THE COUNCIL OF THE CITY OF NEW ORLEANS, LA

REQUEST FOR QUALIFICATIONS STATEMENTS

FOR

DEMAND SIDE MANAGEMENT CONSULTANT

ISSUED SEPTEMBER 15, 2017

APPENDICES VI-XI

REQUEST FOR QUALIFICATIONS STATEMENTS

FOR

DEMAND SIDE MANAGEMENT CONSULTANT

ISSUED SEPTEMBER 15, 2017

APPENDIX VI

ENTERGY NEW ORLEANS'

2012 INTEGRATED RESOURCE PLAN

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.

[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

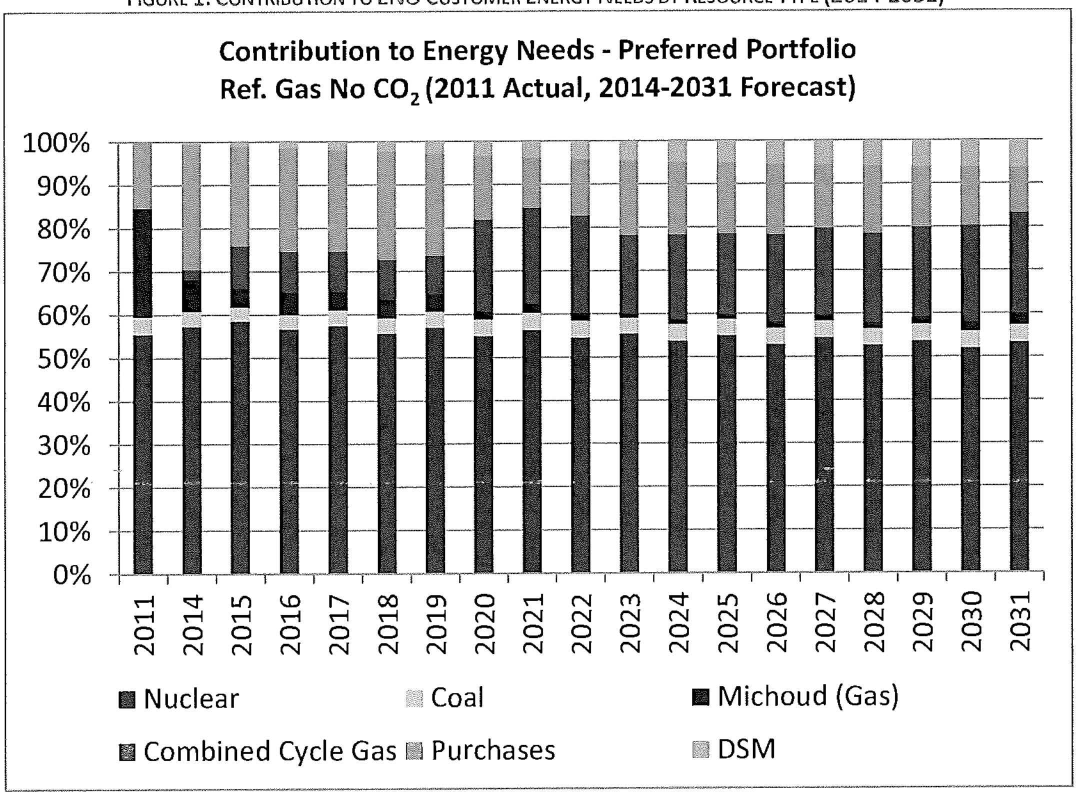
Sector	Type	Program Name	Energy Smart?	Level of Spending on Incentives
C&I	EE	Large Commercial Energy solutions	Yes	Low
C&I	EE	Small Commercial Energy Solutions	Yes	Low
Res.	EE	Energy Smart New Homes	Yes	Low
Res.	EE	ENERGY STAR Air Conditioning	Yes	Low
Res.	EE	Residential Lighting and Appliances	Yes	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]

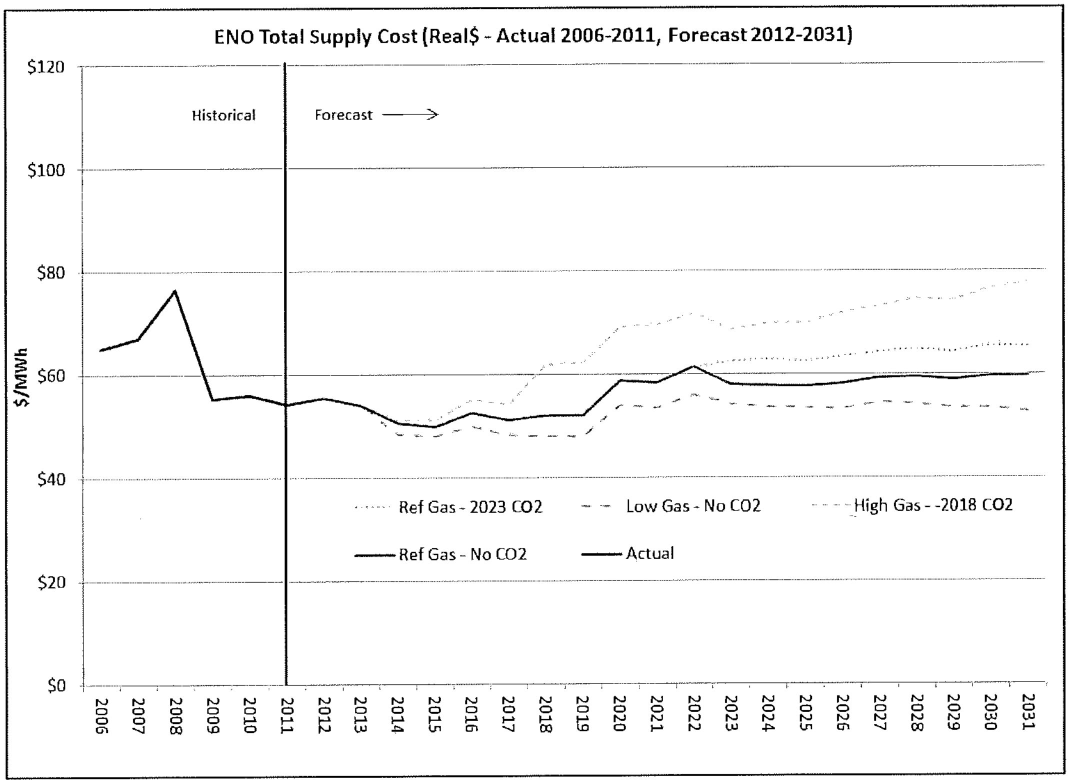


[4] 2011 data does not include DSM associated with Energy Smart due to the timing of program implementation.

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.

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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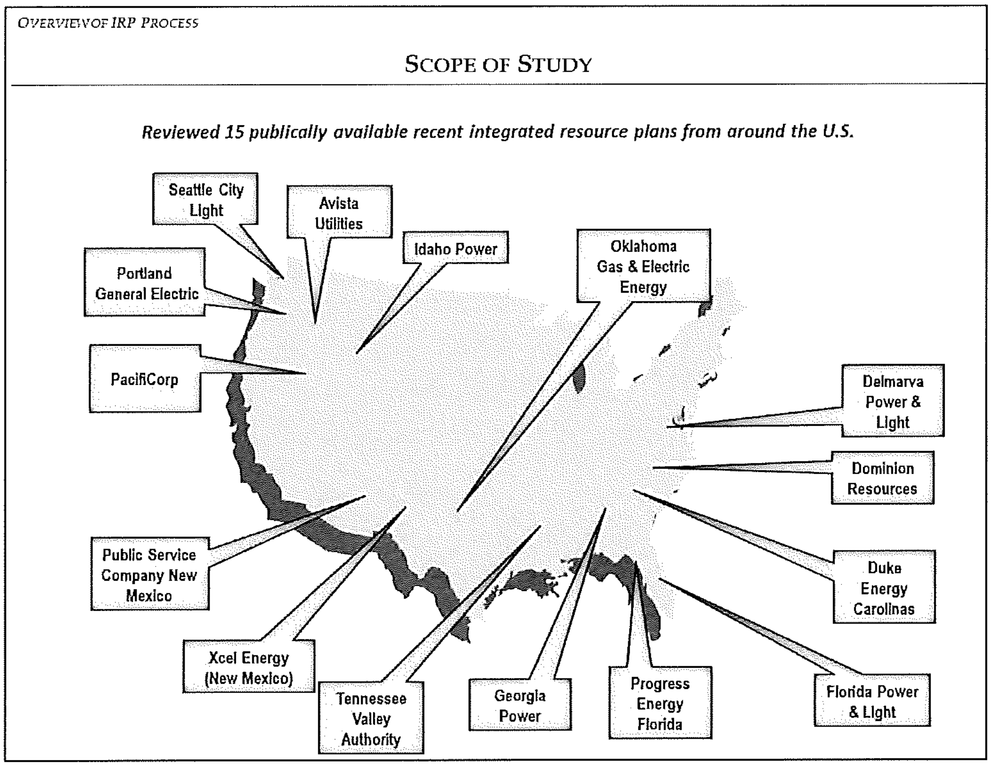
[7] Ordering paragraph no. 12 of Council Resolution R-10-142 included the following direction: "The Council, looking back on the successful process utilized in establishing the Energy Smart Plan earlier in this Docket [UD-08-02], directs that a similar open and transparent process be followed regarding 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 2nd 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

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[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

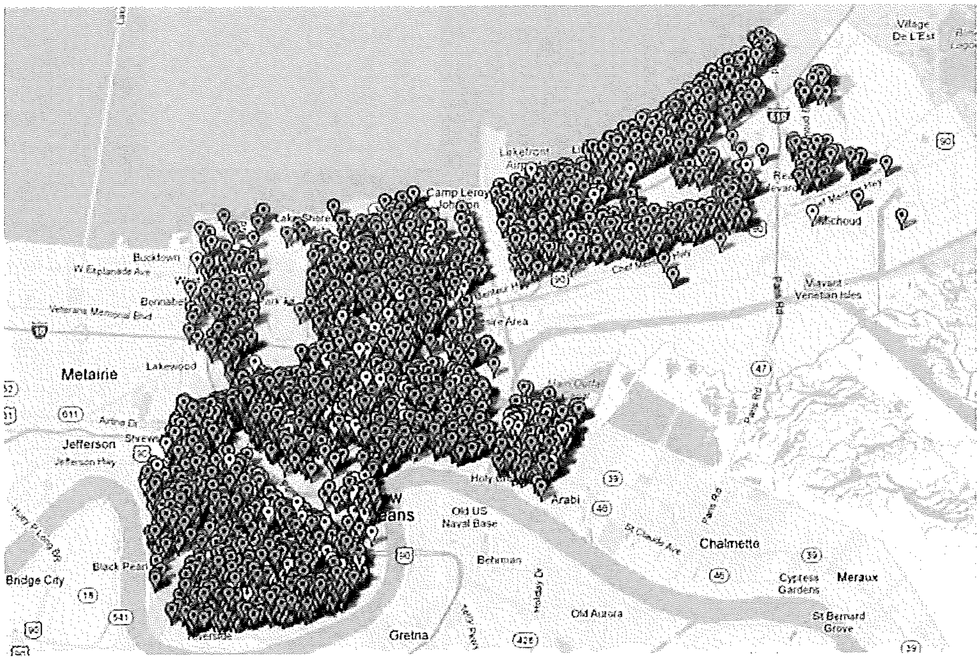
ENO recently made a filing with the Council in docket UD-12-01 requesting approval for a change of ownership of electric transmission businesses through a spin-merge transaction with ITC. Should all regulatory approvals be obtained, the transaction would result in ITC owning and operating the Entergy 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.

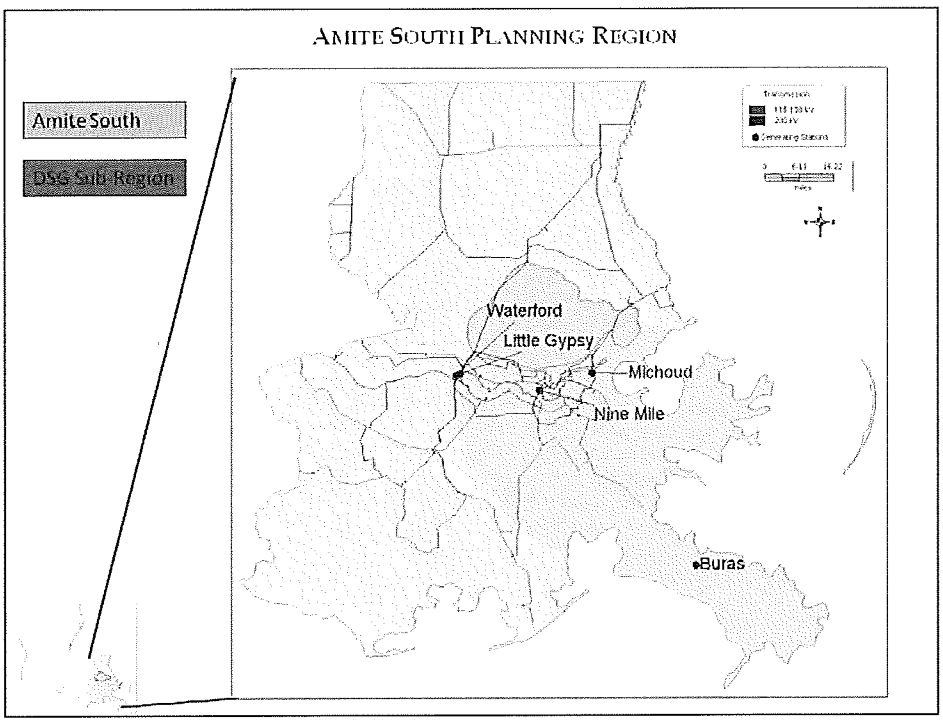
Area Planning

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

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.

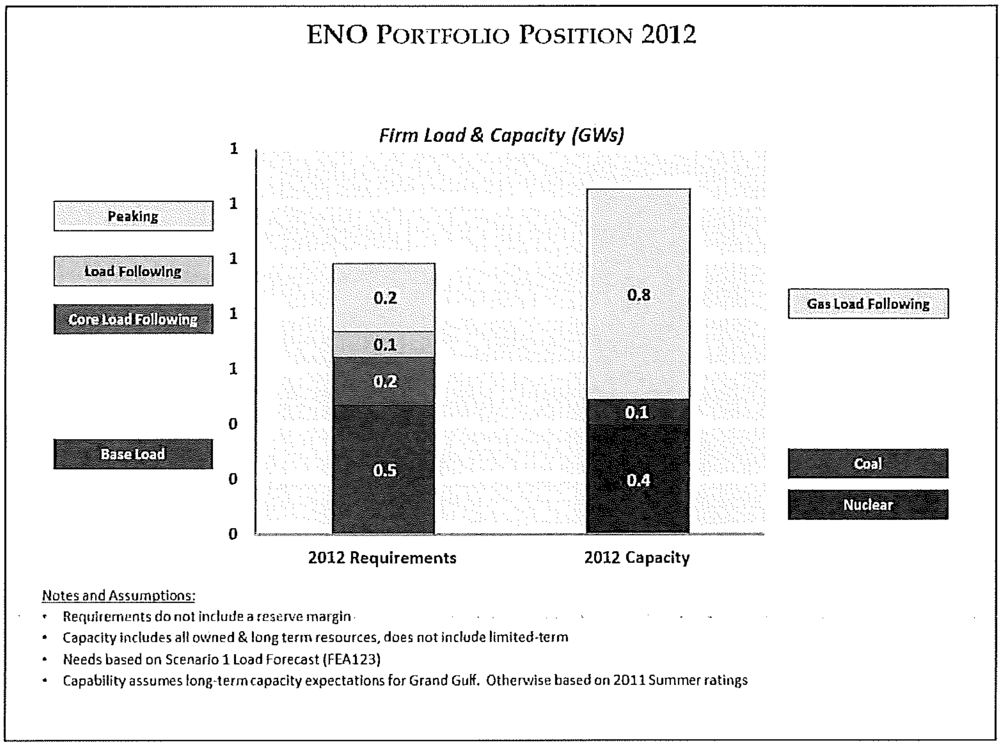
[22] Riverbend Nuclear Station is owned by EGSL which sells 1/3 of its wholesale capacity and energy to ENO through a life-of-unit PPA.

[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)

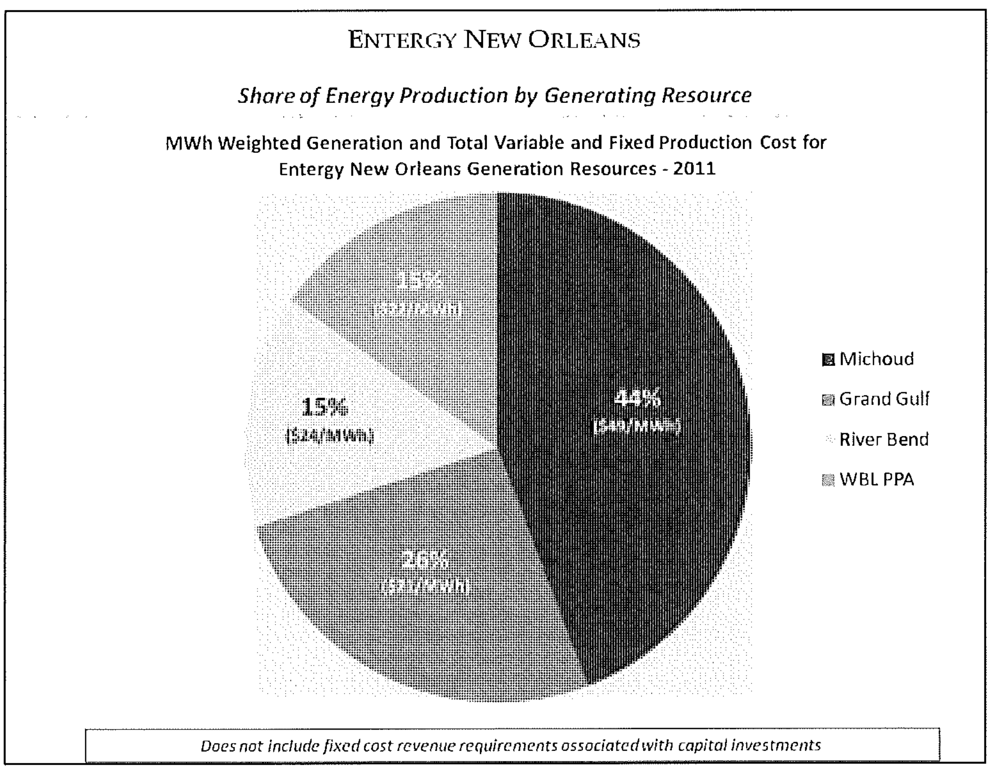


FIGURE 8: HISTORICAL COST OF ENO SUPPLY RESOURCES (BASELOAD)

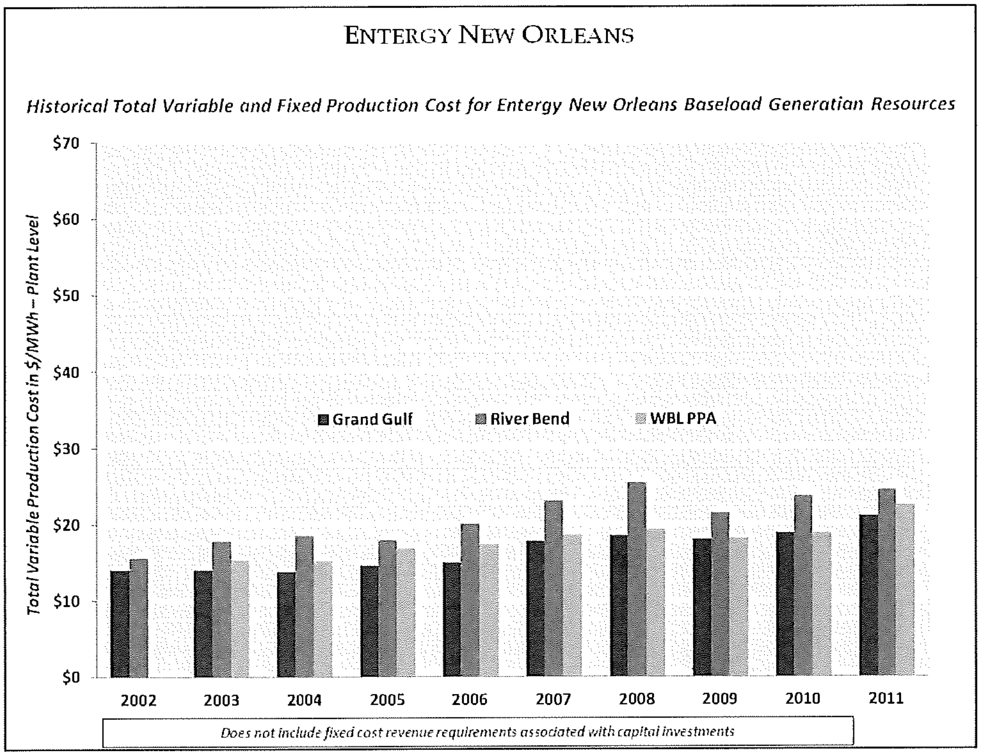
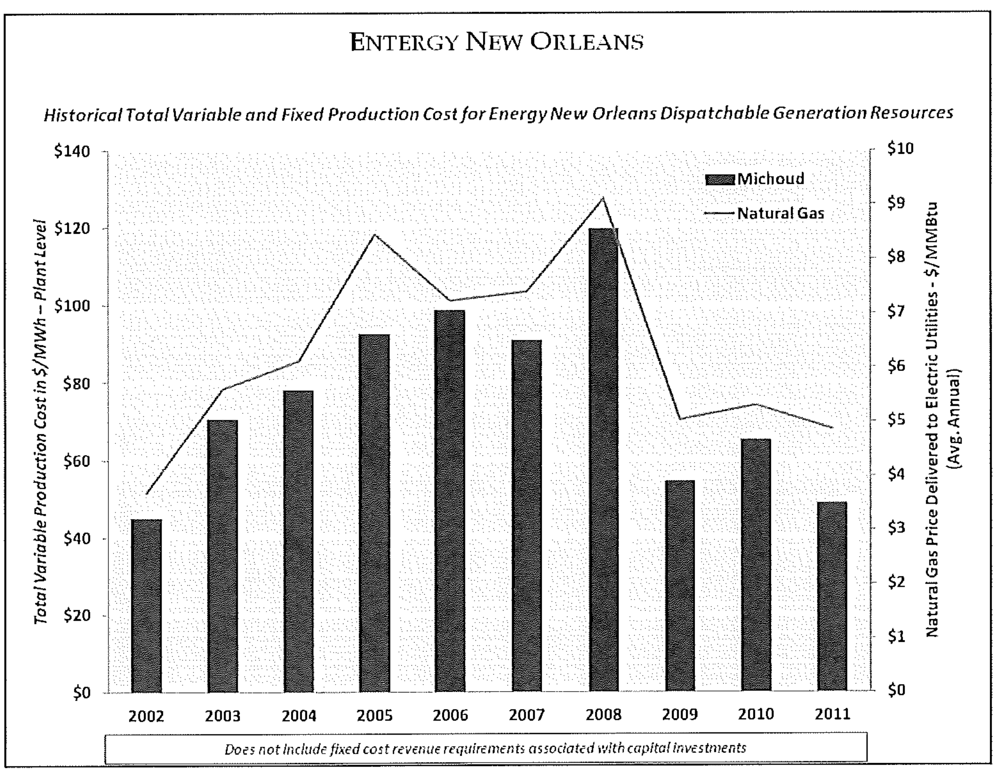


FIGURE 9: HISTORICAL COST OF ENO SUPPLY RESOURCES (DISPATCHABLE)



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.

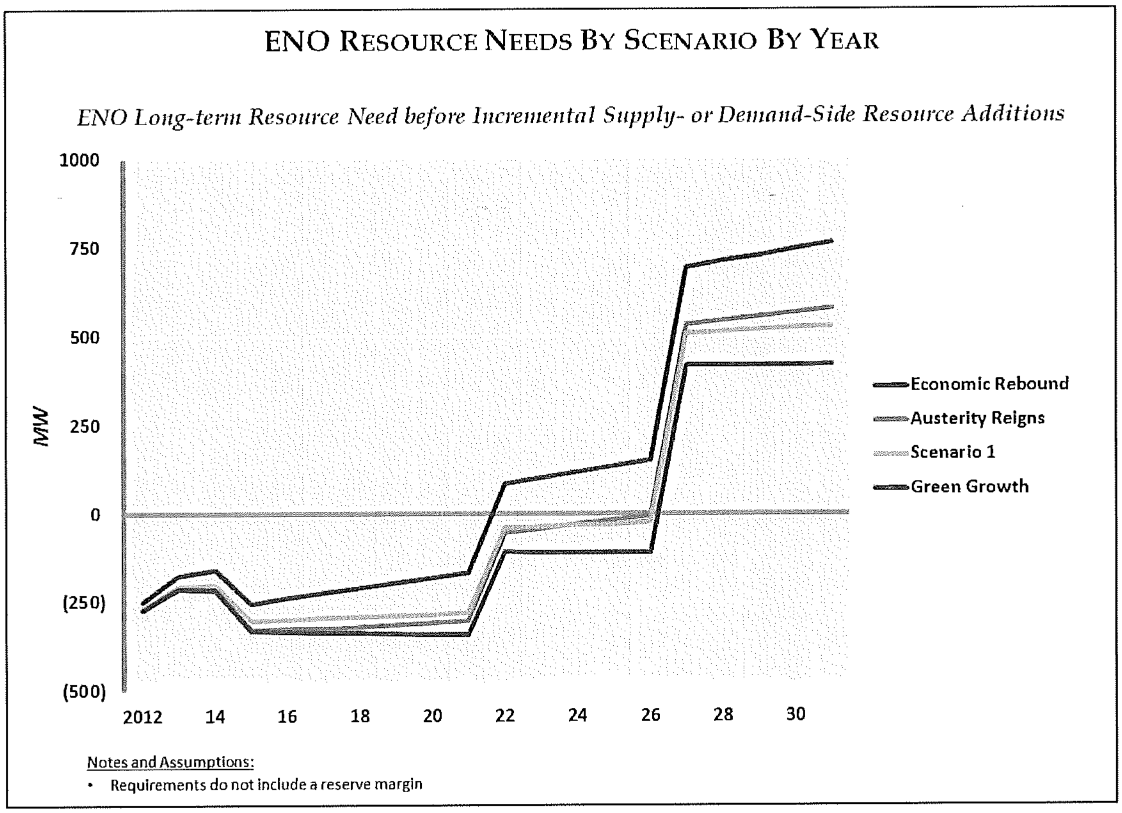
[27] Assumptions regarding the deactivation of generating units are made for planning purposes only. Whether a given until will be deactivated depends upon the planning needs and economics of options available when the decision is made.

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.

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

REQUEST FOR QUALIFICATIONS STATEMENTS

FOR

DEMAND SIDE MANAGEMENT CONSULTANT

ISSUED SEPTEMBER 15, 2017

APPENDIX VII

ENTERGY NEW ORLEANS'

2015 INTEGRATED RESOURCE PLAN

Entergy

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Timothy S. Cragin
Assistant General Counsel
Legal Services - Regulatory

February 1, 2016

Via Hand Delivery

Ms. Lora W. Johnson
Clerk of Council
Council of the City of New Orleans
Room 1E09, City Hall
1300 Perdido Street
New Orleans, LA 70112

Re: *In Re*: Resolution Regarding Proposed Rulemaking to Establish Integrated Resource Planning Components and Reporting Requirements for Entergy New Orleans, Inc. (Docket No. UD-08-02)

Dear Ms. Johnson:

Pursuant to Council Resolution R-14-224, enclosed please find an original and three copies of Entergy New Orleans, Inc.'s ("ENO") Final 2015 Integrated Resource Plan ("IRP") Report, including a disk containing the Supplements 1-3, 5, and 7-11, and the Public Versions of Supplements 4 and 6. Please file an original and two copies into the record in the above-referenced matter, and return a date-stamped copy to our courier.

A copy of the Highly Sensitive versions of Supplements 4 and 6 have been designated "Highly Sensitive Protected Materials" and will be distributed under separate cover to authorized Reviewing Representatives pursuant to the Council's Official Protective Order adopted in Council Resolution R-07-432.

Thank you for your assistance with this matter.

Sincerely,

Timothy S. Cragin

TSC:pe
Enclosures
cc: Official Service List UD-08-02 *(via electronic mail)*

RECEIVED
FEB 01 2016
BY:

FEB - 4 50

CERTIFICATE OF SERVICE
Docket No. UD-08-02

I hereby certify that I have this 1st day of February 2016, served the required number of copies of the foregoing report upon all other known parties of this proceeding, by: ☒ electronic mail, ☐ facsimile, ☐ overnight mail, ☒ hand delivery, and/or ☒ United States Postal Service, postage prepaid.

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New Orleans, Louisiana, this 1st day of February, 2016.

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Entergy New Orleans, Inc.

2015 Integrated

Resource Plan

February 1, 2016

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EXECUTIVE SUMMARY

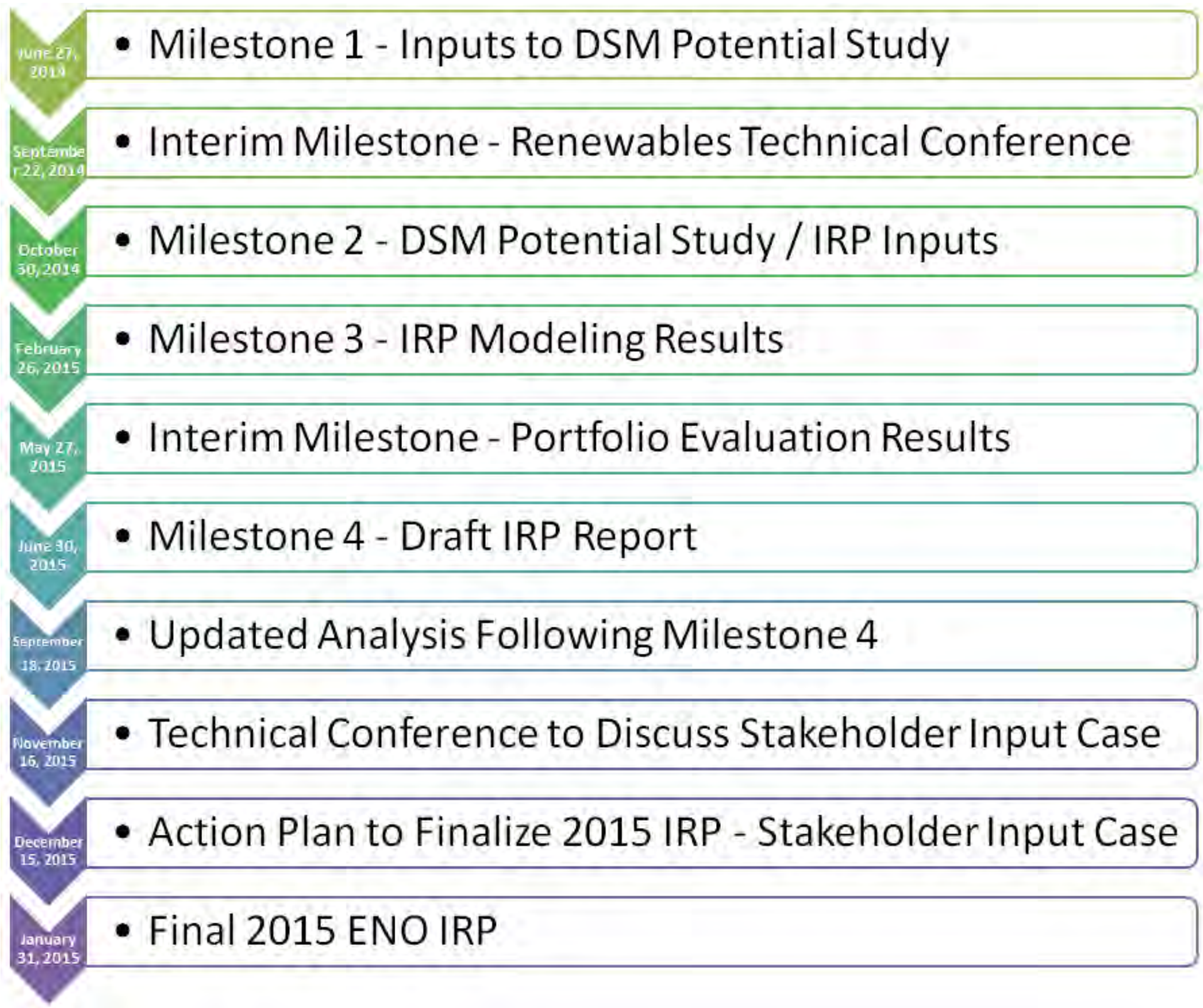
Introduction

This report documents the process and results of Entergy New Orleans, Inc.'s ("ENO") 2015 Integrated Resource Plan ("IRP"). This ENO 2015 IRP reflects the culmination of over 18 months of collaboration and analysis on the part of ENO and stakeholders including the public, intervenors and the legal and technical advisors ("Advisors") to the Council of the City of New Orleans ("Council"). The 2015 IRP reflects a balanced and reasonable resource plan for the coming 20 years (2015-2034)[1] that provides meaningful guidance and insight on the preferred types, combination and timing of changes to ENO's long-term resource portfolio that will contribute to ENO's ability to continue providing safe and reliable electric service to its customers at the lowest reasonable cost while mitigating risk. Inherent in the design of the ENO 2015 IRP Preferred Portfolio is the flexibility necessary to adapt to changing market, environmental and regulatory conditions. In developing the 2015 IRP, ENO's key areas of focus include addressing the planned deactivation of aging supply resources, and identifying the optimal combination of supply and demand-side resources necessary to maintain reliability, mitigate price uncertainty, promote fuel diversity and stability, and address environmental uncertainties.

In developing the 2015 IRP, ENO was guided by the process previously established by the Council for development of, and stakeholder input to, the ENO 2015 IRP in Resolution R-14-224, which requires a series of milestones be met with corresponding documentation, and provides for timely stakeholder input through contemporaneous technical meetings and Q&A sessions with the public and parties to the IRP proceeding. As shown in Figure 1, below, the process for the 2015 IRP consisted of four primary milestones, as well as 2 interim milestones. To address stakeholder and Advisor concerns, ENO agreed to perform additional analysis after Milestone 4 regarding changes to various input assumptions that occurred during the IRP process. To allow for this analysis to occur, ENO was granted an extension to file the final IRP by January 31, 2016. This additional analysis is discussed herein, where applicable, and is supported by a Demand-Side Management ("DSM") supplement and a Stakeholder Input Case supplement. The information provided in each supplement, along with the draft IRP, helped inform the development of the Final 2015 IRP Preferred Portfolio and corresponding Action Plan.

[1] At the request of stakeholders, additional analysis was performed using alternative assumptions for the years 2016-2035, the results of which are included in the Updated Assumptions supplement

Figure 1: IRP Milestones



Current Assessment

ENO is an integrated utility responsible for serving the electric and natural gas demands of Orleans Parish, Louisiana which includes 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. DSG generally encompasses the area south of Lake Pontchartrain and east to the Gulf of Mexico.

<u>Supply-Side Resources</u>

As of the time of this filing, ENO's supply-side electric generation portfolio consists of approximately 1,318MW of long-term generation resources across a range of technologies and fuel types including nuclear, natural gas, as well as a small amount of hydro and coal. Currently, over half of ENO's generating capacity consists of legacy natural gas-fired generating units (Michoud Units 2 and 3); however, with the deactivation of Michoud Units 2 (239 MW) and 3 (542 MW) scheduled to occur in 2016, ENO's remaining resource portfolio will consist primarily of nuclear and combined-cycle gas turbine ("CCGT") resources which are projected to provide roughly half of ENO's capacity and energy needs. Additionally, subject to receipt of all applicable regulatory approvals ENO will secure an additional 510 MW of CCGT capacity and associated energy through the acquisition of Power Block 1 of the Union Power Station. As a result, the Preferred Portfolio reflects that ENO will meet its projected base load and core load-following needs with existing resources; however, as discussed in more detail in this report ENO will need additional resources to meet its projected peak capacity and reserve requirement.

Demand-Side Resources

Currently in its fifth year of existence, Energy Smart is a comprehensive utility-sponsored 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. Funding for the first three years of Energy Smart was recovered from customers through ENO's electric rates. Program years 4-6 (April 1, 2014 – March 31, 2017) are being funded primarily by Rough Production Cost Equalization remedy payments received from other Entergy Operating Companies pursuant to prior decisions of the Federal Energy Regulatory Commission.

The initial phase of Energy Smart consisted of three consecutive annual program years lasting from April 2011 through March 2014. During those three years, Orleans Parish ratepayers saved over 52 million kWh of electricity[2] through a variety of cost-effective programs. Incentives were provided for energy efficient measures including, but not limited to, energy audits, direct install CFL bulbs, low flow fixtures, weatherization, HVAC, A/C Tune-ups and lighting. Program Year 4 was a continuation of the initial phase, offering the same programs and saving another 16,449,016 kWh.

Design of the Energy Smart energy efficiency programs begins with, and is informed by, ENO's long-term DSM Potential Studies undertaken in each Triennial IRP cycle. In evaluating the extent to which cost-effective DSM is achievable in New Orleans, the 2015 DSM Potential Study considered the results attained, and experiences learned, through previous years of Energy Smart. Similarly, in development of the second phase of Energy Smart (April 1, 2015 – March

[2] Average annual percent of sales from 2011-2014 was .34%.

31, 2017), the results of the 2012 IRP provided general guidance on the types of energy efficiency programs which were considered. This link between the IRP, and the design of DSM programs is expected to continue; however, there are differences between the results of long-term potential studies and the details of program design and implementation, and those differences are reasonable and to be expected.

Interruptible Load

In addition to Energy Smart, ENO's portfolio of demand-side resources includes interruptible load associated with a large industrial customer located in its service area. Subject to the terms of the customer's service agreement, ENO can call on the customer to reduce its electric use to reduce ENO's peak resource needs to help mitigate periods when demand could exceed available supply during certain contingency events. Importantly, this load is included in the calculation of ENO's long-term resource needs as a load-modifying resource and will be registered for participation in the Midcontinent Independent System Operator, Inc. ("MISO") Resource Adequacy process for the 2016 – 2017 planning year.

Advanced Metering Infrastructure

Entergy's regulated utilities are currently considering various future investments to modernize the distribution grid and more fully utilize new technologies. Such investments will provide benefits including improved grid resiliency, enhanced operations and communications, and new decision-making tools for customers. Among those investments is advanced metering infrastructure ("AMI"). Some benefits of AMI include enabling faster outage restoration during storm events thru more accurate real-time operations data as well as improved restoration planning and communications; providing customers with greater knowledge and control over their electric usage, which could enhance conservation; and facilitating more timely response to service inquiries, especially service connects and reconnects. AMI also provides a foundation upon which other investments to modernize the grid can be made. At this point, AMI continues to be analyzed and ENO plans to talk further with the City Council and its Advisors regarding potential future AMI investments.

Resource Need

The purpose of the IRP is to develop a long-range plan that is capable of meeting ENO's projected resource needs and support ENO's primary objective to continue providing safe and reliable service to ENO's customers at the lowest reasonable cost. In support of that objective, the 2015 ENO IRP identifies and evaluates a range of potential resource combinations from the available, cost-effective demand- and supply-side alternatives, and selects from those alternatives the optimal combination that results in the lowest reasonable cost while considering reliability and risk.

Although ENO's current supply and demand-side resource portfolio meets existing customer load requirements, new resources will be needed in the future to maintain reliability as load grows and aging supply resources are deactivated. The addition of load to ENO through the Algiers acquisition, which was finalized on September 1, 2015, only enhances ENO's need as the load in Algiers grows and aging resources allocated to ENO pursuant to the Algiers PPA deactivate. By the end of the twenty-year planning horizon, ENO is projected to need between 750 - 821 MW of new capacity resources[3]. This need is driven primarily by the planned deactivation of Michoud Units 2 and 3 in 2016. These units, which combine to provide approximately 780 MW of capacity, represent over half of ENO's generating capacity. Furthermore, by 2034 ENO's projected peak demand is expected to increase between 123 - 160 MW.[4]

Long-Term Achievable DSM Potential

For the 2015 IRP, ENO engaged the services of ICF International to assess the long-term market-achievable potential for DSM programs ("Potential Study") that could be deployed over the planning horizon. A comprehensive measure database that included 228 measure types and 1,056 measures in total was used to evaluate the market-achievable potential for DSM programs for ENO. Commercially available electric and gas measures covering each relevant savings opportunity within each end-use and sector were included.

Measures were then screened for cost-effectiveness using the measure Total Resource Cost (TRC) test. With few exceptions, only measures with a TRC test result of 1.0 or better were passed on to the next stage of the analysis. ICF's analysis found 814 measures to be cost effective. These economic measures are then mapped into programs. The program types are usually based on the set of existing programs offered in the service area plus additional programs for which there are cost-effective applicable measures. These additional programs are generally based on best practice designs. Based on the 814 cost-effective measures, the ICF Potential Study designed 24 programs to be assessed further in the IRP process. 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 to participating customers.[5]

[3] Capacity need by 2035 in Stakeholder Input Case is approximately 901 MW

[4] Peak demand increase from 2016 to 2035 is approximately 167 MW in Stakeholder Input Case

[5] Program incentives are paid to participating customers, thereby reducing the customer's upfront cost and corresponding payback period for a given program.

Supply-Side Resource Alternatives

The IRP process considers a range of alternatives available to meet planning objectives, including the existing fleet of generating units, as well as new demand-side management and supply-side resource alternatives. As part of this process, a Technology Assessment was conducted to identify potential supply-side resource alternatives that may be technologically and economically suited to meet ENO's projected resource needs. The initial screening phase of the Technology Assessment reviewed the supply-side generation technology landscape to identify resource alternatives that merited more detailed analysis.[6] A list of the technologies selected for further more detailed evaluation in the IRP included:

I. Natural Gas Fired Technologies
   a. Combustion Turbine ("CT")
   b. Combined-Cycle Gas Turbine ("CCGT")
   c. Large scale aero-derivative CT
   d. Small scale aero-derivative CT
   e. Internal combustion engine

II. Nuclear
   a. Advanced boiling water reactor

III. Renewable Technologies
   a. Solar Photovoltaic ("PV") (fixed tilt and tracking)
   b. Wind (onshore)
   c. Biomass

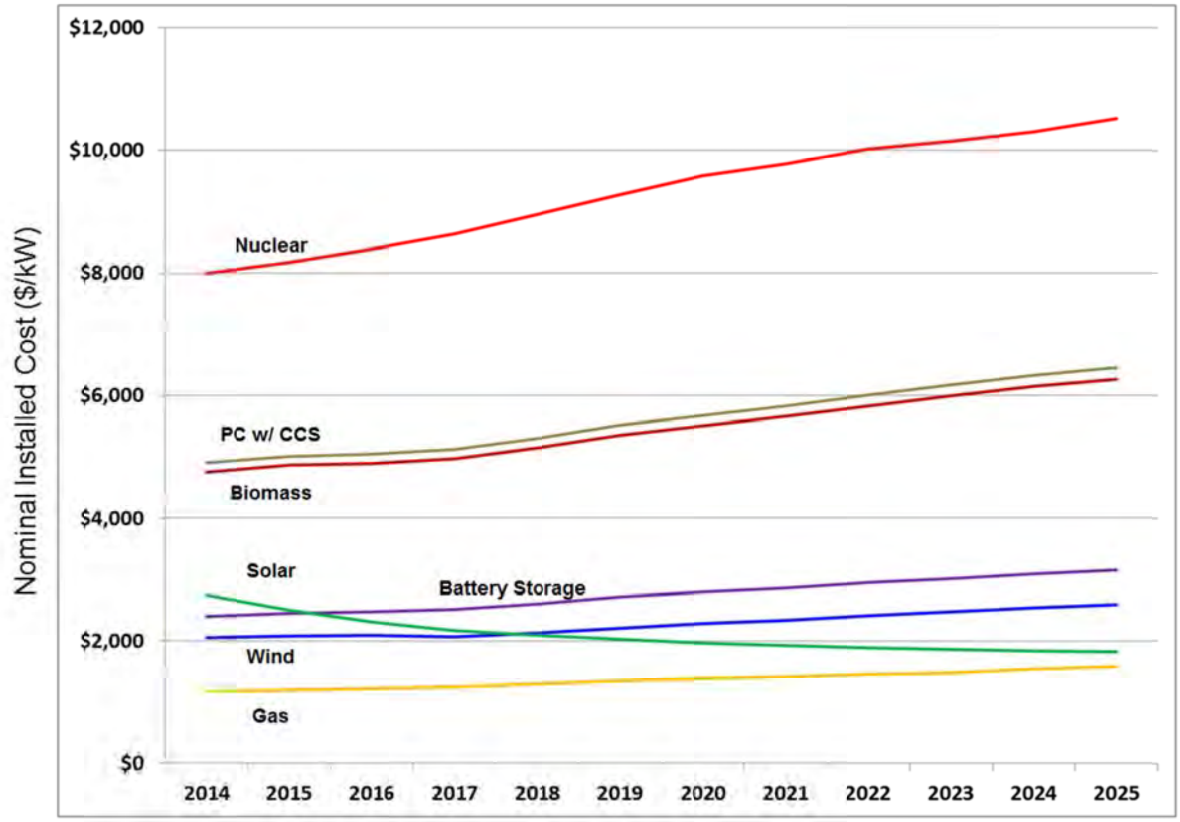
IV. Battery Storage

V. Pulverized Coal
   a. Supercritical pulverized coal with carbon capture and storage

During the initial phase, a number of resource alternatives were eliminated from further consideration based on a range of factors including technical maturity, stage of commercial development, and busbar economics. These resource alternatives will continue to be monitored for possible future development. A key output of the Technology Assessment was the projected levelized cost of the resource alternatives listed above. Figure 2 below summarizes the projected trend in installed costs of those alternatives selected for further evaluation in the 2015 IRP.

[6] See Technical Supplement 2 for the 2015 IRP Technology Assessment.

Figure 2: Projected Trend in Installed Cost of Supply-Side Resource Alternatives



Modeling

ENO used the AURORAxmp Electric Market Model ("AURORA"), a product of EPIS, Inc., in the development of this IRP. AURORA uses a linear optimization process and iterative calculations to find the optimal combination of resources to meet projected load-serving needs.

In development of the 2015 IRP, ENO designed four broad macroeconomic scenarios designed to capture a wide range of potential futures: Industrial Renaissance (Reference Case), Business Boom, Distributed Disruption, and Generation Shift. Assumptions differ for each case with respect to peak demand and load growth, fuel prices, and environmental costs. In addition to the four scenarios, ENO performed sensitivity analyses on the Industrial Renaissance Scenario to account for the effects of uncertainty in the future price of natural gas, potential for and extent of CO_2 regulation, and a combination of changes in the price of natural gas and CO_2. A further discussion of the AURORA modeling process is provided in Sections 2 and 4 of this report.[7]

Stakeholder Input

During the Council's process for development of the 2015 IRP, ENO received input from a broad range of stakeholders including members of the general public, intervenors in the IRP docket, and the Council's Advisors. ENO took all questions and comments received into consideration in producing this 2015 IRP and posted responses to questions and comments received to the public ENO IRP website. Although questions and comments received covered a wide range of issues, in general, there were several topics of particular and sometimes recurring interest in the 2015 IRP cycle that merit further consideration here. They include, but are not limited to ENO's:

1) Natural gas price forecast;
2) Capacity price forecast in MISO;
3) Cost assumptions for intermittent resources (*e.g.*, Onshore Wind and Solar PV);
4) Treatment of Distributed Generation;
5) Fuel diversity;
6) Carbon regulation;
7) Nuclear Relicensing; and
8) Public involvement

These issues are addressed in more detail in Section 2. For more information on the 2015 IRP process, including prior plans and more detailed information presented during the 2015 IRP cycle, please visit the ENO IRP website located at: www.entergy-neworleans.com/IRP/.

In response to stakeholder and Advisor concerns regarding dated assumptions used in the draft IRP, ENO agreed to perform additional production cost analysis using updated assumptions in support of the Final ENO 2015 IRP. The updated analysis is referred to herein as the "Stakeholder Input Case" scenario using contemporaneous information regarding load, commodity prices and generator status. Once the Stakeholder Input case was established, ENO ran six additional AURORA simulations for each of the portfolios previously evaluated in the draft IRP. The input assumptions and results related to the Stakeholder Input Case, including how they differed from the original assumptions and analyses, will be reported in each section where applicable. For additional details regarding the Stakeholder Input Case, please see the two supplements described below and attached with this final IRP report.

[7] In response to Stakeholder comments following Milestone 3, ENO filed a Modeling Process Workpaper which explains the AURORA modeling process in more detail.

DSM Supplement

The DSM supplement contains an overview of the following items:

- ENO's existing DSM programs
- Review of ICF Potential Study Methodology and Assumptions
- Sate of the Market for Demand Response
- Demand Response in MISO Markets
- DSM Breakeven Analysis and Program Selection

Stakeholder Input Case Supplement

The Stakeholder Input Case Supplement contains the following items:

- Updated forecast assumptions (natural gas, CO_2, renewable costs, etc.)
- Updated Load and Capability for all portfolios
- Updated Total Supply Cost for all portfolios
- Rate Effects for the Preferred Portfolio

Preferred Portfolio and Action Plan

The Final 2015 IRP has been developed to inform future resource procurement and implementation activities. The ENO Preferred Portfolio includes a combination of cost-effective demand- and supply-side resources that mitigate the risk of future uncertainty over a range of alternative potential future scenarios for energy and load growth, fuel prices, and environmental regulations. Importantly, the Preferred Portfolio is not prescriptive and includes the following key elements that will continue to be evaluated in future IRPs:

- ENO continues to meet the bulk of its reliability requirements from long-term capacity resources, 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 resource needs.
- All existing nuclear capacity, and the small amount of existing coal capacity, currently in ENO's portfolio continue operations throughout the planning horizon.[8]
- New supply resources, when needed come from peaking resources (*e.g.,* Combustion Turbines). As described in Sections 3 and 4 of the report, ENO is

[8] In the Stakeholder Input Case, Arkansas Nuclear One has a deactivation date of 2034, and White Bluff 1 and 2 have a deactivation assumption of 2026 and 2027 respectively.

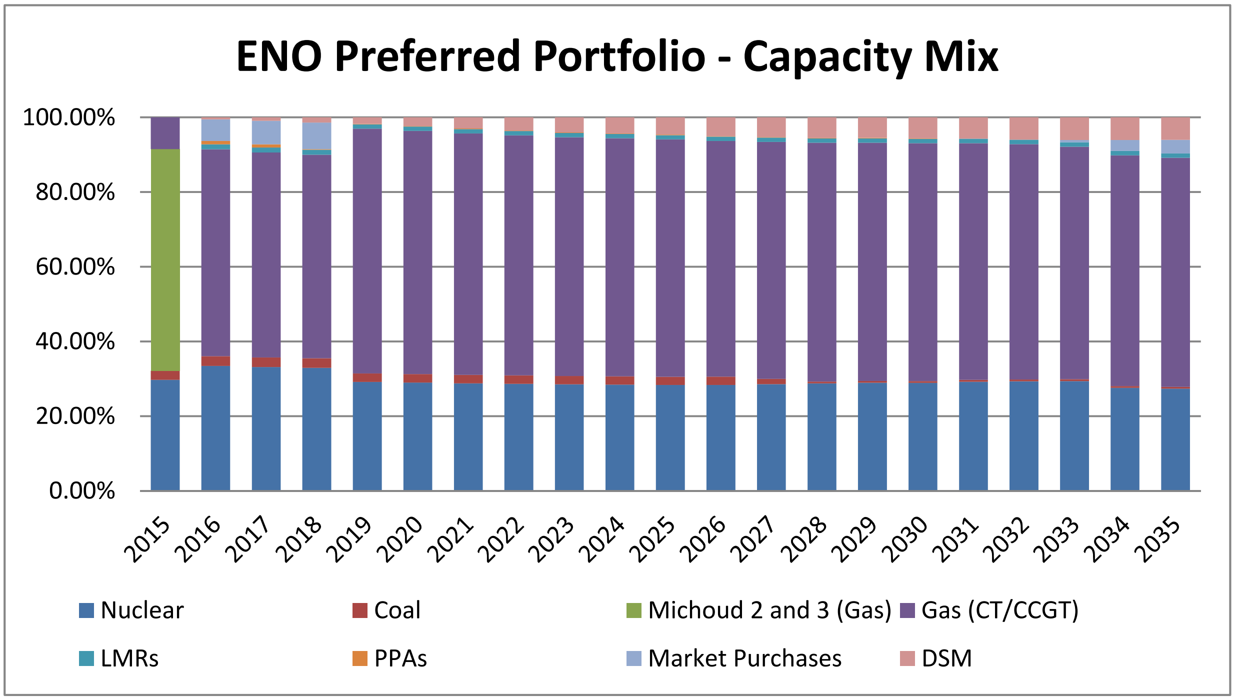
projected to need additional peaking resources as ENO's base load and core load-following needs are expected to be met by existing nuclear and CCGT resources and the planned addition of Union Power Block 1. Peaking resources such as Combustion Turbines are cost-effective, highly reliable and proven technology with minimal risk.

- While intermittent technologies such as renewable supply-side resources were not included in the Preferred Portfolio, ENO recognizes the potential fuel diversification and technology benefits such resources can contribute and has indicated in the Action Plan the intent to issue a Request for Proposals ("RFP") for renewable resources as described below. The Renewable RFP will provide valuable information on the availability and price for proven renewable technologies. ENO will continue to evaluate those and other alternatives for inclusion in future long-range plans, as the 2015 IRP does not preclude ENO from adopting those alternatives in future IRPs.
- The ENO Renewable RFP will be conducted during 2016 and request proposals for cost-effective renewable supply-side projects. This will provide a greater understanding of the cost and deliverability of renewable resources. A draft of the RFP is scheduled for release during the 2nd quarter of 2016, and will seek proposals for up to 20 MW of proven renewable energy technologies, with a preference for resources located in or near Orleans parish.
- In further support of the objective to evaluate the potential benefits of renewable technologies, ENO recently announced plans to conduct a 1 MW pilot project that will integrate solar PV generation and battery storage technology. The trend in the installed cost of photovoltaics and battery storage suggest a pilot project is prudent to help determine the degree to which battery storage can address the intermittent nature of photovoltaics, while simultaneously establishing a benchmark for utility-scale solar PV performance and cost/benefit in ENO's service area.
- The Preferred Portfolio includes 19 DSM (17 energy efficiency and 2 demand response) programs selected on the basis of their ability to cost-effectively reduce ENO's future resource needs. While this level of DSM is considered economically attractive, it presents ratemaking and policy issues that must be addressed in connection with the adoption of such programs. A variety of factors, many of which are highly uncertain, will affect the amount of DSM that can and will be achieved over the planning horizon, which factors would be addressed during the detailed implementation proceedings before the Council.[9]

Figure 3 below illustrates the mix of resources in the ENO Preferred Portfolio that contribute to meeting customer needs during the term of the planning horizon.

[9] Please refer to the DSM supplement for additional details.

Figure 3: ENO Preferred Portfolio (Stakeholder Input Case) - Capacity Mix



In support of the Preferred Portfolio, ENO has identified the key areas of focus and near-term steps in the Action Plan below that are necessary to continue moving forward on implementation of planned resources included in the Preferred Portfolio. Though the Preferred Portfolio calls for the addition of a peaking resource in 2019, the projected resource additions do not represent firm planning decisions. ENO will continue to closely monitor its current generation fleet and load requirements to ensure timely and cost-effective resource additions. The results of the modeling process, selection of the Preferred Portfolio, and a discussion of the Action Plan are provided in Sections 4 and 5.[10]

Customer Impact

Table 1 highlights the estimated impact of the Preferred Portfolio on an average ENO residential customer's electric bill.

[10] The Preferred Portfolio reflects assumptions used in the Stakeholder Input Case

Table 1: ENO Average Residential Customer Electric Bill (Preferred Portfolio)[11]

Projected ENO Residential Customer Bill and Energy Usage				
Customer Segment	Actual 2014 Usage (KWh/mo.)	Actual 2014 Average Monthly Bill	Projected 2035 Usage (KWh/mo.)	Projected 2035 Average Monthly bill
Residential (Legacy)	1,081	$109	1,332	$147
Residential (Algiers)	_	_	1,561	$149

The estimated typical bill effects associated with the cost to meet customer's needs through the Preferred Portfolio over the next two decades are modest. 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 (reflected in the last column in Table 2) during the IRP planning horizon are expected to grow below inflation expectations.

Table 2: Rate Effects – ENO Preferred Portfolio (Stakeholder Input Case)

Projected ENO Average Monthly Customer Bill				
Customer Segment	2016	2026	2035	CAGR[12]
Residential (Legacy)	$110	$127	$147	1.5%
Commercial (Legacy)	$1,095	$1,111	$1,135	0.2%
Industrial (Legacy)	$1,302	$1,151	$1,009	(-1.3%)
Government (Legacy)	$3,377	$3,815	$4,096	1.0%
Residential (Algiers)	$100	$132	$149	2.0 %
Commercial (Algiers)	$628	$836	$922	1.9%
Industrial (Algiers)	$234	$348	$406	2.8%
Government (Algiers)	$1,282	$1,775	$2,050	2.4%

SECTION 1: PLANNING FRAMEWORK

ENO's planning process seeks to accomplish three broad objectives:

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

[12] Compound Annual Growth Rate ("CAGR") measures the average annual rate of growth in typical customer bills over the planning horizon.

- To serve customers' power needs reliably;
- To do so at the lowest reasonable supply cost; and
- To mitigate the effects and the risk of production cost volatility resulting from fuel price and purchased power cost uncertainty, RTO-related charges such as congestion costs, and possible supply disruptions.

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

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

- *Reliability* – sufficient resources to meet customer peak demands with adequate reliability.

- *Base Load Production Costs* – low-cost base load resources to serve base load requirements, which are defined as the firm load level that is expected to be exceeded for at least 85% of all hours per year.

- *Load-Following Production Cost and Flexible Capability* – efficient, dispatchable, load-following resources to serve the time-varying load shape levels that are above the base load supply requirement, and also sufficient flexible capability to respond to factors such as load volatility caused by changes in weather.

- *Generation Portfolio Enhancement* – a generation portfolio that avoids an over-reliance on aging resources by accounting for factors such as current operating role, unit age, unit condition, historic and projected investment levels, and unit economics, and taking into consideration the manner in which MISO dispatches units.

- *Price Stability Risk Mitigation* – mitigation of the exposure to price volatility associated with uncertainties in fuel and purchased power costs.

- *Supply Diversity Risk Mitigation* – mitigation of the exposure to major supply disruptions that could occur from specific risks such as outages at a single generation facility.

Transmission and Distribution Planning

ENO's transmission planning ensures that the transmission system (1) remains compliant with applicable NERC Reliability Standards and related SERC and local planning criteria, and (2) is designed to efficiently and reliably deliver energy to end-use customers at the lowest reasonable cost. Since joining MISO, ENO plans its transmission system in accordance with the MISO Tariff. Expansion of, and enhancements to, transmission facilities must be planned well in advance of the need for such improvements given that regulatory, permitting processes and construction significantly extend the timeframe required to bring a transmission project to completion. Advanced planning requires that computer models be used to evaluate current and projected use of the bulk electric transmission system taking into account how those uses may change over time, generation and load forecasts, and transmission facilities already included in construction plan. On an annual basis, ENO's Transmission Planning Group performs analyses to determine the reliability and economic performance needs of ENO's portion of the interconnected transmission system. The projects developed are included in the Long Term Transmission Plan ("LTTP") for submission to the MISO Transmission Expansion Planning ("MTEP") process as part of a bottom-up planning process for MISO's consideration and review. The LTTP consists of transmission projects planned to be in-service in an ensuing 10-year planning period. The projects included in the LTTP serve several purposes: to serve specific customer needs, to provide economic benefit to customers, to meet NERC TPL reliability standards, to facilitate incremental block load additions, and to enable open access transmission service to be sold and generators to interconnect to the electric grid.

With regard to transmission planning aimed at providing economic benefit to customers, ENO has played, and will continue to play, an integral role in MISO's top-down regional economic planning process referred to as the Market Congestion Planning Study ("MCPS"), which is a part of the MTEP process. MISO's MCPS relies on the input of transmission owners and other stakeholders, both with regard to the assumptions and scenarios utilized in the analysis of proposed economic projects. Based on this stakeholder input, MISO evaluates the economic benefits of the submitted transmission projects, while ensuring continued reliability of the system. The intended result of the MCPS is a project(s) determined to be economically beneficial[13] to customers for consideration by the MISO Board of Directors for approval.

ENO has and continues to be actively involved in MISO's stakeholder processes to develop and finalize the assumptions and future scenarios proposed by MISO in the MCPS process for evaluation of projects proposed for consideration in MTEP15. ENOassessed the congestion on the transmission system in the MTEP15 Promod models and analyzed the economic benefits

[13] MISO determines cost-benefit by evaluating estimated production cost savings before and after the transmission upgrade adjusted for the fixed cost of the investment.

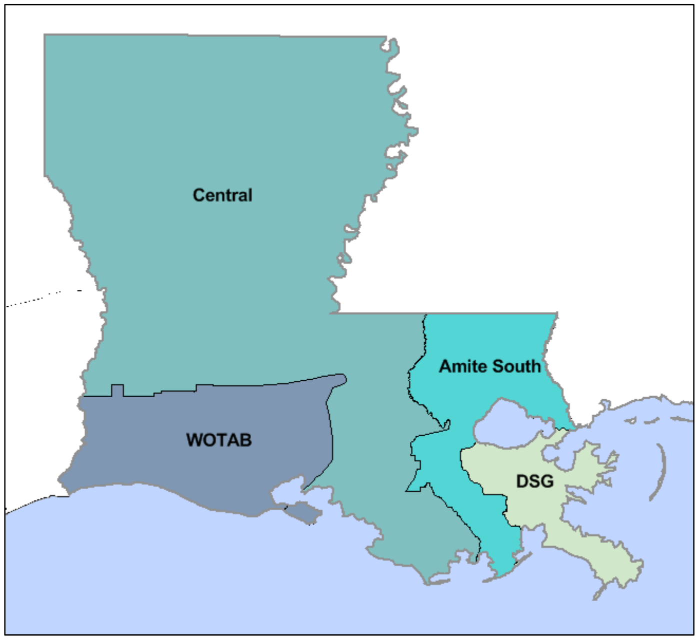
to ENO customers of candidate economic projects and also to satisfy the reliability requirements. Candidate transmission project ideas were due to MISO on June 19. Following the submittal of stakeholder projects and further economic analysis of those projects, MISO recommended transmission projects that meet MISO's economic benefits test to the MISO Board for approval. The MISO Board officially approved MTEP15 in December 2015. Out of the approved projects in Appendix A of the MTEP15 study, approximately 59 projects were located throughout the four states of the Entergy service footprint, with 3 projects planned for the ENO footprint.

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 a consideration in determining the most cost-effective way to access 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 Orleans. The 2015 IRP assumes that the distribution system will continue to receive ongoing capital investment necessary to continue meeting those needs.

Area Planning

Although resource planning is performed with the goal of meeting planning objectives at the overall lowest reasonable cost, physical and operational factors dictate that regional reliability needs must be considered when planning for the reliable operation within the area. Thus, one aspect of the planning process is the development of planning studies to identify supply needs within specific geographic areas, and to evaluate supply options to meet those needs.

Figure 4: Map of Louisiana Planning Areas



For planning purposes, planning areas are determined based on characteristics of the electric 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 region served by ENO is within the DSG sub-area of the Amite South planning area identified in Figure 4. The planning area and sub-area are described further below:

- Amite South – the area generally east of the Baton Rouge metropolitan area to the Mississippi state line, and the area south to the Gulf of Mexico.
    - Downstream of Gypsy ("DSG") – a sub-area encompassing the Southeast portion of Amite South, generally including the area down river of the Little Gypsy plant including metropolitan New Orleans south to the Gulf of Mexico.

Notwithstanding the termination of the Entergy System Agreement, as discussed in more detail below, area planning will continue to be an important part of ENO's long-term integrated resource planning process for the foreseeable future. The planning areas are a function of historical design and build-out of the bulk electric grid in the region as well as corresponding power flows on the grid.

Participation in MISO

ENO, along with its affiliate Entergy Operating Companies ("EOCs"), became market participants in MISO on December 19, 2013. MISO is a regional transmission organization

(“RTO”) allowing ENO access to a large structured market that enhances the resource alternatives available to meet ENO’s customers’ near-term power needs. Over the long-term, the availability and price of power in the MISO market is taken into consideration in developing ENO’s resource strategy and portfolio design, however; ENO retains responsibility for providing safe and reliable service to its customers. Thus, the ENO 2015 IRP is designed to help ensure development of a long-term integrated resource plan for New Orleans that reflects that responsibility and balances the objective of minimizing the cost of service while considering factors that affect risk and reliability. Operations in MISO are key considerations in the development and modeling of the 2015 IRP. More detail on how ENO’s participation in MISO is taken into consideration in developing the 2015 IRP is discussed briefly below and throughout the remainder of this report.

RESOURCE ADEQUACY REQUIREMENTS

As a load serving entity (”LSE”) within MISO, ENO is responsible for maintaining sufficient generation capacity to meet the Planning Reserve Margin Requirement (“PRMR”) set each year by MISO pursuant to its Tariff. Resource Adequacy is the process by which MISO ensures that participating LSEs meet those requirements.

Under MISO’s Resource Adequacy process, MISO annually determines (by November 1 each year) the PRMR applicable to each Local Resource Zone (“LRZ”) for the next planning year (June – May). LSEs are required to provide planning resource credits for generation or demand-side capacity resources to meet their forecasted peak load coincident with the MISO peak load plus the PRMR established by MISO. Planning resource credits are measured by unforced capacity (installed capacity multiplied by an appropriate forced outage rate). The annual PRMR for the LRZ 9 (which includes ENO), as determined by MISO, sets the minimum PRMR[14] that ENO must meet. MISO does not calculate a long-term planning reserve requirement, so for purposes of long-term planning, ENO has determined that a 12% reserve margin based on installed capacity ratings and forecasted (non-coincident) firm peak load is reasonable and adequate to cover MISO’s Resource Adequacy requirements and uncertainties such as MISO’s future required reserve margins, generator unit forced outage rates, and forecasted peak load coincidence factors.[15]

[14] In MISO, Resource Adequacy PRMR is expressed based on unforced capacity ratings and MISO System coincident peak load. Traditionally, ENO and other LSEs have stated planning reserve requirements based on installed capacity ratings and forecasted (non-coincident) peak load.

[15] It can be shown mathematically that the planning reserve margin determined by using unforced capacity and coincident peak load is roughly equivalent to the planning reserve margin determined by using installed capacity and non-coincident peak load.

Entergy System Agreement

The electric generation and bulk transmission facilities of the EOCs party to the Entergy System Agreement currently are planned and operated on an integrated, coordinated basis as a single electric system and are referred to collectively as the “Entergy System.”

The EOCs that party to the System Agreement are ENO, Entergy Gulf States Louisiana, L.L.C. (“EGSL”), Entergy Louisiana LLC (“ELL”), and Entergy Texas, Inc. (“ETI”).[16] As provided for pursuant to the terms for exit from the System Agreement, ETI provided notice that it would terminate its participation on October 18, 2018.[17] On February 14, 2014, EGSL and ELL provided written notice to the other participating EOCs of the termination of their participation in the System Agreement. In light of those decisions, the 2015 IRP was prepared assuming that ENO will no longer participate in the System Agreement as of February 14, 2019[18]. Prior to and during the 2015 IRP cycle, the retail regulators of EGSL, ELL, ETI and ENO were engaged in settlement discussions with the EOCs party to the System Agreement for terms necessary to terminate the System Agreement early. Subsequent to those discussions, the parties reached agreement and approved a settlement agreement to terminate the System Agreement on August 31, 2016. On December 29, 2015, the FERC approved the settlement agreement. Although ENO could not have known the outcome of settlement discussions at the time assumptions were established for the 2015 IRP cycle, the reasonable and still appropriate assumption was made that current resource planning efforts acknowledge that stand-alone operations are on the front-end of the 2015 IRP planning horizon, thus ENO should begin taking steps now to account for the corresponding effects post-termination of the System Agreement.

SECTION 2: ASSUMPTIONS

Technology Assessment

The IRP process considers a range of alternatives available to meet the planning objectives, including the existing fleet of generating units, as well as new DSM and supply-side resource alternatives. As part of this process, a Technology Assessment was prepared to identify potential supply-side resource alternatives that may be technologically and economically suited to meet projected resource needs. The initial screening phase of the Technology Assessment

[16] Entergy Arkansas, Inc. (“EAI”) and Entergy Mississippi, Inc. (“EMI”), also EOCs, terminated their participation in the System Agreement effective December 18, 2013 and November 7, 2015, respectively.

[17] Subject to the FERC’s ruling in Docket No. ER14-75-000 which is the FERC proceeding filed to amend the notice provisions of Section 1.01 of the System Agreement.

[18] EGSL’s and ELL’s notice would be effective February 14, 2019 or such other date consistent with the FERC’s ruling in Docket No. ER14-75-000, effectively leaving ENO as the only remaining Operating Company in the System Agreement. However, a settlement agreement was reached and approved by FERC for early termination of the System Agreement.

reviewed the supply-side generation technology landscape to identify resource alternatives that merited more detailed analysis. A list of the technologies selected for further more detailed evaluation in the IRP included:

I. Natural Gas Fired Technologies
   a. Combustion Turbine ("CT")
   b. Combined-Cycle Gas Turbine ("CCGT")
   c. Large scale aero-derivative CT
   d. Small scale aero-derivative CT
   e. Internal combustion engine
II. Nuclear
   a. Advanced boiling water reactor
III. Renewable Technologies
   a. Solar PV (fixed tilt and tracking)
   b. Onshore Wind
   c. Biomass
IV. Battery Storage
V. Pulverized Coal
   a. Supercritical pulverized coal with carbon capture and storage

Upon completion of the screening level analysis, more detailed analysis (including revenue requirements modeling of remaining resource alternatives) was conducted across a range of operating roles and under a range of input assumptions. The analysis resulted in the following conclusions:

- Among conventional generation resource alternatives, CCGT and CT technologies are the most cost-effective. The gas-fired alternatives are economically attractive across a range of assumptions concerning operations and input costs.

- New nuclear and new coal alternatives are not cost-effective near-term options relative to gas-fired technology. The low price of gas and the uncertainties around emissions regulation make coal technologies unattractive. Nuclear is currently unattractive due to both capital and regulatory requirements.

- Despite recent declines in the installed cost and improvements in the operational viability of renewable generation alternatives, they are still less cost-effective when compared to CCGT and CT alternatives due primarily to:

    - Declines in the long-term outlook for natural gas prices brought on by the shale gas boom; and

  - The uncertain near-term outlook for regulation of CO_2 emissions.

- Among renewable generation alternatives, wind and solar are the most likely to become cost competitive with conventional alternatives. However, uncertainties with respect to capacity credit granted to intermittent resources by MISO, and the extent and timing of CO_2 regulations likely will affect the competitiveness of renewable resource alternatives.

  - MISO determines the capacity value for wind generation based on a probabilistic analytical approach. The application of this approach resulted in a capacity value of approximately 14.1% for wind resource during the 2014-15 MISO planning year. In ENO's Technology Assessment, wind was assessed a capacity match-up cost to reflect the fact that wind receives partial capacity value in MISO due to its intermittent nature. ***The capacity match-up is only used in the screening analysis of supply-side resources, and is not considered in any further analysis in the ENO IRP.*** Furthermore, ENO's service area is not favorable for wind generation. The transmission cost to serve load with wind power from remote resources will further erode the economics of wind as compared to conventional supply-side resource alternatives.

  - In MISO, solar resources currently receive capacity credit equal to 25% of their nameplate (AC) rating within the first year of operation. Once operational, solar-powered resources must submit all operating data for the prior summer with a minimum of 30 consecutive days to obtain capacity that more closely aligns to operational capability. Thus, MISO grants capacity credit for solar resources on a case by case basis, which creates uncertainty for purposes of planning. Despite this uncertainty, ENO assumed a reasonable 25% capacity value for solar resources in its service area for further evaluation in the 2015 IRP.

Table 3 summarizes the results of the Technology Assessment for a number of resource alternatives.

Table 3: 2014 Technology Sensitivity Assessment

Based on Generic Cost of Capital[19]		No CO_2 (Lifecycle Levelized $/MWh)			CO_2 Beginning 2023 (Lifecycle Levelized $/MWh)		
Technology	Capacity Factor[20]	Reference Fuel	High Fuel	Low Fuel	Reference Fuel	High Fuel	Low Fuel
F Frame CT	10%	$198	$224	$179	$204	$230	$184
F Frame CT w/ Selective Catalytic Reduction	20%	$141	$167	$121	$146	$173	$126
E Frame CT	10%	$240	$274	$215	$247	$281	$222
Large Aeroderivative CT	40%	$108	$131	$91	$113	$136	$95
Small Aeroderivative CT	40%	$125	$150	$106	$130	$156	$112
Internal Combustion	40%	$115	$137	$99	$120	$141	$104
2x1 F Frame CCGT	65%	$79	$97	$67	$83	$100	$70
2x1 F Frame CCGT w/ Supplemental	65%	$75	$93	$61	$78	$97	$65
2x1 G Frame CCGT	65%	$76	$93	$63	$79	$96	$67
2x1 G Frame CCGT w/ Supplemental	65%	$72	$90	$59	$76	$94	$63
1x1 F Frame CCGT	65%	$82	$100	$69	$86	$104	$73
1x1 J Frame CCGT	65%	$73	$90	$61	$77	$93	$65
1x1 J Frame CCGT w/ Supplemental	65%	$72	$132	$59	$76	$136	$63
Pulverized Coal w/ Carbon Capturing Sequestration	85%	$163	$230	$94	$165	$232	$96
Biomass	85%	$175	$321	$142	$175	$321	$142
Nuclear	90%	$157	$169	$157	$157	$169	$157
Wind[21]	34%	$109	$109	$109	$109	$109	$109
Wind w/ Production Tax Credit	34%	$102	$102	$102	$102	$102	$102
Solar PV (fixed tilt)[22]	18%	$190	$190	$190	$190	$190	$190
Solar PV (tracking)[23]	21%	$179	$179	$179	$179	$179	$179
Battery Storage[24]	20%	$217	$217	$217	$217	$217	$217

[19] A general discount rate (7.656%) was used in order to accurately model these resources in the Market Modeling stage of the IRP.
[20] Assumption used to calculate life cycle resource cost.
[21] Includes capacity match-up cost of $18.76/MWh due to wind's 14.1% capacity credit in MISO, which cost was not assessed in the production cost modeling.
[22] Includes capacity match-up cost of $30.93/MWh assuming a 25.0% capacity credit in MISO, which cost was not assessed in the production cost modeling.
[23] Includes capacity match-up cost of $26.51/MWh assuming a 25.0% capacity credit in MISO, which cost was not assessed in the production cost modeling.
[24] Includes cost of $25/MWh required to charge batteries.

Long-Term Achievable Demand Side Management Potential

For the 2015 IRP, ENO engaged the services of ICF International to assess the market-achievable potential for DSM programs that could be deployed over the planning horizon. A comprehensive measure database that included 228 measure types and 1,056 measures in total was used to evaluate the market-achievable potential for DSM programs for ENO. Commercially available electric and gas measures covering each relevant savings opportunity within each end use and sector were included.

Measures were then screened for cost-effectiveness using the measure Total Resource Cost (TRC) test. With few exceptions, only measures with a TRC test result of 1.0 or better were passed on to the next stage of the analysis. ICF's analysis found 814 measures to be cost effective. These economic measures are then mapped into programs. The program types are usually based on the set of existing programs offered in the service area plus additional programs for which there are cost-effective applicable measures. These additional programs are usually based on best practice designs. Based on the 814 cost-effective measures, the ICF Potential Study designed 24 programs to be assessed further in the IRP process.

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 investment level estimate of DSM potential indicates approximately 112 MW of peak demand reduction could be achieved by 2034 if ENO's investment in the 24 DSM programs was sustained for a 20-year period. For the purpose of DSM modeling in the IRP, ENO selected the incentive level for each program with the highest TRC ratio. This resulted in a range of incentive levels modeled.

The methodology of the Potential Study was consistent with ENO's primary objective to identify cost-effective DSM alternatives available to meet customers' needs. Furthermore, the MISO Tariff outlines that energy efficiency resources must be fully implemented at all times during the planning year, without any requirement of dispatch. Examples of these resources include, but are not limited to, efficient lighting and appliances, and building insulation. Demand response resources are defined as resources that allow the ability of a market participant to reduce its electric consumption, with either discretely interruptible or continuously controllable loads, in response to an instruction resource from MISO. The demand response and energy efficiency programs identified and analyzed in the Potential Study were consistent with MISO's requirements.

DSM program costs utilized in the IRP include incentives paid to participants and program delivery costs such as marketing, training, and program administration. Program delivery costs were estimated to reflect average annual costs over the 20 year planning horizon of the DSM

Potential Study. The costs reflect an assumption that over the planning horizon, program efficiencies will be achieved resulting in lower expected costs. That is, as experience is gained with current and future programs, actual cost may decrease over time. As such, actual near-term costs associated with implementation of current and future programs may be higher than the assumptions used to determine the optimal cost-effective level identified in ENO's Preferred Portfolio. Therefore, future DSM program goals and implementation plans should reflect this uncertainty.

Natural Gas Price Forecast

System Planning and Operations[25] ("SPO") prepared the natural gas price forecast[26] used in the 2015 IRP. The near term portion of the natural gas forecast is based on NYMEX Henry Hub forward prices, which serve as an indicator of market expectations of future prices. Because the NYMEX futures market becomes increasingly illiquid as the time horizon increases, NYMEX forward prices are not a reliable predictor of future prices in the long-term. Due to this uncertainty, SPO prepares a long term point-of-view ("POV") regarding future natural gas prices utilizing a number of independent expert consultant forecasts to determine an industry consensus regarding long-term prices.

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. In developing high and low gas price POVs, SPO utilizes several proprietary independent expert consultant forecasts, as well as publicly available information, to determine long term price consensus. The long-term gas price forecast used in the 2015 IRP is shown in the table below.

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

[26] The forecast was prepared from the July 2014 gas price forecast.

Table 4: Long-Term Henry Hub Natural Gas Price Forecasts

Henry Hub Natural Gas Prices						
	Nominal $/MMBtu			Real 2014$/MMBtu		
	Low	Reference	High	Low	Reference	High
Real Levelized'[27] (2015-2034)	$4.57	$5.77	$9.72	$3.84	$4.87	$8.17
Average (2015-2034)	$4.82	$6.28	$10.79	$3.66	$5.00	$8.08
20-Year CAGR	2.5%	3.1%	6.2%	0.4%	1.0%	4.1%

CO_2 Assumptions

At this time, it is not possible to predict with any degree of certainty whether or the extent to which the Clean Power Plan will survive the substantial litigation already filed against the EPA since issuing the final rule in August 2015. In order to consider the effects of this uncertainty on resource choice and portfolio design, the IRP process evaluated the effect of CO_2 regulation *by analyzing a range of projected CO_2 cost outcomes*. The reference case assumes that CO_2 legislation does not occur over the 20-year planning horizon. The mid case assumes that a cap and trade program starts in 2023 with an emission allowance cost of $7.54/U.S. ton and a 2015-2034 levelized cost in 2014$ of $6.83/U.S. ton.[28] The high case assumes that a cap and trade program starts in 2023 at $22.84/U.S. ton with a 2015-2034 levelized cost in 2014$ of $14.61/U.S. ton. Importantly, the Stakeholder Input Case includes the current POV mid case for CO_2 prices. By evaluating a range of potential outcomes, the IRP is better informed regarding the impact that the extent and timing of CO_2 regulation can have on the optimal mix of resources.

Market Modeling

AURORA MODEL

The development of the IRP relied on the AURORA Electric Market Model to simulate market operations and produce a long-term forecast of the revenues and cost of energy procurement for ENO in MISO.[29]

[27] "Real levelized" prices refer to the price in 2014$ where the NPV of that price grown with inflation over the 2015-2034 period would equal the NPV of levelized nominal prices over the 2015-2034 period.
[28] Includes a discount rate of 6.93%.
[29] The AURORA model replaces the PROMOD IV and PROSYM models that ENO previously used.

AURORA[30] 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 estimates price and dispatch using hourly demands and individual resource-operating characteristics in a transmission-constrained, chronological dispatch algorithm. The optimization process within AURORA identifies the set of resources among existing and potential future demand- and supply-side resources with the highest and lowest market values to produce economically consistent capacity expansion. AURORA chooses from new resource alternatives based on the net real levelized values per MW ("RLV/MW") of hourly market values and compares those values to existing resources in an iterative process to optimize the set of resources.

SCENARIOS

The 2015 ENO IRP and corresponding analyses were built on four scenarios designed to assess alternative portfolios across a range of potential future outcomes. The four scenarios are:

- *Industrial Renaissance (Reference)* – Assumes the U.S. energy market continues to grow with reference fuel prices. Current fuel prices drive load growth and economic opportunity in the region. The Industrial Renaissance scenario assumes reference load, reference gas and no CO_2 costs.

- *Business Boom* – Assumes the U.S. energy boom continues with low gas and coal prices. Low fuel prices drive high load growth. A modest CO_2 tax or cap and trade program is implemented beginning in 2023.

- *Distributed Disruption* – Assumes states continue to support distributed generation. Consumers and businesses have a greater interest in installing distributed generation, which leads to a decrease in energy demand at the customer's meter. Overall economic conditions are steady with moderate GDP growth, which enables investment in energy infrastructure. However, natural gas prices are driven higher by EPA regulation of hydraulic fracturing. Congress or the EPA also implements a moderate CO_2 tax or cap and trade program.

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

- *Generation Shift* – Assumes government policy and public interest drive support for government subsidies for renewable generation and strict rules on CO_2 emissions. High natural gas exports and more coal exports lead to higher fuel prices.

Each scenario was modeled in AURORA. The resulting market modeling, which included projected power prices, provided a basis for assessing the economics of long-term (twenty years) resource portfolio alternatives.

Table 5: Summary of Key Scenario Assumptions

Summary of Key Scenario Assumptions				
	Industrial Renaissance (Ref. Case)	**Business Boom**	**Distributed Disruption**	**Generation Shift**
Electricity CAGR (Energy GWh)[31]	~1.0%	~1.0%	~0.40%	~0.80%
Peak Load Growth CAGR	~0.7%	~0.7%	~0.7%	~0.7%
Henry Hub Natural Gas Price ($/MMBtu)	Reference Case ($4.87 levelized 2014$)	Low Case ($3.84 levelized 2014$)	Reference Case ($4.87 levelized 2014$)	High Case ($8.18 levelized 2014$)
CO_2 Price ($/U.S. ton)	Low Case: None	Cap and trade starts in 2023 $6.83 levelized 2014$	Cap and trade starts in 2023 $6.83 levelized 2014$	Cap and trade starts in 2023 $14.61 levelized 2014$

Stakeholder Input

During the Council's process for development of the 2015 IRP, ENO received input from a broad range of stakeholders including members of the general public, interveners in the IRP docket, and the Council's Advisors. ENO took all questions and comments received into consideration in producing this 2015 IRP and posted responses to questions and comments received from the public to the ENO IRP website. Although questions and comments received covered a wide range of issues, in general, there were several topics of particular, and sometimes recurring, interest in the 2015 IRP cycle that merit further consideration here. They include, but are not limited to ENO's:

1) Natural gas price forecast;

[31] All compound annual growth rates ("CAGRs") in this table: 2015-2034 (20 Years) for the market modeled in AURORA.

2) Capacity price forecast in MISO;
3) Cost assumptions for intermittent resources (e.g. Wind and Solar PV);
4) Treatment of Distributed Generation;
5) Fuel diversity;
6) Carbon regulation;
7) Nuclear Relicensing; and
8) Public involvement

During the development of the IRP, ENO was required to provide information regarding its input assumptions to the IRP very early on in the Council's process. In order to maintain the integrity of the Council's process, ENO complied with those requirements and solicited feedback from the public and intervenors on those assumptions as provided for by the Council. Unfortunately, much of the input ENO received regarding the input assumptions was not received until after the first 2 milestones. Notwithstanding, to reflect ENO's consideration of the input received on these key issues, a brief summary of each is provided below.

NATURAL GAS PRICE FORECAST

Regarding the IRP forecast of long-term natural gas prices, ENO received comments questioning the IRP forecast as too low, as well as too high. While the current outlook for natural gas prices is lower than the gas price forecast used in the 2015 IRP, the IRP Low Forecast is in line with current gas prices. Moreover, in the IRP process, each portfolio was assessed with each gas price forecast (low, reference, and high) to capture the impact of gas price fluctuations over the planning horizon. As a final step, ENO used the most current gas price forecast in the Stakeholder Input Case.

CAPACITY PRICE FORECAST IN MISO

Regarding ENO's projected capacity price curve used in the calculation of avoided costs associated with investing in demand-side resources, the auction clearing price for MISO Local Resource Zones 8 and 9 settled at $1.20/kW-yr. in the 2015/2016 Planning Resource Auction. These results were concurrent with the corresponding portion of ENO's capacity price projections used in the 2015 IRP.

COST ASSUMPTIONS FOR INTERMITTENT RESOURCES (*E.G.*, WIND AND SOLAR PV)

The Technology Assessment indicates that solar costs are likely to decline over the next five years; however, wind cost and performance are not expected to materially improve or decline over this time period. If wind and solar cost and performance improve more than expected in this IRP, then future IRPs will capture that.

The IRP seeks to identify generation technologies that are technologically mature and could reasonably be expected to be operational in or around ENO's regulated service area consistent with the timing of projected resource needs. In the detailed modeling phase of the 2015 IRP, ENO assumed a 34% capacity factor assumption for wind resources that could be developed in or around the Entergy regulated service areas. In response, ENO received comments that the cost assumptions for wind in the 2015 IRP were significantly above recent transactions for utility scale wind resources across the U.S.

Notwithstanding, as a member of MISO, ENO is required to adhere to MISO's capacity values for wind, which is 14.1% as outlined in MISO's Resource Adequacy Tariff (Module E) and Resource Adequacy Business Practice Manual. As such, in the IRP a capacity "match up" reflects the fact that wind receives partial capacity value in MISO due to wind's intermittent nature. <u>Importantly, the capacity match-up is only used in the screening analysis of supply-side resources in the Technology Assessment</u>. When modeled in AURORA, wind is evaluated without the capacity match up relative to other resources. For example, in the Technology Assessment ENO reflected a Levelized Cost of Electricity ("LCOE") for wind resources ranging from \$102 - \$115/MWh (nominal \$2014), which includes a match-up cost assumption of \$18.76/MWh. In contrast, in the detailed modeling phase of the 2015 IRP where AURORA determines the optimal combination of demand- and supply-side resources through an iterative process, ENO did not include the match-up cost.

TREATMENT OF DISTRIBUTED GENERATION

With respect to the treatment of Distributed Generating ("DG") resources in the context of a long-term IRP, ENO received comments and questions pertaining to the appropriateness of the methodology used in the IRP as compared to alternative methodologies. In the 2015 IRP, ENO accounted for the effects of the explosive growth in residential rooftop Solar PV, a type of DG, in New Orleans through a forecasted reduction in ENO's load. Although there are alternative methods to account for DG in the planning process, ENO believes accounting for them on the demand-side through a reduction to the load forecast appropriately recognizes that they are behind the customer's meter and require the customer to make the investment decision, neither of which are under ENO's control. Moreover, it is ENO's position that while state and federal tax incentives available to rooftop Solar PV in Louisiana, and current net metering policy in New Orleans, have combined to drive the growth in residential rooftop Solar PV in New Orleans; Such growth should not be construed as suggesting that DG resources are cost-effective alternatives to central-station utility-scale generation capable of achieving significant economies of scale resulting in lower average installation and operating costs. The state and federal tax incentives still represent a cost that must be factored into the Council's decision criteria regarding the need to specifically address the policy for treatment of DG in the planning process, as well as future net metering policy for New Orleans under consideration in Council Docket No. UD-13-02. ENO's recently announced Solar Pilot will establish a benchmark of the capabilities and operational costs for utility-scale solar and integrated battery storage in New Orleans. The Solar Pilot is a reasonable first step to ensure a balanced approach to the adoption of intermittent technologies that will help inform future IRPs.

FUEL DIVERSITY

A key objective of the 2015 IRP is to design a Preferred Portfolio that mitigates risk of uncertain future supply costs such as the price of natural gas. This key uncertainty is addressed in 2 ways. First, ENO establishes a basis for evaluating the fuel mix of the existing portfolio of resources by benchmarking the amount of capacity and energy sourced from each fuel type (*e.g.*, natural gas, nuclear, coal, etc.). In Section 3 additional details are provided on the current and projected fuel mix of ENO's existing portfolio before and after deactivation of the Michoud units. As discussed in more detail in Section 3, ENO's existing portfolio before and after the planned deactivation of the Michoud units results in a balanced fuel mix among gas, nuclear and coal on an energy basis. Whereas ENO relies on the Michoud units for a significant amount of capacity, those resources do not contribute an equivalent amount of energy, thus following their planned deactivation the fuel mix of ENO's energy requirements will remain balanced with room for some amount of modern, efficient and reliable gas-fired replacement resources as discussed in Section 3.

Second, the IRP gas price forecast is developed with a reference, high and low case to capture a range of future price outcomes. The gas price forecasts are then used to evaluate the alternative portfolios in each of the four macroeconomic scenarios developed for the IRP. In this way, ENO assesses the range of potential impacts of higher and lower gas prices on each of the alternative portfolios and the corresponding total supply costs to ENO's customers.

Many of the comments ENO received regarding fuel diversity centered around the notion that ENO is already over-exposed to natural gas fired resources, thus the addition of new gas-fired resources to ENO's portfolio will only exacerbate that issue. To the contrary, as discussed in Section 3 below, while ENO's portfolio consists of a significant amount of gas-fired capacity, those resources do not contribute an equivalent amount of energy, thus leaving room for gas-fired replacement resources following their planned deactivation. Moreover, those same comments suggested that incorporation of renewable resources would reduce the need to rely on gas-fired resources; however, as explained in the Cost Assumptions for Renewables section above, because renewable resources like wind and solar are intermittent neither MISO nor ENO can rely on those resources exclusively, and precisely because renewables such as wind and solar do not allow ENO to avoid an equivalent amount of conventional supply-side resources, the capacity match-up cost should be taken into consideration when evaluating the appropriateness of adopting renewables. A simple example is that if ENO needs 100 MW of resources, if it wanted to rely exclusively on renewables such as wind and solar, because they are intermittent ENO would have to add approximately 714 MW of wind resources or 400 MW of solar resources to provide a comparable amount of capacity as provided by a conventional supply-side resource such as CCGT or CT. Even in that scenario, precisely because those resources are intermittent ENO may not avoid the need to carry additional reserves to ensure proper commitment and dispatch necessary to maintain reliability.

CARBON REGULATION

Regarding the assumptions around regulation of CO_2, ENO received comments raising concerns that the company should assume CO_2 regulation in all of the IRP scenarios. In the IRP, ENO evaluated a range of CO_2 price assumptions in the IRP across the four scenarios to reflect the uncertain likelihood, extent and timing of CO_2 regulation. Moreover, the sensitivity analysis evaluates the effects of different CO_2 prices for each scenario. *ENO believes it would be imprudent to assume CO_2 regulation in all of the IRP scenarios, as that would effectively assume that there is no uncertainty regarding the likelihood, extent and timing of CO_2 regulation, and more importantly, that ENO's customers should pay for CO_2 regulation regardless of whether regulation actually occurs*. Notwithstanding, ENO included the current POV mid case CO_2 in the Stakeholder Input Case.

NUCLEAR RELICENSING

Nuclear resources require license renewals to extend their operational lifetime. All of the nuclear resources in ENO's portfolio have received, or are currently in the process of, seeking operating license renewals. License extensions for Arkansas Nuclear One Units 1 and 2 have been approved by the Nuclear Regulatory Commission ("NRC") and thus are licensed to operate through May 2034 and July 2038, respectively. Grand Gulf Nuclear Station has filed its license renewal application, which is currently under review by the NRC. The license renewal application for River Bend Nuclear Station is expected to be filed in the 1st quarter of 2017. License renewal for nuclear resources is estimated to cost approximately $20-$25M over a 5 year timeline per unit, not including major component refurbishment or replacement. Therefore, relicensing the nuclear units in ENO's portfolio provides for the continuation of a low cost alternative for base load capacity and energy.

PUBLIC INVOLVEMENT

Pursuant to the Council's process for the 2015 IRP, ENO is required to seek input from the public at each of 4 milestones. As a part of that process, the Council requires ENO to provide public notice no later than 30 days before any public IRP meeting. While the requirements do not explicitly state how the notice should be provided, ENO has consistently provided notice in two ways. First, notice is made in the print edition of the Times-Picayune and separately in the New Orleans Advocate. Second, notice is contemporaneously posted to ENO's public IRP website. Both actions are taken no later than 30 days prior to the public meeting as required by the Council. Further, ENO is aware that various stakeholders normally take separate actions to further "spread the word" in order to make the public aware that ENO is holding a meeting.

Each meeting is open to the public and does not require participants to register in advance in order to attend or even participate. By providing public notice in two major news outlets and on the public IRP website, ENO has consistently sought to encourage participation by members of the public interested in learning about the IRP process and providing input to the development of the 2015 IRP. Moreover, ENO invited any questions or concerns to be voiced during the 7-day public comment period following the technical conferences, and for those members of the public who cannot attend a meeting, all of the meeting materials are posted to the IRP website for review (www.entergy-neworleans.com/IRP/).

Regarding location of the public meeting, all of the meetings are held at the University of New Orleans' Lakefront Campus in order to provide a central, accessible, consistent and neutral meeting location. Generally speaking, attendance by the public has varied at each meeting; however, ENO does not believe that is due to the location. Conducting the meetings in locations that may be more conducive to participation by certain residents of the City may be less conducive to others. ENO believes that a balance must be struck regarding the approach to public involvement as it would be irrational and cost-prohibitive to design a process in which all of ENO's customers were able to participate in the public meetings directly.

Stakeholder Input Case

In addition to creating the four scenarios (Industrial Renaissance, Business Boom, Distributed Disruption, and Generation Shift), a Stakeholder Input Case scenario was created based on the most up to date assumptions available to ENO as of December 2015. This alternative case was conducted based on input from the Advisors and intervenors that the assumptions used in the IRP were dated and not reflective of current events. The evaluation period for the Stakeholder Input case is 2016-2035. It is important to note that the various assumption changes are detailed below; however, direct comparison of the results from the Stakeholder Input Case and the results of the four scenarios developed at the beginning of the IRP process is not appropriate.

TECHNOLOGY ASSESSMENT

The Stakeholder Input case scenario modeled four main technology types. Frame CT and Frame CCGT technology was based on the Mitsubishi Heavy Industries G Frame turbines. G Frame technologies have a lower heat rate than the F Frame technologies, as well as higher capacity. As part of the Stakeholder Input Case, the cost curve for Solar PV technology was updated based on the October 2015 IHS CERA Solar Report and is a region specific forecast (MISO South). Figures 5 and 6 below shows how Solar PV cost estimates changed over time throughout the IRP process and how IHS CERA's estimates compare to other industry standards.

Table 6: Stakeholder Input Case Technology Assumptions

Stakeholder Input Case Technology Assumptions		
Technology	**Capacity (MW)**	**Capital Cost ($/kW)[32]**
G Frame CT	250	$734
1x1 G Frame CCGT	450	$1139
Wind	Variable[33]	$2087
Solar PV (tracking)	Variable[34]	$1838

[32] 2016 Nominal Cost. Capacity rating for gas fired resources based on ICAP.
[33] Effective capacity of a wind installment is based on MISO's 15/16 capacity credit of 14.7%.
[34] Effective capacity of a solar installment is based on MISO's 15/16 capacity credit of 25%.

Figure 5: Timeline of Solar Tracking Install Costs (2013$/kW)

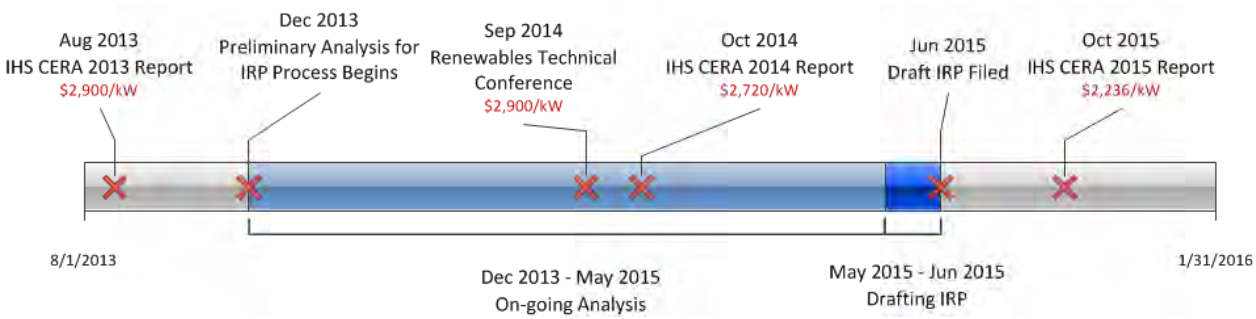
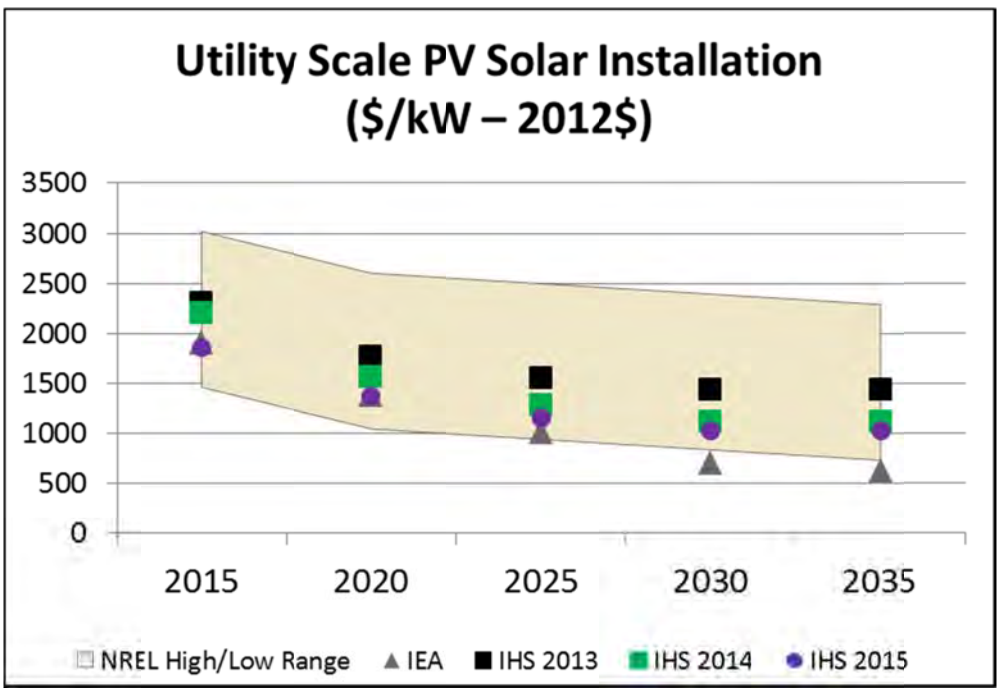


Figure 6: Solar PV Tracking Install Cost Comparison by Source



DEMAND SIDE MANAGEMENT

In an update to the draft IRP, filed on September 18, 2015, certain updates to the DSM component of the IRP were included. To reflect input from the Advisors regarding Council-approved incentives available to ENO for years 5 and 6 of Energy Smart, ENO included the assumption that the incentives would be available associated with the long-term DSM potential identified in the IRP, and were modeled as part of the total cost of the DSM programs. In addition, updated load reduction information for three demand response programs not included in the draft IRP were provided by ICF and re-evaluated for inclusion in the Final IRP. These three programs were the Dynamic Pricing Program, Non-Residential Dynamic Pricing

Program, and Direct Load Control Program. Through the updated analysis, it was determined that all three of these programs were cost-effective, and are now included in the Preferred Portfolio.

In addition to the changes made on September 18, 2015, the Stakeholder Input Case includes a secondary analysis of DSM programs that did not break even in the 20-year evaluation period. This analysis incorporated the trailing benefits (kWh savings) that a program might exhibit beyond the 20-year evaluation period. It was assumed that further investment into the DSM measures would no longer occur after 2035, thus making the cost of DSM beyond the evaluation period zero for each program. The trailing benefits declined at different rates for each program, affecting the amount of kWh savings and how long the benefits endured after 2035. These trailing benefits were included in a new breakeven analysis to determine if more DSM programs would be selected, resulting in the potential for an additional two DSM programs not previously included to become cost-beneficial when including trailing benefits. *It should be noted that projecting trailing benefits is highly uncertain and may lead to the adoption of DSM programs that do not meet near-term kWh savings goals*.

NATURAL GAS PRICE

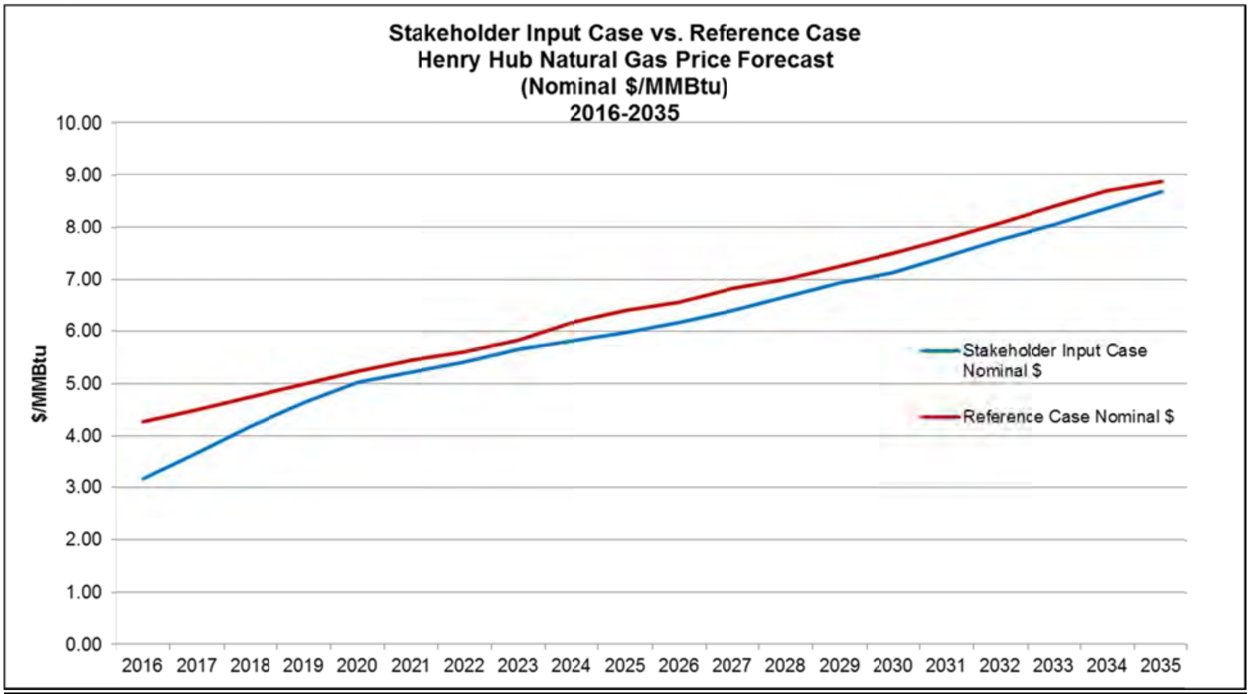
The natural gas price forecast for the Stakeholder Input Case was lower than the reference case forecast used in the Industrial Renaissance scenario. This forecast was influenced by historically strong production driven by the continued economics of Northeast shale gas combined with mild weather. These factors have created a supply and storage glut. This oversupply is expected to continue in the near-term and put downward pressure on prices, assuming normal weather patterns. Long-term structural demand increases (LNG exports, exports to Mexico, power demand) are expected to continue to develop, holding off potential price decreases in the long-run.

Table 7: Stakeholder Input Case Natural Gas Price Forecast

Henry Hub Natural Gas Prices		
	Nominal $/MMBtu	**Real 2014$/MMBtu**
Real Levelized[35] (2016-2035)	$5.54	$4.57
Average (2016-2035)	$6.12	$4.76
20-Year CAGR	5.2%	3.2%

[35] "Real levelized" prices refer to the price in 2014$ where the NPV of that price grown with inflation over the 2016-2035 period would equal the NPV of levelized nominal prices over the 2016-2035 period.

Figure 7: Stakeholder Input Case Natural Gas Price Forecast

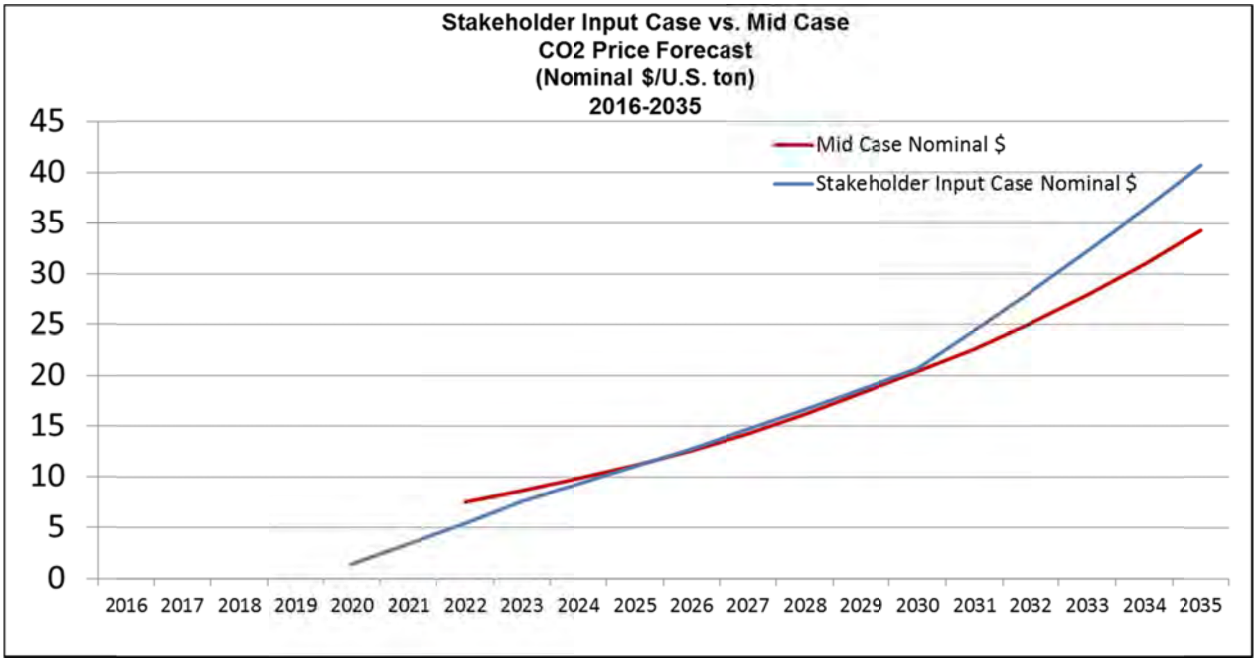


CO_2 PRICE

The Stakeholder Input Case CO_2 price forecast was taken from Entergy corporate CO_2 POV developed in March 2015. The basis for Entergy corporate POV for the mid-price forecast shown below is based on the ICF 1Q 2015 Reference Case. The Stakeholder Input Case forecast shows CO_2 prices that begin in 2020 at $1.39/U.S. ton and escalate more quickly than the mid-price forecast. The 2016-2035 levelized cost in 2014$ for the Stakeholder Input Case is $8.00/U.S. ton.[36]

[36] Includes a discount rate of 7.12%.

Figure 8: Stakeholder Input Case CO_2 Price Forecast



SECTION 3: CURRENT FLEET & PROJECTED NEEDS

Current Fleet

ENO currently controls approximately 1,318 MW of generating capacity either through direct ownership or through life-of-unit contracts with affiliate EOCs. Table 6 indicates the supply resources by fuel type measured in installed MW with percentages of the overall portfolio.

As reflected in Table 8, over half of ENO's existing generating capacity consists of legacy gas units — Michoud Units 2 and 3; however, they only contribute approximately 18% of ENO's energy requirements. Both units are currently scheduled to deactivate June 1, 2016, which creates room in the portfolio for modern gas-fired peaking resources.

Upon close of the acquisition by ENO of Power Block 1 of the Union Power Station, ENO will add approximately 510 MW of modern and highly efficient CCGT capacity to its portfolio helping to fill a significant portion of the long-term need caused by the deactivation of Michoud Units 2 and 3. When combined with ENO's existing baseload resources, the addition of Union to ENO's portfolio is expected to substantially meet ENO's long-term baseload and load-following resource needs. ENO's remaining needs will necessitate replacement resources that are designed to provide low cost capacity and produce limited amounts of energy. Peaking resources such as Combustion Turbines ("CT") are particularly well suited to meet this need. ENO's existing portfolio does not currently include a CT resource.

Table 8: ENO's Current Resource Portfolio

Resource Type	MW	%
Coal	32	2.4
Combined Cycle Gas Turbine (CCGT)	112	8.5
Nuclear	392	29.7
Legacy Gas	782	59.3
Total	1318	100.0

Historical production costs for ENO's current fleet can be seen in Table 9 below.

Table 9: ENO Historical Production Costs of Current Fleet

ENO Production Costs			
	Year-end		
	2012	2013	2014
MWhs (net Non-Requirements Sales for Resale and Net Transmission Losses)	5,192,000	5,370,000	5,314,000
Total Production Cost ($)	$302,950,000	$348,920,000	$324,883,000
Total Production Cost ($/MWh)	$58.35	$64.98	$61.14
RPCE equalization receipts/(payments)	$14,599,000	$15,325,000	-
Total Production Cost with RPCE receipts/(payments) ($)	$288,351,000	$333,595,000	$324,883,000
Total Production Cost with RPCE receipts/(payments) ($/MWh)	$55.54	$62.12	$61.14

DEACTIVATION OF MICHOUD 2 AND 3

ENO's existing Michoud Units 2 and 3 are scheduled to deactivate June 1, 2016. Originally placed in service in 1963 and 1967, respectively, units 2 and 3 are among the oldest active Entergy-owned units in Louisiana, and significantly older than the average age of the fleet. Both units were designed to operate in load-following and baseload roles; however, both units are increasingly being dispatched with greater frequency (*i.e.,* in a peaking role) which increases operating cost and reliability fatigue associated with more start up and shut down cycles. As part of its ongoing assessment of both units, prior independent engineering studies identified the need for significant upgrades to allow for safe and reliable operations over the next 10 years. An economic analysis comparing the cost of extending the life of Michoud 2 and 3 to deactivating each unit and deploying new resources concluded that deactivation was the preferred solution in order to mitigate risks associated with uncertainty that extending the life of either unit would yield benefits to customers. Given these realities, ENO submitted an Attachment Y request to MISO to study the impact on the transmission system associated with deactivation of units 2 and 3, which study was ultimately completed approving the deactivation of both units upon completion of certain transmission upgrades.[37]

Load Forecast

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

- Levels of economic activity and growth;
- The potential for technological change to affect the efficiency of electric consumption;
- Potential changes in the purposes for which customers use electricity (*e.g.*, the adoption of electric vehicles);
- The potential expansion of customer-owned (*i.e.*, behind-the-meter) self-generation technologies and the long-term performance of existing installed systems (*e.g.*, rooftop solar panels); and
- The cost-effectiveness of energy efficiency, conservation measures, and demand response.

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

In order to consider the potential implications of load uncertainties on long-term resource needs, four load forecast scenarios were prepared for the 2015 IRP, which are described in general below:

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[37] For additional details regarding the condition assessment of Michoud Units 2 and 3, see Technical Supplement 7].

INDUSTRIAL RENAISSANCE – REFERENCE LOAD

Assumes significant load growth will occur in the commercial class due to known commercial projects. Distributed generation in the form of rooftop solar is expected to dampen growth in the residential and commercial classes.

BUSINESS BOOM

Assumes smaller impact from distributed generation, accelerated ramp of a commercial project, and a load expansion at a commercial project.

DISTRIBUTED DISRUPTION

Decrements the Reference load scenario for Combined Heat and Power ("CHP") impact and distributed solar PV system impact.

GENERATION SHIFT

Assumes distributed generation will have a greater impact on residential and commercial growth. Also assumes major new commercial project is delayed.

METHODOLOGY

SPO has consistently used Itron computer software to develop the IRP load forecasts. Itron is used to develop a 20-year, hour-by-hour load forecast. The MetrixND®[38] and the MetrixLT™[39] programs are used widely in the utility industry, to the point where they may be considered an industry standard for energy forecasting, weather normalization, and hourly load and peak load forecasting.

To develop the load forecast, SPO allocates ENO's Retail Energy Forecast (by month) and the Wholesale Energy Forecast (by month) to each hour of a 20-year period based on historical load shapes developed by ESI's Load Research Department. Fifteen-year "typical weather" is used to convert historic load shapes into "typical load shapes." For example, if the actual sales for the Company's residential customers occurred during very hot weather conditions, the typical load shape would flatten the historic load shape. If the actual weather were mild, the typical load shape would raise the historic load shape. Each customer class responds differently to weather, so each has its own weather response function. MetrixND® is used to adjust the historical load shapes by typical weather, and MetrixLT™ is used to create the 20-year, hourly load forecast.

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[38] MetrixND by ITron is an advanced statistics program for analysis and forecasting of time series data.
[39] MetrixLT™ by ITron is a specialized tool for developing medium and long run load shapes that are consistent with monthly sales and peak forecasts.

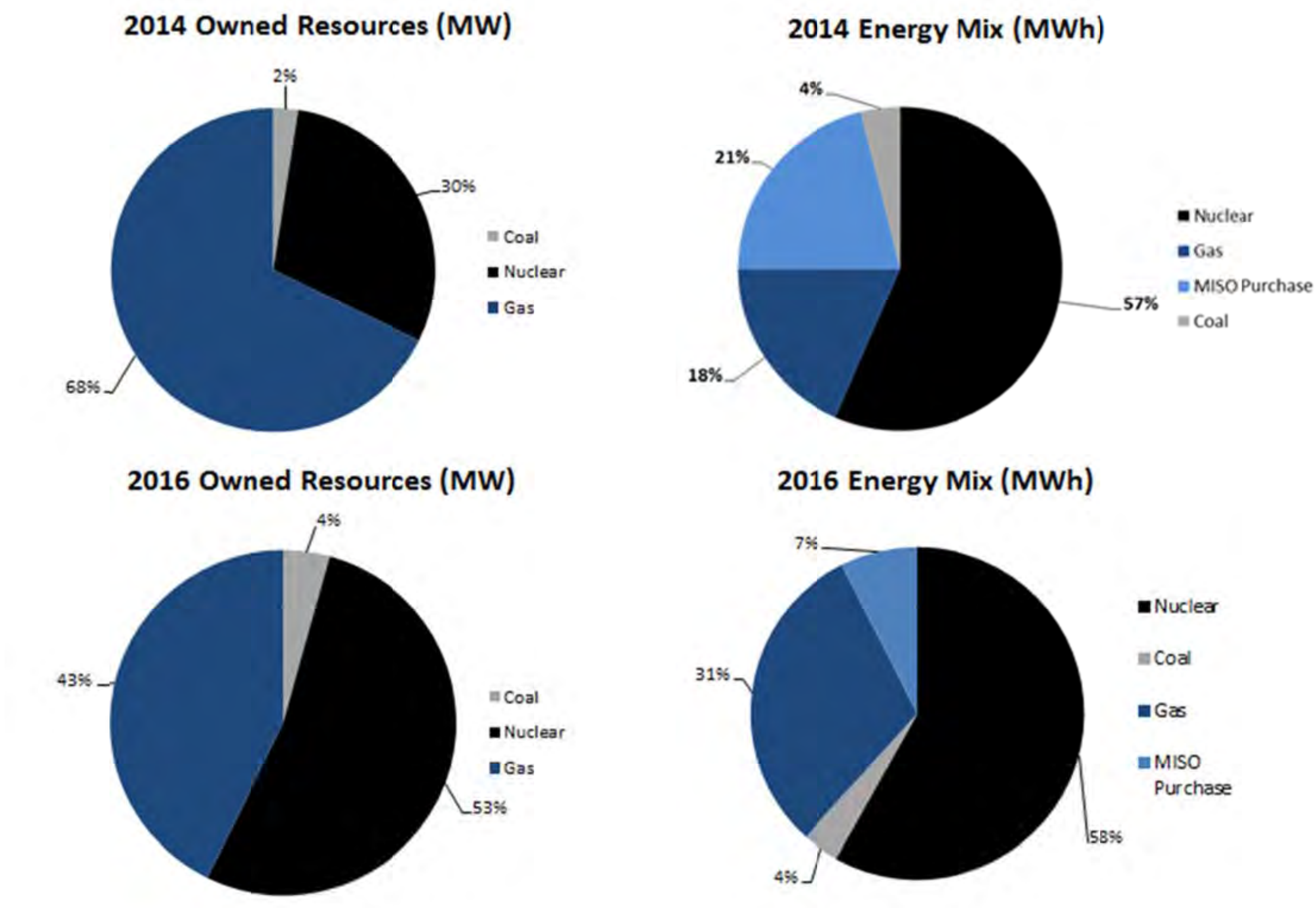
The load forecast is then grossed up to include average transmission and distribution line losses. Loss factors are applied to each revenue class after the forecast is developed and after accounting for energy efficiency.

Energy savings from company-sponsored DSM programs are decremented from the Retail energy forecast. Energy savings from naturally occurring energy efficiency, as estimated by the Energy Information Administration, are also taken into consideration. The load forecast uses the decremented energy forecast to develop annual peaks that reflect the savings from utility-sponsored programs as well as non-utility sponsored customer adoption of more efficient technologies.

Resource Needs

Over the 20-year planning horizon of the IRP, ENO expects to add new generating capacity, as the DSM Potential Study did not identify enough cost-effective achievable DSM resources to independently meet ENO's projected needs. ENO's long-term resource needs are driven primarily by the scheduled deactivation of the approximately 781 MW Michoud Units 2 and 3 in 2016. Michoud Units 2 and 3 are scheduled to deactivate due to high expected forward costs to sustain these older units. These units represent over half of ENO's existing capacity, but do not provide an equivalent amount of energy. Following the planned deactivation of Michoud 2 and 3, ENO's nuclear (and to a lesser extent, coal) resources will provide about 57% of ENO's capacity and over 60% of energy as shown in Figure 9 below. Although the deactivation of Michoud Units 2 and 3 will result in a significant need for replacement capacity resources, those resources would not be called on to generate an equivalent amount of energy. Following the planned deactivation of Michoud Units 2 and 3, the fuel mix of ENO's energy resources will remained balanced with a significant portion sourcing from stable-priced base load nuclear resources, leaving room for cost-effective gas-fired resource additions beyond ENO's share of the new Ninemile 6 CCGT resource and Power Block 1 of the Union Power Station.

Figure 9: ENO's Capacity and Energy Mix



Based on current deactivation assumptions, no other units are expected to deactivate during the planning period. Assumptions made for the IRP are not final decisions regarding future investment in any identified or planned resource. Unit-specific portfolio decisions, such as sustainability investments in legacy resources, environmental compliance investments, or unit deactivations, are based on economic and technical evaluations considering such factors as projected forward costs, anticipated operating roles, and the cost of supply alternatives at the time of the decision. These factors are dynamic, and as a result, actual decisions may differ from planning assumptions as greater certainty is gained regarding requirements of legislation, regulation, and relative economics.

As shown in Table 10, by 2034, it is expected that ENO will experience between 123 MW and 160 MW of total load growth.

Table 10: Projected Peak Forecast Increase from 2015

	Industrial Renaissance (MW)	Business Boom (MW)	Distributed Disruption (MW)	Generation Shift (MW)
By 2034	147	160	123	146

The combination of the projected load growth and the planned deactivation of the Michoud units will result in a significant need for long-term capacity resources as shown in Table 11. By 2034, ENO's projected capacity need (before planned additions) is expected to be approximately 781 MW.

Table 11: ENO Resource Needs by Scenario (MW)

Capacity Surplus/(Need) (Before IRP Additions)				
	Industrial Renaissance	**Business Boom**	**Distributed Disruption**	**Generation Shift**
By 2024	(691)	(727)	(683)	(688)
By 2034	(781)	(821)	(753)	(778)

**Includes 12% planning reserve margin*

ENO has a number of alternatives for meeting its long-term resource needs, including:

- Incremental long-term resource additions including:
    - Self-Supply alternatives
    - Acquisitions
    - Long Term PPAs
- Demand Side Resources
    - Energy efficiency
    - Demand response

As a member of MISO, ENO has access to a large structured marketplace that offers short-term capacity and energy products. While those alternatives are viable alternatives for meeting ENO's short-term resource needs, they are not appropriate for meeting long-term resource needs.

Types of Resources Needed

In order to provide safe and reliable service to its customers at the lowest reasonable cost, ENO must maintain a portfolio of generation resources that includes the right amount and types of capacity. With respect to the amount of capacity, ENO must maintain sufficient generating capacity to meet its peak load plus a planning reserve margin. As described above, ENO plans to meet its annual reserve margin target, which is assumed to be 12% for long-term planning. In general, as demonstrated in Table 12, ENO's capacity needs by supply role include:

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

Table 12: Projected Resource Needs in 2034 by Supply Roles (without Planned Additions) in Industrial Renaissance Scenario

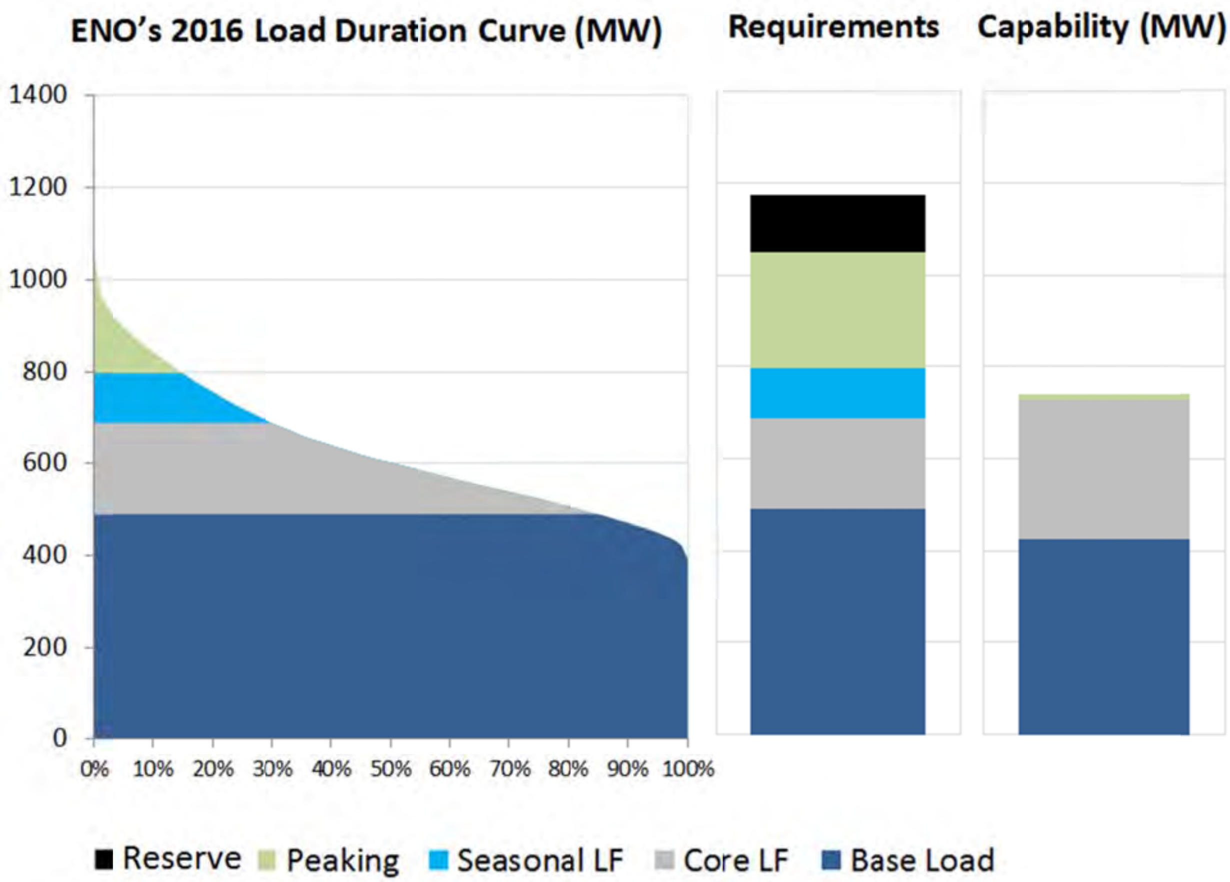
	Need	Resources	Surplus/ (Deficit)
Base Load and Load-Following (MW)	915	525	(390)
Peaking & Reserve (MW)	403	12	(391)
Totals	1318	537	(781)

However, with the planned addition of the Council approved Union resource, ENO would expect to meet its base load and load-following resource needs as indicated in Table 13.

Table 13: Projected Resource Needs in 2034 by Supply Roles (with Planned Additions) in the Industrial Renaissance Scenario

	Need	Resources	Surplus/ (Deficit)
Base Load and Load Following (MW)	915	965	50
Peaking & Reserve (MW)	403	12	(391)
Totals	1318	977	(781)

Figure 10: ENO's Supply Role Needs 2016



Following the deactivation of Michoud Units 2 and 3 and the close of the transaction to acquire the Union Power Block 1 resource, both in 2016, ENO's remaining need is primarily for peaking and reserve resources. Peaking requirements are most economically served with resources with low fixed costs and quick start times. Peaking units, such as CTs, typically operate at a capacity factor of less than 15% and are particularly well suited to meet this need. Thus, the evaluation of adding CT resources to ENO's portfolio for further evaluation is a prudent and reasonable step that was evaluated further in the detailed stages of the modeling for the 2015 IRP, and is discussed further below. As indicated by the DSM Potential Study, there are not enough cost-effective demand-side resources to meet ENO's projected peaking resource needs. In addition, because 1 MW of renewable resources such as wind and solar only provide approximately .14 - .25 MW of capacity toward meeting ENO's resource needs, ENO demonstrates in Section 4 and 5 below that renewables such as wind and solar cannot be relied upon to cost-effectively meet ENO's projected resource needs following the planned deactivation of Michoud Units 2 and 3.

Current Fleet & Projected Needs: Stakeholder Input Case

Due to the changes that were filed September 18, 2015 and the creation of the Stakeholder Input Case, the differences in the current fleet assessment and projected needs assessment are documented below.

FINAL IRP UPDATE ON CURRENT FLEET

ENO received Council approval for the transfer of Algiers from ELL to ENO in May 2015, which transaction closed on September 1, 2015. The Algiers resources were included in the portfolio of the existing fleet of the Stakeholder Input Case, resulting in an increase of 117 MW from 537 MW to 654 MW of owned resources and affiliate power purchase agreements in 2016.

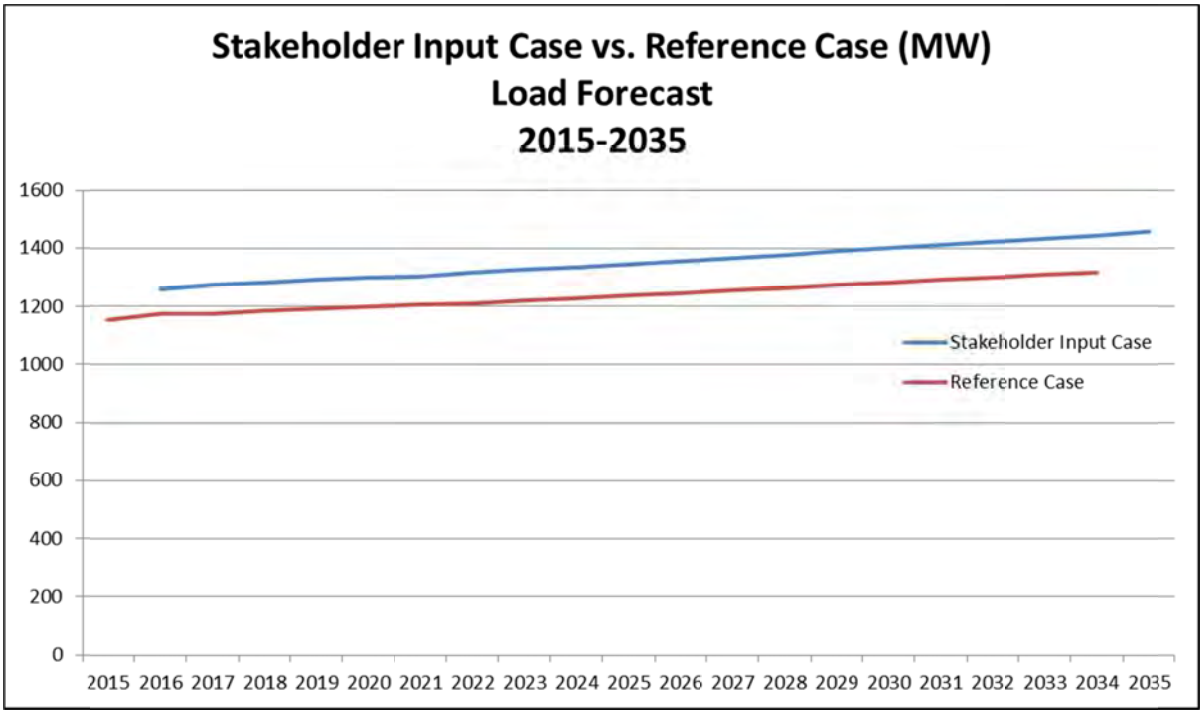
Table 14: Incremental Capacity from Algiers Transfer (MW)

Resource Name	Resource Type	MW
Acadia	CCGT	7
Buras 8	Legacy Gas	0.2
Grand Gulf	Nuclear	3
Little Gypsy 2	Legacy Gas	8
Little Gypsy 3	Legacy Gas	10
Ninemile 4	Legacy Gas	13
Ninemile 5	Legacy Gas	13
Perryville 1	CCGT	2
Perryville 2	CT	1
Riverbend	Nuclear	4
Waterford 1	Legacy Gas	7
Waterford 2	Legacy Gas	8
Waterford 3	Nuclear	21
Waterford 4	Oil	1
Sterlington 7	CCGT	1
Ninemile 6	CCGT	6
Oxy-Taft	CCGT	9
Toledo Bend	Hydro	0.4
Vidalia	Hydro	2
Total		117

LOAD FORECAST

For the Stakeholder Input Case, the load was changed to reflect the load forecast of the most current business plan, which also included the Algiers transfer. This resulted in an increase of 84 MW in the total resource requirement in 2016 compared to the Final IRP reference case load.

Figure 11: Stakeholder Input Case Load Forecast



RESOURCE NEEDS

Resource needs changed in the Stakeholder Input Case due to changes in the load forecast as well as the addition of incremental capacity from the Algiers transfer. Planned resource additions also changed from the affiliate PPA's of the Union and Amite South resources to the ownership of Union Power Block 1. This change is highlighted in Table 15 below. Despite these changes to the Stakeholder Input Case, ENO's needs were determined to be similar to the reference case: ENO largely meets its base load/core load-following need while still being deficient in peaking and total capacity.

Table 15: Reallocation of Planned Resource Additions

Reallocation of Planned Resource Additions			
Resource	**IR/BB/DD/GS Scenarios (MW)**	**Stakeholder Input Case (MW)**	**Change**
Union	204	510	306
Amite South	229	0	(229)
Totals	433	510	77

Table 16: Stakeholder Input Case Projected Peak Forecast Increase by 2035

Stakeholder Input Case (MW)		
2016	**2035**	**Increase**
1,125	1,301	176

Table 17: Stakeholder Input Case ENO Resource Needs (MW)

Capacity Surplus/(Need) (Before IRP Additions)	
By 2025	(685)
By 2035	(901)

Table 18: Projected Resource Needs in 2035 by Supply Roles (Stakeholder Input Case)

	Need	Resources	Surplus/ (Deficit)	Planned Additions	Surplus/ (Deficit)
Base Load and Load-Following (MW)	1043	526	(517)	510	(7)
Peaking & Reserve (MW)	414	30	(384)	0	(384)
Totals	1457	556	(901)	510	(391)

SECTION 4: PORTFOLIO DESIGN ANALYTICS

The IRP utilized a two-step approach to construct and assess alternative resource portfolios to meet the customer needs:

1. Market Modeling
2. Portfolio Design & Risk Assessment

Market Modeling

The first step of the IRP modeling process was to develop within the AURORA model a projection of the future power market for each of the four scenarios. This projection looks at the power market for the entire MISO footprint excluding New Orleans to gain perspective on the broader market outside the state. The purpose of this step was to provide projected power prices to assess potential portfolio strategies within each scenario as resource additions made outside of New Orleans will have an impact on the economics of the resource alternatives available to ENO. In order to achieve this, assumptions were required about the future supply of power. The process for developing those assumptions relied on the AURORA Capacity Expansion Model to identify the optimal set of resource additions in the market to meet reliability and economic constraints. Resulting assumptions regarding new capacity additions in each scenario are summarized in Table 19. It is important to recognize that the resource additions identified in Table 19 are what the AURORA model predict would be added outside of New Orleans by other companies to meet the capacity and energy requirements of the MISO market excluding New Orleans. In this way, ENO is attempting to model and isolate the effect of resource additions outside of New Orleans in order to establish a benchmark for evaluation of the optimal combination of resource additions in New Orleans.

Table 19: Results of MISO Market Modeling

Results of MISO Market Modeling (MISO Footprint, excluding New Orleans) Incremental Capacity Mix by Scenario				
	Industrial Renaissance (Ref. Case)	**Business Boom**	**Distributed Disruption**	**Generation Shift**
CCGT	45%	81%	97%	61%
CT	55%	19%	3%	3%
Wind	0%	0%	0%	12%
Solar	0%	0%	0%	24%
Year of First Addition	2017	2017	2017	2017
Total GWs Added (through 2034)	59	65	39	101

The results of the Capacity Expansion Modeling are supported by conclusions from the Technology Assessment, as discussed earlier, were reasonably consistent across scenarios. These results, as summarized below, are the output of the model based on the market conditions that the model analyzed:

- In general, new build capacity is required to meet overall reliability needs.
- Gas-fired resources, CTs and CCGTs, are the preferred technologies for new build resources in most outcomes.
- The model did not select new nuclear or new coal for any scenario.
- Solar PV and wind generation has a significant role in only one of the scenarios, which assumes high gas and carbon prices and the continuation of subsidies.

Portfolio Design & Risk Assessment

The IRP informs future planning and procurement activities. In order to establish a potential resource mix for a given scenario, ENO first relied on the AURORA Capacity Expansion Model to develop the optimal DSM program mix. After assessing DSM programs, ENO relied on AURORA to create an optimal portfolio, with both demand- and supply-side resources, for each scenario. Based on these results, ENO designed additional portfolios based on ENO's planning objectives and needs.

The AURORA Capacity Expansion Model analyzes least cost portfolios to meet ENO's resource needs using the cost-effective achievable demand-side resources identified in the ICF DSM Potential Study, and the supply-side resource alternatives identified in the Technology Assessment. The AURORA Capacity Model was used to develop a portfolio for each of the scenarios in a two-step process, which first assessed DSM programs, and then supply-side alternatives. DSM programs were evaluated first without consideration of supply-side alternatives by allowing the AURORA Capacity Expansion Model to determine which of the DSM programs may be able to provide capacity and energy benefits in excess of their costs. All economic DSM programs were included in each portfolio.[40] The specific programs selected for each scenario are listed in Appendix A to this report. In addition to this analysis, in response to

[40] In evaluating the economics of DSM programs, the model evaluates the cost and benefit of the DSM programs, but does not take into consideration ratemaking and policy issues implicated by DSM programs, which must be appropriately addressed as part of DSM implementation.

comments received following Milestone 2 of the IRP process, ENO conducted additional sensitivity analysis of the reference case DSM Portfolio to ensure that the cost-effectiveness of the selected programs, as well as those that were not selected, would not be significantly affected by either having to compete with supply-side resource alternatives or delaying their implementation start date beyond 2015. In both cases, the analysis supports the selected programs as a reasonable basis for determining which programs to include in the Preferred Portfolio. [41]

Once the level of economic DSM was determined within each scenario/portfolio combination, the AURORA Capacity Expansion Model was used to identify the most economic level and type of supply-side resources needed to meet reliability requirements. The result of this process was a portfolio of both DSM and supply-side alternatives that produces the lowest total supply cost to meet the identified need in each scenario. Table 20 details the resource mix for the AURORA Capacity Expansion Portfolios.

Table 20: AURORA Capacity Expansion Portfolio Design Mix

AURORA Capacity Expansion Portfolio Design Mix				
	Industrial Renaissance (Ref. Case)	Business Boom	Distributed Disruption	Generation Shift
DSM	14 Programs	12 Programs	15 Programs	17 Programs
DSM Maximum (MW)[42]	41	26	40	43
CCGTs (MW)	382	382	382	0
CTs (MW)	0	0	0	0
Solar (MW)	0	0	0	1,150
Wind (MW)	0	0	0	50

As demonstrated in the Section 3 above, ENO's projected supply role needs are primarily for peaking and reserve resources. The results of the AURORA Capacity Expansion Portfolios selected mainly base load and load-following resources. This is due in large part to the way in which AURORA evaluates the resources alternatives. In AURORA, a resource is dispatched based on its ability to serve the load in MISO, regardless of who owns the generating resources. Because CCGT resources are expected to be dispatched before peaking resources due to their

[41] This analysis was shared publicly at the Interim Milestone public meeting held on May 27, 2015, and is available on ENO's IRP website located at www.entergy-neworleans.com/IRP/.
[42] Demand Side Management (DSM) total is grossed up for Planning Reserve Margin (12%) and transmission losses (2.4%).

relative efficiency, the selection by AURORA of CCGT resources to serve load in MISO is predicated on the need for the energy those resources are dispatched to serve. ENO's challenge is that while CCGT resources may be more economic than peaking resources (*e.g.*, CTs), it would not be prudent for ENO to add CCGT resources to its capacity portfolio if it does not have a corresponding need for the energy those resources are expected to produce when dispatched by MISO. If ENO were to add more CCGT resources beyond Union Power Block 1 than can be supported by the supply role needs analysis discussed in Section 3, effectively ENO would be exposing its customers to unnecessary risk associated with the known high fixed cost of CCGT resources as compared to the unknown market price for the excess energy necessary to make those resource additions economic.

As a result of this unique planning conundrum, ENO designed an additional four portfolios to reflect this challenge and develop a reasonable prudent set of alternative portfolios capable of meeting ENO's planning objectives based on the identified resource needs and the best available resource alternatives. This also provided a meaningful set of alternatives against which the AURORA portfolios could be compared. All portfolios constructed included CTs as they are well suited to economically serve ENO's peaking and reserve supply role needs. Three of the portfolios included renewable resources to assess whether a certain amount of renewable resource additions to ENO's portfolio could improve the portfolio performance in terms of cost and risk. All four of these additional portfolios relied on the Industrial Renaissance Scenario's DSM portfolio, which as discussed above proved to be robust under a range of alternative assumptions regarding start date for implementation and cost-effectiveness as compared to supply-side resource alternatives. The resulting four portfolios are described below. As discussed in more detail below, the AURORA portfolios result in the addition of resources that produce significantly more energy than identified as necessary in the analysis of ENO's resource needs by supply role, suggesting that the alternative portfolios summarized in Table 21 provide a reasonable set of alternatives prudent for further consideration in the development of the Preferred Portfolio. Figures 12 through 17 show the load and capability charts for each of the six portfolios.

Table 21: Alternative Portfolio Design Mix – Installed Capacity

Alternative Portfolio Design Mix – Installed Capacity				
	CT Portfolio	**CT/Solar Portfolio**	**CT/Wind Portfolio**	**CT/Wind/Solar Portfolio**
DSM Programs	14 Programs	14 Programs	14 Programs	14 Programs

CCGTs	0	0	0	0
CTs	194	194	194	194
Solar	0	100	0	50
Wind	0	0	100	50

Figure 12: AURORA - CCGT Portfolio

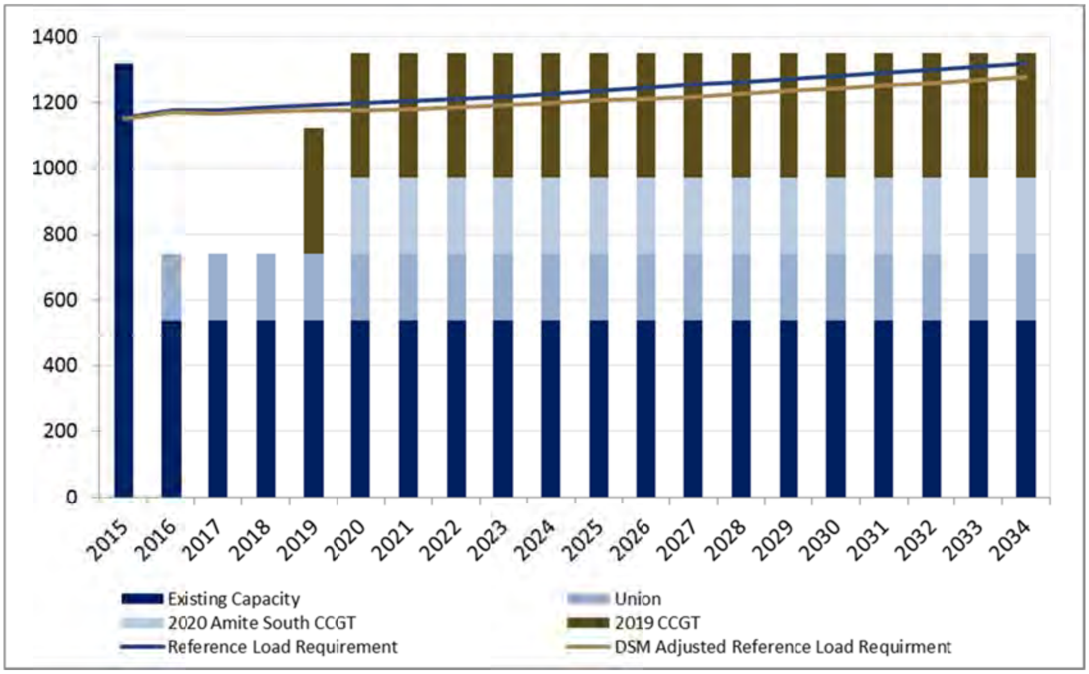


Figure 13: AURORA - Solar Portfolio

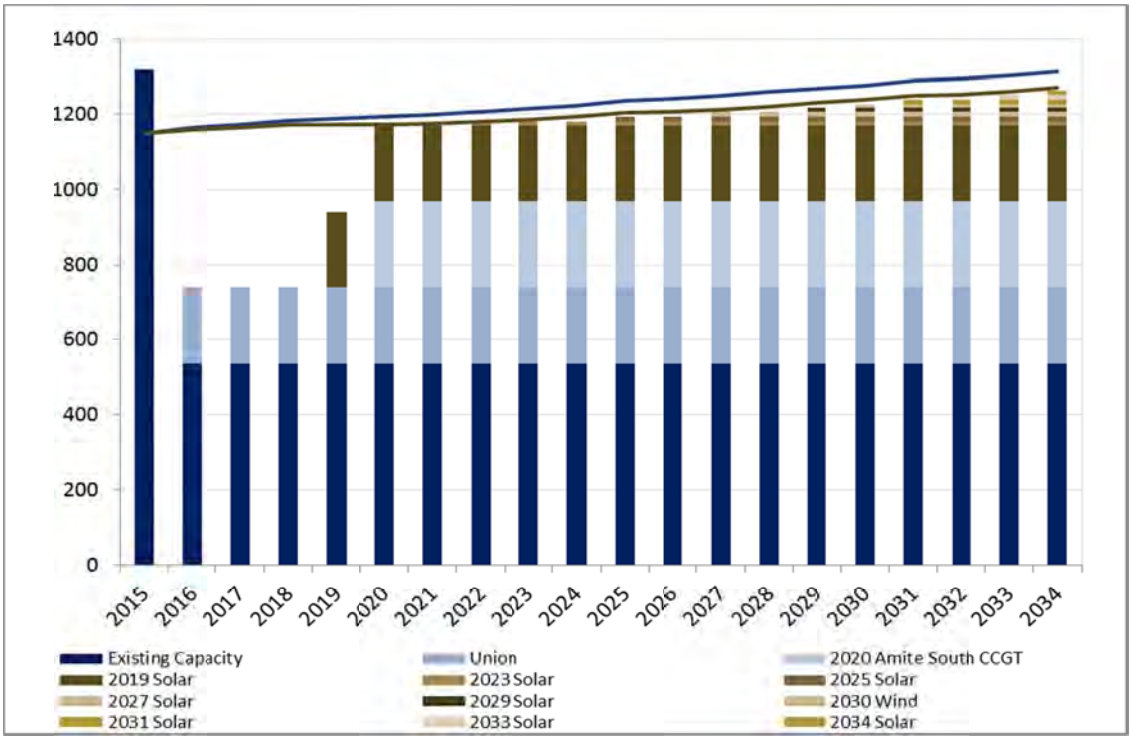


Figure 14: CT Portfolio

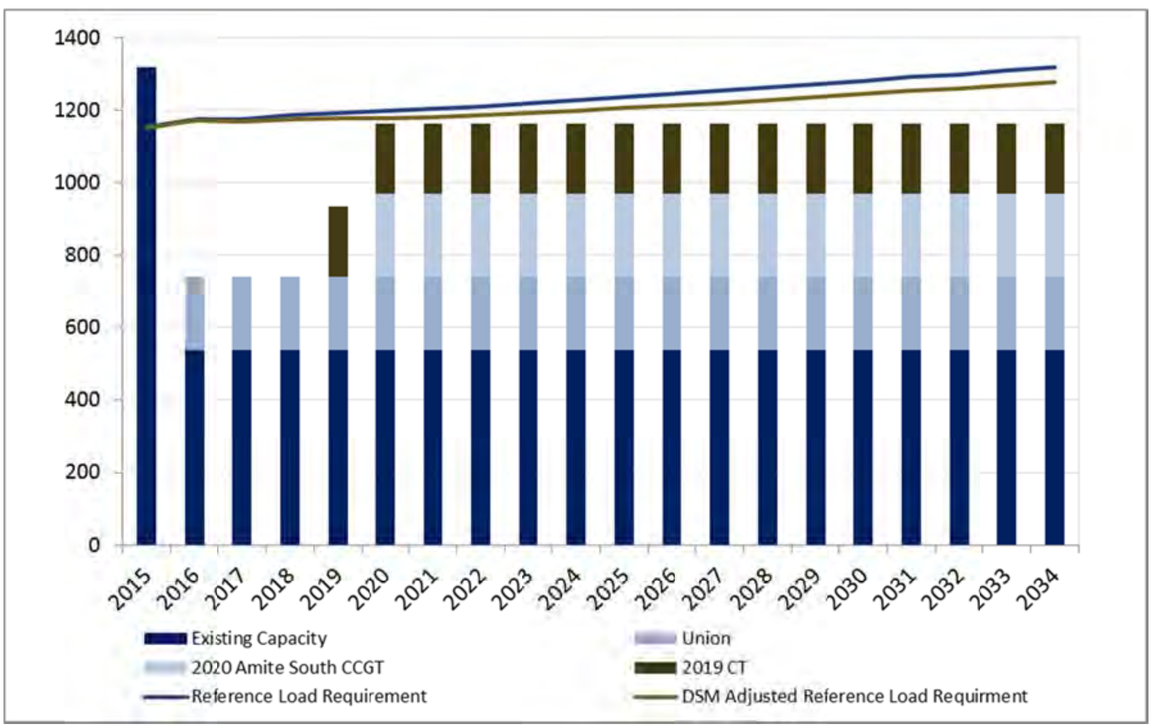


Figure 15: CT/Solar Portfolio

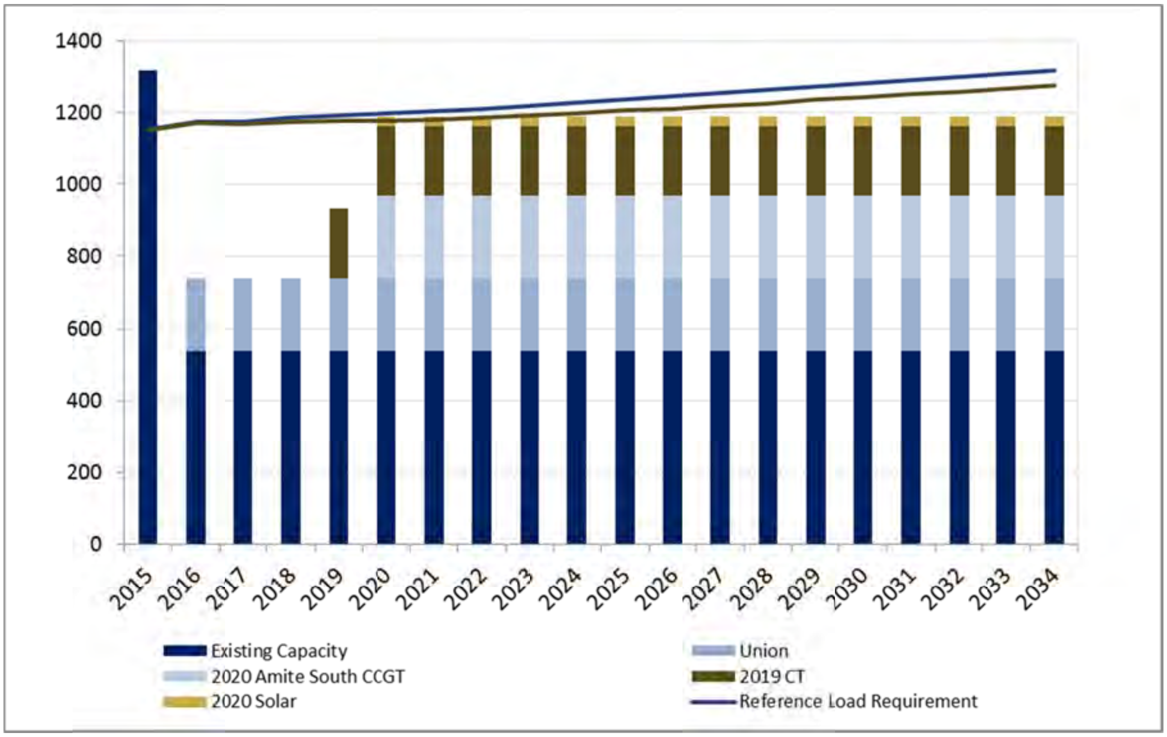


Figure 16: CT/Wind Portfolio

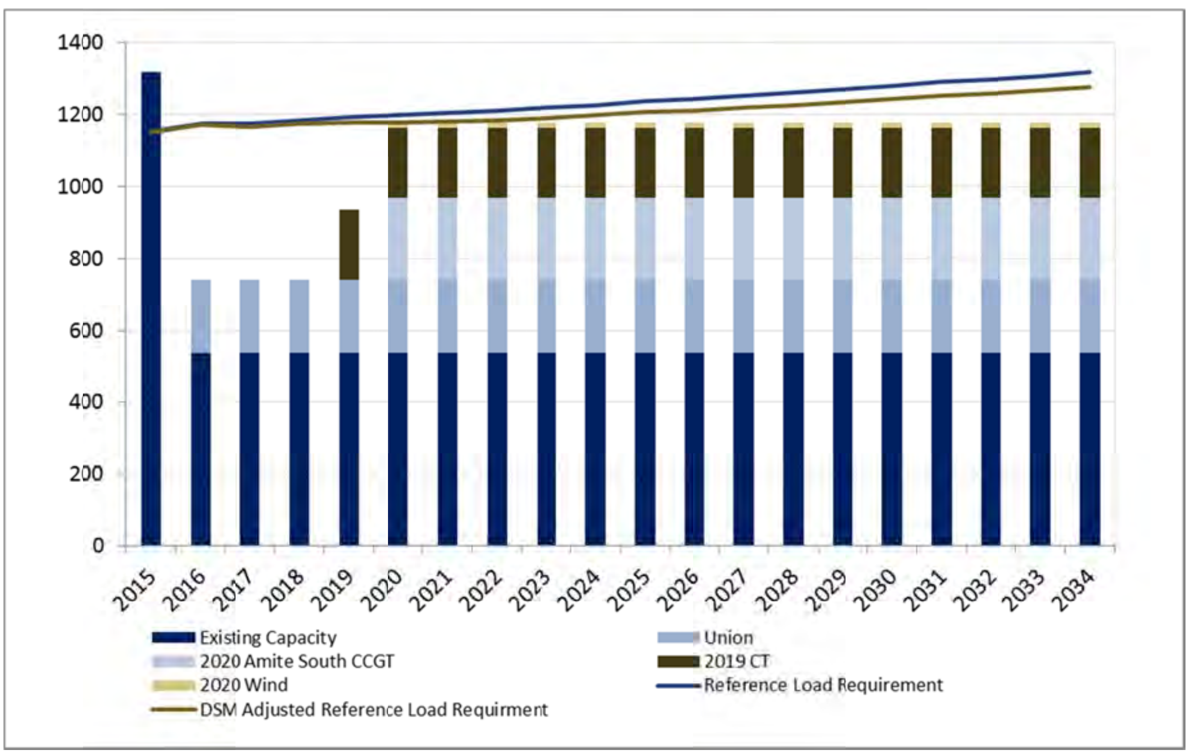
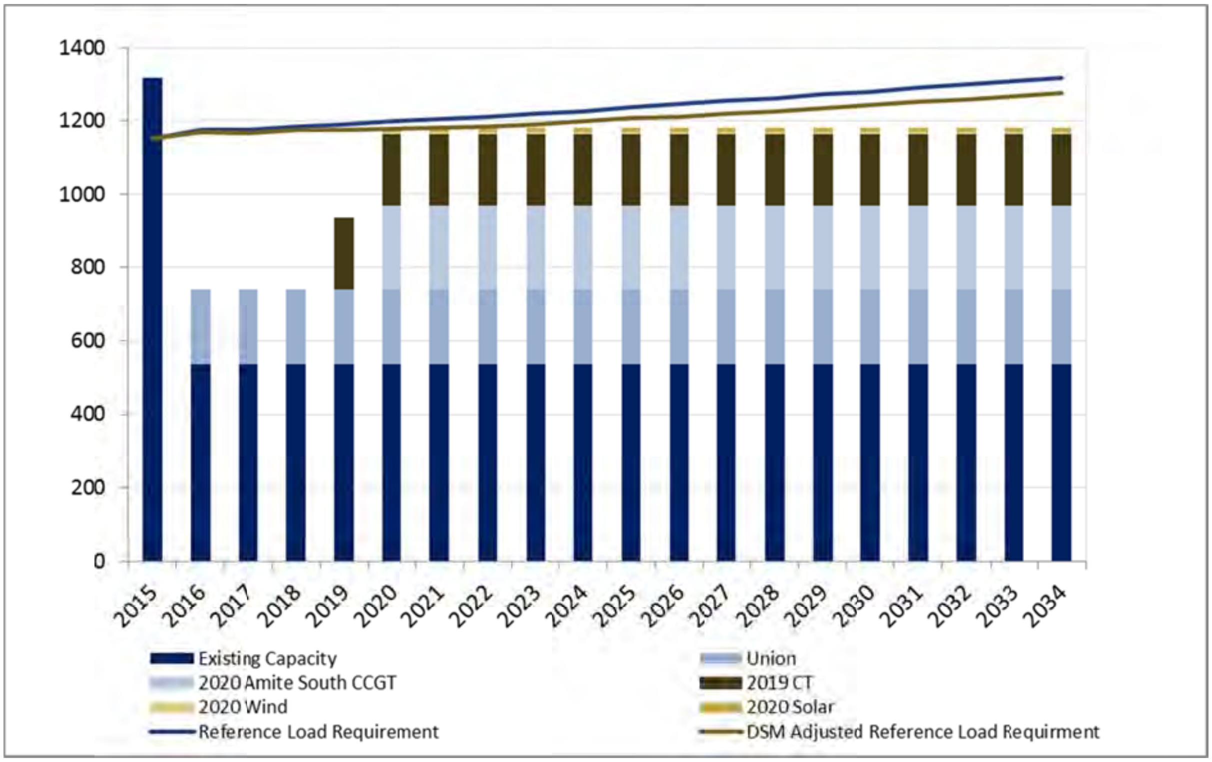


Figure 17: CT/Wind/Solar Portfolio



Each of the six portfolios illustrated above were modeled in AURORA and tested in the four scenarios described earlier to create a total of 32 cases. The results of the AURORA production cost simulations were combined with the fixed costs of the incremental resource additions to yield the total forward revenue requirements excluding sunk costs of ENO's existing portfolio. The total forward non-sunk revenue requirement results and rankings by scenario are provided in Table 22 and Table 23 below.

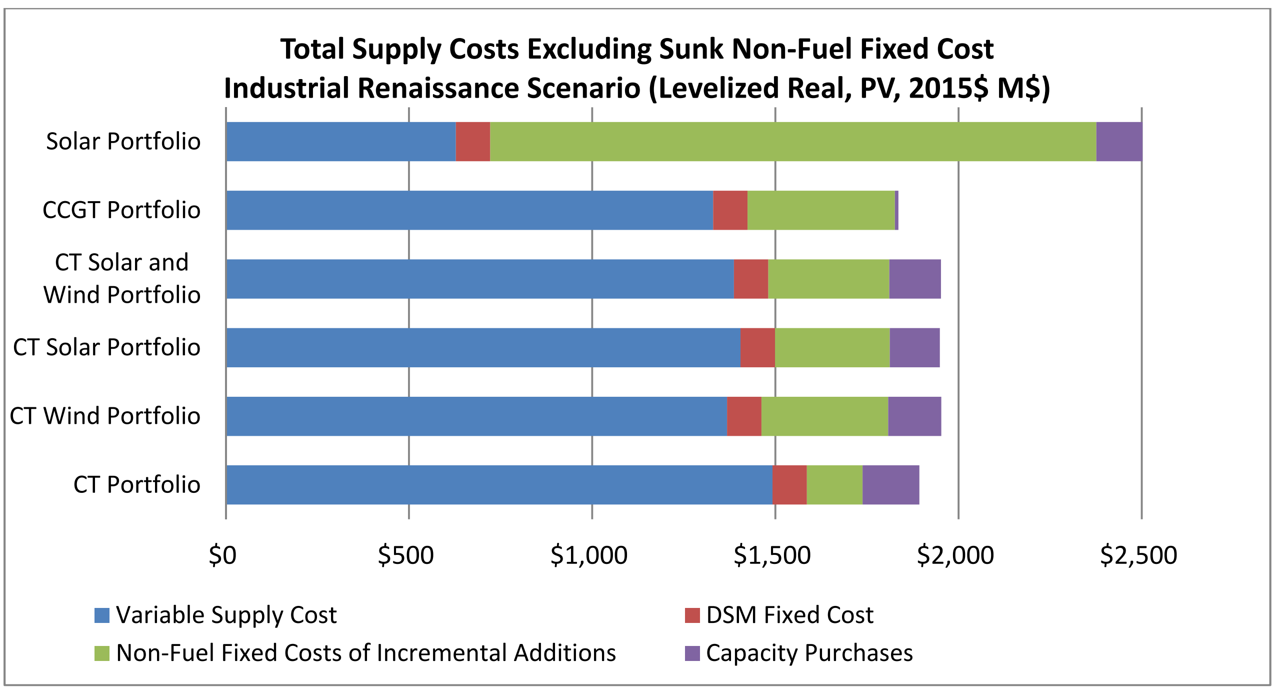
Table 22: PV of Total Supply Costs excluding Sunk Non-Fuel Costs by Scenario

PV of Forward Revenue Requirements ($M) (2015-2034)				
	IR Scenario	BB Scenario	DD Scenario	GS Scenario
AURORA - CCGT Portfolio	$1,836	$1,538	$1,754	$2,228
AURORA - Solar Portfolio	$2,501	$2,432	$2,403	$2,100
CT Portfolio	$1,893	$1,687	$1,837	$2,374

CT/Solar Portfolio	$1,949	$1,756	$1,889	$2,343
CT/Wind Portfolio	$1,952	$1,765	$1,885	$2,310
CT/Solar/Wind Portfolio	$1,951	$1,760	$1,887	$2,326

Figure 18 below, breaks down the analysis of total supply cost excluding sunk non-fuel fixed cost for each of the six portfolios using assumptions in the Industrial Renaissance Scenario into the component costs. As demonstrated in Figure 18, while the Solar Portfolio has the lowest variable supply costs, it is has the highest non-fuel fixed costs as compared to the other portfolios. In contrast, the CT Portfolio has lower non-fuel fixed costs than the other five portfolios. Because ENO's projected resource needs following the planned deactivation of Michoud Units 2 and 3 reflect the need for peaking and reserve capacity resources, more weight should be placed on the non-fuel fixed costs than variable cost savings in considering resource additions to the Preferred Portfolio.

Figure 18: Total Supply Costs Excluding Sunk Non-Fuel Fixed Costs in the IR Scenario



The columns in Table 23, below, provides the rankings of each of the six modeled portfolios in each of the scenarios based on the economic performance of the portfolios shown in Table 22.

Table 23: Portfolio Ranking by Scenario

Portfolio Ranking by Scenario				
	IR Scenario	BB Scenario	DD Scenario	GS Scenario
AURORA – CCGT Portfolio	1	1	1	2
AURORA – Solar Portfolio	6	6	6	1
CT Portfolio	2	2	2	6
CT/Solar Portfolio	3	3	5	5
CT/Wind Portfolio	5	5	3	3
CT/Solar/Wind Portfolio	4	4	4	4

Table 23 demonstrates that the CCGT Portfolio ranks higher on a total cost basis in the Industrial Renaissance, Business Boom, and Distributed Disruption Scenarios. However, the CCGT has more risk than the CT portfolios because of higher fixed costs being offset by uncertain potential variable cost savings. The Solar Portfolio ranks lowest in all of the other scenarios. Moreover, the Solar Portfolio is highly ranked in the Generation Shift Scenario due to the confluence of the assumption that the ITC and PTC subsidies will continue, gas prices will move significantly higher, and CO_2 will become regulated and at be priced at the upper bound of the IRP CO_2 price forecast. Those are very aggressive assumptions that when taken into context suggests that it would not be prudent to incorporate large scale adoption of solar into the Preferred Portfolio at this time given the low likelihood that all of these assumptions will turn out as predicted in the Generation Shift scenario. In general, the CT Portfolio performs well in most scenarios, presents lower non-fuel fixed cost risk, is consistent with ENO's resource needs, and complements ENO's existing portfolio. When renewables were added to the CT Portfolio, the renewables did not improve the performance on both a cost and a risk basis in any scenario other than Generation Shift, even under a range of potential outcomes for gas prices and regulation of CO_2.

Risk Assessment

The next and final step in the evaluation of the six portfolios was to perform sensitivity analyses using the reference case assumptions (Industrial Renaissance Scenario) to assess the effects of changes in natural gas prices, carbon prices, and a combination of a change in natural gas prices and carbon prices.

The range of the total supply costs excluding sunk non-fuel costs results by portfolio in the Industrial Renaissance Scenario is provided in the following three figures.

Figure 19: Reference - IR Scenario Sensitivity: Natural Gas (PV $2015, $M)

Figure 20: Reference IR Scenario Sensitivity: CO_2 (PV \$2015, \$M)

Figure 21: Reference - IR Scenario Sensitivity: Natural Gas and CO_2 (PV \$2015, \$M)

Results of the sensitivity assessment indicate that while the Solar Portfolio is less volatile when faced with a change in gas price, CO_2 price, or the combination of natural gas price and CO_2 price, it is significantly more costly than the other portfolios. This is a result of the Solar Portfolio's higher incremental fixed costs, relative to the other five portfolios, due to the requirement to add many times more Solar capacity than conventional alternatives in order to overcome the lower capacity credit available to solar resources. The CCGT and the CT portfolios are similarly affected by changes in gas price assumptions. However, in comparison to the CT Portfolios, the CCGT is relatively less affected by changes in CO_2 price assumptions. It is important to note that implicit in the sensitivity analysis of the CCGT portfolio selected by AURORA is that regardless of whether gas or CO_2 prices are higher or lower than the reference case assumptions, because CCGT resources come with higher non-fuel fixed costs than CT resources, ENO will be relying on the market price for excess energy generating by the CCGT resource exposing ENO's customers to unnecessary risk.

Portfolio Design: Stakeholder Input Case

Due to the changes that were filed September 18, 2015 and the creation of the Stakeholder Input Case, the differences in portfolio design are documented below.

SEPTEMBER 18, 2015 REFRESH

Total supply cost was recalculated to account for the changes in capacity purchases that resulted from the Union reallocation. In addition, three demand response programs were added to the Industrial Renaissance portfolio. Below is the total supply cost for the Industrial Renaissance scenario that reflects the September 18, 2015 changes. Details on the analysis performed on the three demand response programs can be found in the Demand Side Management supplement.

Figure 22: CT Portfolio Load and Capability after September 18, 2015 Update (IR Scenario)

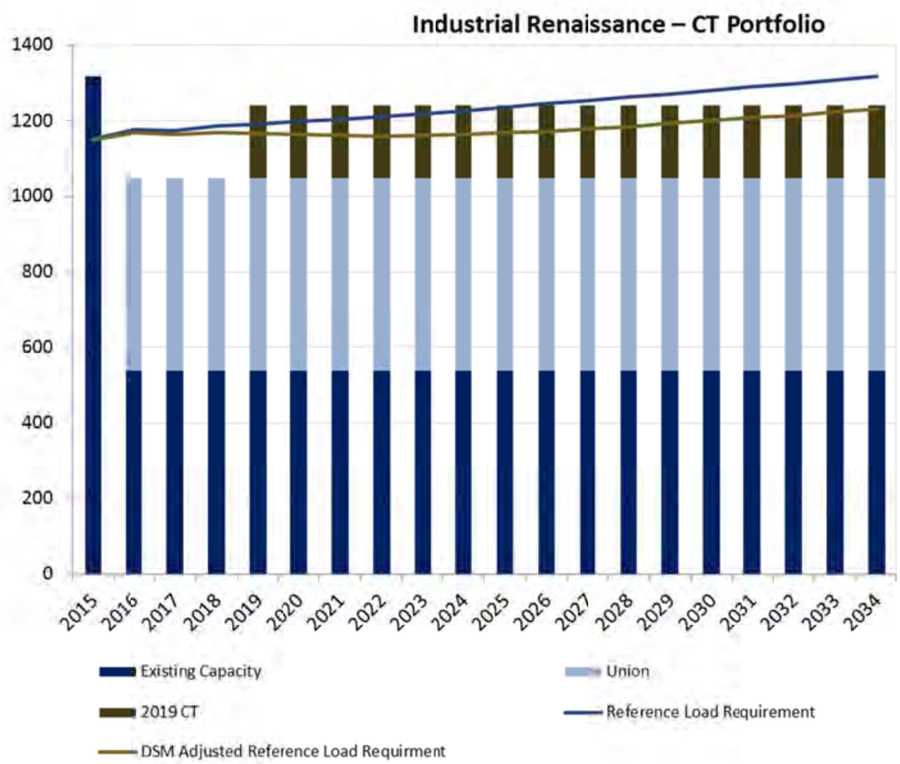
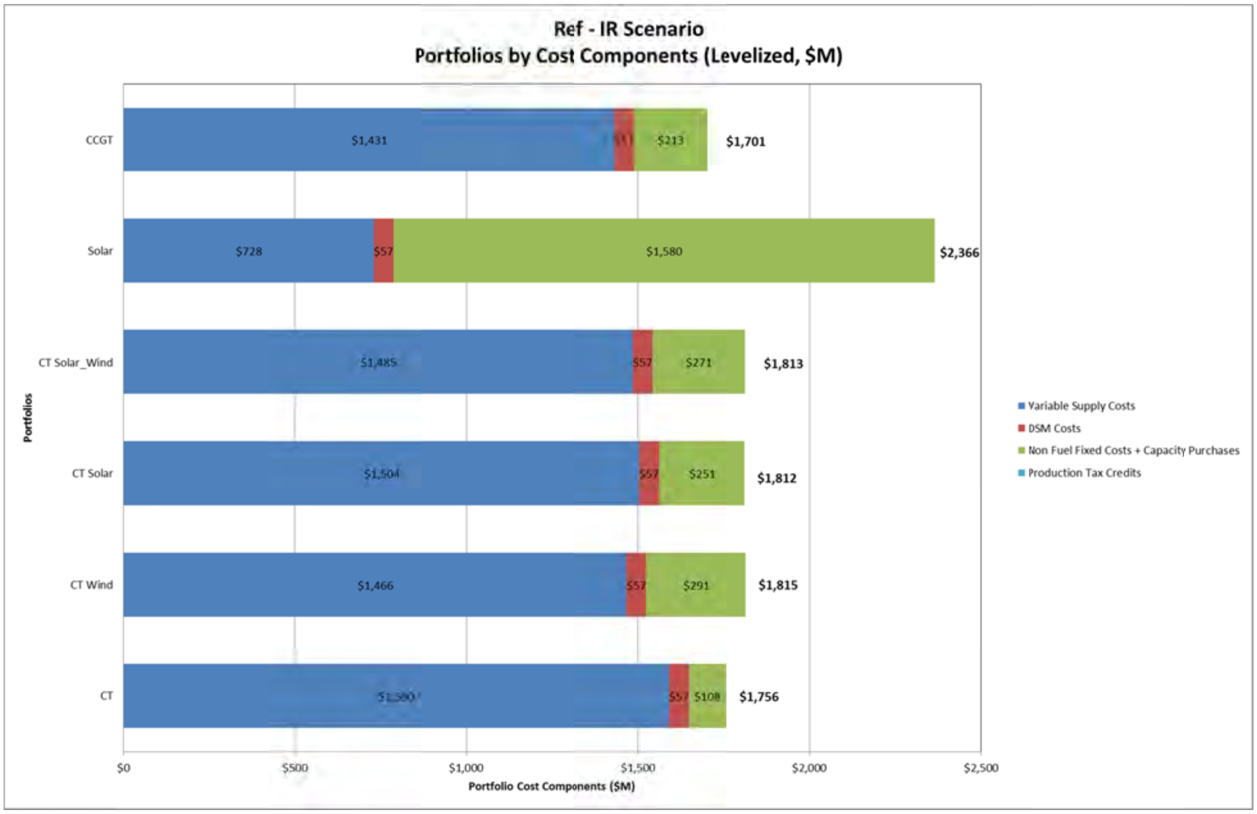


Figure 23: Total Supply Costs Excluding Sunk Non-Fuel Fixed Costs in the Industrial Renaissance Scenario After September 18, 2015 Refresh



STAKEHOLDER INPUT CASE CHANGES

ENO also created a Stakeholder Input Case scenario using the assumptions outlined in Section 2. Once established, ENO ran six additional AURORA simulations for each of the portfolios derived from the same market modeling and manual portfolio design process established earlier in this report. Additional analysis was also done in the selection of DSM programs from the Potential Study. This analysis consisted of determining the optimal implementation year of three demand response programs based on dynamic pricing and load control as well as a trailing benefits assessment of programs initially shown not to breakeven. If the residual benefits of these programs that extended beyond the evaluation period resulted in the programs becoming cost effective, they were added to the portfolio. All six portfolios under the Stakeholder Input Case contain a total of 19 DSM programs listed in Table 25 below. More information on the DSM analysis can be found in the DSM supplement.

Table 24: Portfolio Design Mix – Installed Capacity

Design Mix – Installed Capacity						
	AURORA Capacity Expansion Portfolios		Alternative Portfolios			
	CCGT Portfolio	Solar Portfolio	CT Portfolio	CT/Solar Portfolio	CT/Wind Portfolio	CT/Wind/ Solar Portfolio
DSM Programs	19 Programs	19 Programs	19 Programs	19 Programs	19 Programs	19 Programs
CCGTs	450	0	0	0	0	0
CTs	0	0	250	250	250	250
Solar	0	1200	0	100	0	50
Wind	0	0	0	0	100	50

Table 25: Selected DSM Programs for All Portfolios under Stakeholder Input Case

Sector	Program Name	DSM Program #
Commercial	Commercial Prescriptive & Custom	DSM 1
Commercial	Retro Commissioning	DSM 4
Commercial	Commercial New Construction	DSM 5
Commercial	Data Center	DSM 6
Industrial	Machine Drive	DSM 7
Industrial	Process Heating	DSM 8
Industrial	Process Cooling and Refrigeration	DSM 9
Industrial	Facility HVAC	DSM 10
Industrial	Facility Lighting	DSM 11
Industrial	Other Process/Non-Process Use	DSM 12
Residential	Residential Lighting & Appliances	DSM 13
Residential	ENERGY STAR Air Conditioning	DSM 15
Residential	Efficient New Homes	DSM 18
Residential	Multifamily	DSM 19
Commercial	Non-Residential Dynamic Pricing	DSM 3
Residential	Direct Load Control	DSM 22
Residential	Dynamic Pricing	DSM 23
Residential	Water Heating	DSM 20
Residential	Pool Pump	DSM 21

Figure 24: Cumulative Load Reduction from All DSM Programs (MW)

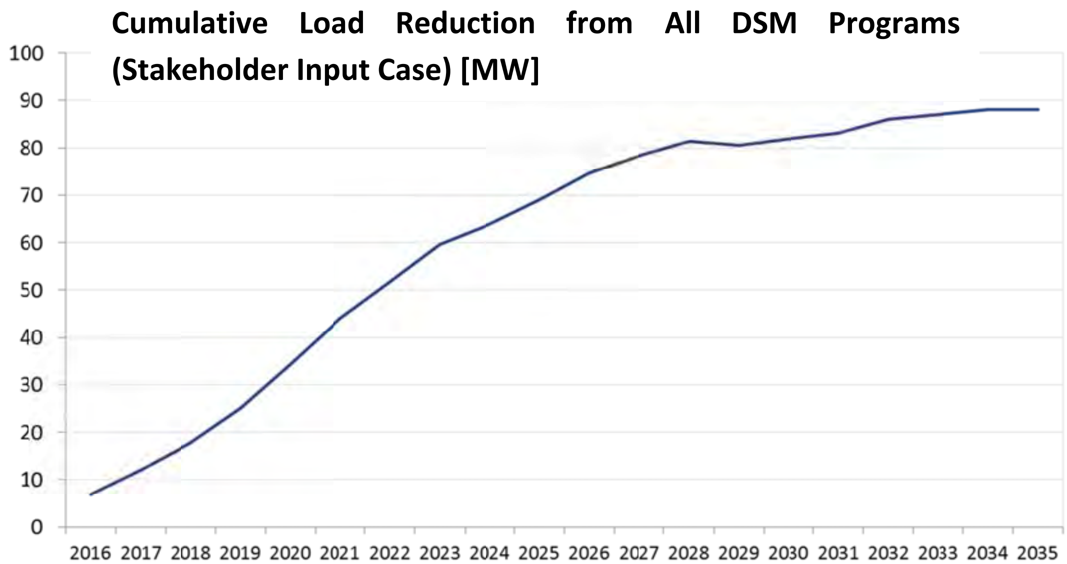


Figure 25: Stakeholder Input Case Scenario CT Portfolio

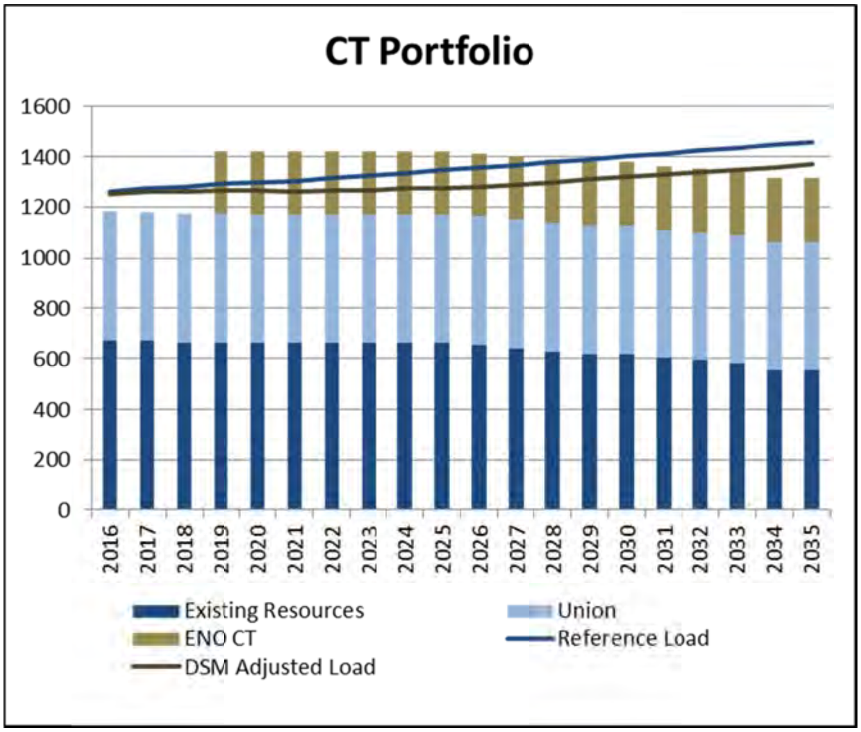


Figure 26: Stakeholder Input Case Scenario CT/Wind Portfolio

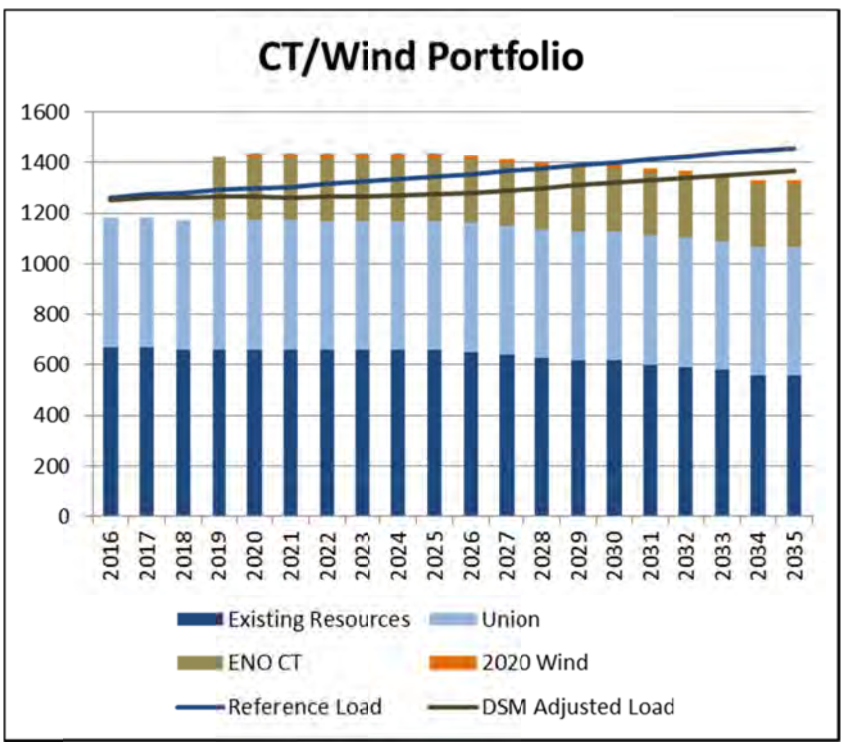


Figure 27: Stakeholder Input Case Scenario CT/Solar Portfolio

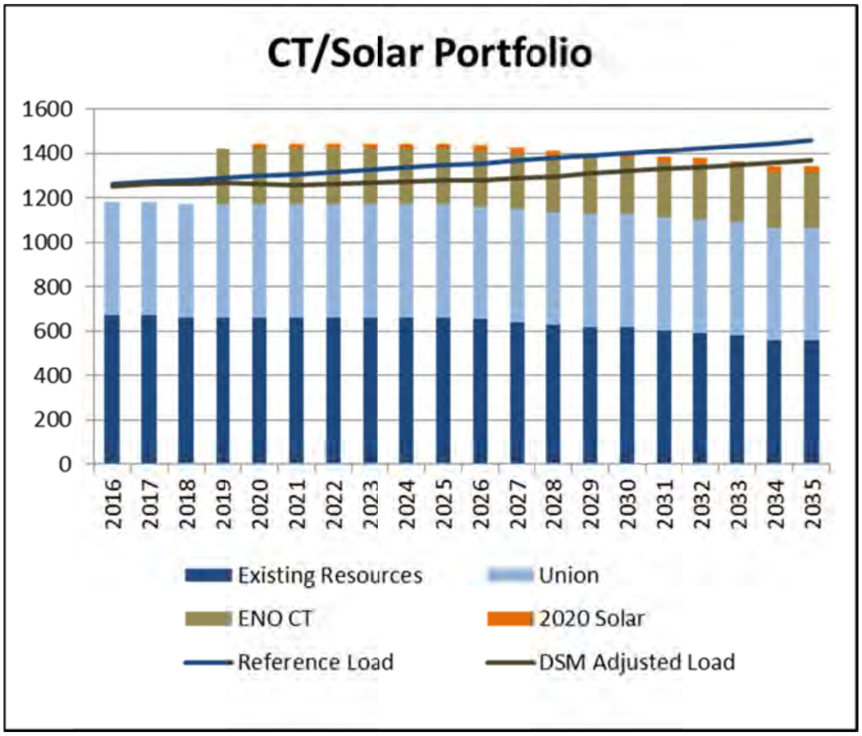


Figure 28: Stakeholder Input Case Scenario CT/Solar/Wind Portfolio

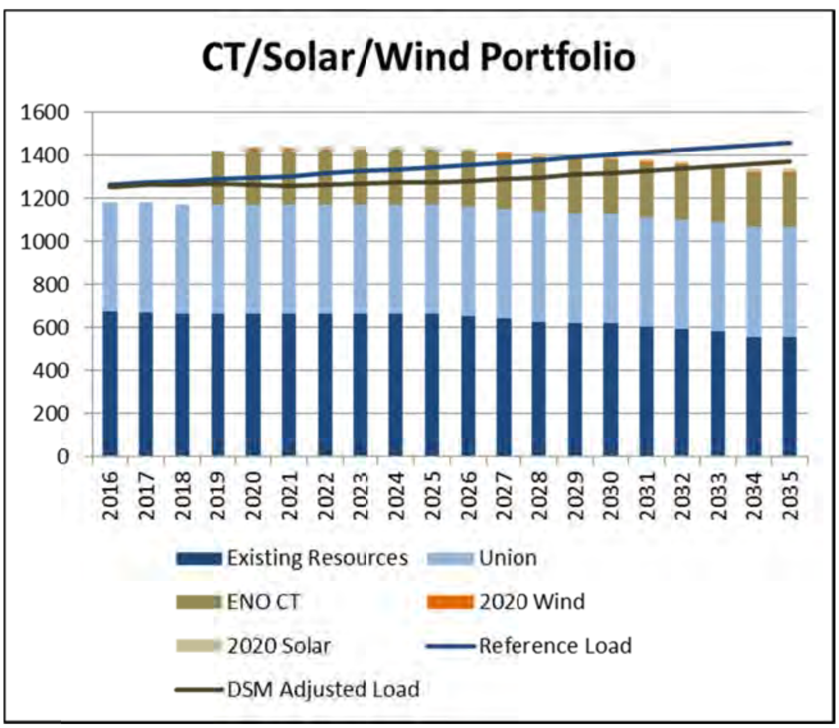


Figure 29: Stakeholder Input Case Scenario CCGT Portfolio

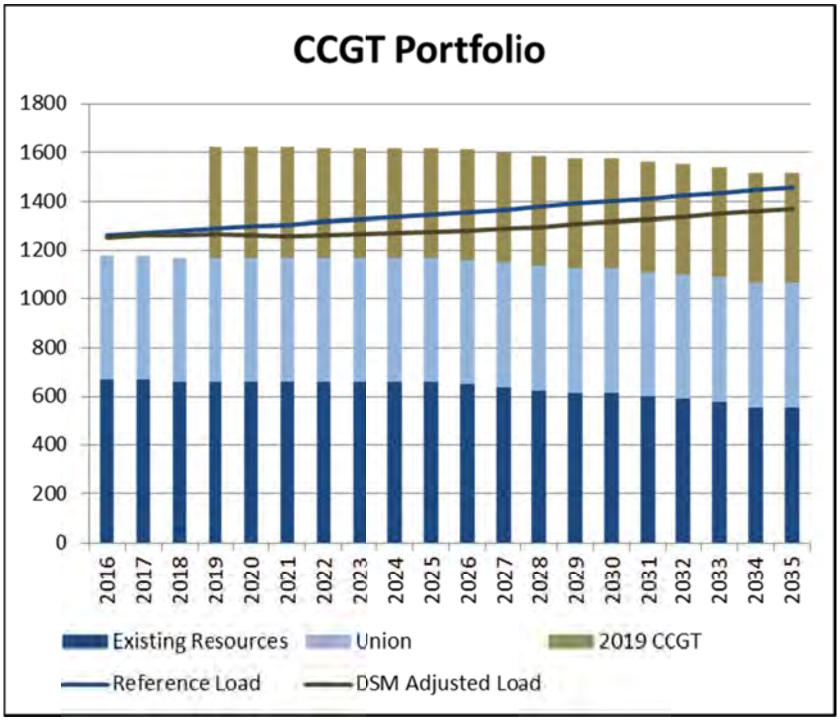


Figure 30: Stakeholder Input Case Scenario Solar Portfolio

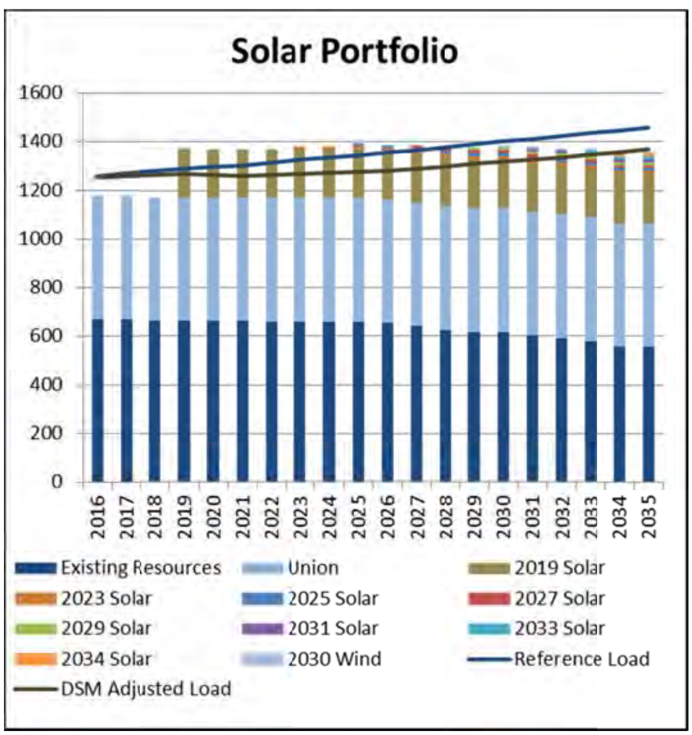


Figure 31 below shows the total supply costs of all six portfolios in the Stakeholder Input case. The CT portfolio is the least expensive while the Solar portfolio is the most expensive.

Figure 31: Total Supply Costs Excluding Sunk Non-Fuel Fixed Costs in the Stakeholder Input Case

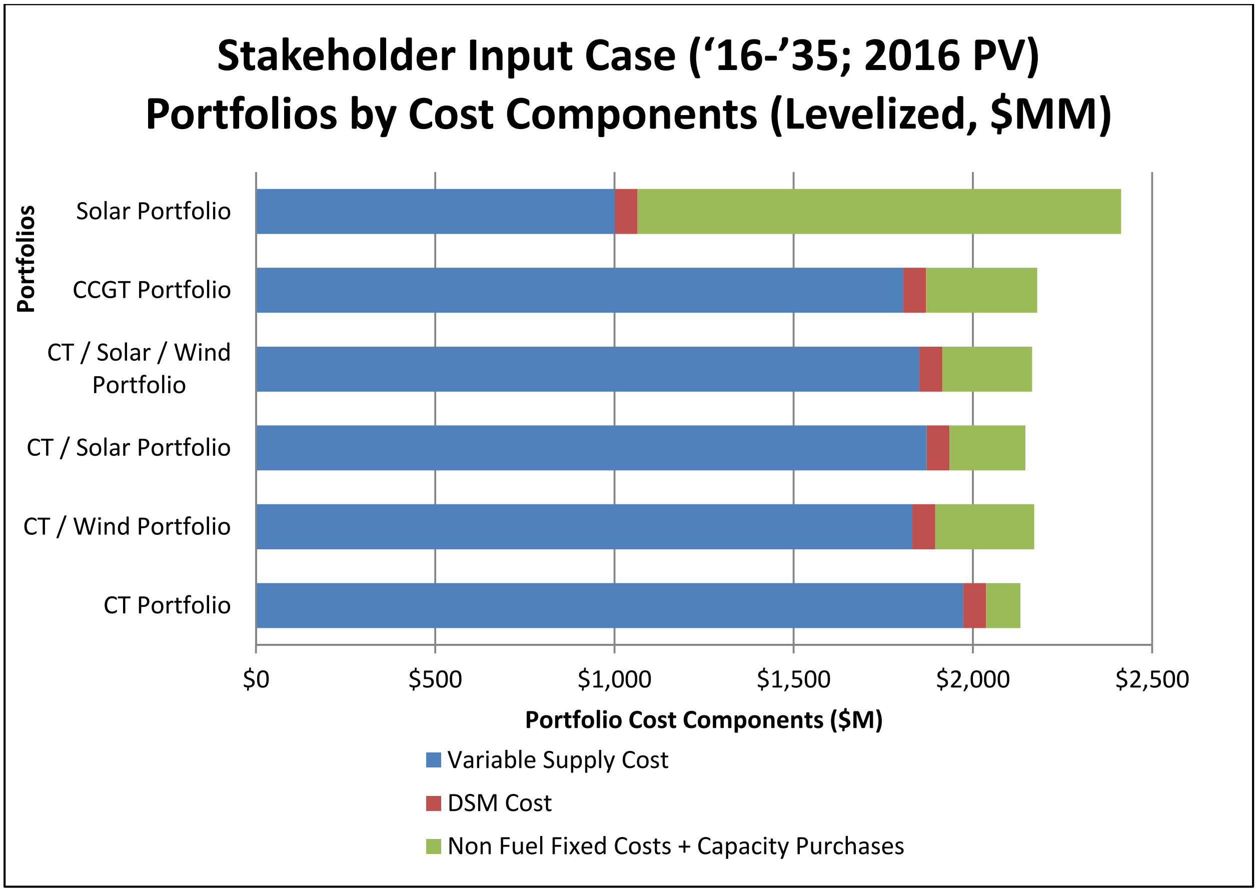


Table 26: Total Supply Cost Portfolio Rankings for Stakeholder Input Case

Total Supply Cost Portfolio Rankings for Stakeholder Input Case		
Portfolios	**Total Relevant Supply Cost Levelized Real ($MM)**	**Ranking**
Solar	$2,413	6
CCGT	$2,180	5
CT Solar_Wind	$2,165	3
CT Solar	$2,146	2
CT Wind	$2,171	4
CT	$2,132	1

Summary of Findings and Conclusions

In summary, ENO reached the following conclusions regarding portfolio design and analytics in the 2015 IRP that form the basis for development of the Preferred Portfolio:

- Supply-side economics were consistent with technology screening analysis.

- Some level of DSM was economic in every scenario.

- At prevailing installed costs as determined by independent third party expert analysis retained by ENO, renewables are not economic under most assumptions. Renewable resources depend on the confluence of high gas and carbon prices and the continuation of subsidies in order to be economic relative to CT and CCGT resources. Moreover, renewables do not provide a comparable amount of capacity as conventional forms of generation, further eroding their economics.

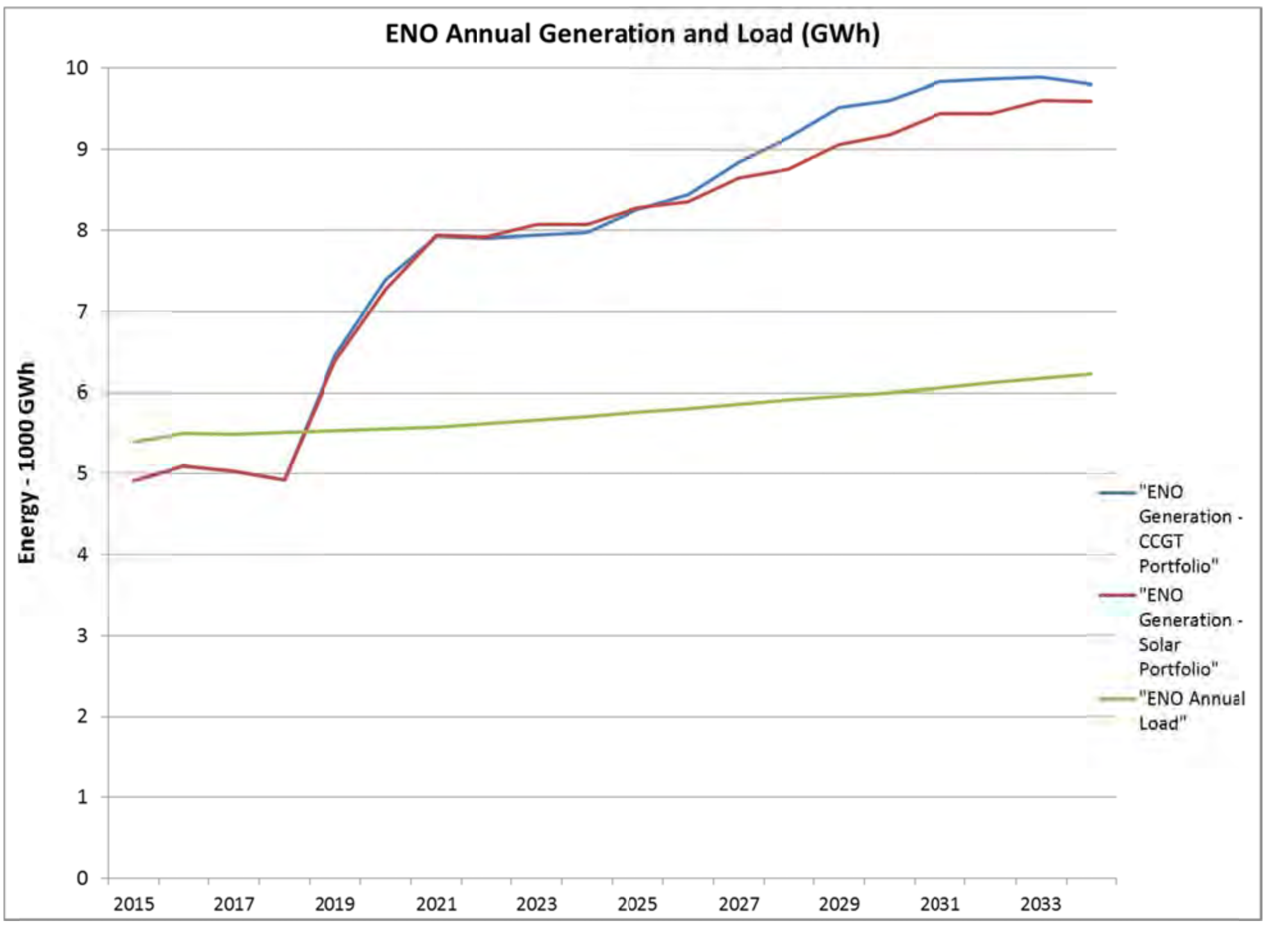
- The AURORA CCGT Portfolio performs well across most scenarios and ranks higher on a total cost basis than the other portfolios. However, ENO's existing portfolio is expected to have adequate Base Load and Core Load Following capacity following the addition of the Council approved Union resource. The CCGT Portfolio has more risk than the CT Portfolios because ENO does not need the energy expected to be produced by those resources, and because CCGT resources have higher fixed costs it would leave ENO and its customers dependent on uncertain potential variable cost savings in the MISO market.

- The CT Portfolio performs well in most scenarios and although it is not the lowest total supply cost portfolio, it has lower risk and is consistent with ENO's resource needs as compared to the other portfolios.

- As show in Figure 32 below, the CCGT portfolio (which is the lowest cost portfolio in the Industrial Renaissance, Business Boom, and Distributed Disruption Scenarios) and the Solar Portfolio (which is the lowest cost portfolio in the Generation Shift Scenario) results in an excess of energy generation in comparison to ENO's projected load requirements. A surplus of energy has a high degree of risk as it exposes ENO to a volatile energy market where it is uncertain that ENO will receive energy revenues sufficient to justify the higher fixed cost.

- In contrast, the CT portfolio presents less risk while providing good economic performance. The CT portfolio performed similarly to the CCGT portfolio in the sensitivity analyses, and its performance did not improve significantly with the addition of renewable technologies. Moreover, the CT has the lowest non-fuel fixed cost in comparison to the other portfolios as indicated in Figure 31.

Figure 32: ENO's Solar and CCGT Portfolios' Annual Generation vs. ENO's Annual Reference Load



SECTION 5: PREFERRED PORTFOLIO & ACTION PLAN

Preferred Portfolio

The IRP process resulted in the identification of a Preferred Portfolio that represents ENO's best available strategy for meeting customers' long-term power needs at the lowest reasonable supply cost, while considering reliability and risk. The Preferred Portfolio is based on the following assumptions:

- In order to reliably meet the power needs of customers at the lowest reasonable cost, ENO will maintain a portfolio of generation resources that includes the right amount and types of long-term capacity resources.

  - With respect to the amount of capacity, ENO must maintain sufficient generating capacity to meet its peak load plus a planning reserve margin. ENO will continue to plan to a 12% reserve margin.

  - With respect to the type of capacity, ENO's supply role needs include primarily peaking and reserve resources following planned additions such as the Council approved transaction to acquire the Union resource. As such, ENO seeks to add modern, proven and highly reliable CT resources consistent with those needs.

- ENO will continue to meet the bulk of its reliability requirements with either owned assets or long-term PPAs. The emphasis on long-term resources mitigates exposure to capacity price volatility and ensures the availability of resources sufficient to meet long-term resource needs.

- A portion of ENO's near-term resource needs may be met through a limited reliance on short-term power purchase products including zonal resource credits available through the MISO capacity market; to the extent these are economically available in consideration of risk.

- Some level of DSM is considered economically attractive over the long-term, but DSM presents ratemaking and policy issues that must be addressed in connection with the adoption of such programs. A variety of factors, many of which are highly uncertain, will affect the amount of DSM that can and will be achieved over the planning horizon.

Table 27: ENO Preferred Portfolio of DSM Programs

Sector	Program Name	DSM Program #
Commercial	Commercial Prescriptive & Custom	DSM 1
Commercial	Retro Commissioning	DSM 4
Commercial	Commercial New Construction	DSM 5
Commercial	Data Center	DSM 6
Industrial	Machine Drive	DSM 7
Industrial	Process Heating	DSM 8
Industrial	Process Cooling and Refrigeration	DSM 9
Industrial	Facility HVAC	DSM 10
Industrial	Facility Lighting	DSM 11
Industrial	Other Process/Non-Process Use	DSM 12
Residential	Residential Lighting & Appliances	DSM 13
Residential	ENERGY STAR Air Conditioning	DSM 15
Residential	Efficient New Homes	DSM 18
Residential	Multifamily	DSM 19
Commercial	Non-Residential Dynamic Pricing	DSM 3
Residential	Direct Load Control	DSM 22
Residential	Dynamic Pricing	DSM 23
Residential	Water Heating	DSM 20
Residential	Pool Pump	DSM 21

- All nuclear units are assumed to receive license extensions from the Nuclear Regulatory Commission ("NRC") to operate up to 60 years.

- New build capacity, when needed in 2019 and beyond, comes from new CT resources. New build capacity may be obtained through owned resources or long-term power purchase contracts. For the purpose of preparing the IRP, the economics were assumed to be equivalent.

- No new solid fuel or new nuclear capacity is added.

- While renewable resources were not selected as economically attractive relative to conventional gas turbine technology to meet ENO's projected resource needs, ENO is committed to continuing to study and evaluate energy resources that make sense for its customers. Case in point, ENO recently announced plans to conduct a 1 MW solar pilot project that will include utility scale solar generation integrated with battery storage technology. The project is estimated to be in service in mid-2016. Additionally, ENO will conduct an RFP for up to 20 MW of renewable resources to determine the most up to date and accurate state of the market.

The Preferred Portfolio shown in Table 28 includes assumptions regarding future resource additions, such as the Union Power acquisition recently approved by the Council, as well as assumptions regarding implementation of cost-effective DSM programs beyond the programs recently approved by the Council for years 5 and 6 of Energy Smart. The actual resources deployed (including the amount and timing of technology and power purchase products) and DSM implemented, 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 (magnitude and timing), 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

There are two overarching points to consider when reviewing the Preferred Portfolio. First, the decision to procure a given resource will be contingent upon a review of available alternatives at that time, including the economics of any viable transmission alternatives available that would be coupled with a purchase of capacity and/or energy. 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, and the time required for obtaining regulatory approvals. By deferring specific resource decisions until deployment is needed, ENO retains the flexibility to respond to changes in circumstance up to the time that a commitment is made.

Second, a variety of factors, many of which are highly uncertain, will affect the amount of DSM that can and will be implemented over the planning horizon. DSM assumptions, including the level of cost-effective DSM identified through the IRP process, are not intended as definitive commitments to particular programs, program levels or program timing. The implementation of cost-effective DSM requires consistent, sustained regulatory support and approval. ENO's investment in DSM must be supported by a reasonable opportunity to timely recover all of the costs, including lost contribution to fixed cost, associated with those programs. It is important that appropriate mechanisms 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 opportunity to recover lost contributions to fixed cost and earn performance-based incentives.

Table 28: ENO Preferred Portfolio Stakeholder Input Case--Load & Capability 2015-2035 (All values in MW)

Load & Capability 2016—2035																				
	2016	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
Requirements																				
Peak Load	1,125	1,136	1,143	1,153	1,159	1,163	1,175	1,183	1,193	1,201	1,209	1,220	1,230	1,241	1,251	1,261	1,271	1,281	1,291	1,301
Reserve Margin (12%)	135	136	137	138	139	140	141	142	143	144	145	146	148	149	150	151	153	154	155	156
Total Requirements	1,260	1,273	1,280	1,291	1,298	1,303	1,316	1,325	1,336	1,345	1,355	1,366	1,378	1,390	1,401	1,412	1,424	1,435	1,446	1,457
Resources																				
Existing Resources																				
Owned Resources	642	642	642	642	642	642	641	641	641	641	633	621	608	598	598	585	575	562	539	539
PPA Contracts	11	11	2	2	2	2	2	2	2	2	2	2	2	2	2	-	-	-	-	-
LMRs	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17
Identified Planned Resources																				
Union[43]	510	510	510	510	510	510	510	510	510	510	510	510	510	510	510	510	510	510	510	510
Other Planned Resources																				46
DSM[44]	7	12	18	25	34	44	52	60	64	69	75	78	81	80	82	83	86	87	88	88
CT	-	-	-	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250
Market Purchases (Sales)	73	80	91	(156)	(158)	(162)	(156)	(154)	(148)	(144)	(133)	(112)	(90)	(67)	(58)	(33)	(15)	9	42	53
Total Resources	1,260	1,273	1,280	1,291	1,298	1,303	1,316	1,325	1,336	1,345	1,355	1,366	1,378	1,390	1,401	1,412	1,424	1,435	1,446	1,457

[43] Union plant acquisition is completed pending regulatory approvals.
[44] Demand Side Management (DSM) total is grossed up for Planning Reserve Margin (12%) and transmission losses (2.4%).

Rate Effects

The estimated typical bill effects associated with the cost to meet customer's needs through the Preferred Portfolio over the next two decades are modest. 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 (reflected in the last column in Table 29) during the IRP planning horizon are expected to grow below inflation expectations.

Table 29: ENO Average Residential Customer Electric Bill (Preferred Portfolio)[45]

Projected ENO Residential Customer Bill and Energy Usage				
Customer Segment	Actual 2014 Usage (KWh/mo.)	Actual 2014 Average Monthly Bill	Projected 2035 Usage (KWh/mo.)	Projected 2035 Average Monthly bill
Residential (Legacy)	1,081	$109	1,332	$147
Residential (Algiers)	_	_	1,561	$149

Table 30: Rate Effects – ENO Preferred Portfolio[46]

Projected ENO Average Monthly Customer Bill				
Customer Segment	2016	2026	2035	CAGR[47]
Residential (Legacy)	$110	$127	$147	1.5%
Commercial (Legacy)	$1,095	$1,111	$1,135	0.2%
Industrial (Legacy)	$1,302	$1,151	$1,009	(-1.3%)
Government (Legacy)	$3,377	$3,815	$4,096	1.0%
Residential (Algiers)	$100	$132	$149	2.0 %
Commercial (Algiers)	$628	$836	$922	1.9%
Industrial (Algiers)	$234	$348	$406	2.8%
Government (Algiers)	$1,282	$1,775	$2,050	2.4%

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

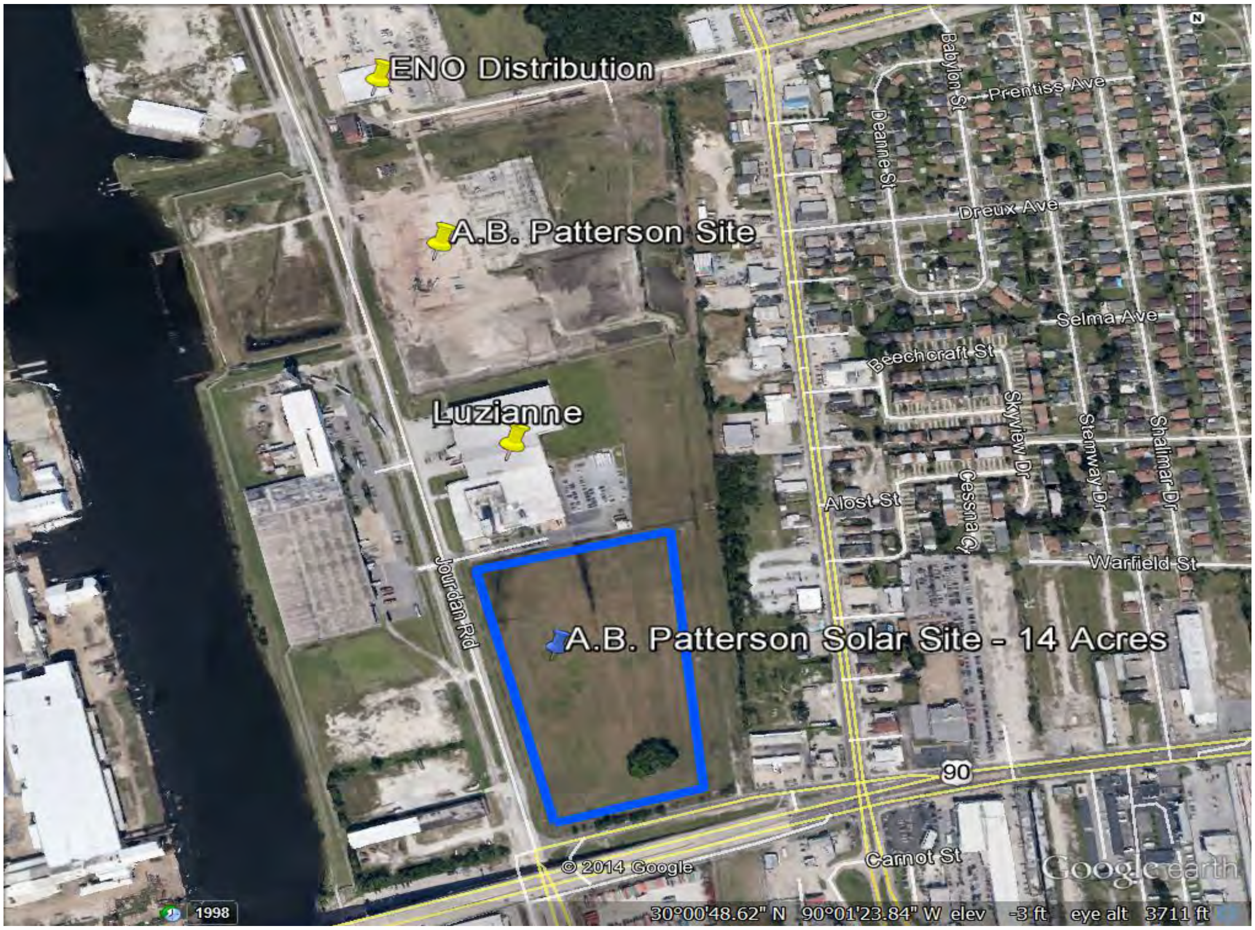
[46] The updated rate effects for the Preferred Portfolio are found in the Updated Assumptions Supplement.

[47] Compound Annual Growth Rate ("CAGR") measures the average annual rate of growth in typical customer bills over the planning horizon.

Solar Pilot

As previously mentioned in the Executive Summary, ENO plans to conduct a 1 MW solar storage pilot project that will integrate solar PV generation and battery storage technology. The pilot project will be constructed within ENO's service territory, specifically, on a plot of land in New Orleans East as shown in Figure 33 below.

Figure 33: Map of ENO Solar Pilot Project



The target in service date is summer 2016.

Stakeholder Input Case

In response to stakeholder and Advisor concerns regarding dated assumptions used in the draft IRP, ENO agreed to perform additional production cost analysis using updated assumptions in support of the Final ENO 2015 IRP. Throughout the IRP process, ENO attempted to the balance the time required to run analysis and move through the IRP process with using the best available information. Notwithstanding, ENO requested more time to run updated cases and thus updated many assumptions based on stakeholder and Advisor concerns. Once the

Stakeholder Input Case was established, ENO ran six additional AURORA simulations for each of the portfolios previously evaluated in the draft IRP. ENO added carbon to the Reference Case and found that there was no significant change in the results. ENO also updated the natural gas assumptions and installed solar cost assumptions in the Stakeholder Input Case. These updates, and the subsequent results of the analysis, substantiated the results of the Draft IRP. The CT Portfolio has the lowest total supply cost in the Stakeholder Input Case.

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 31 below. As discussed above, ENO's projected near-term resource needs create both challenges and opportunities. Planning to address these challenges is already underway as outlined in the 2015 IRP; however, additional steps are necessary to ensure those resources are implemented in a timely and cost-effective manner. The ENO 2015 Preferred Portfolio will modernize ENO's generating fleet, contribute to ENO's long term resource needs and facilitate investment in regional generation, transmission and distribution resources to ensure ENO is capable of continuing to provide safe and reliable service to its customers at the lowest reasonable cost. 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.

Recap: 2012 Action Plan

Table 29: Recap of 2012 Action Plan

<table>
<tr><th>Category</th><th>Action to be taken</th></tr>
<tr><td>Supply-side Alternatives</td><td>➢ Continue to take steps necessary to support new generation in DSG to support eventual deactivation of aging fleet.
➢ Evaluate costs and benefits of investing in existing resources in order to support reliable operation beyond deactivation date.</td></tr>
<tr><td colspan="2"><u>2015 Update</u>
➢ Completed PPA with Entergy Louisiana for a share of Ninemile 6.
➢ Conducted an economic analysis comparing the cost of extending the life of Michoud Units 2 and 3 to deactivating each unit and deploying new resources.
➢ Submitted an Attachment Y request to MISO to study the impact on the transmission system associated with deactivation of Units 2 and 3.</td></tr>
<tr><td>Demand-side Alternatives</td><td>➢ Develop program and implementation plan for next phase of DSM for New Orleans.</td></tr>
</table>

	➢ File plan with the Council by March 31, 2013 ➢ Implement programs beginning April 1, 2014
<u>2015 Update</u> ➢ The first phase of EnergySmart programs were extended until March 31, 2015 ➢ The second phase of EnergySmart programs were implemented on April 1, 2015	
MISO Transition	➢ Monitor MISO's resource adequacy requirements as the Entergy System integration process moves forward. ➢ Conduct evaluation of MISO baseload hedging entitlements and impact on production costs.
<u>2015 Update</u> ➢ Filed first Post Integration Annual Monitoring report as required by the Council on May 11, 2015 ➢ Completed evaluation of the adequacy of ENO's baseload hedging entitlements	
Area Planning	➢ Refine supply plan based on experience in MISO. ➢ Integrate MISO's MTEP into the IRP planning process.
<u>2015 Update</u> Completed integration of experience in MISO, including MTEP, into 2015 IRP	

Table 30: ENO 2015 Action Plan

Category	Action to be taken
Deactivation of Michoud Units 2 and 3	➢ Confirmed Attachment Y deactivation request complete for Michoud 2and 3 pursuant to the MISO tariff. ➢ Units 2 and 3 will be deactivated June 1, 2016 subject to completion of necessary transmission upgrades as required by Attachment Y
Union Power Station	➢ Obtained council approval on November 19, 2015 for ENO purchase of Union Power Block 1 ➢ Transaction scheduled to close in early 2016
ENO Solar Pilot	➢ Construction to begin 1st quarter 2016 ➢ Target in service date Summer 2016
In-region Peaking Generation	➢ Continue development activities and finalize preliminary design and site location ➢ File for Council approval in a timely manner ➢ Target 2019 in service date
Clean Power Plan	➢ Continue to monitor pending litigation of the rule and the status of Louisiana Department of Environmental Quality plan to comply

DSM	➢ Continue implementation and performance monitoring of Council approved programs for EnergySmart Years 5 and 6 through March 2017
Resource Needs	➢ Continue to monitor resource needs (load, customer count, net metering, resource deactivations) and adjust near-term action items plan accordingly
Renewable RFP	➢ Conduct a Renewable RFP to obtain actionable information on the cost and deliverability of renewable resources
Distributed Generation	➢ Evaluate alternative methods for the treatment of DG in the integrated resource planning process for opportunities for improvement
AMI	➢ Entergy is currently considering various future investments to modernize the distribution grid and more fully utilize new technologies ➢ AMI continues to be analyzed and ENO plans to talk further with the City Council and the Advisors regarding potential future AMI investments

REQUEST FOR QUALIFICATIONS STATEMENTS

FOR

DEMAND SIDE MANAGEMENT CONSULTANT

ISSUED SEPTEMBER 15, 2017

APPENDIX VIII

ENERGY SMART PROGRAM YEARS 7-9

APPROVED BUDGET AND SAVINGS

Entergy New Orleans, Inc. Energy Smart
Pro-Rated Total Budget for Program Years 7-9

April 1, 2107 - December 21, 2017	EM&V	Administration	Implementation	Non-Incentive	Incentive	Total	kWh	kW
Small C&I	$60,739	$32,632	$408,337	$501,707	$432,735	$934,442	2,826,269	560.2
Large C&I	$143,198	$65,990	$825,771	$1,034,958	$1,168,081	$2,203,039	9,401,126	1,391.6
Publicly Funded Institutions	$19,226	$14,153	$177,102	$210,481	$85,305	$295,786	658,899	97.7
Home Performance with Energy Star	$39,991	$34,939	$231,669	$306,599	$308,648	$615,247	1,265,269	268.0
Residential Lighting & Appliances	$42,025	$18,300	$118,006	$178,331	$468,209	$646,540	3,872,885	652.1
Green Light New Orleans	$1,955	$0	$0	$1,955	$28,125	$30,080	199,125	32.7
Energy Smart for Multi-Family	$9,260	$5,409	$43,022	$57,692	$84,777	$142,468	297,474	59.1
Low Income Audit & Wx	$52,042	$57,769	$352,928	$462,739	$337,912	$800,651	1,064,655	232.7
School Kits & Education	$24,130	$21,911	$274,188	$320,229	$51,000	$371,229	292,993	39.9
High Efficiency Tune Up	$15,862	$17,682	$110,283	$143,827	$100,200	$244,027	622,470	178.6
Behavioral	$12,777	$13,601	$170,194	$196,572	$0	$196,572	0	0.0
Direct Load Control	$39,255	$61,557	$448,123	$548,935	$55,000	$603,935	0	892.1
Energy Smart Programs Total	$460,461	$343,943	$3,159,621	$3,964,025	$3,119,991	$7,084,016	20,501,165	4,404.7
Utility Lost Contribution of Fixed Costs						$0		
Utility Performance Incentive						$397,500		
Overall Total						$7,481,516		

January 1, 2018 - December 31, 2018	EM&V	Administration	Implementation	Non-Incentive	Incentive	Total	kWh	kW
Small C&I	$121,601	$45,391	$567,999	$734,991	$1,135,794	$1,870,785	5,796,034	1,169.1
Large C&I	$330,709	$116,139	$1,453,307	$1,900,155	$3,187,674	$5,087,828	21,312,583	3,177.6
Publicly Funded Institutions	$52,923	$23,070	$288,691	$364,684	$449,520	$814,205	2,816,753	433.0
Home Performance with Energy Star	$66,382	$42,907	$282,253	$391,542	$629,724	$1,021,266	2,577,411	545.7
Residential Lighting & Appliances	$42,811	$22,286	$141,346	$206,443	$452,186	$658,629	4,106,839	729.4
Green Light New Orleans	$2,607	$0	$0	$2,607	$37,500	$40,107	265,500	43.6
Energy Smart for Multi-Family	$14,118	$6,330	$48,637	$69,085	$148,119	$217,204	514,029	102.5
Low Income Audit & Wx	$65,540	$70,541	$424,309	$560,390	$447,916	$1,008,306	1,409,557	308.4
School Kits & Education	$34,942	$28,388	$355,234	$418,564	$119,000	$537,564	683,478	93.0
High Efficiency Tune Up	$24,568	$21,486	$131,342	$177,396	$200,575	$377,971	1,235,976	355.1
Behavioral	$22,715	$24,179	$302,568	$349,462	$0	$349,462	5,000,000	4,250.0
Direct Load Control	$54,651	$79,146	$586,992	$720,789	$120,000	$840,789	0	1,189.5
Energy Smart Programs Total	$833,568	$479,863	$4,582,678	$5,896,109	$6,928,008	$12,824,116	45,718,160	12,397.0
Utility Lost Contribution of Fixed Costs						$0		
Utility Performance Incentive						$530,000		
Overall Total						$13,354,116		

January 1, 2019 - December 31, 2019	EM&V	Administration	Implementation	Non-Incentive	Incentive	Total	kWh	kW
Small C&I	$131,404	$48,674	$609,088	$789,166	$1,232,441	$2,021,607	6,287,537	1,262.4
Large C&I	$385,538	$131,813	$1,649,440	$2,166,791	$3,764,559	$5,931,349	25,004,401	3,683.8
Publicly Funded Institutions	$65,965	$32,791	$410,334	$509,090	$505,762	$1,014,852	3,173,822	487.0
Home Performance with Energy Star	$90,516	$48,705	$321,369	$460,590	$931,958	$1,392,548	3,811,980	806.4
Residential Lighting & Appliances	$39,541	$25,509	$163,634	$228,684	$379,642	$608,326	3,092,109	608.8
Energy Smart for Multi-Family	$20,217	$7,383	$57,814	$85,414	$225,623	$311,038	783,889	156.1
Low Income Audit & Wx	$70,362	$80,126	$484,092	$634,580	$447,916	$1,082,496	1,409,557	308.4
School Kits & Education	$34,942	$28,388	$355,234	$418,564	$119,000	$537,564	683,478	93.0
High Efficiency Tune Up	$31,103	$24,470	$150,628	$206,201	$272,300	$478,501	1,677,118	477.8
Behavioral	$22,715	$24,179	$302,568	$349,462	$0	$349,462	8,000,000	6,800.0
Direct Load Control	$59,679	$82,081	$604,380	$746,140	$172,000	$918,140	0	1,189.5
Energy Smart Programs Total	$951,982	$534,118	$5,108,582	$6,594,682	$8,051,201	$14,645,883	53,923,891	15,873.2
Utility Lost Contribution of Fixed Costs						$0		
Utility Performance Incentive						$530,000		
Overall Total						$15,175,883		

REQUEST FOR QUALIFICATIONS STATEMENTS

FOR

DEMAND SIDE MANAGEMENT CONSULTANT

ISSUED SEPTEMBER 15, 2017

APPENDIX IX

ENTERGY NEW ORLEANS' 2015

DSM POTENTIAL STUDY REPORT

Long-Term Demand Side Management Potential in the Entergy New Orleans Service Area

DRAFT Report

June, 23, 2015

Submitted to:
Entergy Services, Inc.
Entergy New Orleans

Prepared by:
ICF International
9300 Lee Highway
Fairfax, VA 22031

13-034

Executive Summary

This report summarizes the results of a demand side management (DSM) potential analysis (Potential Study) conducted by ICF International for Entergy Services, Inc. (ESI) and Entergy New Orleans (ENO). The objectives of the analysis were: (1)To develop high-level, long-run **achievable electric DSM program potential estimates** appropriate for inclusion in ESI's Integrated Resource Planning (IRP) analysis of the ENO service area, and; (2) To develop **achievable gas DSM program potential estimates** consistent with New Orleans City Council requirements, and for consideration by ENO in long-term DSM program strategy.

Consistent with IRP requirements, this Potential Study includes forecasts covering a **20-year planning horizon (2015-2034)**. ESI's System Planning and Operations group's (SPO) primary requirements from the Potential Study were hourly **electric loadshapes and program cost projections** representing **three levels—low, reference, and high—of achievable DSM program savings** from 2015 through 2034. These load shapes and costs are the demand side inputs into their IRP analysis. The outputs of the gas study include **gas savings forecasts**, **program costs**, and **cost-effectiveness estimates**.

The long-run planning nature of the Potential Study means that **the estimates 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. Program plans require a different level of attention to program design, costs, delivery mechanisms, measure mix, participation, regulatory guidelines, rate impacts, and other factors.

Note also that the characterization of ICF's achievable potential forecast in this report does not represent how SPO utilized the data for the purposes of the IRP, nor are the loadshapes produced for SPO included in this report.

Approach Summary

ICF used a bottom-up approach to estimate DSM potential. "Bottom-up," in the context of achievable potential studies, refers to an analytical approach that begins with characterizing the market size, or eligible stock of efficiency measures, screening measures for cost-effectiveness, forecasting savings for those measures first at the measure-level, then summing savings to the program, and service area levels.

It was assumed that programs with gas measures would be operated jointly with electric programs. That is, we assumed there would be no stand alone gas programs. This is because there were not any cost-effective gas measures that required the creation of new programs, and because gas savings potential is too small in scale to operate gas programs independently of electric programs.

Types of Potential Estimated

For ESI's and ENO's purposes it was necessary only to estimate **achievable potential**, which is **the level of cost-effective net DSM savings estimated to be reasonably achievable through utility-administered programs in the course of the planning horizon**. Achievable program potential estimates are a function of baseline energy use, energy costs, current levels of efficiency measure market saturation, program inventive levels, program market barriers, and other factors.

Technical and economic potential were not estimated. Technical potential is the estimated level of efficiency savings that could technically be achieved without consideration of economics, customer behavior, and other barriers. Technical potential assumes that customers adopt all of the most energy efficient measures regardless of cost or other market barriers. Economic potential is the cost-effective subset of technical potential. Economic potential assumes that all customers will purchase the most cost-effective measures available regardless of market barriers. Technical and economic potential estimates are theoretical and therefore not suitable for use in this study since they do not reflect the level of DSM that could actually be achieved through utility programs.

Scenarios

Achievable energy efficiency potential was forecasted under three scenarios, which are defined below. ICF first developed the reference case estimates by measure for each program. Then, the high and low case scenarios were developed around the reference case.

- **Reference case potential**. The realistic level of cost-effective savings that could be achieved by utility programs given the best information available at the time of the Potential Study. Incentive levels are generally between 25% and 75% of incremental cost, with the exception of hard-to-reach markets, e.g., small business, where incentives need to be different.
- **High case potential**. The level of cost-effective savings that could be achieved by utility programs at maximum incentive levels. Incentive levels were set to 100% of incremental costs where possible.
- **Low case potential**. The level of cost-effective savings that could be achieved at lower incentive levels. In most cases incentives were capped at 25%.

Uncertainty

DSM potential studies are forecasts, and all forecasts have forecast error, or uncertainty. This Study includes thousands of assumptions, including baseline data, measure parameters, avoided costs, program assumptions, and other inputs. While it is impossible to eliminate uncertainty, it can be mitigated through certain analytical strategies. The most basic strategy is to use the best information available at the time of the analysis. Where possible, this Study used data specific to the ENO service area. Where service area- specific data was unavailable, ICF used the most accurate proxy data available, such as Louisiana-specific data or data specific to the Southern region.

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Another basic strategy is to use a bottom-up approach such as the one employed in this Study. Using a bottom-up approach ensures that the market size for efficiency measures is accounted for in developing the forecast. In addition, ICF program managers developed participation estimates at the measure level; these were then aggregated to the program and service area levels. By not using a single, formulaic approach to forecasting all measures, we ensured that baselines changes and market barriers applicable to specific measures were not washed-out in the analysis. Finally, benchmarking data on program performance in other jurisdictions was used, where possible, to help gauge the reasonableness of the estimates.

Energy Efficiency Potential

Figure 1, below, provides an overall summary of this Study's electric forecast including GWh and MW savings, savings impacts, costs, benefits, and cost-effectiveness.

Figure 2 provides similar outputs for gas programs. To review the electric forecast:

- ICF estimates that, in the reference case, **ENO can achieve cost-effective cumulative electric savings equal to 6.1% of load over the 2015 to 2034 time horizon**. Total program **costs** over this 20-year period are estimated to **equal $111 Million**.[1] Total **net benefits** are estimated to equal **$100 Million**.
- In the high case, we estimate that ENO could achieve an additional 223 GWh in savings for an additional $28 Million in program spending beyond the reference case. That is, in the high case, savings would increase 59% over reference case levels while spending would increase 25%.
- In the low case, ICF estimates that ENO would achieve 35% less savings than in the reference case, while costs would decrease 17% compared to the reference case.

To review the gas forecast:

- ICF estimates that, in the reference case, **ENO can achieve cost-effective cumulative gas savings equal to 0.5% of sales over the 2015 to 2034 time horizon**. Total program **costs** over this 20-year period are estimated to equal **$9 Million**.[2] Total **net benefits** are estimated to equal **$24 Million**.
- In the high case, we estimate that ENO could achieve an additional 705,876 therms in savings for an additional $8 Million in program spending beyond the reference case. That is, in the high case, savings would increase 211% over reference case levels while spending would increase 189%.
- In the low case, ICF estimates that ENO would achieve 27% less savings than in the reference case, while costs would decrease 56% compared to the reference case.

[1] Including program incentive and non-incentive costs.
[2] Including program incentive and non-incentive costs.

Combined benefits and costs of all electric and gas programs are shown Figure 3.[3]

A key take-away from the gas analysis is that there is insufficient cost-effective gas potential for ENO to run "gas only" programs - the market size is simply too small. This does not mean cost-effective gas measures should not be considered by ENO, but that they should be included in programs that would be combined electric and gas offerings.

One of the most important things to take in account when reviewing the estimates in this report is that program costs and savings of historical programs, particularly from jurisdictions dissimilar to ENO, cannot be compared on an apples-to-apples basis to the long-run costs and savings forecasted for ENO. This is mainly because minimum efficiency standards for equipment and buildings have improved, significantly in some cases. For example, minimum efficiency standards for the most common light bulbs will require such bulbs to be 60% to 70% more efficient in 2020 than they were in 2012. This and other adopted minimum efficiency standards for lighting, appliances, and new buildings mean that future programs will achieve lower savings levels, and at higher costs, than comparable programs in the past, all else equal.

Figure 1. Total Electric Savings, Savings Impacts, Benefits, Costs and Costs-Effectiveness

Scenario	Cumula-tive GWh Savings (2015-2034)	Cumula-tive GWh Savings as % of Sales	Cumula-tive MW Savings (2015-2034)	Cumula-tive MW Savings as % of Peak[4]	Total TRC Benefits, 2015-2034 ($Mil.)	Total TRC Costs, 2015-2034 ($Mil.)[5]	Net TRC Benefits, 2015-2034 ($Mil.)[6]	TRC B/C Ratio	Total Pro-gram Costs, 2015-2034 ($Mil.)[7]	Level-ized Cost per kWh[8]
Low	246	3.9%	69	5.9%	$182	$124	$58	1.5	$92	$0.05
Reference	378	6.1%	112	9.6%	$293	$193	$100	1.5	$111	$0.06
High	601	10.0%	168	14.5%	$790	$463	$320	1.7	$139	$0.09

[3] Includes benefits and costs of all programs, not just the ten programs noted in Section 5 that include electric and gas measures, but also the benefits and costs of the eight additional programs that include only electric measures.

[4] Forecasted non-coincident peak demand.

[5] TRC (Total Resource Cost) test costs include total measure incremental costs and program non-incentive costs over the time horizon of the forecast (2015-2034).

[6] TRC (Total Resource Cost) test benefits include total electric generation (kWh), capacity (kW), and gas (therm) costs avoided over the time horizon of the forecast (2015-2034).

[7] Program costs include incentive costs and non-incentive costs (e.g., administration, marketing, etc.).

[8] Id.

Figure 2. Total Gas Savings, Savings Impacts, Benefits, Costs and Costs-Effectiveness

Scenario	Cumulative Therm Savings (2015-2034)	Cumulative Therm Savings as % of Sales	Total TRC Benefits, 2015-2034 ($Mil.)	Total TRC Costs, 2015-2034 ($Mil.)[9]	Net TRC Benefits, 2015-2034 ($Mil.)[10]	TRC B/C Ratio	Total Pro-gram Costs, 2015-2034 ($Mil.)[11]	Level-ized Cost per Therm
Low	462,039	0.4%	$19	$5	$14	3.7	$4	$0.71
Reference	634,173	0.5%	$31	$6	$24	4.9	$9	$1.16
High	1,340,048	1.1%	$51	$17	$35	3.1	$17	$1.08

Figure 3. Combined Electric and Gas Benefits and Costs for All Programs

Scenario	Total TRC Benefits, 2015-2034 ($Mil.)	Total TRC Costs, 2015-2034 ($Mil.)	Net TRC Benefits, 2015-2034 ($Mil.)	TRC B/C Ratio	Total Pro-gram Costs, 2015-2034 ($Mil.)
Low	$201	$129	$72	1.6	$96
Reference	$324	$199	$124	1.6	$120
High	$841	$480	$355	1.8	$156

Organization of the Remainder of the Report

Section 1 of this report describes ICF's approach to estimating achievable potential. Section 2 covers baseline energy use in the ENO service area, and Sections 3 and 4 cover the achievable potential forecasts for electricity and gas, respectively. Individual appendices are listed in Section 5, and the actual appendices are provided separately from this report.

[9] TRC (Total Resource Cost) test costs include total measure incremental costs and program non-incentive costs over the time horizon of the forecast (2015-2034).

[10] TRC (Total Resource Cost) test benefits include gas (therm) costs avoided over the time horizon of the forecast (2015-2034).

[11] Program costs include incentive costs and non-incentive costs (e.g., administration, marketing, etc.).

List of Acronyms

Acronym	Full Description
ACEEE	American Council for an Energy-Efficient Economy
AHRI	Air Conditioning Heating and Refrigeration Institute
CBECS	U.S. Department of Energy Commercial Buildings Energy Consumption Survey
CBI	Commercial Building Inventory
CHP	Combined heat and power
DOE	U.S. Department of Energy
DSM	Demand side management
EIA	U.S. Department of Energy, Energy Information Administration
ENO	Entergy New Orleans
EE	Energy efficiency
ESI	Entergy Services, Inc.
LBNL	Lawrence Berkeley National Laboratory
MECS	U.S. Department of Energy Manufacturing Energy Consumption Survey Consumption Survey
MISO	Midcontinent Independent System Operator
RASS	Residential Appliance Saturation Survey
RECS	U.S. Department of Energy Residential Energy Consumption Survey
SEER	Seasonal Energy Efficiency Ratio
SPO	System Planning and Operations
TRC	Total Resource Cost
TRM	Technical Resource Manual

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1 Analysis Approach

1.1 Overview of Approach

ICF used a bottom-up approach to estimate energy efficiency potential. The approach is illustrated in Figure 4. "Bottom-up," in the context of achievable potential studies, refers to an analytical approach that begins with characterizing the market size, or eligible stock of efficiency measures, screening measures for cost-effectiveness, forecasting savings for those measures first at the measure-level, then summing savings to the program, and service territory levels.

This analysis started with collecting data on all relevant inputs, including baseline data, measure data, and program data. Data types collected are itemized in Figure 5.

Estimating the eligible stock of efficiency options was the next step of the analysis. The eligible stock is the size of the market for efficiency measures, in measure units, such as bulbs, tons of cooling, or homes. ICF estimated the eligible stock for each measure within each end use and sector. This required data on the number on customer types in each service territory, the number and types of buildings, what types of energy using equipment are in each building type, and the current saturation of efficient equipment.

A comprehensive measure database was also developed in the first stages of the analysis. This database includes 228 measure types and 1,056 measures in total. Commercially available electric and gas measures covering each relevant savings opportunity within each end use and sector were included. The database includes prescriptive or "deemed" type measures, whole building and custom options, and behavioral measures. The database is comprised primarily of retrofit measures but also includes replace-on-burnout and new construction measures.

Measures were then screened for cost-effectiveness using the measure Total Resource Cost (TRC) test. With few exceptions, only measures with a TRC test result of 1.0 or better were passed on to the next stage of the analysis.

With the eligible stock and measures defined, ICF then performed the achievable potential analysis, which involved developing savings forecasts for measures included in 17 program types across three sectors over the 2015 to 2034 time period under three scenarios:

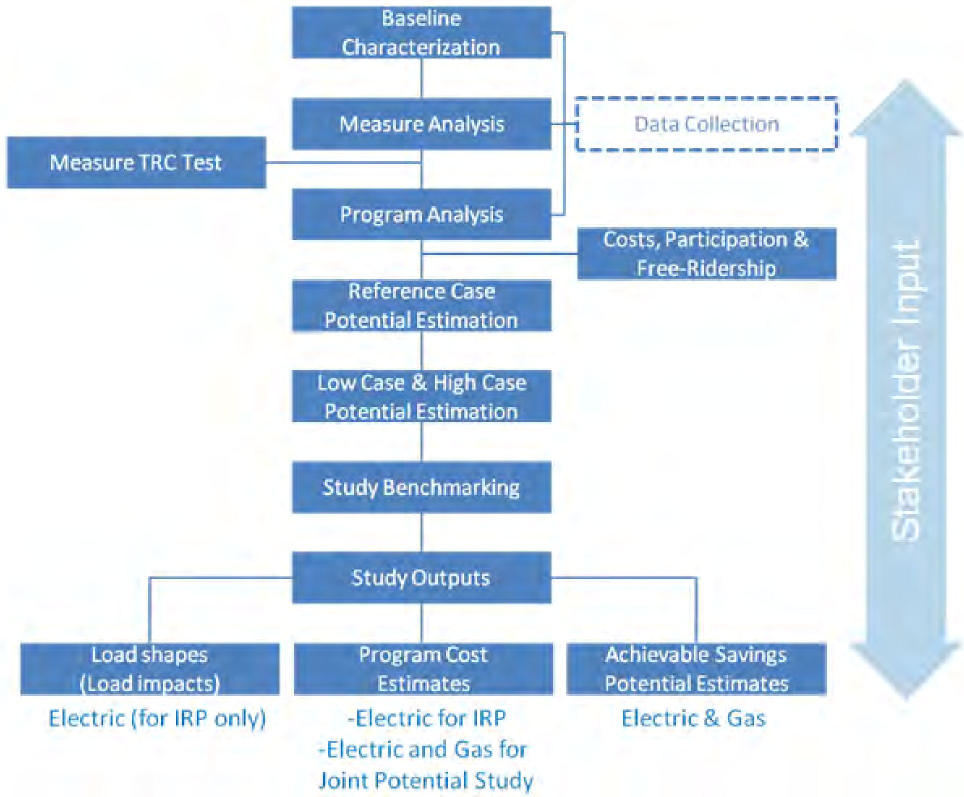
- **Reference case potential**. The realistic level of cost-effective savings that could be achieved by utility programs given the best information available at the time of the Potential Study. Incentive levels are generally between 25% and 75% of incremental cost, with the exception of hard-to-reach markets, e.g., small business, where incentives need to be different.[12]

[12] Incentives for programs targeting hard-to-reach customers tend to be higher than for other programs, since to these customers energy efficiency is less affordable. For example, incentives for the Low Income Weatherization program modeled in this Study are 100% of incremental costs.

- **High case potential**. The level of cost-effective savings that could be achieved by utility programs at maximum incentive levels. Incentive levels were to 100% of incremental costs where possible.
- **Low case potential**. The level of cost-effective savings that could be achieved at lower incentive levels. In most cases incentives were capped at 25%.

Finally, ICF provided Entergy SPO with the DSM inputs required for the IRP. These included loadshapes for each program, which reflect savings forecasted for every hour of every year of the analysis, and annual program costs. Gas savings potential and program costs were also developed, though these were not inputs to the electric IRP. In the sub-sections below, ICF discusses each step in the analysis in further detail.

Figure 4. Potential Study Approach



1.2 Data Collection

The sources of data used in the analysis are shown in Figure 5. Every effort was made to use data that was as current as possible, and to use assumptions specific to the ENO service area; primary data was used where possible.

Figure 5. Data Used in Analysis

<table>
<tr><th>Data/Information Type</th><th>Source (Year)</th><th>Type of Data</th><th>Primary Purpose in this Study</th></tr>
<tr><td colspan="4">Utility Information</td></tr>
<tr><td>Avoided costs</td><td>Entergy (2014)</td><td>Forecast</td><td>Cost-effectiveness testing</td></tr>
<tr><td>Customer counts</td><td>Entergy (2014)</td><td>Actual</td><td>Calculating the eligible stock</td></tr>
<tr><td>Load forecast</td><td>Energy (2014)</td><td>Forecast</td><td>Calculating load impacts of EE potential</td></tr>
<tr><td>Retail rates</td><td>Entergy (2014)</td><td>Actual</td><td>Achievable potential analysis</td></tr>
<tr><td colspan="4">Baseline Data</td></tr>
<tr><td rowspan="6">Residential building characteristics and efficiency saturation</td><td>Entergy Residential Appliance Saturation Survey (2006)</td><td>Primary</td><td rowspan="11">Calculating the eligible stock</td></tr>
<tr><td>Post-Katrina Study by GCR (2008)</td><td>Primary</td></tr>
<tr><td>U.S. DOE Residential Energy Consumption Survey (RECS, 2009)</td><td>Secondary</td></tr>
<tr><td>U.S. Census Data (2009)</td><td>Secondary</td></tr>
<tr><td>Other Secondary Sources (See Appendix)</td><td>Secondary</td></tr>
<tr><td>ICF expert judgment</td><td>Secondary</td></tr>
<tr><td rowspan="3">Commercial building characteristics and efficiency saturation</td><td>Commercial Building Inventory (CBI) data for Louisiana (2014)</td><td>Secondary</td></tr>
<tr><td>Air Conditioning Heating and Refrigeration Institute (AHRI, 2014)</td><td>Secondary</td></tr>
<tr><td>U.S. DOE Commercial Buildings Energy Consumption Survey (CBECS, 2003)</td><td>Secondary</td></tr>
<tr><td rowspan="2">Commercial building characteristics and efficiency saturation</td><td>Other Secondary Sources (See Appendix)</td><td>Secondary</td></tr>
<tr><td>ICF expert judgment</td><td>Secondary</td></tr>
</table>

Data/Information Type	Source (Year)	Type of Data	Primary Purpose in this Study
Industrial sub-sector characteristics and efficiency saturation	U.S. DOE Manufacturing Energy Consumption Survey (MECS, 2010)	Secondary	

13-034 © 2013

Data/Information Type	Source (Year)	Type of Data	Primary Purpose in this Study
Measure Assumptions			
Residential measure data	AR Technical Resource Manual (TRM) v. 3.0 (2014)	Measure parameters	Measure database development
	OK TRM (2014)[13]		
	CA DEER (2014)		
	Mid-Atlantic TRM (2014)		
	NREL (2014)		
	IL TRM (2014)[14]		
	ICF measure databases (2014)		
Commercial measure data	AR Technical Resource Manual v. 3.0 (2014)		
	OK TRM (2014)[15]		
	IL TRM (2014)[16]		
	Mid-Atlantic TRM (2014)		
	ICF measure databases (2014)		
Industrial measure data	U.S. DOE studies; U.S. EPA studies; LBNL studies; other published studies (see Appendix)		
	ICF estimates (2014)		
Program Information			
ICF program data and expert judgment	ICF	Secondary	Estimating achievable potential
Historical program savings data	U.S. EIA (2010-2012)	Secondary	Program savings benchmarking
Program cost data	ACEEE (2014)	Secondary	Program cost benchmarking
Customer survey data	ICF	Primary	Payback acceptance calculations

13 Adjustments to cooling and heating degree days made for weather sensitive measures.

14 Id.

15 Id.

16 Id.

1.3 Eligible Stock

After data collection, estimating the eligible stock of efficiency options was the next step of the analysis. The eligible stock is the size of the market for efficiency measures, in measure units, such as bulbs, tons of cooling, or homes. ICF estimated the eligible stock for each measure within each end use and sector. Key data from the baseline sources noted above includes items such as:

- The percent of homes with a particular type of equipment (e.g., light bulbs, central air conditioner, refrigerator),
- Equipment counts (e.g., number of bulbs per home, tons of cooling per home, refrigerators per home),
- Equipment efficiency level (e.g., bulb type, SEER rating, ENERGY STAR Rating), and
- Equipment age.

A simple example of an eligible stock calculation for residential specialty bulbs is shown below. This example shows there are 1.8 million incandescent specialty screw-in bulbs installed in homes in ENO's service area (row g). This equals 100% of all specialty light bulbs installed (row f). That is, based on the best available information, 100% percent of the existing stock of residential specialty screw-in bulbs could be replaced with more efficient units (e.g., a reflector LED).

Since this is a "replace-on-burnout" measure, the eligible stock must account for stock turnover (row h). Stock turnover is the rate at which existing equipment expires and requires replacement. It is the inverse of equipment age, or one divided by the equipment's effective useful life (EUL).[17] After the application of the stock turnover rate, the total number of specialty bulbs eligible to be replaced in 2014 equals 3.2 million (row i).[18]

[17] For retrofit measures, annual replacement eligibility equals 100%.

[18] ICF's potential model updates the eligible stock in every year of the analysis to account for measures installed in previous years.

Figure 6. Example Eligible Stock Calculation

	Variable	Value	Source/Calculation
	Efficient unit	12 Watt LED Specialty Lamp	AR TRM v. 3.0
	Baseline unit	60W Incandescent Specialty Lamp	AR TRM v. 3.0
a	Baseline unit effective useful life	2	AR TRM v. 3.0
b	# ENO Residential Customers	162,863	Entergy SPO
c	# Bulbs per Home	33.9	U.S. DOE RECS (2009)
d	% Applicability (% of bulbs that are specialty applications)	32%	Entergy RASS
e	Efficient unit saturation	0%	U.S. DOE RECS (2009)
f	Not yet adopted rate	100%	1-e
g	Total eligible stock in 2014	1,766,734	b*c*d*f
h	Annual replacement eligibility (stock turnover rate)	50%	1/a
i	Total # bulbs eligible to be replaced in 2013	883,367	b*c*d*f*h

For many measures, this information is broken down further in ICF's energy efficiency potential model. For example, the eligible stock for residential central air conditioners is further broken down by:

- Efficiency rating (SEER level),
- Home heating type (electric or gas), and
- Decision type (replace-on-burnout, retrofit, new construction).

1.4 Measure Analysis

ICF developed a comprehensive measure database for this Study. The database includes most measures in the Arkansas Technical Reference Manual ("TRM") version 3.0[19] plus additional measures included based on a gap analysis. The final database includes commercially available measures covering each relevant savings opportunity within each end use and sector. The database includes prescriptive or "deemed" type measures, whole building options (such as commercial custom and new construction projects), and behavioral measures (such as residential Home Energy Use Benchmarking and

[19] The AR TRM v.3.0 was the most current, regulator-approved TRM applicable to Entergy services territories at the time of this analysis.

Retrocommissioning measures). Data for each of the characteristics shown in Column A in Figure 7 was developed for each measure.

Figure 7. Illustrative Measure Characteristics (Wall Insulation)

(A) Measure Characteristic	(B) Value
1. Applicable sector	Residential
2. Applicable subsector	Single Family
3. Building type	AC with Gas Heat
4. End-use	Shell
5. Measure name	Wall insulation
6. Measure definition	R-13
7. Baseline definition	No insulation
8. Measure unit	Home
9. Measure delivery type	Retrofit
10. Incremental cost	$1,310 (materials and labor)
11. Baseline unit effective useful life	N/A (baseline=no insulation)
12. Efficient unit effective useful life	20 years
13. Incremental (annual) kWh savings	1,073 kWh
14. Incremental kW savings	0.796 kW
15. Annual Gas savings (Therms)	132.36

1.4.1 Measures Evaluated

In total, ICF analyzed 228 measure types for this Study; 148 electric-only measure types, 66 gas-only measure types, and 14 measures that result in both electric and gas savings. An example of a measure type is a residential central air conditioner (CAC). These measure types represent all end uses and savings opportunities. Many measures required permutations for different applications, such as different building types, lamp wattages, efficiency levels and decision types. For example, there are permutations of CACs by SEER level, subsector, and building type. As shown in Figure 8, ICF developed a total of 1,056 measure permutations for this Study. Sixty-seven percent of these measures are retrofit in nature, 31% are replace-on-burnout type measures, and 2% are new construction type measures.

Descriptions of each measure type and permutation are in the Appendix, as well as measure cost-effectiveness results.

Figure 8. Number of Measures Evaluated and Included

Sector	# Measure Types Evaluated	Total # Measures Evaluated (All Measure Permutations)	# Measures Cost-Effective (TRC>=1)	# Measures Included in Analysis
Electric Only Measures				
Residential	40	94	70	66
Commercial	44	476	363	336
Industrial	64	197	187	187
Total Electric Only	**148**	**767**	**620**	**589**
Gas Only Measures				
Residential	10	30	2	3
Commercial	12	37	10	2
Industrial	44	183	152	149
Total Gas Only	**66**	**250**	**164**	**154**
Electric and Gas Measures				
Residential	13	14	10	10
Commercial	1	25	20	20
Industrial	0	0	0	0
Total Electric and Gas	**14**	**39**	30	30
GRAND TOTAL	**228**	**1,056**	**814**	**773**

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1.4.2 Measure Benefit Cost-Screening

All measures were analyzed for cost effectiveness using the measure Total Resource Cost (TRC) test.[20] Electric measure TRC results were calculated in three test years: 2014, 2020, and 2022. Most studies only test measure cost-effectiveness in the base year. However, we decided to test electric measure cost-effectiveness in 2020 and 2022, in addition to doing so in 2014, because short-term avoided electric costs are very low, due in large part to a short-term capacity surplus in MISO. The capacity cost forecast increases every year and stabilizes in 2022.Thus, ICF believes 2022 is a more representative year for testing measure cost-effectiveness for the purposes of this long-run Study, than is 2014.[21] [22]

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

[21] All else equal, an electric measure tested for cost-effectiveness in 2022 had a higher measure TRC ratio than the same measure tested in 2014.

[22] 2014 was used as the test year for gas only measures.

Therefore, for nearly all electric measures, measure cost-effectiveness was assessed using 2022 as the test year. The only exceptions were for measures that phase-out prior to 2022. Lighting measures impacted by EISA 2007 Tier 2 were tested using 2020 as the test year. Air conditioning and heat pump measures impacted by DOE rules were tested in 2014 (see Section 1.4.3 for a description of how codes and standards were treated in this Study).

In most cases, only measures with a TRC of 1.0 or higher (in their representative test years) were passed on to the next stage of the analysis. A measure TRC result of 1.0 indicates that the measure is cost-effective on a standalone basis (before consideration of program costs or net-to-gross ratios). Exceptions to this rule were made for some low-income measures (the assumption being that low income programs are required by policy), and for non-economic measure permutations where a majority of the permutations of that measure type were cost-effective. For example, if a measure type was cost-effective for a majority of but not all applicable building types, ICF included the measure type for all building types in the achievable potential analysis. This is because it can be impractical in implementation to exclude participation by customers in specific building types.

Some cost-effective measures were also not included in the analysis. If a measure was cost-effective for a minority of building types, ICF excluded all permutations of the measure in the achievable potential analysis since it can be impractical in implementation to limit participation to certain building types. There were also some cost-effective measures with little to no known technical applicability[23] in New Orleans; certain types of commercial gas boiler measures, for example.[24] In such cases, the measure was also excluded from the analysis.

1.4.3 Treatment of Codes and Standards

The treatment of equipment and building energy baselines in this Study is summarized below.

- The Energy Independence and Security Act of 2007 (EISA) set energy efficiency standards for light bulbs manufactured from 2012 forward. From 2012 through 2014, Tier 1 of EISA took effect, phasing-out the manufacture and import of traditional filament incandescent 100W bulbs in 2012 and 75W bulbs in 2013. In 2014, the EISA legislation impacted 60 watt and 40 watt incandescent light bulbs, which are the most common light bulbs in use. The next EISA milestone, Tier 2, takes effect in 2020. This phase will require that all light bulbs manufactured are 60-70% more efficient

[23] Technical applicability is the fraction of the relevant building stock where the measure can actually be installed, or used.

[24] For example, ICF examined commercial boiler cut-out controls as a possible gas measure. However, there was insufficient data on the number and age of commercial boilers in New Orleans to be able to estimate potential for this measure. ICF program experience in the South also suggests that, due to the very low number of heating degree days (HDD) in the region, commercial boiler use for space heating in New Orleans is minimal, and that such boilers are used largely for water heating. Cut-out controls are not applicable in such situations, as their use would result in turning off the hot water supply to the building.

than before EISA took effect. Lighting industry experts and program planners expect residential lighting program savings to be viable up until 2020. However, the current assumption of many experts and planners is that programs may not be able to claim savings for most CFLs and LEDs after 2020 due to the baseline changes, and to significant price decreases of LEDs.[25] The exceptions are specialty CFLs and reflector LEDs, which are exempt from EISA 2007.

- U.S. DOE rules pertaining to commercial lamps and ballasts are reflected in baselines for linear florescent lighting.[26] These rules result in a 20% improvement in baseline efficiency for linear florescent lamps.[27] This is important because efficient linear florescent lighting accounts for the largest portion of historical commercial lighting savings in many jurisdictions.
- U.S. DOE energy conservation standards for residential heat pumps (HPs) and single package central air conditioners (CACs) go into effect in 2015 and 2016, respectively. The improvement from a SEER 13 to a SEER 14 baseline for these units has a negative impact on the savings and cost-effectiveness of CAC and HP measures.
- Louisiana's current commercial building energy code is compliant with ASHRAE 90.1-2007. However, ICF assumed commercial new construction baselines consistent with the next (and more efficient) version of the code, which is ASHRAE 90.1-2010 for the 2015 to 2018 period; for the remainder of the Study period (2019-2034) we assumed the adopted code would be ASHRAE 90.1-2013. These are reasonable assumptions given the long-run nature of the Study.
- Similarly, Louisiana's current residential building energy code is compliant with IECC 2009. However, ICF assumed residential new construction baselines consistent with the next (and more efficient) version of the code, which is IECC 2012. Again, this is a reasonable assumption given the long-run nature of the Study.

1.5 Achievable Potential Approach

This section describes ICF's approach to modeling achievable potential, starting with the program types modeled, followed by subsections on the development of program assumptions, and on the scenario analysis.

1.5.1 Programs Modeled

Eighteen program types were modeled for this Study. These are briefly described below, by sector.

[25] ENERGY STAR-compliant A-line LEDs were available at Home Depot stores in Louisiana for $10 at the time this Study was completed, and prices continue to decline toward the cost of CFLs.

[26] Consistent with the U.S. Energy Policy Act of 2005.

[27] The rules specify a switch from magnetic ballast baseline to an electronic ballast baseline.

Residential Programs

- **Home Energy Use Benchmarking**. Program designed around directly influencing household habits and decision-making on energy consumption through quantitative or graphical feedback on consumption, accompanied by tips on saving energy.
- **Lighting and Appliances**. Midstream incentive program that brings down the cost of efficient lighting, appliances and consumer electronics.
- **Multifamily**. Commercial building characteristics
and efficiency saturation. Program designed to encourage the installation of measures in common areas and units for residential structures of more than four units. Aimed at building owners, managers, and tenants. Due to the very small size of the multifamily housing sector in the ENO service area, it was assumed that this program would merge with the Home Energy Audit and Retrofit program in the long run.
- **Efficient New Homes**. Program that provides incentives to builders for new homes built or manufactured to energy performance standards higher than applicable code.
- **ENERGY STAR Air Conditioning**. Program designed to encourage the distribution, sale, purchase, and installation of residential air conditioners and heat pumps that are more efficient than current standards.
- **Home Energy Audit and Retrofit**. Residential audit program that provides a comprehensive assessment of a home's energy consumption and identification of opportunities to save energy. Incentives are paid for the installation of identified measures such as insulation and duct sealing. Program includes a direct install element where low cost measures are installed with participant permission.
- **Pool Pump**. Program that incentivizes the installation of higher efficiency pumps or variable speed pumps for swimming pools.
- **Water Heating**. Program designed to encourage the distribution, sale, purchase, and installation of water heating systems that are more efficient than current standards.
- **Solar Hot Water**. Program required by City Council of New Orleans to encourage the distribution, sale, purchase, and installation of solar water heating systems.
- **Low Income Weatherization**. Program for qualifying low-income customers that provides home weatherization (e.g., air sealing, insulation) free of charge.
- **Direct Load Control**. A demand response program by which the utility remotely shuts down or cycles a customer’s air conditioner.
- **Dynamic Pricing**. Tariff in which residential customers are charged more during times when electricity is more expensive, and less when it is less expensive.

Commercial Programs

- **Commercial Prescriptive and Custom**. Program that provides both financial incentives and technical assistance to all eligible commercial customers seeking to improve the efficiency of existing facilities; provides resources for new higher efficiency equipment purchases, facility modernization, and other efficiency improvements.
- **Data Centers**. Custom program around large-scale server floors or data centers. Projects tend to be site specific and involve some combination of measures for servers, networking devices, HVAC, and energy management systems and software.
- **New Construction**.: Program that provides technical support in the building design phase, and incentives to owners, builders, architects and similar parties for buildings that exceed current energy efficiency codes by prescribed levels.
- **Retrocommissioning (RCx)**. Provides in-depth engineering studies on commercial buildings that focus on operational adjustments designed to optimize building system performance. Incentives are paid for implementing measures identified in studies.
- **Small Business**. Program that provides basic energy audits and direct install measures to small business customers, and deep discounts/incentives for additional measures identified through audits.
- **Dynamic Pricing**. Tariff in which commercial customers are charged more during times when electricity is more expensive, and less when it is less expensive.

Industrial Programs

- **Industrial Prescriptive and Custom**. Program that provides both financial incentives and technical assistance to all eligible industrial customers seeking to improve the efficiency of existing plants; provides resources for new higher efficiency equipment purchases, facility modernization, and other efficiency improvements. Industrial Prescriptive and Custom sub-programs modeled for this Study include:
  - Machine Drive
  - Process Heating
  - Boilers
  - Process Cooling and Refrigeration
  - Facility HVAC
  - Facility Lighting
  - Other Process/Non-Process Use

1.5.2 Gas Programs Modeled

It was assumed that programs with gas measures would be operated jointly with their analogous electric programs. That is, we assumed there would be no stand alone gas programs. This is because there were not any cost-effective gas measures that required the creation of new programs, and because gas savings potential is too small in scale to operate gas programs independently of electric programs.

Ten of the programs described above would include both electric and gas measures:

A. Residential Programs
   1. Efficient New Homes
   2. Home Audit and Retrofit
   3. Home Energy Use Benchmarking
   4. Low Income Weatherization
B. Commercial and Industrial Programs
   5. Commercial Prescriptive and Custom
   6. Industrial Boilers
   7. Industrial HVAC
   8. Industrial Process Heating
   9. Industrial All End Uses
   10. Small Business Solutions

1.5.3 Program Assumptions

This section describes how key assumptions were developed for programs. Key assumptions include costs, participation rates, and net-to-gross ratios.

Program Costs

Program costs were estimated to reflect average annual costs over the long run. Notwithstanding the baseline improvements discussed above, ICF expects program costs in the long run to be lower than program costs today. This is because Louisiana is an immature market for DSM. As programs grow and the market matures, program delivery costs are expected to decrease as a percentage of overall program costs.[28]

Incentive and non-incentive program cost estimates were developed. Incentives are program payments to customers, contractors, retailers, or manufacturers that lower the cost of efficient products and services. Non-incentive costs include administration, marketing, education and training, and evaluation costs. Individual non-incentive cost categories were not estimated for this Potential Study. ICF program experience and program costs in other territories were considered in developing program costs for this

[28] For example, fixed costs associated with program start-up increase program costs in the short-run, not in the long-run.

Potential Study. Cost estimates by program are shown in aggregate in Sections 3 and 4 and by program in the Appendix.

Participation

A participation rate is the percent of the eligible stock or applicable customer population predicted to install an efficiency measure in a given year. The approach to developing participation rates in this potential Study was similar to the approach used in most potential studies. It involves:

1. Developing a maximum market acceptance rate or (S_{max}), which is the maximum annual participation rate for a given measure.
2. Estimating a participation rate in year 1 of the program.
3. Developing a ramp-up schedule from year 1 to the year in which S_{max} is predicted to occur
4. Forecasting participation for the years after the year in which the S_{max} is expected to be achieved.

The shape of participation curves can take a variety of forms depending on the nature of the measure, the program in which it is being delivered, the relevant market barriers, baseline changes and the size and nature of the eligible stock. ICF assessed achievable participation on a measure-by-measure basis. Because such a wide variety of measures are included in this Study, ICF could not apply just one formulaic approach to estimating program participation for all measures. This is illustrated generally by the participation approach types described below, and by the participation estimates for individual measures shown in Appendix A. Each measure was put in a group[29] with similar measures for the purpose of assigning participation approaches and payback curves; these assignments are shown in Appendix C.

Participation Approach A

This approach to estimating participation combines research on customer financial decision making with research on the diffusion of innovative technologies in the marketplace.

[29] Most programs have multiple measure groupings, or bundles. Some, such as Home Energy Use Benchmarking, only have one group.

One way that programs motivate customers to participate is by improving the financial attractiveness of the efficient option over the standard, or baseline option. Financial attractiveness in Approach A is a function of how much the incentive lowers the customer simple payback. Customer payback is the amount of time it takes for a customer to recover the costs of investing in the efficient unit instead of the standard unit. Customer payback equals the difference in cost between the efficient and standard units (commonly known as the incremental cost), divided by the utility bill savings due to the efficient unit.[30] Payback before the incentive is applied is calculated as:

Pre-incentive Customer payback (Years) =
Incremental cost ÷ Utility bill savings

And payback after the incentive is applied is calculated as:

Post-incentive Customer payback (Years) =
(Incremental cost—Incentive cost) ÷ Utility bill savings

In the reference case, measure incentives were calculated to bring down the customer payback to two years, with a cap of 75% of incremental cost, and a minimum incentive of 25% of incremental cost.[31] An incentive calculation for an <u>illustrative</u> measure is shown in Figure 9.[32]

For this illustrative measure the pre-incentive payback is 6.3 years (row 10) and the post-incentive payback is two years (row 17). Not all incentives bring down the payback to two years. This happens when the maximum incentive is reached, when the pre-incentive payback is already less than two years, or when the incentive would need to be greater than the incremental cost to bring the payback down to two years.

[30] Incremental costs include the difference in the cost of equipment, labor and operations, and maintenance.

[31] Incentive levels for other scenarios are shown in Section 1.5.4.

[32] Values shown in Figure 9 are generic and shown only to demonstrate approach. The values should not be construed as actual assumptions used in this Study. Actual assumptions are noted as such in the body of this report and in the Appendix.

Figure 9. Illustrative Measure Incentive Calculation

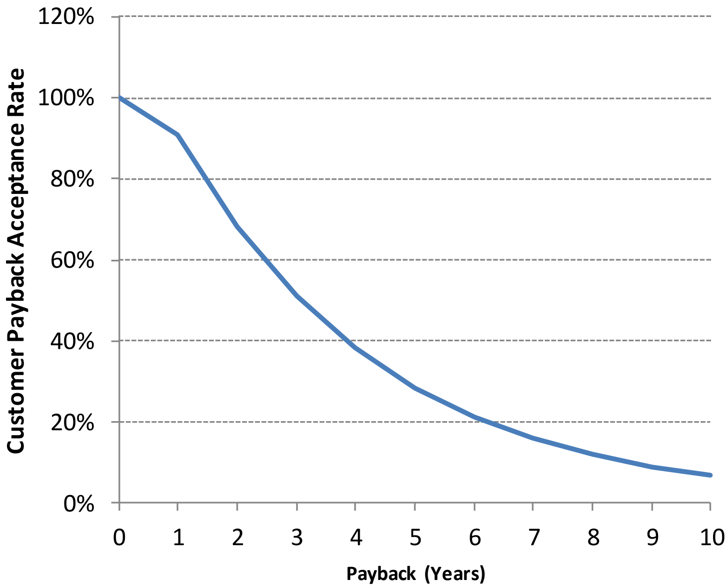
	Incentive Calculations	Value	Source/Calculation
1	Retail Electricity Rate—kWh	$ 0.09	Utility
2	Retail Capacity Charge—kW	$ 0.00	Utility
3	Retail Gas Rate—therm	$ 0.95	Utility
4	Base Measure Life	15	Deemed Savings
5	Total Incremental Cost`	$ 238.00	Deemed Savings
6	Annual kWh Savings	417.33	Deemed Savings
7	Annual kWh Summer-Peak Savings	0.12	Deemed Savings
8	Annual Gas Savings	0.00	Deemed Savings
9	Annual Bill Savings	$ 37.91	Annual Energy Savings by Participant
10	Pre-incentive Payback (Years)	6.3	Total Incremental Cost/Annual Bill Savings
11	**Incentive Assumptions**		
12	Minimum Incentive Level	25%	Reference Case Assumption
13	Maximum Incentive Level	75%	Reference Case Assumption
14	Post-incentive Payback Target (Years)	2	Reference Case Assumption
15	Incentive as % of Incremental Cost	68%	MAX [MIN (Minimum Incentive Level, 1-Post-rebate Payback Target/Pre-rebate Payback)]
16	Incentive	$ 162.18	Incentive as % of Incremental Cost x Total Incremental Cost
17	Post-incentive Payback	2	(Total Incremental Cost-Incentive) / Annual Bill Savings

Incentives are used to calculate program costs and to forecast participation. ICF uses the post-incentive payback to estimate the fraction of customers that may choose the efficient unit over the standard unit. This is done using payback acceptance curves, an example of which is shown in Figure 10. Different payback curves were utilized for each sector. All payback curves utilized in this Study are shown in Appendix C.

The curve in Figure 10 plots results from a residential survey on payback acceptance.[33] The curve shows that 68% of eligible residential customers stated they are willing to accept a two-year measure payback. However, people tend to overstate their payback acceptance in surveys. This is sometimes called survey response bias; when customers are making actual decisions about installing equipment, they are usually willing to accept much shorter payback levels than they stated they would in a survey.

[33] Surveys were conducted prior to this Study outside of Entergy service areas.

Figure 10. Illustrative Payback Acceptance Curve



Survey response bias as well as market barriers need to be accounted for in developing program participation estimates. Market barriers to participation include financial barriers, such as lack of access to capital; information barriers, such as lack of customer understanding about the benefits of efficient equipment; and, delivery barriers, such as contractor recruitment and participation. Response bias and market barriers are considered by ICF when developing participation curves.

In participation Approach A, three variables determine the shape of the participation curve for a measure:

1. A *maximum market acceptance rate*, or "S_{max}"(row 2 in Figure 11) is used to estimate the maximum annual participation rate;[34] next the ramp-up schedule is determined using
2. A *ramp-up rate* (row 3 in Figure 11) to estimate first year participation; and
3. A *ramp-up shape* (row 4 in Figure 11) is applied to reflect how quickly a program could reach the maximum annual participation rate.

The maximum annual market acceptance (S_{max})[35] is the product of the customer stated payback acceptance and the program market acceptance rate (row 8 in Figure 11):

Maximum annual market acceptance rate (S_{max}) =
Customer stated payback acceptance x Program Market Acceptance rate

Moreover, the first year participation rate is maximum annual market rate, divided by the ramp-up rate (row 9 in Figure 11). To summarize:

First year participation rate =
Maximum annual market acceptance rate ÷ Program ramp up rate

Figure 11. Illustrative Market Diffusion Assumptions

	Program Assumptions	Value	Source/Calculation
1	Customer Stated Payback Acceptance	68%	Payback Acceptance Calculation
2	Program Market Acceptance Rate	30%	ICF Program Assumption
3	Ramp-up Rate	5	ICF Program Assumption
4	Ramp-up Shape	100%	ICF Program Assumption
5	Program Start Year	2015	
6	Study Period (years)	20	
7	First Year Participation Estimates		
8	Maximum Annual Market Acceptance (S_{max})	20.4%	Program Market Rate Acceptance x Customer Stated Payback Acceptance
9	First Year Share of Installations (S_o)	4.1%	Maximum Annual Market Acceptance (S_{max})/ Ramp-Up Rate

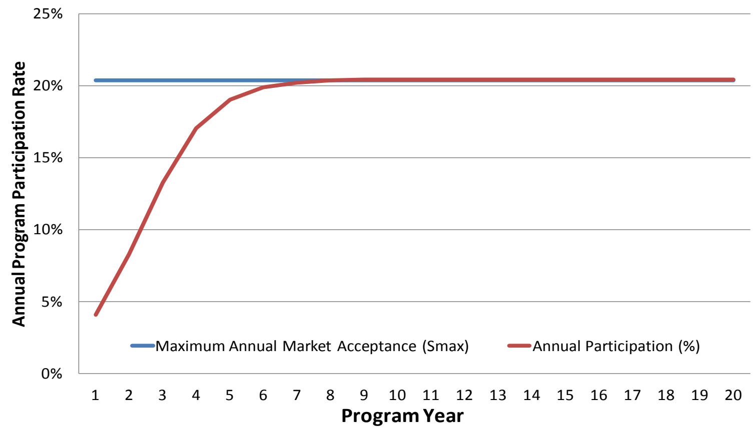
Figure 12 illustrates the outcome of Approach A. Program participation in the first year is 4%. The participation rate in each year grows until it reaches the maximum estimated level of 20%. Increasing

[34] The program participation rate in the year the program reaches maturity.

[35] The highest estimated level of program market penetration in a given year.

the ramp-up shape steepens the curve, and decreasing it makes the curve more gradual. This figure is an example of a "market diffusion" or "s-curve."

Figure 12. Market Diffusion Curve



This approach to modeling DSM program participation is only applicable to measure and program types where payback acceptance is relevant to customer financial decision-making.

Participation Approach B

Participation Approach A is not applicable to DSM measure and program types where payback acceptance is a less relevant proxy for customer financial decision making. This is the case for residential new homes programs, for example, where qualified homebuilders are the target market, not homebuyers. Nor does the payback acceptance survey data apply to customer decisions about participating in demand response programs. For measures where Approach B was used, participation rates were individually inputted for each year based on program experience.

Demand Response Program Participation

Two types of demand response (DR) programs were modeled for this Study: Dynamic Pricing (for Residential and for C&I) and Residential Direct Load Control.

Direct load control participation requires the utility to install a controlling device on the customer's AC or to install a "smart thermostat" inside the customer's home. Participation estimates were split evenly between these two options.

DR participation forecasts in this Study were based on the Expanded Business as Usual (EBAU) case for Louisiana developed for FERC by The Brattle Group.[36] DR programs were assumed to be voluntary, or "opt-in" in nature. This is generally consistent with current regulation of DR options in most service areas.

Net-to-Gross Ratios

Program evaluators independently verify reported savings and conduct empirical studies and other activities to estimate actual energy savings during the period of performance. The ratio of evaluated savings to reported savings is called the program net-to-gross (NTG) ratio. Applying the NTG ratio to gross savings results in net savings. Net savings estimates are reflected in the load shapes provided to SPO for this Potential Study.

Reference case NTG ratios were estimated based on program impact evaluation results from California, Illinois and from the Northeast, and are shown the in Appendix. As noted above, NTG ratios were generally increased in the high scenario, as evaluation research has shown that higher incentive levels are correlated with lower free-ridership. This principal was also applied in the low case; NTG ratios were lowered in most cases from reference case levels since incentives in the low case are lower than in the reference case.

1.5.4 Scenario Development

Achievable energy efficiency potential was forecasted for the above programs under three scenarios, which are defined below. ICF first developed the reference case estimates by measure for each program using the approaches describe d above. Then, the high and low case scenarios were developed around the reference case.

- **Reference case potential**. The realistic level of cost-effective savings that could be achieved by utility programs given the best information available at the time of the Potential Study. Incentive levels are generally between 25% and 75% of incremental cost, with the exception of hard-to-reach markets, e.g., small business, where incentives need to be different.
- **High case potential**. The level of cost-effective savings that could be achieved by utility programs at maximum incentive levels. Incentive levels were set to 100% of incremental costs where possible.
- **Low case potential**. The level of cost-effective savings that could be achieved at lower incentive levels. In most cases incentives were capped at 25%.

Besides incentive levels, program designs were assumed to be identical across scenarios. Assumptions about customer preferences and decision making criteria, utility assumptions such as avoided costs and discount rates, as well as exogenous economic factors such as growth and inflation were all held

[36] Federal Energy Regulatory Commission. A National Assessment of Demand Response Potential. Prepared by The Brattle Group et al. June 2009.

constant across scenarios.[37] As such, the ICF's scenario analysis focused on the impact of varying incentive levels.

Below we provide additional information on how the high and low cases were developed subsequent to the completion of the reference case. Since readers tend to focus more on the high than the low case, more description is provided regarding the development of the high case.

- **Comparative incentive analysis.** Incentive levels in the reference case are generally between 25% and 75% of measure incremental cost. All incentives in the high case are 100% of incremental cost, except as noted below. In the high case, for measures or programs where incentives are less important, the additional incentive has little to no impact. This is true for the Commercial New Construction program. In other cases, the 100% incentive has a large impact, as with the Commercial Prescriptive and Custom program.
- **Cost-effectiveness constraints.** In the high scenario, incentives could not be increased to 100% for every program due to cost-effectiveness constraints. This is because changing incentive levels can change the mix of measures installed. For example, increasing the incentive to 100% increases participation of high efficiency air conditioners (e.g., SEER 16+), which save more energy than efficient SEER 14-15 units, but also cost considerably more; as a result, they are less cost-effective than the SEER 14-15 options. Increasing uptake of such measures reduced overall cost-effectiveness compared to reference case levels for some programs. In such cases, incentives were increased up to the point where, when non-incentive program costs were added, the program was still cost-effective.
- **Non-incentive program costs.** Changing incentive levels also requires adjusting program non-incentive costs for most programs. If increasing incentives increases participation, then more incentive processing is required, more inspections and other quality assurance must occur, more trainings must be held, etc. And the converse is true when incentives are decreased. Therefore, non-incentive costs were adjusted from reference case levels in the low and high cases commensurate with changes in gross savings estimates. This was done on a program-by-program basis, and required expert input from ICF DSM program managers.
- **Net-to-gross ratios.** Finally, for most programs*,* incentive levels are negatively correlated with free-ridership; higher incentives generally correspond to lower free-ridership, and vice versa. Therefore, NTG ratios for most programs were decreased in the low scenario, and increased in the high scenario. NTG assumptions for each scenario are shown in the Appendix.

[37] One reason these factors are held constant in ICF's model is that ICF's DSM forecasts are used as inputs to SPO's IRP model, which is a dynamic model that varies utility, macroeconomic, and other assumptions.

2 Energy Use in the ENO Service Area

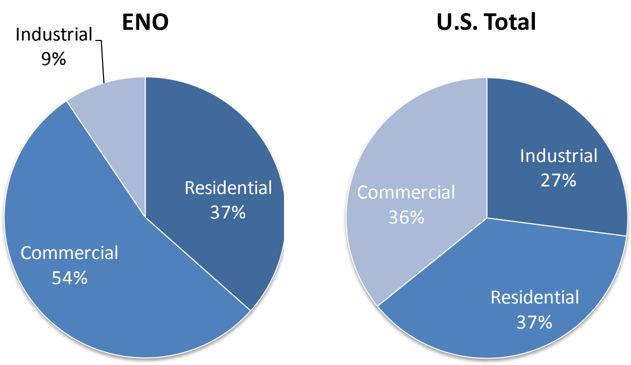
This section of the report begins by briefly describing baseline electricity use in the ENO service area. Next, the baseline natural gas use is described.

2.1 Electricity

Below we describe base year (2013) electricity use in the ENO service territory, in aggregate and by sector by end use. Figure 13 shows the distribution of electricity use in 2013 for ENO and for the U.S. in total. Note the ENO industrial share is one-third the U.S. industrial share, and that the ENO commercial share is 50% higher than the U.S. commercial share. Figure 14 and Figure 15 show the distributions of residential and commercial electricity use by end use. Figure 16 disaggregates industrial use by sector by end use.

As discussed in the Approach section, measures were developed for each applicable end use, and an eligible stock, or market size, was estimated for each measure. Data on the eligible stock is included in the measures section of the Appendix.

Figure 13. Distribution of Total Base Year Electric Electricity Use, by Sector, for ENO and U.S. Total (ENO Total 2013 Sales= 5,105 GWh)[38]



[38] Commercial for ENO also includes government and lighting sales; industrial sales % also includes industrial CHP, which is not included in the industrial subsector totals in Figure 16.

Figure 14. Distribution of Base Year ENO Residential Electricity Use by End Use (Total 2013 Residential Sales=1,867 GWh)[39]

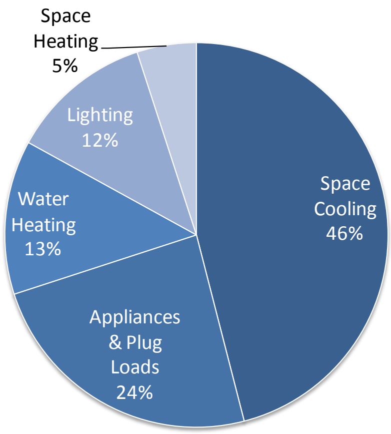
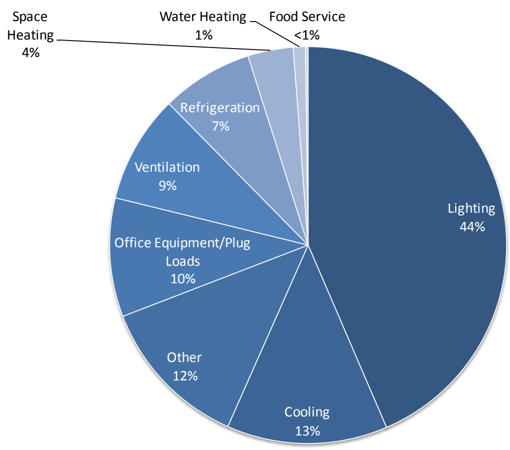


Figure 15. Base Year ENO Commercial Electricity Use by End Use (Total 2013 Commercial Sales=2,767 GWh)[40]



[39] Sources: ICF estimates based on U.S. DOE (CBECS 2003) and CBI commercial building data for Louisiana.

[40] Includes Government and Lighting sales. Sources: Entergy (2014), U.S. DOE (CBECS 2003), Commercial Building Institute (2014)

Figure 16. Base Year Industrial Electricity Use by Sector by End Use (ENO)[41]

	Large Industrial			Small Industrial	All Sectors
	Food Products	Industrial Gases	All Other - Large Industrial		
Total Industrial Base Year (2013) Sales, GWh	65	226	40	150	**481**
% Total Industrial Base Year (2013) Sales	13%	47%	8%	31%	**100%**
End Use	**% Base Year (2013) MWh Use by Sector by End Use**				
Machine Drive	47%	52%	52%	52%	**52%**
-Pumps	11%	14%	14%	14%	**14%**
-Fans	5%	8%	8%	8%	**7%**
-Compressors	5%	9%	9%	9%	**8%**
-Materials handling	4%	7%	7%	7%	**6%**
-Materials processing	17%	13%	13%	13%	**13%**
-Motor - Other Applications	4%	2%	2%	2%	**2%**
Process Heating	5%	11%	11%	11%	**11%**
Process Cooling and Refrigeration	28%	7%	7%	7%	**10%**
Other Process Uses	0%	2%	2%	2%	**2%**
Electro-Chemical	0%	9%	9%	9%	**8%**
Facility HVAC	8%	8%	8%	8%	**8%**
Facility Lighting	8%	6%	6%	6%	**7%**
Other non-process use	3%	2%	2%	2%	**2%**
Other process/Other non-process use	0%	0%	0%	0%	**0%**

[41] Sources: Entergy (2014), U.S. DOE (MECS 2010). Note industrial total sales shown in the table do not include combined heat and power (CHP). Note also that the industrial sales forecast provided by SPO and used by ICF to determine the industrial baseline for this Potential Study has been updated since this analysis was performed. SPO's updated industrial sector forecast shows higher growth in industrial electricity use than the previous forecast. All else equal, this may mean that industrial savings potential could be slightly underestimated in this Potential Study, but it is too difficult to draw any specific conclusions about the impacts of the updated industrial forecast without further analysis.

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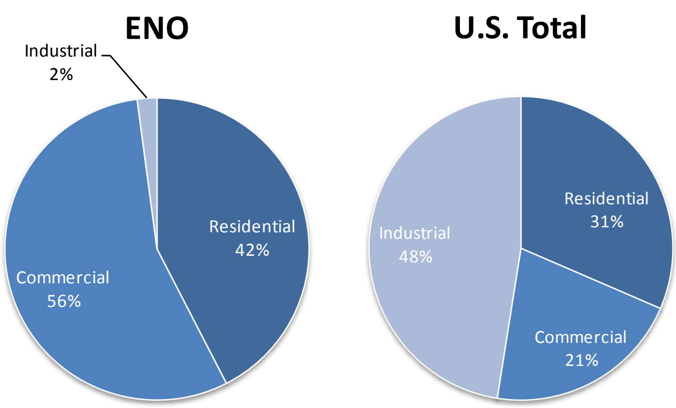
2.2 Natural Gas

Below we describe base year (2013) natural gas use in the ENO service territory, in aggregate and by sector by end use. Figure 17 shows the distribution of natural gas use in 2013 for ENO and for the U.S. in total. Note the ENO industrial share 4% of the U.S. industrial share, and the ENO commercial share is 267% of the U.S. commercial share. Figure 18 and Figure 19 show the distributions of residential and commercial electricity use by end use. Figure 20 disaggregates industrial use by sector by end use.

As discussed in the Approach section, measures were developed for each applicable end use, and an eligible stock, or market size, was estimated for each measure. Data on the eligible stock is included in the measures section of the Appendix.

Figure 17. Distribution of Total Base Year Natural Gas Use, by Sector, for ENO and U.S. Total (ENO Total 2013 Sales= 92,223,913 Therms)[42] [43]



[42] Commercial for ENO includes government. ENO industrial share excludes sales to non-jurisdictional ("NJ") large industrial customers served by ENO under negotiated rates, terms and conditions specific to each of those customers.

[43] Sources: ENO; U.S. EIA, 2014.

Figure 18. Distribution of Base Year ENO Residential Natural Gas Use by End Use (Total 2013 Residential Sales= 39,130,304 Therms)[44]

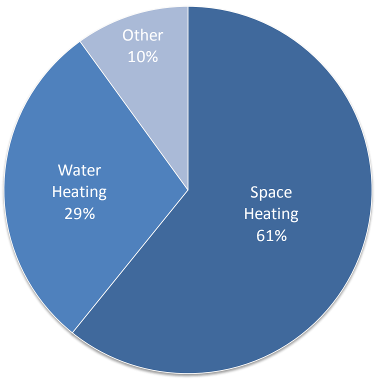
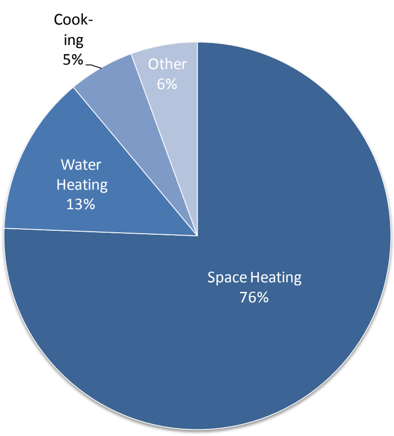


Figure 19. Base Year ENO Commercial Natural Gas Use by End Use (Total 2013 Commercial Sales=51,156,855 Therms)[45]



[44] Sources: Entergy Services, U.S. DOE RECS 2009

[45] Includes Government. Sources: Entergy (2014), U.S. DOE (CBECS 2003), Commercial Building Institute (2014)

Figure 20. Base Year Industrial Natural Gas Use by Sector by End Use [46]

	Large			
	Industrial Gases	All Other - Large Industrial	Small Industrial	All Sectors
Total Industrial Base Year (2013) Sales, Therms	1,051,744	186,724	698,286	**1,936,754**
% Total Industrial Base Year (2013) Sales	54%	10%	36%	**100%**
End Use				
Boilers	18%	13%	13%	**16%**
CHP/Cogeneration	42%	37%	37%	**40%**
Other Electricity Generation	<1%	<1%	<1%	**<1%**
Process Heating	32%	42%	42%	**36%**
Process Cooling and Refrigeration	<1%	<1%	<1%	**<1%**
Other Process Uses	2%	2%	2%	**2%**
Machine Drive	3%	2%	2%	**3%**
HVAC	1%	3%	3%	**2%**
Onsite Transportation	<1%	1%	1%	**1%**
Other Nonprocess	<1%	<1%	<1%	**<1%**

[46] Sources: Entergy (2014), U.S. DOE (MECS 2010). Note industrial total sales shown in the table do not include combined heat and power (CHP). Note also that the industrial sales forecast provided by SPO and used by ICF to determine the industrial baseline for this Potential Study has been updated since this analysis was performed. SPO's updated industrial sector forecast shows higher growth in industrial electricity use than the previous forecast. All else equal, this may mean that industrial savings potential could be slightly underestimated in this Potential Study, but it is too difficult to draw any specific conclusions about the impacts of the updated industrial forecast without further analysis.

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3 Achievable Electric Energy Efficiency Potential

This section includes the presentation and analysis of ICF's forecast of total achievable electric DSM potential for the ENO service area for 2015 through 2034. Total achievable potential is the sum of residential, commercial, and industrial potential. Electric savings and program cost estimates are shown, as well as benefit-cost estimates. The forecast is put in context through benchmarking analysis.

3.1 Cumulative Potential

Total achievable potential is the sum of achievable potential estimated for each measure in the analysis. Total cumulative achievable potential estimates are shown in Figure 21, along with cumulative savings[47] impacts. Figure 22 provides an overall summary of this Study's forecast including electricity and demand savings, savings impacts, costs, benefits, and cost-effectiveness. To review the forecast:

- ICF estimates that, in the reference case, ENO can achieve cost-effective cumulative electric savings equal to 6.1% of load over the 2015 to 2034 time horizon. Total program costs over this 20-year period are estimated to equal $111 Million.[48] Total net benefits are estimated to equal $100 Million.
- In the high case, we estimate that ENO could achieve an additional 223 GWh in savings for an additional $28 Million in program spending beyond the reference case. That is, in the high case, savings would increase 59% over reference case levels while spending would increase 25%.
- In the low case, ICF estimates that ENO would achieve 35% less savings than in the reference case, while costs would decrease 17% compared to the reference case.

[47] The summation of savings from multiple projects or programs over 2015-2034, taking into account the time of measure installation in the first year, annual energy savings for subsequent years, and the life of the installed measures.

[48] Including program incentive and non-incentive costs.

Figure 21. ENO Cumulative MWh Savings Forecast, by Scenario

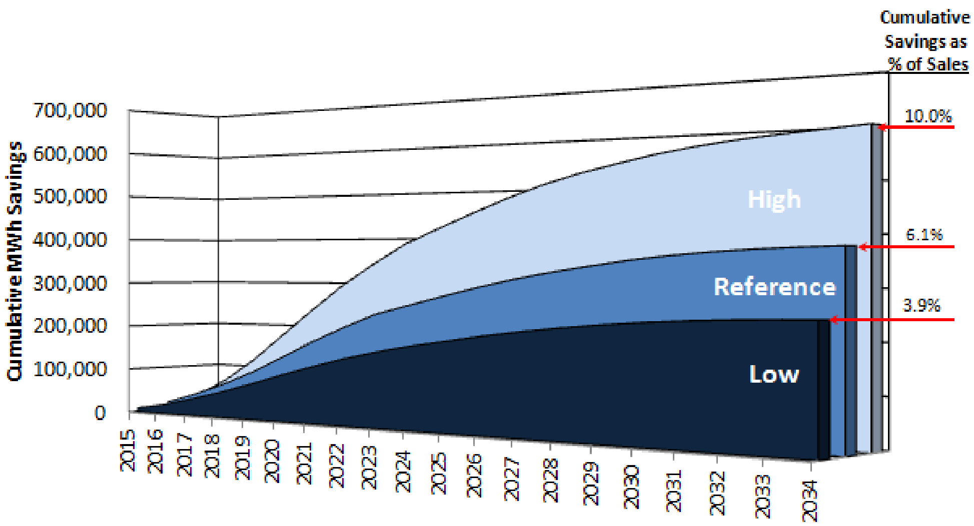

Figure 22. Total Electric Savings, Savings Impacts, Benefits, Costs and Costs-Effectiveness, by Scenario

Scenario	Cumula-tive GWh Savings (2015-2034)	Cumula-tive GWh Savings as % of Sales	Cumula-tive MW Savings (2015-2034)	Cumula-tive MW Savings as % of Peak[49]	Total TRC Benefits, 2015-2034 ($Mil.)	Total TRC Costs, 2015-2034 ($Mil.)[50]	Net TRC Benefits, 2015-2034 ($Mil.)[51]	TRC B/C Ratio	Total Pro-gram Costs, 2015-2034 ($Mil.)[52]	Level-ized Cost per kWh[53]
Low	246	3.9%	69	5.9%	$182	$124	$58	1.5	$92	$0.05
Reference	378	6.1%	112	9.6%	$293	$193	$100	1.5	$111	$0.06
High	601	10.0%	168	14.5%	$790	$463	$320	1.7	$139	$0.09

[49] Forecasted non-coincident peak demand.

[50] TRC (Total Resource Cost) test costs include total measure incremental costs and program non-incentive costs over the time horizon of the forecast (2015-2034).

[51] TRC (Total Resource Cost) test benefits include total electric generation (kWh), capacity (kW), and gas (therm) costs avoided over the time horizon of the forecast (2015-2034).

[52] Program costs include incentive costs and non-incentive costs (e.g., administration, marketing, etc.).

[53] Id.

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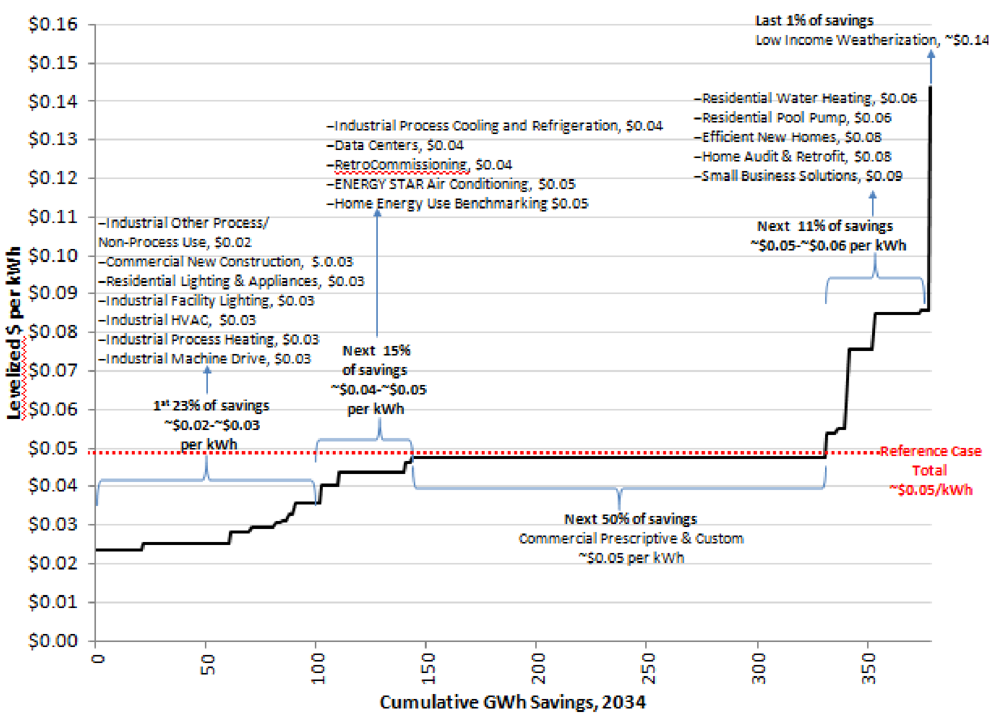
Figure 23 shows the reference case DSM supply curve, which plots cumulative electric savings on the x-axis and levelized program costs on the y-axis.[54] The graph shows that 23% of savings could be achieved through programs that cost $0.02-$0.03 per kWh. Moving from left to right, each additional group of programs shown in the graph is more costly on a per kWh basis. The programs listed in each group on the supply curve are sorted from lowest to highest levelized cost per kWh; Industrial Other Process/Non-Process Use and Commercial New Construction are the least costly; Low Income Weatherization is the most costly. The program with the largest savings impact is Commercial Prescriptive and Custom.

Figure 23. ENO Electric DSM Supply Curve, Reference Case[55]



[54] Levelized costs are the result of a computational approach used to compare the cost of different projects or technologies. The stream of each project's net costs is discounted to a single year using a discount rate (creating a net present value) and divided by the project's expected lifetime output (kWh in this case).

[55] Reference case total levelized cost shown ($0.05/kWh) does not include DR programs. If DR is included, the Reference case total levelized cost is $0.06/kWh.

3.2 Costs in Context

A recent ACEEE report[56] summarized levelized program costs over the 2009 to 2012 period across 20 states. Data reported in this study was used to develop Figure 24.[57] Although historical program costs in other states are not necessarily comparable to future program costs in Louisiana due to differences in baselines, customer mixes, avoided costs, and other factors, it is helpful to put the costs projected in this Potential Study into context.

The total levelized cost per kWh in the reference case in this Potential Study is about $0.05 per kWh. This is at the upper end of the costs shown for other states in Figure 24 and are similar to the costs researched by ACEEE for Vermont, California, Rhode Island, Connecticut and Massachusetts; this makes sense for at least two reasons.

First, the portfolio of programs modeled for this Study is comprehensive in scope. It includes a wide variety of measures and programs covering all customer sectors, including hard-to-reach markets. Such is the nature of the portfolios run by administrators in the states listed above. If cost-effectiveness was the only goal for energy efficiency, DSM program administrators would likely spend program funding on elements at the lower end of the supply curve.

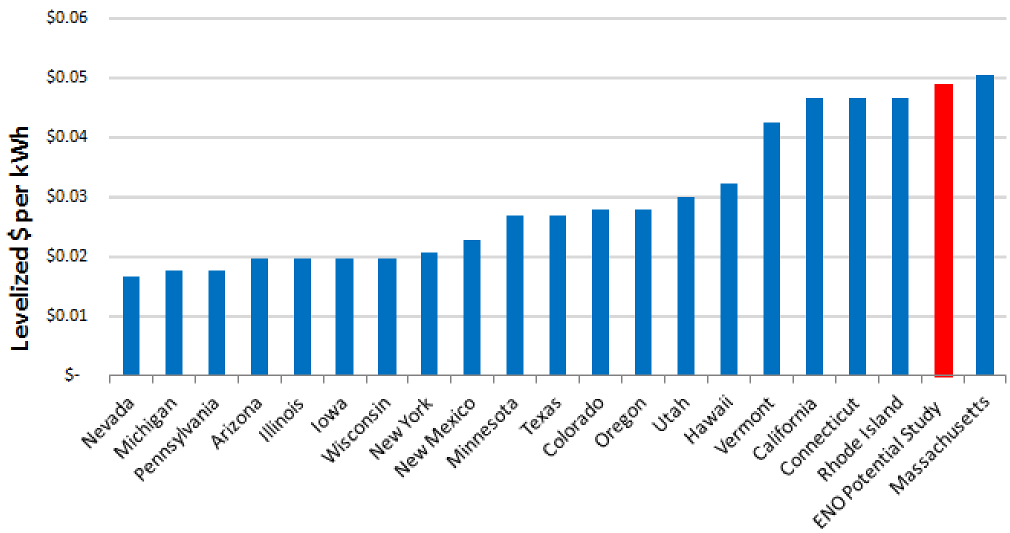
Second, costs in the ACEEE report reflect historical baselines, and heavy program reliance on very cost-effective, popular measures such as CFLs that will either not be available to programs in the future, or will have significantly diminished savings due to baseline changes. For example, according to Efficiency Vermont's 2010 Annual Report, 74% of cumulative residential program savings in 2010 were due to lighting measures.[58] By comparison, only 39% of cumulative residential program savings for ENO is forecasted to be due to lighting measures -- this is largely due to the impacts of EISA 2007. Given what ICF knows today, such improvements to technology and new construction minimum efficiency standards mean that, all else equal, future programs are likely to be less cost-effective than historical programs.

[56] Maggie Molina. The Best Value for America’s Energy Dollar: A National Review of the Cost of Utility Energy Efficiency Programs. ACEEE Report U1402. March 2014.

[57] Note that that the levelized costs reported in the ACEEE report reflect savings at the meter, whereas costs in this Study are reported at generator. Also, ACEEE's assumed discount rate was 5%, whereas ENO's discount rate is closer to 7%. ACEEE estimates that accounting for line losses and bringing the savings to the generator level would reduce levelized costs about 7%, and that increasing the discount rate from 5% to 7% would increase levelized costs 10%. These adjustments were made to the levelized cost values reported by ACEEE, and are reflected in Figure 24.

[58] Efficiency Vermont. Annual Report 2010. February 2012.

Figure 24. Average Levelized Costs of Energy Efficiency in 20 States (2009-2012) and as Forecasted for ENO for this Potential Study (2015-2034)



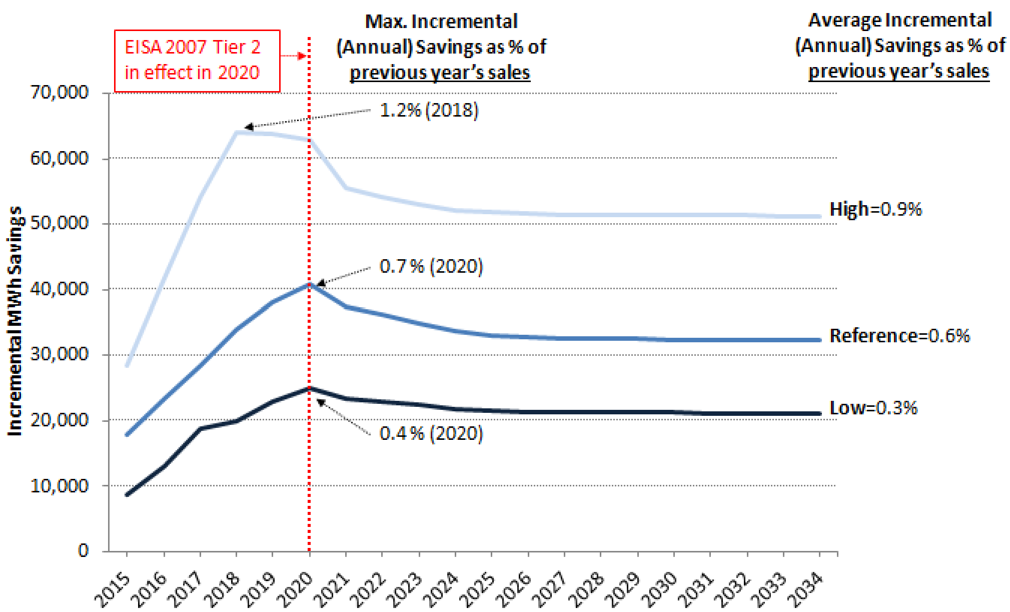
3.3 Incremental Savings Potential

Figure 25 shows the total incremental MWh savings[59] forecast by scenario. The graph shows that programs are assumed to have different ramp-up schedules in each scenario, with the schedules being the most aggressive in the high case due to the very high incentive levels.

Figure 25 also shows the impacts of EISA 2007 Tier 2, where savings drop significantly post-2020. Prior to 2020, ICF assumed ENO would pursue very aggressive (but achievable) CFL and LED lighting savings for bulb-types that will be phased-out.

[59] The difference between the amount of energy savings acquired or planned to be acquired as a result of energy efficiency activities in one year, and the amount of energy savings acquired or planned to be acquired as a result of the energy efficiency activities in the prior year.

Figure 25. Incremental MWh Savings, by Scenario



3.4 Savings in context

Figure 26 compares forecasted incremental savings impacts for this Study to savings impacts in Southern states achieved during 2010 through 2012. Column A describes the relevant statistic. Column B provides the statistical values in savings as % of load (i.e., savings as % of sales) for Southern states, and Column C provides a description of the forecast in this Study compared to Column B. To develop the statistics in this table, program performance data was aggregated across 27 EE portfolios and 10 states in the South[60] over 2010 to 2012.[61] In total there were 76 administrator-program year pairings used for benchmarking. This data is shown in the Appendix.

Average reference case savings impacts forecasted for this Study are equal to the 86th percentile of the benchmarking sample, or 0.6% of sales. In simple terms, this means ICF forecasts that ENO's DSM portfolio could achieve higher savings impacts than did 86% of Southern DSM portfolios during the 2010 to 2012 period. ICF forecasts that, at a minimum, ENO could achieve median-level savings. The maximum level of savings in an average year is equal to the 98% percentile of Southern DSM portfolios during the 2010 to 2012 time period.

[60] Based on climate zone designations. States in Southern climate zones include: Alabama, Arkansas, Florida, Georgia, Louisiana, Mississippi, North Carolina, Oklahoma, South Carolina, Texas and Virginia.

[61] Using U.S. EIA Form 861 data.

Figure 26. Incremental Savings in Context

(A) Statistic	(B) Savings as % of Load of Southern Portfolios over 2010-12	(C) Relation of (B) to ENO Forecast Scenario (Savings as % of Load)
Minimum	<0.1%	
25th Percentile	0.2%	
50th Percentile (Median)	0.3%	Low case average
73rd Percentile	0.4%	Low case maximum (2020)
86th Percentile	0.6%	Reference case average
92nd Percentile	0.7%	Reference case maximum (2020)
98th Percentile	0.9%	High case average
99th Percentile	1.2%	High case maximum (2018)
Maximum	1.3%	
Average	0.3%	

It is appropriate to compare ENO program performance to that of other programs in the Southern region, and not to a broader, national database of programs for at least two reasons:

- **Comparable Retail Rates.** As shown in Figure 27, Louisiana has some of the lowest retail electric rates in the country. Although there are other barriers to EE besides cost, cost is important, and higher retail rates mean that measures pay for themselves faster, and are therefore more attractive to customers.

13-034 © 2013

Figure 27. U.S. Retail Electric Rates, 2013[62]

Census Division	2013 YTD Avg Retail Rate ($/kWh)
West South Central	$0.085
-Louisiana	$0.080
East South Central	$0.087
West North Central	$0.090
Mountain	$0.092
East North Central	$0.093
South Atlantic	$0.097
Pacific Contiguous	$0.121
Middle Atlantic	$0.129
New England	$0.145
Pacific Noncontiguous	$0.266
U.S. Total	**$0.101**

- **Comparable Weather.** Louisiana is in the Southern U.S. Climate region. This is relevant to EE because many measures, such as air conditioners and insulation, are weather sensitive. These measures have similar savings levels across states with similar climates. For example, air conditioners have a much higher number of operating hours in the South than in the North, and conversely, insulation results in more winter savings in the North than in the South. This is one reason why is it difficult to compare the performance of Southern and Northern programs.

It is true there are administrators with retail rates and weather that are comparable to ENO and that have achieved savings levels higher than that forecasted in this Study. However, those are exceptions and would need to be benchmarked against ENO on a case-by-case basis.

[62] Source: U.S. EIA Electric Power Monthly, February 2014.

4 Achievable Natural Gas Efficiency Potential

This section includes the presentation and analysis of ICF's forecast of total achievable natural gas energy efficiency potential for the ENO service area for 2015 through 2034. Total achievable potential is the sum of residential, commercial, and industrial potential. Gas savings and program cost estimates are shown, as well as benefit-cost estimates..

4.1 Cumulative Potential

Total achievable potential is the sum of achievable potential estimated for each measure in the analysis. Total cumulative achievable potential estimates are shown in Figure 21, along with cumulative savings[63] impacts. Figure 29 provides an overall summary of this Study's gas forecast including savings, savings impacts, costs, benefits, and cost-effectiveness. To review the forecast:

- ICF estimates that, in the reference case, ENO can achieve cost-effective cumulative gas savings equal to 0.5% of sales over the 2015 to 2034 time horizon. Total program costs over this 20-year period are estimated to equal $9 Million.[64] Total net benefits are estimated to equal $24 Million.
- In the high case, we estimate that ENO could achieve an additional 705,876 therms in savings for an additional $8 Million in program spending beyond the reference case. That is, in the high case, savings would increase 211% over reference case levels while spending would increase 189%.
- In the low case, ICF estimates that ENO would achieve 27% less savings than in the reference case, while costs would decrease 56% compared to the reference case.

[63] The summation of savings from multiple projects or programs over 2015-2034, taking into account the time of measure installation in the first year, annual energy savings for subsequent years, and the life of the installed measures.

[64] Including program incentive and non-incentive costs.

Figure 28. Cumulative Achievable Natural Gas Energy Efficiency Potential, by Scenario

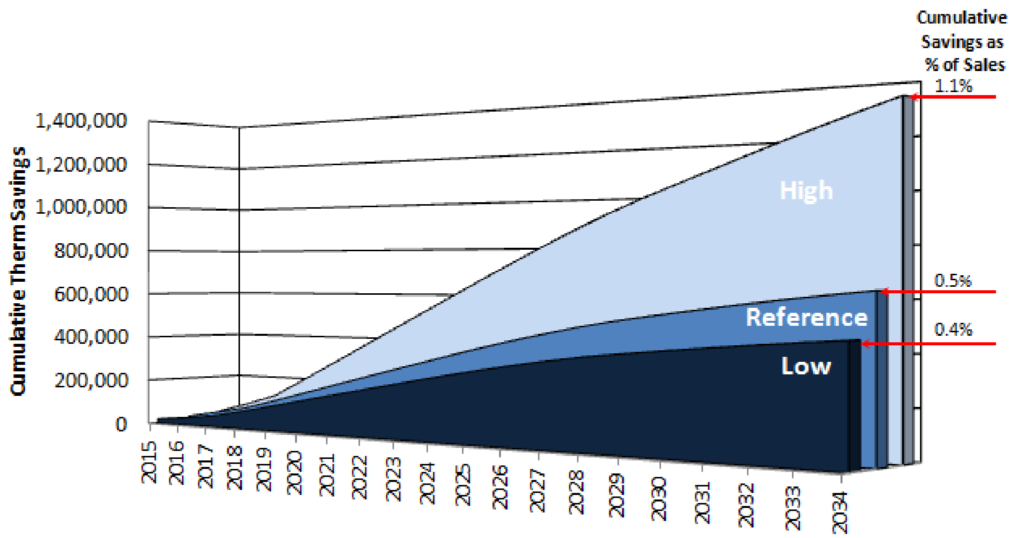


Figure 29. Total Gas Savings, Savings Impacts, Benefits, Costs and Costs-Effectiveness, by Scenario

Scenario	Cumulative Therm Savings (2015-2034)	Cumulative Therm Savings as % of Sales	Total TRC Benefits, 2015-2034 ($Mil.)	Total TRC Costs, 2015-2034 ($Mil.)[65]	Net TRC Benefits, 2015-2034 ($Mil.)[66]	TRC B/C Ratio	Total Program Costs, 2015-2034 ($Mil.)[67]	Level-ized Cost per Therm
Low	462,039	0.4%	$19	$5	$14	3.7	$4	$0.71
Reference	634,173	0.5%	$31	$6	$24	4.9	$9	$1.16
High	1,340,048	1.1%	$51	$17	$35	3.1	$17	$1.08

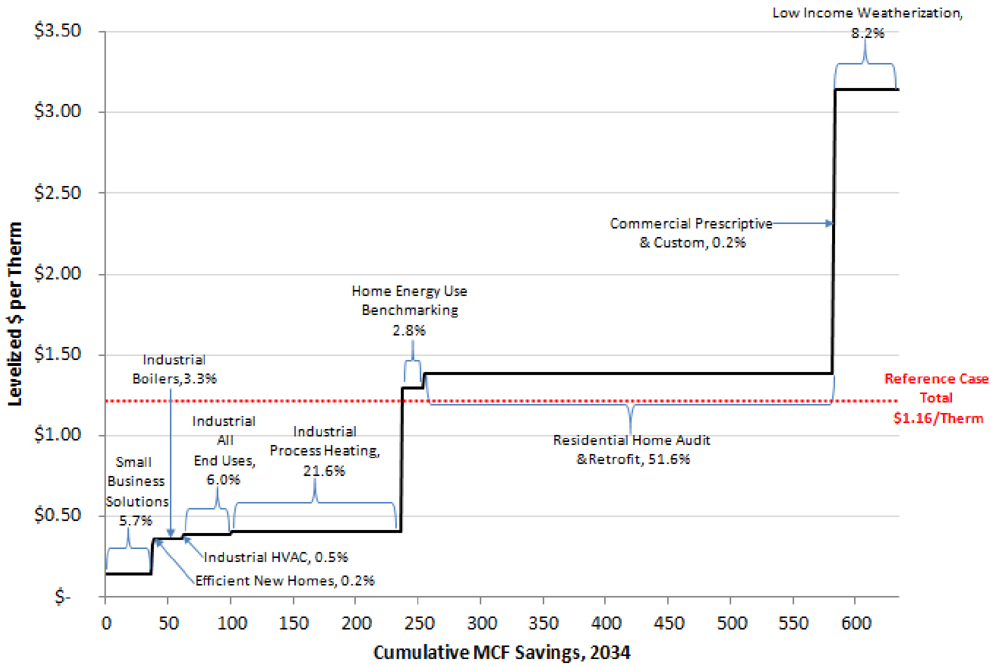
[65] TRC (Total Resource Cost) test costs include total measure incremental costs and program non-incentive costs over the time horizon of the forecast (2015-2034).

[66] TRC (Total Resource Cost) test benefits include gas (therm) costs avoided over the time horizon of the forecast (2015-2034).

[67] Program costs include incentive costs and non-incentive costs (e.g., administration, marketing, etc.).

Figure 30 shows the reference case gas efficiency supply curve, which plots cumulative gas savings on the x-axis and levelized program costs on the y-axis.[68] The first horizontal segment on the bottom left of the plot shows that 5.7% of savings could be achieved through the Small Business program at a cost of $0.14 per therm. Moving from left to right, each additional program shown in the graph is more costly on a per therm basis. Residential Home Audit and Retrofit is the program with the largest gas savings potential, while Efficient New Homes and Commercial Prescriptive and Custom have the smallest levels of gas savings potential.

Figure 30. ENO Gas Efficiency Supply Curve, Reference Case

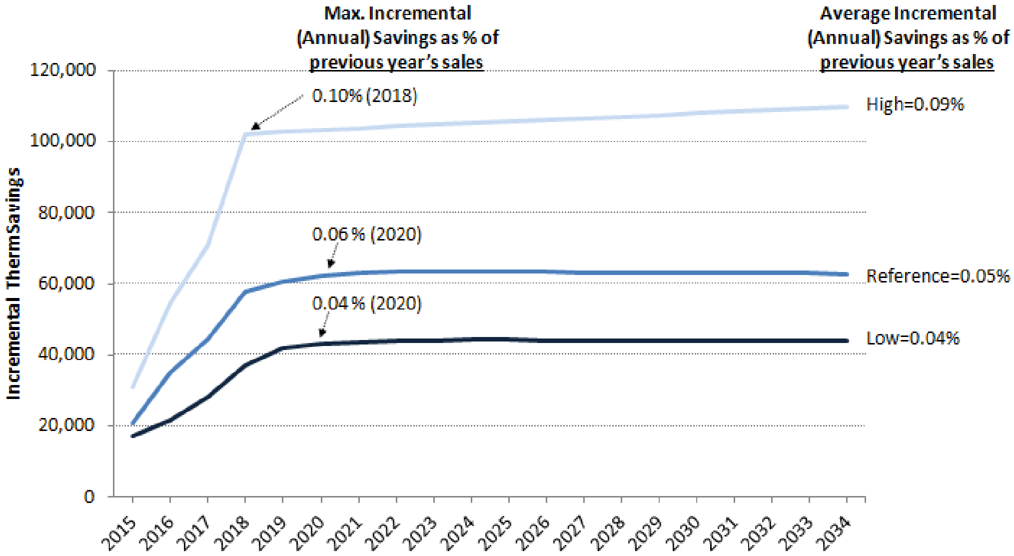


[68] Levelized costs are the result of a computational approach used to compare the cost of different projects or technologies. The stream of each project's net costs is discounted to a single year using a discount rate (creating a net present value) and divided by the project's expected lifetime output (Therms in this case).

4.2 Incremental Potential

Figure 31 shows the total incremental therm savings[69] forecast by scenario. The graph shows that programs are assumed to have different ramp-up schedules in each scenario, with the schedules being the most aggressive in the high case due to the very high incentive levels.

Figure 31. Incremental Achievable Natural Gas Energy Efficiency Potential, by Scenario



4.3 Gas Program Benchmarking

Research indicates there are an insufficient number of existing gas efficiency programs in the Southern region against which to benchmark the ENO gas potential forecasts. Finding appropriate peer administrators for ENO gas programs is further complicated by the unique composition of ENO's gas customer base, as shown in Figure 17.

Readers may note that gas savings potential is small compared to electric savings potential. There are at least three reasons for this:

[69] The difference between the amount of energy savings acquired or planned to be acquired as a result of energy efficiency activities in one year, and the amount of energy savings acquired or planned to be acquired as a result of the energy efficiency activities in the prior year.

1. The cost of natural gas is low, and forecasts at the time of the analysis indicate it will continue to be low for the foreseeable future. This limited the number of gas measures that passed the measure TRC cost-effectiveness screen.
2. For residential and commercial gas measures that are cost-effective, there is limited gas savings since these measures are weather sensitive. New Orleans is in the Southern U.S. Climate Region where there is a low number of annual heating degree days.
3. While most industrial gas measures are not weather sensitive, the market size for this sector is small—industrial constitutes only 2% of gas sales.

A key take-away from the gas analysis is that there is insufficient cost-effective gas potential for ENO to run "gas only" programs - the market size is simply too small. This does not mean cost-effective gas measures should not be considered by ENO, but that they should be included in programs that would be combined electric and gas offerings.

5 Combined Electric & Gas Benefits & Costs

Combined electric and gas program benefits and costs are shown in Figure 32.[70] As stated above in the Approach section, it was assumed that programs with gas measures would be operated jointly with their analogous electric programs. That is, we assumed there would be no stand alone gas programs. This is because there were not any cost-effective gas measures that required the creation of new programs, and because gas savings potential is too small in scale to operate gas programs independently of electric programs.

Ten of the programs described in Section 1.5.1, Programs Modeled, would include both electric and gas measures:

A. Residential Programs
    1. Efficient New Homes
    2. Home Audit and Retrofit
    3. Home Energy Use Benchmarking
    4. Low Income Weatherization
B. Commercial and Industrial Programs
    5. Commercial Prescriptive and Custom
    6. Industrial Boilers
    7. Industrial HVAC

[70] Figure 32 includes benefits and costs for all electric and gas programs, i.e., not just for the ten programs listed where there are electric and gas measures included.

8. Industrial Process Heating
9. Industrial All End Uses
10. Small Business Solutions

Figure 32. Combined Electric and Gas Benefits and Costs for All Programs

Scenario	Total TRC Benefits, 2015-2034 ($Mil.)	Total TRC Costs, 2015-2034 ($Mil.)	Net TRC Benefits, 2015-2034 ($Mil.)	TRC B/C Ratio	Total Program Costs, 2015-2034 ($Mil.)
Low	$201	$129	$72	1.6	$96
Reference	$324	$199	$124	1.6	$120
High	$841	$480	$355	1.8	$156

6 Appendices

A. Measure characteristics and assumptions
B. Net-to-gross assumptions
C. Payback acceptance curves and participation approaches utilized
D. Program level savings, costs and cost-effectiveness
E. Benchmarking data
F. Avoided costs

REQUEST FOR QUALIFICATIONS STATEMENTS

FOR

DEMAND SIDE MANAGEMENT CONSULTANT

ISSUED SEPTEMBER 15, 2017

APPENDIX X

ENTERGY NEW ORLEANS'

ENERGY EFFICIENCY POTENTIAL STUDY BY NAVIGANT

Entergy New Orleans – Energy Efficiency Potential Study

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DISCLAIMER

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1. EXECUTIVE SUMMARY

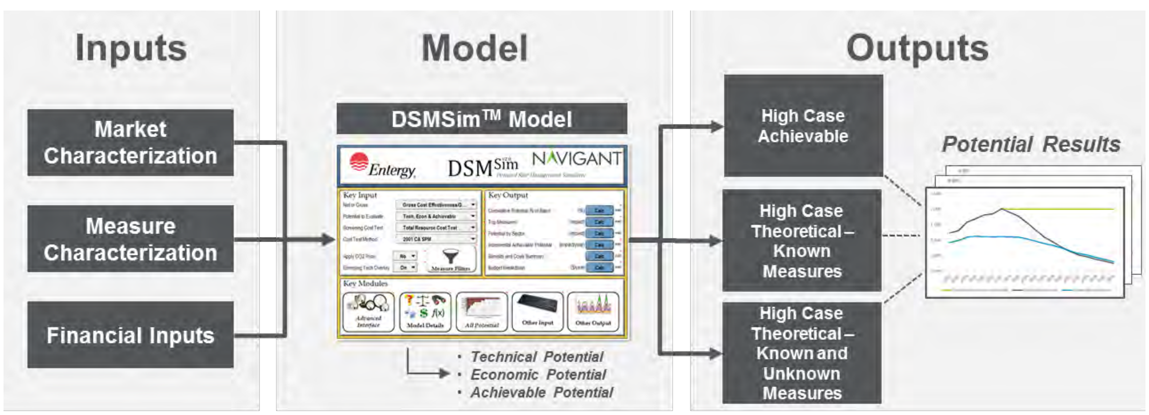
Introduction and Background

The New Orleans City Council (Council) recently issued a resolution that stated: "the Council believes it would be reasonable in the development of subsequent Energy Smart Program Years (Program Year 7 and beyond) for the Company to incorporate in its Energy Smart and IRP filings for evaluation by the Advisors, Intervenors, and the Council the goal of increasing the projected savings from the Energy Smart program by 0.2% per year, until such time as the program generates kWh savings at a rate equal to 2% annual kWh sales."[1] The purpose of this report is to provide an independent assessment of the EE savings potential for the ENO territory and to assess whether it is possible to achieve the 2% reduction goal in the ENO territory in a cost-effective manner.

Approach to Estimating Market Potential

Using Navigant's Demand Side Management Simulator (DSMSim™) model, Navigant calculated achievable energy efficiency potential across ENO's territory. As outlined in Figure 1, the central inputs to the model include characterizing the ENO territory market, characterizing the energy efficiency measures for inclusion in the analysis and solidifying financial model assumptions.

Figure 1. Energy Efficiency Potential Study Approach for ENO



[1] Resolution NO. R-15-599, Docket NO. UD-08-02, Council Review of Energy Smart Program Year 4 and Energy Smart Programs' Sources and Uses of Funds, and Available Funding Sources. December 10, 2015.

Source: Navigant

Market Characterization

Navigant worked with ENO to understand the breakdown of total electricity consumption by customer sector, based on ENO's forecast. Total electricity demand is projected to increase from 5,586 GWh in 2017 to 6,628 GWh in 2036, with almost proportional increases in residential and commercial and industrial (C&I) consumption. This electric consumption forecast serves as the basis of the energy efficiency market potential analysis. Details are provided in Appendix A.

Measure Characterization

This potential study leveraged the database of electric measures characterized as part of the 2015 Arkansas Energy Efficiency Potential study, which was conducted by Navigant.[2] The 2015 study used the Arkansas Technical Reference Manual (TRM) to specify the effective useful life (EUL) and how to calculate energy savings for each measure listed in the TRM. Because there is not a New Orleans or Louisiana TRM, using the Arkansas TRM was deemed appropriate by the Navigant team. Navigant developed estimates of implementation costs, estimates of measure density, baseline density and technical applicability in addition to calculating per unit savings based on the TRM. Electric-only impacts are captured as part this ENO analysis, and gas savings do not impact the cost-benefit evaluation of measures (i.e. if implementation of an electric measure increases or decreases gas use).

The Arkansas measure assumptions serve as a basis for this study given the relatively few changes in technology performance or measure costs since the 2015 study. In cases where material changes to measures have occurred, Navigant updated the underlying measures' assumptions to reflect more recent inputs.

Financial Inputs

Appendix A. Model Global Assumptions key global assumptions used in the analysis for all three scenarios. The significance of these global assumptions is that they serve as key financial and valuation parameters (e.g., inflation and discount rates, avoided costs, etc.) used in the calculation of the achievable potential.

Estimating Achievable Potential

Navigant evaluated three potential scenarios as part of this study which included the following:

- **Scenario 1: High Case Achievable**: Represents Navigant's best estimate regarding a level of EE potential that could be achievable by ENO with an aggressive roll-out of EE programs.
- **Scenario 2: High Case Theoretical – Known Measures**: Represents a theoretical level of potential under a set of conditions that may not be realistic. This theoretical scenario yields a

[2] Navigant Consulting, Inc., Arkansas Energy Efficiency Potential Study, June 1, 2015, http://www.apscservices.info/pdf/13/13-002-U_212_2.pdf

2.0% per year annual incremental savings potential as a percentage of utility sales in at least one year of the simulation horizon.

- **Scenario 3: High Case Theoretical – Known and Unknown Measures**: Identical to Scenario 2 with the exception that the incremental savings as a percentage of sales is assumed to be held at 2.0% per year after 2024, the year in which Scenario 2 reaches 2.0%.

Additional information about these scenarios is provided in Chapter 3.

Key Findings

Key study findings include the following:

- The High Case Achievable Scenario illustrates that with a comprehensive portfolio of efficiency measures, aggressive marketing and incentives, and realistic assumptions, ENO could cost-effectively reduce forecast load by roughly 17% over the next 20 years, an average of 0.85%/year. The cost of these savings is roughly $16 million/year in 2017 and $25 million/year in 2024. Costs decline thereafter as the market for known measures saturates. This portfolio is cost effective with a Total Resource Cost (TRC) ranging from 1.7-2.0 over the simulation horizon.
- The High Case Theoretical – Known Measures Scenario calculates the potential savings and program cost for a scenario where a peak incremental savings as a percentage of forecast sales equals 2.0%, which occurs in 2023 and declines thereafter due to market saturation of known measures. In this scenario, forecast load could be reduced by 23.4% over the 20-year simulation horizon, an average of 1.17%/year. Costs for this scenario are considerably higher than in the High Case Achievable Scenario due to higher incentive levels and increases in marketing expenditures. Annual expenditures to achieve this ramp up are roughly $59 million in 2017, rising to about $112 million in 2023 and declining thereafter due to market saturation. However, the high ramp rate of this scenario is likely unrealistic and would be difficult to achieve under real-world conditions.
- The High Case Theoretical – Known and Unknown Measures Scenario calculates the potential savings and costs for a portfolio that ramps up to 2.0%/year of incremental savings by 2023, and holds that level of incremental savings through 2036. This scenario requires the assumption that emerging efficiency measures, not currently known, will enter the market at a cost roughly equivalent to the modeled costs in 2023, escalated for inflation. This scenario is therefore the most theoretical and costly of all three scenarios, and requires assumptions that are highly theoretical and have not been proven in actual market conditions.

The incremental potential savings as a percentage of sales,[3] and the calculated budgets required, for each of the three scenarios analyzed are provided below in Table 1 and Table 2.

[3] Navigant used a fixed forecast which does not change with each increment of efficiency achieved year over year.

Table 1. Incremental Potential by Scenario As a Percentage of Forecasted Sales

Year	Achievable	Theoretical Known Measures	Theoretical Known + Unknown Measures
2017	0.92%	1.23%	1.23%
2018	0.99%	1.30%	1.30%
2019	1.09%	1.58%	1.58%
2020	1.13%	1.69%	1.69%
2021	1.11%	1.81%	1.81%
2022	1.10%	1.85%	1.85%
2023	1.11%	2.01%	2.01%
2024	1.10%	1.90%	2.00%
2025	1.10%	1.77%	2.00%
2026	1.04%	1.55%	2.00%
2027	0.96%	1.33%	2.00%
2028	0.89%	1.09%	2.00%
2029	0.83%	0.94%	2.00%
2030	0.74%	0.77%	2.00%
2031	0.65%	0.63%	2.00%
2032	0.57%	0.52%	2.00%
2033	0.51%	0.46%	2.00%
2034	0.44%	0.38%	2.00%
2035	0.38%	0.32%	2.00%
2036	0.31%	0.25%	2.00%

Table 2. Estimated Total Budget by Scenario

Year	Achievable	Theoretical Known Measures	Theoretical Known + Unknown Measures
2017	$16,337,839	$59,178,008	$59,178,008
2018	$18,497,144	$64,668,401	$64,668,401
2019	$20,693,198	$77,904,113	$77,904,113
2020	$22,242,507	$85,198,537	$85,198,537
2021	$22,604,926	$94,963,854	$94,963,854
2022	$23,269,646	$99,948,935	$99,948,935
2023	$24,540,273	$111,776,522	$111,776,522
2024	$24,855,094	$110,115,415	$112,248,420
2025	$24,577,105	$103,770,105	$114,462,735
2026	$23,869,782	$95,241,648	$116,931,982
2027	$22,715,858	$85,292,210	$119,535,115
2028	$22,491,790	$76,982,709	$122,477,648
2029	$21,262,691	$66,801,521	$125,236,611
2030	$19,569,272	$57,773,006	$128,062,123
2031	$17,918,234	$50,518,123	$131,014,890
2032	$16,306,604	$44,381,172	$134,102,404
2033	$14,820,661	$39,347,486	$137,104,595
2034	$13,493,010	$35,351,082	$140,266,300
2035	$12,327,376	$32,199,756	$143,532,518
2036	$11,391,712	$30,363,460	$147,103,475

2. INTRODUCTION

Background

The New Orleans City Council (Council) recently issued a resolution that stated: "the Council believes it would be reasonable in the development of subsequent Energy Smart Program Years (Program Year 7 and beyond) for the Company to incorporate in its Energy Smart and IRP filings for evaluation by the Advisors, Intervenors, and the Council the goal of increasing the projected savings from the Energy Smart program by 0.2% per year, until such time as the program generates kWh savings at a rate equal to 2% annual kWh sales." [4] The purpose of this report is to provide an independent assessment of the EE savings potential for the ENO territory and to assess whether it is possible to achieve the 2% reduction goal in the ENO territory in a cost-effective manner.

Organization of Report

This report is organized as follows:

- Section 3 describes the approach to estimating achievable potential and the scenarios evaluated.
- Section 4 describes the results of the high case achievable, high case theoretical known measures, and high case theoretical known and unknown measures scenarios.
- Section 5 benchmarks this study's achievable potential results against neighboring states and utilities.
- Section 6 provides program recommendations for immediate and future implementation.
- Appendix A provides additional modeling assumptions.

Caveats and Limitations

The caveats and limitations associated with the results of this study are detailed in this section.

Forecasting Limitations

Navigant obtained future energy sales forecast from ENO. This forecast contains assumptions, methodologies, and exclusions. Navigant has leveraged the assumptions underlying these forecasts, as much as possible, as inputs into the development of the Reference Case stock and energy demand projections. Where sufficient and detailed information could not be extracted, Navigant developed independent projections of commercial building stock. These independent projections were developed based on secondary data resources and in collaboration with ENO. These secondary resources and any underlying assumptions are referenced throughout this report.

[4] Resolution NO. R-15-599, Docket NO. UD-08-02, Council Review of Energy Smart Program Year 4 and Energy Smart Programs' Sources and Uses of Funds, and Available Funding Sources. December 10, 2015.

Program Design

The results of this study provide a big picture view of future savings potential in ENO's service territory. However, this study is not considered a detailed program design tool. The nature of potential studies is for long-term planning and hence estimates should not be applied to short-term DSM planning activities.

Measure Characterization

Efficiency potential studies may employ a variety of primary data collection techniques (e.g., customer surveys, on-site equipment saturation studies, and telephone interviews), which can enhance the accuracy of the results, though not without associated cost and time requirements. Due to the limited timeline for the development of this potential study for the ENO territory, Navigant utilized the measure characterization from a 2015 EE potential study conducted by Navigant for Entergy Arkansas and six other investor-owned utilities in that state.[5] Additional reasons for leveraging this study include similar energy efficiency measure mixes, comparable climate, and the existence of an established Technical Reference Manual (TRM), (which Louisiana and New Orleans currently do not have). To ensure the analysis accounted for differences in ENO's territory in 2017, Navigant made several key adjustments to the Arkansas-based EE measures to reflect 2017 markets and ENO's unique conditions.

Furthermore, the team considers the measure list used in this study to appropriately focus on those EE measures likely to have the highest impact on savings potential over the potential study time horizon. However, there is always the possibility that emerging technologies may arise that could increase savings opportunities over the forecast horizon, and broader societal changes may affect levels of energy use in ways not anticipated in the study.

Net Savings Study

Navigant and ENO agreed to show savings from this study at the net level, rather than gross, consistent with the existing reporting requirements and savings goals established as net of free-ridership. This means all savings reported in this study account for the effect of possible free ridership.

Unknown Measures

The High Case Theoretical – Known and Unknown Measures scenario assumes a hypothetical suite of currently unknown measures will become available in the future at an assumed aggregate cost ($/kWh basis) that is extrapolated from the modeled output. These specific measures (e.g., possible future emerging technologies not currently on the market) have not been identified as part of this study and would potentially permit maintaining the modeled level of savings.

Study Uncertainty

[5] Navigant Consulting, Arkansas Energy Efficiency Potential Study, June 1, 2015, http://www.apscservices.info/pdf/13/13-002-U_212_2.pdf

The forecasting nature of potential studies have inherent uncertainty. Potential studies include thousands of data points and assumptions, including utility forecasting, measure parameters, existing saturation levels, avoided costs, program assumptions, measure costs, and other inputs. Eliminating uncertainty is impossible, but the use of best available data minimizes the impact of these uncertainties.

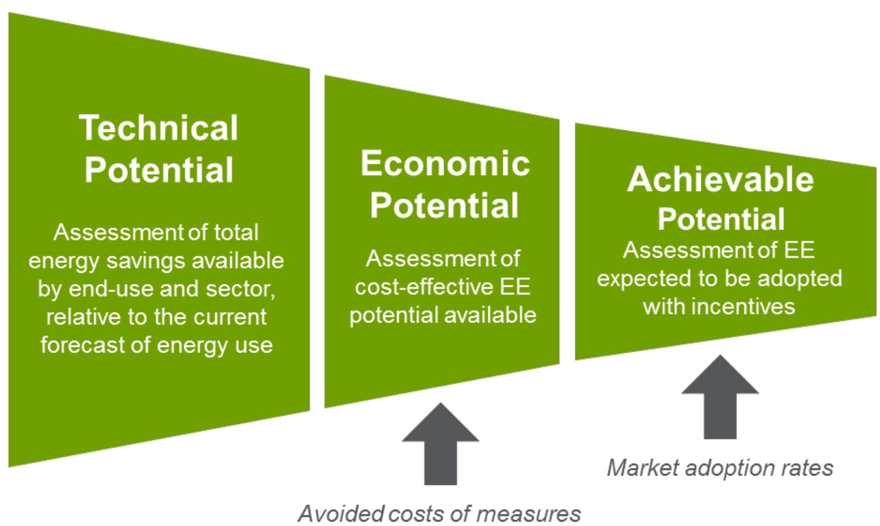
3. APPROACH TO ESTIMATING ACHIEVABLE POTENTIAL

This section describes the methodology Navigant employed for estimating energy savings across the ENO service territory, including measure characterization, reference case forecast, and the definition of technical, economic, and achievable potential.

Estimating Achievable Potential

Figure 2 shows a graphical representation of technical, economic, and achievable potential. Navigant follows methodologies for conducting energy efficiency potential studies that have been developed and refined over the years through industry experience and guidebooks.[6] This study defines technical potential as the total energy savings available, assuming all installed measures can *immediately* be replaced with the "efficient" measure/technology—wherever technically feasible—regardless of the cost, and market acceptance. Economic potential is a subset of technical potential, using the same assumptions as technical potential, but including only those measures that have passed the benefit-cost test chosen for measure screening. Achievable potential is a subset of economic potential that considers the likely rate of DSM acquisition, given factors like the rate of equipment turnover, simulated incentive levels, consumer willingness to adopt efficient technologies, and the likely rate at which marketing activities can facilitate technology adoption. The goal of this study is to calculate the electric achievable potential in ENO service territory.

Figure 2. Technical, Economic, and Achievable Potential



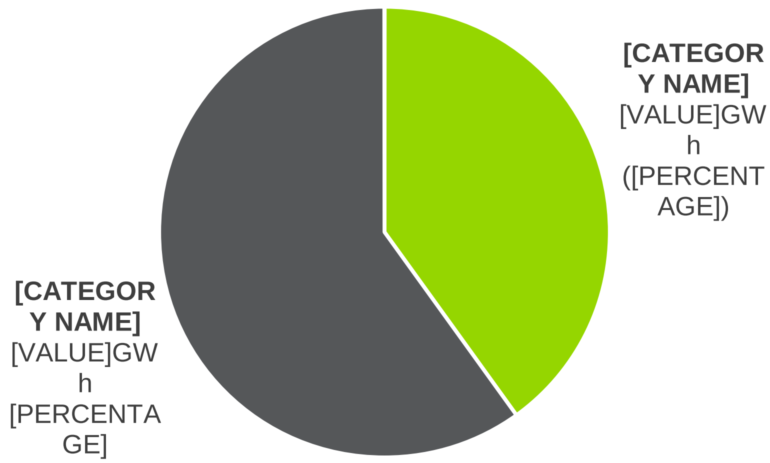
Source: Navigant

[6] For more general information on methods and approaches used for energy efficiency potential studies, please see USEPA/USDOE joint report titled *Guide for Conducting Energy Efficiency Potential Studies: A Resource of the National Action Plan for Energy Efficiency*, November 2007.

Market Characterization

Figure 3 shows the breakdown of total electricity consumption by customer sector forecasted for 2017, based on ENO's load forecast. Approximately, 40% of electricity consumption comes from the residential sector – equivalent to 2,346 GWh – while 60% comes from the commercial and industrial (C&I) sector – equivalent to 3,510 GWh.

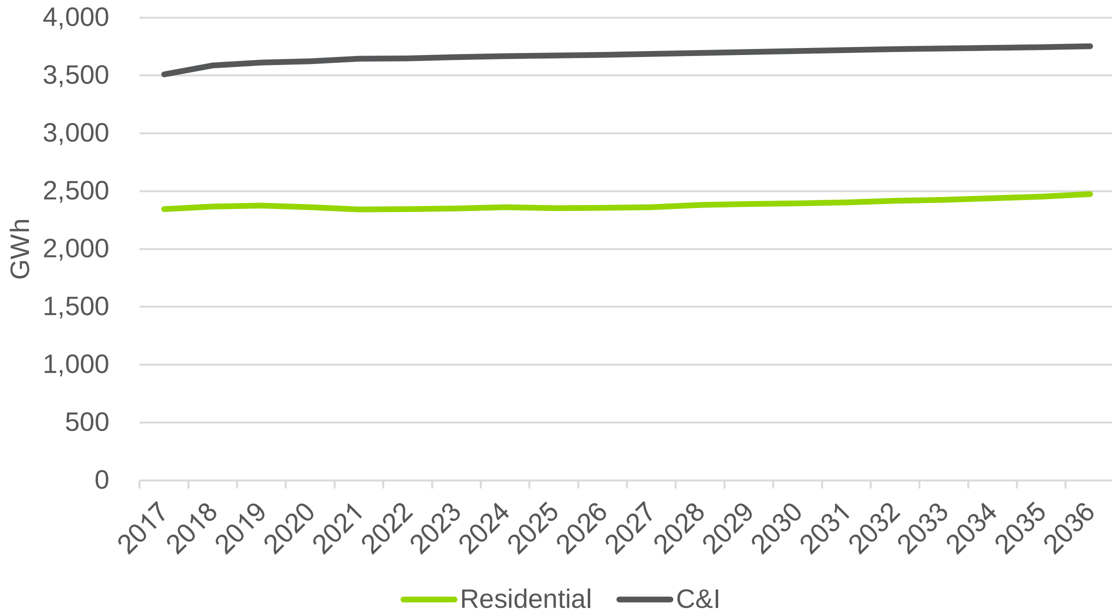
Figure 3. 2017 Electricity Consumption by Sector (Total = 5,586 GWh)



Source: ENO Load Forecast

Figure 4 shows the forecast of residential and C&I electricity consumption through 2036. Total electricity demand is projected to increase from 5,586 GWh in 2017 to 6,628 GWh in 2036, with almost proportional increases in residential and C&I consumption. Residential consumption increases 6% to 2,476 GWh in 2036, while C&I consumption increases 7% to 3,752 GWh in 2036. Table 3. 2017-2036 ENO Electricity Consumption Forecast by Sector (GWh) shows the ENO's tabular load forecast. Figure 4 shows ENO's load forecast in tabular form.

Figure 4. 2017-2036 ENO Electricity Consumption Forecast by Sector



Source: ENO Load Forecast

Table 3. 2017-2036 ENO Electricity Consumption Forecast by Sector (GWh)

Sector	2017	2020	2025	2030	2036
Residential	2,346	2,361	2,354	2,395	2,476
Commercial & Industrial	3,510	3,622	3,671	3,711	3,752
Total	**5,856**	**5,983**	**6,025**	**6,105**	**6,228**

Source: ENO Load Forecast

Measure Characterization

This potential study leveraged the database of electric measures characterized as part of the 2015 Arkansas Energy Efficiency Potential study. In 2015, Navigant conducted an Arkansas-wide study of energy efficiency potential for the seven investor-owned electric and gas utilities in Arkansas, including Entergy Arkansas, Inc. The 2015 study used the Arkansas Technical Reference Manual (TRM) to specify the effective useful life (EUL) and calculations for energy savings for each measure listed in the TRM. Navigant developed estimates of implementation costs, measure density, baseline density and technical applicability in addition to calculating per unit savings based on the TRM. This ENO analysis differs from the 2015 study in that it captures electric-only impacts. This study also assumes that gas savings do not impact the cost-benefit evaluation of measures (i.e. if implementation of an electric measure increases or decreases gas use).

Information regarding the allocation of end use energy, energy intensities, the existing saturation of energy-efficient devices, etc. required to estimate the EE potential for each measure was derived from a variety of sources. The Arkansas measure-assumptions serve as a basis for this study given the relatively few changes in technology performance or measure costs since the 2015 study. In cases where changes to measure inputs have occurred, Navigant updated the underlying measure assumptions to reflect those changes. Similarly, where ENO-specific information was available, such as penetration of electric space heating, heat pumps, and space cooling, Navigant used these specific ENO inputs. The following list details specific adjustments made to the modeled measures to reflect 2017 data and ENO territory characteristics:

- All costs assumptions for LED measures were updated to reflect declines in technology costs.
- LED baseline technologies through 2020 are assumed to be EISA compliant. 2020 and beyond, baseline wattages are at CFL levels.
- All CFL and standard T8 fluorescent retrofits have been removed.
- All high bay lighting retrofits are LED.
- LED lamp and fixture retrofit options have been added.
- Home energy reports have a higher technical applicability than the Arkansas study.
- Duct sealing savings have been updated based on the Evaluation of PY5 Energy Efficiency Programs Portfolio, July 2016 report submitted by ADM Associates, Inc.
- Smart thermostat saturation levels have been reduced, indicating higher technical potential for this measure than the Arkansas study.
- Baseline saturation levels have been modified (percent of eligible stock that are at baseline conditions – i.e. are not retrofitted) for ceiling insulation, wall insulation, and central air conditioners by 20% to adjust for higher efficiency conditions because of re-construction post-Katrina. See Appendix A for more details.

The measure characterization consisted of estimating and defining key parameters across the various residential and C&I customer segments and inputting them into the **DSMSim™** model to calculate the various potential scenarios. Navigant defined the parameters as follows:

1. **Measure Description:** Qualitatively indicates the EE action that is being performed by this measure.
2. **Baseline Assumption**: The baseline technology (base) characterized per the Arkansas TRM or Navigant's engineering assumptions. The base represents existing technology.
3. **End-Use, Sector and Segment Mapping:** These parameters facilitate the mapping of each measure to the appropriate end uses, sectors, and customer segments.
4. **Measure Lifetime:** The lifetime in years for the base and EE technologies. The base and EE lifetime only vary in instances where the two cases represent inherently different technologies, such as LED or CFL bulbs compared to a baseline incandescent.
5. **Measure Costs:** The base (existing or code-based) and EE material and labor costs are used as inputs for the incremental measure costs.
6. **Annual Energy Consumption:** The annual energy consumption in kilowatt-hours (kWh) for each of the base and EE technologies.

Approach to Achievable Potential Scenarios

This section describes the three achievable potential scenarios included in this study.

Scenario 1: High Case Achievable Potential

The High Case Achievable Potential scenario represents Navigant's best judgment regarding a level of EE potential that would be achievable with an aggressive roll-out of EE programs. The modeled measures cover a broad array of efficiency measures in existence today, adjusting for some known technology cost and efficiency advancements across the residential, commercial, and industrial sectors. It assumes aggressive, yet realistic, levels of program marketing of both hardware and behavioral measures, in addition to a comparatively high level of incentives. It further assumes that all measures are screened for cost effectiveness using a total resource cost (TRC) test. [7,8] A summary of key modeling assumptions is provided below.

- TRC >= 1.0 at the measure level. Overall portfolio is also cost effective.
- Incentives cover ~60% of a measure's total incremental cost.
- High, yet realistic, assumed program marketing effectiveness.
- Administrative costs on a $/kWh basis are roughly in line with historic levels.
- Includes known measures in existence today.

Scenario 2: High Case Theoretical – Known Measures

The High Case Theoretical – Known Measures scenario represents a theoretical level of potential under a set of conditions that may not be realistic. This theoretical scenario yields a 2.0%/year annual incremental savings potential as a percentage of utility sales in at least one year of the simulation horizon. To model the potential of this scenario, the requirement for measure-level cost effectiveness was reduced to a TRC >=0.3. To generate a fast adoption profile over time, the program marketing effectiveness values are higher than realistic. Further, this scenario assumes all incentives cover 100% of incremental measure cost, which is also higher than realistic. Similar to the High Case Achievable Potential scenario, this scenario only includes measures known to be in existence today. A summary of key modeling assumptions is provided below.

- TRC >= 0.3 at the measure level.
- Incentives cover 100% of a measure's total incremental cost.
- Very high program marketing effectiveness.
- Administrative costs are ~50% higher than historic administrative costs, due to the increased marketing requirements.

[7] The total resource cost test, TRC, is a benefit to cost ratio that includes the benefits and costs from the perspective of all customers in a utility service territory. The benefits are typically the avoided energy and capacity costs (sometimes other benefits are included) and the costs are the program costs (not including incentives) plus the incremental measure costs.
[8] "Understanding Cost-Effectiveness of Energy Efficiency Programs: Best Practices, Technical Methods, and Emerging Issues for Policy-Makers" Nov 2008, https://www.epa.gov/sites/production/files/2015-08/documents/cost-effectiveness.pdf

- Includes measures known to be in existence today.

Scenario 3: High Case Theoretical – Known and Unknown Measures

The High Case Theoretical – Known and Unknown Measures scenario is identical to Scenario 2 with the exception that the incremental savings as a percentage of sales is assumed to be held at 2.0%/year after 2024, the year in which Scenario 2 reaches 2.0%. In Scenario 2, the simulated model output shows a marked decline in incremental annual potential due to saturation of the market for efficiency technologies. Scenario 3 holds the incremental savings level constant. This analysis does not postulate specific measures that would account for the difference between Scenario 2 and Scenario 3; as such, it is assumed that some set of measures unknown now would be introduced at the same incremental cost as simulated in 2023, escalated only for inflation.

A summary of key modeling assumptions is provided below.

- TRC >= 0.3 at the measure level.
- Incentives cover 100% of a measure's total incremental cost.
- Very high program marketing effectiveness.
- Administrative costs are ~50% higher than historic administrative costs, due to the increased marketing requirements.
- Includes known measures in existence today and unknown measures not currently on the market but presumed to be potentially available in the future. The unknown measure costs equal the costs seen in 2023, the year in which incremental annual potential peaked in Scenario 2, and are escalated for inflation.

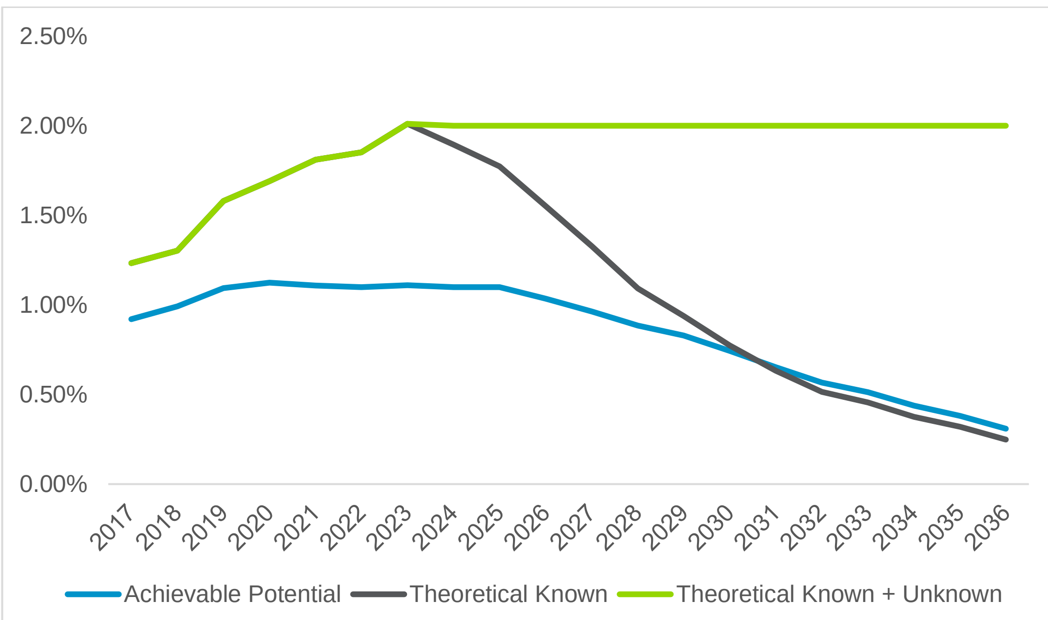
4. RESULTS

The following section outlines the results of the efficiency potential analysis. The following section include results for the three separate scenarios, as described in Chapter 3:

- Scenario 1: High Case Achievable
- Scenario 2: High Case Theoretical – Known Measures
- Scenario 3: High Case Theoretical – Known and Unknown Measures

Figure 5 provides an estimate of the incremental annual potential as a percentage of unadjusted forecast sales[9] in the absence of efficiency programs from 2017 – 2036 for each scenario, which are described in detail in the subsequent sections.

Figure 5. Electric Incremental Potential as Percentage of Forecasted Electric Sales 2017 – 2036



Scenario 1: High Case Achievable Forecast

The High Case Achievable Potential Forecast represents Navigant's best judgment regarding a level of EE potential that would be achievable with an aggressive roll-out of EE programs.

Table 4 shows the high case achievable results by sector, cumulatively and incrementally by year. In this scenario, we estimate that ENO has the potential to achieve a cumulative savings of 1,057 GWh by 2036,

[9] Navigant used a fixed forecast which does not change with each increment of efficiency achieved year over year.

or an average annual savings of 53 GWh per year, on a net basis (i.e., accounting for estimate free ridership).

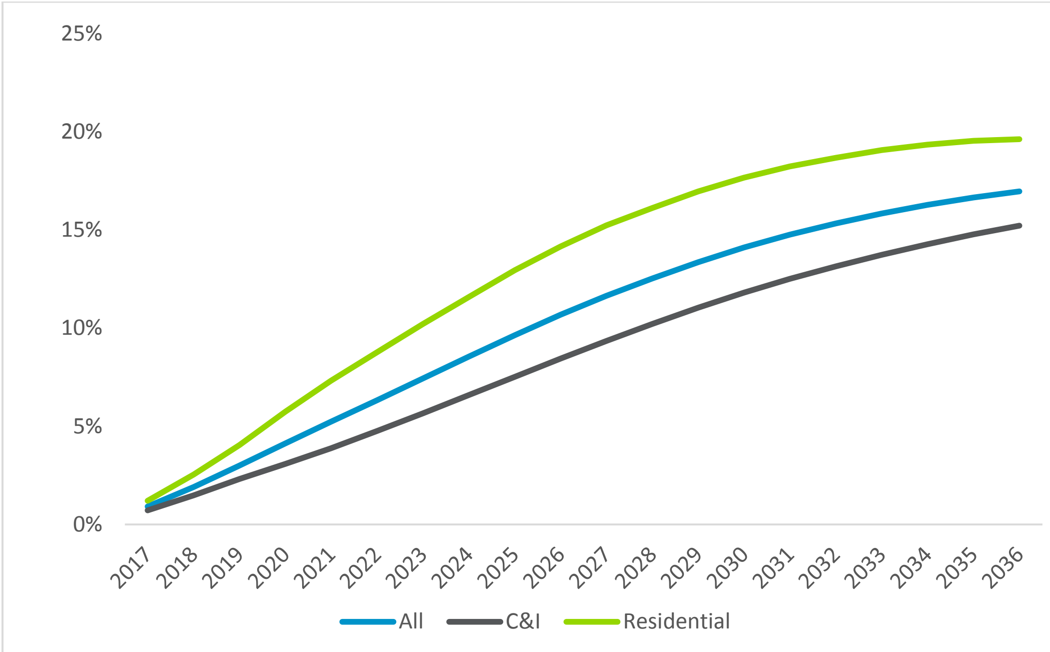
Table 4. Cumulative & Incremental Achievable Potential (GWh/Year)

	Cumulative			Incremental		
Year	**C&I**	**Res**	**All**	**C&I**	**Res**	**All**
2017	26	28	54	26	28	54
2018	53	61	114	28	32	60
2019	84	96	180	30	36	66
2020	112	136	247	28	39	67
2021	142	172	314	30	36	67
2022	174	206	380	32	34	66
2023	208	240	448	33	34	68
2024	242	274	515	34	33	68
2025	276	305	582	35	31	66
2026	311	334	645	34	29	63
2027	345	360	705	34	26	60
2028	378	384	762	33	24	57
2029	409	405	814	31	21	52
2030	438	423	862	29	18	47
2031	466	439	904	27	15	43
2032	490	452	942	25	13	38
2033	513	463	976	23	11	34
2034	534	472	1006	21	9	30
2035	554	479	1033	19	8	27
2036	571	486	1057	18	7	24

Note: C&I and Res refer to Commercial, Industrial, and Residential Sectors, respectively.

Values defined as “cumulative potential” represent the accumulation of each year’s annual achievable potential. For example, an annual achievable potential of 20 GWh per year results in a cumulative achievable potential of 100 GWh over a 5-year period. The same concept applies to achievable potential results represented as a percentage of sales; an annual achievable potential of 0.9% per year, for ten years, would result in a cumulative achievable potential of 9 percent of forecasted sales. Figure 6 below show the cumulative achievable potential as a percentage of forecasted electric sales for this study. We see below that ENO can reduce forecast sales in 2036 by 17% with a comprehensive set of efficiency programs that are aggressively marketed and incentivized.

Figure 6. Cumulative Achievable Potential by Sector as a Percentage of Forecasted Sales



As illustrated above, although C&I has the greater potential in absolute terms, measuring by GWh/year, the residential sector has the greatest cumulative potential savings as a percentage of forecast sales, with an opportunity to reduce forecast sales by ~20% over the study horizon. The high potential for duct sealing, insulation, and air conditioning tune-ups drives this forecasted savings.

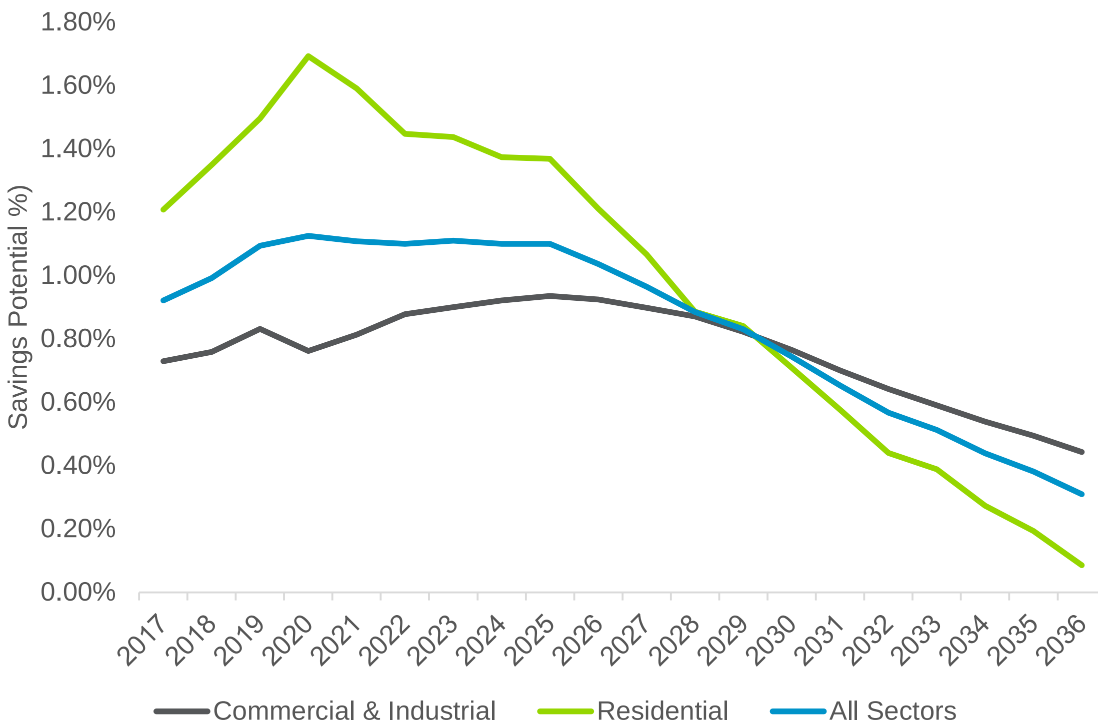
Potential savings can also be represented on a yearly basis as “incremental” annual achievable potential. Table 5 and Figure 7 show ENO’s incremental achievable savings per year from 2017 – 2036 as a percentage of sales. As seen below, savings potential quickly ramps up to ~1%/year after 2019 and stays slightly above this value for roughly a decade. After ~10 years, incremental annual potential as a percentage of sales tails off due to known measure saturation of the market. In other words, the bucket of potential savings begins to empty, and therefore the rate at which the bucket of savings can be implemented diminishes over time. Given sufficient time, the incremental annual potential would be reduced to zero once all savings were completely harvested, unless replenished by new savings opportunities due to the emergence of new technologies, or introduction of new building stock through new construction.

Table 5. Incremental Achievable Potential as a Percentage of Forecasted Sales

Year	C&I	Res	All
2017	0.73%	1.21%	0.92%
2018	0.76%	1.35%	0.99%
2019	0.83%	1.50%	1.09%
2020	0.76%	1.69%	1.13%
2021	0.81%	1.59%	1.11%
2022	0.88%	1.45%	1.10%
2023	0.90%	1.44%	1.11%
2024	0.92%	1.37%	1.10%
2025	0.94%	1.37%	1.10%
2026	0.92%	1.21%	1.04%
2027	0.90%	1.07%	0.96%
2028	0.87%	0.89%	0.89%
2029	0.82%	0.84%	0.83%
2030	0.77%	0.71%	0.74%
2031	0.70%	0.58%	0.65%
2032	0.64%	0.44%	0.57%
2033	0.59%	0.39%	0.51%
2034	0.54%	0.27%	0.44%
2035	0.49%	0.19%	0.38%
2036	0.44%	0.09%	0.31%

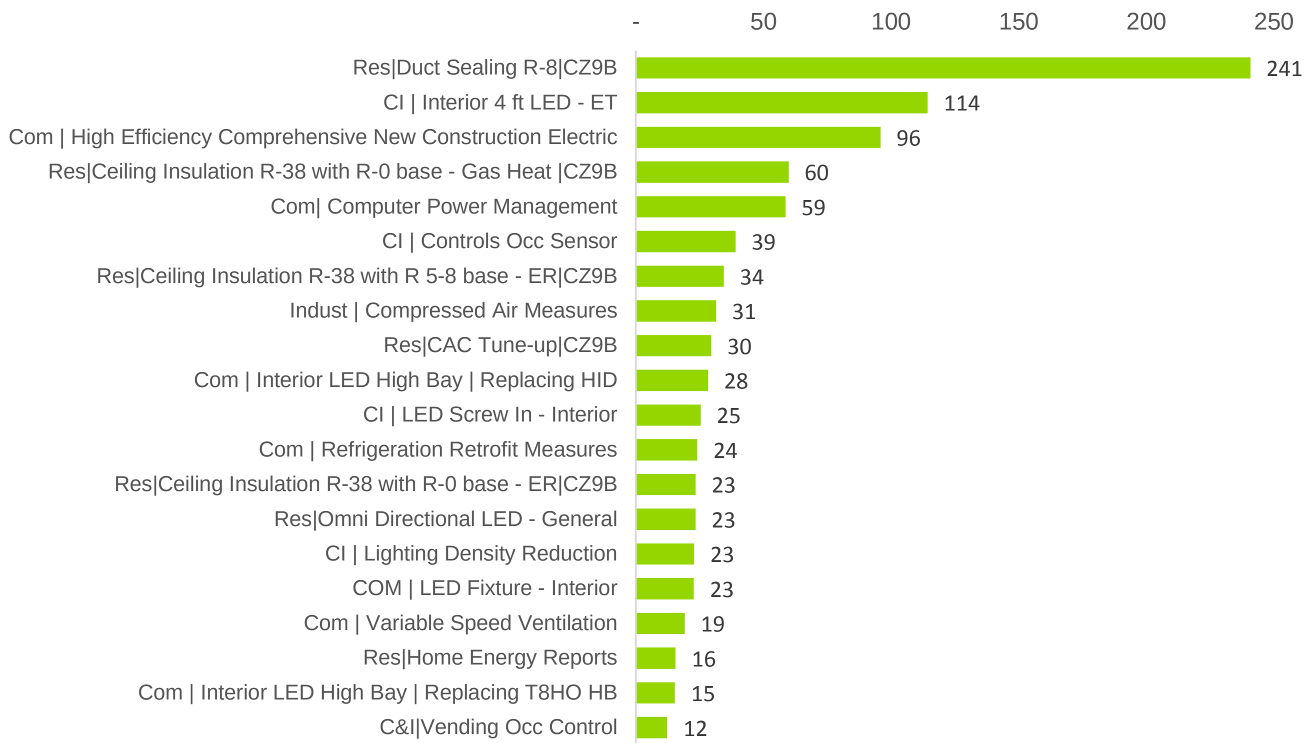
Note: C&I and Res refer to Commercial, Industrial, and Residential Sectors, respectively.

Figure 7. Incremental Achievable Potential as a Percentage of Forecasted Sales



In addition to overall results by sector, the analysis yielded results by measure. The measure with the highest potential was duct sealing in the residential sector, followed by high efficiency new construction and interior 4-ft LED lights, both in the commercial and industrial sector. These measure results are based on the measure characterizations described in Chapter 3, which are consistent with industry standards and benchmarked to ENO program performance in previous years. Figure 8 shows the top 20 achievable potential measures by average annual GWh, a key input into the incremental and cumulative achievable potential results outlined above.

Figure 8. Cumulative Achievable Potential 2017 – 2036 – Top 20 Measures (GWh)



Budget

The budget estimate for the high case achievable scenario is presented below in Table 6, which includes an estimate of administration cost as well as incentive costs. Administration costs of $0.135/kWh are slightly higher than historical administrative costs in ENO’s service territory due to adjustments for inflation. Incentive costs were calculated based on forecast measure adoption, incremental measure costs, and assumed incentive levels as described in the Chapter 3 scenario sections. Total cost of first year savings in 2017 is ~$0.28/first-year kWh compares favorably (i.e., on the low end) of program costs presented in the Chapter 5. Costs of first-year savings rise to ~$0.45/kWh over the simulation horizon due to inflation and a changing measure mix over time. As noted in Chapter 3, all measures in this scenario are cost effective with a TRC >=1.0. Inclusive of administrative costs, the portfolio is cost effective with a portfolio TRC ranging from ~1.7 to ~2.0 over the simulation horizon.

Table 6. Estimated Budget for High Case Achievable Potential

Year	Administration	Incentives	Total
2017	$7,921,933	$8,415,905	$16,337,839
2018	$8,994,417	$9,502,727	$18,497,144
2019	$10,117,456	$10,575,742	$20,693,198
2020	$10,549,450	$11,693,058	$22,242,507
2021	$10,595,340	$12,009,587	$22,604,926
2022	$10,661,628	$12,608,018	$23,269,646
2023	$11,135,036	$13,405,238	$24,540,273
2024	$11,308,934	$13,546,160	$24,855,094
2025	$11,240,073	$13,337,032	$24,577,105
2026	$10,954,917	$12,914,864	$23,869,782
2027	$10,489,144	$12,226,714	$22,715,858
2028	$10,174,767	$12,317,023	$22,491,790
2029	$9,529,195	$11,733,497	$21,262,691
2030	$8,751,218	$10,818,053	$19,569,272
2031	$7,977,849	$9,940,386	$17,918,234
2032	$7,235,021	$9,071,583	$16,306,604
2033	$6,540,929	$8,279,731	$14,820,661
2034	$5,913,374	$7,579,637	$13,493,010
2035	$5,370,357	$6,957,019	$12,327,376
2036	$4,929,933	$6,461,779	$11,391,712

Scenario 2: High Case Theoretical – Known Measures

The High Case Theoretical – Known Measures scenario represents a theoretical level of potential assuming 100% of incremental costs are covered by incentives, and assuming a program ramp rate that would permit achieving a target of 2.0%/year in at least one year of the simulation horizon (See Chapter 3 for more detailed scenario assumptions). This ramp rate as well as the estimated incremental costs covered by the utility are not considered realistic, though savings and costs estimates are provided in this Chapter as a point of reference. Additionally, this scenario models a lower cost-effectiveness screening level threshold than Scenario 1. As seen in Table 7, incremental annual potential as a percentage of sales tails off after about 2023 due to market saturation of known measures. This rise and subsequent fall of incremental savings is consistent with expectations and is characteristic of typical technology adoption patterns.

Table 7. Incremental Theoretical Known Measures Potential as a Percentage of Forecasted Sales

Year	C&I	Res	All
2017	0.98%	1.62%	1.23%
2018	1.01%	1.75%	1.30%
2019	1.24%	2.10%	1.58%
2020	1.28%	2.33%	1.69%
2021	1.41%	2.46%	1.81%
2022	1.56%	2.31%	1.85%
2023	1.67%	2.54%	2.01%
2024	1.57%	2.40%	1.90%
2025	1.44%	2.32%	1.77%
2026	1.27%	2.00%	1.55%
2027	1.10%	1.69%	1.33%
2028	0.93%	1.31%	1.09%
2029	0.79%	1.17%	0.94%
2030	0.67%	0.93%	0.77%
2031	0.57%	0.73%	0.63%
2032	0.49%	0.53%	0.52%
2033	0.45%	0.46%	0.46%
2034	0.40%	0.31%	0.38%
2035	0.38%	0.21%	0.32%
2036	0.34%	0.07%	0.25%

Note: C&I and Res refer to Commercial, Industrial, and Residential Sectors, respectively.

Budget

In addition to forecasting potential savings, Navigant estimated the associated administration and incentive costs. The estimated budget reflects the potential savings forecast for this scenario in that costs and savings increase until reaching peak potential and then decrease every year thereafter. Table 8 illustrates these costs and the total budget for each forecast year.

Table 8. Estimated Budget for Theoretical Known Measures Potential

Year	Administration	Incentives	Total
2017	$15,888,700	$43,289,308	$59,178,008
2018	$17,667,699	$47,000,703	$64,668,401
2019	$21,796,146	$56,107,967	$77,904,113
2020	$23,494,153	$61,704,384	$85,198,537
2021	$25,700,886	$69,262,968	$94,963,854
2022	$26,621,758	$73,327,177	$99,948,935
2023	$29,922,060	$81,854,462	$111,776,522
2024	$29,025,058	$81,090,358	$110,115,415
2025	$27,181,798	$76,588,307	$103,770,105
2026	$24,745,803	$70,495,845	$95,241,648
2027	$21,951,653	$63,340,558	$85,292,210
2028	$19,367,559	$57,615,150	$76,982,709
2029	$16,649,166	$50,152,355	$66,801,521
2030	$14,247,172	$43,525,834	$57,773,006
2031	$12,286,922	$38,231,201	$50,518,123
2032	$10,669,987	$33,711,185	$44,381,172
2033	$9,379,602	$29,967,885	$39,347,486
2034	$8,372,842	$26,978,240	$35,351,082
2035	$7,604,282	$24,595,475	$32,199,756
2036	$7,119,074	$23,244,385	$30,363,460

Scenario 3: High Case Theoretical – Known and Unknown Measures

This scenario is similar to Scenario 2 with the exception that the forecast assumes that ENO can maintain its annual percent savings from 2023 onwards through the emergence of unknown technologies at an assumed cost, rather than achieving a declining rate of savings due to market saturation, as described in Chapter 3. Table 9 shows projected savings per year, as a percentage of forecast sales, based on these assumptions.

Table 9. Incremental Theoretical Known & Unknown Measures Potential as a Percentage of Forecasted Sales

Year	C&I	Res	All
2017	0.98%	1.62%	1.23%
2018	1.01%	1.75%	1.30%
2019	1.24%	2.10%	1.58%
2020	1.28%	2.33%	1.69%
2021	1.41%	2.46%	1.81%
2022	1.56%	2.31%	1.85%
2023	1.67%	2.54%	2.01%
2024	1.66%	2.53%	2.00%
2025	1.66%	2.54%	2.00%
2026	1.66%	2.54%	2.00%
2027	1.66%	2.54%	2.00%
2028	1.66%	2.53%	2.00%
2029	1.66%	2.53%	2.00%
2030	1.66%	2.53%	2.00%
2031	1.66%	2.53%	2.00%
2032	1.66%	2.52%	2.00%
2033	1.66%	2.52%	2.00%
2034	1.67%	2.51%	2.00%
2035	1.67%	2.50%	2.00%
2036	1.67%	2.49%	2.00%

Note: C&I and Res refer to Commercial, Industrial, and Residential Sectors, respectively.

Budget

Based on the measures and assumptions in this scenario, Navigant modeled potential costs. Similar to the potential savings for this forecast, costs do not decrease after the utility has reached its peak potential. Instead, costs continue to increase to account for new, unknown measures, which we assume cost the same as the suite of measures modeled in 2023 (the year of peak modeled savings), escalated for inflation. Table 10 shows the administrative, incentive, and total costs per year for the High Case Theoretical – Known and Unknown Measures scenario.

Table 10. Estimated Budget for Theoretical Known & Unknown Measures Potential

Year	Administration	Incentives	Total
2017	$15,888,700	$43,289,308	$59,178,008
2018	$17,667,699	$47,000,703	$64,668,401
2019	$21,796,146	$56,107,967	$77,904,113
2020	$23,494,153	$61,704,384	$85,198,537
2021	$25,700,886	$69,262,968	$94,963,854
2022	$26,621,758	$73,327,177	$99,948,935
2023	$29,922,060	$81,854,462	$111,776,522
2024	$30,048,385	$82,200,035	$112,248,420
2025	$30,641,147	$83,821,588	$114,462,735
2026	$31,302,153	$85,629,828	$116,931,982
2027	$31,999,000	$87,536,115	$119,535,115
2028	$32,786,703	$89,690,945	$122,477,648
2029	$33,525,264	$91,711,347	$125,236,611
2030	$34,281,641	$93,780,482	$128,062,123
2031	$35,072,083	$95,942,807	$131,014,890
2032	$35,898,596	$98,203,807	$134,102,404
2033	$36,702,269	$100,402,326	$137,104,595
2034	$37,548,643	$102,717,657	$140,266,300
2035	$38,422,994	$105,109,524	$143,532,518
2036	$39,378,923	$107,724,552	$147,103,475

5. BENCHMARKING THE RESULTS

As part of this study, Navigant benchmarked the achievable energy efficiency potential results relative to regionwide achievable potential, actual savings, and actual savings costs. Navigant also benchmarked these figures against leading regions, states, and utilities for a comprehensive comparison. The analysis leveraged recent potential studies as well as data from two leading energy institutions, the American Council for an Energy-Efficient Economy (ACEEE), a non-profit advocacy group, and the US Department of Energy's Energy Information Administration (EIA). In doing so, Navigant sought to contextualize the study's results within the region, determining broader trends in the regional area and across the country. For comparison purposes, all savings figures are presented as a percent of electric sales. Table 11 shows the data and studies used in this benchmarking analysis.

Table 11. ENO EE Benchmarking Analysis Sources

Information Type	Source
Achievable Potential Studies	• 2015 Navigant Study – Arkansas Energy Efficiency Potential Study • 2015 ICF International Study – Long-Term Demand Side Management Potential in the Entergy New Orleans Service Area • 2013 ACEEE Study – A Guide to Growing an Energy-Efficient Economy in Mississippi • 2013 ACEEE Study – Louisiana's 2030 Energy Efficiency Roadmap • 2011 Global Energy Partners Study – Tennessee Valley Authority Potential Study • 2007 ACEEE Study – Potential for Energy Efficiency, Demand Response, and Onsite Renewable Energy to Meet Texas's Growing Electricity Needs
Actual Savings Data	• 2015 ACEEE Spending and Savings Table • 2010 ACEEE Spending and Savings Table

Actual Portfolio Cost Data	• Navigant Data • 2016 Mississippi Public Service Commission Working Session – Energy Efficiency in Mississippi • 2015 ACEEE Spending and Savings Table • 2015 Frontier Associates – Energy Efficiency Accomplishments of Texas Investor Owned Utilities Calendar Year 2015 • Derived from EIA Form 861 – Electric Power Sales, Revenue, and Energy Efficiency Form EIA 861 Detailed Data Files

Review of Entergy New Orleans EE Accomplishments

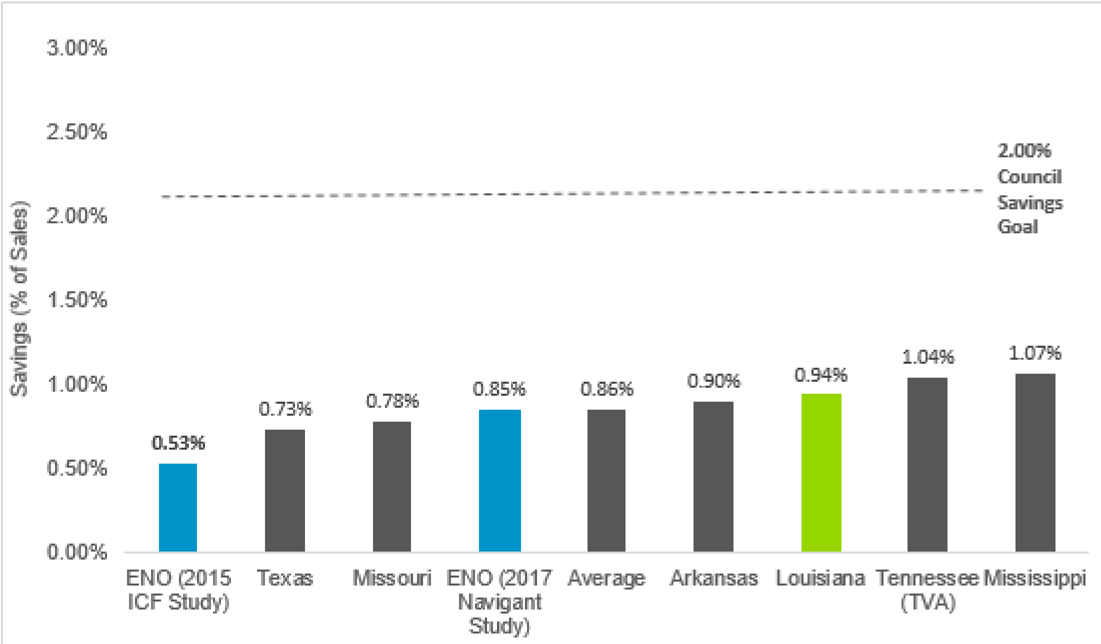
In 2015, ICF International completed a demand side management (DSM) potential study, spanning 2015 – 2034 for ENO territory. The study estimated that ENO had a cumulative achievable potential of 3.9% - 10% savings over the study horizon, depending on incentive levels.[10] This equates to an average annual savings of 0.3% - 0.5%. The ICF study came to this conclusion using a bottom-up approach, aggregating baseline data, measure data, and program data. The low case achievable potential defined by ICF aligns closely to ENO's actual savings in 2015. In ENO's most recent Energy Efficiency Programs Portfolio Evaluation from project year five, the utility realized 0.4% in actual savings.[11]

Market Potential Savings Benchmark at the State-Level

Navigant compared this study's results against other recent potential studies. The team conducted a comprehensive review of potential studies, specifically focusing on achievable potential from surrounding states for a regionwide comparison. The studies researched provided data on cumulative savings throughout the next decade. Since the Navigant ENO study defines achievable potential on an annual basis, the research team determined the average savings per year for comparison. Figure 9 shows average annual future savings potential over a 15-year timeframe for the 6-state region surrounding the ENO territory. The figure also illustrates that Navigant's achievable potential estimate aligns to regionwide expectations. It is important to note that the achievable savings reported below (Figure 9) reflect an average of cumulative savings over the study period.[12]

[10] ICF International, "Long-Term Demand Side Management Potential in the Entergy New Orleans Service Area," June 23, 2015.
[11] ADM Associates, "Evaluation of PY5 Energy Efficiency Programs Portfolio," July 2016.
[12] To determine annual percent savings, we divided the total percent savings by the study period.

Figure 9. Average Achievable Potential Savings Per Year as a Percentage of Sales in the South



Actual Savings Benchmark at the State-Level

In addition to evaluating the future potential for energy efficiency, Navigant also researched actual accomplished energy efficiency savings at the state-level to determine regionwide trends. The research team examined states surrounding ENO as well as high-performing states in other regions. The differences in actual savings across the country likely relates to differing program maturities, policies, retail rates, energy efficiency costs, energy efficiency spending, and other factors. This specific portion of the benchmarking aimed to verify how closely actual savings reflected achievable potential. Navigant used the most recent data from the EIA and ACEEE to derive this information. Figure 10 shows actual savings by state and region, including the 2015 median actual savings across the US of 0.61%.

Figure 10. 2015 Actual Accomplished Net Savings by State

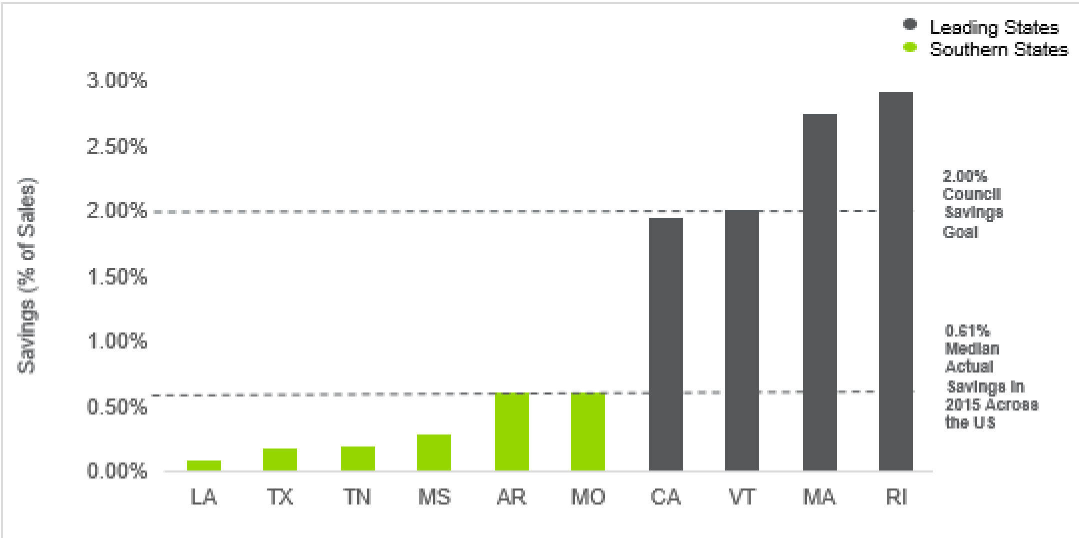


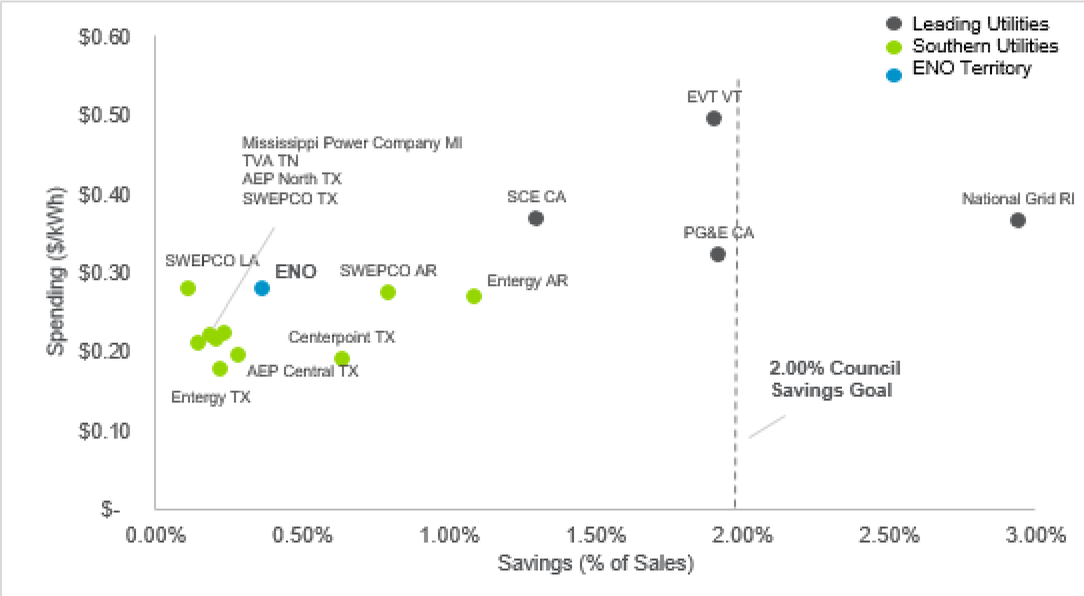
Figure 10 illustrates that utilities do not necessarily achieve their achievable potential; achievable potential only loosely predicts actual savings. For example, Arkansas and Missouri accomplished savings of .61%, which is below the lowest achievable potential averages of 0.73% for the region. Additionally, Texas accomplished 0.18% in actual savings, compared to its achievable potential of 0.73% (Figure 9).

Additionally, one year of savings data does not guarantee that utilities will have consistent yearly savings at this level. For instance, Vermont achieved 2.32% savings in 2010 and 2.01% in 2015, demonstrating that savings may fluctuate. Also, California achieved 1.79% savings in 2010 and 1.95% savings in 2015, showing that achieving a stable 2% savings solely through EE measures can be challenging even in states with leading energy efficiency programs for the past 30 years.

Actual Savings and Cost of Savings Benchmark at the Utility-Level

Navigant also benchmarked actual savings and EE program expenditures at the utility-level to further examine the accuracy of achievable potential, determine key trends, and identify potential savings constraints. This process involved aggregating key data from local investor-owned utilities and nationwide peers with industry-leading energy efficiency programs. Figure 11 shows actual spending and saving from different utilities across the country.

Figure 11. 2015 Actual Spending and Savings by Utility



As illustrated by the figure above, utility level energy efficiency savings tend to reflect statewide achievable potential and actual savings. More specifically, utilities in the South generally achieved less than 1% savings in 2015. The exception to this group is Entergy Arkansas which achieved a savings of 1.1%, more than the expected achievable potential and the actual savings of Arkansas. Those in leading energy efficiency states follow similar trends with utilities achieving roughly 1.5 – 3% savings in 2015, similar to statewide actual savings (Figure 11).

In terms of costs, the figure demonstrates that utilities with higher energy efficiency savings tend to spend more on a $/kWh basis than utilities with lower savings. The correlation indicates that percent kWh savings partially depends on the $/kWh a utility is willing to spend, and therefore, costs may be partially dependent on actual kWh savings. A recent 2014 study by the South-central Partnership for Energy Efficiency as a Resource (SPEER) came to a similar conclusion after comparing per capita (rather than $/kWh) energy efficiency spending by state.[13] The study also noted that budget may limit incentives and advertising for energy efficiency programs, which in turn limits savings. Another 2010 study by Georgia Tech and Duke University, specifically cited legislation as a limitation to achieving high energy efficiency savings in the South.[14] Additionally, electricity rates vary across regions and therefore, may also affect spending, potential achievable savings, and actual savings, since certain measures may not be as cost effective in some locations. Many other factors, including regional labor rates, specific regional infrastructure (e.g. nonprofit and community leader support) and an existing contractor network

[13] South-central Partnership for Energy Efficiency as a Resource (SPEER), Energy Efficiency as a Resource in Texas, August 2014, https://eepartnership.org/wp-content/uploads/2015/07/energy-efficiency-as-a-texas-resource-whitepaper-for-speer-commssion-august-2014.pdf.
[14] Georgia Tech & Duke University, Energy Efficiency in the South, April 12, 2010, https://nicholasinstitute.duke.edu/sites/default/files/publications/energy-efficiency-in-the-south-paper.pdf.

supporting EE installations, impact EE savings and costs. These studies and the figures above illustrate the myriad factors that can influence energy efficiency savings.

APPENDIX A. MODEL GLOBAL ASSUMPTIONS

Table 12 shows a selection of key global assumptions used in the analysis of energy efficiency for ENO. The significance of these global assumptions is that they serve as key financial and valuation parameters (e.g., inflation and discount rates, avoided costs, etc.) used in the calculation of economic and achievable potential.

Table 12. Global Assumptions

Assumption	Value
Inflation Rate (%/year)	2%
Discount Rate (%/year)	7.427% nominal, for all Cost Tests
Avoided Costs	Electric energy: $37/MWh (2017 $)
	Generation capacity: $75/kW-yr (2017 $)
Line Losses	Total Retail Average: 6.24%

Source: ENO

Stock Forecast

One of the key global inputs used in Navigant's DSMSim is a forecast of residential and C&I stock. Residential stock is measured in residential accounts while C&I stock is measured through floor space (e.g., 1000 square feet of floor area).

Residential Stock Forecast

Navigant developed the residential stock forecast based on ENO's forecast of residential accounts from 2017 through 2036. The table below shows the residential stock in 2017 and 2036. Residential stock increases from 180,129 accounts in 2017 to 197,926 accounts in 2036.

Commercial Stock Forecast

Navigant developed the commercial floor space stock based on ENO's C&I electricity consumption and electricity-intensity estimates (kWh/sq. ft.) from the Commercial Building Energy Consumption Survey (CBECS). Navigant divided ENO's C&I consumption (3,510 GWh) by the CBECS electricity intensity (18.6 kWh/sq. ft.), to determine a 2017 floor space stock of 189 million sq. ft. To project the forecast of C&I stock through 2036, Navigant analyzed historical employment levels in New Orleans using data from the New Orleans Regional Council for Business Economics (NORCBE).[15] Historical employment levels indicate commercial and industrial economic activity, as well as electricity and natural gas demand. Navigant used the five-year historical employment levels from 2012 to 2016 to determine an average annual growth rate of 1.1% per year, applying the rate to the 2017 stock to forecast C&I stock through

[15] NORCBE. New Orleans Regional Economic Index (April 2017). Table 11. Available at: http://www.norcbe.org/images/THE_NEW_ORLEANS_REGIONAL_RECOVERY_INDEXMARCH_2017.pdf

2036. Table 13 shows the C&I stock in 2017 and 2036, with stock increasing from 189 million sq. ft. in 2017 to 232 million sq. ft. in 2036.

Table 13. Stock Forecast – Residential and C&I

Sector	Units	2017	2036
Residential	# of accounts	180,129	197,926
C&I	million sq. ft.	189	232

Source: ENO data, and Navigant analysis

Katrina Effect

The report refers to the “Katrina effect” as the impact of Hurricane Katrina on the mix of customer end-use equipment; specifically, the increased adoption of high efficiency equipment in the post-Katrina period due to the significant proportion of stock that sustained severe damage during the storm.

Navigant quantified the Katrina effect based on data obtained from three different reports and presentations by the U.S. Department of Housing and Urban Development (HUD).[16, 17, 18] Quantifying the impact of Katrina on the mix of end-use equipment is difficult for several reasons.

- Different studies report various estimates of destroyed, damaged, and/or repaired stock due to differing methodologies, study areas, and dates of reference. The date of reference is also important because some studies may be based on data recorded following other non-Katrina storms (e.g., the compounded impact of Katrina, Rita, etc.).
- Property damage is measured based on a qualitative scale of damage, which introduces a certain degree of bias (e.g., “minor”, “major”, and “severe” damage).
- Each energy efficiency measure is unique and the likelihood that a given measure – for example, a refrigerator, roof insulation, or a central AC system – might be upgraded is subject to the likelihood that a home experienced flooding and/or wind damage.

Given these challenges in quantifying the Katrina effect, Navigant estimated the fraction of existing stock with high efficiency equipment based on two criteria (1) stock that experienced severe or major damage, and (2) stock that experienced both flooding and wind-damage. Navigant also calculated the fraction of existing stock was destroyed and later rebuilt. Navigant added these two estimates (damaged & repaired stock, and destroyed & rebuilt stock) and applied it to the measure-penetration assumptions used in the

[16] HUD. December 2010. Housing Recovery in the Gulf Coast Phase I: Results of Windshield Observations in Louisiana, Mississippi, and Texas. Available at: https://www.huduser.gov/Publications/pdf/Housing_Recovery_in_the_Gulf_Coast_PhaseI_v2.pdf
[17] HUD. July 2011. American Housing Survey. Components of Inventory Change and Rental Dynamics: New Orleans 2004-2009. Available at: https://www.huduser.gov/portal/datasets/cinch/cinch09/neworleans_CINCH_Report_04_09.pdf
[18] HUD. September 2010. American Housing Survey: Preliminary Findings from the 2009 New Orleans Metropolitan Survey. Available at: https://www.huduser.gov/portal/pdf/hsg_mrkt/Chi_AHSPresentation.pdf

REQUEST FOR QUALIFICATIONS STATEMENTS

FOR

DEMAND SIDE MANAGEMENT CONSULTANT

ISSUED SEPTEMBER 15, 2017

APPENDIX XI

MOTION NO. M-17-164

COUNCIL UTILITIES REGULATORY OFFICE

WORK & BILLING PRACTICES

MOTION
(AS AMENDED)
NO. M-17-164

CITY HALL: March 23, 2017

BY: COUNCILMEMBER HEAD

SECONDED BY: COUNCILMEMBER WILLIAMS

WHEREAS the New Orleans Office of Inspector General (OIG) released a report entitled "New Orleans Utilities Regulation" on June 17, 2015; and

WHEREAS, the OIG's report contained a recommendation, among several others, that "[t]he Council should create and implement a standard set of billing guidelines and require outside consultants to comply with its requirements"; and

WHEREAS, billing guidelines for consultants and attorneys are standard practice and are incorporated into contracts in order to allow for the efficient provision of services on behalf of clients; and

WHEREAS, the ultimate cost of consultant and attorney services is paid by ratepayers, and any savings in such costs will save ratepayers money; and

WHEREAS, the Council Utilities Regulatory Office ("CURO") conferred with regulatory commissioners in other jurisdictions, researched industry standards and best practices in billing guidelines, and reviewed billing guidelines used by other regulators; and

WHEREAS, the CURO distributed a draft set of billing guidelines on January 12, 2017, offered the opportunity to meet with Councilmembers and staff members, and solicited, received, and distributed feedback on those guidelines from the OIG; and

WHEREAS, the CURO met with Councilmembers and staff members and the draft billing guidelines have been collaboratively revised to address concerns of the Councilmembers and the OIG, resulting in the set of billing guidelines attached hereto; and

WHEREAS, the Council's Utility Advisor contracts expired as of December 31, 2016, and motions to authorize month-to-month contracts for the Council's Utility Advisors were deferred at the Council Utility, Cable, Telecommunications and Technology Committee meeting on January 19, 2017; and

WHEREAS, the Council authorized new Utility Advisor contracts during its January 12, 2017, regular meeting, but those contracts have not been signed; and

WHEREAS, there is "uniformity in a desire for billing guidelines among the committee," and a "goal of curbing costs through a set of mutually agreed upon billing guidelines," according to the Chair of the Council Utility, Cable, Telecommunications and Technology Committee; and

WHEREAS, the Council, led by the Chair of the Council Utility, Cable, Telecommunications and Technology Committee, is developing a comprehensive set of CURO protocols responsive to the OIG's observations, which will govern CURO's role in the regulatory process, including the management of the Council's Utility Advisor contracts; and

WHEREAS, billing guidelines should be mutually agreed upon, incorporated, and enforced as provisions of the Council's Utility Advisor contracts, and CURO should enforce the provisions in those contracts when necessary; and

WHEREAS, the Council is ready to move forward with the attached set of billing guidelines, in order to incorporate them into the Council's Utility Advisor contracts currently being negotiated; **NOW THEREFORE**

BE IT MOVED BY THE COUNCIL OF THE CITY OF NEW ORLEANS, That the set of billing guidelines attached hereto as Exhibit A is hereby approved, and that the billing guidelines shall be incorporated into and enforced as provisions of all contracts between the Council and its Utility, Cable, Telecommunications and Technology Committee (CUTTC) Advisors, as mutually agreed upon in contract negotiations.

THE FOREGOING MOTION WAS READ IN FULL, THE ROLL WAS CALLED ON THE ADOPTION THEREOF AND RESULTED AS FOLLOWS:

YEAS: Brossett, Cantrell, Gray, Guidry, Head, Ramsey, Williams - 7

NAYS: 0

ABSENT: 0

AND THE MOTION WAS ADOPTED.

THE FOREGOING IS CERTIFIED
TO BE A TRUE AND CORRECT COPY
Lora W. Johnson
CLERK OF COUNCIL

SUBSTITUTE EXHIBIT A TO MOTION TO M-17-164

City Council Utility Regulatory Office Work and Billing Practices Policy for Utility, Cable, Telecommunications and Technology Committee Advisors

March 23, 2017

City Council (Council) Utility Regulatory Office (CURO) Work and Billing Practices Policy for Utility, Cable, Telecommunications and Technology Committee (UCTTC) Advisors
March 23, 2017

Note: The following applies to a UCTTC Advisor, or multiple Advisors, or Advisor firms, hereafter referred to as "Advisor" or "Advisors." In this policy, the terms "Invoice" and "Bill" or "Billing" are used interchangeably. "CURO" refers to the CURO Chief and the Deputy Chief/Director, or if one is unavailable then the other, together with any person serving in an interim role in one of those positions.

Purpose:

1) To ensure that services are reasonably billed and are in accordance with contractual terms.

2) To facilitate efficient administration of the contracts and prompt review and payment of invoices.

3) To facilitate analysis of contractual service costs for planning and budgeting purposes.

4) To prevent inadvertent disclosure of privileged information and/or strategies.

Permitted Work:

All professional services are subject to the provisions of the Advisor contracts. The Council views every bill from an Advisor as a certification by the Advisor and his or her firm that the services and disbursements reflected on the bill are reasonable for the matter involved and necessary for the proper provision of professional services to the Council. Staffing shall be efficient. Time and disbursements that are not necessary for the cost-effective handling of a matter should not be billed. Compliance with this procedure will avoid delays in processing invoices.

Subject to additional direction given by the Council, or UCTTC, or its Chair with a copy to CURO, the following work may be performed, provided it is in compliance with the remaining Work and Billing Practices hereafter:

1) Reasonable monitoring and information gathering with respect to issues that are, or could be, of interest to the UCTTC.

2) Strategic analysis, reports and discussions with other consultants, members of the Council, and Council employees.

3) Contacts with persons interested in issues that are, or could be, before the UCTTC.

4) Consultation, coordination and advocacy with others to ensure that the interests of the UCTTC are served; and in connection therewith, personal appearances and the preparation and filing of documents.

5) Intervention and participation in Administrative or Judicial proceedings; and in connection therewith, personal appearances and the preparation and filing of documents, pleadings, etc.

6) Lobbying or monitoring activities with respect to legislation of material interest to the UCTTC; and in connection therewith, personal appearances and the preparation and filing of documents.

7) Preparation of draft legislation, resolutions, recommendations and decisions.

8) Attend meetings and coordinate activities with other city agencies and other bodies.

9) Calls and attending meetings with, and prepare materials for, the Council, its members, th UCTTC, and CURO on utility regulatory and such other matters as the Council, UCTTC or individual members thereof may request.

Process for Billing and Payment:

Invoices shall be submitted electronically to CURO on a monthly basis by the end of the month following the month in which charges are made. If requested, Advisors shall concurrently provide copies to the Chairperson of the UCTTC and the Council Chief of Staff or Interim Council Chief of Staff. Unless authorized by CURO, invoices should not include time from outside the statement's monthly billing period. Within 30 days of receipt of the invoice, CURO shall complete its review and provide the Chairperson of the UCTTC with a memo containing any recommendations and a request for approval for CURO to process the invoice for payment.

Upon receipt of the recommendations and request for approval to process for payment, the Chairperson of the UCTTC shall complete the invoice review and by memo to CURO: 1) authorize the payment of the original invoice amount, or 2) substitute a different amount that is authorized for payment. If a different-than-original invoice amount is authorized for payment by CURO, the Council Chief of Staff or Interim Council Chief of Staff, and submitting Advisor should be immediately notified, with opportunity given for discussion of the substituted amount. Upon the conclusion of this discussion, the Chairperson of the UCTTC shall make a final determination of the amount authorized for payment and authorize CURO to immediately process for payment of that amount.

Billings:

At the commencement of the contract period, Advisors shall identify, and the Chair of the UCTTC shall approve, with a copy to CURO, all work categories in which Permitted Work as described herein is expected to be necessary. Legal and technical Advisors for Utilities and legal and technical Advisors for Cable, Telecommunications and Technology shall identify categories of work in a clear and concise manner and shall include the use of FERC and Council docket numbers, resolutions and motion numbers as well as clear and concise descriptions of the work performed. The Advisors shall coordinate these identified work categories with their counterpart Advisors within each of these two areas of work covered by the UCTTC, so that categories of work appearing on bills are uniform for every Advisor billing, within each of the two areas of work.

As it pertains to work that is not associated with an existing Utilities docket, billings should identify the party directing the work by use of the following codes. If multiple entities direct work, all applicable codes should be used.

Council Entity	[illegible]
Council Chief of Staff	CC2010
At-Large Division 1	CC2011
At-Large Division 2	CC2012
District "A"	CC2013
District "B"	CC2014
District "C"	CC2015
District "D"	CC2016
District "E"	CC2017
Council Fiscal	CC2040
Council Utilities	CC2050

If, during a contract period, Advisors determine a new category of work is needed, the Chair of the UCTTC shall be promptly notified, with a copy to CURO, following which the Chair of the UCTTC shall approve the new category before it is used in a bill. Existing categories should not be used for work for which a new category should be created.

A "Miscellaneous or General Matters" category may be used for entries which do not fit into existing categories and do not total greater than 10% of the total bill for the month. Entries in this category should include a sufficient description so that it can be clear to the reviewer what work was performed.

Final work product for which a time entry or entries exceed, or are expected to exceed, three hours for preparation inclusive of research time, should be provided to CURO concurrent with its preparation if possible, but in any event concurrent with the invoice. If an Advisor determines it should not be timely produced in order to protect the interests of the Council, the reason why it is not being provided shall be timely communicated to CURO, with a copy to the Chair of the UCTTC. If applicable, the work product shall be marked as follows or with any applicable sub-part of the following: "Confidential; attorney-client privileged communication; protected attorney work product." Work product provided prior to the invoice shall be accompanied by an explanation of where it can be expected to appear on the invoice (i.e., client matter number).

Efforts should be made to identify other clients of Advisors not in conflict with the Council, who could be expected to benefit from research or other Permitted Work that Advisors perform for the Council. If work benefits other clients of Advisor, only the appropriate proportionate share of the cost should be billed to the Council.

Time records, by date, for each professional rendering service within each category shall be entered in increments of 1/10th of hours (e.g.: ".7," or "1.6") and include a brief description of the work performed.

"Block billings" (billings combining a number of activities under a single time entry with little or no description of individual tasks performed or the time taken for each) in excess of 1 hour should not occur. An occasional exception may be made when brief work activities within a category cannot be accurately or efficiently billed by making individual time entries, in which case a description of the tasks performed may be provided under a single time entry for a short period of total time. This exception should be limited to a circumstance where a number of short tasks within a category are performed on the same day and billing for each would significantly increase the total time billed for the tasks.

Each time entry should be accompanied by a corresponding dollar amount charged, based on approved hourly rates. Subtotals should be provided for each category, each person billing within the category, and all expenses billed within the category.

Billings should account for time without disclosing sensitive areas of strategic focus. When the subject of the work is sensitive—for example if the work involves strategy pertaining to a current or potential administrative or court proceeding—the specific nature of the discussions, analysis, or meeting, as well as the other persons involved, may need to be left out of the detailed time summaries. However, this information should be retained by Advisors, available to be immediately provided to the UCTTC or CURO if requested.

Advisors should review each billing prior to its submission to determine that each billing entry clearly and succinctly describes the task performed and the reason for the task, if the same is not apparent from the task description itself. Individual and total charges for time and expenses should be checked to make certain they are accurate.

When describing work performed, task descriptions should be written in plain English. Advisors should not use overly general descriptions such as:

- Attention to or request attention to
- Review
- Continued (followed by a task)
- Organize file
- Follow up

When possible, advisors should use the following descriptions:

- Read________
- Write________

- Prepare for________
- Edit (or Revise) ________
- Attend_______
- Conduct ________
- Phone conference with regarding________
- Email to (or from) regarding________
- Draft (in relation to reports, pleadings, motions and briefs) ________
- Correspondence with________ regarding________
- Legal research regarding________
- Write legal memorandum to________regarding________
- Meeting with________ regarding________

Utility Advisors: work related to the Federal Energy Regulatory Commission (FERC) shall be billed under a single category, but if work is performed in connection with a specific FERC docket or simultaneous multiple dockets, the corresponding time shall be billed as a sub-category identifying said docket or dockets, or in the alternative, the docket numbers shall be provided in individual time entries.

Work should not be billed at a rate higher than the rate charged by the least-expensive person who can effectively handle the work. For example, a legal assistant, paralegal, or law clerk's time should be billed at an agreed-upon rate associated with that position if the work can be effectively performed for a lower charge by that person than otherwise would be charged. By way of further example, if an attorney chooses to perform research that could be effectively performed by a law clerk, or a technical advisor chooses to perform research that could be effectively handled by a research assistant, the professional should not bill at an hourly rate greater than the rate charged for a law clerk or research assistant. If such research is billed at the higher rate, sufficient explanation should be provided of the necessity of the performance of the work by the higher-billing person.

Non-billable work (for which Advisors will not be paid):

1) Research or review of industry literature or trade publications.

2) Attendance at professional conferences, educational seminars, or continuing legal education activities.

3) Research and review of basic substantive law at issue in the matter for which the firm was retained.

4) Advisors should be judicious in not having more than one person in attendance at meetings, depositions, hearings or other proceedings unless necessary and in the interest of protecting the Council's interests. The Council specifically recognizes that from time to time there are differing kinds of expertise among the professionals in the Advisor firms which may dictate the necessity for more than one person of an Advisor firm in attendance at such meetings, depositions, hearings, negotiations, strategy sessions and the like in furtherance of the Council's interests. When not adverse to the Council's best interests more than one person within the Advisor's firm attends the same meeting (whether the meeting occurs within the firm or outside the firm), deposition, hearing or other proceeding, or performs the same work, only one person may bill, unless billings by multiple persons for these activities are approved by the Chair of the UCTTC . As the phrase is used here, persons can perform the "same work" regardless of whether the work is performed simultaneously or sequentially. When meetings of more than two persons are

scheduled (other than meetings of the Advisors with Council members), CURO shall be notified concurrent with the scheduling or as soon thereafter as is reasonably possible, regardless of whether the meeting will be telephonic, web-based, or in-person. Unless a sufficient reason exists to not invite CURO, CURO shall be invited. If CURO is not invited, the reason shall be provided concurrent with the scheduling or as soon thereafter as is reasonably possible.

5) Administrative tasks, such as support or clerical services (work customarily performed by secretaries, word processors, proofreaders, managing clerks, information system technicians, librarians, computer operators, etc., including but not limited to photocopying, routine file maintenance, filing or delivering materials, arranging travel or scheduling depositions or meetings) shall not .be billed, either regularly or as overtime. Attorneys, paralegals, and law clerks shall not bill for performing such tasks, unless such tasks are performed by such personnel at the specific request of CURO.

6) Time spent preparing, discussing, or supporting Advisor's invoices, including time or expense associated with delivering or collecting Advisor's invoices.

7) Downtime or learning time that may result from staffing changes.

8) Time spent on staffing issues.

9) Time spent by Advisors traveling to or from New Orleans. If Permitted Work is performed during such travel, it may be billed as described herein.

10) Time spent traveling to attend MISO, OMS, or ERSC-related meetings or events. If Permitted Work is performed during such travel, it may be billed as described herein.

Expenses:

To qualify for reimbursement, expenses should be reasonable, documented and itemized, and occur in conjunction with services described in the time entries. Expenses should identify the bill category to which they pertain. The number of persons present in connection with an expense item should be indicated where such information is relevant to ensure that the expense is reasonable.

Advisors should make an effort to perform research without resorting to paid electronic research services, when practicable. Fees charged by electronic or other research services, such as Lexis Nexus and West Law charges and fees, library fees, or online connection charges shall be billed at actual cost.

Costs of court reporters and transcripts shall be billed at actual cost. Advisors should obtain the lowest possible charge reasonably available for court reporting fees, including any possible volume discounts. The least-expensive sufficient option for transcripts shall be selected. Any billing for more than a single transcript of the same testimony or event for all Advisors must be adequately explained; otherwise, the billing attorney shall receive the transcript and provide for the distribution of copies to other Advisors as an administrative expense to the extent permitted by law.

Electronic transfer of documents (e.g., e-mail) shall be used if possible. Billings for express mail or courier charges will not be paid unless an acceptable explanation is provided of why such measures were necessary. If such charges are necessary, actual reasonable charges will be reimbursed. If an Advisor has a volume discount arrangement with a vendor, charges shall be made on that basis. Charges for time spent preparing express mail packages are not reimbursable.

Items or services that will not be reimbursed: customary office supplies; routine postage; facsimile charges; fees incurred by a timekeeper for printing or scanning; and long-distance charges or other telephone charges for phone calls made at an Advisor's office or place of business.

Photocopying charges not exceeding $0.10 per page will be reimbursed. If the use of an outside copying service would be more economical and confidentiality is not an issue, the service should be used.

Approval must be obtained in writing from CURO prior to using any third-party services for which reimbursement will be requested, other than legal-process servers and court reporters. If approved, actual reasonable charges will be reimbursed.

Except for meetings requested by a member of the Council, all necessary and ordinary travel expenses are reimbursable only if prior authorization for the travel is provided by CURO or the Chair of the UCTTC. "Ordinary" as used here means the lowest-cost airfare that is reasonably available, reasonable-cost ground transportation and parking, and meals that do not exceed in cost the amounts allowed employees of the City of New Orleans as described in City Policy Memo 9 (R).

Bills containing requests for reimbursement should include the dates, the destination of travel, and the name of the traveler. Receipts should be provided. In rare cases, exceptions to this required detail may be approved by CURO for reasons of confidentiality or where it is clear that requirements are unduly burdensome or otherwise not feasible. Otherwise, the following expenses require receipts: telephone bills, reproductions/copies, ground transportation, airfare, auto rental, taxi, hotel/lodging, third party, research, business meals, publications, courier services, overnight delivery services, special mail handling, postage, and individual miscellaneous expenses. In cases where no receipt is available, such as internal office photocopying, the bill should contain office records verifying the charge.