.

provide economic and reliable service is a function of capital expenditures, service role, and general condition. However, experience indicates that at some point it is likely that it will be more economic to replace existing capacity rather than to continue to incur capital and operating and maintenance expenses.

Baseload and Core Load-following Needs

ELL's portfolio lacks sufficient base load and modern gas-fired CCGT capacity. System resources must support ELL's base load and core load following requirements.

Reference Planning Scenario

There are a myriad of uncertainties affecting future resource needs and alternatives available to meet those needs. However, a Reference Planning Scenario has been developed for ELL which charts a course through a reasonable set of assumptions, and results in a plan that satisfies the planning objectives while providing the flexibility to respond to changing conditions. The Reference Planning Scenario is a reference point that can be used to evaluate a variety of future outcomes, but the outcome of a wide number of uncertainties will affect customer needs and the best portfolio choices to meet those needs over the next two decades.

This section describes the Reference Planning Scenario, by discussing:

- Portfolio assumptions;
- Recommendations regarding strategic direction; and
- Plans for addressing uncertainties (including several alternative planning scenarios)

The Reference Planning Scenario describes a portfolio of resources to meet ELL customer needs for the next 20 years. The Reference Planning Scenario:

- Balances the supply objectives of reliability, cost minimization, and risk mitigation;
- Accomplishes these planning objectives while considering utilization of natural resources and effects on the environment;
- Outlines a disciplined approach to resource additions while allowing the flexibility to respond to changing circumstances;
- Meets the bulk of reliability needs through long-term resources (owned or power purchase contracts);

- Includes the addition of gas-fired CCGT resources to meet load-following needs and overall reliability requirements;

- Includes the addition of reasonable levels of renewable generation and DSM to address fuel diversity and to meet overall capacity needs.

Reference Planning Scenario Assumptions

The Reference Planning Scenario assumes that incremental resource needs will be met primarily by gas-fired CCGT resources coupled with economically attractive levels of renewable generation and DSM consistent with regulatory mandates and appropriate cost recovery mechanisms. Specific portfolio assumptions include the following:

- 1,000 MW of existing gas-fired steam capacity is deactivated.

- 800 MW of gas-fired CCGT resources are added.

- 500 MW of renewable generation resources are added between 2014 and 2028, representing a level of economically attractive renewable generation that is realistically achievable given current cost estimates. Entergy Services, Inc. conducted a Request for Information ("RFI") relating to renewable generation and, depending on federal and/or state RPS activity, may conduct a Request for Proposals for renewable generation within the next year. The results of those initiatives will inform future planning efforts and will result in appropriate adjustments to the levels of renewable generation included in future SRP Updates.

- The continued operation of all existing coal-fired capacity throughout the planning horizon.

- The continued operation of all existing nuclear facilities throughout the planning horizon.

- The addition of 22 MW (160 MW Utility total) of nuclear capacity through an uprate at the Grand Gulf Nuclear Station in 2012 and 25 MW (125 MW Utility total) of nuclear capacity through an uprate at the River Bend Station in 2015. However, there have been no final decisions to implement the uprates. If the projects prove to be uneconomic or technically unfeasible, this capacity would be replaced with additional CCGT resources.

- No new solid fuel or nuclear facilities additions (other than the uprates previously discussed) over the following 20 years. Potential new nuclear capacity is addressed among the alternative planning scenarios.

Strategic Recommendations

The Reference Planning Scenario incorporates the following strategic recommendations:

- Focus on gas-fired CCGT capacity as the basic building block of the portfolio.
- Pursue reasonable levels of economically attractive renewable generation. The levels and type of renewable generation actually deployed will depend on evolving mandates and an on-going assessment of cost and availability, including market tests with suppliers. The Reference Planning Scenario indicates that:
  - Near-term renewable resource additions are anticipated to be primarily biomass.
  - 50 MW of renewable capacity (700 MW for all six of the Operating Companies) may be added to ELL's portfolio over the first 10 years.
- Continue to monitor the costs and benefits of new nuclear and solid fuel and propose specific plans to implement these options in the future if and when analyses results warrant. The Reference Planning Scenario does not reflect an expectation that any new nuclear or solid fuel resources will enter service over the 20 year planning horizon. However, it would be appropriate to maintain readiness of new nuclear through spending levels consistent with results of on-going assessment.
- Continue to develop long-term integrated planning efforts with Entergy Transmission to identify portfolio solutions that best balance planning objectives. Results of integrated supply and transmission planning efforts that are now allowed subsequent to FERC Order 717 may result in adjustments to the timing and location of resource needs.
- Pursue cost-effective DSM, consistent with the following discussion.

Demand Side Management Assumptions

The Reference Planning Scenario assumes that, over the SRP planning horizon, ELL-sponsored DSM programs reduce peak load by 264 MW and reduce cumulative energy consumption by 740 GWh by 2028 at an eventual cost of $170 million (nominal $, cumulative). These results are consistent with a detailed potential study recently prepared by ICF International, a leading consulting firm in the DSM community.[9] The ICF International study found a potential of about 140 MW over first 10 years for ELL, adjusted for reasonable implementation and approval timeline.

Figure ELL-7: Entergy Louisiana, LLC. DSM Potential Assumption – Cumulative Non-Coincident Peak Demand Reduction (MW) and Energy Saved (GWh)

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Demand Reduction	0	0	9	21	35	41	59	82	109	140
Energy Saved	0	0	33	76	132	183	246	320	403	498

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Demand Reduction	175	214	238	264	264	264	264	264	264	264
Energy Saved	603	719	727	738	738	740	738	738	738	740

Barriers to DSM Implementation

Traditional rate regulation presents several barriers or disincentives to electric utility investment in DSM resources. These include regulatory lag associated with recovering the incremental investment and expenses of programs, the lack of an opportunity to earn a comparable return on DSM programs as with other utility investments, and the loss of revenues that frequently accompanies DSM programs that reduce a utility's contribution to its fixed costs. A regulatory framework that addresses these three elements will ultimately benefit all stakeholders and encourage utility support for the continued development and implementation of DSM programs and begin to position investments in DSM and supply side resources on an equivalent basis for the Company.

Regulatory Framework for Cost Recovery

As ELL pursues cost-effective DSM as a means for meeting a portion of its future resource needs, the regulatory framework for treatment of DSM investments will need to be addressed. An equitable regulatory framework that addresses the removal of the disincentives for the implementation of DSM programs is a fundamental prerequisite to creating a successful DSM

[9] The ICF, International study is discussed in detail in Chapter 9 of the SRP.

environment. The lack of necessary regulatory mechanisms means that DSM and supply-side resources are not on a level playing field. Appropriate mechanisms must be implemented to ensure that the benefits of DSM accrue to customers and that investors are adequately compensated for their investment. It is important to note that the LPSC has recently opened a new rulemaking docket to address energy efficiency. Based on recent comments of the LPSC Staff, it is anticipated that the energy efficiency rulemaking will begin in earnest during early 2010.

DSM is an important component of the resource planning process and requires that the Company properly assess the market achievable potential and make adjustments as needed due to changes in external market forces, changes to Operating Company schedules for implementing DSM programs as well as the advanced metering infrastructure ("AMI") systems that enable demand response programs. Changes to these assumptions and others may result in the need to revise the overall DSM resource potential or the timing of when those resources may be available.

Uncertainty

The amount of market-achievable DSM potential that should be reflected in the 2009 SRP Update is subject to a variety of factors, many of which are highly uncertain. These DSM assumptions are not intended as definitive commitments to particular programs, program levels, or program timing. The level of DSM programs that will be implemented over the planning horizon will depend on a number of factors including:

- The level of DSM that the Operating Companies' retail regulators agree should be deployed, and the implementation of appropriate regulatory review, approval, and cost recovery mechanisms to allow the Operating Companies a reasonable opportunity to recover the costs associated with those programs;
- The relative cost of DSM versus alternative supply-side options. Chapter 10 discusses the uncertainties that affect supply-side alternatives, both conventional and renewable alternatives. The cost and availability of supply-side alternatives are matters of uncertainty which could alter the relative attractiveness of DSM alternatives.
- Experience with the DSM programs. As DSM programs are implemented over time, ELL will be able to refine the estimates of market-achievable potential, the cost of implementing programs, and the speed at which programs can be deployed.

Renewable Generation Assumptions

Subject to various assumptions and uncertainties, it is reasonable to expect that renewable generation will become a component of ELL's long-term supply portfolio over the next decade. However, it is not realistic to assume that renewable generation will be able to technically or economically satisfy all or even most of ELL's incremental needs.[10] However, in light of a growing interest from policymakers and the potential for renewables to mitigate the effects of regulations regarding CO_2, the Reference Planning Scenario assumes 450 MW of renewable generation will be added to ELL's portfolio over the planning horizon, as shown in Figure ELL-8.

Figure ELL-8: Entergy Louisiana, LLC. Reference Planning Scenario Renewable Generation Resource Additions

Renewable Generation Resource Additions (2009-2028)			
COD	**Technology**	**Size (MW)**	**Operating Company**
2018	Biomass	50	ELL
2019	Biomass	100	ELL
2021	In-Stream Hydro	50	ELL
2022	In-Stream Hydro	50	ELL
2023	In-Stream Hydro	50	ELL
2023	Off-System Wind	150	ELL
	2009 – 2028 Total	**450**	

Deactivation Assumptions

In addition to being able to meet growing load, additional resources will be needed in the future to replace any part of the current portfolio that can no longer be expected to be technically or economically viable. Thus, the resource planning process must incorporate assumptions regarding the continued viability of the existing generating units that comprise the current portfolio.[11] As part of the ongoing planning process, the existing units are assessed to determine their ability to economically remain in the portfolio relative to other available resource alternatives. The results of this assessment can change because the projected cost to maintain a generating unit can be affected by unexpected equipment degradation or failure and unanticipated

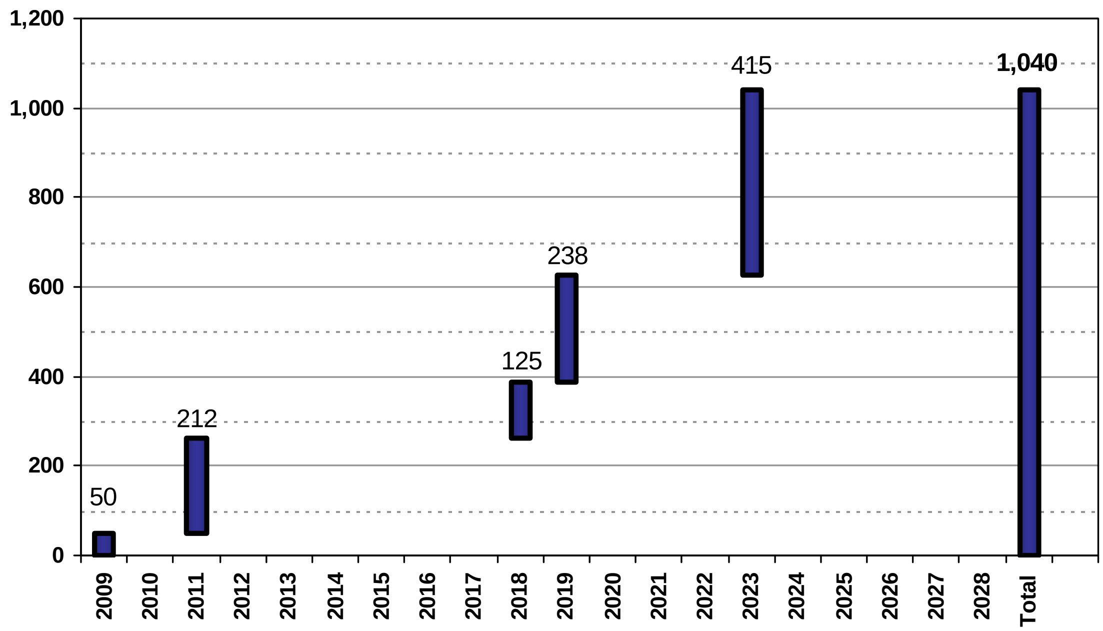
[10] Chapter 10 of the SRP presents a detailed technical and economic discussion of renewable resources.
[11] A more complete discussion of the process for evaluating potential unit deactivations is discussed in Chapter 8 of the SRP.

operational requirements that significantly impact the unit condition. Therefore, these deactivation assumptions are for long-term capacity planning purposes only and should not be interpreted as a retirement schedule for existing generating units.

All of the existing nuclear, coal, and hydro units as well as the modern simple-cycle combustion turbine ("CT") and CCGT units are expected to remain viable during the planning period. Older technology gas fired units with heat rates around 10,000 Btu/kWh are economic for load following roles at current expectations for natural gas prices and carbon legislation. However, as generating units age, it is reasonable to expect that their maintenance requirements may increase and/or that their reliability may decrease. Therefore, some currently operable gas-fired generating units will likely be deactivated during the planning period. Others will continue to operate. In some cases additional investment may be warranted to maintain performance.

Figure ELL-9 shows the deactivation assumptions that form the basis for estimating ELL's resource needs. However, as indicated above, a decision has not been made to actually deactivate any specific unit.

Figure ELL-9: Entergy Louisiana, LLC. Capacity Deactivation Assumptions (MW)



Based upon the Reference Case assumptions regarding load growth (including the effects of DSM), an assessment of the state of the current portfolio, renewable and DSM mandates, and the economics of alternative resources, the resource additions in ELL's Reference Planning Scenario are shown in the following four figures.

Figure ELL-10: Entergy Louisiana, LLC. Summary of Reference Planning Scenario Resource Additions

Resource Additions (2009-2028)			
COD	**Technology**	**Size (MW)**	**Operating Company**
2011	CCGT	387	ELL
2012	Nuclear Uprate	22	ELL
2015	CCGT	400	ELL
2015	Nuclear Uprate	25	ELL
2018	Biomass	50	ELL
2019	Biomass	100	ELL
2021	In-Stream Hydro	50	ELL
2022	In-Stream Hydro	50	ELL
2023	In-Stream Hydro	50	ELL
2023	Off-System Wind	150	ELL
	2009 – 2018 Total	**884**	
	2019 – 2028 Total	**400**	
	2009 – 2028 Total	**1,284**	

Figure ELL-11: Entergy Louisiana, LLC. Reference Planning Scenario Capacity Additions by Type (MW)

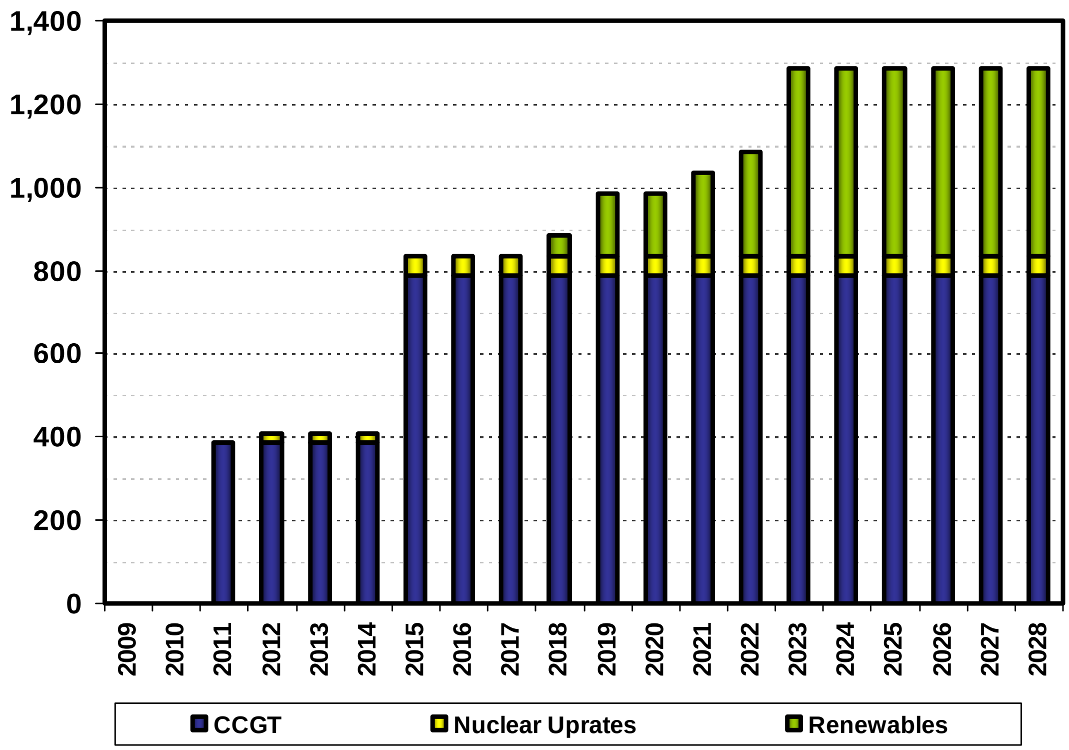
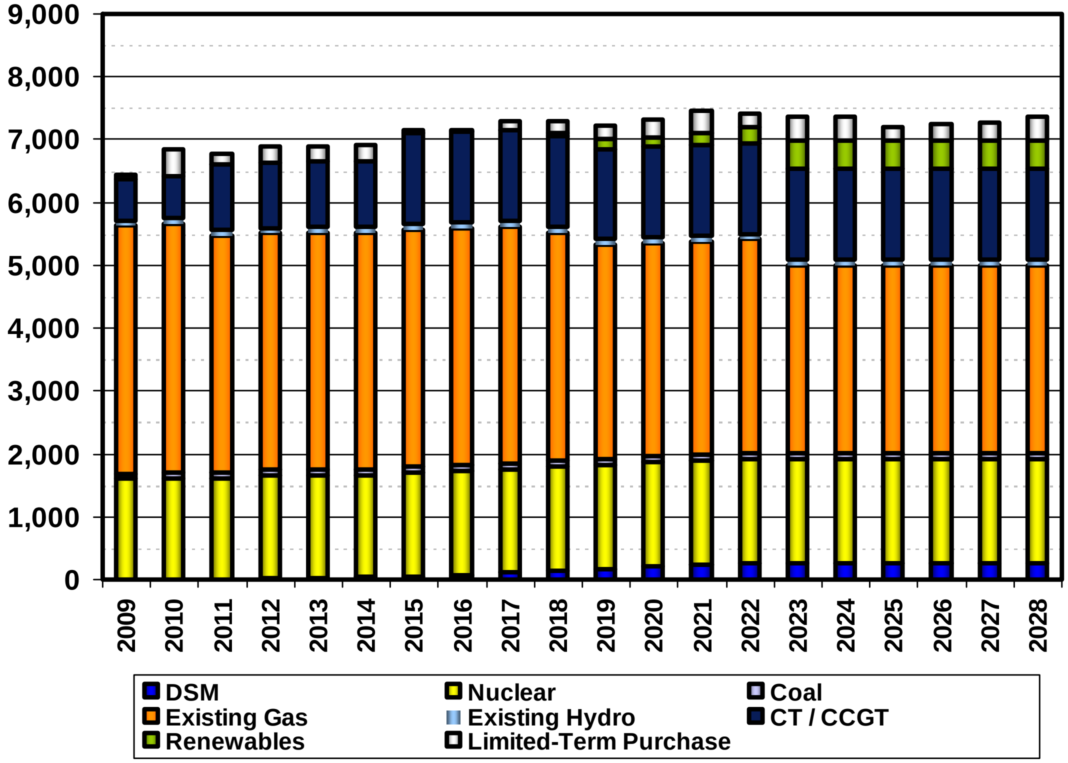


Figure ELL-12: Entergy Louisiana, LLC. Summary of Reference Planning Scenario Portfolio Composition (GW)

	Year																			
Resource	**09**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**	**25**	**26**	**27**	**28**
DSM	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Nuclear	1.6	1.6	1.6	1.6	1.6	1.6	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7
Coal	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Existing Hydro	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Existing Gas	3.9	4.0	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.6	3.4	3.4	3.4	3.4	3.0	3.0	3.0	3.0	3.0	3.0
Renewable Generation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.2	0.2	0.2	0.3	0.5	0.5	0.5	0.5	0.5	0.5
CT / CCGT	0.7	0.7	1.0	1.0	1.0	1.0	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4
Limited-Term Purchases	0.1	0.4	0.2	0.3	0.2	0.3	0.1	0.0	0.2	0.2	0.2	0.3	0.3	0.2	0.4	0.4	0.2	0.3	0.3	0.4
Total	**6.4**	**6.8**	**6.8**	**6.9**	**6.9**	**6.9**	**7.2**	**7.2**	**7.3**	**7.3**	**7.2**	**7.3**	**7.5**	**7.4**	**7.4**	**7.4**	**7.2**	**7.2**	**7.3**	**7.4**

Figure ELL-13: Entergy Louisiana, LLC. Summary of Reference Planning Scenario Portfolio Composition (MW)



Alternative Planning Scenarios

The Reference Planning Scenario charts a course for meeting customer needs that balances the planning objectives of reliability, reasonable cost, and risk mitigation. In doing so, the Reference Planning Scenario considers uncertainty and describes a portfolio of resources that is reasonably robust in accomplishing these objectives across a range of outcomes. However, the SRP recognizes that the outcome of a wide range of uncertainties will affect customer needs and the best alternatives to meet those needs.

Alternative Planning Scenarios have been developed to describe how the Reference Planning Scenario would be adjusted in the future to respond to specific contingencies. These scenarios include:

- New Nuclear Planning Scenario
- High Growth Planning Scenario
- Low Growth Planning Scenario

Each is described in the following sections.

New Nuclear Planning Scenario

Although the Reference Planning Scenario does not presume that a new nuclear facility will begin supplying capacity and energy to ELL's customers over the course of the planning period, the SRP recognizes that new nuclear offers the potential for an economic source of stable-priced base load capacity with zero carbon emissions. In light of this potential, the Reference Planning Scenario assumes the following strategic actions with respect to new nuclear:

- Continue to monitor the economics of new nuclear and propose to strike on this option in the future if and when analyses warrant.
- Maintain the readiness to evaluate and develop new nuclear through spending levels consistent with results of on-going assessment.

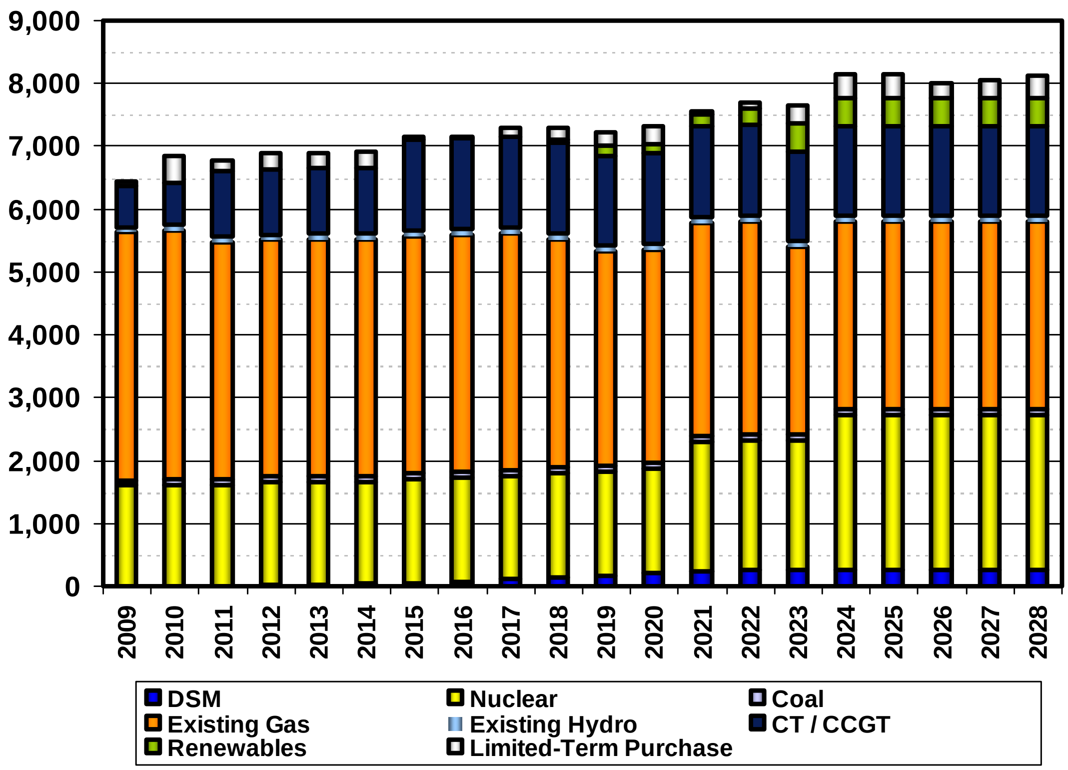
The New Nuclear Planning Scenario describes how planned resource additions would be adjusted if results of on-going monitoring activities indicate that new nuclear technology proves to be a viable, economically attractive alternative to meet base load needs in the future. The New Nuclear Planning Scenario assumes the addition of new nuclear in the 2020 – 2025 time frame. Detailed assumptions include the following:

- Two units, 1,000 MW each, are added in 2021 and 2024, respectively. ELL will own 40% of each unit for a total of 800 MW.
- Given lead times associated with new nuclear development, it is not anticipated that new nuclear could be incorporated into portfolios prior to the second half of the planning horizon.
- The unit capacity assumptions are generic representations of potential new nuclear unit additions and do not reflect an assumption as to the specific technology chosen. The actual unit size and number of units would depend on technology selected.
- If new nuclear is determined to be economic, it is not anticipated that more than 2,000 MW of new nuclear could be added in this planning horizon. The capital cost and challenges associated with development and construction limit the amount of new nuclear that realistically could be deployed within a defined time period.
- The GE ESBWR technology contemplates a unit size of about 1,500 MW. The Nuclear Planning Scenario assumes that if this technology were chosen, only one unit would be deployable within the planning horizon.
- New nuclear additions would be expected to replace comparable amounts of CCGT capacity in the Reference Planning Scenario.

Figure ELL-14: Entergy Louisiana, LLC. Summary of New Nuclear Planning Scenario Portfolio Composition (GW)

	Year																			
Resource	**09**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**	**25**	**26**	**27**	**28**
DSM	-	-	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Nuclear	1.6	1.6	1.6	1.6	1.6	1.6	1.7	1.7	1.7	1.7	1.7	1.7	2.1	2.1	2.1	2.5	2.5	2.5	2.5	2.5
Coal	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Existing Hydro	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Existing Gas	3.9	4.0	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.6	3.4	3.4	3.4	3.4	3.0	3.0	3.0	3.0	3.0	3.0
Renewable Generation	-	-	-	-	-	-	-	-	-	0.1	0.2	0.2	0.2	0.3	0.5	0.5	0.5	0.5	0.5	0.5
CT / CCGT	0.7	0.7	1.0	1.0	1.0	1.0	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4
Limited-Term Purchases	0.1	0.4	0.2	0.3	0.2	0.3	0.1	0.0	0.2	0.2	0.2	0.3	0.0	0.1	0.3	0.4	0.4	0.2	0.3	0.3
Total	**6.4**	**6.8**	**6.8**	**6.9**	**6.9**	**6.9**	**7.2**	**7.2**	**7.3**	**7.3**	**7.2**	**7.3**	**7.6**	**7.7**	**7.6**	**8.2**	**8.2**	**8.0**	**8.0**	**8.1**

Figure ELL15: Entergy Louisiana, LLC. Summary of New Nuclear Planning Scenario Portfolio Composition (MW)



Carbon Implications

Nuclear generation results in zero carbon emissions. Consequently, replacing CCGT capacity with new nuclear capacity would be expected to result in a lower carbon footprint.

High Growth Planning Scenario

In addition to a reference case, the load forecast described above includes both high and low load growth projections. The High Growth Planning Scenario describes how planned resource additions would be adjusted if actual load growth tends toward the upper forecast. Load growth averages 2.0% over the 20 year planning horizon in the High Growth Planning Scenario. This scenario assumes that additional supply-side resources would be required over the planning horizon in order to meet higher projected loads.

- The High Growth Planning Scenario does not rely on specific assumptions as to the drivers of higher sustained load. Higher growth could be driven by a number of factors including, for example;
    - Sustained strong economic growth within the region;
    - Adoption of new electric technologies, such as, plug-in hybrid vehicles; and
    - Deployment of DSM at lower levels than assumed in the Reference Planning Scenario.

As described above, it is assumed for planning purposes that ELL will remain a participant in the Entergy System Agreement in whatever form that may take. Therefore, ELL's capacity additions will support the larger integrated 5-company, or 4-company, Entergy System. The System's overall capacity needs will depend on load growth.

As a result, the 4-company Operating System (post EAI and EMI exit) will need 2,000 MW of additional capacity to meet reliability needs. ELL's planned capacity under the High Growth Planning Scenario is not expected to vary from that under the Reference Planning Scenario. Due to greater reliability requirements, these 2,000 MW of incremental capacity may be added to EGSL and ETI (1,000 MW each).

Low Growth Planning Scenario

The Low Growth Planning Scenario describes how planned resource additions would be adjusted if actual load growth tends toward the lower forecast. Load growth averages about 0.5% over the 20 year planning horizon in the Low Growth Planning Scenario. This scenario assumes that, as compared to the

Reference Planning Scenario, fewer supply-side resources would be required over the planning horizon in order to meet lower projected load growth.

- The Low Growth Planning Scenario does not rely on specific assumptions as to the drivers of lower load. Lower loads could result from a number of factors including, for example:
  - Sustained weak economic growth within the region;
  - Adoption of energy efficiency by end use customers; and
  - Higher levels of DSM deployment than assumed in the Reference Planning Scenario.

As a result, compared with the Reference Planning Scenario, 1,000 MW less of incremental capacity is needed to meet reliability needs over the twenty year planning horizon for the 4-company Operating System (post EAI and EMI exit). ELL's planned capacity under the Low Growth Planning Scenario is not expected to vary from that under the Reference Planning Scenario. Instead, 1,000 MW of incremental capacity would be reduced within ETI's jurisdiction, due to lower reliability requirements.

Other Key Portfolio Drivers

The Alternative Planning Scenarios described above provide guidance relating to the effect of uncertainties pertaining to load growth and new nuclear. The outcomes of these uncertainties are unknown at this time. But, the implications of these uncertainties on portfolio design and the range of foreseeable outcomes suggest both a potential benefit from developing alternative scenarios and a reasonable basis for doing so.

It is not possible, however, to predict all the factors that may affect portfolio design over the next 20 years. In the case of many other drivers the uncertainties become so unknown or so speculative, that constructing specific alternative planning scenarios becomes practically impossible or, at least, of little planning value. In some cases the drivers themselves may not be identifiable at this time. The strategic flexibility inherent in the Reference Planning Scenario (described in an earlier section within this chapter) provides the key tool for responding to changing circumstances. However, two additional uncertainties, while not incorporated into alternative planning scenarios merit additional discussion, plant betterment opportunities and renewable generation alternatives.

Plant Betterment Initiative

The Reference Planning Scenario assumes that 1,040 MW of ELL's existing gas-fired generation is deactivated over the coming twenty years. These deactivation assumptions were developed for long-range planning purposes, as a basis for assessing long-term incremental capacity needs, and not as a schedule of retirements for existing units. While the assumptions about unit deactivations consider knowledge of unit condition and expectations about future operating role, these assumptions do not represent a decision to deactivate any particular unit. Specific unit portfolio decisions are made during the tactical business planning process (three-year planning horizon) based on economic and technical evaluation considering projected forward cost, anticipated operating roles, and cost of supply alternatives.

Plant betterment activities involve proactive repair and replacement of specific components to maintain capability and safety of a generating unit. These repairs and replacements are consistent with OEM/Vendor recommendations and good utility practice. Some of the existing gas-fired generating units may be candidates for refurbishment and/or upgrade beyond proactive repair and replacement.

Planners and plant engineers are currently assessing potential opportunities presented by older gas-fired resources. In some cases continued additional spending at these units may provide customers with economic benefits by deferring more expensive incremental capacity needs. This analysis is on-going and is anticipated to result in preliminary recommendations over the next twelve months. To the extent the analysis results in recommendations to proactively maintain existing gas-fired resources in operation beyond currently assumed deactivation dates, the Reference Planning Scenario would be adjusted accordingly by deferring incremental CCGT additions or reducing limited-term purchases or both.

Renewable Generation

The Reference Planning Scenario assumes that 450 MW of renewable generation is added over the twenty year planning horizon and provides assumptions about what type of technology might be deployed to achieve that level. These assumptions are based on current information about technology cost and availability, including projections of long-term cost for emerging technologies such as in-stream hydro. The actual amount and type of renewable generation that will be deployed over the twenty-year planning horizon will depend on actual prices, availability, as well as consideration of any federal and/or state mandates. Depending on possible federal and/or state legislation, the Entergy Operating Companies may conduct a RFP for renewable resources within the next twelve months. The results of that effort should provide additional information about the potential for renewable generation. In the event that economic renewable generation cannot be identified in levels assumed in the Reference Planning Scenario, additional CCGT capacity would be anticipated to meet reliability requirements.