SPO PLANNING ANALYSIS

2015 ELL/EGSL DRAFT IRP REPORT

Overview

SECOND STAKEHOLDER MEETING
BATON ROUGE, LA
FEBRUARY 24, 2015

ELL/EGSL IRP – PROCESS RECAP

Procedural History

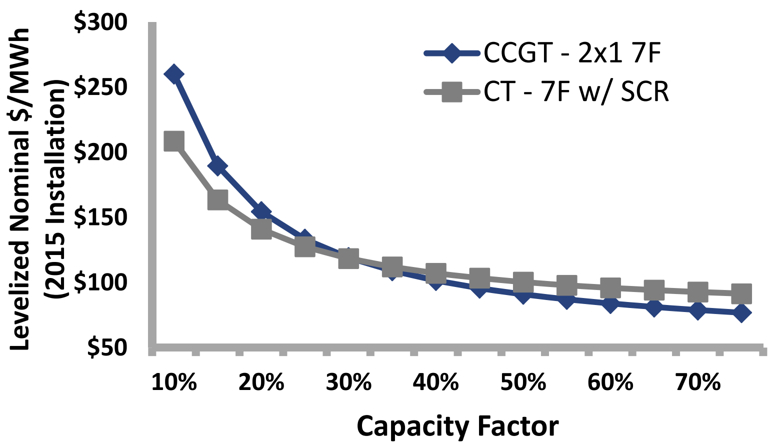
- The Commission issued its IRP General Order on April 20, 2012.
  - IOUs were allowed an 18 month delay before commencing their first planning cycle
- The Companies initiated their planning cycle in October 2013
- They filed their initial data assumptions in December 2013 and held their first public Stakeholder Meeting on January 22, 2014.
  - The Companies supplemented their data assumptions with additional information in February, April, and May 2014
  - Stakeholders filed comments in May 2014
- In November 2014, the Companies filed updated inputs to reflect the change in the reference case assumptions to the Industrial Renaissance
  - This filing also included the Demand-Side Management ("DSM") Potential Study prepared by ICF Consulting.
  - On January 30, 2015, the Companies filed their draft IRP Report for the 2015-2034 planning period.

Next Steps

- Under the current timeline, Stakeholder Comments will be due in April and Staff Comments in May
- Final IRP Report is due August 3, 2015.

GENERATION TECHNOLOGY ASSESSMENT

- An understanding of generation technology cost and performance is a necessary input to planning and decision support activities.
- The process has two main steps: a screening level analysis and a detailed analysis
- The Generation Technology Assessment began by surveying available central station electricity generation technologies, generally those that are two megawatts or greater. The objective is to identify a reasonably wide range of generation technologies. The initial list was subject to a screening analysis to identify generation technologies that are technologically mature and could reasonably be expected to be operational in or around the Entergy regulated service territory.



The following technologies are carried forward for detailed analysis:

- Pulverized Coal
  - Supercritical Pulverized Coal with carbon capture and storage
- Natural Gas Fired
  - Combustion Turbine ("CT")
  - Combined Cycle Gas Turbine ("CCGT")
  - Large Scale Aeroderivative CT
  - Small Scale Aeroderivative CT
  - Internal Combustion Engine
- Nuclear
  - Advanced Boiling Water Reactor
- Renewable Technologies
  - Biomass
  - Wind
  - Solar PV (Fixed Tilt and Tracking)
- Battery Storage

DSM DISCUSSION

SCENARIO ASSUMPTIONS AND OVERVIEW

Four scenarios are evaluated to assess alternative portfolio strategies under varying market conditions.

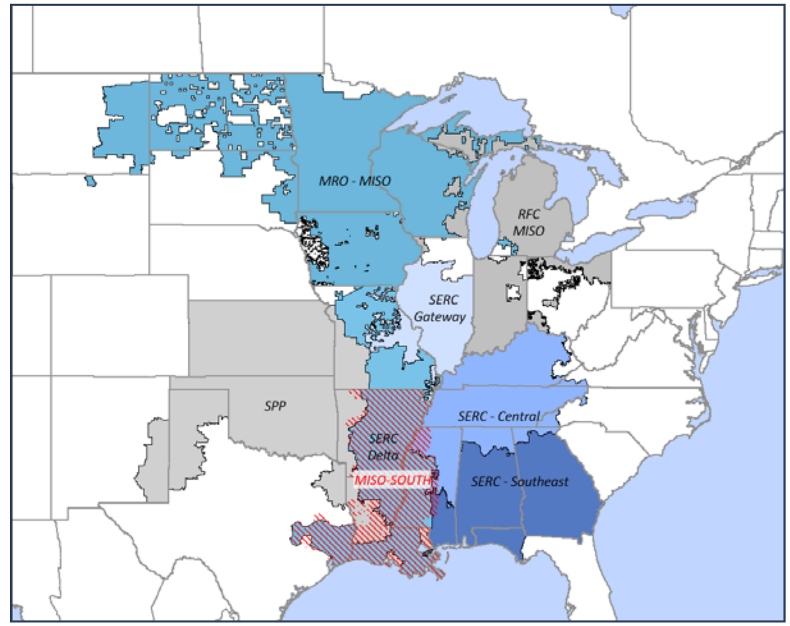
Summary of Key Scenario Assumptions

	Industrial Renaissance (Ref. Case)	Business Boom	Distributed Disruption	Generation Shift
Electricity CAGR (Energy GWh)	~1.45%	~1.70%	~0.90%	~1.20%
Peak Load Growth CAGR	~1.05%	~1.10%	~0.75%	~0.85%
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 ($8.17 levelized 2014$)
CO_2 Price ($/short ton)	Low Case: None	Reference Case: Cap and trade starts in 2023 $6.83 levelized 2014$	Reference Case: Cap and trade starts in 2023 $6.83 levelized 2014$	High Case: Cap and trade starts in 2023 $14.61 levelized 2014$

- Industrial Renaissance (Reference) – Assumes the U.S. energy market continues with reference fuel prices.
- Business Boom – Assumes the U.S. energy boom continues with low gas and coal prices.
- Distributed Disruption – Assumes states continue to support distributed generation.
- Generation Shift – Assumes government policy and public interest drive support for government subsidies for renewable generation and strict rules on CO2 emissions.

MISO MARKET MODELING

- The AURORA model is used to develop a projection of the future power market for each of the four scenarios.
- The AURORA model as configured for IRP analysis uses a zonal representation of MISO and 1st Tier markets.



Results of MISO Market Modeling
(MISO North and South, excluding Louisiana)

	Industrial Renaissance (Ref. Case)	Business Boom	Distributed Disruption	Generation Shift
CCGT	52%	91%	98%	53%
CT	48%	9%	2%	1%
Wind	0%	0%	0%	31%
Solar	0%	0%	0%	15%
Year of First Addition	2020	2020	2020	2020
Total GWs Added (through 2034)	117	127	73	226

DSM Optimization and Supply Side Resource Selection

- The AURORA Capacity Expansion 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.

- The result of this process was an optimal portfolio for each scenario consisting of both DSM and supply-side alternatives.

Portfolio Design Mix

	IR Portfolio	BB Portfolio	DD Portfolio	GS Portfolio
DSM	18 Programs	14 Programs	16 Programs	20 Programs
DSM Maximum (MWs)	497	407	539	467
CTs/CCGTs (MWs)	7,348	8,404	6,876	6,512
Wind (MWs)	0	0	0	4,000

PORTFOLIO ASSESSMENT

PV of Forward Revenue Requirements by Scenario ($B) (2015-2034)

	IR Scenario	BB Scenario	DD Scenario	GS Scenario
IR Portfolio	35.5	31.9	35.6	45.9
BB Portfolio	35.7	31.7	35.9	45.8
DD Portfolio	35.5	31.7	35.7	45.7
GS Portfolio	37.3	34.5	36.9	42.5

Total Supply Cost Net of 2014 Fuel Cost Annuity and Sunk Fixed Revenue Requirements (PV $B) (2015-2034)

	IR Scenario	BB Scenario	DD Scenario	GS Scenario
IR Portfolio	8.5	4.9	8.5	18.8
BB Portfolio	8.7	4.7	8.8	18.8
DD Portfolio	8.5	4.6	8.6	18.7
GS Portfolio	10.3	7.5	9.8	15.5

- Variable costs from the AURORA simulations (the load payment net of the generation energy margins) were combined with the fixed costs of the incremental resource additions to yield the total forward revenue requirements excluding sunk costs of the portfolio.

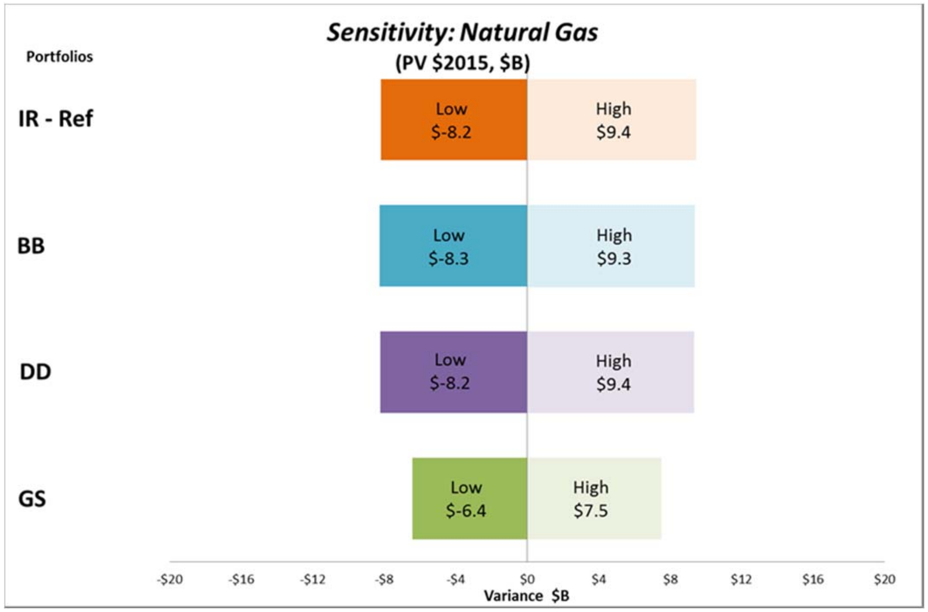
- Total supply costs net of 2014 fuel costs annuity and sunk fixed revenue requirements.

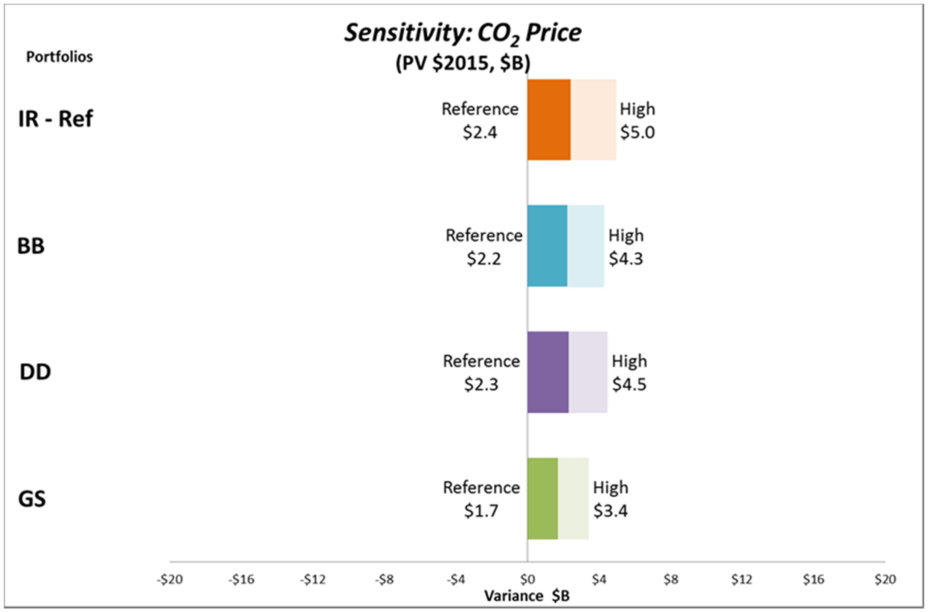
Note: The highlighted cell represents the lowest cost portfolio for the scenario.

PORTFOLIO SENSITIVITY ASSESSMENT

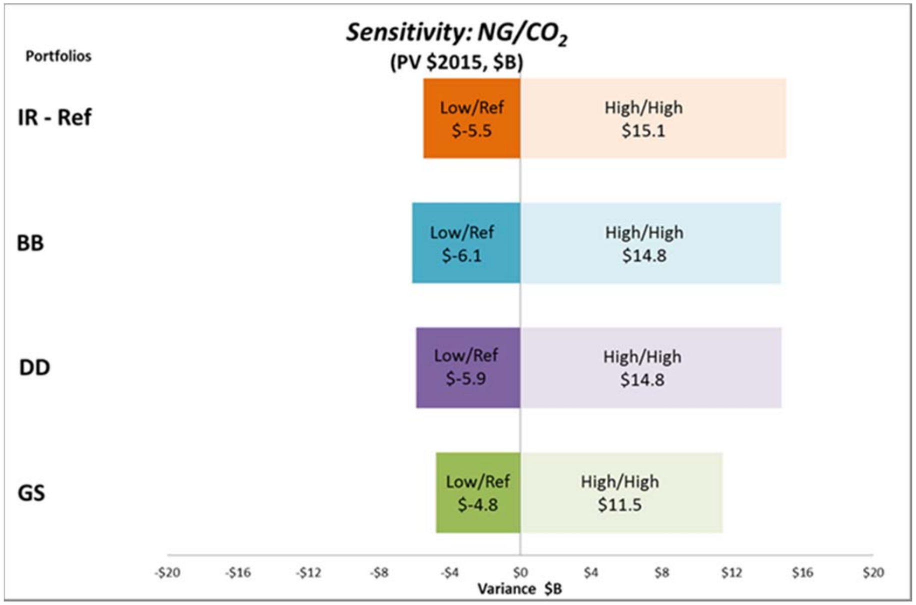
- Sensitivity analyses were performed on each portfolio by adjusting one variable at a time (or two variables in the case of Gas Prices and CO_2 Costs) and computing the PV of forward revenue requirements excluding sunk costs.

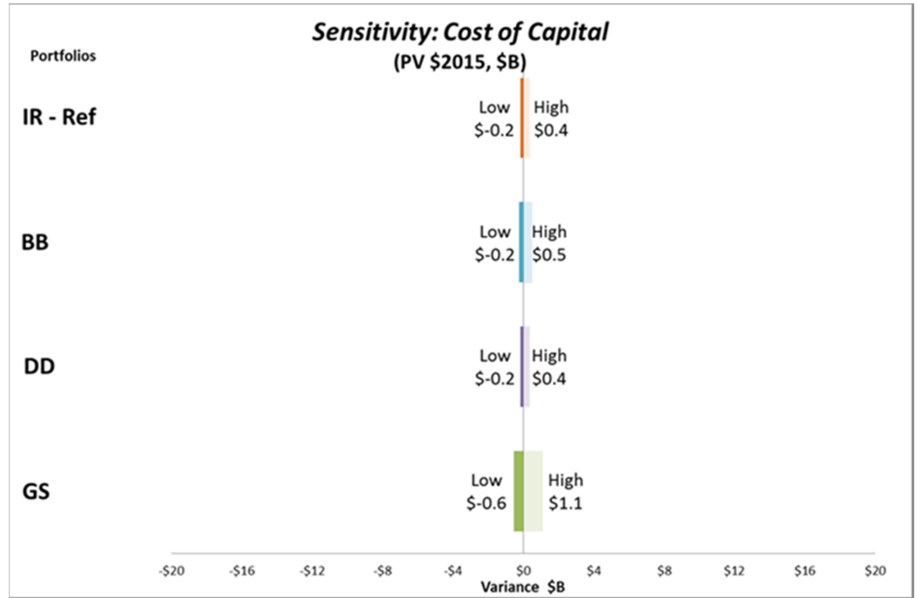
- Each portfolio was tested across the range of assumptions for:
  - Natural Gas Prices
  - CO_2 Costs
  - Natural Gas Prices and CO_2 Costs Combinations
  - Cost of Capital
  - Installed Cost

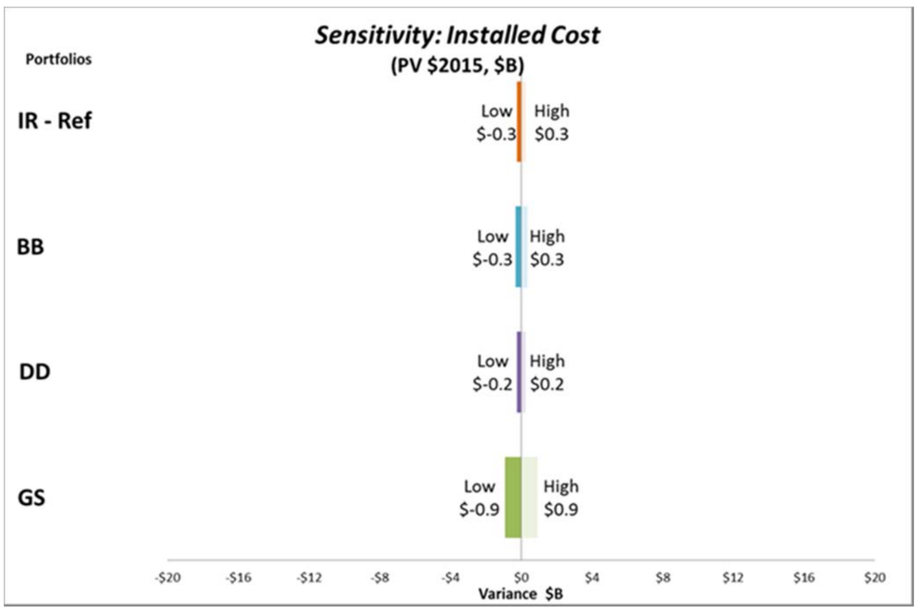




PORTFOLIO SENSITIVITY ASSESSMENT



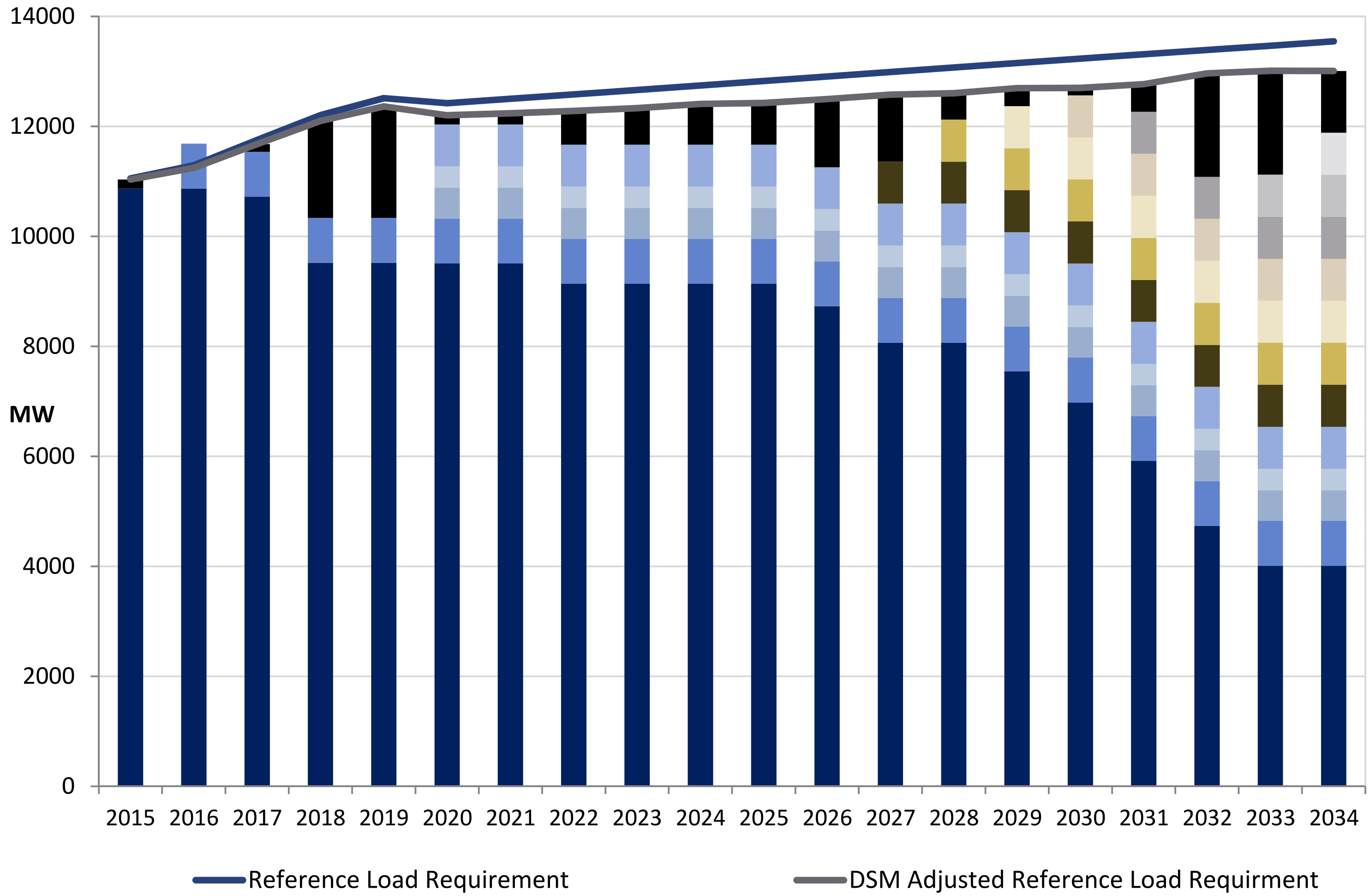




- Results of the sensitivity assessments indicate that the installed cost and cost of capital have a lower impact on the variability of total forward revenue requirements

- Natural gas prices, CO_2 prices, and the combination of CO_2 and natural gas prices have a greater impact on the variability of total forward revenue requirements.

FINAL REFERENCE RESOURCE PLAN



Resource Addition	Capacity (MW)
Market Purchases	165-1889
2034 CCGT	764
2033 CCGT	764
2031 CCGT	764
2030 CCGT	764
2029 CCGT	764
2028 CCGT	764
2027 CCGT	764
2020 CCGT	764
2020 CTs	388
2020 Amite South CCGT	560
Union	816
Existing Capacity	10869-4009

- Total load requirement adjusts for the peak load diversity between the two companies.
- The JSP PPAs are included in the Existing Capacity.
- Union plant acquisition is completed pending regulatory approvals. 816 MW is two trains of the facility less 20% allocation to ENO.
- ELL/EGSL share of Amite South RFP is presently estimated at 560 MW. RFP responses are currently being evaluated; actual capacity of selected resource could range between 650 to 1,000 MW and a portion of that capacity may be shared with another Entergy operating company. As a result, actual capacity may exceed 560 MW.

FINAL REFERENCE RESOURCE PLAN: LOAD & CAPABILITY

ALL VALUES IN MW

Load & Capability 2015—2034

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Requirements																				
Peak Load	9,869	10,081	10,495	10,896	11,172	11,090	11,162	11,231	11,303	11,376	11,452	11,526	11,599	11,672	11,743	11,811	11,882	11,952	12,024	12,095
Reserve Margin (12%)	1,184	1,210	1,259	1,307	1,341	1,331	1,339	1,348	1,356	1,365	1,374	1,383	1,392	1,401	1,409	1,417	1,426	1,434	1,443	1,451
Total Requirements	11,053	11,290	11,754	12,203	12,513	12,421	12,502	12,578	12,659	12,741	12,826	12,909	12,991	13,073	13,152	13,229	13,308	13,387	13,466	13,546
Resources																				
Existing Resources																				
Owned Resources	9457	9354	9354	8631	8631	8619	8619	8494	8494	8494	8494	8083	7421	7421	6901	6333	5376	4224	3507	3507
PPA Contracts	1103	1103	1061	581	581	581	581	338	338	338	338	338	338	338	338	338	233	203	195	195
LMRs	308	308	308	308	308	308	308	308	308	308	308	308	308	308	308	308	308	308	308	308
Identified Planned Resources																				
Union	-	816	816	816	816	816	816	816	816	816	816	816	816	816	816	816	816	816	816	816
Amite South CCGT	-	-	-	-	-	560	560	560	560	560	560	560	560	560	560	560	560	560	560	560
Other Planned Resources																				
DSM	19	44	77	105	151	220	266	299	329	334	403	413	414	471	457	532	539	423	456	538
CTs (2)	-	-	-	-	-	388	388	388	388	388	388	388	388	388	388	388	388	388	388	388
CCGT 1	-	-	-	-	-	764	764	764	764	764	764	764	764	764	764	764	764	764	764	764
CCGT 2	-	-	-	-	-	-	-	-	-	-	-	-	764	764	764	764	764	764	764	764
CCGT 3	-	-	-	-	-	-	-	-	-	-	-	-	-	764	764	764	764	764	764	764
CCGT 4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	764	764	764	764	764	764
CCGT 5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	764	764	764	764	764
CCGT 6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	764	764	764	764
CCGT 7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	764	764
CCGT 8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	764
Market Purchase	165	-	138	1,762	2,026	165	200	611	663	739	755	1,239	1,218	478	328	133	503	1,881	1,889	1,122
Total Resources	11,053	11,625	11,754	12,203	12,513	12,421	12,502	12,578	12,659	12,741	12,826	12,909	12,991	13,073	13,152	13,229	13,308	13,387	13,466	13,546

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- Demand Side Management (DSM) total is grossed up for Planning Reserve Margin (12%) and transmission losses (2.4%).

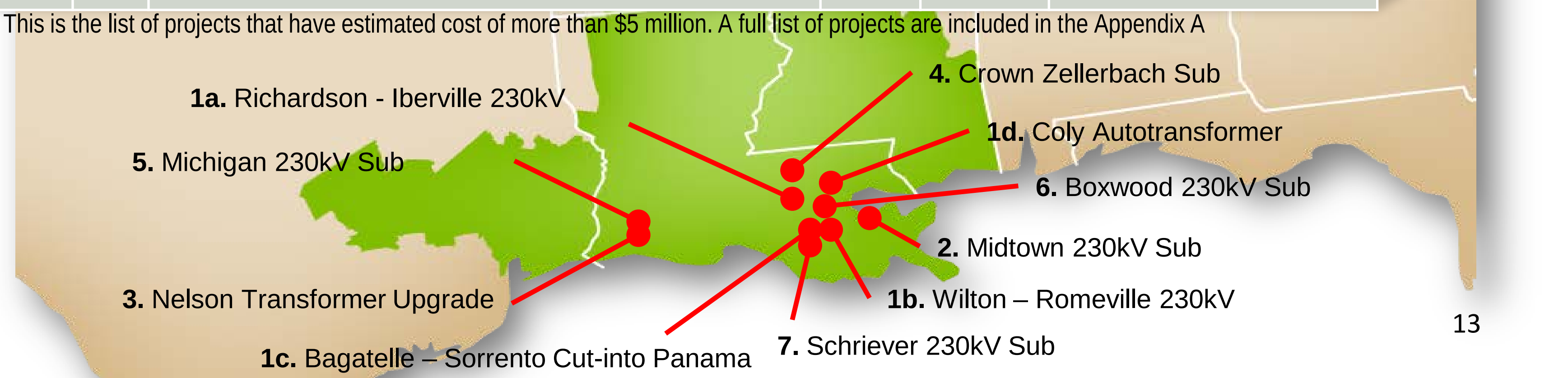
ACTION PLAN

- The Companies' IRP includes an Action Plan in accordance with the IRP Rules. The Action Plan includes several key components regarding supply side and demand side resources
- Supply Side
  - Complete Union Power acquisition
  - Continue to assess development of CTs in Lake Charles area around 2020
  - Complete the 2020 Amite South RFP
  - Pursue a CCGT in Lake Charles for 2020-2021 timeframe
  - Continue to assess development of additional CTs in WOTAB and Amite South as necessary
  - Explore opportunities for long-term gas supplies to mitigate price volatility
  - Evaluate solar and storage pilot projects (<5MW)
  - Evaluate costs/benefits of investing in existing resources
  - Evaluate costs/benefits of PPAs as viable tools to meet long-term needs
- Demand Side
  - Evaluate results of Quick Start EE programs
  - Work with regulators to develop rules for implementing programs beyond QS phase

Louisiana MTEP14 Project Highlights

Rank by Cost *	ID	Project Description	Cost ($M)	Type	Impact
1	8284	Richardson - Iberville 230kV & Bagatelle – Sorrento 230kV cut-in to Panama 230kV & Coly 500/230kV transformer & Upgrade Wilton – Romeville 230kV	$56	Economic	Reduce congestion
2	4794	Midtown 230 KV transformer (Entergy New Orleans)	$27	Load Srv	Improve load serving capability in the industrial load growth areas
3	4625	Nelson transformer upgrade	$21	Reliability	Improve system reliability
4	4605	Crown Zellerbach area substation	$20	Reliability	
5	4720	Michigan 230 kV substation	$15	Load Srv	Improve load serving capability in the industrial load growth areas
6	4768	Boxwood 230 kV substation	$11	Load Srv	
7	4769	Schriever 230 kV substation	$9	Load Srv	

* Note: This is the list of projects that have estimated cost of more than $5 million. A full list of projects are included in the Appendix A



Map for illustrative purposes only

The MISO Voltage and Local Reliability (VLR) Study

Scope and Overview

- Reliability constraints in the load pockets of the Southern Region have resulted in the commitment of local generation (due to VLR constraints) out of economic merit order, which, in turn has given rise to make whole payments to recover the uplift charges

- Stakeholders expressed an interest in an analysis aimed at studying the elimination or mitigation of VLR uplift costs

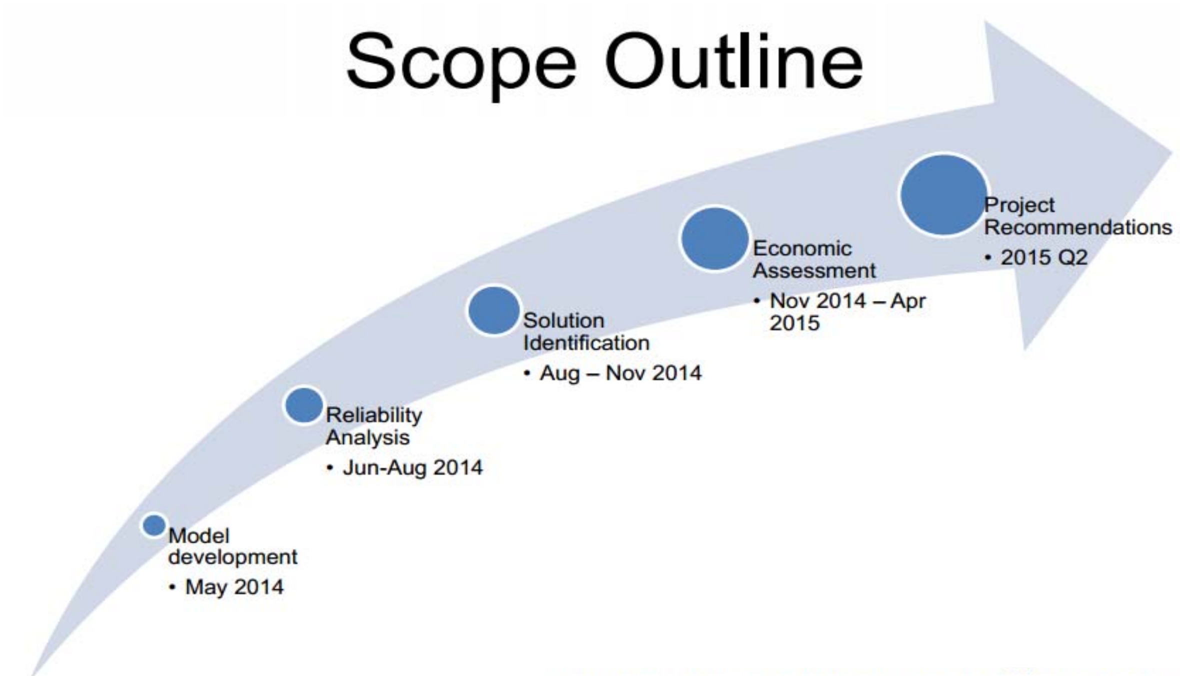
    The study scope is similar to that of the Minimization of Bulk Power Costs study that was completed in June 2012, which was conducted by an independent consultant under the oversight of the E-RSC.

- MISO initiated the VLR study to investigate cost-effective transmission solutions for minimizing VLR commitments and to minimize the total cost of delivered energy to consumers

    – The study recognizes that VLR commitment of a unit may be less costly than the annual revenue requirements of a transmission solution

The MISO Voltage and Local Reliability (VLR) Study

Overall Study Schedule



Timetable in 2015