2012 Integrated Resource Plan

Entergy System

This document describes the Entergy System's Integrated Resource Plan for the period 2012 – 2031. The Integrated Resource Planning Process results in a Preferred Portfolio that describes the System's long-range strategy for meeting customers' power needs.

October 2, 2012

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INTRODUCTION

The six Entergy Operating Companies ("OPCOs") are Entergy Arkansas, Inc. ("EAI"), Entergy Gulf States Louisiana, L.L.C. ("EGSL"), Entergy Louisiana, LLC ("ELL"), Entergy Mississippi, Inc. ("EMI"), Entergy Texas, Inc. ("ETI") and Entergy New Orleans, Inc. ("ENO"). The electric generation and bulk transmission facilities of the OPCOs participating in the Entergy System Agreement are operated on an integrated, coordinated basis as a single electric system and are referred to collectively as the "Entergy System" or the "System."

In 2002 the System began work to develop a new planning process. That work culminated in January 2003 when the Entergy Operating Committee[1] approved a long-term resource plan, the Strategic Supply Resource Plan ("SSRP"). The SSRP comprehended a set of planning objectives and principles for long-term resource planning. Following its approval in 2003 the SSRP was updated, as necessary, to reflect changing circumstances and conditions. However, the framework – the principles and objectives – and to a large degree the resource strategy described by the SSRP remained constant. In 2009 the long-range plan was renamed from the SSRP to the Strategic Resource Plan ("SRP") to reflect more accurately the full scope of the planning efforts[2]. This document once again presents the results of the update to the System's long-term plan. In this update the SSRP and SRP nomenclature has been abandoned in favor of the more typical Integrated Resource Plan ("IRP").

System Agreement

On December 19, 2005, EAI provided notice pursuant to Section 1.01 of the System Agreement that it will terminate its participation in the System Agreement effective December 18, 2013. EMI provided similar notice to the OPCOs on November 8, 2007 that it would terminate its participation effective November 7, 2015. Resource planning decisions reflect EAI's and EMI's notice to terminate participation in the System Agreement. Thus, the IRP contemplates long-term plans for the four-company system, while also looking at the near-term effects of the participation of EAI and EMI in the System Agreement.

The Entergy System IRP described in this document does not address the long-term resource plans for EAI and EMI for the period following their termination of participation in the System Agreement which will be addressed through separate processes. EAI will file its IRP in October 2012. An IRP for EMI is planned for 2013.

[1] The Entergy Operating Committee administers the Entergy System Agreement, a FERC-approved rate schedule and contract among Entergy Services, Inc. ("ESI") and the Operating Companies, which requires the Operating Companies to plan, construct and operate their electric generation and bulk transmission facilities as a single, integrated electric system.

[2] The earlier name, SSRP, suggested that the scope of the planning efforts was limited to supply-side alternatives. The revised name, SRP, more accurately recognized the fact that the planning process considers the full range of alternatives available to meet customer needs including demand-side alternatives.

Participation in MISO

The Entergy OPCOs have proposed to join the Midwest Independent Transmission System Operator, Inc. ("MISO"). The proposed transition to MISO involves a number of uncertainties, including whether local regulators will approve the proposal to join MISO and, if so, when participation would become effective. Integrating the Operating Companies into MISO will require the implementation of a number of different decisions regarding the form and structure of the OpCos participation in MISO. The outcomes of such uncertainties could affect the System's resource plans. The assumption in this IRP is that the System joins MISO effective January 1, 2014.

Planning Reserve Margin

The 2012 IRP is premised on the planning assumption that the Entergy System will be required to maintain a 12% planning reserve margin based on its annual peak load (that is, the coincident peak load for all of the OPCOs that participate in the System Agreement at that time). Once the Entergy OPCOs join MISO, the planning reserve margin requirement that MISO will require as part of its Resource Adequacy construct will be determined annually by MISO based on a loss of load expectation ("LOLE") analysis performed by MISO for the MISO system. The 12% planning reserve margin assumption reflected in this IRP is consistent with current estimates of planning reserves likely to be required of the System by MISO.[3] However, MISO requirements will be determined annually and results could vary from year to year. Moreover, the manner in which the Entergy OPCOs structure their participation in MISO could affect reserve requirements. If the Entergy OPCOs do not join MISO or their participation is delayed, the System's planning reserve requirement likely would be higher than 12%. In the event that planning reserve margin requirements prove to be greater than 12%, additional capacity requirements will be addressed in the near term through adjustments in the levels of power purchase contracts made by the System.

Jurisdictional IRP Developments

Arkansas

The Arkansas Public Service Commission's ("APSC") Integrated Resource Planning ("IRP") rule requires EAI to file an IRP every three years. Under those rules EAI is required to file a new IRP in the 4th quarter of 2012. In light of EAI's withdrawal from the System Agreement, EAI's IRP is being prepared through a separate and distinct planning process where EAI's resource planning decisions are made by EAI management and not the System Operating Committee. EAI's long-term resource needs are not addressed in this the 2012 System IRP.

Louisiana

[3] MISO determines planning reserve margin requirements based on projected MISO peak load. On that basis, the most recent MISO LOLE study indicates a reserve margin requirement of 16.7%. Load serving entities ("LSE") are assigned a planning reserve requirement based on their projected contribution to the MISO peak that is based on their projected load at the time of MISO peak. Load diversity effects – the extent to which an LSE's peak occurs at a time other then the MISO peak – serve to lower an LSE's planning reserve requirement as measured against it peak load.

The Louisiana Public Service Commission ("LPSC") adopted IRP rules in Corrected General Order R-30021, issued April 20, 2012. In accordance with the rules, ELL and EGSL filed an initial IRP report consisting of the 2009 SRP and the 2009 SRP Refresh in June 2012. The rules require the Companies to commence their first full IRP cycle within 18 months following the issuance of the General Order (i.e., October 2013), and to file their first full IRP report within 19 months after that (i.e., May 2015).

Mississippi

At present, the Mississippi Public Service Commission ("MPSC") has not adopted a formal IRP requirement. However, the MPSC continues to evaluate the need for IRP rules.

New Orleans

ENO is required to file an IRP in the 4th quarter 2012 according to the City Council of New Orleans IRP rules which were adopted in 2008. ENO has worked with stakeholders over the past year in the preparation of ENO's IRP.

Texas

At present, The Public Utility Commission of Texas does not have an IRP requirement.

Organization

This report is organized into four sections:

1. Planning Framework
2. Assumptions
3. Portfolio Analytics
4. Conclusions

PART 1 PLANNING FRAMEWORK

The System's planning process seeks to achieve three objectives:

- First and foremost, serve customers' power needs reliably.
- Second, provide power at the lowest reasonable cost considering reliability
- Third, mitigate the effects of production cost volatility that can result from risks such as fuel price uncertainty, purchased power cost uncertainty, or possible supply disruptions.

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

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

- Reliability – The IRP should provide adequate resources to meet customer peak demands with adequate reliability.
- Base Load Production Costs – The IRP should provide low-cost base load resources to serve base load requirements, which are defined as the firm load level that is expected to be exceeded for at least 85% of all hours per year.
- Load-Following Production Cost and Flexible Capability – The IRP should provide efficient, dispatchable, load-following resources to serve the time-varying load shape levels that are above the base load supply requirement. Further the IRP should provide sufficient flexible capability to respond to factors such as load volatility caused by changes in weather or by inherent characteristics of industrial operations, the need for meeting energy imbalances caused by independent power producers interconnected to the System, and the need to absorb energy that may be put to the System by co-generators.[4]
- Generation Portfolio Enhancement – The IRP should provide a generation portfolio that avoids an over-reliance on aging resources. Reliance on older resources is determined by a number of factors such as current operating role, unit age, unit condition, historic and projected investment levels and unit economics.
- Price Stability Risk Mitigation – The IRP should mitigate the exposure to price volatility associated with uncertainties in fuel and purchased power costs.

[4] Anticipated effects of the OPCOs' participation in MISO may result in a reduction in the System's portfolio requirements for flexibility capability.

- Supply Diversity Risk Mitigation – The IRP should mitigate the exposure to major supply disruptions that could occur from specific risks such as outages at a single generation facility.

Resource Allocation

The System Planning Process follows this sequence. First, resource needs for the System are determined. Second, resource additions are identified. Third, resources are allocated among the Operating Companies. In other words, resources are planned to meet the needs of the System and then allocated among the Operating Companies. To guide decisions regarding the allocation of long-term resource additions for the Entergy System, the Entergy Operating Committee has adopted a set of resource allocation factors. The factors rest on the guiding principle that each Operating Company should, over time and consistent with the multi-year planning and procurement processes of the System, support a sufficient amount of generation available for coordinated economic dispatch for each supply role used to serve its load shape[5]. Over time, application of that principle will result in a portfolio of resources that meets planning objectives and customers' needs at the lowest reasonable cost. The factors are described in the following table.

Table 1: Resource Allocation Factors

Resource Allocation Factors	
Relative Production Cost	• OPCO participation in new resources should seek to maintain, over time, production cost trends consistent with rough production cost equalization of OPCO total production costs relative to the System average total production costs.
Capacity Deficit	• OPCO participation in new resources should consider each OPCO's longer-term portfolio with regard to providing a proportionate share of the resources that are expected to be used for overall System reliability and coordinated dispatch.
Base Load Capacity Deficit	• OPCO participation in new base load resources should consider each OPCO's resource position with regard to having sufficient base load generation resources to serve its base load requirements. This "Base Load Capacity Deficit" is defined as the shortfall in base load generation required to serve the firm load level that is expected for greater than 85% of annual hours.
Load Following Capacity Deficit	• OPCO participation in new load following resources should consider each OPCO's resource position with regard to having sufficient load following resources to serve its load requirements. The "Load Following Capacity Deficit" is defined as the shortfall in dispatchable load following resources that would be expected to be included in the System's coordinated commitment and dispatch to serve the System's load following requirements.
Responsibility Ratio	• OPCO participation in short term resources acquired for System reliability and/or System economy purposes will typically be allocated on a Responsibility Ratio basis. •

[5] The factors that address matching the composition of each Operating Company's resource portfolio to the resource requirements suggested by that Company's load shape are applicable regardless of the number of Operating Companies that comprise the System.

Resource Allocation Factors	
Supply Risks	• OPCO resource participation decisions should also consider supply resource diversity, seeking to reduce the reliability and price risks resulting from an OPCO's exposure to single contingency generation outages or from its exposure to generation supplied by a single resource, fuel type, or fuel supply source.
Location	• OPCO participation in new resources should consider each OPCO's load relative to the location of the resource in order to enhance the resource's ability to provide reliability, cost, and risk mitigation benefits.

Area Planning

Although the Entergy System performs resource planning on a System-wide basis, with the goal of meeting the planning objectives at the overall lowest reasonable cost, physical and operational practicalities dictate that regional reliability needs must be considered when planning for the reliable operation of the Entergy System. Thus, one aspect of the planning process is the development of planning studies to identify supply needs within specific geographic areas of some Operating Companies, evaluate supply options to meet those needs, and establish targeted regional supply portfolios.

For planning purposes, the region served by the Entergy Operating Companies is divided into four major planning areas and two sub-areas. These areas are determined based on characteristics of the Entergy System including the ability to transfer power between areas as defined by the available transfer capability, the location and amount of load, and the location and amount of generation. The four major planning areas and two sub-areas are described generally as follows:

- North Arkansas – the northern portion of Arkansas generally north of Sheridan, Arkansas.
- West of the Atchafalaya Basin ("WOTAB") – the area generally west of the Baton Rouge, Louisiana metropolitan area, to the westernmost portion of Entergy's service territory in Texas. The westernmost portion of WOTAB is the Western Area (a sub-area), which encompasses the westernmost part of ETI's service territory, generally west of the Trinity River.[6]
- Amite South – the area generally from east of the Baton Rouge, Louisiana metropolitan area to the Mississippi state line and south to the Gulf of Mexico. The Southeast portion of the Amite South area is known as the Downstream of Gypsy ("DSG") area (a sub-area) and generally encompasses the area down river of the Little Gypsy plant including metropolitan New Orleans south to the Gulf of Mexico.
- Central – the area generally south of the North Arkansas area and north of the WOTAB and Amite South areas, but includes the Baton Rouge, Louisiana metropolitan area.

[6] In some documents The Western Area has been referred to as the "Western Region" or Western Sub-Region". These terms are interchangeable.

As described later in the report, assessments of two areas, Amite South and WOTAB (in particular Western Area) indicate need for additional resources early in the next decade.

PART 2 ASSUMPTIONS

Technology Assessment

The IRP process considers the range of alternatives available to meet the planning objectives including the existing fleet of generating units, potential conventional generation resource additions, potential renewable generation resource additions, and demand-side management. System Planning & Operations[7] ("SPO"), as part of on-going long-term resource planning activities, periodically prepares a Technology Assessment to identify supply alternatives that may be technologically and economically suited to meet customer needs. In preparation for the 2012 System IRP, SPO updated the Technology Assessment in light of current cost and performance information. The initial screening phase of the Technology Assessment reviewed the technology landscape to identify technologies that merited more detailed analysis. Table 2 summarizes the results of the Technology Assessment for a number of technologies. At this phase a number of technologies were eliminated from further consideration based on a range of factors including technical maturity, stage of commercial development, and economics. The following technologies were found appropriate for further more detailed analysis:

- Pulverized Coal – Supercritical Pulverized Coal
- Pulverized Coal – Supercritical Pulverized Coal with carbon capture
- Fluidized Bed – Atmospheric Fluidized Bed also known as "Circulating Fluidized bed" or ("CFB")
- Natural Gas Fired Technology
    - Simple Cycle Combustion Turbines ("CT")
    - Combined Cycle Gas Turbines ("CCGT")
    - Small Scale Aeroderivatives
- Nuclear – (Generation III Technology)
- Renewable Technologies
    - Biomass
    - On shore Wind Power

[7] System Planning and Operations is a department within ESI tasked with: (1) the procurement of fossil fuel and purchased power, (2) the dispatch of the resources of the Entergy Operating Companies, and (3) the planning and procuring of additional resources required to provide reliable and economic electric service to the Entergy Operating Companies' customers. SPO also is responsible for carrying out the directives of the Operating Committee and the daily administration of aspects of the Entergy System Agreement not related to transmission.

- Solar Photovoltaic ("PV")

Following the screening level analysis, more detailed revenue requirements modeling of remaining technologies was conducted across a range of operating roles and under a range of input assumptions. The analysis resulted in the following conclusions.

- Among conventional resource alternatives CCGT and CT technologies are the most attractive. The gas-fired technologies are economically attractive across a range of assumptions concerning operations and input costs (fuel and CO_2).

- New nuclear and new coal technologies are not attractive near-term options relative to gas-fired technology based on current assumptions.
- Recent developments have made renewable generation less economically attractive:

  - Declines in the long-term outlook for natural gas prices have disadvantaged even the most promising renewable technologies relative to natural gas-fired resources.

  - Current federal tax incentives for most renewable generation alternatives could expire as soon as year-end 2012. Solar incentives are currently expected to end in 2016.

  - The outlook for national CO_2 regulation, at least in the near-term, has dimmed.

- Among renewable technologies, wind power is the most likely to be cost competitive with CCGT and CT technologies. However, under most cases wind remains less economic than natural gas.
- Most other renewable generation technologies are not economic at this time.

Table 2: Technology Cost Comparisons

Levelized $/MWh Over Expected Life of Resource[8,9] (Nominal$)							
		No CO_2			CO_2 Beginning 2018		
Technology	Capacity Factor	Reference Gas / Coal	High Gas / Coal	Low Gas / Coal	Reference Gas / Coal	High Gas / Coal	Low Gas / Coal
2X0 CT-7FA	15%	$164	$189	$140	$174	$199	$150
LM6000	15%	$187	$210	$166	$196	$220	$175
CT-LMS 100	15%	$188	$209	$168	$196	$218	$176
2X1 CCGT 7FA	15%	$194	$210	$179	$201	$217	$185
2X0 CT-7FA	65%	$94	$119	$70	$104	$129	$80
2X1 CCGT 7FA	65%	$82	$98	$67	$88	$105	$73
2X1 CCGT 7FA	90%	$73	$89	$57	$79	$95	$64
1X1 CCGT 7H	90%	$79	$95	$64	$85	$101	$70
Super Critical Pulverized Coal	90%	$85	$94	$76	$107	$116	$98
Super Critical Pulverized Coal with Carbon Capture	90%	$137	$150	$124	$140	$153	$127
Circulating Fluidized Bed	90%	$108	$119	$97	$133	$144	$122
Nuclear (Gen III)	90%	$145	$145	$145	$145	$145	$145
Onshore Wind	39%	$111	$111	$111	$111	$111	$111
Solar PV	20%	$326	$326	$326	$326	$326	$326
Biomass	75%	$119	$119	$119	$119	$119	$119

Natural Gas Price Forecast

System Planning and Operations ("SPO") prepared the natural gas price forecast used in the 2012 System IRP. The near-term portion of the natural gas forecast is based on NYMEX forward Henry Hub gas prices. Because the NYMEX futures market becomes increasingly less liquid in months further away from the current month, the ability of NYMEX futures prices to provide a reliable view of future gas prices is limited. In recognition of this, the long-term natural gas price forecast is based on a point-of-view ("POV") prepared by SPO. To prepare the long-term POV, SPO considers reports and research prepared by a number of independent experts in energy, as well as additional information that may be available concerning market fundamentals.

The long term natural gas forecast used in the 2012 IRP includes sensitivities for high and low gas prices to support analysis across a range of future scenarios.

[8] Renewable Technology costs assume existing federal subsidies. Intermittent technologies include cost of integration and match-up capacity.

[9] Discount rate equals 7.81%.

Table 3: Henry Hub Natural Gas Prices

Henry Hub Natural Gas Prices 2012 – 2031						
	Nominal $/MMBtu			Real $/MMBtu		
	Low	Reference	High	Low	Reference	High
Real Levelized[10]	$3.97	$5.79	$7.58	$3.40	$4.96	$6.48
Average	$4.38	$6.66	$9.15	$3.51	$5.29	$7.20
20-Year CAGR	1.77%	4.41%	6.60%	-0.21%	2.37%	4.52%

CO_2 Assumptions

At this time, it is not possible to predict with any degree of certainty whether national CO_2 legislation will eventually be enacted, and if it is enacted, when it would become effective, or what form it would take. In order to consider the effects of carbon uncertainty on resource choice and portfolio design, the 2012 IRP process relied on a range of projected CO_2 cost outcomes. These cases were developed by Entergy personnel working with the ICF International consulting firm. The low case assumes that CO_2 legislation does not occur over the 20-year planning horizon. The reference case assumes that a cap and trade program starts in 2023 with an emission allowance cost of $24.12/U.S. ton and a 2012-2031 levelized cost in 2011$ of $6.56/U.S. ton[11]. The high case assumes that a cap and trade program starts in 2018 at $25.41/U.S. ton with a 2012-2031 levelized cost in 2011$s of $16.65/U.S. ton.

Load Forecast

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

- 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 (for example, the adoption of electric vehicles);
- The potential adoption of end-use (behind-the-meter) self-generation technologies (for example, roof top solar panels); and
- The level of energy efficiency and conservation measures adopted by customers.

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

[10] Real levelized prices refer to the price in 2011$ where the NPV of that price grown with inflation over the 2012-2031 period would equal the NPV of levelized nominal prices over the 2012-2031 period when the discount rate is 9.25%.

[11] The discount rate and levelization methodology for CO_2 prices is the same as that for natural gas prices.

In order to consider the potential implications of load uncertainties on long-term resource needs, four load forecast sensitivities were prepared for the System 2012 IRP. System load forecasts reflect the exits from the System Agreement of EAI and EMI on December 18, 2012 and November 17, 2015, respectively. Table 4 summarizes key assumptions, including load growth, for the planning scenarios used preparing this IRP.

Market Modeling

Aurora Model

The development of the 2012 System IRP relied on the AURORAxmp Electric Market Model ("AURORA") to simulate market operations and produce a long-term forecast of the revenues and cost of energy procurement for the Entergy System[12].

AURORA[13] is a production cost model and resource capacity expansion optimization tool that uses projected market economics to determine the optimal long-term resource portfolio under varying future conditions including fuel prices, available generation technologies, environmental constraints, and future demand forecasts. AURORA's optimization process identifies the set of resources among existing and potential future resources with the highest and lowest market values to produce economically consistent capacity expansion and retirement schedules. AURORA estimates price and dispatch using hourly demands and individual resource-operating characteristics in a transmission-constrained, chronological dispatch algorithm. AURORA chooses from new resource alternatives based on the net present value (" NPV") of hourly market values. AURORA compares those values to existing resources in an iterative process to optimize the set of new units.

Scenarios

IRP analytics relied on four scenarios to assess alternative portfolios across a range of outcomes. The four scenarios are:

- Scenario 1 – Assumes Reference Load, Reference Gas, and no CO_2 cost
- Scenario 2 (Economic Rebound) – Assumes the U.S. economy recovers and resumes expansion at relatively high rates.
- Scenario 3 (Green Growth) – Assumes government policy and public interest drive a "green agenda" marked by government subsidies for renewable generation; regulatory support for energy efficiency; and consumer acceptance of higher cost for "green."
- Scenario 4 (Austerity Reigns) – Assumes sustained poor economic conditions in the U.S.

[12] The Aurora model effectively replaces the PROMOD IV and PROSYM models that the System has used for many years.

[13] SPO selected the Aurora model for the 2012 System IRP as well as other analytic work after an extensive analysis of electricity simulation tools available in the marketplace. Aurora is capable of supporting a variety of resource planning activities and is well suited by for scenario modeling and risk assessment modeling. It is widely used by load serving entities, consultants and independent power producers.

Each scenario was modeled in Aurora. The resulting Market Modeling provided a basis (including projected power prices) for assessing the economics of long-term resource portfolio alternatives.

Table 4: Summary of Key Scenario Assumptions

Summary of Key Scenario Assumptions				
	Scenario 1	**Economic Rebound**	**Green Growth**	**Austerity Reigns**
Electricity CAGR (Energy GWh)[14]	~0.8%	~1.5%	~0.3%	~1.1%
Peak Load Growth CAGR	~0.8%	~1.4%	~0.2%	~1.1%
Henry Hub Natural Gas Price ($/MMBtu)	Reference ($4.96 levelized 2011$)	Reference ($4.96 levelized 2011$)	High Case ($6.48 levelized 2011$)	Low Case ($3.40 levelized 2011$)
CO_2 Price ($/short ton)	None	Cap and trade starts in 2023 $6.56 levelized 2011$	Cap and trade starts in 2018 $16.65 levelized 2011$	None

Fleet Assumptions

For the purposes of developing the IRP, assumptions must be made about the future of generating units currently in the portfolio. That is, among the existing fleet, which units will continue to be used within the portfolio and which will be removed from service and when? Such planning assumptions provide a basis for assessing the nature of future resource needs.

Based on factors such as current operating role, unit age and condition, historical and projected investment, and projected cost, approximately 2.0 GWs are assumed to deactivate in the first ten years of the planning horizon and a similar amount is assumed in the next ten.

Assumptions made for the IRP are not actual decisions regarding the future investment in resources. Unit-specific portfolio decisions – e.g., sustainability investments, environmental compliance investment, or unit retirements/betterments – are based on economic and technical evaluations considering such factors as projected forward costs, anticipated operating roles, and the cost of supply alternatives. These factors are dynamic, and as a result, actual decisions may differ from planning assumptions as greater certainty is gained regarding requirements of legislation, regulation and relative economics. By taking no action until it is needed, the System retains the flexibility to respond to changes in circumstances up to the time that a commitment is made.

[14] All CAGRs in this table: 2011-2031 (20 Years) for the market modeled in Aurora (a sub-set of the Eastern Interconnect which is about 34% of the U.S., based on 2011 GWh energy sales).

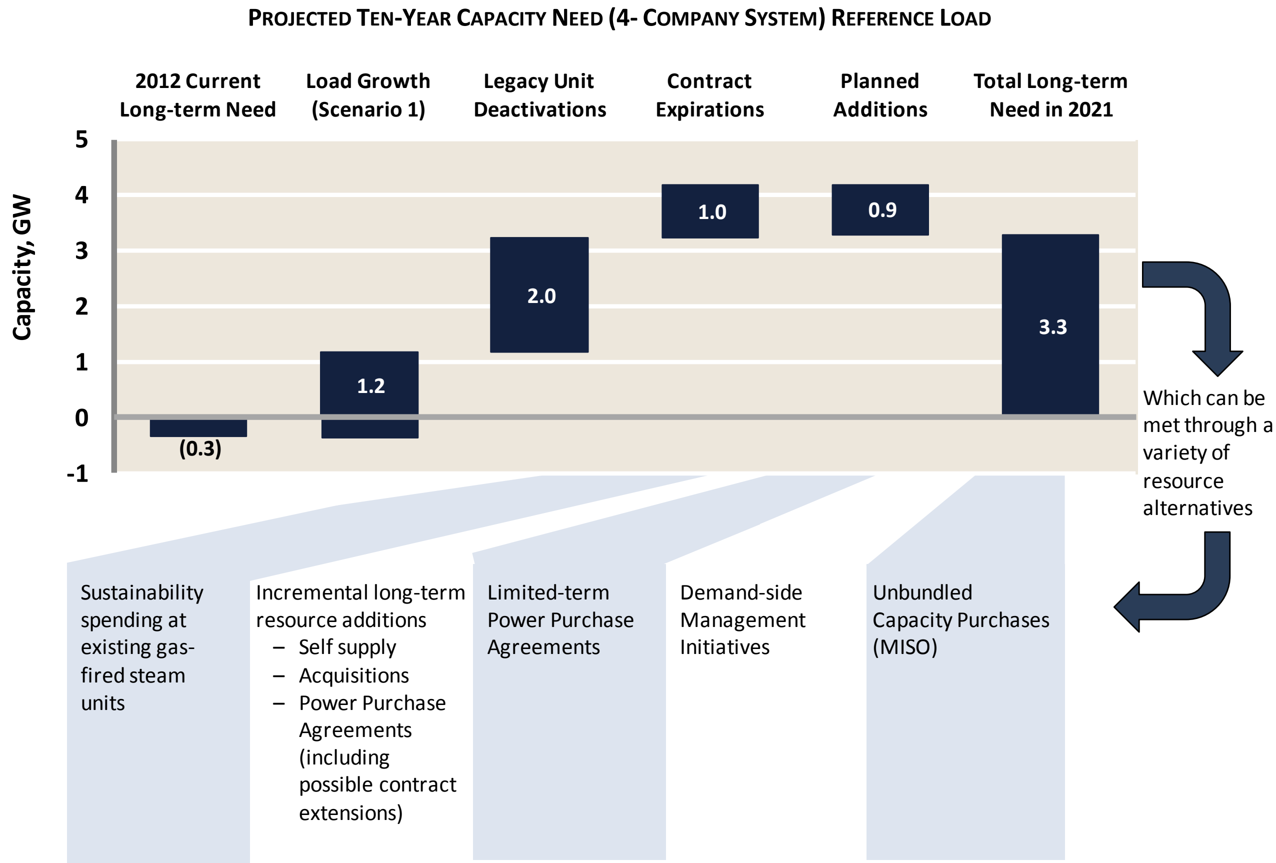
IRP Portfolio Design Analytics discussed in Part 3 of this report , suggest that continuing to maintain some units beyond their assumed deactivation date may be an economic alternative for meeting customers' power needs.

Resource Needs

In recent years planning and procurement efforts have transformed the System's portfolio such that the portfolio of long-term resources is more closely matched to the System's load shape. However, in the coming years the System will face the need for additional resources. Long-term resource needs depend in part on load growth which is uncertain. By 2021 the System is projected to need 3.3 GWs of capacity under the Scenario 1 (Reference Load Forecast) and from 2.5 GWs to 4.9 GWs across the three other scenarios. In addition to load growth, other drivers of resource need include potential legacy unit deactivations and contract expirations. However, a number of alternatives are available to the System to address these needs including:

- Spending at existing units to keep them operational beyond assumed deactivation dates;
- Incremental long-term resource additions, including:
    - Self-supply alternatives,
    - Acquisitions,
    - Power purchase agreements (including contract extensions);
- Limited-term power purchase agreements;
- Demand-side initiatives;
- Short-term capacity purchases (available in MISO).

Figure 1: Projected Ten-Year Capacity Need



Type of Resources Needed

The long-term planning process seeks to provide a portfolio of resources that, in total, achieves the planning objectives in a balanced and cost effective manner. Economically meeting customer needs requires a mix of resources capable of serving a variety of supply roles. In general, supply role needs include:

- Base Load – These resources are expected to operate in most hours.
- Load-following – These resources are capable of responding to the time-varying needs of customers.
- Peaking and Reserve – These resources are expected to operate relatively few hours, if at all.

In addition to a mix of supply roles, a mix of technologies and fuel sources provide supply diversity that mitigates risk.

Table 5: Resource Need by Supply Role

2012 Long-term Resource[15] Needs By Supply Role 4-Company System (MWs)				
	Base Load	Load-following	Peaking Reserve	Total
Load Shape Need	7,291	3,220	4,599	15,110
2012 Resources	3,737	10,653	1,068	15,458
Surplus (Deficit)	(3,554)	7,433	(3,531)	348

Since at least 2002, the System's long-term planning process has identified a need for additional long-term base load resources and resources with stable fuel prices. The System's generation mix, particularly the mix of the four Operating Companies that will continue to participate in the System Agreement after the exits of EAI and EMI, is primarily based upon gas-fired generation resources.. The history of natural gas prices has demonstrated considerable price volatility. Stably priced solid fuel-fired resources such as coal and nuclear mitigate the risk of natural gas price volatility. However, results of the Technology Assessment indicate that new coal and new nuclear resources are not near-term economic options based on present assumptions. The System intends to periodically reassess solid fuel alternatives in light of evolving assumptions. Further, the System will seek opportunities to add solid fuel base load resources when economically attractive.

Area Planning

Results of Area Planning Assessments indicate that two regions, Amite South (in particular, DSG) and WOTAB (in particular Western), may need new resources toward the beginning of the next decade.

<u>Amite South/ DSG</u>

Presently, ELL is constructing a CCGT resource at its Ninemile site in Amite South. The addition of Ninemile 6 will address near-term reliability and economic objectives in Amite South / DSG. However, because of a number of factors in the Amite South area as described below, additional capacity will be needed in the coming years to preserve reliability and provide economic benefit. At this time, the Entergy System has not determined when a new resource will be proposed. However, the IRP includes a placeholder for a new Amite South CCGT to come on-line in 2020. System planning activities will continue to assess Amite South requirements and resource alternatives.

New generation is needed in Amite South, primarily in DSG, to maintain reliability in the region as the existing gas-fired generation fleet ages and those units ultimately are deactivated. While Ninemile 6 is a critical addition to the DSG fleet, because of reliability needs in the Amite South region, additional

[15] Long-term Resources are defined as resources whether contracted or owned with a duration of ten years or greater from the time first placed into the System portfolio. As described in a later section of this report, the System has adopted a resource strategy that seeks to meet the bulk of its requirements through long-term resources. Capacity shown as base load reflects coal and nuclear resources.

generation investment in this area eventually will be necessary, whether through significant investment in existing generation and/or the construction of additional generating capacity by the Operating Companies or by other entities who will sell power to the Companies (and other load-serving entities) via contract. As the recently-completed Minimizing Bulk Power Costs Study concluded, there currently is not an economic transmission solution that would offset the need for local generation in the Amite South region.[16] Given expected load growth, and efficient retirement/refurbishment decisions for the existing, but aging, Amite South fleet, it will be necessary to add additional generating capacity to the Amite South area approximately every five years. Because of the long lead time needed to develop new generation projects (whether constructed by the Operating Companies or by third parties with power purchase agreements ("PPAs") to the Companies), the System must begin today planning for this investment.

WOTAB / Western

A request for proposals ("RFP") soliciting an additional 300 MWs to meet resource needs in the Western Area is underway. The addition of a 300 MW resource from the 2011 Western RFP in 2017 is planned to address the near-term reliability and economic objectives in Western. Looking further into the future, however, additional actions – sustainability spending, transmission investment, and / or new generation – may be needed to offset consequences of aging Western supply resources, purchased power contract expirations, and continued higher than average load growth. The timing and type of additional supply resources will be determined by assessing the ability of the supply portfolio to meet planning targets and through Loss of Load Expectation assessments. The IRP Preferred Portfolio assumes that a new CT (300 MWs) will be added in Western in 2021. A number of uncertainties could affect the timing and or magnitude of resource requirements in Western, including the outcome of the 2011 Western Request for Proposals, load growth in-region, and transmission investments.

Demand-side Management

The scope of DSM resources considered in this plan include programs that the Entergy System Operating Companies have or may be able to deploy to manage the level and timing of customers' energy use over the planning horizon.

The Entergy System Operating Companies engaged the services of the ICF International consulting firm to assess the market-achievable potential for incremental utility-sponsored DSM programs. The DSM Potential Study was completed for the period 2012-2031 for each Entergy System Operating Company.

[16] Minimizing Bulk Power Costs Study (May 3, 2012), available at http://www.spp.org/publications/MBPC%20Study%20Executive%20Summary%20-%20final.pdf. I note that while ITC witness Johannes Pfeifenberger suggests there may be projects after the Companies' transition to the MISO Day 2 market that could reduce the generation requirements in the DSG region, the study performed by ITC witness Johannes Pfeifenberger and his colleagues at The Brattle Group is indicative only. Those projects have not been studied to determine their cost-effectiveness or feasibility as part of the RTO planning process.

The DSM Potential Study estimated the peak load and annual energy reduction that results from a low, reference and high level of program spending on a full range of potential DSM programs across the residential, commercial and industrial sectors.

The results of the DSM Potential Study form the basis for the incremental utility-sponsored DSM assumption in the 2012 IRP. Jurisdictions in the Entergy System differ in regards to the level of maturity of DSM development. The DSM assumption for ENO reflected the results of an optimization process that was developed in collaboration with ENO stakeholders. Levels of DSM assumed for other Entergy Operating Companies reflect the current state of DSM Program maturity in each jurisdiction.

A variety of factors, many of which are highly uncertain, will affect the amount of DSM that can and will be achieved over the planning horizon. The IRP process will continue to assess the market-achievable potential of DSM 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 communications infrastructure 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. Therefore, DSM assumptions , including the level of cost-effective DSM identified through the IRP process, are not intended as definitive commitments to particular programs, program levels or program timing.

The implementation of cost-effective DSM requires consistent, sustained regulatory support and approval. The Operating Companies' investment in DSM must be met with a reasonable opportunity to timely recover all of the costs, including lost contribution to fixed cost, associated with those programs. Appropriate mechanisms must be put into place to ensure the DSM potential actually accrues to the benefit of customers and that utility investors are adequately compensated for their investment.

PART 3 PORTFOLIO DESIGN ANALYTICS

The 2012 System IRP utilized a four-step approach to assess alternative portfolios to meet customers' needs:

1. Capacity Expansion Modeling
2. Initial Portfolio Design & Risk Assessment
3. Final Risk Assessment
4. Preferred Portfolio Design

Capacity Expansion Modeling

This step relied on the Aurora Capacity Expansion model to develop a capacity build-out for each market scenario. The Aurora Model determined the timing, amount, type, and regional location of capacity additions within the MISO South footprint. Aurora adds new resources when needed to meet regional reliability requirements (planning reserve margins). Additional resources are added if market price levels are sufficiently high to make an investment in incremental capacity economically attractive. This step resulted in a capacity expansion schedule for each market scenario in the overall MISO South footprint. Results at this step of the process do not yield Entergy specific portfolios.

Table 6: Results of Capacity Expansion Modeling

Results of Capacity Expansion Modeling Incremental Capacity Mix by Scenario				
	Scenario 1	Economic Rebound	Green Growth	Austerity Reigns
CCGT	9%	42%	65%	0%
CT	52%	33%	0%	67%
Sustain Existing Units	39%	25%	28%	33%
Wind	0%	1%	8%	0%
Other	0%	0%	0%	0%
Year of First Addition	2021	2021	2031	2021
Total MWs[17] Added (through 2031)	6,361	13,590	2,642	8,881

Results of the Capacity Expansion Modeling which supported conclusions from the Technology Assessment discussed earlier were reasonably consistent across scenarios:

[17] Intermittent resources are discounted based on contribution to planning reserves. Fifteen percent (15%) capacity value is attributed to wind.

- In general, new build capacity is not required to meet MISO South overall reliability needs, nor is new build construction economically supported by regional market prices until the early years of the next decade. The driver for the next new build additions will be local area supply conditions in Amite South and Western local areas.
- Gas-fired resources, Simple Cycle Gas-fired Combustion Turbines (“CT”) and Combined Cycle Gas Turbines (“CCGT”) are the preferred technologies for new build resources in most outcomes.
- In no scenario were new nuclear or new coal built.
- In no scenario were PV or biomass built.
- Wind generation has a limited role, primarily in the later years and then only in scenarios involving high gas and / or carbon.
- Investment in existing generation resources to extend operations before currently assumed deactivation dates may be a low cost alternative to meet customer needs.

Initial Portfolio Design & Risk Assessment

The focus in this step was to develop portfolios for the Entergy System that met Entergy planning objectives. Informed by the results of the Capacity Expansion Modeling, Entergy portfolio plans were developed for each scenario. Each plan described the type, amount, timing, and regional location (as applicable) of portfolio additions. The resulting portfolios included resource additions from the capacity expansion (step 1) plus other portfolio additions (e.g., power purchase assumptions) necessary to meet planning objectives.

Purchase Power Assumptions

The System has adopted a strategy to meet reliability requirements largely through long-term resources whether owned assets or long-term power purchase agreements. The emphasis on long-term resources helps protect customers from risk associated with the price and availability of power. This strategy is reflected in the 2012 System IRP. Accordingly, the amount of short-term and limited-term power purchases required to meet reliability requirements were limited to the following levels which reflect historical practice:

- Limited-term Contracts for reliability: 500 – 1000 MWs
- Short-term Capacity Contracts for reliability: 500 – 1000 MWs
- Short-term purchases for economic reasons: Unlimited

Table 7: Results of Initial Portfolio Design & Risk Assessment

Results of Initial Portfolio Design & Risk Assessment Forward Supply Cost[18],[19]				
	Scenario 1	Economic Rebound	Green Growth	Austerity Reigns
2012 $ NPV Billions				
Incremental Fixed Cost	$4.5	$6.8	$3.7	$4.8
Variable Cost	$33.5	$38.4	$43.6	$23.0
Total	$38.0	$45.2	$47.3	$27.8
$/MWh Levelized				
Incremental Fixed Cost	$5.94	$8.96	$4.87	$6.33
Variable Cost	$43.82	$50.23	$57.07	$30.10
Total	$49.76	$59.19	$61.94	$36.43

Results illustrate the uncertainty regarding future supply costs with outcomes in the four scenarios ranging from $27.8 billion to $47.3 billion on an NPV basis.

<u>MISO Market Implications</u>

Consistent with its current strategy, the System will enter MISO with the bulk of its reliability requirements covered by long-term resources. Once it joins MISO the Entergy System will be able to fully participate in MISO's Day 2 market, which includes (in part) unbundled capacity and energy products, an annual capacity auction, and a requirement that resources that are counted as capacity also participate in the energy market. It is possible that the advantages of this market may enable the System to relax to some extent its reliance on long-term capacity. Experience gained during the first years within MISO will provide the System with the opportunity to evaluate its current power purchase strategy and adjust according.

Final Risk Assessment

The Final Risk Assessment assessed how alternative portfolio mixes performed across sensitivities for natural gas prices, carbon costs, and purchase power costs. Given that the analysis through this point had indicated that CT and CCGT technology tended to be the technologies of choice in most scenario outcomes, the Final Risk Assessment compared portfolios that included alternative mixes of CT and CCGT technologies. During this step, portfolios were designed based on the Reference Load Forecast. In other words, each portfolio was comparable in terms of capacity. This enabled the analysis to focus on the effects of the key drivers being varied – natural gas, carbon and purchased power cost. The Final Risk Assessment also considered a high DSM scenario that had been identified in the ENO DSM optimization effort as potentially economic in high carbon cost outcomes. Four portfolios were assessed:

[18] Data includes forward cost for the period 2014-2031. Sunk cost excluded.

[19] Discounted at 7.81 % weighted average cost of capital (assumes 50 % debt, 50% equity).

- CCGT Dominant Portfolio
- CT Dominant Portfolio
- Balanced Portfolio
- High DSM Portfolio

Each portfolio was modeled in Aurora and tested in four sensitivities for a total of 16 cases. The four sensitivities were:

- Reference Gas Prices / No CO_2
- Reference Gas & CO_2 Beginning 2023
- Low Gas & No CO_2
- High Gas & CO_2 Beginning 2018

Table 8: NPV of Forward Revenue Req. by Case

NPV of Forward Revenue Requirements (2014 – 2031)[20] 2012$ Billions				
Portfolio	**Reference Gas & No CO_2**	**Reference Gas & 2023 CO_2**	**Low Gas & No CO_2**	**High Gas & 2018 CO_2**
CCGT Dominant	37.76	41.20	30.24	53.93
CT Dominant	38.74	42.26	30.84	54.64
Balanced CCGT / CT	38.76	42.28	30.84	54.64
High DSM	38.78	42.23	30.90	54.60

The lowest NPV of revenue requirements occurred in the CCGT Dominant Portfolio and Low Gas & No CO_2 Sensitivity Case. As a basis for assessing risk the following table provides the difference between each case and lowest case.

Table 9: NPV of Rev. Req. In Excess of Low Case

NPV of Revenue Requirements in Excess of Lowest Cost Outcome 2012 $Billions				
Portfolio	**Reference Gas & No CO_2**	**Reference Gas & 2023 CO_2**	**Low Gas & No CO_2**	**High Gas & 2018 CO_2**
CCGT Dominant	7.52	10.96	0.0	23.69
CT Dominant	8.49	12.02	0.60	24.39
Balanced CCGT / CT	8.51	12.03	0.60	24.40
High DSM	8.54	11.98	0.66	24.36

Findings

- Variability among portfolios within a Sensitivity Case is relatively modest. In other words, variability across the sixteen outcomes is primarily driven by the gas and CO_2 assumption as opposed to the portfolio mix.

[20] Discounted at 7.81% weighted cost of capital. Excludes sunk cost.

- The CCGT Dominant Portfolio tends to be the lowest cost. The High DSM Portfolio tends to be at or near the highest cost except under the High Gas & 2018 CO_2 sensitivity.
- There is a tradeoff between fixed and variable cost among portfolios. Although CCGT Dominant Portfolio tends to be lowest overall cost it is also, the portfolio with the highest fixed cost. CT Dominant Portfolio is the lowest fixed cost.
- Considering the tradeoffs between CCGT and CT and the relative modest differences among portfolio assessment results, the Preferred Portfolio described in the next section adopts a balanced CT and CCGT mix.

PART 4 CONCLUSIONS

Preferred Portfolio

The IRP process results in a Preferred Portfolio that defines the System's Strategy for meeting customers' long-term power needs. The Preferred Portfolio includes the following elements:

- The System continues to meet the bulk of its reliability requirements from long-term capacity whether owned assets or long-term power purchase agreements. The emphasis on long-term resources mitigates exposure to price volatility and ensures the availability of resources sufficient to meet long-term reliability needs.
- A portion of reliability requirements is met through a reasonable but limited reliance on limited-term power purchase products.
- The Ninemile 6 CCGT presently under construction in Amite South is completed and begins operations in 2015.
- The IRP assumes that 300 MWs of capacity is added to the Western Area in 2017 as a result of the RFP presently in progress. In addition, a new CT (370 MWs) is added in Western in 2021. A number of uncertainties could affect the timing and or magnitude of resource requirements in Western, including the outcome of the 2011 Western Request for Proposals, load growth in-region, and transmission investments.
- Near-term incremental needs (until 2020) are met largely from purchased power from existing facilities. Beyond Ninemile 6 and the possible Western Area resource no new build resources are anticipated until 2020.
- All existing coal and nuclear units continue in operations throughout the planning horizon. All nuclear units are assumed to receive license extensions to operate up to 60 years from the Nuclear Regulatory Commission ("NRC").
- New build capacity, when needed in 2020 and beyond, comes from a combination of CT and CCGT resources. New build capacity may be either owned resources or long-term power purchase contracts. For the purposes of preparing the IRP, the economics were assumed to be equivalent.
- No new solid fuel capacity is added and new nuclear development remains in the monitoring phase.
- In the second half of the planning horizon investments are made to continue to operate several units beyond their assumed deactivation dates.

The IRP Preferred Portfolio includes assumptions regarding future resource additions. However, with the exception of the Ninemile 6 resource presently under construction in Amite South the System has not made a decision to implement any particular future capacity addition. The actual resources deployed – the amount, timing, technology, power purchase products – will depend on factors which may differ from assumptions used in the development of the IRP. Such long-term uncertainties include, but are not limited to:

- Load growth, which will determine actual resource needs;
- The relative economics of alternative technologies, which may change over time;
- Environmental compliance requirements;
- Practical considerations that may constrain the ability to deploy resource alternatives such as the availability of adequate sources of capital at reasonable cost.

The actual decision to procure a given resource will be contingent upon a review of the economics of any viable transmission alternatives available.

The actual decision to procure a specific resource in a specific location must reflect the specific lead time for that type of resource, which will vary by resource type. By taking no action until it is needed, the System retains the flexibility to respond to changes in circumstances up to the time that a commitment is made.

Table 10: Load & Capability (Preferred Portfolio)

Load & Capability 2012 – 2021[21] (MW)										
	2012	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
Requirements										
Peak Load	21,558	21,910	17,375	17,541	14,217	14,350	14,488	14,616	14,731	14,851
DSM	(3)	(40)	(102)	(177)	(258)	(342)	(440)	(507)	(557)	(616)
Planning Reserve (12%)	2,587	2,624	2,073	2,084	1,675	1,681	1,686	1,693	1,701	1,708
Total Requirements	24,141	24,494	19,345	19,448	15,634	15,688	15,734	15,802	15,875	15,943
Resources										
Existing Resources										
– Owned Resources	21,811	22,451	16,734	16,734	12,809	11,999	11,424	11,189	10,762	10,527
– Power Purchase Contracts	2,802	2,506	2,551	2,541	2,457	2,457	1,908	1,833	1,833	1,533
Identified Planned Resources										
– Ninemile 6				560	560	560	560	560	560	560
– 2011 Western Region RFP[22]						300	300	300	300	300
– Other		40	40	40	40	40	40	40	40	40
Other Planned Resources										
– Amite South (CCGT)									570	570
– Western (CT)										370
– CCGT										
– CT										
– Sustain Existing Units										
– Long-term Purchases[23]							500	500	500	500
– Limited-term Power Purchases/(Sales) Contracts		(59)				50	550	750	200	450
– Short-term Capacity Purchases[24]		115	115	115	115	283	453	633	686	858
Total Resources	24,613	25,052	19,429	19,989	15,980	15,688	15,734	15,802	15,875	15,943

[21] Totals may not add due to rounding.
[22] The 2011 Western Region RFP has not been completed. It has not been determined whether any resource will be selected and/ or whether such a resource would be an owned resource or a power purchase contract.
[23] May also be an acquisition of an existing resource.
[24] Includes up to 115 MW in as available capacity through ETI's Competitive Generation Service Tariff

Load & Capability 2022 – 2031 (MW)										
	2022	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
Requirements										
Peak Load	14,973	15,097	15,236	15,359	15,470	15,599	15,729	15,870	16,007	16,147
DSM	(662)	(705)	(769)	(811)	(841)	(876)	(896)	(933)	(961)	(990)
Planning Reserve (12%)	1,717	1,727	1,736	1,746	1,756	1,767	1,780	1,792	1,806	1,819
Total Requirements	**16,028**	**16,118**	**16,203**	**16,295**	**16,385**	**16,490**	**16,613**	**16,729**	**16,852**	**16,976**
Resources										
Existing Resources										
– Owned Resources	10,527	10,117	9,727	9,727	9,205	8,676	8,676	8,676	8,526	7,464
– Power Purchase Contracts	1,048	1,048	1,048	1,048	1,048	1,048	1,048	1,048	1,048	1,048
Identified Planned Resources										
– Ninemile 6	560	560	560	560	560	560	560	560	560	560
– 2011 Western Region RFP	300	300	300	300	300	300	300	300	300	300
– Other	40	40	40	40	40	40	40	40	40	40
Other Planned Resources										
– Amite South (CCGT)	570	570	570	570	570	570	570	570	570	570
– Western (CT)	370	370	370	370	370	370	370	370	370	370
– CCGT										570
– CT							370	370	740	1,480
– Sustain Existing Units					522	1,051	1,051	1,051	1,051	1,785
– Long-term Purchases	1,000	1,300	2,300	2,300	2,300	2,300	1,800	1,800	1,800	1,800
– Limited-term Power Purchases/(Sales) Contracts	750	950	400	500	600	750	1,000	1,000	1,000	500
– Short-term Capacity Purchases	864	864	889	880	870	826	828	945	848	489
Total Resources	16,029	16,119	16,203	16,295	16,386	16,490	16,613	16,729	16,852	16,976

Action Plan

Table 11: Action Plan

Category	Item	Action to be taken
Supply-side Alternatives	Combustion Turbine	– Improve analytics and understanding of relative benefits between simple cycle combustion turbine and combined cycle combustion turbine technologies – particularly in a structured market – as a basis for assessing CT's role in the portfolio.
	New Nuclear	– Continue to monitor new nuclear technologies. Maintain readiness to execute new nuclear projects when and if they appear viable through spending levels consistent with results of the on-going assessment.
	Renewable Generation	– Continue to monitor renewable technologies.
	Legacy Fleet	– Evaluate opportunities to extend unit operations. – Continue to monitor environmental compliance developments and evaluate compliance options including installing controls, changing unit rules and resource replacements.
Demand-side Alternatives		– Work with regulators to implement cost effective DSM programs that provide appropriate cost recovery.
MISO Transition	Resource Adequacy	– Monitor decisions regarding the System's market participation structure and consider effects on resource requirements.
	Mid-term Plan	– Develop Mid-term supply plan describing the System's strategy for meeting resource adequacy requirements over first three years of MISO participation.
	Portfolio Design	– As clarity is obtained regarding the OPCOs' proposed participation in MISO, including the structure of the OPCOs' participation, consider the implication for the System's Preferred Portfolio. – As experience is gained in the MISO market refine the System's purchase power strategy.
Area Planning	Amite South	– Continue to assess resource requirements in Amite South. – Refine point-of-view regarding timing and technology for next resource addition. – Develop long-term Baseline Planning Scenario for Amite South.
	Western Area	– Assess long-term Western Area requirements in light of RFP outcome and planned transmission investments. – Refine point-of-view regarding timing and technology for next resource addition. – Develop long-term Baseline Planning Scenario for Western.
Procurement	Requests for Proposals	– Determine resolution of 2011 Western RFP. – Complete 2010 RFP for Long-term Renewable Resources. – Complete 2012 Long-term Base Load RFP.

Category	Item	Action to be taken
Jurisdictional IRP Requirements	Louisiana	– Respond to evolving jurisdictional IRP requirements and adapt planning processes and methods, as appropriate. – Comply with requirements of LPSC IRP rules by filing full report by May 2015,
	New Orleans	– Complete IRP filing in October 2012.
Modeling	Aurora	– Continue to implement and enhance Aurora modeling capabilities.