ENTERGY NEW ORLEANS

Supporting Technical Materials

2015 ENO Integrated Resource Plan

JUNE 2015

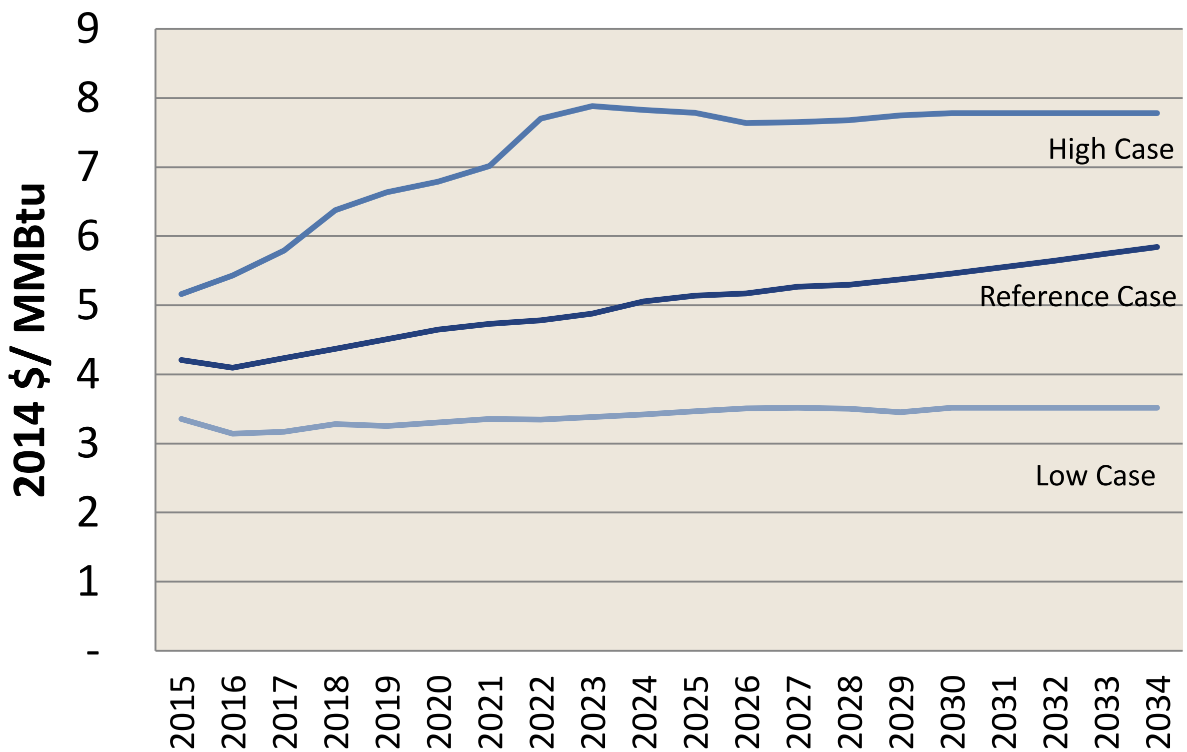
COMMODITY FORECASTS

HENRY HUB NATURAL GAS PRICE FORECAST

SPO 2015 Long-Term Henry Hub Natural Gas Price Forecasts (2014$/MMBtu)

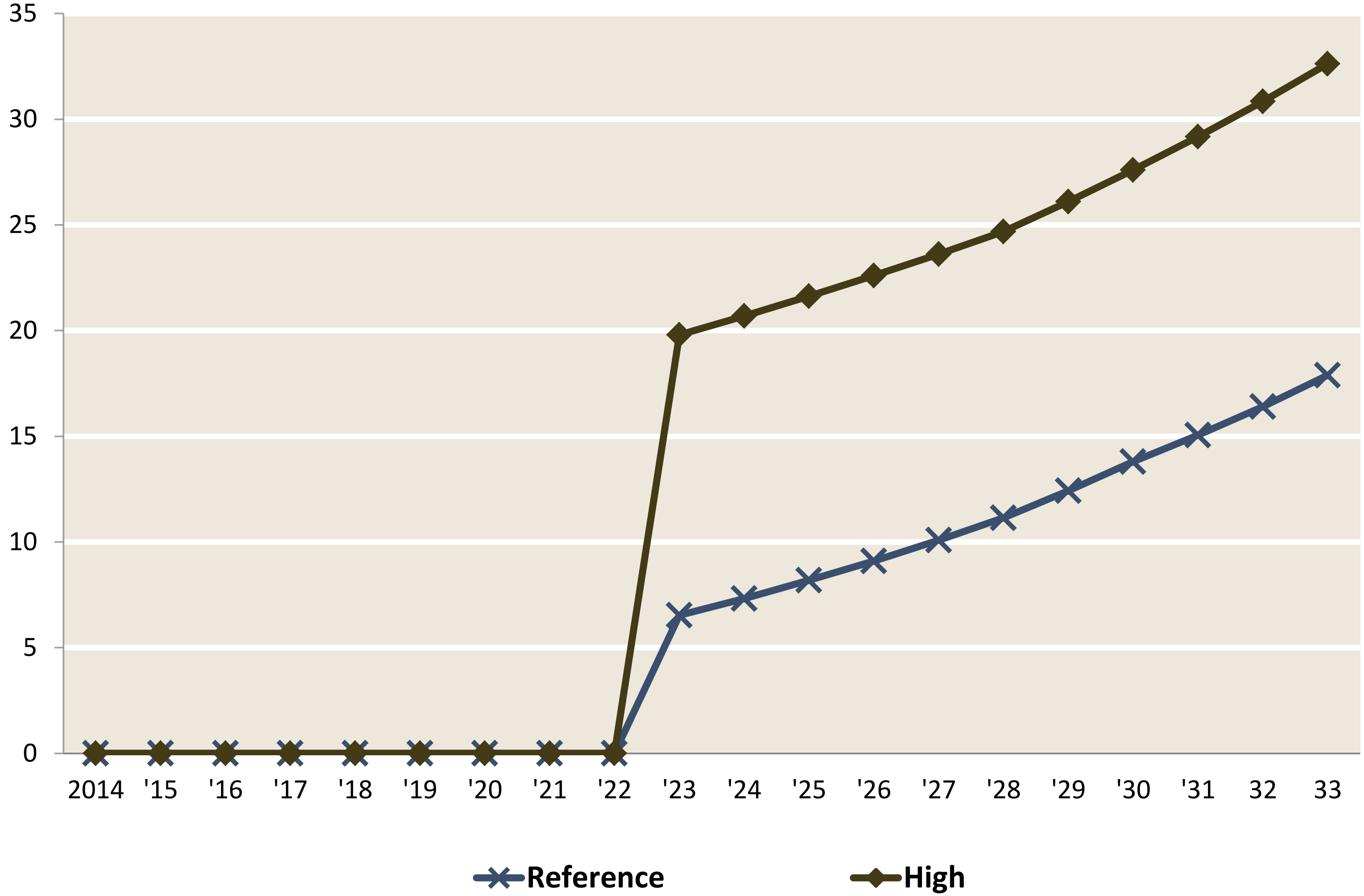
Process

- SPO Planning Analysis relies on a number of leading consultants in preparing the natural gas price forecast.
- The early years of the long-term forecast (~1st 3 years) are based on NYMEX forward prices without modification.
- In the later years, the Industrial Renaissance Natural Gas forecast represents a consensus view of the consultants' forecasts.
- The High and Low Cases represent plausible alternative scenarios developed by SPO (informed by consultants and a review of historical fundamentals and prices).



CO_2 PRICE FORECAST

April 2013 Long-Term CO_2 Price Forecast (2013$/U.S. Ton) Reaffirmed in August 2014

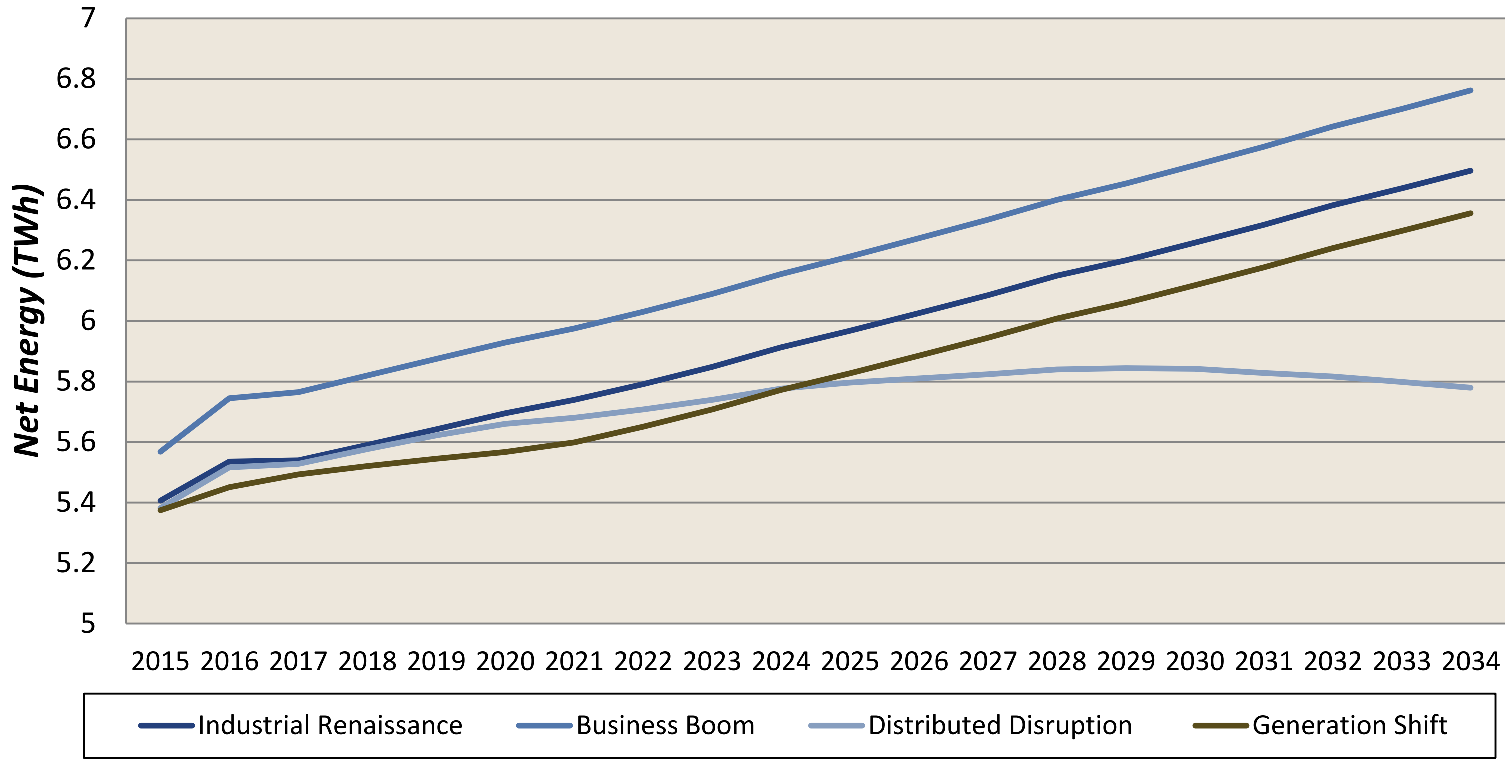


HISTORIC LOAD AND LOAD FORECAST

ENO HISTORIC PEAK DEMAND AND ENERGY

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Peak (MW)	1,254	912	904	882	998	1,005	1,018	1,018	1,012	987
Load (MWh)	5,255,932	4,787,343	4,642,137	4,748,723	5,006,068	5,302,305	5,335,801	5,216,204	5,343,109	5,318,457

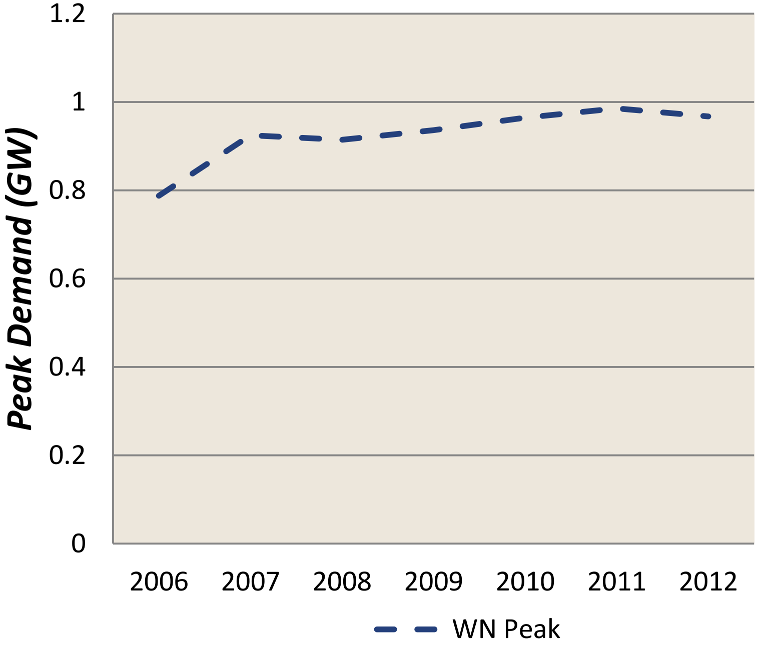
ENO TOTAL ENERGY LOAD FORECAST



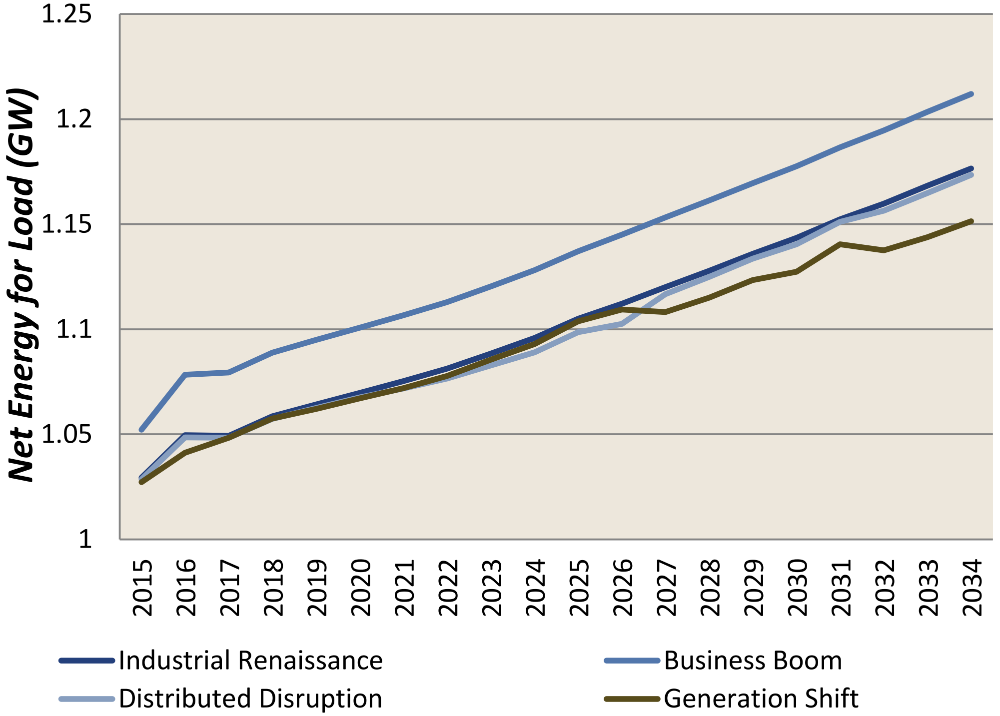
2015 Update	2015-2025 CAGR	2025-2034 CAGR
Industrial Renaissance	1.0%	0.9%
Business Boom	1.1%	0.9%
Distributed Disruption	0.7%	0.0%
Generation Shift	0.8%	0.9%

2015 Update Energy Forecast (GWh)	2015	2020	2025	2030	2034
Industrial Renaissance	5,406	5,695	5,968	6,258	6,497
Business Boom	5,568	5,929	6,213	6,514	6,762
Distributed Disruption	5,383	5,660	5,796	5,842	5,779
Generation Shift	5,375	5,567	5,827	6,117	6,356

ENO PEAK FORECAST



WN Peak = Actual peak adjusted to normal weather



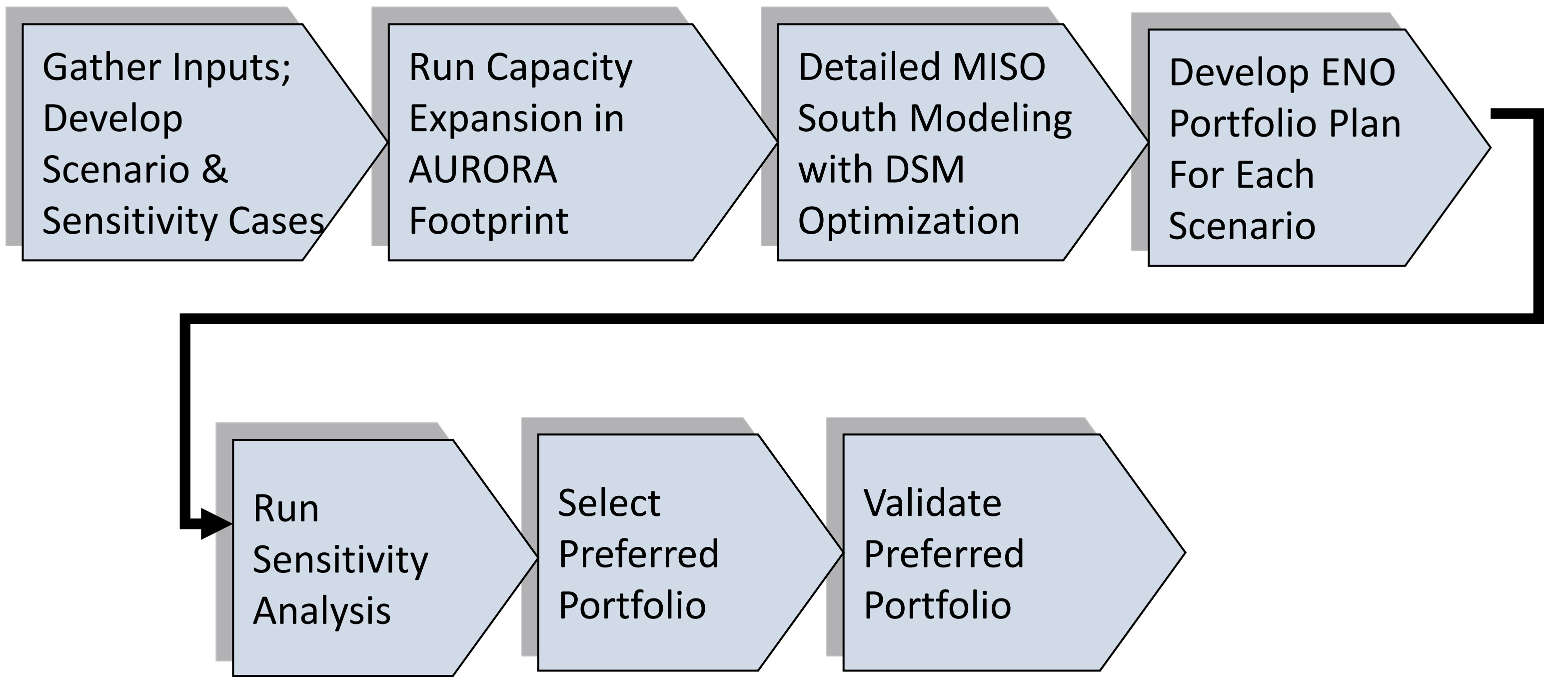
2015 Update	2015-2025 CAGR	2025-2034 CAGR
Industrial Renaissance	0.7%	0.6%
Business Boom	0.8%	0.6%
Distributed Disruption	0.7%	0.5%
Generation Shift	0.7%	0.6%

2015 Update Total Peak Forecast (MWs)	2015	2020	2025	2030	2034
Industrial Renaissance	1,029	1,070	1,105	1,143	1,176
Business Boom	1,052	1,101	1,137	1,178	1,212
Distributed Disruption	1,029	1,068	1,099	1,127	1,151
Generation Shift	1,027	1,067	1,104	1,141	1,173

Portfolio Design Analytics (Scenarios & Sensitivities)

PORTFOLIO DESIGN ANALYTICS

As required in Resolution R-10-142, IRP analytics will rely on a combination of scenario and sensitivity analyses. The process will include seven broad steps:



The IRP is a dynamic process for long-range planning that provides for a flexible approach to resource selection. The Preferred Portfolio resulting from the IRP planning process provides guidance regarding long-term resource additions, but is not intended as a static plan or pre-determined schedule for resource additions. Actual portfolio decisions are made at the time of execution.

SCENARIOS AND SENSITIVITIES TO BE PERFORMED

The companies plan to examine four scenarios to assess alternative portfolio strategies under varying market conditions. The four scenarios are:

- Scenario 1 (Industrial Renaissance)
  - Reference Load, Gas, Oil, and Coal Prices
  - No direct CO_2 cap and trade or tax on existing resources or new resources but EPA CO_2 standards for new resources allowed to go into effect as currently proposed.
  - Most renewable incentives allowed to sunset
  - No new RPS Standards
- Three additional scenarios listed below and described on the next page.
  - Scenario 2 (Business Boom)
  - Scenario 3 (Distributed Disruption)
  - Scenario 4 (Generation Shift)

*ENO uses MISO capacity market purchases/sales to ensure appropriate resource adequacy

**To the extent that there is a CO_2 cap and trade or tax it is assumed to apply to new and existing resources equally.

The Sensitivity Analysis considered the following uncertainties:

- Natural gas prices
- Implementation of CO_2 cost**
- Gas and CO_2 combination**

SCENARIO STORYLINES

	Scenario 2	Scenario 3	Scenario 4
	Business Boom	**Distributed Disruption**	**Generation Shift**
General Themes	• U.S. energy boom continues with low gas and coal prices discounted to world prices. U.S. oil production remains strong but price stays linked to world market. • Low fuel prices drive high load growth especially in industrial class, but with Residential and Commercial class spillover benefits. • Higher capital cost for new power plants.	• States continue to support distributed generation. Consumers and businesses see it as a way to manage their own energy uses. • Medium-high oil prices drive consumer awareness across energy spectrum. • Overall economic conditions are steady with moderate GDP growth which enables investment in energy infrastructure.	• High natural gas exports and more coal exports lead to higher prices at home. • Slow economic growth due to higher energy prices. • Consumers and government look for utility transformation to cleaner and more stable fuels. • Conditions are ripe for renewables and new nuclear but their challenges remain.
Power Sales	• Power sales driven by industrial growth and modest rate increases due to low natural gas and coal prices.	• Power sales growth slows and ultimately turns negative. • Solar PV and Combined Heat and Power impact utility sales, however, most customers stay grid connected. • Customers seek maximum flexibility and reliability by relying on self generation and grid power to meet their needs.	• Slow economic growth leads to relatively low power sales.
CO_2 Policy	• Congress or the EPA ultimately passes a mild CO_2 cap and trade program (power sector only) effective in 2023.	• Congress or the EPA ultimately passes a mild CO2 cap and trade program (power sector only) effective in 2023.	• Congress takes control of CO2 cap and trade away from EPA and passes a Kerry -Lieberman style CO_2 program effective in 2023.
Energy Policy	• Most renewable energy subsidies sunset. • Not all states meet RPS goals.	• Net metering continues but issues related to cross subsidization are addressed. • Federal and state renewable subsidies continue	• Federal and state renewable subsidies continue • No new state RPSs.
Fuels	• Low fuel prices, but natural gas and coal still plentiful as exploration and production costs are also lower. Coal prices low to retain share.	• Natural gas prices are driven higher by EPA regulation of fracking & local opposition. Coal and oil prices also high.	• Natural gas, coal, and oil prices are high.

20 YEAR MARKET MODEL INPUTS (2015-2034)

	Industrial Renaissance	Business Boom	Distributed Disruption	Generation Shift
Electricity CAGR (Energy GWh)	~1.0%	~1.0%	~0.4%	~0.8%
Peak Load Growth CAGR	~0.7%	~0.7%	~0.7%	~0.7%
Henry Hub Natural Gas Prices ($/MMBtu)*	$4.87 levelized 2014$	Low Case $3.84 levelized 2014$	Same as Reference Case ($4.87 levelized 2014$)	High Case ($8.18 levelized 2014$)
WTI Crude Oil ($/Barrel)*	$73.99 levelized 2013$	Low Case $69.00 levelized 2013$	Medium High ($109.12 levelized 2013$)	High Case ($173.71 levelized 2013$)
CO_2 ($/short ton)*	None	Cap and trade starts in 2023 $6.70 levelized 2013$	Cap and trade starts in 2023 $6.70 levelized 2013$	Cap and trade starts in 2023 $14.32 levelized 2013$
Conventional Emissions Allowance Markets	CSAPR & MATS	CSAPR & MATS	CSAPR & MATS	CSAPR & MATS
Delivered Coal Prices – Entergy Owned Plants (Plant Specific Includes Current Contracts) $/MMBtu*	Reference Case (Vol. Weighted Avg. $2.81 levelized 2013$)	Low Case (Vol. Weighted Avg. $2.43 levelized 2013$)	Same as Reference Case (Vol. Weighted Avg. $2.81 levelized 2013$)	High Case (Vol. Weighted Avg. $2.53 levelized 2013$)
Delivered Coal Prices – Non Entergy Plants In Entergy Region	Reference Case (Price Varies by Plant)	Low Case (Price Varies by Plant)	Same as Reference Case	High Case (Price Varies by Plant)
Delivered Coal Prices – Non Entergy Regions	Reference Case (Price Varies by Plant)	Low Case (Price Varies by Plant)	Same as Reference Case	High Case (Price Varies by Plant)
Coal Retirements Capacity (GW)*	Age 60**	Age 70**	Age 60**	Age 50**

*Figures shown are for the period 2015-2034 covering a sub-set of the Eastern Interconnect which is approximately 34% of total U.S. 2011 TWh electricity sales.
Note: Levelized prices refer to the price in 2013 dollars 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 when the discount rate is 6.93%. (ENO WACC).
**Entergy owned coal plants assumed to operate beyond the end of the IRP (2034). Some non Entergy plants retire early due to environmental compliance considerations

FLEET ASSUMPTIONS

ENO'S GENERATION FLEET 2015

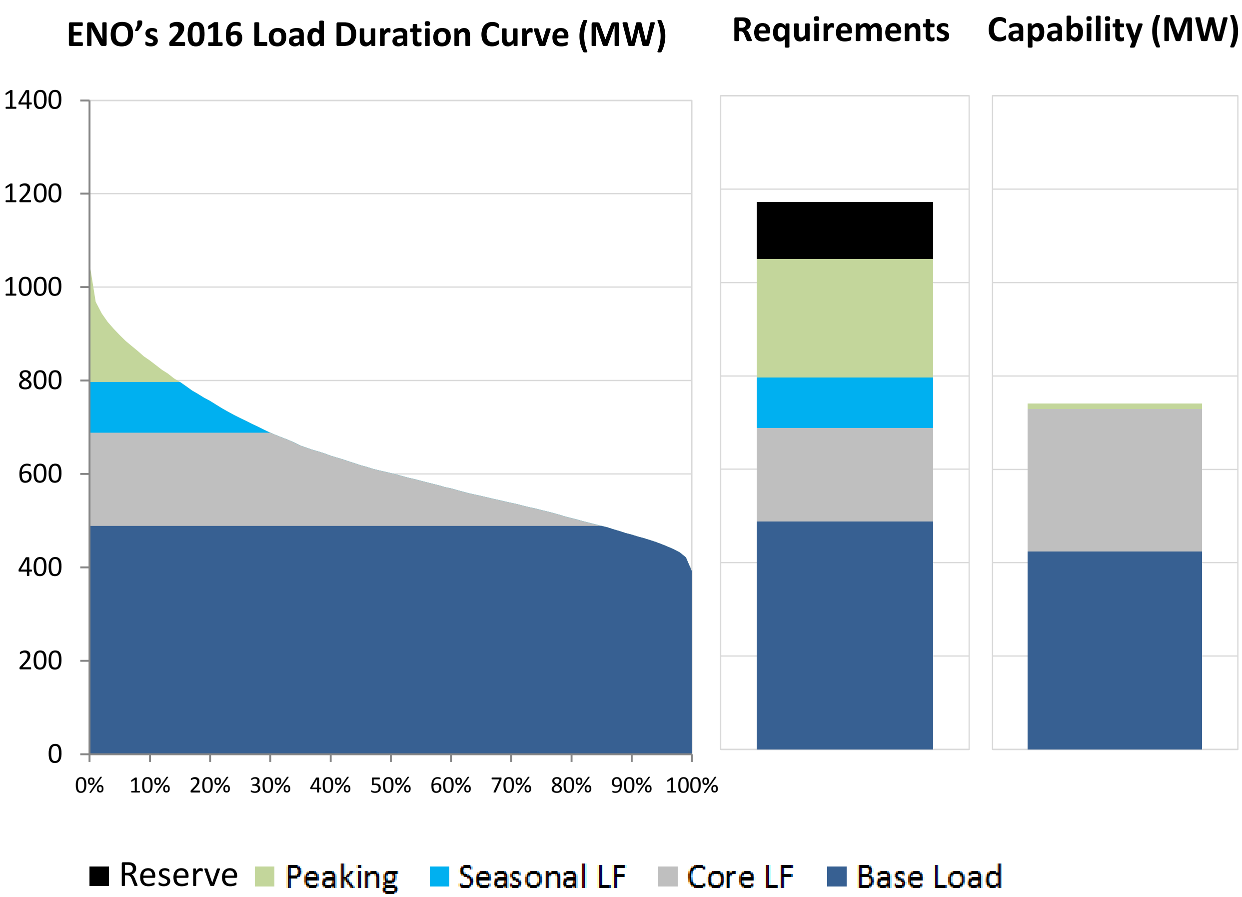
Unit	Fuel	Capability (MW)	Deactivation Assumption
Ninemile 6	Gas	112	N/A
Michoud 2	Gas	239	May 31, 2016
Michoud 3	Gas	542	May 31, 2016
ANO 1	Nuclear	23	N/A
ANO 2	Nuclear	27	N/A
Grand Gulf	Nuclear	247	N/A
Independence 1	Coal	7	N/A
White Bluff 1	Coal	12	N/A
White Bluff 2	Coal	13	N/A

ENO RESOURCE NEEDS BY SCENARIO BY YEAR (MW)

	Industrial Renaissance	Business Boom	Distributed Disruption	Generation Shift
2015	165	140	166	168
2016	(639)	(671)	(638)	(630)
2017	(639)	(672)	(638)	(638)
2018	(649)	(683)	(648)	(648)
2019	(655)	(690)	(654)	(653)
2020	(662)	(696)	(659)	(659)
2021	(668)	(703)	(664)	(664)
2022	(674)	(710)	(669)	(671)
2023	(682)	(718)	(676)	(679)
2024	(691)	(727)	(683)	(688)
2025	(701)	(737)	(694)	(700)
2026	(709)	(746)	(698)	(706)
2027	(718)	(755)	(705)	(714)
2028	(727)	(764)	(712)	(723)
2029	(736)	(773)	(722)	(733)
2030	(744)	(782)	(726)	(741)
2031	(754)	(792)	(741)	(753)
2032	(762)	(801)	(738)	(759)
2033	(772)	(811)	(745)	(768)
2034	(781)	(821)	(753)	(778)

ENO PORTFOLIO AND SUPPLY ROLE NEEDS

ENO's 2016 generation portfolio is projected to have adequate capacity for its Base Load and Core Load Following needs; however, additional peaking capacity is needed

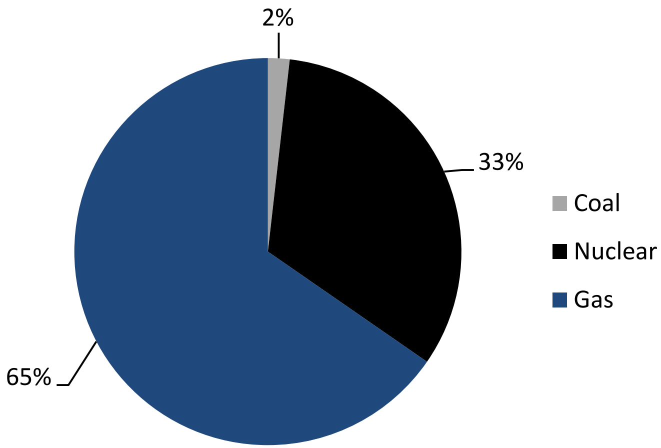


Unit	Fuel	Capability (MW)
Ninemile 6	Gas	112
Union	Gas	204
ANO 1	Nuclear	23
ANO 2	Nuclear	27
Grand Gulf	Nuclear	247
Independence 1	Coal	7
White Bluff 1	Coal	12
White Bluff 2	Coal	13

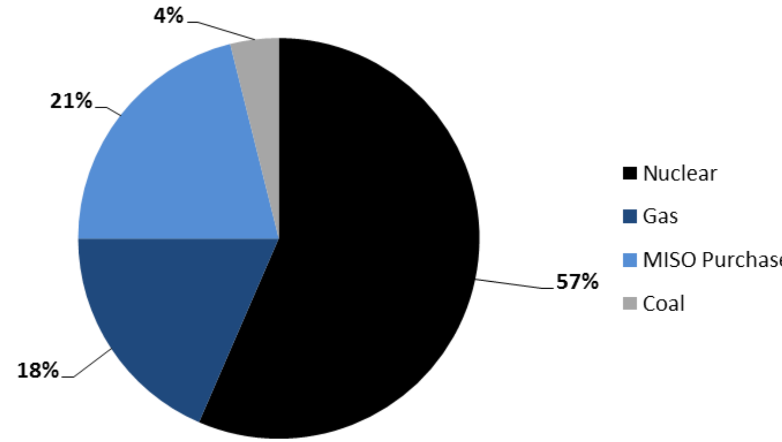
ENO'S CAPACITY & ENERGY MIX

With the planned deactivation of Michoud 2 and 3, nuclear and coal resources provide over 50% of capacity and over 60% of energy needs

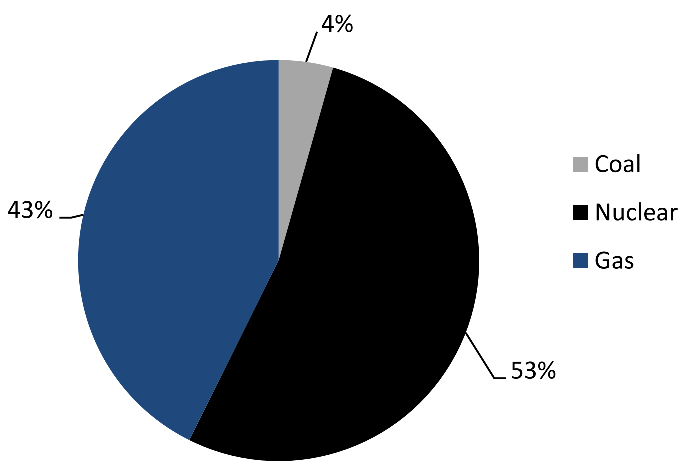
2014 Capacity (MW)



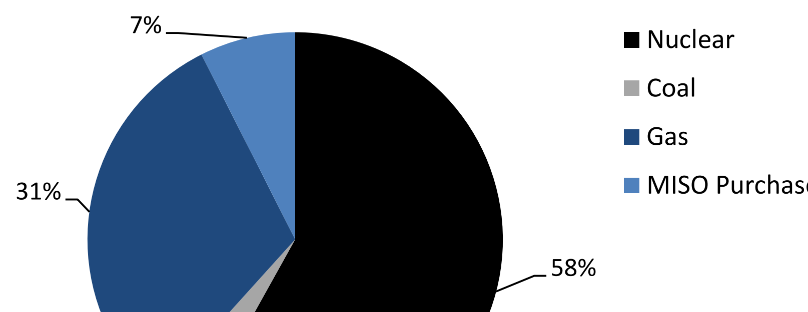
2014 Energy Mix (MWh)



2016 Capacity (MW)



2016 Energy Mix (MWh)



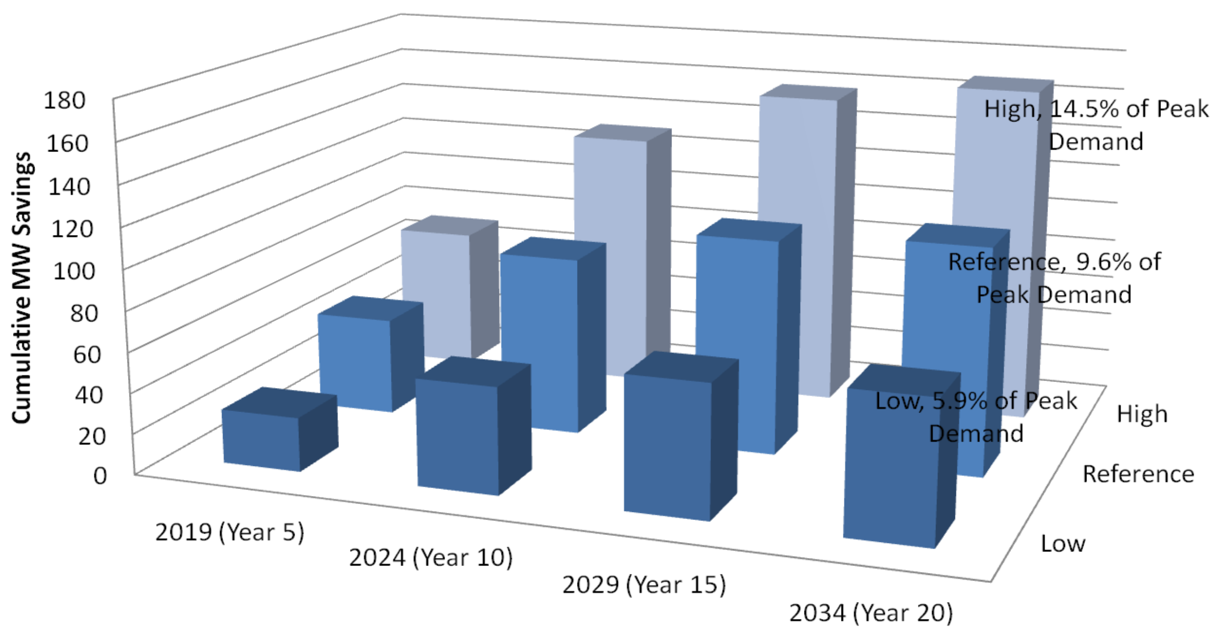
Note: 2016 does not reflect effect of System Agreement

DSM Overview

DSM POTENTIAL STUDY

- ICF conducted a DSM Potential Study to develop high-level, long run achievable DSM program potential estimates for ENO over the 20-year planning horizon (2015-2034).
  - In total, 24 DSM programs were considered cost effective with a Total Resources Cost ("TRC") ratio of 1.0 or better. ICF developed hourly loadshapes and program cost projections representing three levels – low, reference, and high – of achievable DSM program savings. These load shapes and costs are the demand side management inputs in the IRP analysis.

ENO Cumulative Net MW Savings Potential, by Scenario



AURORA Background and Construct

AURORAXMP ELECTRIC MARKET MODEL

- AURORAxmp Electric Market Model (AURORA) is a production cost model licensed by Entergy in April 2011 from software firm EPIS, Inc. in Sandpoint, ID (www.epis.com). Use of the tool at Entergy has advanced to the point where it is now the primary production cost tool used for MISO market modeling and Entergy long-term planning.

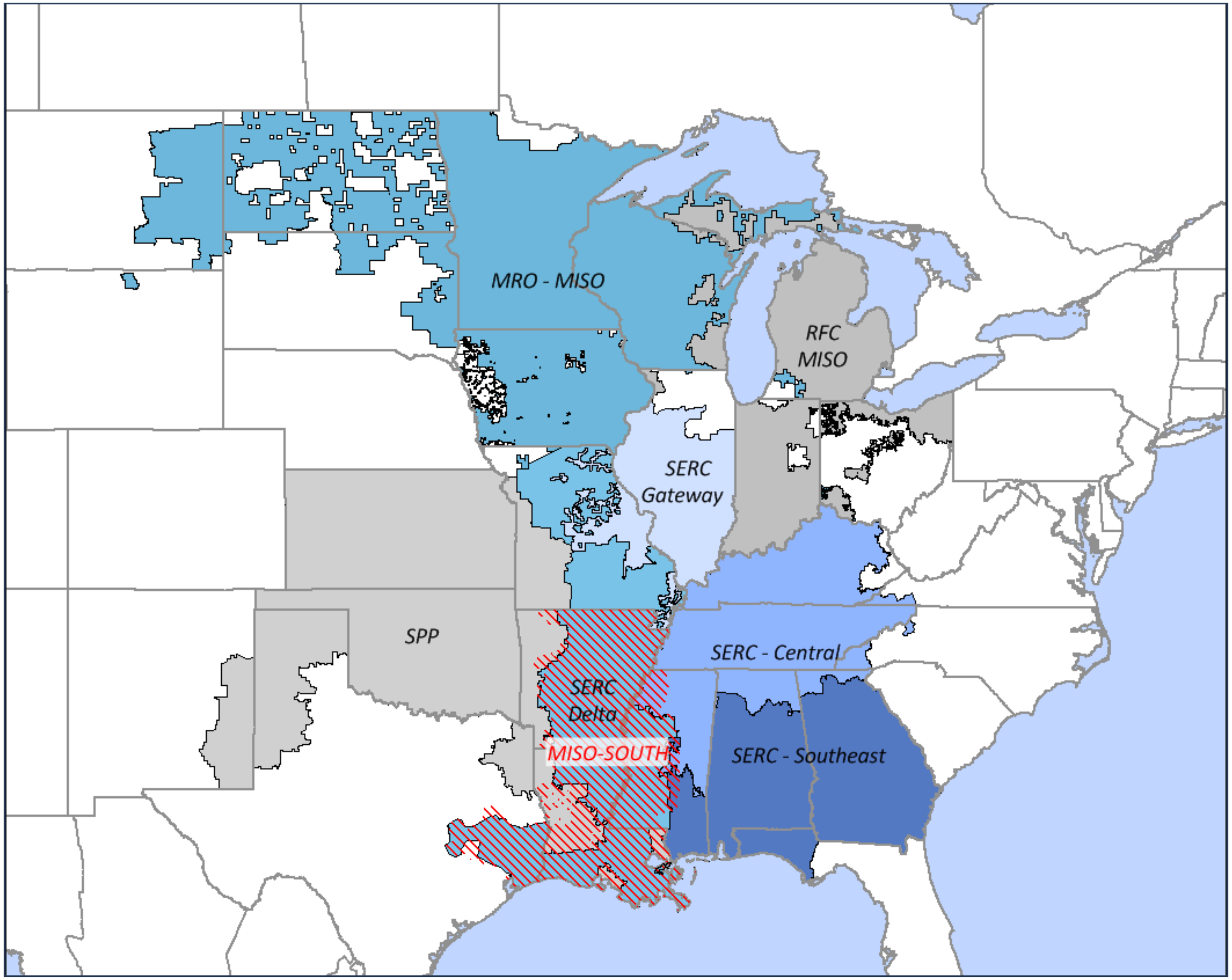
- The 2015 ENO IRP will utilize AURORA in scenario and sensitivity modeling. The 2015 AURORA Update Case has been created using the latest planning assumptions . This will serve as the foundation for ENO's IRP Scenario 1 modeling. Assumptions in the IRP work which materially differ from the 2015 Business Plan case will be noted in the IRP documents. The AURORA model has been calibrated to ensure accuracy of input data and output results. AURORA simulates the hourly operations of a power market over a projected study period. In this case, the model has been populated to allow studies for up to 20 years in length (1/1/2015 to 12/31/2034).

- The ENO IRP consider the years 2015-2034.

- The AURORA model as configured for IRP analysis uses a zonal representation of MISO and 1st Tier markets. The MISO modeling is broken down into two regions, MISO North and MISO South. The MISO North region represents the MISO RTO as it existed prior to Entergy joining the RTO. The MISO South region includes Entergy operating companies, Entergy co-owners, IPPs and Qualifying Facilities, and other non-Entergy companies (i.e. CLECO, LAFA, LEPA, LAGN, and SMEPA) within the Entergy footprint that began participation in the MISO market December 19, 2013. The 1st Tier markets consist of SPP, SERC – Central (TVA), and SERC – Southeast (SERCS).

SCOPE OF AURORA MARKET MODELING

Entergy and surrounding regions will be modeled .



FUEL PRICE METHODOLOGIES USED IN MODELING

Two factors drive the rigor and frequency of fuel price forecast updates. First the impact the fuel price assumption has on forecasting power prices; and secondly whether Entergy resources utilize the fuel in question.

FUEL PRICE METHODLOGY				
Fuel	***Load Serving Entity***	***Commodity Treatment***	***Transportation Treatment***	***Impact on Power Prices***
Natural Gas	Entergy OPCOs	Henry Hub proprietary forecast plus basis adjustments based on a historical analysis of basis	Transportation contracts and taxes to arrive at delivered price.	High
Natural Gas	Non Entergy MISO South	Henry Hub proprietary forecast plus adjustments from consultant averages of the basis differential at each non-Entergy hub	Default transportation adders provided by EPIS based on how they classify the resources (peaking, cycling, etc.)	High
Natural Gas	Other Modeled Footprint	Same as above		High
Coal	Entergy OPCOs	Proprietary forecast using future spot prices of Powder River Basin coal forecast by Energy Ventures Analysis plus existing coal contracts	Proprietary forecast of transportation cost based on rail contracts and forecasted spot rail prices by Energy Ventures Analysis	High
Coal	Non Entergy MISO South	Delivered price forecast on a plant by plant basis from Energy Ventures Analysis		High
Coal	Other Modeled Footprint	Delivered price forecast on a plant by plant basis from Energy Ventures Analysis		High
Nuclear Fuel	Entergy OPCOs	Proprietary forecast of each nuclear unit's commodity & fabrication cost considering existing contracts and future spot transportation cost	Proprietary forecast of each nuclear unit's transport cost considering existing contracts and future spot transportation cost	Low
Nuclear Fuel	Non Entergy MISO South	Volume weighted average cost for Entergy's regulated nuclear plants used for other nuclear plants		Low
Nuclear Fuel	Other Modeled Footprint	Same as above		Low

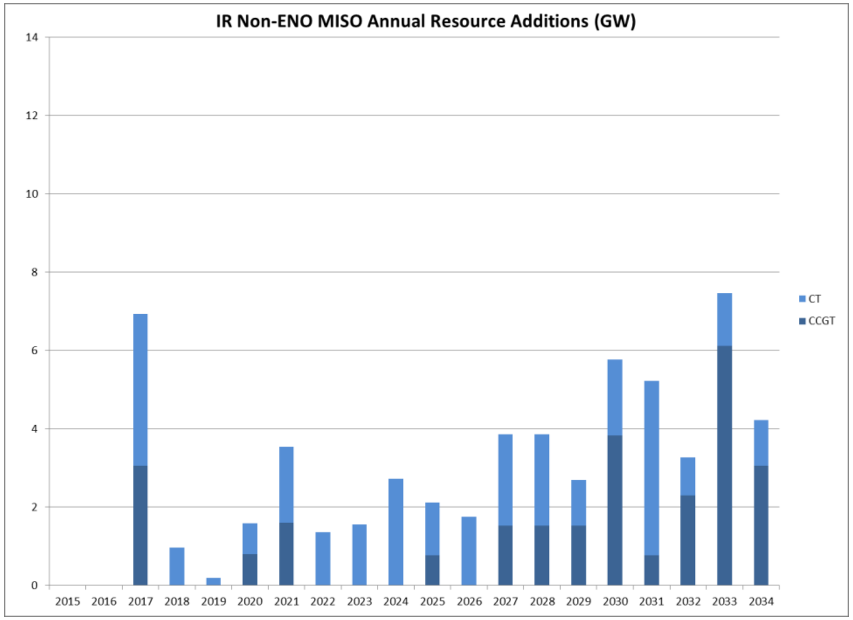
Fuel Price Methodologies Used In Modeling (Continued)

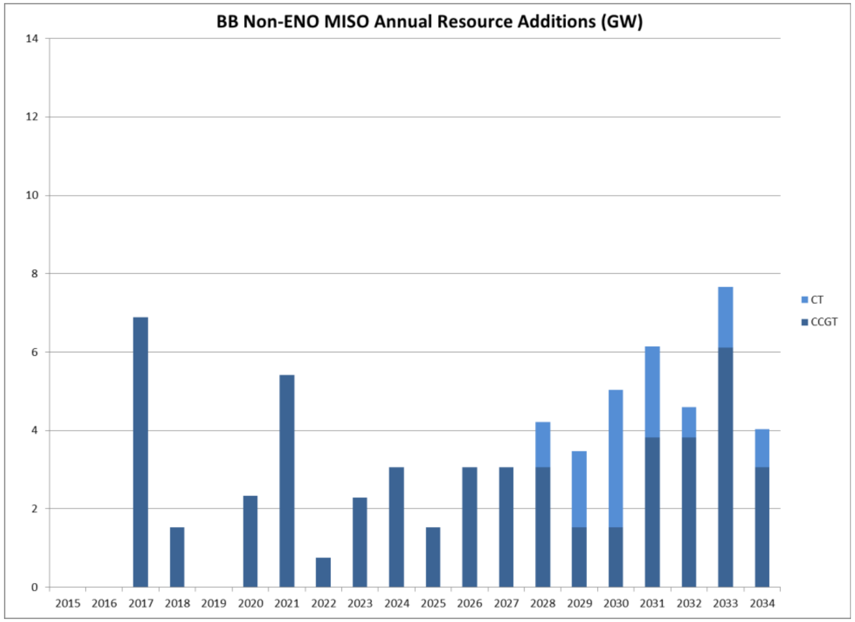
FUEL PRICE METHODLOGY				
Fuel	***Load Serving Entity***	***Commodity Treatment***	***Transportation Treatment***	***Impact on Power Prices***
Diesel/Fuel Oil	Entergy OPCOs	Use of petroleum for emergency use only at selected plants and therefore not modeled		Not meaningful*
Diesel/Fuel Oil	Non Entergy MISO South	Use of petroleum for emergency use only at selected plants and therefore not modeled		Not meaningful*
Diesel/Fuel Oil	Other Modeled Footprint	The delivered price forecast provided by AURORA vendor EPIS is used		Not meaningful*
Biomass	Entergy OPCOs	Proprietary forecast of delivered price based on market assessments by Argus Research and a forecast of lumber and wood price escalations provided by IHS Global Insight		Not meaningful
Biomass	Non Entergy MISO South	Proprietary forecast of delivered price based on market assessments by Argus Research and a forecast of lumber and wood price escalations provided by IHS Global Insight		Not meaningful
Biomass	Other Modeled Footprint	The delivered price forecast provided by AURORA vendor EPIS is used		Not meaningful

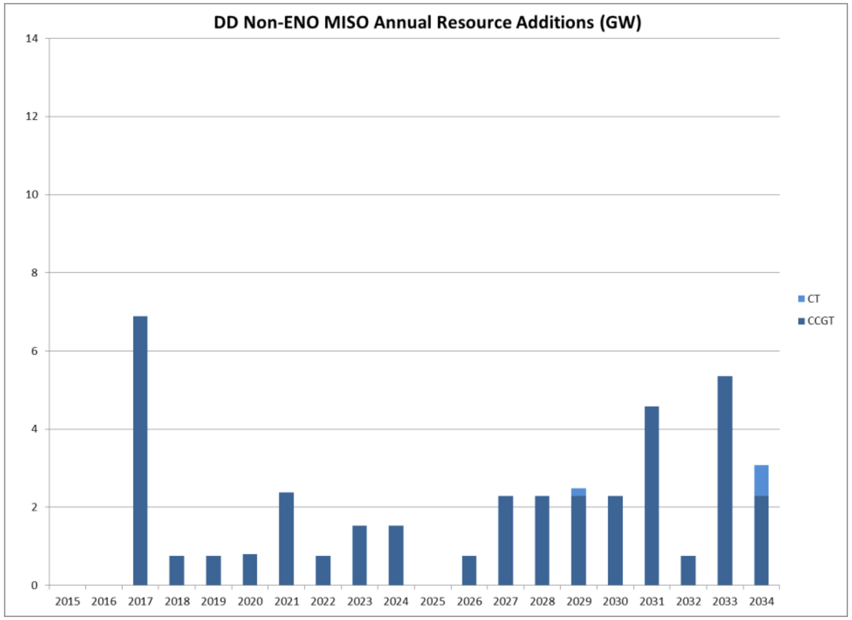
*Diesel prices impact coal transportation cost so the current and future outlook for diesel prices are considered in coal price forecasts.

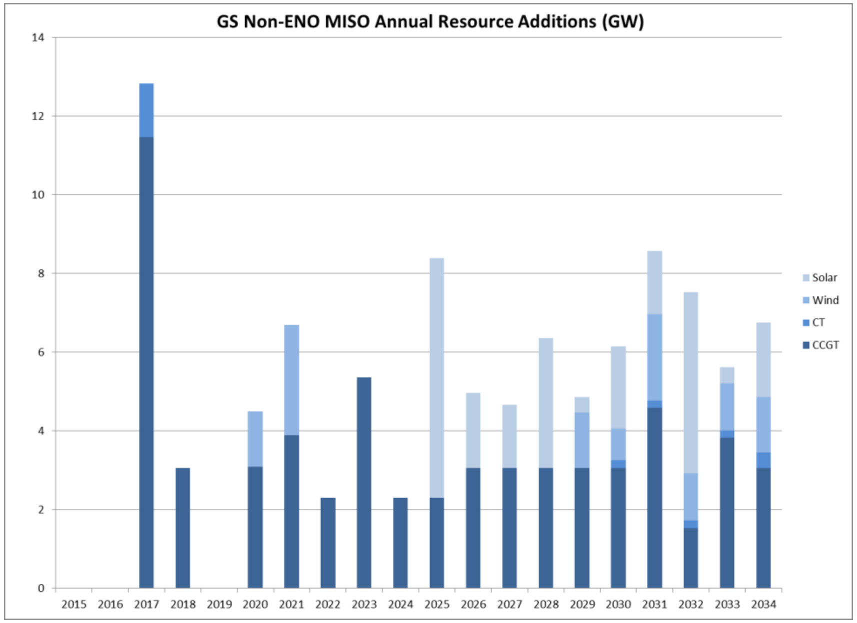
Market Modeling and Portfolio Design

PROJECTED MISO MARKET ADDITIONS BY YEAR







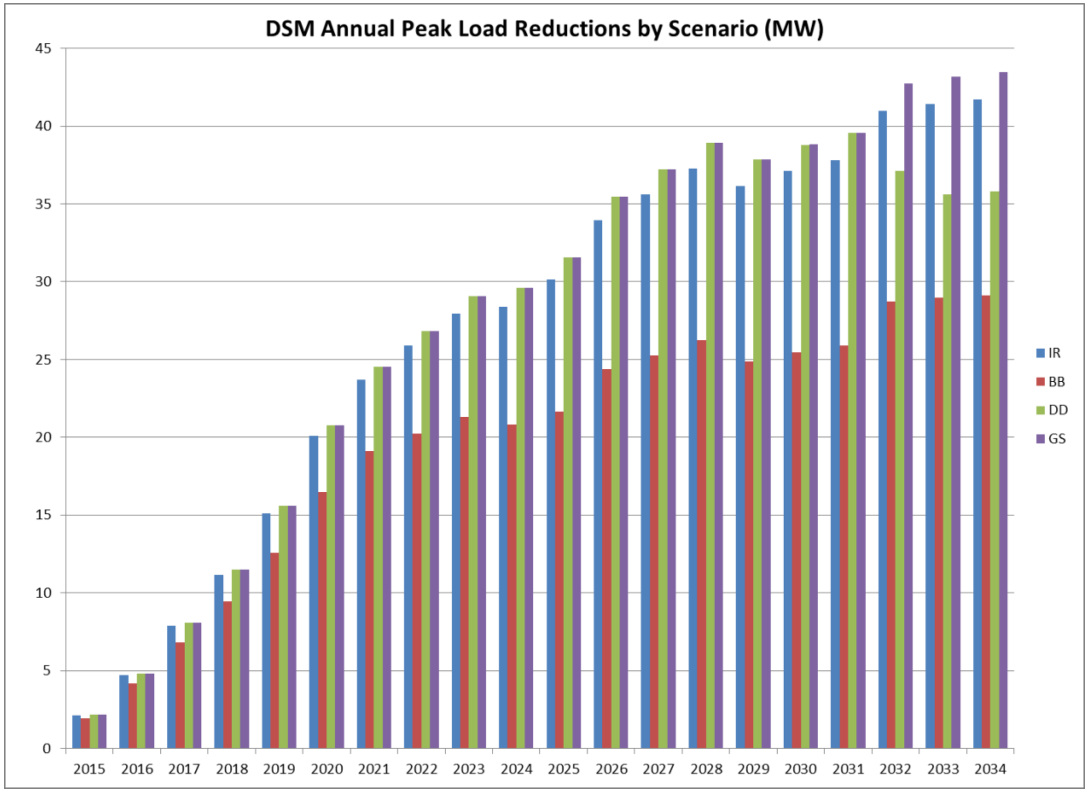


DSM OPTIMIZATION

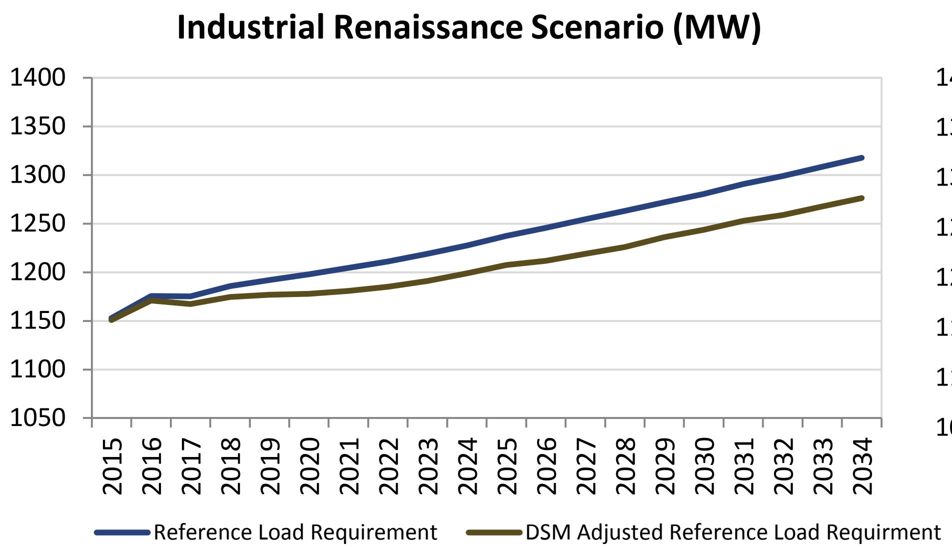
- The AURORA Capacity Expansion Model was used to develop a DSM portfolio for each of the scenarios.
- The result of this process was an optimal DSM portfolio for each scenario.

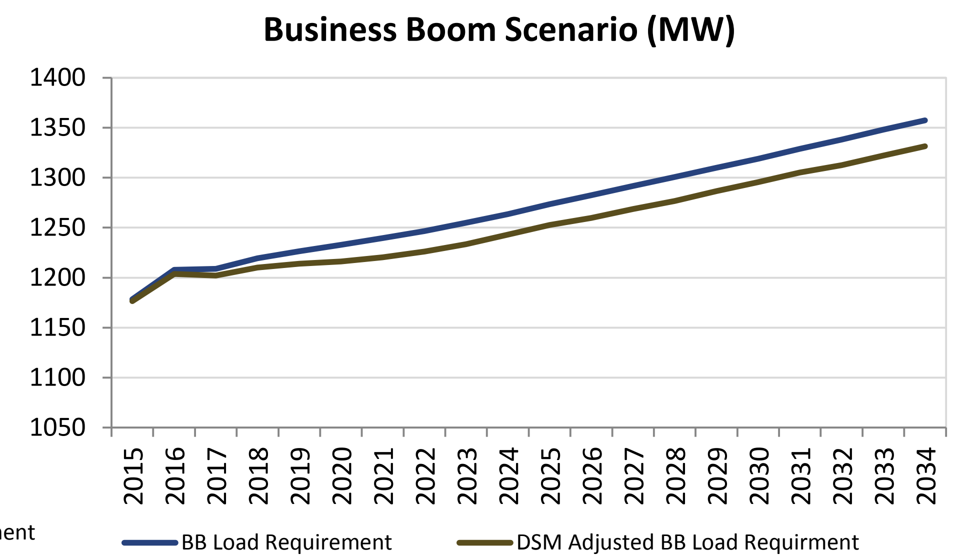
Portfolio Design Mix

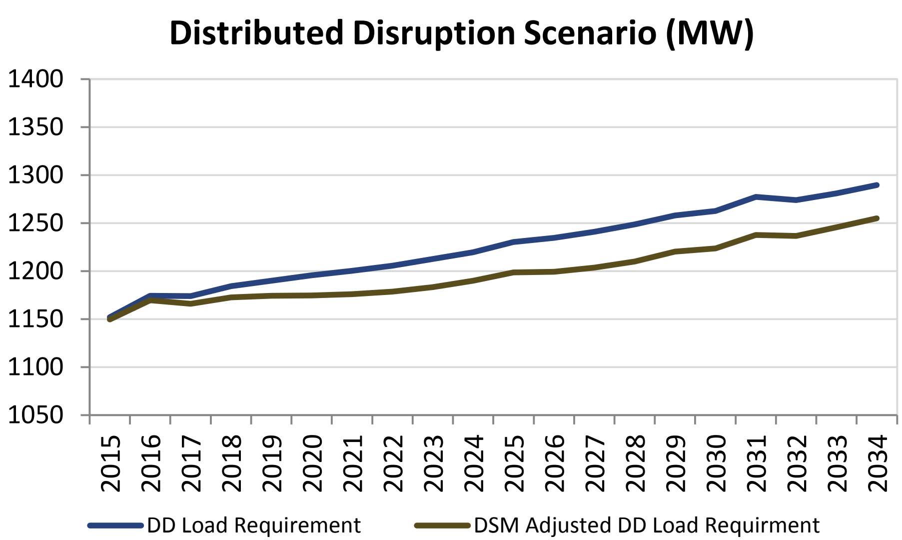
	IR Portfolio	BB Portfolio	DD Portfolio	GS Portfolio
DSM	14 Programs	12 Programs	16 Programs	17 Programs
DSM Maximum (MW)	41	26	40	43

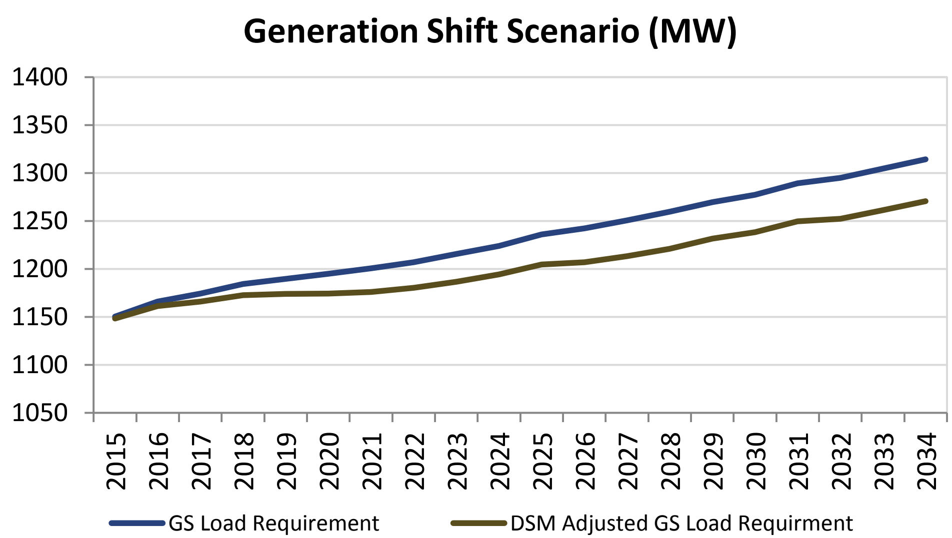


LOAD REQUIREMENTS FOR EACH SCENARIO

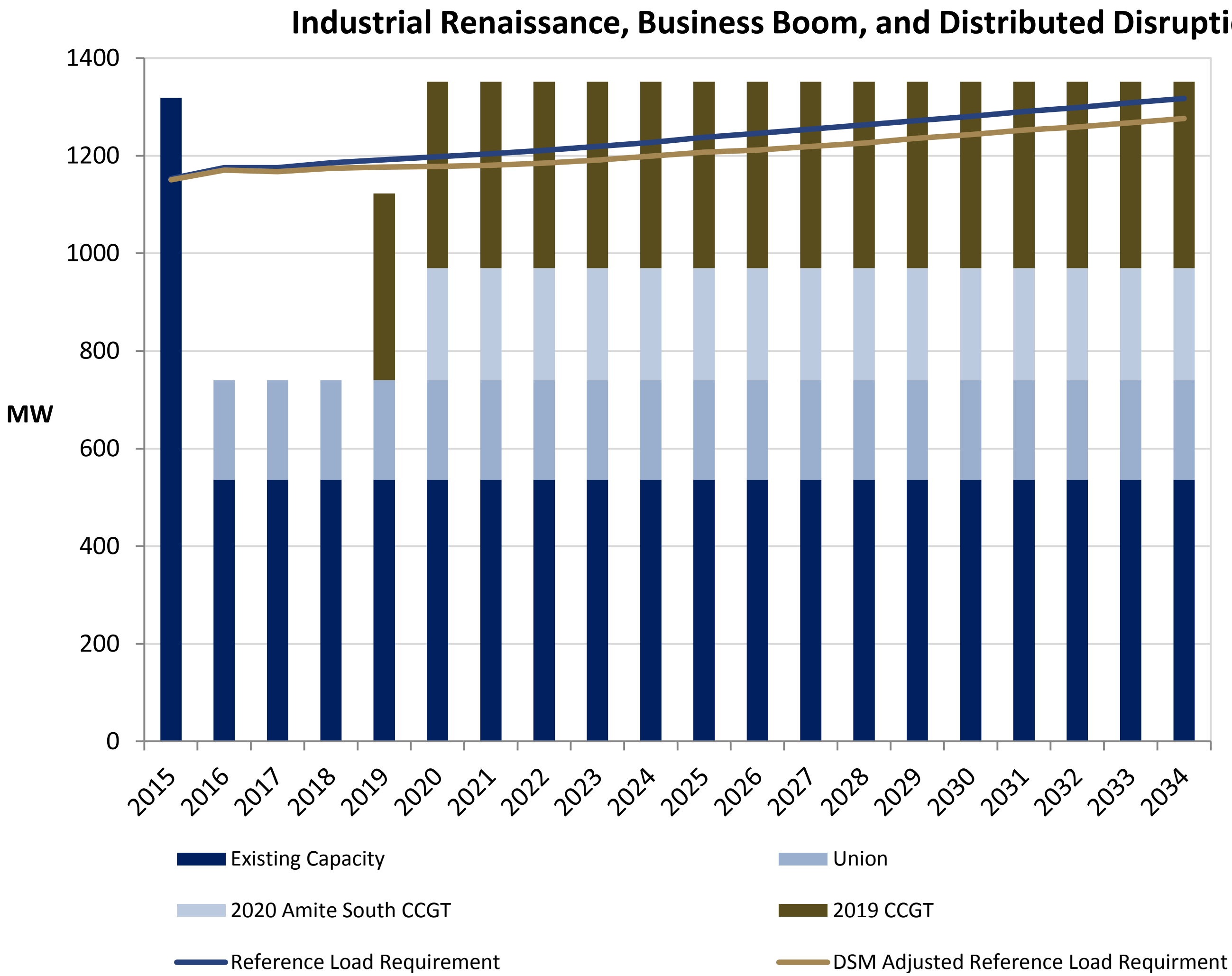








AURORA CAPACITY EXPANSION - SUPPLY SIDE PORTFOLIOS

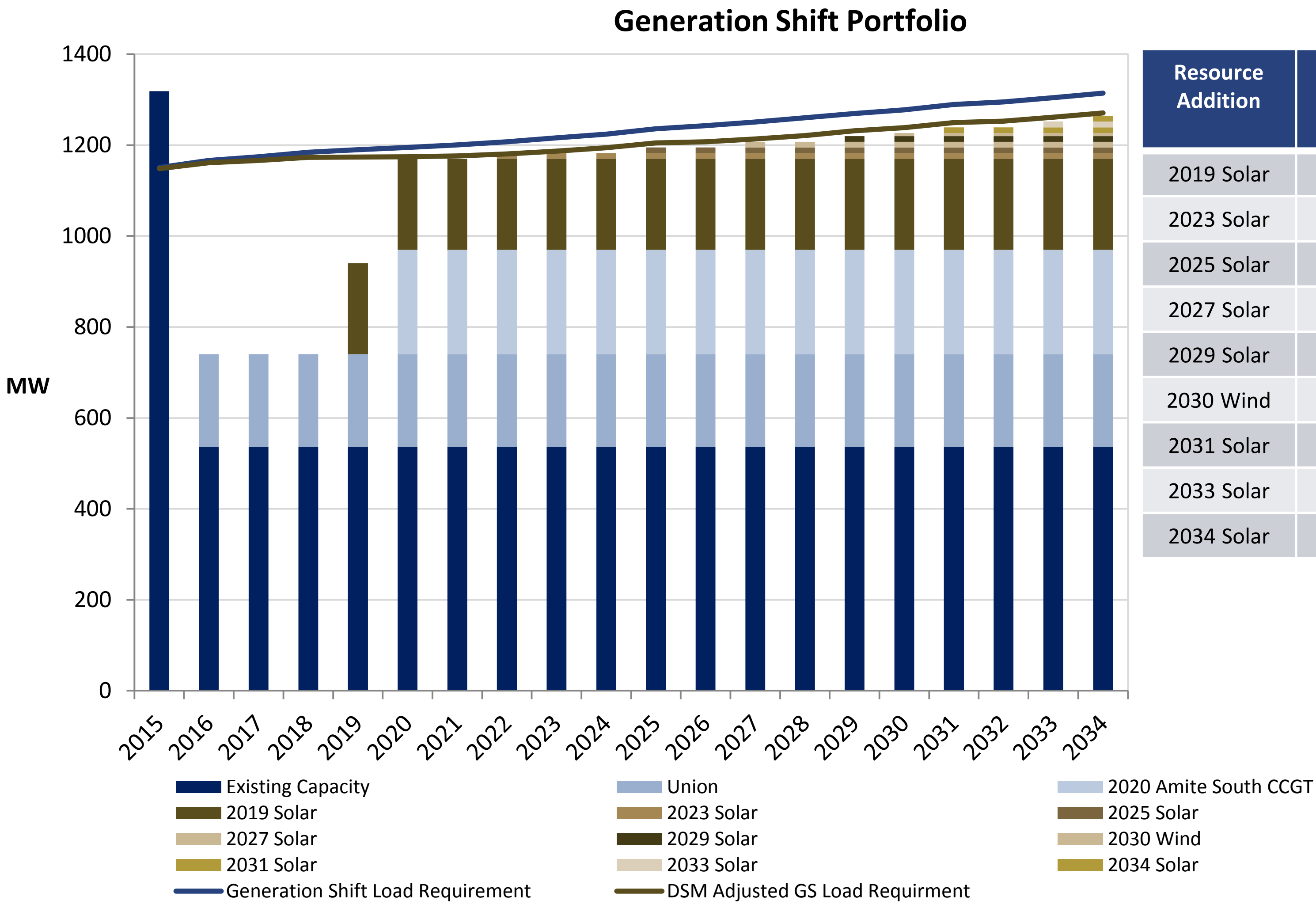


Resource Addition	Capacity (MW)
2019 CCGT	382

*Resources listed in blue are existing and planned resources. Resources additions listed in brown are the resources to be evaluated in the IRP.

Preliminary – Work in Progress

AURORA CAPACITY EXPANSION - SUPPLY SIDE PORTFOLIOS

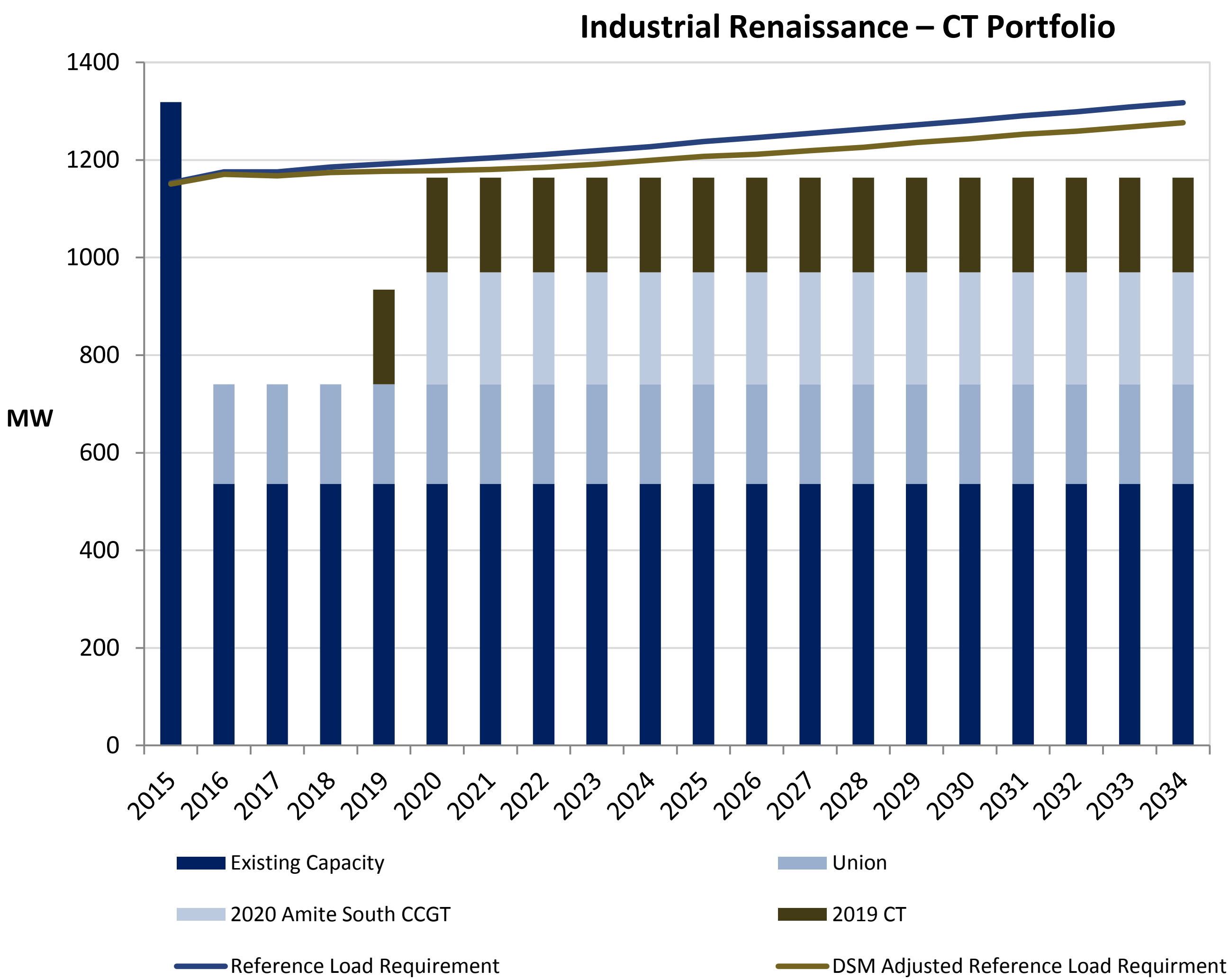


Resource Addition	Capacity (MW)	Effective Capacity (MW)
2019 Solar	800	200
2023 Solar	50	12.5
2025 Solar	50	12.5
2027 Solar	50	12.5
2029 Solar	50	12.5
2030 Wind	50	7
2031 Solar	50	12.5
2033 Solar	50	12.5
2034 Solar	50	12.5

*Resources listed in blue are existing and planned resources. Resources additions listed in brown are the resources to be evaluated in the IRP.

Preliminary – Work in Progress

MANUAL PORTFOLIOS - SUPPLY SIDE PORTFOLIOS

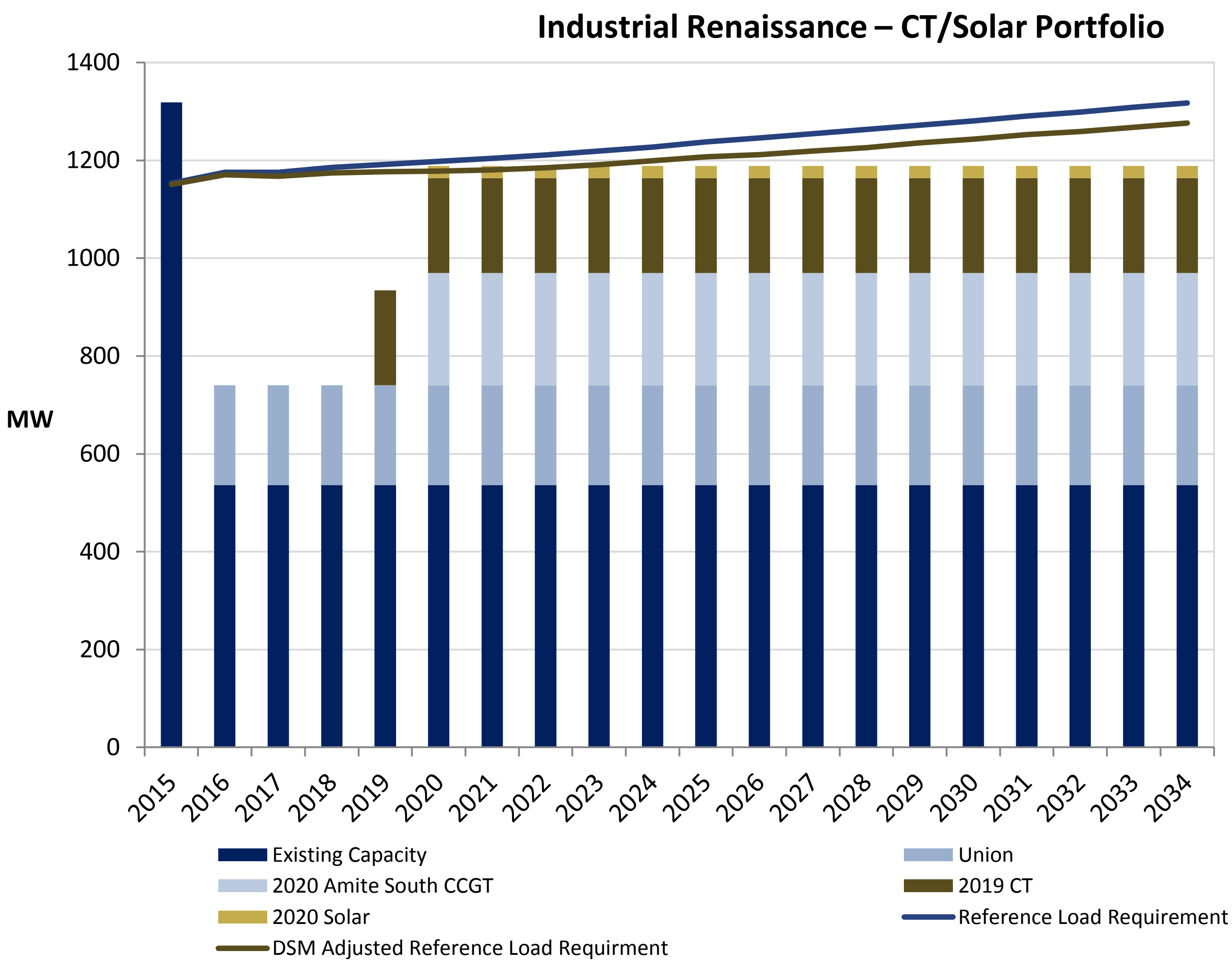


Resource Addition	Capacity (MW)
2019 CT	194

*Resources listed in blue are existing and planned resources. Resources additions listed in brown are the resources to be evaluated in the IRP.

Preliminary – Work in Progress

MANUAL PORTFOLIOS - SUPPLY SIDE PORTFOLIOS

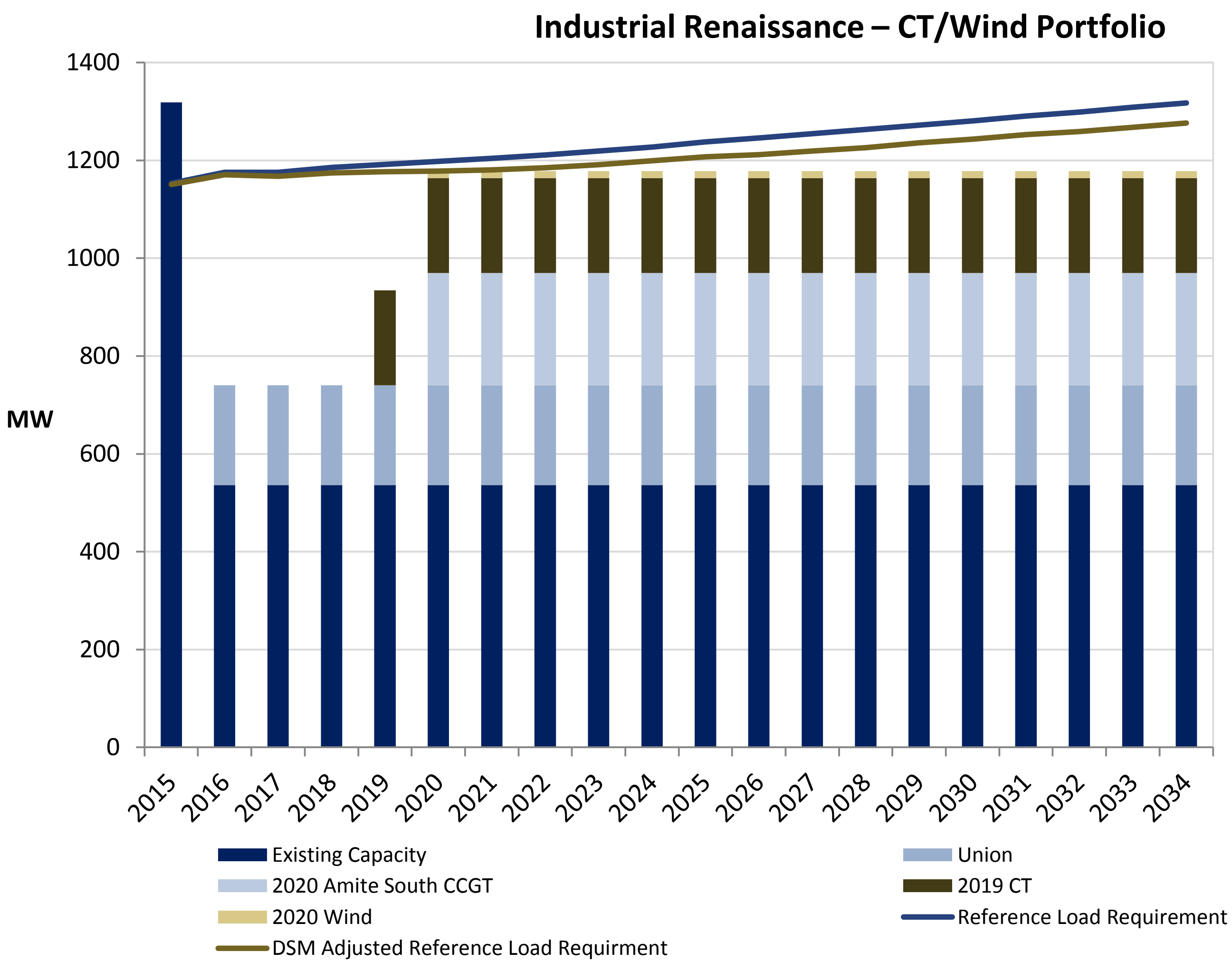


Resource Addition	Capacity (MW)	Effective Capacity (MW)
2019 CT	194	194
2020 Solar	100	25

*Resources listed in blue are existing and planned resources. Resources additions listed in brown are the resources to be evaluated in the IRP.

Preliminary – Work in Progress

Manual Portfolios - Supply Side Portfolios

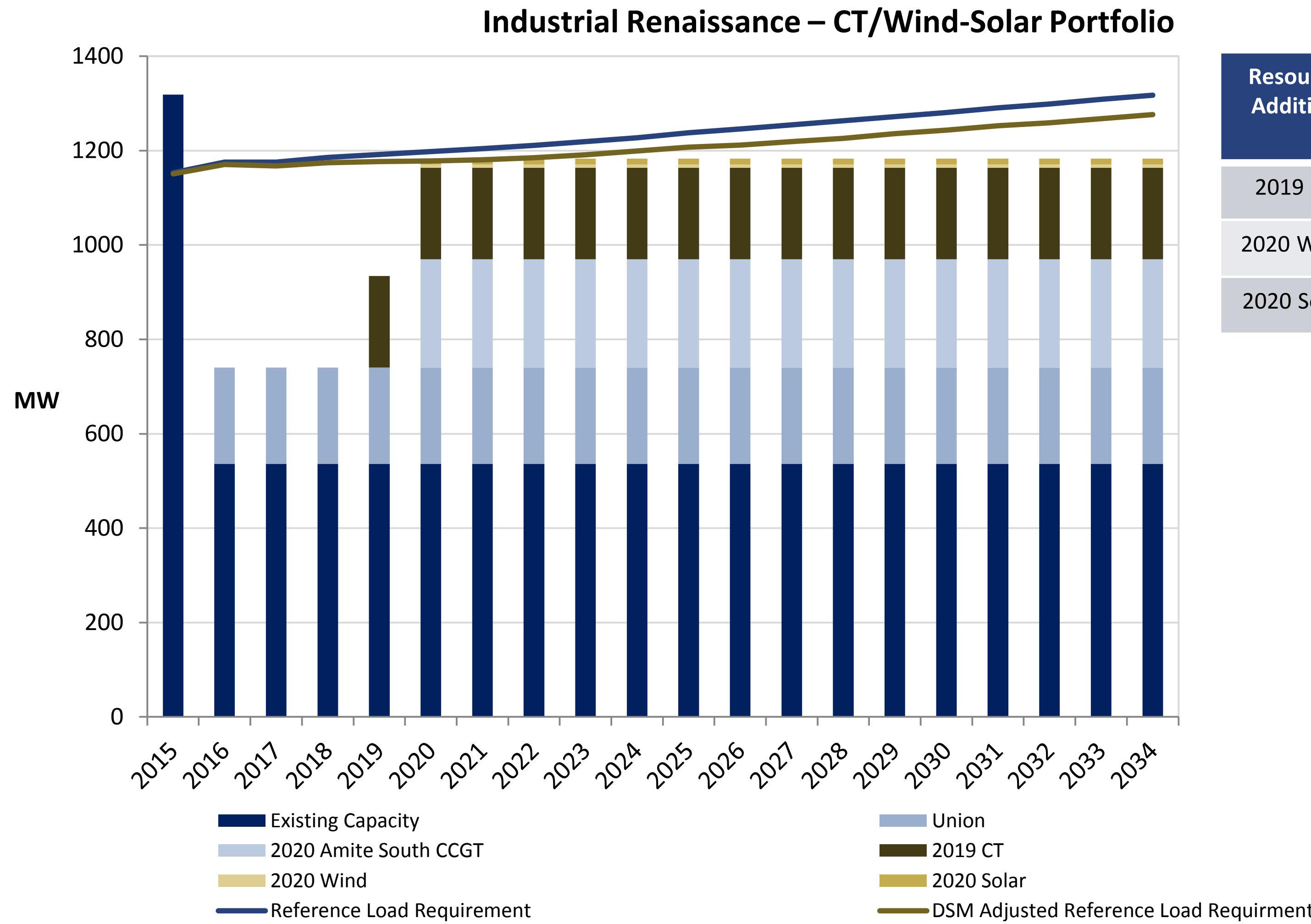


Resource Addition	Capacity (MW)	Effective Capacity (MW)
2019 CT	194	194
2020 Wind	100	14

*Resources listed in blue are existing and planned resources. Resources additions listed in brown are the resources to be evaluated in the IRP.

Preliminary – Work in Progress

MANUAL PORTFOLIOS - SUPPLY SIDE PORTFOLIOS



Resource Addition	Capacit y (MW)	Effective Capacity (MW)
2019 CT	194	194
2020 Wind	50	7
2020 Solar	50	12.5

*Resources listed in blue are existing and planned resources. Resources additions listed in brown are the resources to be evaluated in the IRP.

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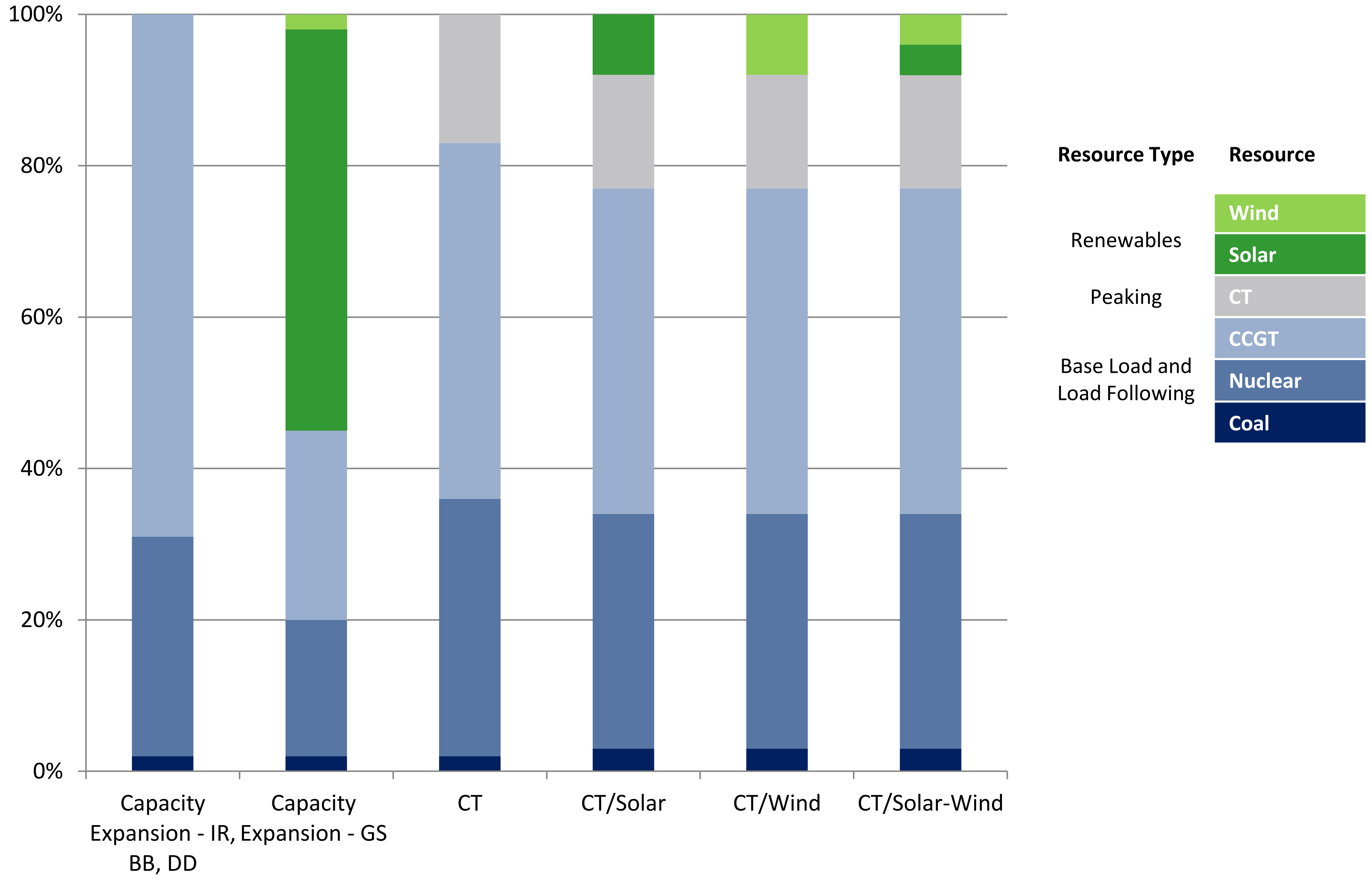
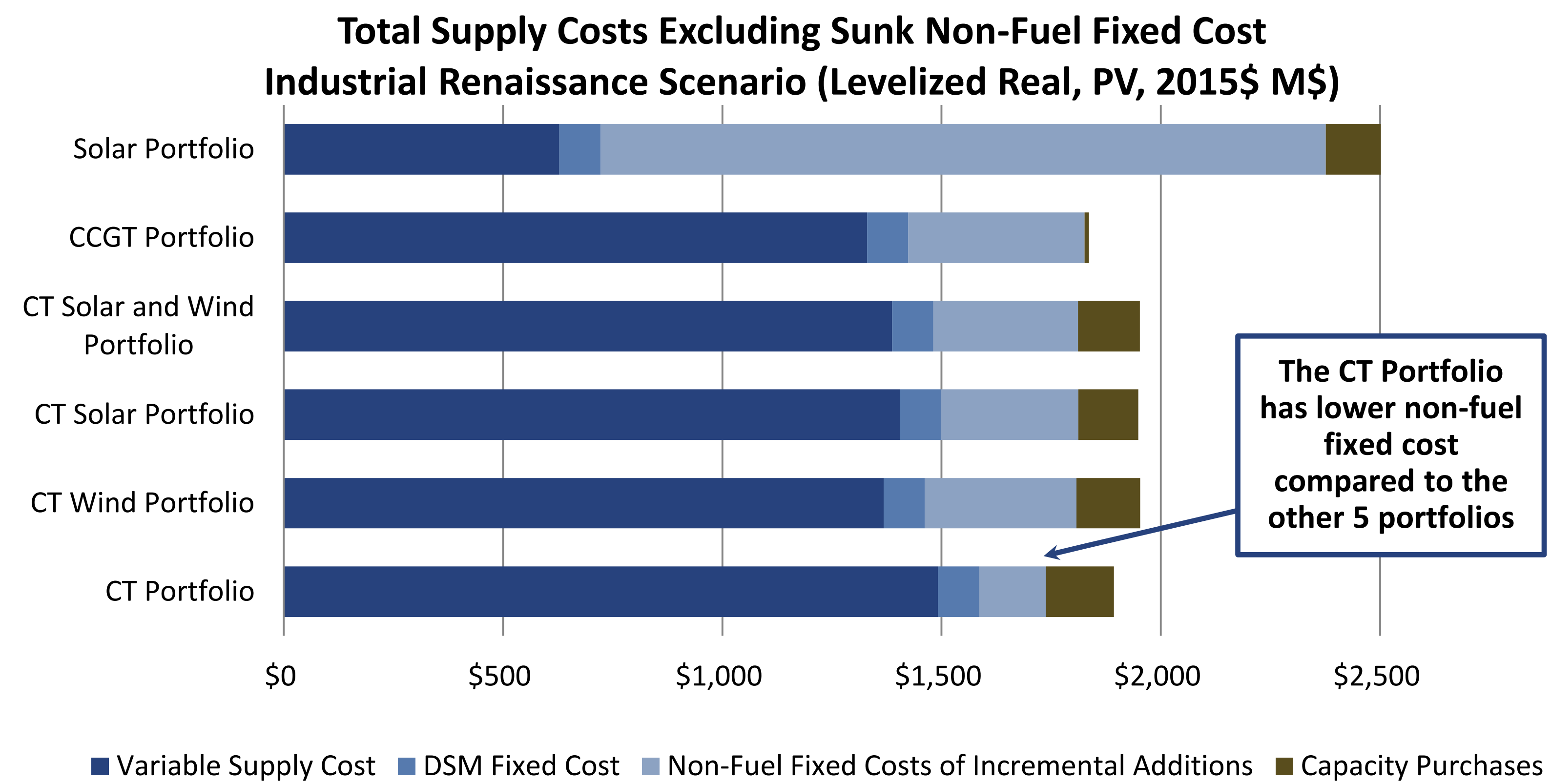
INSTALLED CAPACITY MIX OF EACH PORTFOLIO IN 2034



Portfolio Costs & Sensitivities

TOTAL SUPPLY COST COMPONENTS EXCLUDING SUNK NON-FUEL FIXED COST



Total Supply Costs Excluding Sunk Non-fuel Fixed Costs

Variable Supply Costs
+ DSM Fixed Costs
+ Non Fuel Fixed Costs of Incremental Additions
+ Capacity Purchases
+ Production Tax Credits (PTC) and Investment Tax Credit (ITC) (only included in the GS Scenario)

PORTFOLIO TOTAL SUPPLY COSTS

The CT Portfolio performs well in most scenarios, has lower risk, and complements ENO's existing portfolio

- The CCGT Portfolio ranks high, but has more risk because of higher fixed cost being offset by uncertain potential variable cost savings
- The Solar Portfolio is highly ranked in the Generation Shift Scenario due to continuation of ICT subsidiaries, high gas prices, and high CO2 prices, but ranks lowest in each of the other scenarios
- The addition of Wind and/or Solar to the CT Portfolio is only beneficial in the Generation Shift Scenario

Total Cost by Scenario
Levelized Real ($M)

Portfolios

	Ref - IR	*BB*	*DD*	*GS*
CT	$1,893	$1,687	$1,837	$2,374
CT Wind	$1,952	$1,765	$1,885	$2,310
CT Solar	$1,949	$1,756	$1,889	$2,343
CT Solar_Wind	$1,951	$1,760	$1,887	$2,326
CCGT	***$1,836***	***$1,538***	***$1,754***	$2,228
Solar	$2,501	$2,432	$2,403	***$2,100***

Ranking by Scenario

	Ref - IR	*BB*	*DD*	*GS*
CT	2	2	2	6
CT Wind	5	5	3	3
CT Solar	3	3	5	5
CT Solar_Wind	4	4	4	4
CCGT	***1***	***1***	***1***	2
Solar	6	6	6	***1***

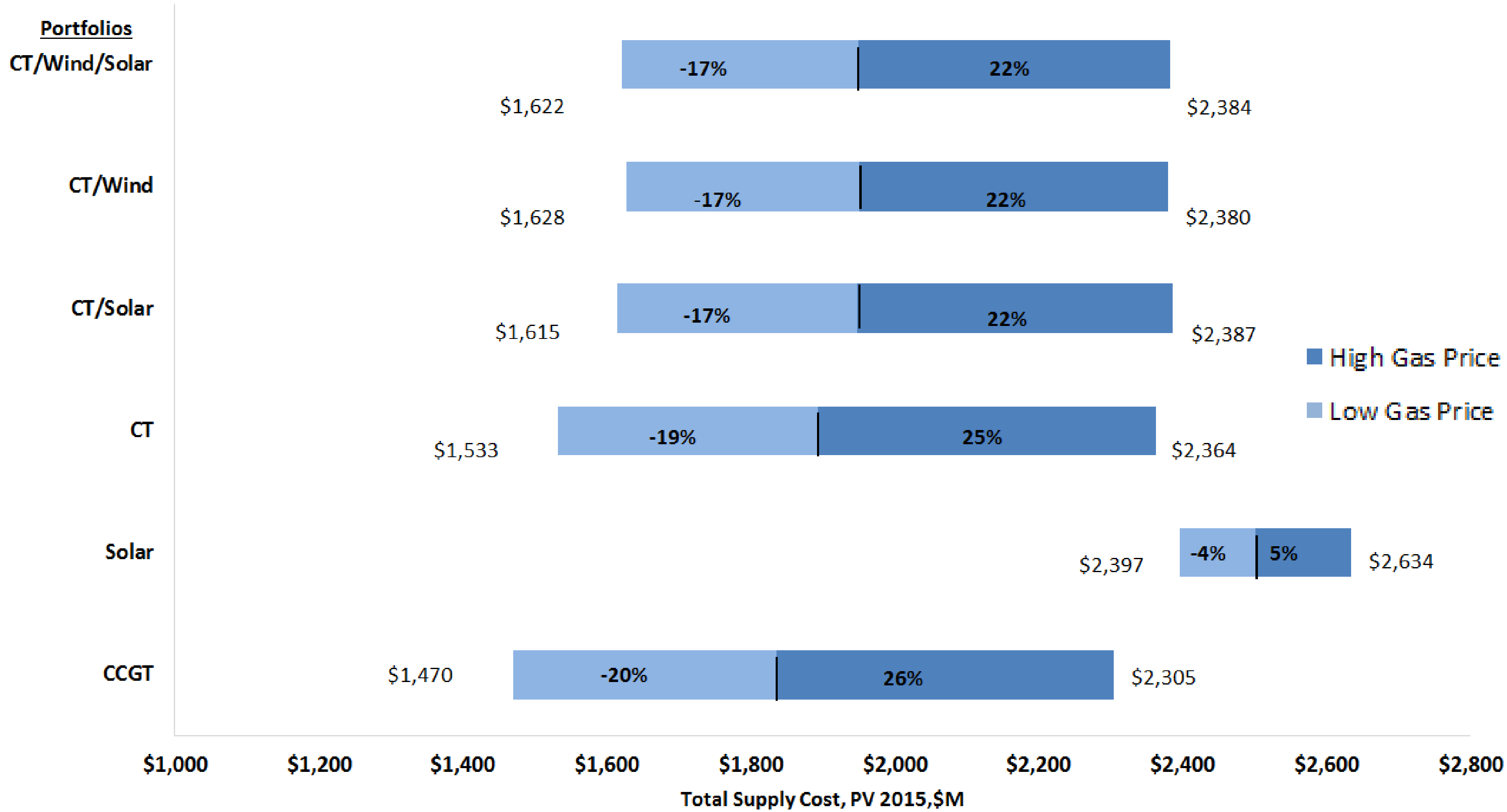
Variance ($M)
relative to highest ranked portfolio

	Ref - IR	*BB*	*DD*	*GS*
CT	$57	$148	$84	$275
CT Wind	$116	$226	$132	$210
CT Solar	$113	$217	$135	$243
CT Solar_Wind	$114	$222	$133	$226
CCGT	***$0***	***$0***	***$0***	$128
Solar	$665	$893	$649	***$0***

Although the CCGT and Solar Portfolios rank higher on a total cost basis, the CT Portfolio presents less risk while providing good economic performance.

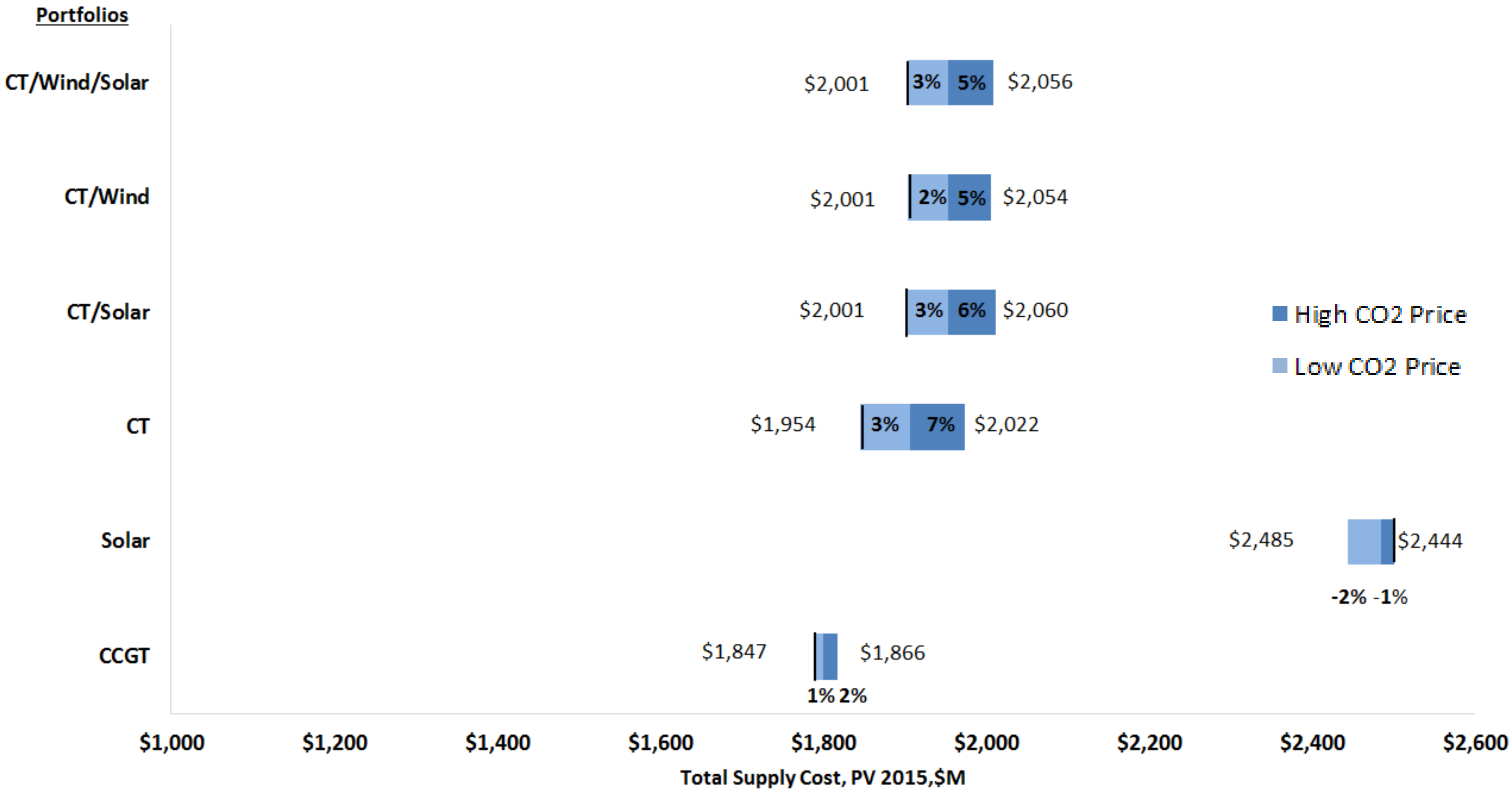
REFERENCE – IR SCENARIO SENSITIVITY: NATURAL GAS (PV $2015, $M)

Although the Solar Portfolio is less volatile, it is more costly than the other portfolios. The CCGT and CT Portfolios are similarly affected by changes in gas price assumptions.



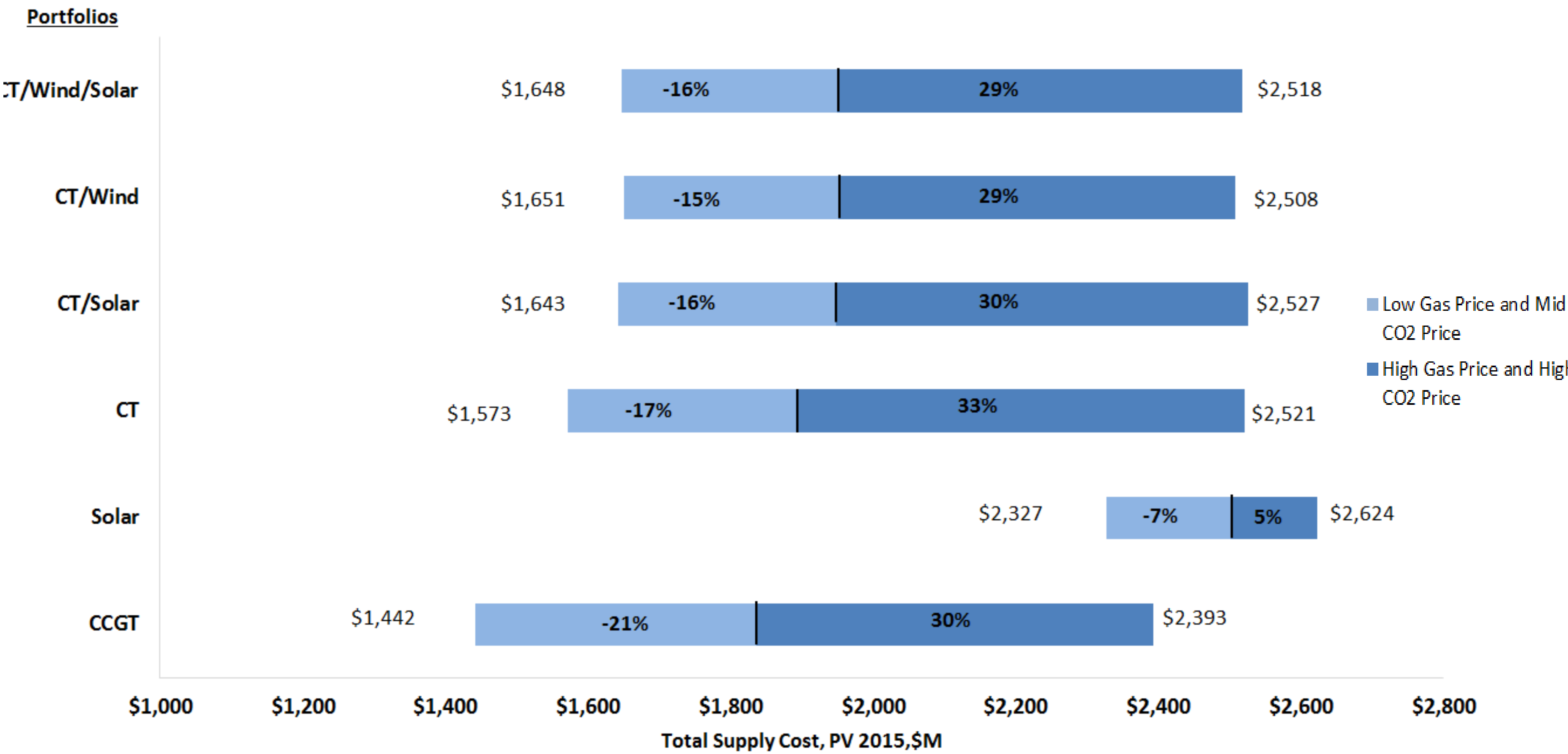
REFERENCE – IR SCENARIO SENSITIVITY: CO_2 (PV $2015, $M)

The CCGT Portfolio is relatively less affected by changes in carbon price assumptions; however, ENO existing portfolio is expected to have adequate Base Load and Core Load Following capacity.



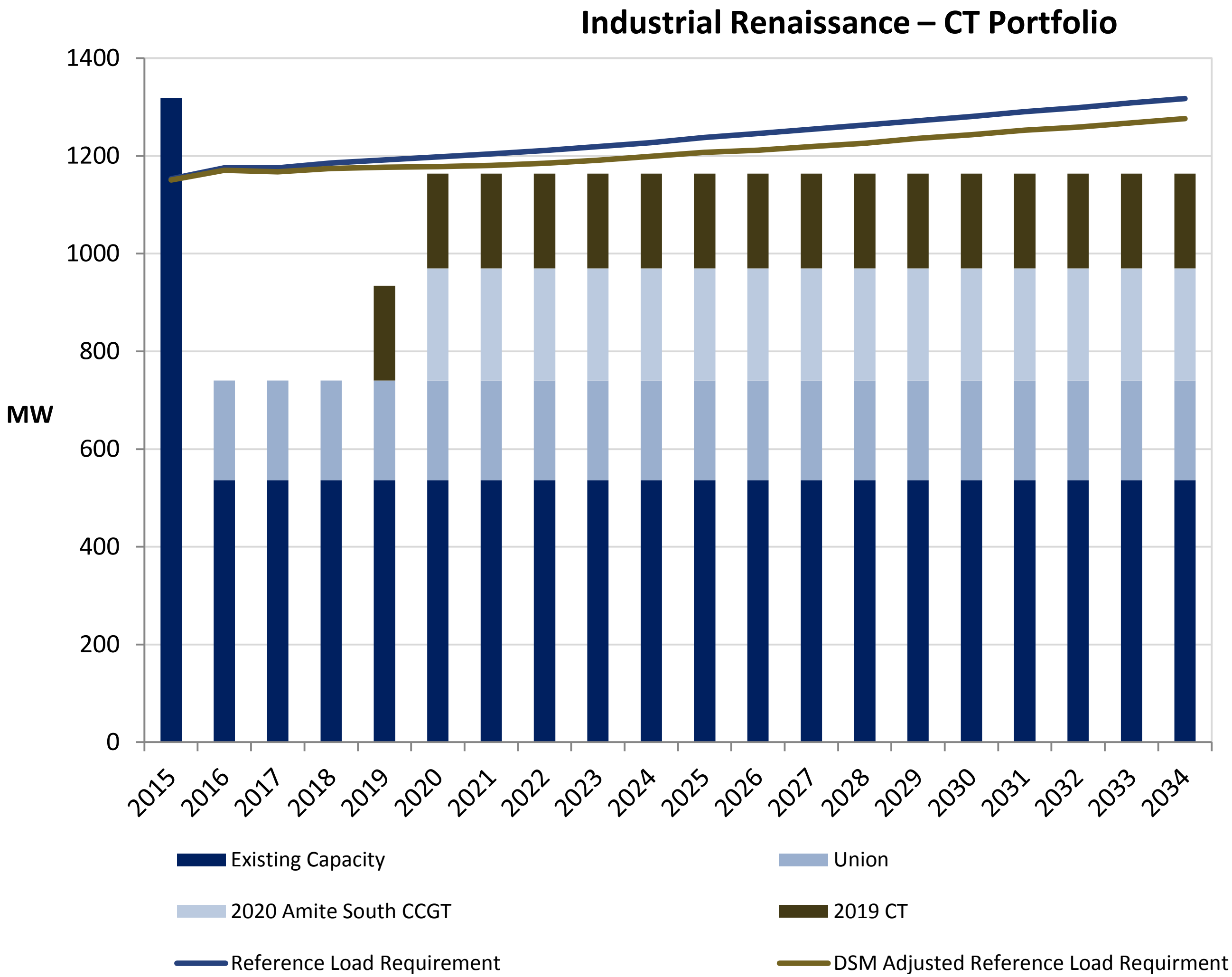
REFERENCE – IR SCENARIO SENSITIVITY: NATURAL GAS AND CO_2 (PV $2015, $M)

Although the Solar Portfolio is less volatile, it is more costly than the other portfolios. The CCGT and CT Portfolios are similarly affected by changes in gas price assumptions.



Preferred Resource Plan

PREFERRED RESOURCE PLAN



Resource Addition	Capacity (MW)
2019 CT	194

*Resources listed in blue are existing and planned resources. Resources additions listed in brown are the resources to be evaluated in the IRP.

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LOAD AND CAPABILITY OF ENO'S PREFERRED RESOURCE PLAN

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	1,029	1,050	1,049	1,059	1,064	1,070	1,075	1,081	1,088	1,096	1,105	1,112	1,120	1,128	1,136	1,143	1,152	1,160	1,168	1,176
Reserve Margin (12%)	124	126	126	127	128	128	129	130	131	132	133	133	134	135	136	137	138	139	1401	141
Total Requirements	1,153	1,176	1,175	1,186	1,192	1,198	1,204	1,211	1,219	1,227	1,238	1,246	1,254	1,263	1,272	1,281	1,291	1,299	1,308	1,318
Resources																				
Existing Resources																				
Owned Resources	1,318	537	537	537	537	537	537	537	537	537	537	537	537	537	537	537	537	537	537	537
PPA Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
LMRs	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Identified Planned Resources																				
Union	-	204	204	204	204	204	204	204	204	204	204	204	204	204	204	204	204	204	204	204
Amite South CCGT	-	-	-	-	-	229	229	229	229	229	229	229	229	229	229	229	229	229	229	229
Other Planned Resources																				
DSM	2	5	9	12	17	23	27	29	31	32	34	38	40	42	40	42	42	45	46	46
CT	-	-	-	-	194	194	194	194	194	194	194	194	194	194	194	194	194	194	194	194
Market Purchases	-	430	426	433	240	12	14	18	24	32	40	44	51	58	68	75	85	90	99	108
Total Resources	1,320	1,176	1,175	1,186	1,192	1,198	1,204	1,211	1,219	1,227	1,238	1,246	1,254	1,263	1,272	1,281	1,291	1,299	1,308	1,318

[1]Union plant acquisition is completed pending regulatory approvals.
[2]ENO share of the Amite South RFP is presently estimated at 229 MW. RFP responses are currently being evaluated. As a result, actual capacity may exceed 560 MW.
[3]Demand Side Management (DSM) total is grossed up for Planning Reserve Margin (12%) and transmission losses (2.4%).