Entergy

2012 Integrated Resource Plan

Entergy New Orleans

This document describes the Entergy New Orleans' Integrated Resource Plan for the period 2012 – 2031. The Integrated Resource Planning process results in a Preferred Portfolio that describes Entergy New Orleans' long-range strategy for meeting customers' power needs. This plan is a component of the 2012 Entergy System Integrated Resource Plan.

October 30, 2012

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INTRODUCTION

This report describes Entergy New Orleans, Inc.'s ("ENO") 2012 Integrated Resource Plan ("IRP") that covers the period 2012 – 2031 referred to as the "planning horizon." Starting in 2008, the Council of the City of New Orleans ("Council") required that ENO file an IRP. Since that time, the Council has adopted several resolutions that describe the objectives of the planning process as well as the desired analytical framework and the expectations for stakeholder input. An integrated resource plan is a comprehensive and complex analysis. This report is intended to provide a relatively short summary of the overall ENO IRP process, the main planning assumptions, and the process utilized. With this report, the six (6) Technical Supplements and six (6) Data Supplements[1], ENO has provided the information required by the Council.

The 2012 ENO IRP is the result of a comprehensive and complex eighteen-month planning process devoted to ensuring that ENO has a long-term plan to position the Company to continue providing reliable service at the lowest reasonable cost to customers. The 2012 ENO IRP planning process included a number of enhancements to better meet Council objectives, reflect the current planning environment, and further the evaluation of supply-side and demand-side resources in a fair and consistent manner. Key enhancements from previous IRP's are summarized below:

- The Entergy Operating Companies have proposed to join the Midwest Independent Transmission System Operator, Inc. ("MISO"). While the proposed transition to MISO involves a number of uncertainties, this IRP is premised on the planning assumption that ENO, the other Entergy Operating Companies, as well as other load serving entities and independent power producers in close proximity to the Entergy Operating Companies join MISO effective January 1, 2014. Consequently, planning models and methodologies have been revised to more accurately represent business in a Regional Transmission Organization ("RTO") like MISO. The IRP collectively refers to this new group of MISO market participants and the region in which they operate as "MISO South".

- One of the Council's key objectives is to optimize both supply- and demand-side resource options included in the ENO IRP. As a result, ENO conducted a study of the market-achievable demand-side management ("DSM") potential ("Potential Study") within New Orleans and then utilized an optimization methodology to estimate the amount of DSM from the Potential Study that results in the lowest total supply cost.

- The development of ENO's IRP included a structured stakeholder process facilitated by the Advisors to the Council. Over the past 12 months, stakeholders met with representatives of ENO's planning team numerous times to review the overall project schedule and to discuss input assumptions and the analytical framework. Because of strong local interest, a separate working group was formed to consider DSM.

- Finally, after the optimal portfolio ("Preferred Portfolio") of supply- and demand-side resources was determined, it was evaluated from a number of perspectives, including an analysis to evaluate certain risks (e.g. exposure to higher costs). The results of that analysis were translated into customer bill impacts in order to assess the impact of future uncertainty on customer rates.

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[1] The Technical Supplements to the 2012 ENO IRP include the 2012 Entergy System IRP, General Technical Supplement, Technology Assessment, DSM Technical Supplement, ICF Achievable DSM Potential Study, and Best Practices Supplement. The Data Supplements include the Customer Demand and Energy Forecasts, Macro Inputs, Total Supply Cost 2006-2031, Portfolio Design Analytics, Energy Supply by Resource Type, and Rate Effects (Data Supplements 1 – 6, respectively).

KEY FINDINGS AND INSIGHTS

Current Assessment

ENO is an integrated utility responsible for serving the electric and natural gas demands of the City of New Orleans. The City of New Orleans is located in a sub-region of the Amite South Planning Region, known as the Downstream of Gypsy ("DSG") area. Planning areas are determined based on the characteristics of the Entergy System, including the ability to transfer power between areas. The DSG area generally encompasses the area south of Lake Pontchartrain and east to the Gulf of Mexico, and in 2011 reached a peak demand of 2,988 MW. ENO's peak customer electric demand in 2011 represented approximately 31% of peak demand within DSG.

The DSG region continues to recover from the devastation of Hurricane Katrina. In 2005, ENO's peak electric demand was 1,254 MW and in 2006 it was 788 MW. Since then, ENO's peak has increased every year and its highest, post-Katrina, non-weather adjusted peak was set in 2011 at 1,018 MW.

ENO's supply-side electric generation portfolio consists of 1,253 MW of long-term generating resources across a range of technologies and fuel types including nuclear, coal, and natural gas. In addition, Entergy Louisiana, LLC ("ELL") is constructing a highly efficient, natural gas-fired combined-cycle turbine ("CCGT") at its Ninemile Generating Station in Westwego, LA ("Ninemile 6"). ENO has obtained approval from the Council to purchase 20% of the power from this new unit through a long-term contract. The addition of Ninemile 6 will address near-term reliability objectives in the Amite South and DSG areas.

ENO's DSM portfolio consists of the Energy Smart New Orleans program launched in March, 2011. ENO has completed the initial year of Energy Smart New Orleans, a 3-year, $11 million plan to offer energy efficiency programs to its customers. In the first year, the Energy Smart New Orleans program provided incentives to more than 8,500 residential and commercial customers to improve the energy efficiency of their homes and businesses. ELL provides electric service to the 15th ward (Algiers), and recently received Council approval to extend the Energy Smart New Orleans programs to residents of Algiers through a program known as Energy Smart Algiers.

Although ENO's current supply- and demand-side resource portfolio compares favorably with its customer load requirements today, new resources will be needed in the future to maintain reliability as the load grows, purchased power contracts expire, and the existing generation fleet ages and units are potentially deactivated.

Resource Need

By the end of the twenty-year planning horizon, ENO's resource capability is expected to be short of its load requirement by 527 MW in the reference case planning scenario ("Scenario 1"). This need is driven primarily by the planning assumption that units at ENO's Michoud generating facility will be deactivated in 2022 (Unit 2) and 2027 (Unit 3). The purpose of the IRP is to outline a plan that will address those needs and support ENO's primary objective to meet current and future customer power needs reliably and at the lowest reasonable cost. In order to do that, the IRP selects from the available cost-effective resource options, both supply- and demand-side, that results in the lowest total cost while considering risk. A primary risk to total cost to serve customers' needs is driven by the cost of fuel (e.g. coal, natural gas) necessary to run generating facilities. As a result, the Preferred Portfolio is designed to mitigate the effects of production cost volatility that can result from over dependence on a particular fuel-type, generating technology, purchased power cost uncertainty, or possible supply disruptions.

Resource Alternatives

The ENO IRP optimization process considered a range of alternatives available to meet planning objectives including transmission solutions, potential conventional generation resource refurbishments or additions, potential renewable resource additions, and DSM.

Transmission Solutions

The historical regional growth and development, as well as geographical features, of the areas served by the Entergy Operating Companies transmission system have resulted in certain regions that are transmission-limited and therefore dependent on local generating facilities to serve the entire customer load. Despite this characteristic, a recently completed study, conducted by a third-party consultant at the request of a consortium of Entergy's retail regulators, concluded that there is currently not an economic transmission solution that would offset the need for local generation in the Amite South region. The conclusions of this study are discussed in the "Area Planning" section below.

Supply-side Alternatives

The Michoud Generating Station is owned by ENO and includes two operating units, Michoud Units 2 and 3 that entered commercial operation in 1963 and 1967, respectively. Michoud is a natural gas-fired steam generating facility that provides ENO with flexible capability to support reliability in DSG. The IRP establishes a plan to address the eventual deactivation of the existing units at the facility.

Among the conventional generating resource alternatives evaluated in the IRP, natural gas-fired technologies prove to be attractive across a range of assumptions concerning operations, fuel costs, and potential future regulation of CO_2. Relative to gas-fired technologies, new nuclear and new coal technologies are less attractive due to certain complexities associated with bringing these technologies into commercial operation. However, ENO's share of existing nuclear[2] and coal-fired generating facilities currently in operation are assumed to remain in ENO's portfolio during the planning horizon[3].

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 and solar incentives are currently expected to end in 2016. Among renewable technologies, wind power is the most likely to be cost-competitive with gas-fired technologies; however, under most cases, wind remains less economic than natural gas.

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[2] The IRP makes an assumption that the nuclear generating facilities in ENO's portfolio are granted extension of each facility's operating license from the Nuclear Regulatory Commission.

[3] ENO currently has one long-term PPA for approximately 60 MW of capacity sourced from a coal-fired generating facility located in Arkansas and operated by EAI that expires in May 2013. The expiration of the PPA is reflected in the IRP.

DEMAND-SIDE MANAGEMENT

ENO engaged the services of the ICF International consulting firm to assess the market-achievable potential for DSM programs that could be deployed over the planning horizon. In all, 899 measures were evaluated and 22 DSM programs were modeled, including eleven energy efficiency programs based on current Energy Smart program designs and six additional energy efficiency programs that expand the options for commercial customers and residential customers including those living in multifamily buildings. ICF also modeled six demand response programs that provide customers with an opportunity to modify their energy usage patterns in response to a price signal. The Potential Study estimated the peak load, annual energy reduction, and program costs that result from a low, reference and high level of spending on program incentives. The reference case estimate of DSM potential indicates that about 200 MW of peak demand reduction could be achieved by 2031 if ENO's investment in DSM were sustained for a 20-year period.

The methodology of the Potential Study was consistent with a primary objective to identify a wide range of DSM potential available to meet customers' needs. In this way, the study results helped ensure that more programs would be identified for further evaluation in the IRP, however; the results of the Potential Study do not reflect a level of DSM spending that would result in a portfolio with the lowest total supply cost for New Orleans. Given one of the IRP objectives was to develop a portfolio that results in the lowest total supply cost, the DSM optimization took the programs identified in the Potential Study and organized them in a way that allowed the model to continue adding DSM programs to ENO's portfolio until they cost more than a supply-side alternative (choosing from the full range of supply-side alternatives available). Therefore the IRP process considered supply- and demand-side alternatives on an equal footing. As such, the level of spending identified in the Potential Study would not consistent with a portfolio that met customers' needs at the lowest reasonable cost.

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

TABLE 1: ENO DSM PROGRAM ALTERNATIVES – REFERENCE CASE

Sector	Type	Program Name	Energy Smart?	TRC Test	Levelized Cost/kWh	Levelized Cost/kW	2031 MW Savings
C&I	EE	Large Commercial Energy solutions	Yes	2.2	$0.03	$161	53.5
C&I	EE	Small Commercial Energy Solutions	Yes	1.8	$0.05	$188	16.6
C&I	EE	Commercial Solar PV	Yes	0.4	$0.31	$605	7.5
Res.	EE	Energy Smart New Homes	Yes	1.2	$0.05	$141	0.2
Res.	EE	ENERGY STAR Air Conditioning	Yes	1.8	$0.05	$175	12.0
Res.	EE	Residential Lighting and Appliances	Yes	1.5	$0.05	$232	8.7
Res.	EE	Residential Energy Solutions	Yes	1.2	$0.08	$252	17.2
Res.	EE	AC Tune-Up	Yes	1.2	$0.09	$244	3.8
Res.	EE	Residential Solar PV	Yes	0.6	$0.04	$75	0.2
Res.	EE	Solar Water Heater Pilot	Yes	0.4	$0.07	$448	0.0
Res.	EE	Low Income Weatherization	Yes	0.9	$0.13	$451	2.9
C&I	EE	Commercial Building Energy Management	No	3.9	$0.02	$95	3.4
C&I	EE	Commercial New Construction	No	2.3	$0.03	$174	9.0
C&I	EE	Industrial	No	2.8	$0.02	$140	5.4
Multi	EE	Multifamily Residential	No	1.4	$0.06	$328	4.4
Res.	EE	Home Energy Use Benchmarking	No	1.3	$0.08	$338	0.8
C&I	DR	Non-Enabled Dynamic Pricing (Non-Res)	No	5.0	--	$38	1.6
C&I	DR	Enabled Dynamic Pricing (Non-Res)	No	2.7	--	$67	2.5
C&I	DR	Interruptible Rate	No	38.7	--	$20	23.4
Res.	DR	Direct Load Control	No	7.8	--	$18	19.2
Res.	DR	Enabled Dynamic Pricing (Res)	No	2.7	--	$67	5.4
Res.	DR	Non-Enabled Dynamic Pricing (Res)	No	3.1	--	$66	2.4
		TOTAL PORTFOLIO – REFERENCE CASE		1.9	$0.05	$160	200.4

ENO Preferred Portfolio

The ENO Preferred Portfolio resulting from the IRP process includes supply- and demand-side resources that perform best over a range of alternative future scenarios for energy and load growth, fuel prices, and environmental regulations. The ENO Preferred Portfolio includes the following key supply-side elements:

- ENO 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.
- All existing coal and nuclear units currently in ENO's supply-side portfolio continue operations throughout the planning horizon.
- Although no final decisions have been made regarding the timing or level of investment that would be necessary to extend reliable operation of the Michoud facility during the IRP planning horizon, the IRP optimization process selected to extend the life of Michoud Unit 3 (as opposed to deactivation) over other available resource alternatives.
- New build capacity, when needed in 2020 and beyond, comes from CCGT resources. With the exception of Ninemile 6 presently under construction, the System has not made a decision to implement any particular future capacity addition.

The level of DSM included in the Preferred Portfolio was determined by an optimization methodology that systematically evaluated increasingly expensive "flights" of DSM programs. That is, a small bundle of the most cost-effective programs were evaluated first, and small bundles of increasingly expensive programs were added until all levels of potential DSM were included. The amount of DSM that minimized the total cost of service was identified as the optimal level of DSM.

Ten different DSM programs are included in the ENO Preferred Portfolio including five of the Energy Smart programs, three additional energy efficiency programs for the non-residential customer sector, and two new demand response programs. The DSM programs reflect the potential to reduce peak load by 203 MW at the end of 2031 at a cost of approximately $5 to $6 million per year.

TABLE 2: ENO DSM PROGRAMS –DSM PROGRAMS IN THE PREFERRED PORTFOLIO

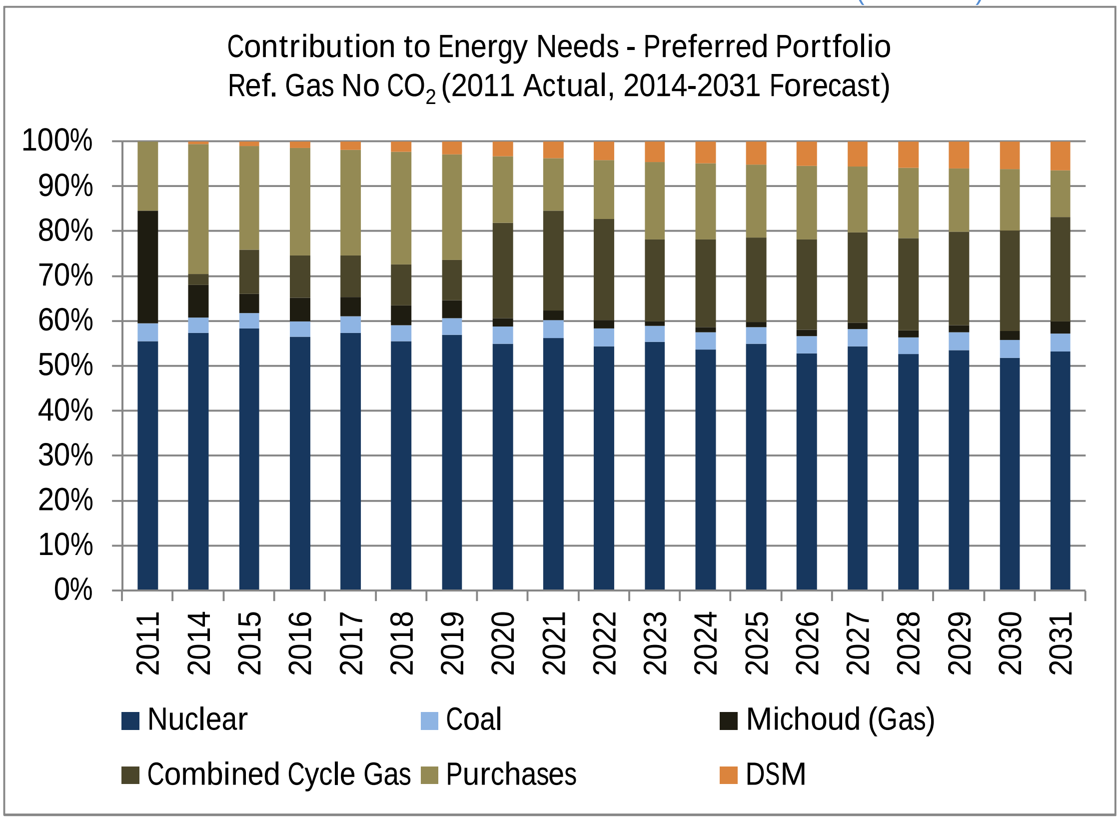
Sector	Type	Program Name	Energy Smart?	Level of Spending on Incentives
C&I	EE	Large Commercial Energy solutions	Yes	Low
C&I	EE	Small Commercial Energy Solutions	Yes	Low
Res.	EE	Energy Smart New Homes	Yes	Low
Res.	EE	ENERGY STAR Air Conditioning	Yes	Low
Res.	EE	Residential Lighting and Appliances	Yes	Low
C&I	EE	Commercial Building Energy Management	No	Low
C&I	EE	Commercial New Construction	No	Low
C&I	EE	Industrial	No	Low
C&I	DR	Interruptible Rate	No	High
Res.	DR	Direct Load Control	No	High

TABLE 3: ENERGY AND DEMAND SAVINGS AND ANNUAL PROGRAM COSTS FOR DSM PROGRAMS IN THE PREFERRED PORTFOLIO

	Cumulative Energy Savings (MWh)	Cumulative Peak Load Reduction (MW)	Annual Program Costs ($M)
2012	5,387	3	0.74
2013	16,290	9	1.50
2014	33,726	19	3.13
2015	54,852	32	3.56
2016	79,762	46	4.27
2017	106,953	58	4.65
2018	135,326	87	4.91
2019	163,543	102	5.06
2020	191,144	105	5.16
2021	218,284	122	5.24
2022	245,103	133	5.30
2023	269,108	140	5.36
2024	290,192	162	5.43
2025	308,501	169	5.49
2026	324,945	174	5.56
2027	340,021	183	5.63
2028	354,012	181	5.70
2029	367,179	188	5.77
2030	380,410	195	5.84
2031	393,019	203	5.92
	Total Spending (Optimal DSM)		94.2
	Average Annual Spending (Optimal DSM)		4.7

A variety of factors, many of which are highly uncertain, will affect the amount of DSM that can be achieved over the planning horizon. ENO's investment in DSM must be met with a reasonable opportunity to timely recover all of the costs associated with DSM programs, including program costs, lost contributions to fixed cost, and the potential to earn incentives. The Preferred Portfolio includes an optimal (cost-effective) mix of supply- and demand-side resources from the alternatives available to meet customers' needs at the lowest reasonable cost while considering reliability and risk. The figure below illustrates the mix of resources in the Preferred Portfolio that contribute to meeting those needs during the term of the planning horizon.

FIGURE 1: CONTRIBUTION TO ENO CUSTOMER ENERGY NEEDS BY RESOURCE TYPE (2014-2031)[4]

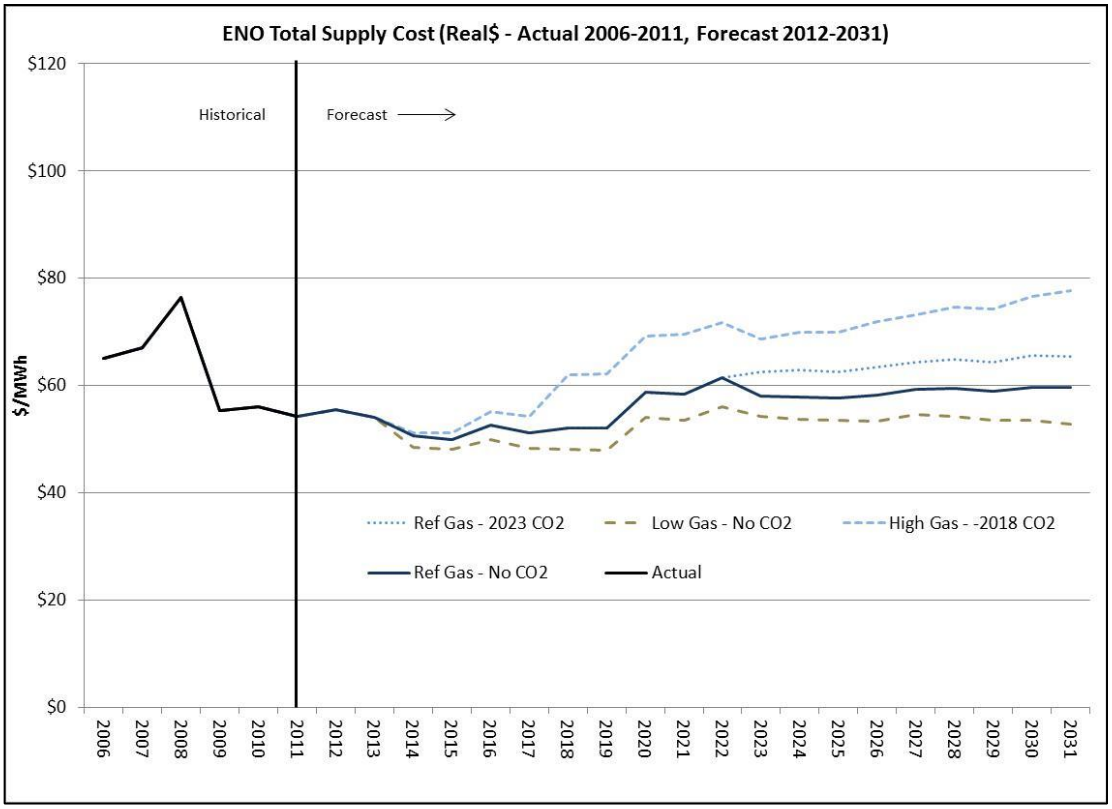


[4] 2011 data does not include DSM associated with Energy Smart due to the timing of program implementation.

Customer Impact

As shown in the figure below, the total estimated cost of the Preferred Portfolio, adjusted for inflation, compares favorably to ENO's historical production cost under a range of potential future scenarios for natural gas prices and CO_2 regulation, both of which are key drivers of the cost to produce electricity.

FIGURE 2: ENO Total Supply Cost (Preferred Portfolio)[5]



The table below highlights the impact of the Preferred Portfolio on an average ENO residential customer's electric bill for potential future natural gas prices and CO_2 regulation. ENO believes these are the two biggest risk factors for the future cost to produce electricity (and therefore, to customer electric bills) over the next twenty years. It should be noted that due to the inclusion of a significant level of DSM in the ENO Preferred Portfolio, and improvements in energy efficiency standards, the average residential customer is expected to reduce their annual electricity consumption by almost 1% per year. An evaluation of the Preferred Portfolio with reference case and low case outlooks for natural gas, and no or modest assumptions for CO_2 regulation, results in annual increases in average customer bills below ENO's forecast for long term inflation (~2% per year). Using a high case outlook for natural gas prices and a more aggressive assumption for the regulation of CO_2, the Preferred Portfolio results in average customer bills that grow slightly faster than the long-

[5] The data includes all variable and fixed cost associated with producing or purchasing electricity to serve ENO customers including cost from historical capital expenditures, demand side management programs and System Agreement effects related to production. The data does not include transmission, distribution or customer service. Assumes rough production cost equalization payments/receipts are zero in forecast years. The results in the figure are shown in 2012 Real dollars (adjusted for inflation).

term outlook for inflation. Stated differently, except under the most aggressive scenario for natural gas prices and CO2 regulation, the ENO Preferred Portfolio is expected to increase the average residential customer's monthly bill by less than the amount that prices for all goods and services are expected to increase over the next 2 decades.

TABLE 4: RISK ANALYSIS – ENO AVERAGE RESIDENTIAL CUSTOMER ELECTRIC BILL (PREFERRED PORTFOLIO)[6]

Risk Scenario	2011 Usage (KWh/mo.)	2011 Bill ($/mo.)	2031 Usage (kWh/mo.)	2031 Bill ($/mo.)	Annual Growth in kWh	Annual Growth in $
Reference Gas, No CO_2	1,111	104	925	132	-0.9%	1.2%
Reference Gas, 2023 CO_2	1,111	104	925	141	-0.9%	1.6%
Low Gas, No CO_2	1,111	104	925	122	-0.9%	0.8%
High Gas, 2018 CO_2	1,111	104	925	160	-0.9%	2.2%

[6] Includes benefits associated with the optimal (cost-effective) level of DSM identified through the DSM Optimization.

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IRP PROCESS OVERVIEW

Starting in October 2011, the Council's Advisors hosted the first in a series of Quarterly Technical Conferences ("Conference") devoted to reviewing ENO's long-term integrated resource planning efforts[7]. The Conferences were originally envisioned to include only intervening parties. As additional parties requested to participate, the group was expanded. This afforded ENO the opportunity to obtain input from all interested parties ("Stakeholders") prior to its filing.[8]

As part of that process, and at the request of the Alliance for Affordable Energy, a sub-team or working-group was established to address issues specific to the DSM portion of the IRP. The "DSM Working Group" (or "Working Group") met eight times over the year and largely consisted of the same participants from the Conferences. Subsequent to the first Conference and Working Group meeting, ENO along with the Advisors endeavored to ensure that Stakeholders concerns were addressed by discussing relevant issues, responding to data requests, revising the inputs to analytics of the DSM Potential Study, and explaining the results of the process to optimize DSM in the context of ENO's IRP.

In total, the Advisors hosted five Conferences and eight DSM Working Group meetings prior to this filing. Prior to each quarterly Conference and Working Group meeting, the Advisors circulated an agenda to the Stakeholders and ENO circulated additional documents prepared for each meeting. At each Conference ENO provided an update on the status of work to complete the IRP, and sought input from Stakeholders. Following each Conference, the Advisors produced and filed with the Council a report summarizing the meeting. As the Conference records[9] reflect, the IRP review process was both thorough and inclusive.

Best Practices

In addition to the Stakeholder process, the System Planning and Operations organization ("SPO") conducted a review of recent IRPs of other U.S. utilities across the nation in order to identify best practices and inform development of the 2012 ENO IRP. As shown in Figure 1, the review included 15 publicly available and recent IRPs from around the U.S. representing a wide-range of company sizes and geographic distribution. The results were presented to Stakeholders in October 2011 at the first Conference. The details of that presentation are included in Best Practices Supplement to the IRP.

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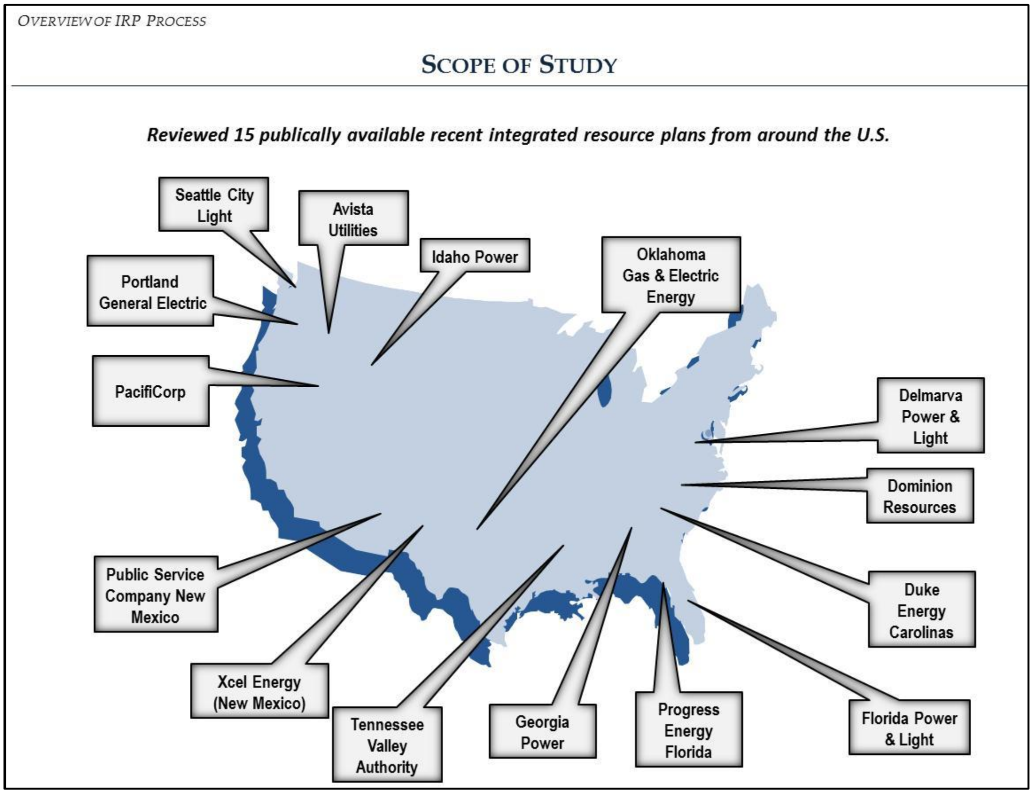
[7] Ordering paragraph no. 12 of Council Resolution R-10-142 included the following direction: "The Council, looking back on the successful process utilized in establishing the Energy Smart Plan earlier in this Docket [UD-08-02], directs that a similar open and transparent process be followed regarding the IRP filing." Council Resolution R-11-301 further required that the Advisors to the Council hold quarterly technical conferences with the Companies and Interveners. *See* Council Resolution R-11-301, ordering paragraph no. 4.

[8] Over the course of the Technical Conferences, Stakeholders have included the Alliance for Affordable Energy, the Sierra Club, the Regulatory Assistance Project, Global Green, the Gulf States Renewable Energy Industry Association, the American Council for an Energy-Efficient Economy, and representatives of the Council.

[9] The Advisors' quarterly reports are filed in Council Docket UD-08-02.

FIGURE 3: SURVEY OF U.S. UTILITY IRPS



IRP Requirements of the Council

In prior Resolutions, the Council established guidelines and requirements for the IRP and Stakeholder processes[10]. Outlined below are the requirements identified therein, including a brief summary of how the current IRP has addressed each requirement.

COMPONENT 1 – IRP OBJECTIVES

Requires the IRP to state and support specific objectives to be accomplished with regard to system planning and also requires the IRP to demonstrate how ENO achieves or will achieve the objectives. It also requires ENO to identify and quantify the costs and benefits of its resource portfolio and compare those to alternatives available in the market.

In addition to the multi-step process used in the 2012 Entergy System IRP to assess alternative portfolios[11], ENO undertook an extensive and detailed analytical effort to determine the optimal mix of resources to meet ENO customers' needs over the next two decades. This effort was conducted in a manner consistent with the Entergy System planning process and sought to achieve the following objectives:

- First, develop a preferred portfolio that economically addresses the needs of the City of New Orleans;

[10] *See* Council Resolutions R-11-301, R-10-142, and R-08-295.
[11] Additional information regarding the Entergy System planning process is provided in the 2012 Entergy System Integrated Resource Plan.

- Second, identify long-term DSM potential in New Orleans;
- Third, evaluate the impact of Michoud deactivation on projected resource needs; and
- Fourth, describe the anticipated effects of the preferred portfolio on customer usage and rates.

Objectives are measured from a customer perspective. That is, the process seeks to design a portfolio of resources that reliably meets ENO customers' power needs at a reasonable cost while considering risk. The analytical framework of the modeling process, as well as the optimization leading up to the Preferred Portfolio, supports these objectives. The customer rate effects associated with the Preferred Portfolio are further discussed in the section "Rate Effects."

Further, the IRP presents a wide range of information and analysis that supports the Preferred Portfolio for ENO, including the costs and benefits compared to alternatives available in the market. In fact, the economic modeling explicitly included market purchases as one type of resource option. Therefore, to the extent market purchases are included in the Preferred Portfolio it is a direct function of their cost relative to alternatives. Moreover, based on a comparison of the Department of Energy's forecast, the ENO IRP Preferred Portfolio compares favorably to projections for other utilities in the East South Central region. The analysis supporting this conclusion is discussed in the "Findings and Conclusions" section below.

Component 2 – Demand and Energy Use Forecast

Requires that ENO collect data needed for the planning process, including market analysis, and develop several annual demand, energy and load profile forecasts for no less than a rolling 10-year planning horizon.

ENO has collected all necessary market and company-specific data and produced forecasts of all relevant inputs necessary to facilitate the development of an IRP, including annual demand and energy forecasts over a 20-year planning horizon, including forecasts by customer class. In addition, a description of the energy sales and peak demand forecasting processes have been provided, including the inputs to those forecasts[12].

Component 3 – Supply- and Demand-side Resources

(i) Requires the IRP to identify and evaluate ENO's existing resources used to serve New Orleans' ratepayers' load and include a comparison of current costs incurred for the previous ten (10) years. (ii) It also requires ENO identify and quantify the success of efforts to develop and implement programs that promote demand-side resources, and to the extent ENO has not achieved its objectives, it must include a time-line indicating when those objectives are expected to be achieved. Included in the requirement is a broad list of the data that must be supplied by ENO as part of its IRP filing. (iii) Finally, this component requires that ENO quantify any specific changes anticipated to its resource portfolio and corresponding change in costs to ENO customers as well as the timing for the changes during the term of the planning horizon.

Regarding the first part of the requirement, the section "ENO Supply Portfolio" of this report provides an overview of ENO's existing supply-side portfolio of resources, including historical cost information for the previous ten years.

[12] To the extent not contained in this report, the information required by the Council can be found in the supporting Technical and Data Supplements to the IRP.

Regarding the second part of the requirement, ENO is currently in the 2^{nd} year of a 3 year DSM program for the City of New Orleans known as "Energy Smart.[13]" At the end of September 2012, Energy Smart has led to a cumulative annual 4.3 MW of peak demand savings and 22,647,323 kWh of energy savings for ENO's customers. The results of Energy Smart have been taken into consideration in developing this IRP. For example, the DSM Potential Study evaluated the extent to which DSM is achievable in New Orleans beyond the current goals established for the New Orleans Energy Smart program. This helps ensure that the DSM inputs to the IRP model more accurately reflect the cost and participation of DSM programs incremental to current Energy Smart programs.

Regarding the follow-on to the second part, as provided throughout the IRP filing, ENO has supplied numerous charts, graphs, data tables and analyses, including Technical and Data Supplements to the IRP with detailed underlying data and information.

Regarding the third part, the "Findings and Conclusion" section of this report provides an overview of the ENO Preferred Portfolio. Included in this section are the specific changes to the resource portfolio as well as the approximate timing and a summary of the average annual changes in costs to ENO customers. Detailed annual revenue requirements and corresponding rate effects can be found in Data Supplement 6 – Rate Effects.

Component 4 – Integration of Delivery

Requires that the IRP explain how Entergy's transmission system (current and planned) and ENO's distribution system are integrated into the overall resource planning process.

As discussed further in the section "ENO Supply Portfolio," the IRP incorporates the results of local area bulk generation and transmission planning for the Amite South and Downstream of Gypsy ("DSG") planning regions. The City of New Orleans is located in the DSG sub-region of Amite South. Area planning takes the existing transmission topology, as well as planned investments, as an input into the process in conjunction with and evaluation of supply-side options[14]. In the case of the Amite South and DSG regions, certain constraints exist within the transmission system that practically limit the extent to which transmission can be relied upon, as concluded in the recently completed Minimizing Bulk Power Costs ("MBPC") study[15]. The MBPC study was initiated by the Entergy Regional State Committee ("E-RSC") to evaluate whether, if transmission were to be built into various Entergy "load-pockets", certain high heat rate/low efficiency generating units could be run at lower levels with the result being that the net operating cost would be less than without the transmission investment. The major conclusions of the MBPC study as they apply to DSG and ENO are discussed in the "Area Planning" section below.

While the distribution system is no less important than generation or transmission, unlike the transmission system, the distribution system is a local area system that functions to distribute power transmitted to the city and therefore is not designed to be expanded for purposes of accessing generation supplies necessary to meet customers' needs. However, ENO's distribution system is planned, operated and maintained as necessary to meet the needs of the City of New

[13] ENO originally filed the Annual Report for the first year of Energy Smart New Orleans on June 1, 2012 in Docket UD-08-02. On July 19, ENO filed an update to the Annual Report reflecting certain changes to the results as originally reported.

[14] Transmission alternatives are more commonly evaluated when a decision to procure a specific resource is being contemplated, such that the actual procurement of a resource is contingent upon a review of the economics of any viable transmission alternatives available.

[15] Minimizing Bulk Power Costs Study (May 3, 2012), *available at* http://www.spp.org/section.asp?group=1818&pageID=27.

Orleans. The IRP makes an assumption that the distribution system will continue to receive ongoing capital investment necessary to continue meeting those needs.

Component 5 – Public Presentation of the IRP

Requires that ENO make its IRP report available for review as part of an open and transparent process as the Council directed in Resolution R-10-142.

Throughout the Stakeholder process, ENO sought input to the IRP objectives, assumptions and results. As part of that process, ENO received substantial input through face-to-face communication as well as written correspondence from Stakeholders. In an effort to address and consider that input, substantial resources were focused on Stakeholder concerns, however; ENO was able to maintain the IRP schedule in terms of meeting the filing deadline as originally established by the Council, although at a higher cost than originally budgeted. This high level of Stakeholder input continued throughout the process, including the 4th quarterly Technical Conference held in August 2012, at which point ENO made a determination, with input from the Council's Advisors, to devote ENO's resources to completion of the IRP in order to file on schedule by October 30, 2012. Prior to filing, ENO provided Stakeholders with an early draft of the IRP documents and held a final Technical Conference on October 15th in order to review the documents and receive comments from Stakeholders.

ENO believes the process established by the Council to facilitate Stakeholder review, as well as the additional DSM Working Group meetings, afforded a level of participation necessary to ensure broad review by interested parties and has addressed this part of the Council's IRP requirements, however; in addition to the Stakeholder process ENO has committed to post the public IRP documents to the ENO website once filed with the Council.

Component 6 – Reporting Requirements and Council Resolutions

Requires that in addition to its triennial IRP filing, ENO shall file IRP status reports every eighteen (18) months to provide the Council with an update on ENO's progress in meeting the objectives established in the IRP.

This report is not yet required. ENO intends to file such a report as required consistent with Council direction.

ASSUMPTIONS

General Planning Inputs

In general, natural gas prices set the price for energy on the "margin" in the Entergy System. In addition, the potential for future regulation of CO_2 emissions from electric generating facilities has the potential to result in additional costs to produce electricity that could have a significant impact on the cost to serve ENO's customers. As a result, the IRP includes a range of natural gas and CO_2 forecasts in order to inform the development of the IRP Preferred Portfolio.

NATURAL GAS PRICE FORECAST

SPO prepared the natural gas price forecast used in the 2012 ENO IRP. The near-term portion of the natural gas forecast is based on New York Mercantile Exchange ("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 IRP includes sensitivities for high and low gas prices to support analysis across a range of future scenarios. The low case assumes real levelized 2012-2031 price of $3.40/MMBtu, the reference case assumes $4.96/MMBtu and the high case assumes $6.48/MMBtu.

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 ICF International. 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 a 2012-2031 levelized emission allowance cost in 2011$ of $6.56/U.S. ton[16]. The high case assumes that a cap and trade program starts in 2018 with a real levelized 2012-2031 cost of $16.65/U.S. ton. The IRP reference case (i.e. Scenario 1) assumes the low case for CO_2. Both the Scenario Modeling and the Final Risk Assessment in the ENO IRP examine the impacts from all three CO_2 cases.

Move to MISO

The Entergy Operating Companies have proposed to join the MISO RTO. ENO's request that the Council find the proposed move to MISO in the public interest is currently pending in docket UD-11-01. The proposed transition to MISO involves a number of uncertainties, including whether regulatory approvals will be obtained and when participation would become effective. In order to reflect a reasonable assumption that ENO, as part of the Entergy System, operates in an organized market over the longer-term, the IRP assumes that both ENO, the rest of the Entergy System, and all other load serving entities and independent power producers in close proximity to the Entergy Operating Companies

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

join MISO effective January 1, 2014. This assumption is consistent with the plans currently in place to support integration of ENO and the Entergy System into MISO should all regulatory approvals be obtained. It is important to recognize that absent participation in MISO, the Entergy Operating Companies would not have the opportunity to realize the benefits of participation in a Day-2 market like the one administered by MISO. Moreover, this assumption is consistent with the primary objectives of the IRP, namely to outline a plan that meets customers' needs at the lowest reasonable cost considering reliability and risk.

ITC Transaction

ENO recently made a filing with the Council in docket UD-12-01 requesting approval for a change of ownership of electric transmission businesses through a spin-merge transaction with ITC. Should all regulatory approvals be obtained, the transaction would result in ITC owning and operating the Entergy Operating Companies' interstate transmission system. The resulting transmission-only company owned and operated by ITC would help lay the foundation for the future electric grid in New Orleans and the surrounding region by placing transmission planning and operations in the hands of an independent company, offering financial strength and flexibility, and providing for singular focus and operational excellence in transmission. The Entergy Operating Companies view the transaction and the corresponding benefits to customers as incremental to the move to MISO and one that offers a timely and unique opportunity to build upon the benefits of a Day-2 market such as the one administered by MISO. The Companies also view the ITC transaction as an opportunity to further enhance operation and investment in the Entergy transmission system. The transaction is expected to lead to long-term benefits for ENO's customers, the specific supporting factors of which are provided for in the filing.

Energy Smart

Energy Smart is a comprehensive energy efficiency program available to all residents and businesses located in Orleans Parish. The plan underlying Energy Smart was developed by the Council, is administered by ENO, and implemented by CLEAResult. Program costs are recovered from customers through electric rates. The DSM Potential Study evaluated the extent to which DSM is achievable in New Orleans beyond the current goals established for New Orleans Energy Smart program. Information from the initial implementation of Energy Smart was incorporated into the DSM Potential study.

In March 2011, Energy Smart completed its first year of a 3 year, $11 million plan. In its first program year, Energy Smart provided incentives to more than 8,500 customers. Incentives were provided for energy efficient measures such as energy audits, direct install CFL bulbs, low flow fixtures, weatherization, HVAC, A/C Tune-ups and lighting, among others. In the first year, the programs saved 15,812,954 kWh of electricity, which was 111% of the savings goal set by the Council. Several programs exceeded their energy savings targets, including the Residential Solutions, CFL Direct Install, Low Income, Small Commercial and Large Commercial Programs. Figure 2 below illustrates the geographic dispersion of participants from the first year of the program. This information can then be utilized to help inform development of future programs and program funding levels.

FIGURE 4: MAP OF ENERGY SMART PARTICIPATION

Originally the Energy Smart New Orleans program was limited to ENO electric customers but, on July 27, 2012, Entergy Louisiana filed for extension of the program to the 15th ward (Algiers) also under the jurisdiction of the Council. The Algiers program and corresponding goals are based on the same objectives as the New Orleans program. On October 18th the Council approved the Energy Smart Algiers program which began October 22nd and will conclude simultaneously with the New Orleans program on March 31, 2014.

In the future, the track record and experience gained through the Energy Smart programs will help ensure that the DSM inputs to the IRP model more accurately reflect the cost and participation in incremental DSM programs. The optimal (cost-effective) level of DSM spending identified in the 2012 ENO IRP can be utilized to determine general funding levels going forward in order to build upon the early success of the current Energy Smart programs. In addition, the IRP can also provide general guidance on the types of energy efficiency programs to be considered in developing future DSM programs as well as the estimated savings expected from these programs. However, specific program design including details on an implementation plan will require further study. Additional guidance is provided on the cost uncertainty and planning activity associated with future programs in the "Findings and Conclusions" section below.

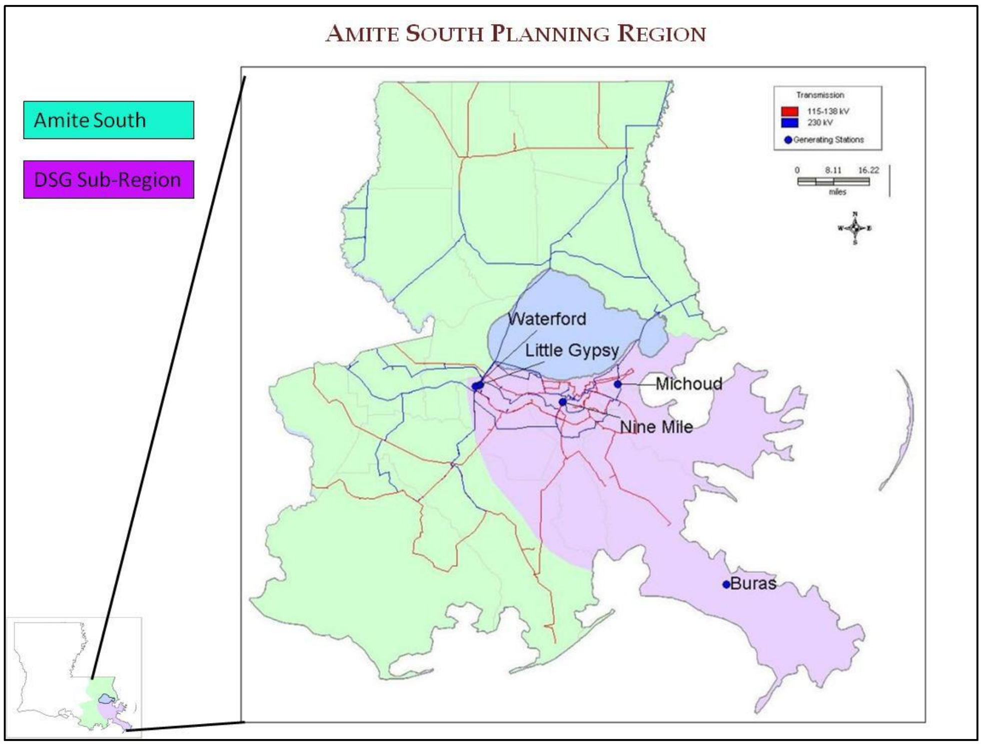
Area Planning

Although the Entergy System performs resource planning on a System-wide basis, with the goal of meeting the System planning objectives at the lowest overall 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 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.

Planning 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 City of New Orleans is within the DSG sub-region of the broader Amite South Planning Region. The ability to import power from outside of the DSG sub-region to serve load within the sub-region is limited by the amount of transmission available. The Amite South and DSG regions are geographically defined as follows:

- 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 Downstream of Gypsy ("DSG") (a sub-region) and generally encompasses the area down river of the Little Gypsy plant including metropolitan New Orleans and south to the Gulf of Mexico.

Figure 5: Map of Amite South & DSG



AMITE SOUTH / DSG

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. Presently, ELL is constructing a Combined-Cycle Generating Turbine ("CCGT") resource at its Ninemile site in DSG[17]. ENO has obtained approval from the Council[18] to

[17] The Ninemile 6 CCGT was selected from a competitive solicitation process referred to as the Summer 2009 RFP. In that RFP, on behalf of the Entergy Operating Companies, Entergy Services, Inc. solicited proposals for long-term resources including developmental resources proposed to be located within Amite South. The Ninemile 6 CCGT was selected among other proposals to move forward and in March 2012 the Louisiana Public Service Commission approved ELL's certification application to construct the unit. The unit is expected to enter commercial operation in early 2015.

[18] On July 8th, 2011 in Docket UD-11-03 ENO filed for approval to participate in the Ninemile 6 CCGT project through a life-of-unit power purchase agreement for 20% of the unit's capacity and energy. In the filing, ENO explained the process and submitted highly

purchase 20% of the power from Ninemile 6 through a long-term contract. The addition of Ninemile 6 will address near-term reliability and economic objectives in Amite South and DSG, including meeting ENO's resource needs. However, because of a number of factors affecting the Amite South area as described below, additional capacity will be needed in the coming years to preserve reliability and provide economic benefit[19]. As the IRP has shown, the requirements in Amite South or DSG cannot be entirely addressed in a cost-effective manner with DSM resources alone. This capacity may come 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 via contract) [20]. As the recently-completed Minimizing Bulk Power Costs Study concluded, there currently is not an economic transmission-only solution that would offset the need for local generation in the Amite South region. This study is discussed below. 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), the System must begin planning for this investment today. 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.

MBPC Study

The MBPC study was developed out of a hypothesis on the part of the Entergy Regional State Committee ("E-RSC") that, if transmission were to be built into various Entergy load-pockets then certain high heat rate/low efficiency generating units could be run at lower levels with the result being that the net operating cost would be less than without the transmission. In essence, if the difference between the initial annual production cost for the Entergy footprint and that for the case with transmission upgrades built in appropriate places was greater than the annualized cost of ownership for those transmission upgrades, then those projects would be candidates for additional refined studies and possibly ultimate construction. Hence, the E-RSC and Southwest Power Pool ("SPP"), in its capacity as the Independent Coordinator of Transmission ("ICT"), commissioned the MBPC study for identifying the most cost-effective transmission project(s) specifically for minimizing generation from the high cost units in five different Entergy load-pockets. Two important general conclusions from the MBPC study are as follows:

- Projected fuel cost savings from eliminating the need for Entergy's older gas-fired legacy fleet of generating units within certain transmission constrained regions would not be sufficient to justify the cost of the necessary transmission upgrades.
- Specifically within DSG, in 2013 the annual carrying cost of capital expenditures for the new transmission exceeded the annual savings that may be realized from reductions in production cost. In 2022 there was at least one transmission alternative where the benefit from lower annual production cost exceeded the yearly

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sensitive data and analysis from the RFP in support of its application. On February 2nd the City Council approved ENO's request in Resolution R-12-29.

[19] At this time, the Entergy System has not determined when a new supply resource will be proposed.

[20] No new generation resources are under construction in DSG beyond Ninemile 6, which is included in this IRP as a planned resource addition. The Summer 2009 RFP is the most recent long-term RFP, within the previous 3 year period, which solicited resources on behalf of ENO and ELL to specifically address needs in the Amite South and DSG regions. The results of that RFP, including the highly sensitive proposal evaluation results, are included in the companies' application in Docket UD-11-03. ENO is not participating in any other resource selected from the RFP beyond its participation in Ninemile 6.

carrying charge of the transmission cost by over a factor of 2, however; that benefit derived from reduced use of the DSG fleet not from deactivation.

In addition to the conclusions reached in the MBPC study, it is important to point out that additional analysis presented by the Entergy Operating Companies to the E-RSC has shown that investing in transmission to permit retirement of ENO's and ELL's DSG fleet could result in cost increases to customers of at least $1.7 billion more than necessary if those units are allowed to continue providing reliable service until longer-term decisions regarding deactivation are made. In determining this increase, the analysis looked at the transmission investment as determined by the MBPC study, and then accounted for the new capacity costs net of the avoided fixed costs from deactivating the DSG fleet. Based on this analysis, ENO and ELL would have to plan to increase total capital expenditures at ELL's Ninemile facility and ENO's Michoud facility by 725% each year to make a transmission-only solution a breakeven proposition.

ENO Supply Portfolio

Currently, ENO's supply-side electric generation portfolio consists of long-term resources either owned or under long-term Purchase Power Agreement ("PPA"). A table listing ENO's current resource portfolio, approximate capacity, and deactivation assumptions in the IRP is provided below.

TABLE 5: DSG SUPPLY PORTFOLIO

Generating Unit	Fuel Type	ENO Capacity (MW)	Included in IRP	Deactivation Assumption
Grand Gulf PPA[21]	Nuclear	218	Y	N/A
Riverbend PPA[22]	Nuclear	97	Y	N/A
WBL PPAs[23]	Nuclear/Coal	174	Y	N/A
Michoud 2	Natural Gas	235	Y	2022
Michoud 3	Natural Gas	529	Y	2027

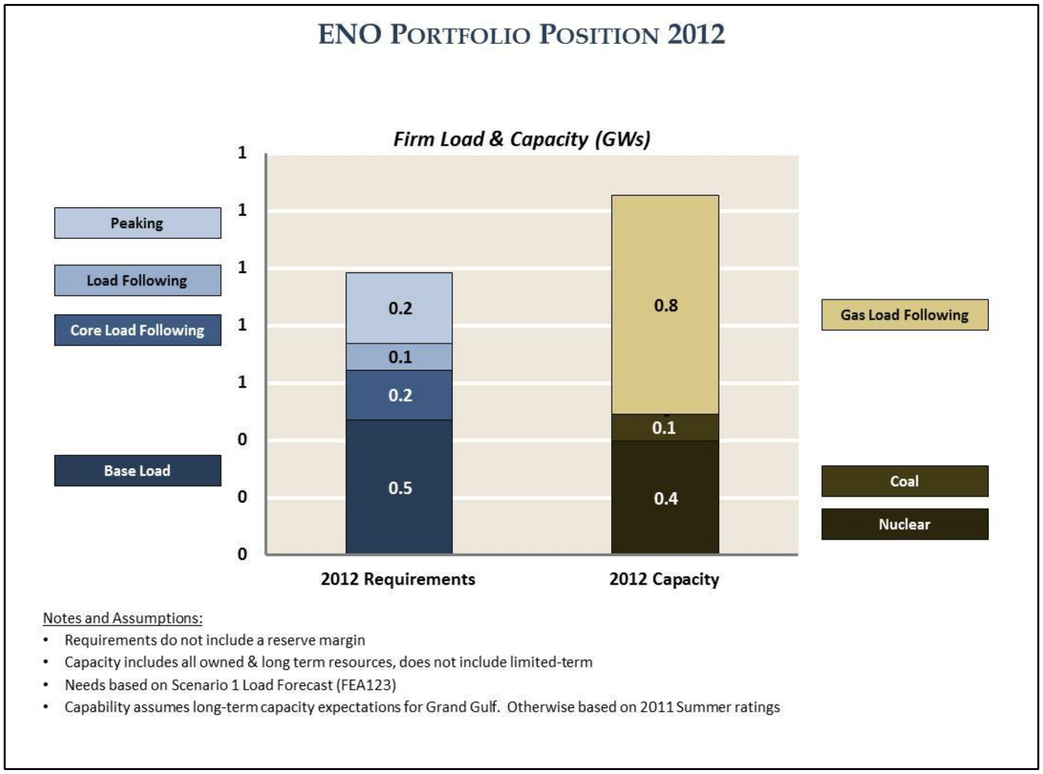
In total, ENO currently has approximately 1,253 MWs of long-term resources across a range of electric generation technologies and fuel types including nuclear, coal- and natural gas-fired. As discussed further in the IRP documentation accompanying this report, ENO's 2012 capability compares favorably with its load requirements. Figure 4 below illustrates this comparison. The primary reason ENO has capacity beyond its requirements in 2012 is because peak demand has not returned to 'pre-Katrina' levels.

The Michoud Generating Station is owned by ENO and includes two operating units – Michoud Units 2 and 3[24]. Michoud Units 2 and 3 entered commercial operation in 1963 and 1967 respectively and are still currently in service collectively representing over 760 MWs of natural gas-fired steam generator capacity. Michoud provides ENO with dispatchable

[21] The Grand Gulf Nuclear Station is majority owned by System Energy Resources, Inc. which sells 17% of its share of Grand Gulf to ENO through a life-of-unit PPA.
[22] Riverbend Nuclear Station is owned by EGSL which sells 1/3 of its wholesale capacity and energy to ENO through a life-of-unit PPA.
[23] The Wholesale Baseload ("WBL") PPAs source capacity and energy from solid fuel generating units located in Arkansas and owned by EAI that is sold to ENO through a life-of-unit PPA.
[24] Michoud Unit 1 entered commercial operation in 1957 and last operated in August 2005 when it sustained significant damage from Hurricane Katrina. The unit was placed into shutdown in 2006 and then inactive reserve in 2008. In 2011 the unit was permanently retired from service.

capacity and energy needed to follow load-swings and support electric reliability in the region. Given the wide dispatch range of Michoud (described as the range between its minimum and maximum MW dispatch level), the facility also represents flexible capability that is necessary to support reliability in DSG.

FIGURE 6: ENO PORTFOLIO POSITION 2012



As part of the area planning analysis discussed above, Michoud was evaluated in order to determine if the life expectancy for the units in operation at the facility is consistent with the planning horizon in the IRP. As a result of that analysis, Michoud 2 and 3 are estimated to be deactivated[25] by approximately 2022 and 2027, which is the assumption made in the IRP. At that time each unit would be approaching 60 years of age, typical of the age range when a deactivation recommendation would be issued for units like those at Michoud absent significant incremental investment. The evaluation process to determine whether significant incremental investment in the Michoud facility is warranted will be developed over time based on further study. The IRP makes a reasonable assumption that absent significant investment in those units, they cannot reasonably be expected to operate reliably beyond 60 years of age. The IRP also assumes that capital spending on Michoud continues at a level necessary to support operations until the assumed deactivation date.

In the case of Michoud Unit 3, the IRP model selected to extend the life of this unit beyond 2027 over other available resource alternatives. Although no final decisions have been made regarding the timing or level of investment in the Michoud facility, the rate effects and corresponding risk analysis discussed in the Findings and Conclusions section

[25] Assumptions regarding the deactivation of generating units are made for planning purposes only. Whether a given unit will be deactivated depends upon the planning needs and economics of options available when the decision is made.

include investment in Michoud 3 beyond 2027 necessary to ensure continued reliable operation, which assumption is reflected in the total supply cost and customer bill impacts associated with the Preferred Portfolio presented in this report.

HISTORICAL COST

ENO's portfolio of supply-side resources consists of stable-priced baseload, and load-following resources sourced from generating facilities representing a range of technologies and fuel types. Historically, ENO has obtained capacity and energy from its baseload resources through long-term PPAs. In addition to the baseload resources, ENO owns the natural gas-fired load-following Michoud facility located in New Orleans.

The drivers of ENO's total historical production costs are a function of fixed and variable operation and maintenance expenses at each generating facility. As shown in Figure 7, ENO's Total Variable Production Cost in 2011 ranged from $21/MWh to $49/MWh depending on the generating resource. Over time, these costs will necessarily vary with the cost of production inputs, however; the extent to which they vary is heavily dependent on the generating technology and fuel type of the generating resource. This effect is shown for each resource over the last ten (10) years in Figures 8 and 9 below.

FIGURE 7: TOTAL VARIABLE PRODUCTION COST -- BY RESOURCE (2011)

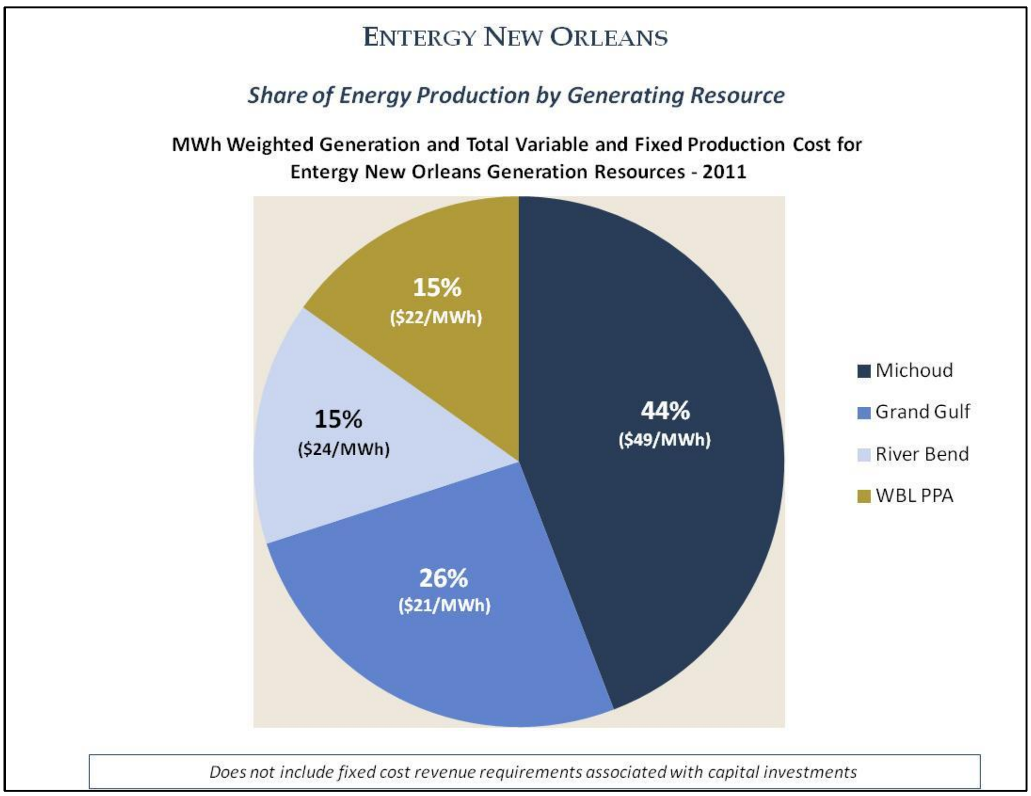


FIGURE 8: HISTORICAL COST OF ENO SUPPLY RESOURCES (BASELOAD)

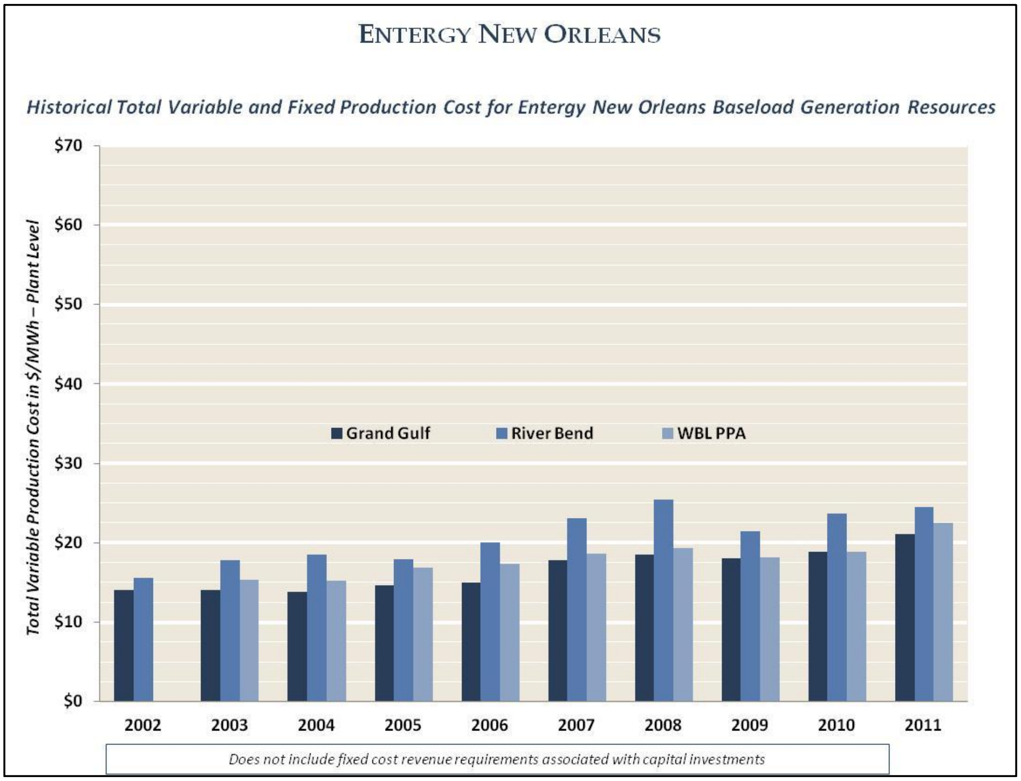
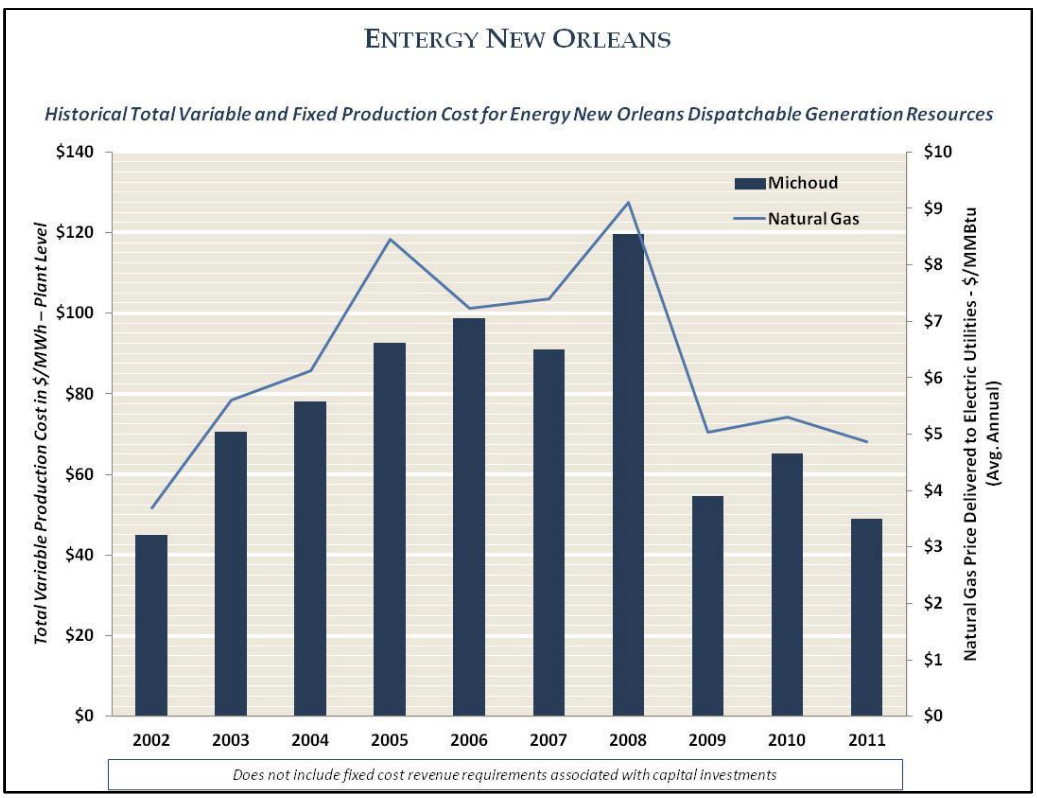


FIGURE 9: HISTORICAL COST OF ENO SUPPLY RESOURCES (DISPATCHABLE)



Load Forecast

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

- Levels of economic activity and growth;
- The potential for technological change to affect the efficiency of electric consumption;
- Potential changes in the purposes for which customers use electricity (for example, 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 ENO's 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.

In order to consider the potential implications of load uncertainties on long-term resource needs, four load forecast sensitivities were prepared corresponding to the four planning scenarios described later in this document. The forecast for ENO and the DSG region are provided in Table 6 and 7 below.

TABLE 6: FIRM PEAK LOAD FORECAST

Firm Peak Load (MWs)								
	ENO				DSG			
	Scenario I	Economic Rebound	Green Growth	Austerity Reigns	Scenario I	Economic Rebound	Green Growth	Austerity Reigns
2011	940	940	940	940	2,988	2,988	2,988	2,988
2012	985	1,006	983	982	3,148	3,232	3,180	3,170
2013	988	1,019	982	982	3,162	3,290	3,181	3,182
2014	994	1,034	978	977	3,200	3,332	3,178	3,177
2015	1,004	1,052	975	980	3,225	3,380	3,179	3,189
2016	1,007	1,069	973	983	3,239	3,430	3,179	3,204
2017	1,012	1,082	969	983	3,257	3,471	3,179	3,213
2018	1,017	1,097	969	988	3,276	3,522	3,186	3,236
2019	1,020	1,111	968	993	3,290	3,568	3,188	3,258
2020	1,022	1,125	966	997	3,320	3,615	3,189	3,280
2021	1,026	1,139	965	1,003	3,319	3,660	3,189	3,301
2022	1,030	1,156	963	1,016	3,333	3,714	3,190	3,346
2023	1,034	1,172	962	1,029	3,346	3,767	3,190	3,389
2024	1,038	1,189	961	1,041	3,360	3,822	3,194	3,431
2025	1,040	1,204	960	1,053	3,376	3,873	3,193	3,471
2026	1,046	1,221	959	1,065	3,391	3,928	3,196	3,510
2027	1,051	1,237	959	1,075	3,406	3,982	3,198	3,545
2028	1,056	1,254	960	1,087	3,422	4,036	3,201	3,581
2029	1,060	1,270	960	1,098	3,436	4,091	3,202	3,618
2030	1,066	1,287	961	1,110	3,453	4,144	3,207	3,656
2031	1,069	1,305	962	1,121	3,472	4,197	3,215	3,692

TABLE 7: ENERGY FORECAST

Firm Peak Load (GWh)								
	ENO				DSG			
	Scenario I	Economic Rebound	Green Growth	Austerity Reigns	Scenario I	Economic Rebound	Green Growth	Austerity Reigns
2011	5,168	5,168	5,168	5,168	17,665	17,665	17,665	17,665
2012	5,449	5,489	5,363	5,364	18,233	18,326	18,026	17,964
2013	5,474	5,569	5,362	5,369	18,535	18,794	18,068	18,071
2014	5,545	5,662	5,344	5,345	18,750	19,063	18,087	18,048
2015	5,617	5,769	5,332	5,361	18,965	19,365	18,133	18,119
2016	5,665	5,861	5,321	5,377	19,154	19,681	18,156	18,196
2017	5,696	5,935	5,302	5,377	19,277	19,926	18,186	18,250
2018	5,742	6,022	5,301	5,404	19,422	20,217	18,246	18,381
2019	5,773	6,098	5,297	5,430	19,540	20,482	18,284	18,505
2020	5,807	6,179	5,288	5,457	19,665	20,759	18,319	18,631
2021	5,836	6,257	5,284	5,487	19,769	21,026	18,356	18,754
2022	5,868	6,347	5,276	5,557	19,884	21,336	18,391	19,011
2023	5,902	6,436	5,268	5,624	19,996	21,643	18,427	19,255
2024	5,940	6,528	5,264	5,693	20,125	21,961	18,464	19,497
2025	5,970	6,612	5,261	5,757	20,225	22,263	18,475	19,730
2026	6,005	6,701	5,260	5,818	20,341	22,583	18,506	19,951
2027	6,039	6,789	5,257	5,876	20,458	22,907	18,534	20,158
2028	6,079	6,883	5,265	5,936	20,590	23,226	18,571	20,364
2029	6,109	6,971	5,264	5,997	20,693	23,552	18,593	20,578
2030	6,147	7,067	5,269	6,061	20,816	23,869	18,634	20,794
2031	6,184	7,162	5,275	6,123	20,941	24,189	18,685	21,004

ENO Long-term Supply Needs

As shown in Table 8 and Figure 10 below, with existing and approved planned resources currently under construction, and before any incremental DSM beyond the current Energy Smart New Orleans program, ENO's Load and Capability reflects a capacity surplus through the first half of the planning horizon (2021) under a range of scenarios[26]. As discussed above, Michoud units 2 and 3 are estimated to be deactivated[27] by approximately 2022 and 2027. While the results of the Preferred Portfolio below reflect the potential for life extension of Michoud unit 3 to be economic relative to alternatives, no decisions have been made regarding the future status of either unit at the Michoud facility.

The data represented in Figure 10 reflects ENO's projected long-term resource needs prior to any resource additions, including life extension for Michoud unit 3, incremental DSM or planning reserves. The first significant change illustrated in the chart is in 2015 when the new Ninemile 6 CCGT resource is anticipated to enter commercial operation. At that point ENO's supply-side surplus increases by an equivalent amount of capacity and remains relatively stable until the assumed deactivation of Michoud 2 in 2022. From that point until 2027 ENO continues to project a supply surplus, where the assumption for deactivation of Michoud 3 is reflected. The resource planning objectives and corresponding

[26] The surplus includes the incremental capacity recently approved by the Council associated with a life-of-unit PPA for a portion of the new Ninemile 6 CCGT currently under construction at ELL's Ninemile Point generating station in Westwego, LA. It also includes ENO's share of capacity associated with a construction project to upgrade the capacity of the Grand Gulf Nuclear Station in Port Gibson, MS.

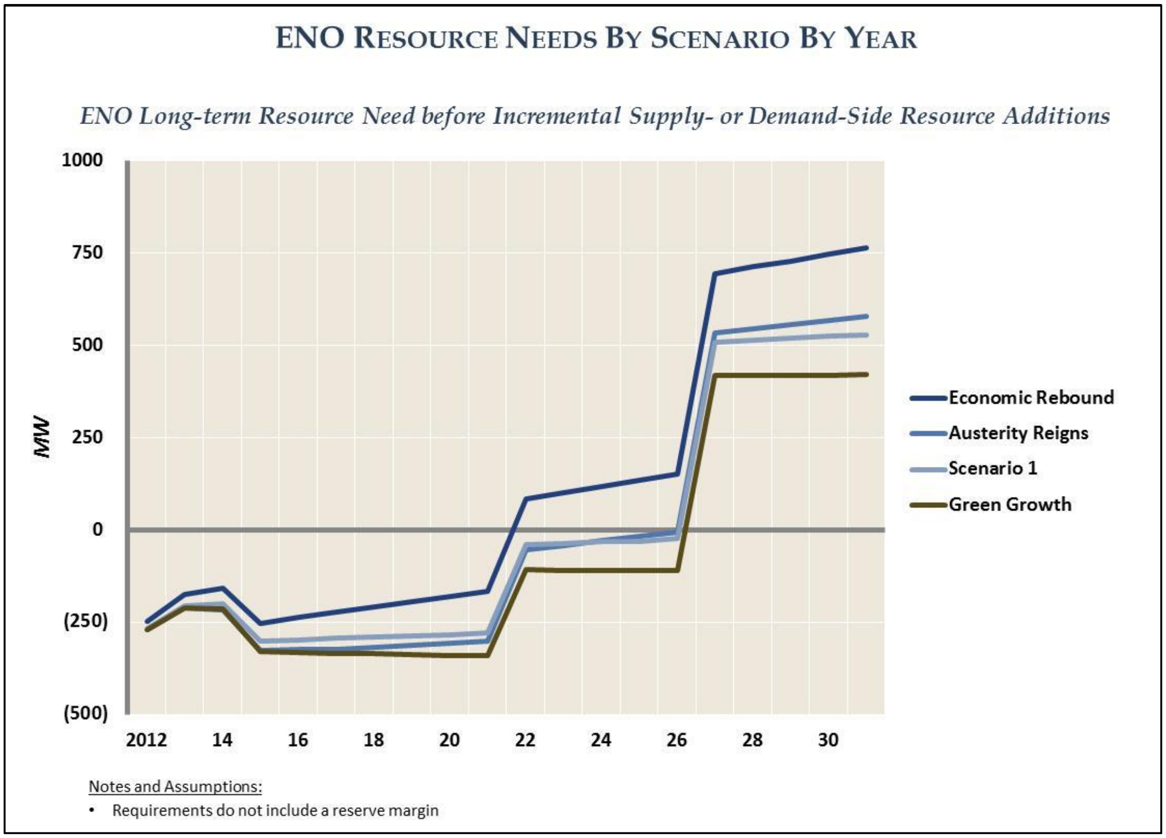
[27] Assumptions regarding the deactivation of generating units are made for planning purposes only. Whether a given until will be deactivated depends upon the planning needs and economics of options available when the decision is made.

Preferred Portfolio discussed herein are directly focused on the steps necessary to address the projected resource deficiency associated with Michoud unit 3.

TABLE 8: ENO RESOURCE NEEDS BY SCENARIO

ENO Resource Need/(Surplus) (Before IRP Additions)[28] (MWs)				
	Scenario I	Economic Rebound	Green Growth	Austerity Reigns
By 2021	(280)	(167)	(341)	(303)
By 2031	527	763	420	580

FIGURE 10: ENO RESOURCE NEEDS BY SCENARIO



[28] Requirements do not include a reserve margin

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, ENO's 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 9: ENO RESOURCE NEEDS BY SUPPLY ROLE

2012 ENO Long-term Resource Needs By Supply Role[29] (MWs)				
	BASE LOAD	LOAD-FOLLOWING	PEAKING RESERVE	TOTAL
Load Shape Need	471	265	367	1,103
2012 Resources	490	764	0	1,254
Surplus (Deficit)	19	499	(367)	151

By the end of the twenty-year planning horizon, ENO is expected to be short by up to 763 MW absent investment in supply resources[30]. Though the addition of Ninemile 6 will meet capacity requirements in the Amite South area including ENO until the 2020 timeframe, capital requirements for the region do not cease when one new resource is added, rather, an orderly and prudent capital plan requires that ENO must immediately begin planning for the next project. Given expected load growth, and efficient retirement/refurbishment decisions for ENO's existing, but aging 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 ENO or third parties with PPAs with ENO), ENO must begin today planning for this investment. With the addition of Ninemile 6, ENO should have sufficient capacity in the near term, however; it must continue investing in order to meet the long-term needs efficiently and cost-effectively.

[29] Long-term resources are defined as resources whether contracted or owned with duration of ten years or greater from the time first placed into the portfolio.

[30] ENO's resource need over the next 20 years is between approximately 420 MW and 763 MW, based on a range of load growth between 0% and 1.4% per year, with a reference case assumption of 527 MW. Note that this resource need is based not only on resources located within the Amite South region, but also reflects ENO's PPAs with generating units outside of the Amite South region (such as Grand Gulf). Decisions regarding incremental investments undertaken to refurbish ENO's existing resources will affect not only ENO's capital needs for additional resources, but also the capital needs associated with maintaining the existing fleet. However, these costs are uncertain, and will ultimately depend on unit condition and the timing of additional new resources beyond Ninemile 6.

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ENO PORTFOLIO OPTIMIZATION PROCESS

Analytic Framework

ENO undertook an extensive and detailed analytical effort to determine the optimal mix of resources to meet ENO customers' needs over the next two decades. This effort which was conducted in a manner consistent with the Entergy System's planning process, sought to achieve the following objectives:

- First, develop a preferred portfolio that economically addresses the needs of the City of New Orleans;
- Second, identify long-term DSM potential in New Orleans;
- Third, evaluate the impact of Michoud deactivation on projected resource needs; and
- Fourth, describe the anticipated effects of the preferred portfolio on customer usage and rates.

Objectives are measured from a customer perspective. That is, the process seeks to design a portfolio of resources that reliably meets ENO customer power needs at a reasonable cost while considering risk. The ENO portfolio optimization process focused specifically on requirements of the DSG sub-region and resulting costs to serve customer load in the City of New Orleans. Results of this process were used as a basis for developing the ENO Preferred Portfolio which is described later in this document.

Modeling

The ENO portfolio optimization process 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 to serve ENO customers. AURORA[31] 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

The ENO portfolio optimization process 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.

[31] SPO selected the Aurora model for the 2012 System IRP as well as other analytic work after an extensive analysis of simulation tools available in the marketplace. Aurora is capable of supporting a variety of resource planning activities and is well suited for scenario modeling and risk assessment modeling. It is widely used by load serving entities, consultants and independent power producers. The Aurora model effectively replaces the PROMOD IV and PROSYM models that the System has used for many years.

- 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 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 conditions in the U.S. economy.

Each scenario was modeled in Aurora using a set of input assumptions specific to each of the four scenarios. The resulting market modeling provided a basis (including projected power prices) for assessing the economics of long-term resource portfolio alternatives.

TABLE 10: SUMMARY OF KEY SCENARIO ASSUMPTIONS

Summary of Key Scenario Assumptions[32]				
	Scenario 1	Economic Rebound	Green Growth	Austerity Reigns
ENO Electric Energy compound annual growth rate	Reference ~0.8%	~1.5%	~0.3%	~1.1%
ENO Peak Load (MW) compound annual growth rate	Reference ~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

Resource Alternatives

The ENO portfolio optimization process considered 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 DSM. The process considered supply- and demand-side resources on an equal basis.

[32] 2011-2031 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).

DSM Resources

A key objective of the ENO IRP process was to determine an optimal level of cost-effective DSM spending for ENO over the next two decades. The scope of DSM resources considered in the ENO IRP include programs that ENO has or may be able to deploy to manage the level and timing of customers' energy use over the planning horizon, however the results of the optimization should not be used to target specific programs or set detailed program goals without additional analysis. Instead, the results are meant to provide guidance on the long-term potential for DSM under a given set of assumptions, which are inherently uncertain.

Estimate of DSM Potential

ENO 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 and 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. In all, 22 DSM programs were modeled, including eleven energy efficiency programs based on current Energy Smart program designs and six additional energy efficiency programs that expand the options for commercial and residential customers including those living in multifamily buildings. ICF also modeled six demand response programs that provide customers with an opportunity to modify their energy usage patterns in response to a price signal. The 22 DSM programs modeled in the DSM Potential study reference case are summarized in Table 11 below.

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

TABLE 11: ENO DSM PROGRAMS – REFERENCE CASE

Sector	Type	Program Name	Energy Smart?	TRC Test	Levelized Cost/kWh	Levelized Cost/kW	2031 Cumulative MW Savings
C&I	EE	Large Commercial Energy solutions	Yes	2.2	$0.03	$161	53.5
C&I	EE	Small Commercial Energy Solutions	Yes	1.8	$0.05	$188	16.6
C&I	EE	Commercial Solar PV	Yes	0.4	$0.31	$605	7.5
Res.	EE	Energy Smart New Homes	Yes	1.2	$0.05	$141	0.2
Res.	EE	ENERGY STAR Air Conditioning	Yes	1.8	$0.05	$175	12.0
Res.	EE	Residential Lighting and Appliances	Yes	1.5	$0.05	$232	8.7
Res.	EE	Residential Energy Solutions	Yes	1.2	$0.08	$252	17.2
Res.	EE	AC Tune-Up	Yes	1.2	$0.09	$244	3.8
Res.	EE	Residential Solar PV	Yes	0.6	$0.04	$75	0.2
Res.	EE	Solar Water Heater Pilot	Yes	0.4	$0.07	$448	0.0
Res.	EE	Low Income Weatherization	Yes	0.9	$0.13	$451	2.9
C&I	EE	Commercial Building Energy Management	No	3.9	$0.02	$95	3.4
C&I	EE	Commercial New Construction	No	2.3	$0.03	$174	9.0
C&I	EE	Industrial	No	2.8	$0.02	$140	5.4
Multi	EE	Multifamily Residential	No	1.4	$0.06	$328	4.4
Res.	EE	Home Energy Use Benchmarking	No	1.3	$0.08	$338	0.8
C&I	DR	Non-Enabled Dynamic Pricing (Non-Res)	No	5.0	--	$38	1.6
C&I	DR	Enabled Dynamic Pricing (Non-Res)	No	2.7	--	$67	2.5
C&I	DR	Interruptible Rate	No	38.7	--	$20	23.4
Res.	DR	Direct Load Control	No	7.8	--	$18	19.2
Res.	DR	Enabled Dynamic Pricing (Res)	No	2.7	--	$67	5.4
Res.	DR	Non-Enabled Dynamic Pricing (Res)	No	3.1	--	$66	2.4
		TOTAL PORTFOLIO – REFERENCE CASE		1.9	$0.05	$160	200.4

DSM OPTIMIZATION PROCESS

The level of DSM included in the ENO IRP was determined by an optimization methodology that systematically evaluated increasingly expensive flights of DSM programs. That is, a small bundle of the most cost effective programs were evaluated first, and small bundles of increasingly expensive programs were added until all levels of potential DSM were included. The amount of DSM that minimized the total cost of service was identified as the optimal level of DSM. The optimization process included the following steps:

Step 1 – The list of cost-effective DSM programs resulting from the DSM Potential Study were combined into groups of programs, called bundles. The programs were organized into six bundles based on program type: energy efficiency ("EE") and demand response ("DR") programs and benefit/cost ratio under the Program Administrator Cost ("PAC") test. For each bundle, a low, reference and high level of program spending was developed. Thus, 18 DSM load-shapes and estimates of annual program costs were developed to model three levels of program spending for six program bundles. The table below shows which programs were included within each bundle.

TABLE 12: ENO DSM PROGRAM BUNDLES

Bundle	Type	Programs	Annual Energy Savings by 2031 (GWh)	Non-coincident Peak Demand Savings in 2031 (MW)	Annual Program Costs in 2031 ($M)
1	DR	Direct Load Control Interruptible Rate	Low – 0 Reference – 0 High – 0	Low – 23 Reference – 43 High – 57	Low – 0.3 Reference – 0.6 High – 1.0
2	EE	Industrial Commercial Building Energy Management Commercial New Construction Large Commercial Energy Solutions	Low – 289 Reference – 380 High – 529	Low – 60 Reference – 82 High – 116	Low – 2.9 Reference – 8.7 High – 18.8
3	DR	Non-enabled Dynamic Pricing Enabled Dynamic Pricing	Low – 0 Reference – 0 High – 0	Low – 7 Reference – 12 High – 16	Low – 0.2 Reference – 0.6 High – 1.0
4	EE	Energy Smart New Homes Energy Star Air Conditioning Residential Lighting & Appliances Small Commercial Energy Solutions	Low – 103 Reference – 140 High – 189	Low – 154 Reference – 255 High – 353	Low – 2.0 Reference – 4.6 High – 8.3
5	EE	Multifamily Residential Energy Solutions AC Tune-Up Home Energy Use Benchmarking	Low – 60 Reference – 91 High – 113	Low – 24 Reference – 39 High – 48	Low – 2.2 Reference 4.6 High – 6.5
6	EE	Residential Solar PV Solar Water Heater Pilot Low Income Weatherization Commercial Solar PV	Low – 7 Reference – 26 High – 29	Low – 4 Reference – 14 High - 16	Low – 0.7 Reference – 4.2 High – 4.9
Total			Low – 460 Reference – 638 High – 861	Low – 272 Reference – 444 High – 605	Low – 8.3 Reference – 23.3 High – 40.5

Step 2 – Next, a "DSM Supply Curve" was developed from the 18 hourly load-shapes. Based on the bundles' benefit/cost ratio under the PAC test, the DSM Supply Curve was built starting with the most cost-effective bundle. The next most cost-effective bundle followed, until the least cost-effective bundle was added to the curve. The PAC test was used for this purpose because it is consistent with the total utility revenue requirements measure that was used throughout the IRP process[33]. The table below shows the level of each bundle at each step on the DSM Supply Curve.

[33] The PAC test was not used to screen individual measures or programs for cost effectiveness. The Total Resource Cost test was used in the DSM Potential Study for this purpose.

TABLE 13: ENO DSM LEVELS

DSM Supply Curve (Flights)	Bundle 1	Bundle 2	Bundle 3	Bundle 4	Bundle 5	Bundle 6	Annual Energy Savings by 2031 (GWh)	Coincident Peak Demand Savings in 2031 (MW)	NPV of Annual Program Costs 2012$
1	Low						0	23	2
2	Ref						0	43	5
3	Ref	Low					289	102	25
4	High	Low					289	116	28
5	High	Low		Low			393	203	45
6	High	Ref		Low			484	224	83
7	High	Ref	Low	Low			484	224	85
8	High	Ref	Ref	Low			484	228	87
9	High	High	Ref	Low			632	262	154
10	High	High	Ref	Ref			669	354	176
11	High	High	Ref	Ref	Low		729	365	195
12	High	High	High	Ref	Low		729	365	198
13	High	High	High	High	Low		778	460	229
14	High	High	High	High	Ref		809	465	249
15	High	High	High	High	High		831	469	266
16	High	High	High	High	High	Low	838	471	272
17	High	High	High	High	High	Ref	857	477	297
18	High	High	High	High	High	High	861	478	304

Step 3 – Production cost modeling was conducted to identify the optimal level of DSM for ENO using the DSM Supply Curve developed in Step 2. The optimal level of DSM is identified as the DSM flight that results in the lowest net present value of total cost of service (2012$, 2014-31) for ENO. The production cost modeling was conducted twice: once assuming no supply-side resource additions and again including supply-side resource additions. *By conducting the production cost modeling with and without supply-side resource additions, the DSM resources were evaluated under the full range of possibilities which provides DSM resources the best opportunity to achieve relative cost-effectiveness and be selected for the ENO portfolio.* This step consisted of 36 production cost model runs for each of the four IRP scenarios, for a total of 144 production cost runs, which resulted in the identification of flight #5 in Scenario 1, Economic Rebound and Austerity Reigns scenarios, and flight #11 in the Green Growth scenario as the levels of DSM investment which result in the lowest total cost of service. The same level of DSM was found to be optimal for each scenario after each iteration of the production cost modeling, with and without supply-side resources.

TABLE 14: ENO DSM RESULTS BY SCENARIO BY LEVEL (NO SUPPLY-SIDE ADDITIONS)

NPV of total cost of service (2012$, 2014-31) with no supply-side additions				
Flight	Scenario 1	Economic Rebound	Austerity Reigns	Green Growth
1	2,683	3,518	1,852	3,842
2	2,686	3,522	1,856	3,845
3	2,623	3,421	1,813	3,734
4	2,627	3,424	1,816	3,737
5	2,611	3,390	1,806	3,701
6	2,623	3,393	1,826	3,699
7	2,625	3,395	1,827	3,701
8	2,627	3,397	1,829	3,703
9	2,652	3,405	1,866	3,702
10	2,662	3,411	1,878	3,705
11	2,662	3,403	1,884	3,694
12	2,665	3,405	1,886	3,697
13	2,679	3,417	1,905	3,703
14	2,690	3,422	1,917	3,707
15	2,699	3,429	1,928	3,713
16	2,702	3,431	1,933	3,714
17	2,721	3,446	1,951	3,729
18	2,725	3,450	1,956	3,732
Optimal DSM Flight #	5	5	5	11

TABLE 15: DSM RESULTS BY SCENARIO BY LEVEL (WITH SUPPLY-SIDE ADDITIONS)

NPV of total cost of service (2012$, 2014-31) with supply-side additions				
Flight	Scenario 1	Economic Rebound	Austerity Reigns	Green Growth
1	2,663	3,288	1,802	3,833
2	2,667	3,292	1,806	3,836
3	2,608	3,218	1,774	3,725
4	2,611	3,221	1,777	3,728
5	2,596	3,201	1,773	3,693
6	2,610	3,210	1,794	3,691
7	2,611	3,212	1,796	3,692
8	2,613	3,214	1,797	3,695
9	2,640	3,232	1,837	3,694
10	2,650	3,239	1,850	3,697
11	2,650	3,237	1,857	3,686
12	2,653	3,239	1,860	3,689
13	2,668	3,252	1,879	3,694
14	2,679	3,260	1,892	3,698
15	2,688	3,269	1,904	3,704
16	2,691	3,272	1,908	3,706
17	2,710	3,290	1,927	3,721
18	2,714	3,294	1,932	3,724
Optimal DSM Flight #	5	5	5	11

Step 4 – The optimal level of DSM for ENO in each of the IRP scenarios as identified in Step 3 was included in the capacity expansion module to produce the optimum level of supply-side resources. Since ENO DSM was being tested, supply-side resource addition changes were limited to the DSG Area (the sub-area which includes the City of New Orleans). In order to further validate the results of Step 3, the capacity expansion module was run using the selected flight #5 (and #11 in Green Growth) as well as alternative flights above and below the selected flight on the DSM supply curve. The alternative flights did not result in a lower total relevant supply cost in any of the scenarios.

Supply-side Assumptions

Assumptions regarding supply-side resources – e.g., cost and performance – were based on results of a Technology Assessment[34]. Table 16 summarizes the results of the Technology Assessment for a number of technologies. After an initial screening, the following technologies were found appropriate for further 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 Aero-derivatives
- Nuclear – (Generation III Technology)
- Renewable Technologies
  - Biomass
  - On-shore Wind Power
  - 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.

[34] The Technology Assessment is provided as a Technical Supplement to the IRP. 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 IRP, SPO updated the Technology Assessment in light of current cost and performance information.

TABLE 16: TECHNOLOGY COST COMPARISONS

Levelized \$/MWh Over Expected Life of Resource[35,36] (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

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

36 Discount rate equals 7.81%.

FINDINGS AND CONCLUSIONS

DSM Potential

A variety of factors, many of which are highly uncertain, will affect the amount of DSM that can 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 Council directives, external market forces, changes to ENO's schedule for implementing DSM programs, and 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 long-run planning nature of the DSM Potential Study and this IRP means that results should not be applied directly to short-term DSM planning activities, including, but not limited to program implementation plans or utility goal setting. Long-run program assumptions do not necessarily translate well for actual implementation in the short-term and may not reflect regulatory or other constraints. What the DSM Potential Study and IRP do provide is guidance on how varying levels of investment in DSM could impact total forward supply costs over the long-term. Actual near-term program plans require more detailed analysis of design, costs, delivery mechanisms, measure mix, participation, regulatory guidelines, rate impacts and other factors. In addition, it is important to point out that DSM program costs utilized in the IRP include both incentives paid to participants and program delivery costs such as marketing, training, and program administration. Program delivery costs were estimated to reflect average annual costs over the twenty-year planning horizon of the DSM Potential Study consistent with markets with more mature DSM programs, and therefore actual program costs associated with current and future DSM programs implemented in New Orleans may be higher. Future program goals and implementation plans should reflect this uncertainty.

The implementation of cost-effective DSM requires consistent, sustained regulatory support and approval. ENO's investment in DSM must be met with a reasonable opportunity to timely recover all of the costs, including lost contribution to fixed costs, 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 through incentives. As noted in the Technical Advisors Report dated June 13, 2011, in reference to ENO's previous IRP filing, "The Council's IRP Requirements require that ENO and ELL integrate "…both supply- and demand-sides in a fair and consistent manner…. "[37] This requires the Companies to consider demand-side resources on an equal footing and in parallel with supply-side resources"[38]. In order for supply- and demand-side resources to be considered on equal footing, it is necessary that the Companies be compensated on an equal footing.

[37] Electric Utility Integrated Resource Plan Requirements of the Council of the City of New Orleans, Page 1
[38] Technical Advisors Report, Entergy New Orleans and Entergy Louisiana, LLC, Integrated Resource Plan Filing on October 19, 2010 in Council Docket No. UD-08-02, Page 5, Section 4.1

Preferred Portfolio

The 2012 ENO IRP Preferred Portfolio is designed to support ENO's strategy for meeting customers' long-term power needs at the lowest reasonable cost considering reliability and risk. The final risk assessment leading up to the Preferred Portfolio focused on the effects of key drivers of total cost varied over time, including natural gas, carbon (i.e. CO_2) and purchased power cost. The final risk assessment also evaluated a high DSM investment scenario that was identified in the ENO DSM optimization effort as potentially economic in high carbon cost outcomes.

The final risk assessment was conducted to determine how the Preferred Portfolio would perform when key variables are changed in order to reflect uncertainty in future costs. As shown in Table 17 below, the CCGT dominant portfolio is the lowest cost portfolio when compared to the alternatives evaluated in the risk assessment. The ENO Preferred Portfolio includes a proportionate share of CCGT resource additions in the DSG region, and therefore is consistent with the lowest cost portfolio evaluated in the final risk assessment. While the Preferred Portfolio for the broader Entergy System includes a mix of CCGT and CT capacity (Balanced Portfolio), the ENO Preferred Portfolio (including the entire DSG sub-region Preferred Portfolio) sourced CCGT technology when new generating resources are assumed to come online to meet resource needs. Correspondingly, the results of the final risk assessment below reflect that the ENO Preferred Portfolio is the low cost portfolio across a wide range of commodity assumptions, including a High DSM case. The High DSM case represents a level of spending on DSM programs beyond the cost-effective level in identified in three of the four scenarios evaluated. The mix of DSM programs included in the Preferred Portfolio, their associated estimated costs and savings are shown in Tables 18 and 19.

TABLE 17: ENO FINAL RISK ASSESSMENT

NPV of ENO Forward Revenue Requirements (2014 – 2031, 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	1.67	1.79	1.44	2.24
CT Dominant	1.69	1.82	1.45	2.25
Balanced CCGT / CT	1.70	1.82	1.45	2.25
High DSM	1.76	1.87	1.54	2.26

The ENO Preferred Portfolio includes the following key supply-side elements:

- ENO 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.
- All existing coal and nuclear units currently in ENO's supply-side portfolio continue operations throughout the planning horizon.
- Although no final decisions have been made regarding the timing or level of investment in the Michoud facility, the IRP optimization process selected to extend the life of Michoud Unit 3 over other available resource alternatives.

- New build capacity, when needed in 2020 and beyond, comes from CCGT resources. With the exception of the Ninemile 6 resource presently under construction, the System has not made a decision to implement any particular future capacity addition.

The level of DSM included in the Preferred Portfolio was determined by an optimization methodology that systematically evaluated increasingly expensive "flights" of DSM programs. That is, a small bundle of the most cost-effective programs were evaluated first (i.e., flight 1), and small bundles of increasingly expensive programs were added until all levels of potential DSM were included (i.e., flight 18). The amount of DSM that minimized the total cost of service was identified as the optimal level of DSM. In contrast, the scope of the DSM Potential Study was to identify market-achievable DSM for New Orleans. The methodology of the potential study was consistent with a primary objective to identify a wide range of DSM potential available to meet customers' need. In this way, the study results helped ensure that more programs would be identified for further evaluation in the IRP, however; the results of the Potential Study do not reflect a level of DSM spending that would result in a preferred portfolio with the lowest total supply cost for New Orleans. Given one of the IRP objectives was to develop a preferred portfolio that results in the lowest total supply cost, the DSM optimization took the programs identified in the Potential Study and organized them in a way that allowed the model to continue adding DSM programs to ENO's portfolio until they cost more than a supply-side alternative (choosing from the full range of supply-side alternatives available). Therefore the IRP process considered supply- and demand-side alternatives on an equal footing. As such, the level of spending identified in the Potential Study would not be expected to result in the lowest reasonable cost.

Ten different DSM programs are included in the Preferred Portfolio including 5 programs currently offered in Energy Smart, 3 additional energy efficiency programs for the non-residential customer sector, and two demand response programs. The DSM programs reflect the potential to reduce peak load by 203 MW by 2031 at a cost of approximately $5 to $6 million per year.

TABLE 18: ENO DSM PROGRAMS –DSM PROGRAMS IN THE PREFERRED PORTFOLIO

Sector	Type	Program Name	Energy Smart?	Level of Spending on Incentives
C&I	EE	Large Commercial Energy solutions	Yes	Low
C&I	EE	Small Commercial Energy Solutions	Yes	Low
Res.	EE	Energy Smart New Homes	Yes	Low
Res.	EE	ENERGY STAR Air Conditioning	Yes	Low
Res.	EE	Residential Lighting and Appliances	Yes	Low
C&I	EE	Commercial Building Energy Management	No	Low
C&I	EE	Commercial New Construction	No	Low
C&I	EE	Industrial	No	Low
C&I	DR	Interruptible Rate	No	High
Res.	DR	Direct Load Control	No	High

TABLE 19: ENO DSM PROGRAMS –DSM PROGRAMS IN THE PREFERRED PORTFOLIO

	Cumulative Energy Savings (MWh)	Cumulative Peak Load Reduction (MW)	Annual Program Costs ($M)
2012	5,387	3	0.74
2013	16,290	9	1.50
2014	33,726	19	3.13
2015	54,852	32	3.56
2016	79,762	46	4.27
2017	106,953	58	4.65
2018	135,326	87	4.91
2019	163,543	102	5.06
2020	191,144	105	5.16
2021	218,284	122	5.24
2022	245,103	133	5.30
2023	269,108	140	5.36
2024	290,192	162	5.43
2025	308,501	169	5.49
2026	324,945	174	5.56
2027	340,021	183	5.63
2028	354,012	181	5.70
2029	367,179	188	5.77
2030	380,410	195	5.84
2031	393,019	203	5.92
Total Spending (Optimal DSM)			94.2
Average Annual Spending (Optimal DSM)			4.7

As measured by the 20-year compound annual growth rate from 2011 weather normalized energy use, DSM spending consistent with the cost-effective level identified in the Preferred Portfolio is projected to cut the growth rate in total customer energy consumption from 0.9% per year to 0.6% per year, a 37% reduction. Projected reductions in peak demand are even more pronounced as exhibited by negative growth over the same period. The projected demand savings associated with the optimal cost-effective DSM spending level over the 20 year planning horizon is almost twice that of ENO's share of Ninemile 6. Essentially, ENO may be able to alleviate the need to procure up to 203 MW of capacity by 2031, however; that would not alleviate the need for the Ninemile 6 capacity or other capacity additions included in the Preferred Portfolio.

The ENO Preferred Portfolio includes assumptions regarding future supply-side resource additions. However, with the exception of the Ninemile 6 resource presently under construction in Amite South, ENO has not made a decision to implement any particular future capacity addition. The actual resources deployed – the amount, timing, technology, whether owned or under long-term PPA – 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; and
- 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. In addition, the 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 20 and 21 below provide the load and capability for ENO as a result of the supply- and demand-side resource additions included in the ENO Preferred Portfolio.

TABLE 20: LOAD & CAPABILITY 2012-2021 (PREFERRED PORTFOLIO – FIRST HALF OF THE PLANNING HORIZON)

ENO Load & Capability 2012 – 2021[39] (MW)										
	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Requirements										
Peak Load	985	988	994	1,004	1,007	1,012	1,017	1,020	1,022	1,026
DSM	(3)	(9)	(19)	(32)	(46)	(58)	(87)	(102)	(105)	(122)
Planning Reserve (12%)	118	117	117	117	115	114	112	110	110	108
Total Requirements	1,100	1,096	1,092	1,089	1,076	1,069	1,041	1,027	1,027	1,012
Resources										
Existing Resources										
– Owned Resources	982	982	982	982	982	982	982	982	982	982
– Power Purchase Contracts	271	211	211	211	211	211	211	211	211	211
Identified Planned Resources										
– Ninemile 6				112	112	112	112	112	112	112
– 2011 Western Region RFP										
– Other										
Other Planned Resources										
– Amite South (CCGT)									171	171
– Western (CT)										
– CCGT										
– CT										
– Sustain Existing Units										
– Long-term Purchases[40]										
– Limited-term Power Purchases/(Sales) Contracts										
– Short-term Capacity Purchases										
Total Resources	1,253	1,193	1,193	1,305	1,305	1,305	1,305	1,305	1,476	1,476

[39] Totals may not add due to rounding.
[40] May also be an acquisition of an existing resource.

TABLE 21: LOAD & CAPABILITY 2022-2031 (PREFERRED PORTFOLIO – SECOND HALF OF THE PLANNING HORIZON)

ENO Load & Capability 2022 – 2031 (MW)										
	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Requirements										
Peak Load	1,030	1,034	1,038	1,040	1,046	1,051	1,056	1,060	1,066	1,069
DSM	(133)	(140)	(162)	(169)	(174)	(183)	(181)	(188)	(195)	(203)
Planning Reserve (12%)	108	107	105	105	105	104	105	105	105	104
Total Requirements	1,004	1,000	980	976	978	972	980	977	975	969
Resources										
Existing Resources										
– Owned Resources	747	747	747	747	747	218	218	218	218	218
– Power Purchase Contracts	211	211	211	211	211	211	211	211	211	211
Identified Planned Resources										
– Ninemile 6	112	112	112	112	112	112	112	112	112	112
– 2011 Western Region RFP										
– Other										
Other Planned Resources										
– Amite South (CCGT)										
– Western (CT)										
– CCGT	171	171	171	171	171	171	171	171	171	171
– CT										
– Sustain Existing Units						529	529	529	529	529
– Long-term Purchases										
– Limited-term Power Purchases/(Sales) Contracts										
– Short-term Capacity Purchases										
Total Resources	1,241	1,241	1,241	1,241	1,241	1,241	1,241	1,241	1,241	1,241

RATE EFFECTS

The typical bill impacts associated with the cost to meet customers' needs over the next two decades are modest, and in some cases are projected to decrease due to the significant DSM potential identified for the City of New Orleans and included in the Preferred Portfolio. Over time, inflation in the broader economy tends to drive prices up for all goods and services, and in general the average annual growth rate in projected customer bills during the IRP planning horizon are expected to increase at or below inflation expectations.

TABLE 22: RATE EFFECTS – ENO PREFERRED PORTFOLIO

ENO Typical Monthly Customer Bill (Ref. Gas, No CO_2)				
Customer Segment	2011	2021	2031	CAGR[41]
Residential	$104	$122	$132	1.2%
Commercial	$929	$960	$896	(0.2)%
Industrial	$1,088	$1,571	$1,640	2.1%
Government	$2,892	$3,010	$2,817	(0.1)%

[41] Cumulative Average Growth Rate ("CAGR") measures the average annual rate of growth in typical customer bills over the planning horizon.

Risk Analysis

In general, the risk analysis conducted sought to determine how the Preferred Portfolio performed, in terms of customer bill impacts, under a range of potential future scenarios for the price of natural gas and CO_2 regulation. The results reflect that the Preferred Portfolio is robust in its ability to provide a reasonable opportunity for customer bills to rise slower than ENO's long-term outlook for inflation (about 2% per year). While rates in a given scenario may be projected to rise at or slightly faster than inflation, it is primarily limited to certain scenarios and/or customer classes. In those circumstances, it is important to point out that those customers are also projected to use less electricity without sacrificing convenience or comfort. This is driven by increasing government mandated energy efficiency standards in new products and utility sponsored DSM spending modeled in the Preferred Portfolio. The rate analysis detailed below assumes the Preferred Portfolio resource additions which includes Flight #5 DSM spending.

Table 23: Risk Analysis – ENO Preferred Portfolio

Average ENO Residential Customer Electric Bill						
	2011 Usage (kWh/mo.)	2011 ($/mo.)	2031 Usage (kWh/mo.)	2031 ($/mo.)	Annual Growth Rate	
Risk Scenario					kWh %	$ %
Reference Gas No CO_2	1,111	104	925	132	-0.9%	1.2%
Reference Gas 2023 CO_2	1,111	104	925	141	-0.9%	1.6%
Low Gas No CO_2	1,111	104	925	122	-0.9%	0.8%
High Gas 2018 CO_2	1,111	104	925	160	-0.9%	2.2%
Average ENO Commercial Customer Electric Bill						
	2011 Usage (kWh/mo.)	2011 ($/mo.)	2031 Usage (kWh/mo.)	2031 ($/mo.)	Annual Growth Rate	
Risk Scenario					kWh %	$ %
Reference Gas No CO_2	18,183	929	13,834	896	-1.4%	-0.2%
Reference Gas 2023 CO_2	18,183	929	13,834	963	-1.4%	0.2%
Low Gas No CO_2	18,183	929	13,834	818	-1.4%	-0.6%
High Gas 2018 CO_2	18,183	929	13,834	1,103	-1.4%	0.9%
Average ENO Industrial Customer Electric Bill						
	2011 Usage (kWh/mo.)	2011 ($/mo.)	2031 Usage (kWh/mo.)	2031 ($/mo.)	Annual Growth Rate	
Risk Scenario					kWh %	$ %
Reference Gas No CO_2	18,183	1,088	13,834	1,535	-1.4%	1.7%
Reference Gas 2023 CO_2	18,183	1,088	13,834	1,670	-1.4%	2.2%
Low Gas No CO_2	18,183	1,088	13,834	1,377	-1.4%	1.2%
High Gas 2018 CO_2	18,183	1,088	13,834	1,954	-1.4%	3.0%
Average ENO Government Customer Electric Bill						
	2011 Usage (kWh/mo.)	2011 ($/mo.)	2031 Usage (kWh/mo.)	2031 ($/mo.)	Annual Growth Rate	
Risk Scenario					kWh %	$ %
Reference Gas No CO_2	38,444	2,892	25,747	2,917	-2.0%	-0.0%
Reference Gas 2023 CO_2	38,444	2,892	25,747	3,169	-2.0%	0.5%
Low Gas No CO_2	38,444	2,892	25,747	2,622	-2.0%	-0.5%
High Gas 2018 CO_2	38,444	2,892	25,747	3,697	-2.0%	1.2%

When evaluating resource portfolios that include DSM, it is more comprehensive to consider changes in average monthly typical customer bills rather than looking at usage and rates separately. However, when benchmarking the reasonableness of the Preferred Portfolio's impact on customers for purposes of an IRP, it is not always possible or practical to examine average bill changes for all the available alternatives. To gauge the reasonableness of the Preferred Portfolio, ENO compared the twenty year compound annual growth rate in its revenues as forecast in the IRP for the Preferred Portfolio with the growth rate for all East South Central electric customers as forecast by the Department of Energy - Energy Information Agency ("EIA") in its 2012 Annual Energy Outlook ("AEO"). The AEO is a comprehensive forecast of U.S. energy sources, uses and prices through 2035[42]. The AEO Reference Case does not include a price on carbon so it is appropriate to compare that case to ENO's Reference Gas and No CO_2 case. The comparison of the rate of change in revenues over time is a general indicator of how total customer costs are expected to change during the planning horizon. As the chart demonstrates, when shown on a comparable basis (2031 versus 2011), ENO's growth rates are reasonable as compared to the AEO.

TABLE 24: ENO REVENUE GROWTH RATES VS. EIA GROWTH RATES FOR ALL EAST SOUTH CENTRAL CUSTOMERS

Compound Growth Rate in ENO Revenue By Class (Reference Case & No CO_2) vs. Growth Rate For All East South Central Customers (EIA 2012 AEO Reference Case Forecast)		
Customer Class	ENO IRP	EIA AEO
Residential	1.4%	1.4%
Commercial & Government	2.8%	3.2%
Industrial	2.7%	2.0%
Total	2.2%	2.0%

Action Plan

As part of the planning process, areas of focus necessary to continue moving in a direction that supports implementation of the Preferred Portfolio for ENO have been highlighted in Table 25 below. As discussed above, despite ENO's projected near-term resource surplus, the evaluation of new resource alternatives versus life-extension investments for the older generating units in DSG continues to present one of the most significant challenges facing ENO. Planning to address these challenges has already begun as indicated in the IRP; however, additional work will be necessary to ensure steps are taken to make resource decisions in a timely manner. Although the results of the DSM Optimization show significant incremental DSM potential for New Orleans, DSM alone cannot address the needs of ENO or the DSG region. While extending the life of existing resources within DSG has been considered, the IRP risk assessment indicates that it is necessary to begin planning for those resources eventual replacement by bringing new resources online in a disciplined fashion over time. The Action Plan provided below sets forth the framework for the ongoing planning process. ENO will continue to work with the Council to solidify the details of this plan as and when appropriate based on the outcome of the IRP proceeding.

[42] http://www.eia.gov/forecasts/aeo/sector_electric_power.cfm

TABLE 25: ACTION PLAN

Category	Item	Action to be taken
Supply-side Alternatives	New Resources	– Continue to take steps necessary to support new generation in DSG to support eventual deactivation of aging fleet.
	Existing Resources	– Evaluate costs and benefits of investing in existing resources in order to support reliable operation beyond deactivation date.
Demand-side Alternatives	Incremental Spending	– Develop program and implementation plan for next phase of DSM for New Orleans – File plan with the Council by March 31, 2013 – Implement programs beginning April 1, 2014
MISO Transition	Resource Adequacy	– Monitor MISO's resource adequacy requirements as the Entergy System integration process moves forward.
	Congestion Management	– Conduct evaluation of MISO baseload hedging entitlements and impact on production costs.
Area Planning	DSG	– Refine supply plan based on experience in MISO.
	Transmission	– Integrate MISO's MTEP into the IRP planning process.

FUTURE DSM PROGRAMS

A key objective of the ENO IRP process was to determine an optimal level of cost-effective DSM spending for ENO over the next two decades. The scope of DSM resources considered in the ENO IRP include programs that ENO has or may be able to deploy to manage the level and timing of customers' energy use over the planning horizon, however the results of the optimization should not be used to target specific programs or set detailed program goals without additional analysis. Instead, the results are meant to provide guidance on the long-term potential for DSM under a given set of assumptions, which are inherently uncertain.

As ENO has noted in its Reply Comments to previous IRP filings and as referenced by the Council in Resolution R-11-301, the DSM Potential Study and the supply plan "are long term analyses and planning tools, and neither is used to make real time decisions on specific asset purchases or particular DSM program implementations and neither provides specific decisions to be implemented over the term of each respective study". Therefore the specific program offered in the next phase of Energy Smart may not match those from the IRP when a more detailed program and implementation plan is developed. The IRP will be used as a guide for cost effective DSM spending levels and expected energy savings in the development of these more detailed plans.

Program Development, Implementation, and Cost Recovery Plans

The current Energy Smart programs will end on March 31, 2014 therefore time is of the essence in developing new programs in order to ensure there will be continuity in funding and DSM program offerings to the citizens of New Orleans. In its most recent Energy Smart Resolution, the Council states that, in order to assure such continuity, ENO and ELL-Algiers are directed "…to file, with the Council, implementation and cost recovery plans for future energy efficiency and DSM programs based on the optimal levels contained in its IRP filing or such other programs as determined by the

Council by March 31, 2013[43]." In order to develop programs, implementation and cost recovery plans in a manner that allows for continuity with current Energy Smart programs in the timeframe outlined by the Council, ENO will assume the optimal spending levels for DSM identified in the DSM Optimization (and included in the Preferred Portfolio and Customer Rate Effects), unless otherwise directed by the Council prior to December 31, 2012.

As part of the ongoing planning effort for DSM, ENO will undertake the detailed development of cost effective programs and an implementation strategy to be filed with the Council in March 2013. A stakeholder review is also incorporated into the timeline. Action by the Council to accept or change programmatic elements or spending levels is also incorporated into the proposed timeline. Lessons learned or changes made for the third program year for Energy Smart must also be incorporated into the new plan. Upon acceptance of the final plan by the Council, the implementation plan will begin and new programs will be available beginning April 1, 2014.

In order to begin collecting program costs prior to program implementation activities in the first quarter of 2014, it will be necessary to identify a rate recovery mechanism which can be in place by this time. The Council has required ENO to address this issue in its March 2013 filing.

TABLE 26: DSM ACTION PLAN

Date	Action	Additional Considerations
10/30/2012	IRP Filing	
3/31/2013	ENO files program, implementation and cost recovery plans per Council directive.	
6/2013-9/1/13	Stakeholder review and comment period; Entergy response period	
By 9/30/2013	Council rules on ENO energy efficiency plans	if significant changes needed timeline may be delayed
11/15/2013	ENO files any required changes to plans	if significant changes needed timeline may be delayed
12/15/2013	Council approves programs, implementation plan and cost recovery	
4Q2013 – 1Q2014	Cost recovery begins	
Jan 2014	Implementation plan roll out	
4/1/2014	Program Launch	

[43] New Orleans City Council Resolution R-12-393