MISO TRANSMISSION EXPANSION PLAN 2016

Appendix E2

EGEAS Assumptions Document

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Preface

This document details the study assumptions used to produce the Electric Generation Expansion Analysis Software (EGEAS) generation expansion plans for the five scenarios modeled in MTEP16. These are the scenarios which were developed through the Planning Advisory Committee beginning in the Fall of 2014 and voted on in early 2015.

Base data assumptions in the associated Powerbase database are presented and include fuel forecasts, new unit construction costs, emissions costs, Renewable Portfolio Standard (RPS) assumptions and regional demand and energy projections. The five MTEP16 scenarios for which assumptions are shown are:

- Business as Usual (BAU)
- High Demand (HD)
- Low Demand (LD)
- Regional Clean Power Plan (CPP)
- Sub-Regional Clean Power Plan (SCPP)

E2.1 MTEP16 Futures Narratives, Matrix and Uncertainty Variables

The futures matrix workbook is a compilation of tables aimed at detailing many of the major modeling assumptions used in each of the MTEP16 scenarios. The workbook covers the following areas: the matrix and uncertainty variables, natural gas modeling assumptions, capital costs, carbon costs, and generation retirements.

The futures narratives provide a high-level overview of the conditions that are modeled in each scenario. The matrix can be thought of as the bridge between the narratives and the final values that define each uncertainty variable. The matrix allows for easy cross-comparison of the modeling assumptions that went into building the scenarios. Within the matrix, the levels low (L), medium (M) and high (H) indicate the associated value of the variable in question. Each L, M or H is directly tied to a value within the uncertainty variables (Table E2.2).

As an example, the intersection of the Business as Usual row in the matrix and the demand growth rate column yields an M value. To find the actual growth rate percentage associated with M, refer to the intersection of the M column in the uncertainty variables table () and the Demand Growth Rate row. The resulting value for the Business as Usual demand growth rate is 0.8 percent. This procedure can be repeated as necessary to find all values associated with each L, M, and H in the matrix, noting that all column headings in the matrix (Table E2.1) are transposed to row headings in the uncertainty variables table (Table E2.2).

The following narratives describe the MTEP16 future scenarios and their key drivers:

- “The baseline, or **Business as Usual**, future captures all current policies and trends in place at the time of futures development and assumes they continue, unchanged, throughout the duration of the study period. Demand and energy growth rates are modeled at a level equivalent to the 50/50 forecasts submitted into the Module E Capacity Tracking (MECT) tool. All current state-level Renewable Portfolio Standard (RPS) and Energy Efficiency Resource Standard (EERS) mandates are modeled. All applicable and enforceable EPA regulations governing electric power generation, transmission and distribution (NAICS 2211) are modeled. To capture the expected effects of environmental regulations on the coal fleet, a total of 12.6 GW of coal unit retirements are modeled, including units which have either already retired or publicly announced they will retire.”
- “The **High Demand** future is designed to capture the effects of increased economic growth resulting in higher energy costs and medium – high gas prices. The magnitude of demand and energy growth is determined by using the upper bound of the Load Forecast Uncertainty metric and also includes forecasted load increases in the South region. All current state-level Renewable Portfolio Standard (RPS) and Energy Efficiency Resource Standard (EERS) mandates are modeled. All existing EPA regulations governing electric power generation, transmission and distribution (NAICS 2211) are incorporated. To capture the expected effects of environmental regulations on the coal fleet, 12.6 GW of coal unit retirements are modeled, including units which have either already retired or publicly announced they will retire. Additional, age-related retirements are captured using 60 years of age as a cutoff for non-coal, non-nuclear The Limited Growth future is designed to capture the effects of the economy turning back toward recession-like levels. All current state-level Renewable Portfolio Standard (RPS) and Energy Efficiency Resource Standard (EERS) mandates are modeled. All applicable EPA regulations governing electric power generation, transmission and distribution (NAICS 2211) are modeled. To capture the expected effects of environmental regulations on the coal fleet, 12.6 GW of coal unit retirements are included.
- “The **Low Demand** future is designed to capture the effects of reduced economic growth resulting in lower energy costs and medium – low gas prices. The magnitude of demand and energy growth is determined by using the lower bound of the Load Forecast Uncertainty metric.

All current state-level Renewable Portfolio Standard (RPS) and Energy Efficiency Resource Standard (EERS) mandates are modeled. All applicable EPA regulations governing electric power generation, transmission and distribution (NAICS 2211) are modeled. To capture the expected effects of environmental regulations on the coal fleet, 12.6 GW of coal unit retirements are modeled, including units which have either already retired or publicly announced they will retire. Additional, age-related retirements are captured using 60 years of age as a cutoff for non-coal, non-nuclear thermal units and 100 years for conventional hydroelectric." Hydro units will retire in the year they reach 100 years of age.

- "The **Regional Clean Power Plan** future focuses on several key items from a footprint wide level which in combination result in significant carbon reductions over the course of the study period. Assumptions are consistent with MISO CPP Phase I & II analyses, and include the following:
  - To capture the expected effects of existing environmental regulations on the coal fleet, 12.6 GW of coal unit retirements are modeled, including existing or announced retirements.
  - 14 GW of additional coal unit retirements, coupled with a $25/ton carbon cost, state mandates for renewables, and half of the EE annual growth used by the EPA, result in a significant reduction in carbon emissions by 2030.
  - Additional, age-related retirements are captured using 60 years of age as a cutoff for non-coal, non-nuclear thermal units and 100 years for conventional hydroelectric.
  - Solar and wind include an economic maturity curve to reflect declining costs over time.
  - Demand and energy growth rates are modeled at levels as reported in Module E.
- *"The **Sub-Regional Clean Power Plan** future focuses on several key items from a zonal or state level which combine to result in significant carbon reductions over the course of the study period. Assumptions are consistent with MISO CPP Phase I & II analyses, and include the following:*
  - *To capture the expected effects of existing environmental regulations on the coal fleet, 12.6 GW of coal unit retirements are modeled, existing or announced retirements.*
  - *20 GW of additional coal unit retirements, coupled with a $40/ton carbon cost, state mandates for renewables, and half of the EE annual growth used by the EPA, result in a significant reduction in carbon emissions by 2030.*
  - *These increased retirements and carbon cost levels from the Regional CPP Future are consistent with regional/sub-regional CPP assessments performed by MISO and other organizations since the CPP's introduction.*
  - *Additional, age-related retirements are captured using 60 years of age as a cutoff for non-coal, non-nuclear thermal units and 100 years for conventional hydroelectric.*
  - *Solar and wind include an economic maturity curve to reflect declining costs over time.*
  - *Demand and energy growth rates are modeled at levels as reported in Module E.*

MTEP16 FUTURES MATRIX

	Uncertainties																														
	Capital Costs														Demand and Energy					Fuel Cost (Starting			Fuel Escalations			Emission Costs			Other Variables		
Future	Coal	CC	CT	Nuclear	Wind Onshore	IGCC	IGCC w/ CCS	CC w/ CCS	Pumped Storage Hydro	Compressed Air Energy Storage	Photovoltaic	Biomass	Conventional Hydro	Wind Offshore	Demand Response Level	Energy Efficiency Level	Demand Growth Rate	Energy Growth Rate	Natural Gas Forecast	Oil	Coal	Uranium	Oil	Coal	Uranium	SO_2	NO_x	CO_2	Inflation	Retirements	Renewable Portfolio Standards
Business As Usual	M	M	M	M	M	M	M	M	M	M	M	M	M	M	M	M	M	M	M	M	M	M	M	M	M	L	L	L	M	L	M
High Demand	H	H	H	H	H	H	H	H	H	H	H	H	H	H	M	M	H	H	M	M	M	M	H	H	H	L	L	L	H	M	M
Low Demand	L	L	L	L	M	L	L	L	L	L	M	L	L	L	M	M	L	L	L	L	L	M	L	L	L	L	L	L	L	M	M
Regional CPP Compliance	H	H	H	M	L	M	M	M	M	M	L	M	M	M	M	H	M	M	H	L	L	M	M	M	M	L	L	M	M	H	H
Sub-Regional CPP Compliance	H	H	H	M	L	M	M	M	M	M	L	M	M	M	M	H	M	M	H	L	L	M	H	H	H	L	L	H	H	H	H

Table E2.1: MTEP16 futures matrix

MTEP16 UNCERTAINTY VARIABLES				
Uncertainty	**Unit**	**Low (L)**	**Mid (M)**	**High (H)**
New Generation Capital Costs[1]				
Coal	($/KW)	2,279	3,039	3,799
CC	($/KW)	795	1,060	1,324
CT	($/KW)	525	700	875
Nuclear	($/KW)	4,296	5,728	7,160
Wind-Onshore	($/KW)	1,750	2,063	2,579
IGCC	($/KW)	2,940	3,919	4,899
IGCC w/ CCS	($/KW)	5,126	6,835	8,544
CC w/ CCS	($/KW)	1,627	2,170	2,712
Pumped Storage Hydro	($/KW)	4,108	5,477	6,846
Compressed Air Energy Storage	($/KW)	971	1,295	1,618
Photovoltaic	($/KW)	1,750	3,009	5,014
Biomass	($/KW)	3,196	4,261	5,326
Conventional Hydro	($/KW)	2,281	3,041	3,801
Wind-Offshore	($/KW)	4,840	6,453	8,066
Demand and Energy				
Baseline 20-Year Demand Growth Rate[2]	%	0.11%	0.75%	1.55%
Baseline 20-Year Energy Growth Rate[3]	%	0.19%	0.82%	1.61%
Demand Response Level	%	State mandates only	State mandates and goals	
Energy Efficiency Level	%	State mandates only	State mandates and goals	State mandates and goals + 1/2 of EPA CPP growth[4]
Natural Gas				
Natural Gas[5]	($/MMBtu)	Bentek -20%	Bentek forecast from Phase III Gas Study	Bentek +20%
Fuel Prices (Starting Values)				
Oil	($/MMBtu)	Powerbase default -20%	Powerbase default[6]	Powerbase default + 20%
Coal	($/MMBtu)	Powerbase default -20%	Powerbase default[7]	Powerbase default + 20%
Uranium	($/MMBtu)	0.91	1.14	1.37
Fuel Prices (Escalation Rates)				
Oil	%	2.0	2.5	4.0
Coal	%	2.0	2.5	4.0
Uranium	%	2.0	2.5	4.0
Emissions Costs				
SO_2	($/ton)	0	0	500
NO_x	($/ton)	0	0	NO_x: 500 Seasonal NO_x: 1000
CO_2	($/ton)	0	25	40
Other Variables				
Inflation	%	2.0	2.5	4.0
Retirements	MW	12.6 GW Coal MATS Retirements	MATS coal + age-related gas/oil/hydro = 22 GW	Regional: MATS + age-related + 14 GW CPP Coal = 36 GW Sub-Regional: MATS + age-related + 20 GW CPP Coal = 41 GW
Renewable Portfolio Standards	%	State mandates only	State mandates and goals	State mandates and goals + cost maturity curves

Table E2.1 E2.1: MTEP16 uncertainty variables

Notes on uncertainty variables:

[1] *All costs are overnight construction costs in 2014 dollars; sourced from EIA and escalated according to the GDP Implicit Price Deflator; H and L values are 20% +/- from the M value, except where otherwise noted*
[2] *Mid values for years 1 - 10 of demand growth are derived from Module-E; Years 11-20 are extrapolated; H & L values are derived using LFU metric*

[3] *Energy values are calculated using the corresponding demand forecast and historical load factors*

[4] *Energy Efficiency grows at half the rate proposed by the EPA in the Clean Power Plan for the MISO system*

[5] *Bentek forecast prices reflect the Henry Hub natural gas price*

[6] *Powerbase default for oil is $19.39/MMBtu*

[7] *Powerbase range for coal is $1 to $4, with an average value of $1.69/MMBtu*

E2.2 Regional Resource Forecasting

Regional Resource Forecasted (RRF) units are an output of step 1 of the MTEP process. The Generation Interconnection Queue is the primary source for out-year capacity; however, the queue is generally limited to five years out or less for new capacity. For this reason, a capacity expansion tool is used to supplement the out years to maintain the load-to-resource balance and Planning Reserve Margin (PRM) target. To use RRF units in a production cost model, they must be sited at buses in the powerflow model. Units are sited based on stakeholder-defined rules and criteria.

The Electric Generation Expansion Analysis System (EGEAS), created by the Electric Power Research Institute (EPRI), is the capacity expansion software tool used for long-term regional resource forecasting. EGEAS performs capacity expansions based on long-term, least-cost optimizations with multiple input variables and alternatives. The objective function of the MTEP15 study optimization aims to minimize the 20-year capital and production costs, with a reserve margin requirement indicating when and what type of resources will be added to the system. The following sections focus on data assumptions and methodologies specific to EGEAS applications.

E2.2.1 Resource Mix

Each planning region within the Eastern Interconnect is made up of a diverse mix of capacity resources. This diversity is clearly demonstrated in Table E2.3 and the pie charts that follow. Table E2.3 shows the nameplate capacity (in MW) for all existing, under construction and planned units.

Region	Coal	Nuclear	Gas	Wind	Solar	Hydro	Pumped Storage	Oil	Other
MISO	71,507	14,953	70,725	16,171	125	2,184	0	4,108	1,429
NYISO	1,380	5,293	21,716	1,794	15	4,948	1,407	4,847	1,412
PJM	72,783	37,144	80,031	9,922	706	3,104	5,610	10,222	2,462
SERC	39,609	22,018	49,578	255	911	6,721	4,626	2,371	646
SPP	24,421	2,449	31,625	14,423	60	4,528	474	1,324	86
TVA*	21,931	8,077	20,196	1,985	66	5,823	1,856	59	5

*For EGEAS analysis, Associated Electric Cooperative Inc. (AECI), Louisville Gas & Electric and Kentucky Utilities are combined with the Tennessee Valley Authority (TVA)

Table E2.1 E2.2: MTEP16 existing, under construction and planned units

Figure E2.1 through E2.6 show the resource mix breakdowns as a percentage of total generation capacity for each modeled Eastern Interconnect region.

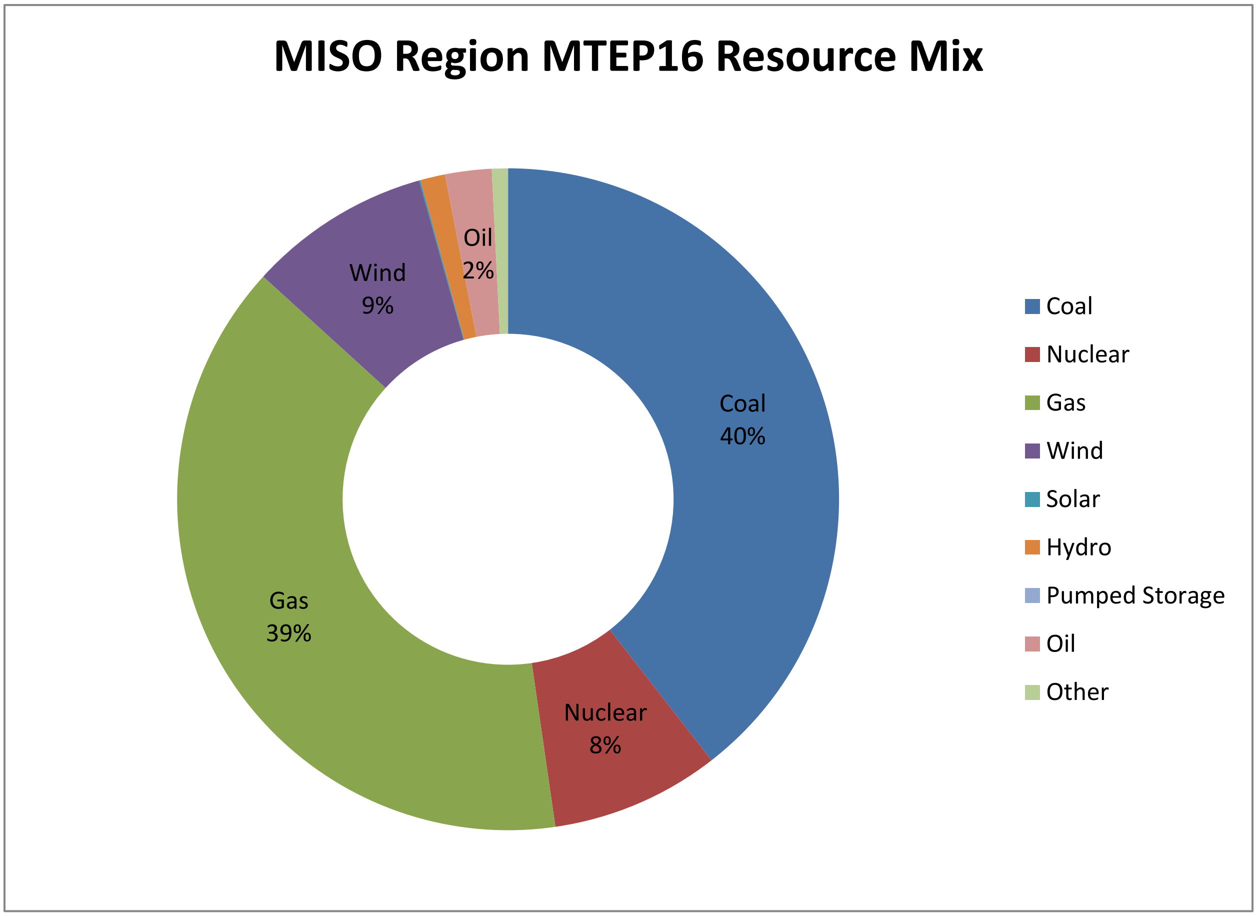


Figure E2.1: MISO resource mix

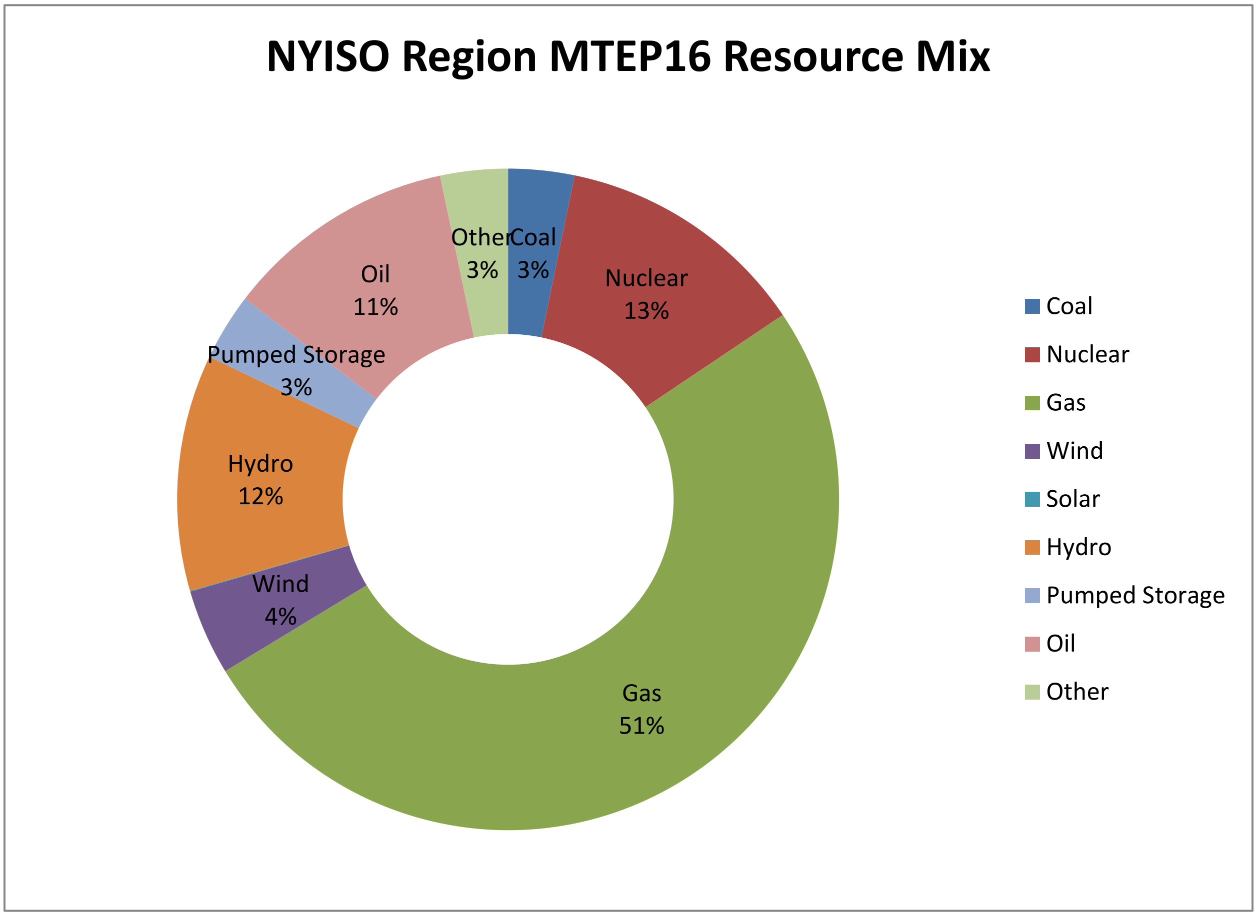


Figure E2.2: NYISO resource mix

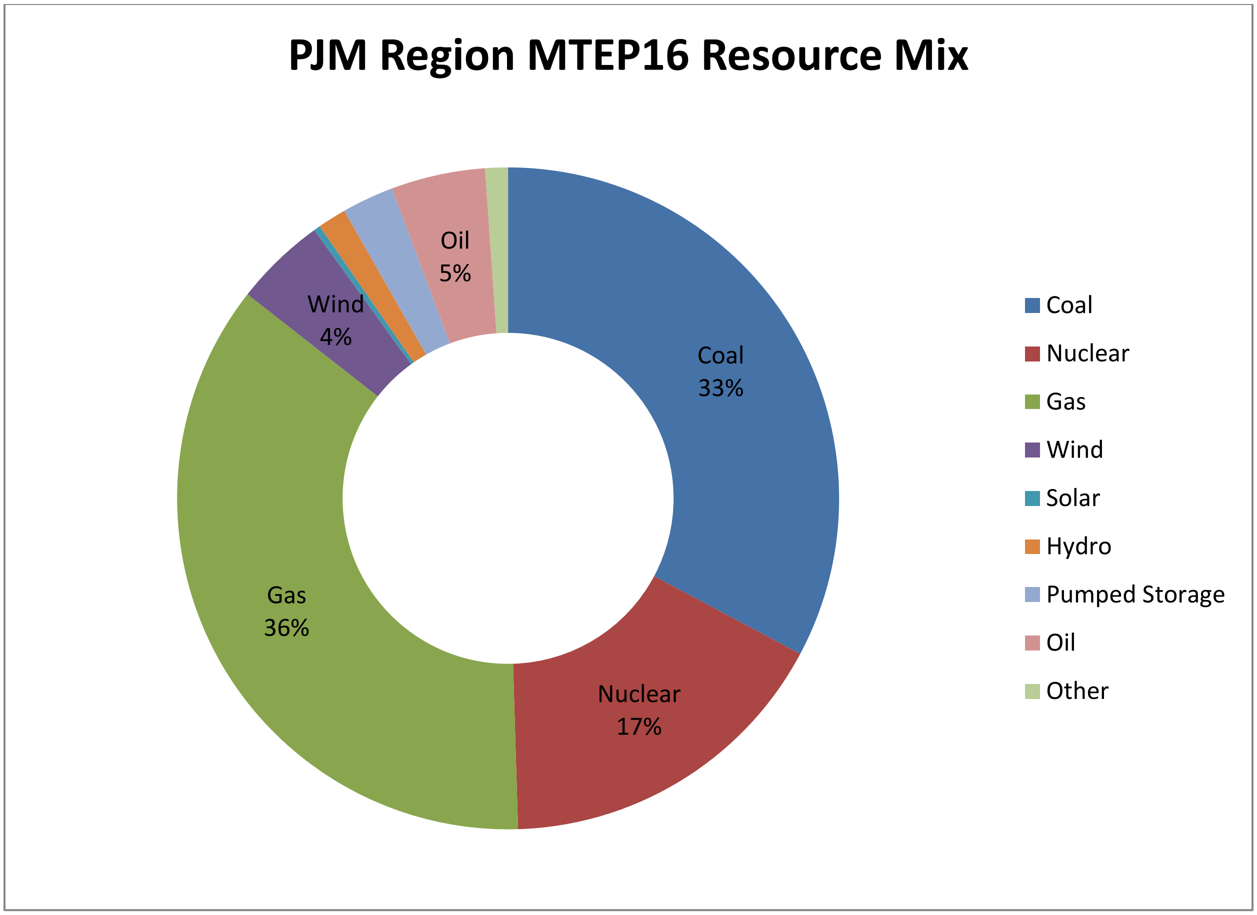


Figure E2.3: PJM resource mix

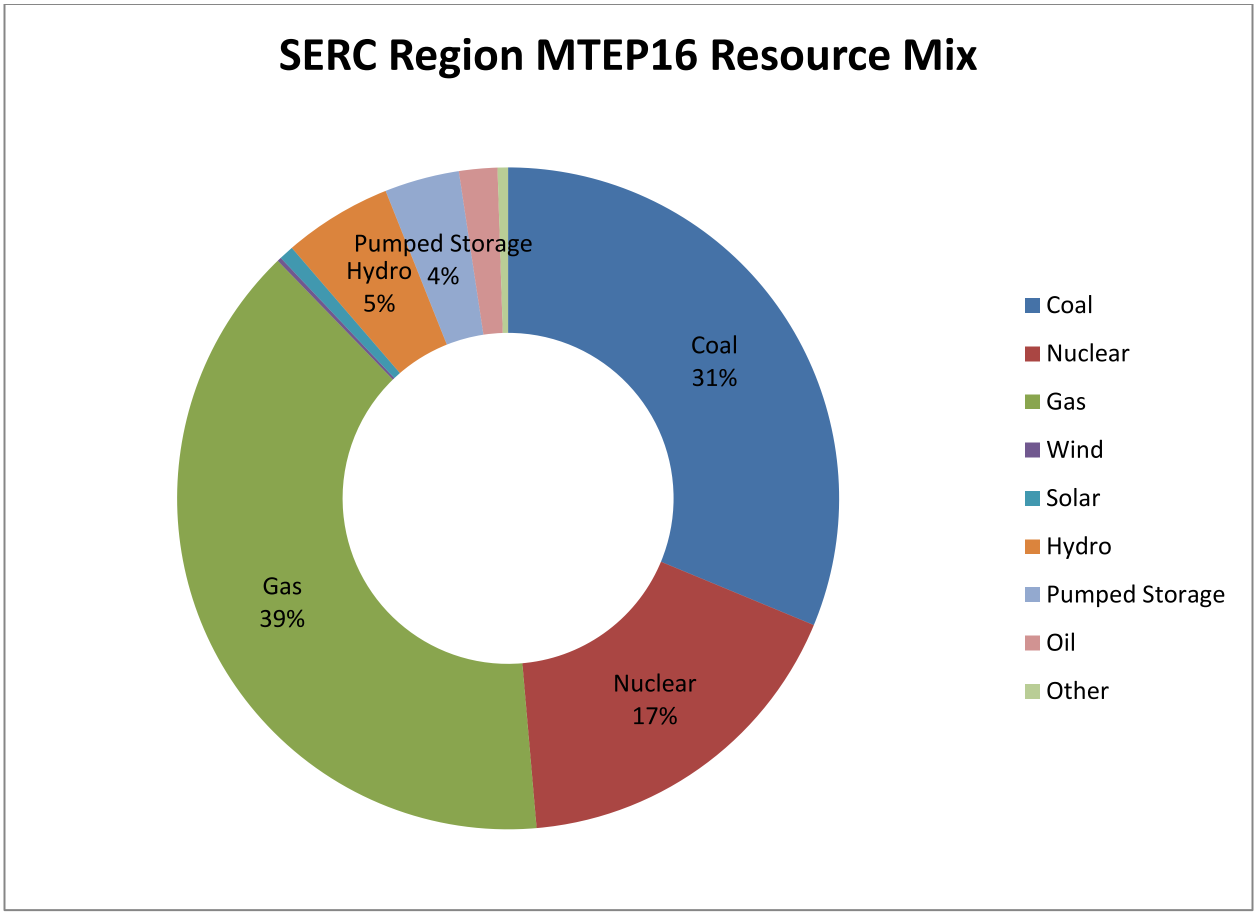


Figure E2.4: SERC resource mix

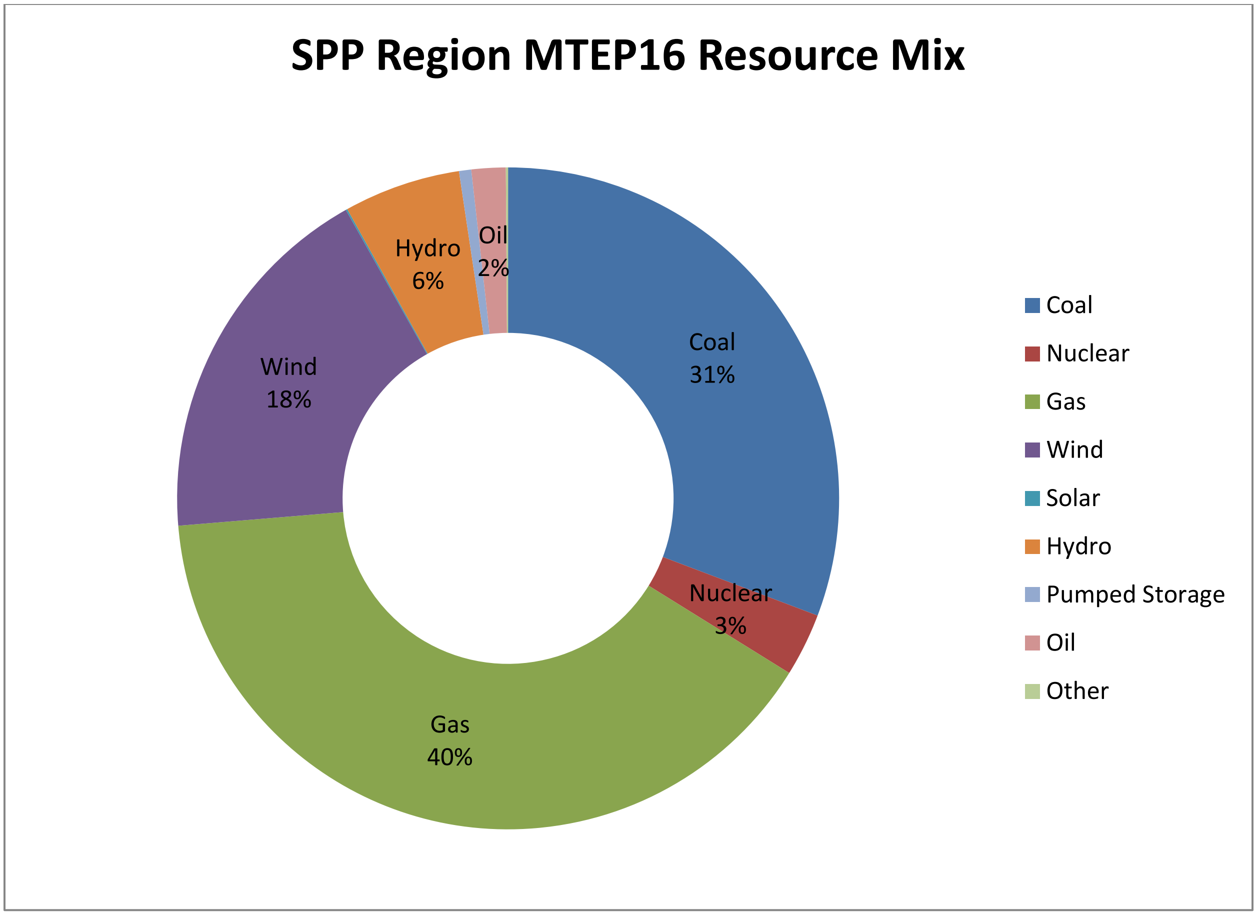


Figure E2.5: SPP resource mix

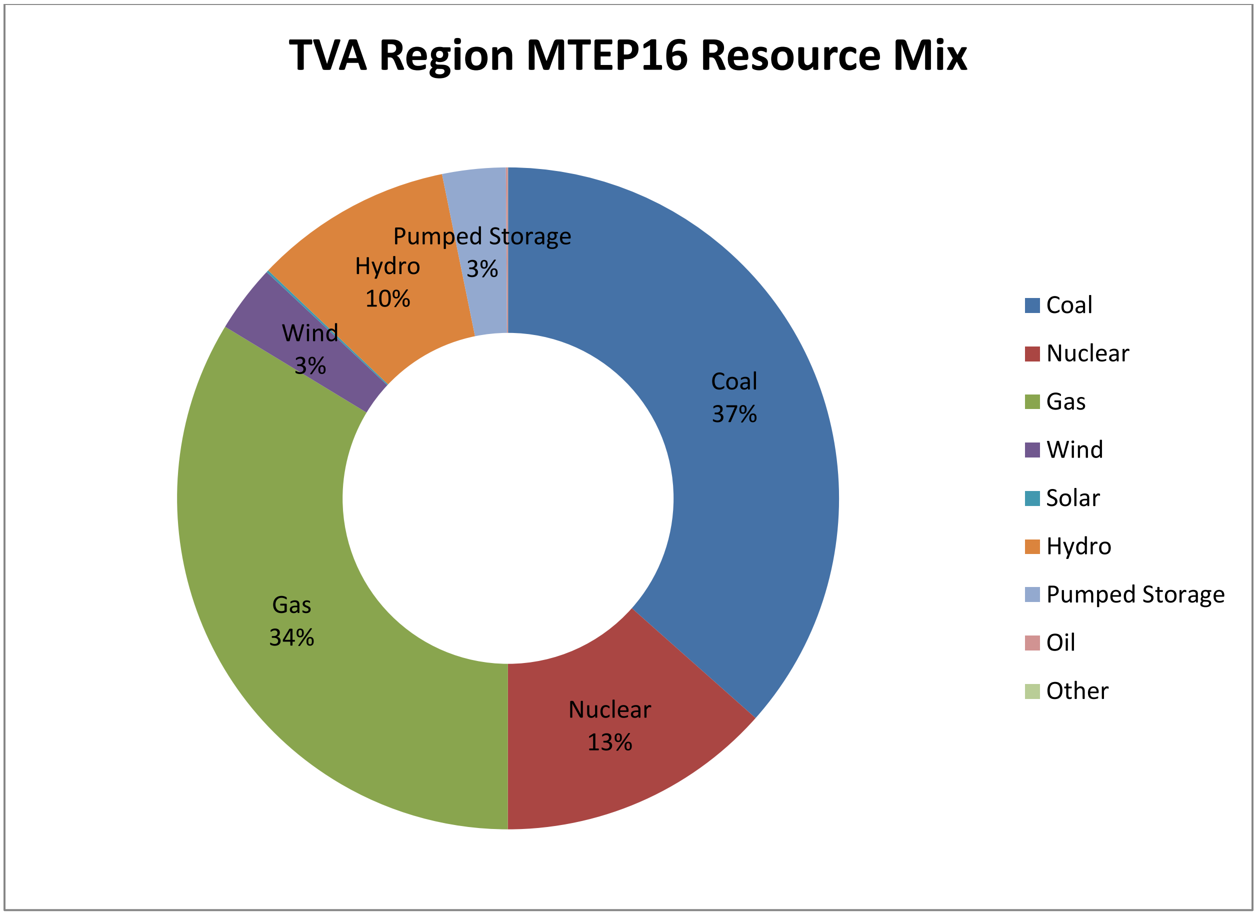


Figure E2.6: TVA resource mix

E2.2.2 Regional Demand and Energy Forecasts

In PowerBase, projected future demand and energy growth rates are input at the company level. For EGEAS purposes, these growth rates must be aggregated up to the regional level for each of the MTEP16 futures. The MISO baseline value (M, in the futures matrix) for the demand growth rate is derived from the Module E 50/50 load forecast growth rate (0.8 percent). Low and high values, for both demand and energy, are achieved by modeling 1.3 standard deviations above and below the baseline. By utilizing the Load Forecast Uncertainty (LFU) metric, there is an 80% probability that the demand and energy forecast will fall within the high and low growth rates of 0.14% to 1.5%.

The effective demand and energy growth rates for each region are calculated after the EGEAS capacity expansion analysis, taking only state-level DSM mandate and goal projections into consideration. In MTEP15, MISO allowed EGEAS to pick additional DSM based on program economics. Without having more recently updated projections of future DSM potential (the Global Energy Partners study was completed in 2010), stakeholders expressed concern over the accuracy of continuing to model GEP-developed DSM estimates. Therefore, MISO only modeled enough DSM to meet state mandates and goals in the BAU, HD and LD scenarios. The CPP and SCPP scenarios include half of the energy efficiency growth based on the EPA's draft CPP proposal. The effective growth rates are ultimately used in the production cost modeling simulations (Table E2.4). In the same timeframe, MISO commissioned the Applied Energy Group (previously Global Energy Partners) to update the DSM study performed in 2010. This updated analysis was presented in specific workshops, in MTEP17 Futures development workshops and PAC meetings and is being implemented in the MTEP17 Futures.

	BAU		HD		LD		CPP		SCPP	
Region	Demand (%)	Energy (%)	Demand (%)	Energy (%)	Demand (%)	Energy (%)	Demand (%)	Energy (%)	Demand (%)	Energy (%)
MISO	0.65%	0.76%	1.43%	1.53%	0.00%	0.11%	0.27%	0.46%	0.27%	0.46%
NYISO	-0.20%	-0.82%	0.71%	-0.70%	-1.04%	-1.03%	0.48%	-0.14%	0.48%	-0.14%
PJM	0.26%	0.45%	1.23%	1.40%	-0.44%	-0.25%	0.68%	0.79%	0.68%	0.79%
SERC	1.33%	1.20%	2.76%	2.36%	0.20%	0.28%	1.25%	1.13%	1.25%	1.13%
SPP	1.13%	1.42%	2.34%	2.79%	0.17%	0.33%	1.02%	1.33%	1.02%	1.33%
TVA	1.60%	0.78%	3.30%	1.53%	0.23%	0.18%	1.55%	0.77%	1.55%	0.77%

Table E2.1 E2.3: Effective demand and energy growth rates (2015-2030)

E2.2.3 Fuel Forecasts

Many of the fuel forecasts are developed in PowerBase using a pointer system. This makes it easier to make adjustments to the fuel forecasts without having to change each individual unit's forecast. A pointer system works by designating one fuel as the fuel index and then all other fuel forecasts are based on this fuel index, with some adjustment (usually due to transportation costs) from the index value. In the MTEP database, all natural gas-fired generators point to the Henry Hub natural gas forecast. Therefore, all references to natural gas in the futures matrix are in terms of the Henry Hub forecast.

For MTEP16, the source for the baseline natural gas forecast is the Phase III Natural Gas report developed for MISO by Bentek[1]. Since Bentek assumed an inflation rate of approximately 3.5 percent in their forecast, it was necessary to remove this inflation rate and to use the inflation rates for each future scenario that was identified by the PAC and MISO in the assumptions development process, with low and high inflation rates in other futures typically 2% and 4%. The five resulting MTEP16 natural gas forecasts are in nominal dollars per MMBtu (Figure E2.7).

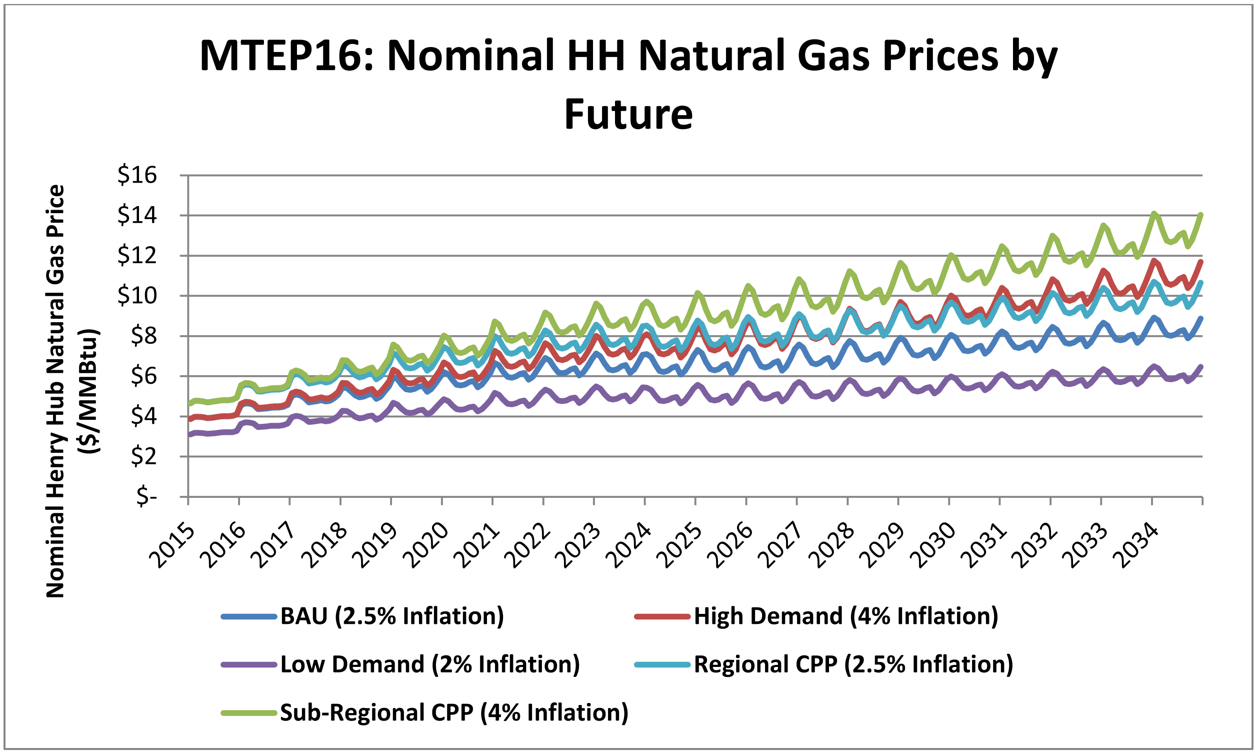


Figure E2.7: MTEP16 natural gas prices by future

E2.2.4 Study Period

The future outlook for MTEP EGEAS simulations is 20 years. The base year for MTEP16 modeling is 2015, extending out to 2034. In order to eliminate any "end effects" an extension period of 40 years is simulated, with no new units forecasted during this time. This additional study period ensures that the selection of generation in the last few years of the forecasting period (e.g. years 18, 19, 20) is based on the costs of generation spread out over the total tax/book life of the new resources (i.e. beyond year 20).

[1] Phase III: Natural Gas-Fired Electric Power Generation Infrastructure Analysis – An Analysis of Pipeline Capacity Availability.

E2.2.5 Study Areas

The MTEP16 database is comprised of all areas in the Eastern Interconnect, with the exception of Florida, ISO New England and Eastern Canada. The eight areas referenced in this appendix are:

- Midwest Reliability Organization (MRO)
- Midcontinent Independent Transmission System Operator (MISO)
- New York Independent System Operator (NYISO)
- PJM Interconnection (PJM)
- SERC Reliability Corporation (SERC)
- Southwest Power Pool (SPP)
- Tennessee Valley Authority (TVA)

All other regions of the Eastern Interconnect, such as Manitoba Hydro and Independent Electricity System Operator (IESO) are deemed to have sufficient capacity resources in all MTEP scenarios and, as such, EGEAS capacity expansions are not needed for these regions. However, these regions are still modeled in the production cost modeling simulations. The TVA region has been modeled as two pools in an effort to more accurately model market behavior, which is constrained by TVA's ability to sell power only to certain companies. The three companies that comprise the "TVA-Other" pool - Associated Electric Cooperative, Louisville Gas & Electric and Kentucky Utilities - do not have such a restriction. The restricted sale phenomenon has been termed the "TVA Fence" and it is captured through PROMOD pool definitions and their associated settings.

E2.2.6 Capacity Types

Generation capacity is categorized into existing, under construction and planned units. Assumptions related to each of these categories include the following:

- Existing: Operating license extensions are assumed on all nuclear units.
- Under Construction: Units with steel in the ground, but not yet under commercial operation.
- Planned: All capacity resources with a signed Generator Interconnection Agreement (GIA).

E2.2.7 Firm Interchange

Firm interchange contributes to resource adequacy by reducing a region's overall internal capacity needs over time. It is assumed that each modeled region will build generation capacity to meet its own resource adequacy needs.

Based upon the 2015 Loss of Load Expectation (LOLE) External Ties Model, MISO assumes a net scheduled interchange of 3,157 MW. This capacity is held constant in all 20 years of the EGEAS modeling and is assumed to be available at the time of MISO peak.

E2.2.8 Planning Reserve Margin Targets

The Planning Reserve Margin (PRM) is entered into EGEAS for the first year of the simulation, and is assumed to remain constant throughout the entire 20-year study period. PRM targets are based on respective system co-incident peaks (MW), with the exception of SPP's, which is based on its non-coincident peak (MW). Table E2.5 presents the 2014 reserve margin, as well as the PRM target, for each region.

Region	2014 Reserve Margin (%)	PRM Target (%)
MISO	22.2	14.30
NYISO	27.0	17.00
PJM	19.3	15.60
SERC	28.5	15.00
SPP	34.9	13.60
TVA	29.1	15.00

Table E2.5: PRM margins and targets

E2.2.9 Wind Hourly Profile and Capacity Credits

A majority of the wind in the MISO footprint is registered as Dispatchable Intermittent Resources, or DIR. Generators with this designation are able to bid into the day-ahead market using high-confidence wind forecast data. Given that this information is not available for future years, EGEAS models all wind as a non-dispatchable technology using actual historical wind data developed during the MISO Regional Generator Outlet Study (RGOS). All the RGOS wind zone profiles within MISO are averaged to arrive at a single profile, which is used in the EGEAS capacity expansion analysis. Similarly, a single profile for each of the regions external to MISO is made by averaging all NREL wind sites within each respective region.

The wind capacity credit is the maximum capacity credit that a wind resource may receive if it meets all other obligations of Module E to be a capacity resource. This value, which is a percent of the maximum nameplate capacity of the unit, reflects the risk associated with reliance upon an intermittent resource, such as wind. The capacity factor is the actual annual energy output of the unit as a percentage of the total potential energy output (based on 8,760 hours in a year). The wind capacity credit is updated annually during the MISO Loss of Load Expectation (LOLE) analysis and, for the 2015 planning year, was calculated to be 14.7 percent. Table E2.6 shows the capacity factors applied to each region as input to the EGEAS model for MTEP16.

Region	Annual Capacity Factor (%)
MISO	40
NYISO	40
PJM	37
SERC	43
SPP	43
TVA	36

Table E2.6: Regional wind modeled capacity factors

E2.2.10 Reserve Contribution

Three specific assumptions were made with regard to reserve contribution:

- 14.7 percent of nameplate wind capacity is counted toward its reserve capacity contribution.
- 25 percent of nameplate solar capacity is counted toward its reserve capacity contribution in the non-CPP futures, and 40 percent of nameplate solar capacity is counted toward its reserve capacity contribution in the CPP futures based on the Minnesota Renewable Energy Integration and Transmission Study.[2]
- The summer de-rated capacity for conventional generation is counted toward its reserve capacity contribution.

E2.2.11 Financial Variables

Variables associated with the financing of new generation projects are listed in Table E2.7. Note that these are average values across the footprint. These financial variables are used in MTEP15 EGEAS simulations.

Variable	Rate (%)
Composite Tax Rate	39.00
Insurance Rate	0.50
Property Tax Rate	1.50
AFUDC* Rate	7.00

* Allowance for Funds Used During Construction

Table E2.7: Financial variables

[2] https://mn.gov/commerce/energy/images/final-mrits-report-2014.pdf

E2.2.12 Load Shapes

EGEAS requires a representative hourly load shape for the system as well as any technologies which are modeled as non-dispatchable. The shapes are provided in per unit values and, in the case of wind, solar and the overall system, are representative system averages across the footprint. The load shapes used in EGEAS simulations and their sources are presented in Table E2.8.

Load Shape	Description and Source
System	2006 hourly profiles from Ventyx, aggregated to regional level
Wind	2006 hourly profiles developed by AWS TrueWind for EWITS
Solar	2006 hourly profile developed by NREL for the Eastern Renewable Generation Integration Study (ERGIS) and used in the Minnesota Renewable Integration and Transmission Study (MRITS)
Energy Efficiency	Representative profile provided by Global Energy Partners, LLC as part of the 2010 Assessment of Demand Response and Energy Efficiency Potential for MISO.

Table E2.8: Load shape descriptions and sources

E2.2.13 Alternative Generator Categories

Table E2.9 and Table E2.10 list the generic categories of generators used when forecasting future units to meet the planning reserve margin requirements.

Supply Side Options
Biomass
Combined Cycle - with and without sequestration
Combustion Turbine
Compressed Air Energy Storage
Hydro
Integrated Gasification Combined Cycle (IGCC) - with and without sequestration
Nuclear
Pumped Hydro Storage
Solar
Wind - on-shore and off-shore

Table E2.9: Alternative generator categories – supply-side

Demand Side Options
Commercial & Industrial (C&I) Low Cost Energy Efficiency (EE) program
C&I Interruptible

Table E2.10: Demand-side management alternatives

E2.2.14 Renewable Maturity Cost Curves

Maturity curve costs are applied to the solar and wind resources to allow economic selection. The curves are shown in the graphs below. The maturity curve was developed by using publicly available information from various reports and documents to establish the assumptions behind what drives the cost down for renewables and the magnitude of reduction in costs that would occur.

The starting value for solar is based on capital costs information from Lazard's annual report on levelized costs of energy. The curve declines at a rate of 10% per year for five years per assumptions in the Annual Energy Outlook 2014 Assumptions Report.[3]

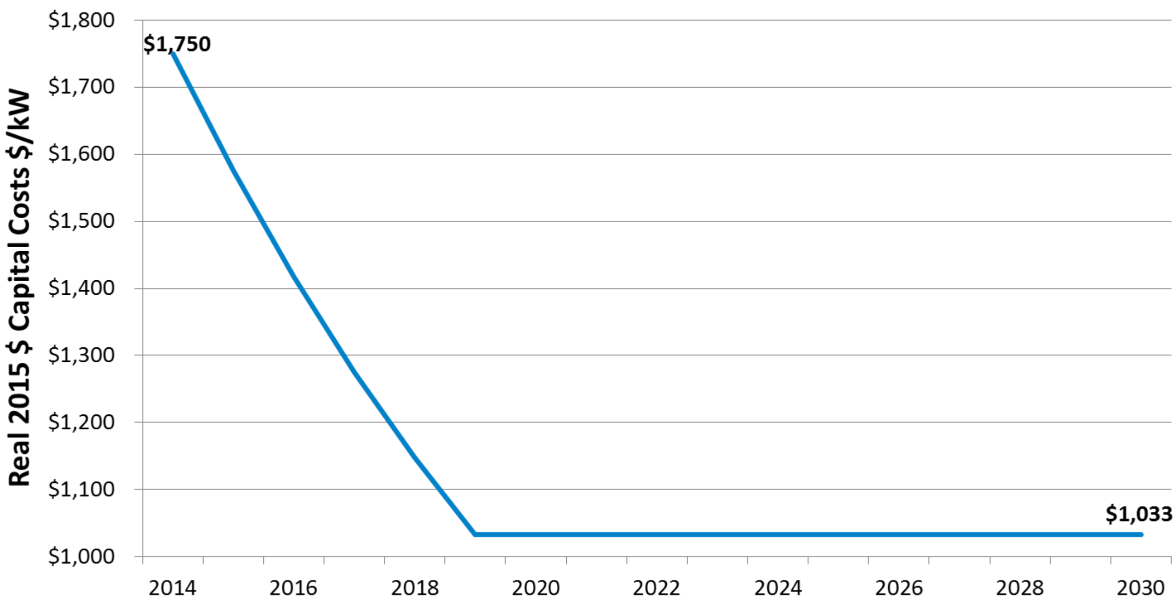


Figure E2.8: Solar Maturity Curve

[3] Starting cost taken from Lazard 2014 LCOE Report: Page 11
http://www.lazard.com/PDF/Levelized%20Cost%20of%20Energy%20-%20Version%208.0.pdf
Estimated cost decline taken from EIA AEO 2014 Assumptions Report: Page 98
http://www.eia.gov/forecasts/aeo/assumptions/pdf/0554(2014).pdf

The starting capital costs for wind are based on information from the DOE LBNL 2013 Wind Technologies Market Report. The curve declines at a rate 1% per year for five years; assumptions based on the Annual Energy Outlook 2014 Assumptions Report.[4]

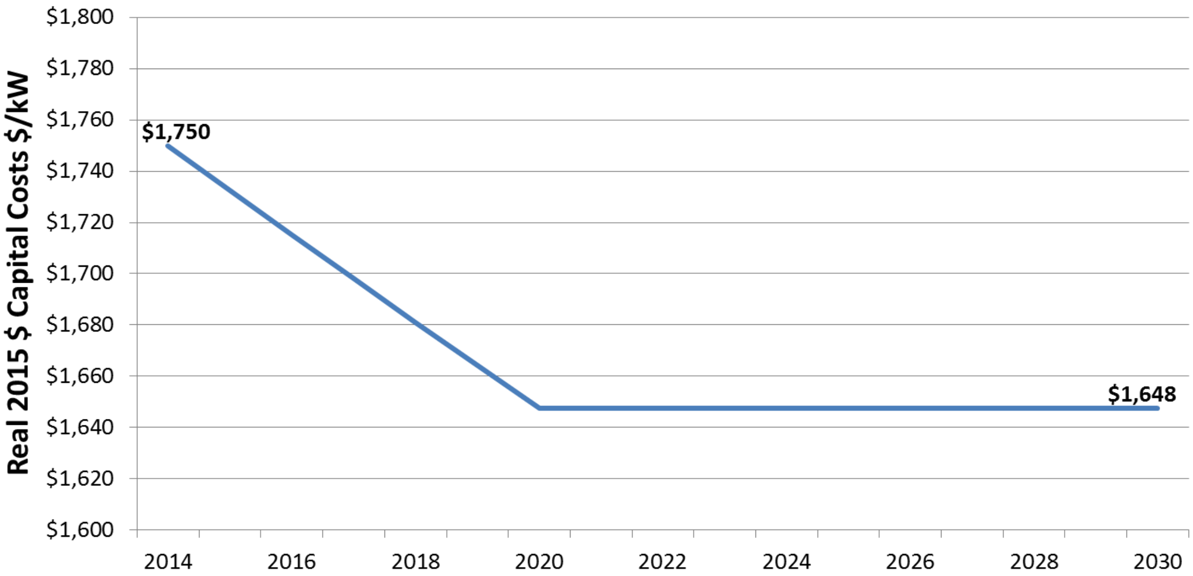


Figure E2.9: Wind Maturity Curve

E2.2.15 Alternative Generator Data

Table E2.11 shows the fixed operation and maintenance (O&M) cost, variable O&M cost, heat rate, lead time (inclusive timeframe for unit construction), maintenance hours, and forced outage rate (FOR) for the alternative supply-side generator categories used in MTEP16 regional resource forecasting. The capacity of each forecasted generic unit from each category is 1,200 MW, with the exception of wind at 300 MW. Monetary values given in the table are in 2015 dollars.

Type	Fixed O&M	Variable O&M	Heat Rate	Lead Time	Maintenance Schedule	Forced Outage Rate
	$/kW-Yr.	$/MWh	MMBtu/MWh	Years	Hours	%
Biomass	105.63	5.26	13.50	4	0	3.25

[4] Starting cost taken from DOE LBNL 2013 Wind Technologies Market Report: Page 50
http://energy.gov/sites/prod/files/2014/08/f18/2013%20Wind%20Technologies%20Market%20Report_1.pdf
Estimated cost decline taken from EIA AEO 2014 Assumptions Report: Page 98
http://www.eia.gov/forecasts/aeo/assumptions/pdf/0554(2014).pdf

CC	10.13	1.59	6.43	3	336	5.11
CCS*	47.98	3.31	7.53	3	504	5.11
CT	8.7	2.46	9.75	2	168	5.93
Hydro	14.13	2.66	0.00	4	0	3.25
IGCC	55.05	6.66	8.70	6	672	5.11
IGCCS**	34.06	7.79	10.70	6	672	5.11
Nuclear	68.7	2.49	10.40	11	672	2.95
PV	21.75	5.00	0	2	0	0
Wind	39.55	5.00	0	2	0	0

* Combined-Cycle with Sequestration
** Integrated Gasification Combined-Cycle with Sequestration

Table E2.11: Alternative generator data

E2.3 Results of Regional Resource Forecasting

The conditions modeled in each future scenario result in various forecasted levels of resource additions and retirements which are shown in the figure below. The non-CPP futures show that levels of resources added are a direct correlation to the demand and energy growth assumptions. In addition, there is a greater selection of CTs over CCs in the non-CPP futures because the additional resources are required to meet the reserve capacity needs of the system as opposed to the energy needs which are met through renewables and DR/EE.

In the CPP cases, the model shows a buildout of more CCs with the main driver being the carbon cost only applied to existing units in accordance with the proposed 111(d) rule. Additionally, economic renewable selection is driven by the carbon cost on the system and the increased retirements from age-related units and coal. In Regional CPP case, solar makes up a majority of the renewable while in the SubRegional CPP case it's split between solar and wind. The primary driver of that spilt is the increased carbon cost applied to the SCPP future.

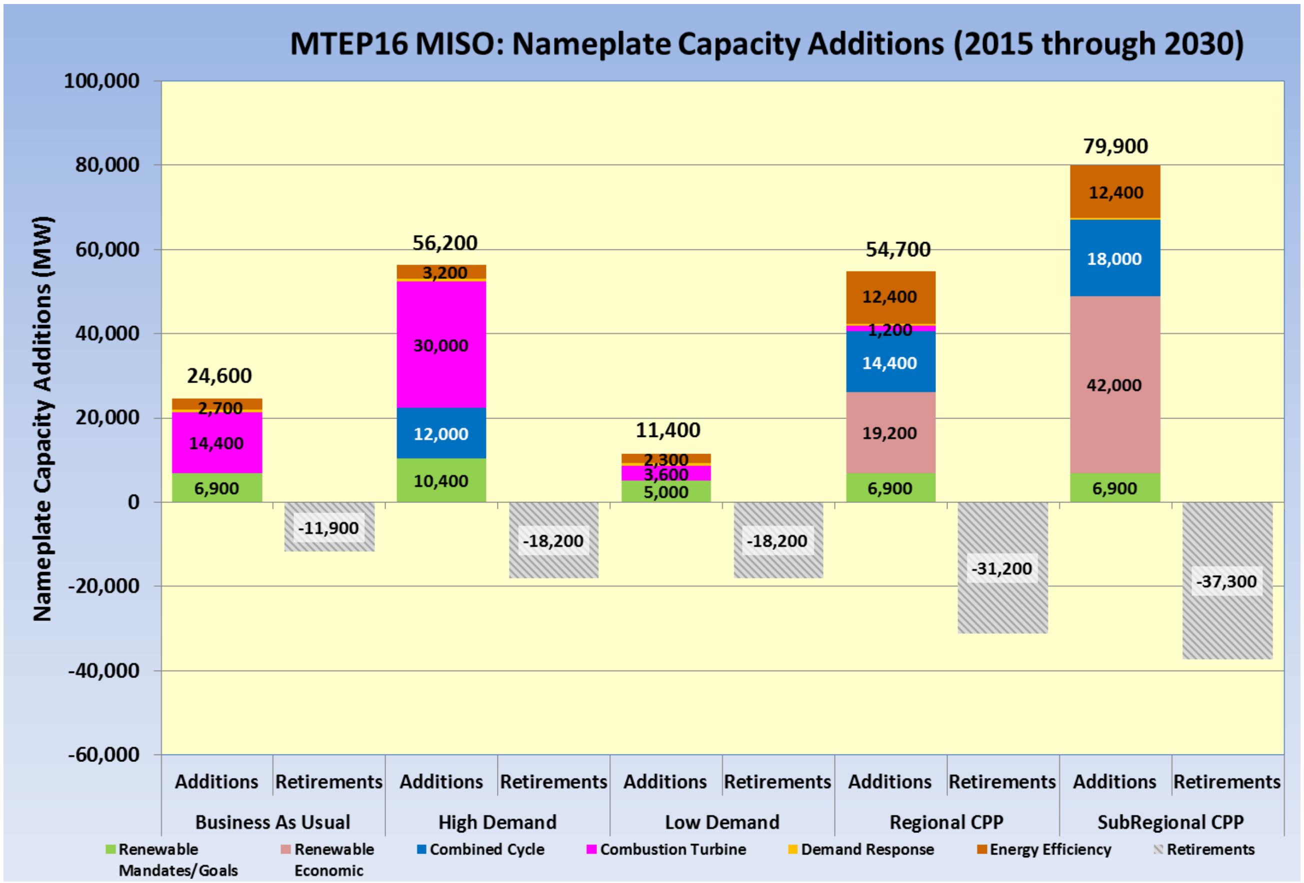
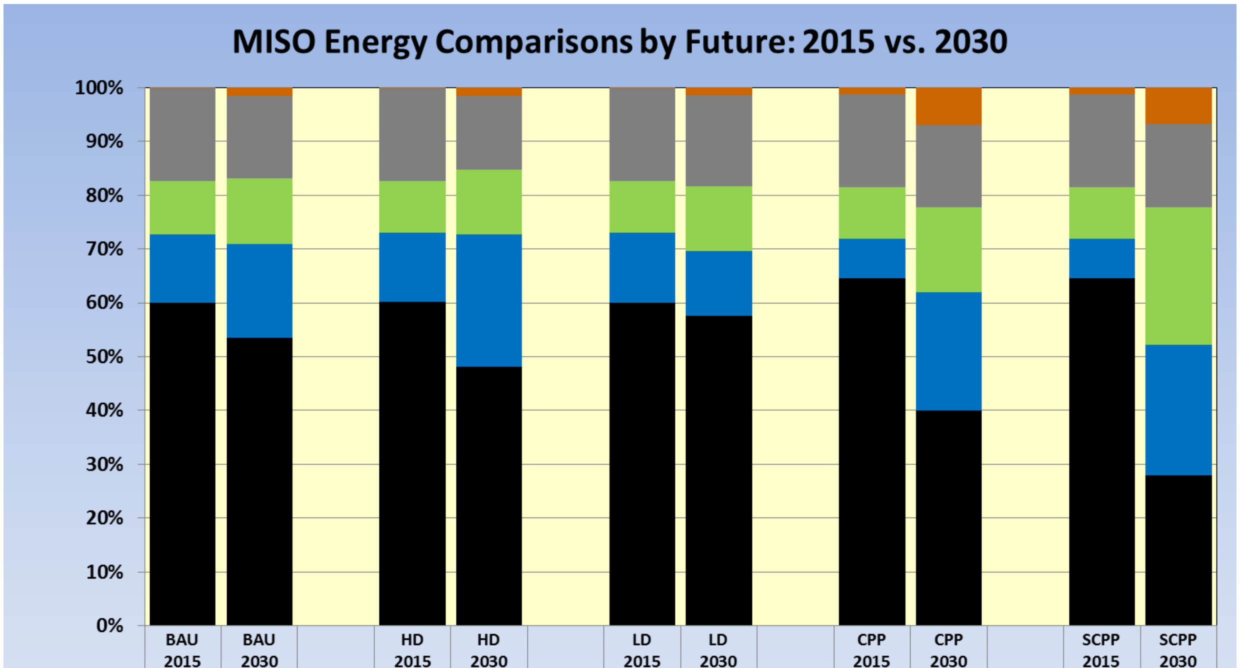


Figure E2.10: Resource Additions and Retirements

The energy usage of the system is shown for each future in the chart below. The chart shows the energy utilization of the system in the year 2015 compared to year 2030. For the non-CPP futures, coal is dispatched at 60% in the base year while coal is dispatched at 64% in the CPP futures. The driver for the difference in base year energy utilization is the starting natural gas price. The higher gas price makes more coal resources get dispatched over gas resources.



	BAU 2015	BAU 2030		HD 2015	HD 2030		LD 2015	LD 2030		CPP 2015	CPP 2030		SCPP 2015	SCPP 2030
DSM	0%	2%		0%	2%		0%	1%		1%	7%		1%	7%
Other	17%	15%		17%	14%		17%	17%		17%	15%		17%	15%
Renewable	10%	12%		10%	12%		10%	12%		10%	16%		10%	26%
Gas	13%	17%		13%	25%		13%	12%		7%	22%		7%	24%
Coal	60%	53%		60%	48%		60%	58%		64%	40%		64%	28%

Figure E2.11: Energy Utilization by Resource

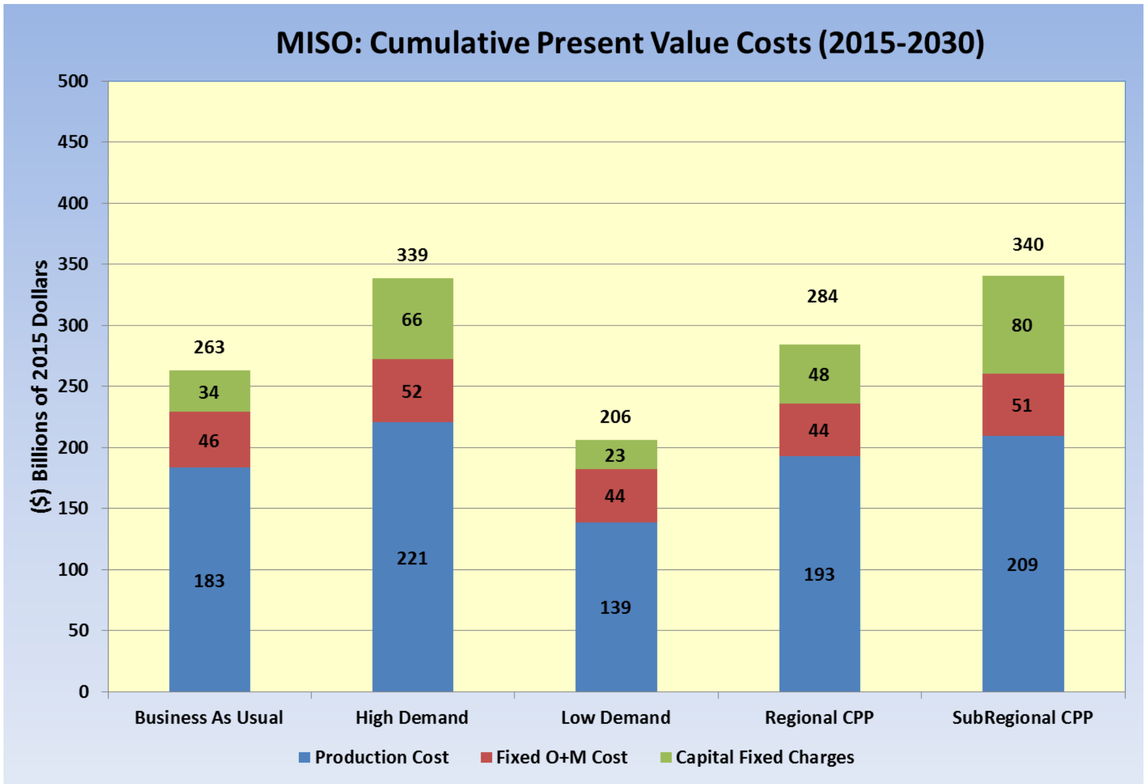


Figure E2.12: Present Value Costs

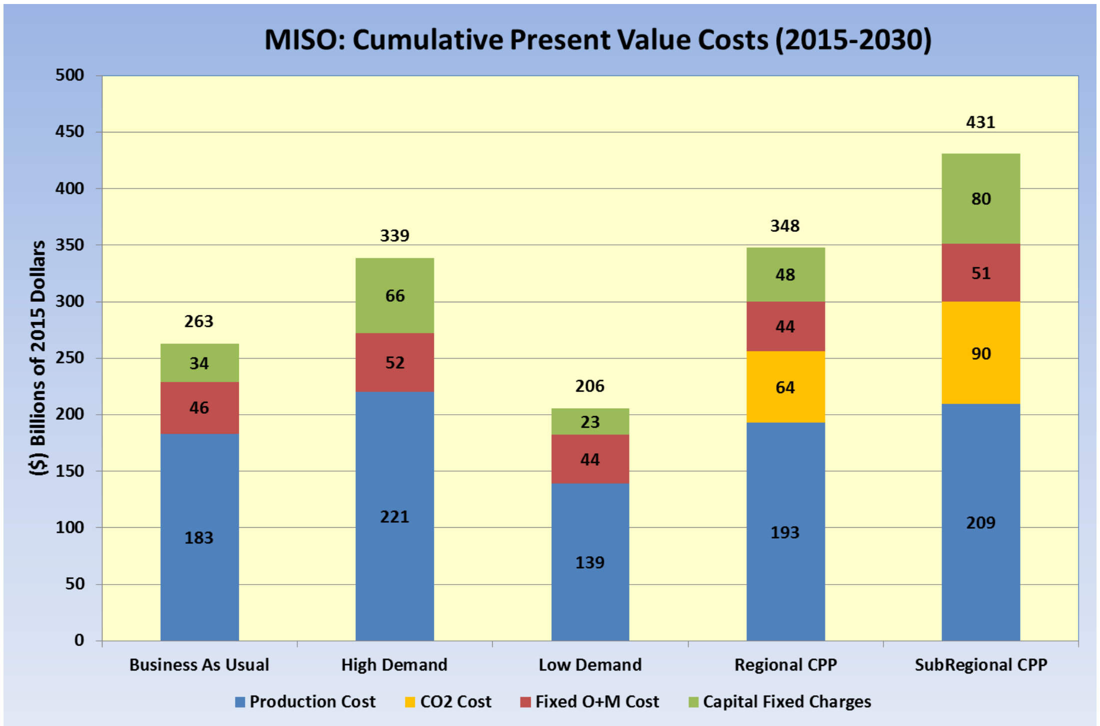


Figure E2.13: Present Value Costs with Carbon Cost

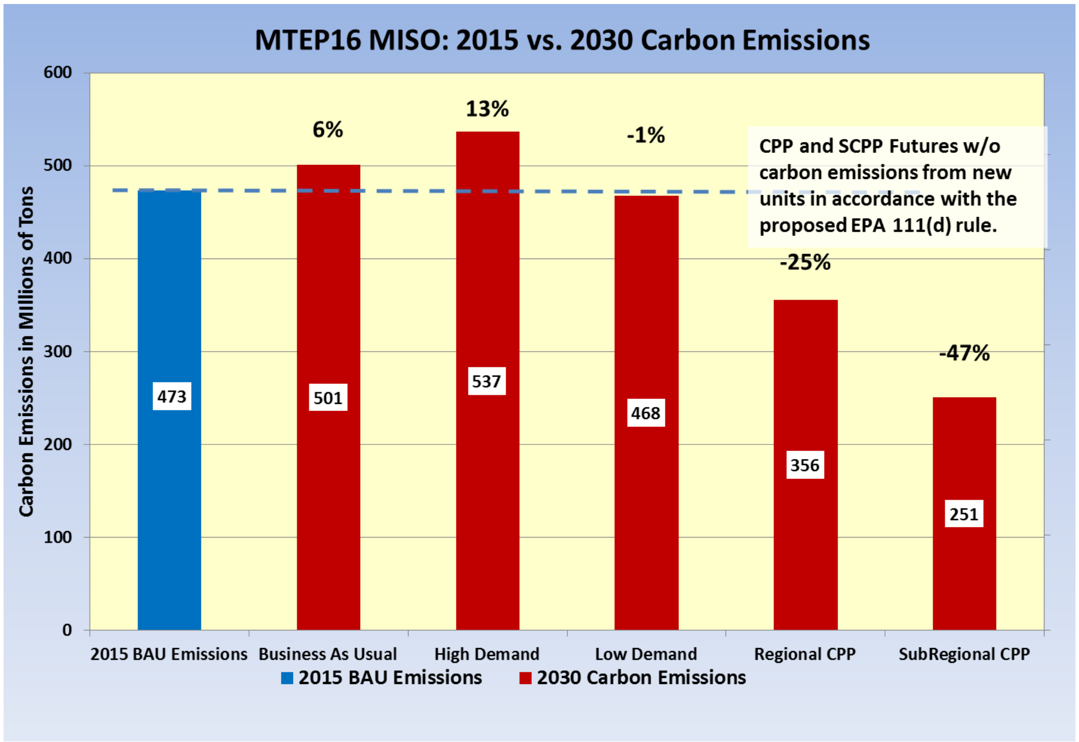


Figure E2.14: Carbon Emissions with only Existing Units

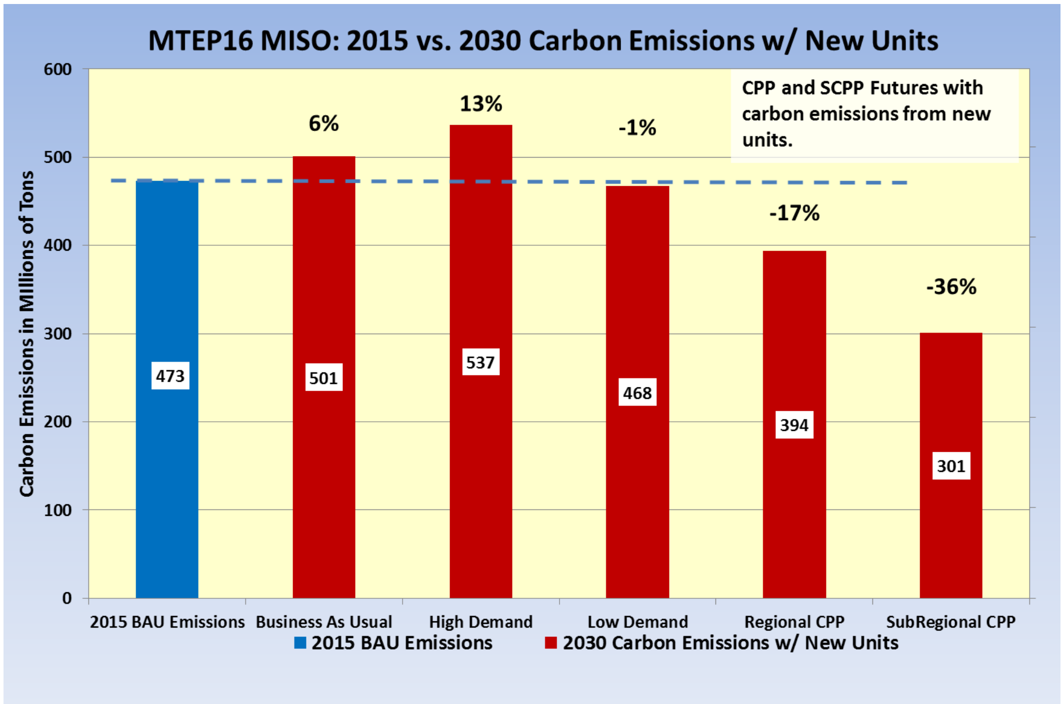


Figure E2.15: Carbon Emissions with New Units

E2.4 Siting of Regional Resource Forecasted Units

Regional Resource Forecasted (RRF) units result after applying the Futures conditions to the system (load growth, fuel and capacity costs, renewable portfolio standards, emissions costs or constraints, etc.) and evaluating what resource mix is the most efficient going forward. Given that the generator interconnection queue is typically only useful for one to five years out for capacity, a capacity expansion tool, such as EGEAS, is used to supplement the out years to maintain the load-to-resource balance. These units must be sited within the powerflow model for use within the production costing models. Beginning with MTEP11, MISO included Demand Response (DR) and Energy Efficiency (EE) units in the EGEAS capacity planning process. While EE is simply netted out of the baseline demand and energy values, DR units also have to be sited into the powerflow models for production cost analysis. Therefore, additional siting methodology for DR has been developed. A Geographic Information System (GIS) software program called MapInfo is used to assist in the generation siting. Siting rules, which are detailed below, are used to develop layers within the mapping software showing the potential locations of the resource forecasted units.

The siting can be broken into four main categories. The categories are general siting rules, future-specific siting rules, siting priority order and, finally, unit-specific greenfield siting. General siting rules apply to all futures, while future-specific siting rules only apply to certain futures (i.e. only use queue units as possible sites). Siting priority sets what sites will be looked at first and then finally how each technology will be sited for greenfield. The overall siting process is being revised as a part of the MTEP17 process, developing additional criteria for thermal fleet siting and additional wind & solar specific zones.

E2.4.1 General Siting Rules

The rules outlined in this section show, at a higher level, many of the underlying assumptions that go into the siting of RRF generation. These criteria could be referred to as the “first pass” siting criteria.

- Site by region, with the exception of wind.
- “Share the Pain” mentality. Not all generation in a region can be placed in one state and one state cannot be excluded from having generation sited.
- Avoid greenfield sites for gas units (CTs and CCs) if possible - prefer to use all brownfield sites.
- Site baseload units in 600 MW increments, except nuclear which is sited at 1,200 MW.
- Limit the total amount of expansion at an existing site to no more than an additional 2,400 MW.
- Restrict greenfield sites to a total size of 2,400 MW.
- Limit using queue generation in multiple futures.
- Transmission is not an initial siting factor, but may be used as a weighting factor, all things being equal.

E2.4.1.1 Generator Developmental Statuses

A generator’s developmental status is required to determine how the unit will be treated in both the EGEAS capacity expansion model and the siting process. Existing and queue generation is given one of the following developmental statuses within the PowerBase database:

- Active – Existing, online generation including committed and uncommitted units. Does not include generation which has been mothballed or decommissioned.
- Planned - A generator that is not online, has a future in-service date, is not suspended or postponed and has proceeded to a point where construction is almost certain, such as it has a signed Interconnection Agreement (IA), all permits have been approved, all study work has been completed, state or administrative law judge has approved, etc.
  - These units are used in the model to meet future demand requirements prior to the economic expansions.

- Future – Generators with a future online date that do not meet the criteria of the “planned” status. Generators with a future status are typically under one of the following categories, proposed, feasibility studies, permits applied, etc.
  - These generators are not used in the models but are considered in the siting of future generation.
- Canceled – Generators that have been suspended canceled, retired or mothballed. These units are not included in the EGEAS capacity expansion model, although their sites are often considered for brownfield locations in the siting process.

E2.4.2 Future-Specific Siting Rules

In an effort to produce capacity expansions that capture a wide range of future possibilities, certain criterion may be applied to one scenario that are not applied to others. Here are some examples of future-specific siting criteria:

- For one future, use non-signed IA queue generators as possible locations, but don’t reuse in other futures
- Use all brownfield/expandable sites in a future, if possible
- Use brownfield sites early, then greenfield sites
- Use a “smart” siting methodology in one future, i.e. “energy park” mentality
  - Site CT near Wind if other criteria are met
  - Site CT, CC, Coal and Wind near each other if all criteria are met

E2.4.3 Site Selection Priority Order

- Priority 1: Generators with a “future” status
  - Queue generators without a signed IA
  - The “New Entrants” Generators defined by Ventyx (noted as “EV” Gens)
  - Both Queue and EV Gens are under the following statuses:
    - Permitted
    - Feasibility
    - Proposed
- Priority 2: Brownfield sites (Coal, CT, CC, Nuclear Methodology)
- Priority 3: Retired/mothballed sites that have not been re-used
- Priority 4: Greenfield sites
  - Queue and “New Entrants” in canceled or postponed status
- Priority 5: Greenfield sites
  - Greenfield siting methodology

E2.4.4 Unit-Specific Greenfield Siting Rules

Thermal unit siting uses a specific set of rules for each type of capacity.

E2.4.4.1 Greenfield Combined-Cycle Siting Rules

Required Criteria:

- Within 1 mile of railroad or navigable waterway
- Within 2 miles of river or a lake (lake has to be larger than 100 mi2)
- Within 10 miles of a gas pipeline (diameter of 12 inches or greater)
- Within 25 miles of a major urban area

E2.4.4.2 Greenfield Combustion Turbine Siting Rules
Required Criteria:
- Within 20 miles of railroad or navigable waterway
- Within 5 miles of a gas pipeline (diameter 12 inches or greater)

Optional Criteria:
- CT's can almost be located anywhere
- CT's historically have been located near metro areas, but not required
- CT's do not need a river for cooling
- Less likely to build pipeline for CT vs. CC
- CT's may be the preferred generation for coal retirement sites within metro areas

E2.4.4.3 Greenfield Nuclear Siting Rules
Required Criteria:
- Use existing nuclear sites only
- All states are eligible for siting of future nuclear generation

E2.4.4.4 Greenfield Wind Siting Rules
Required Criteria:
- Not in a state or national park
- Not in metro areas
- Not on state-managed lands
- Site wind within a state to meet its mandate, unless potential wind capacity is exceeded, then site in neighboring state(s)

E2.4.4.5 Greenfield Photovoltaic Siting Rules
Photovoltaic (PV) is sited using Solar Global Horizontal Irradiance Annual KWh per panel. The Solar Global Horizontal Irradiance Intelligent Map Layer includes monthly and annual solar resource potential for the United States. The insolation values represent the average solar energy available to a horizontal flat plate collector such as a PV panel. In addition to irradiance, proximity to high-voltage buses and a balance of urban & rural sites were used to attempt to capture the urban solar garden trend and to mimic distributed solar.

E2.4.4.6 Demand Response and Energy Efficiency Siting Rules
Demand response capacity is sited at the top five load buses in each LSE. If an LSE serves load in more than one state, the top five load buses in each state having a DR mandate or goal are used, with the DR being allocated based upon the percentage required in each state's mandate or goal.

The impact of energy efficiency is accounted for in the demand and energy growth rates, as EE is typically available during all 8,760 hours in a year.

E2.4.5 RRF Unit Siting Maps
Figures E2-16 to E2-20 are an overview of the Regional Resource Forecast (RRF) unit siting for each of the future scenarios.

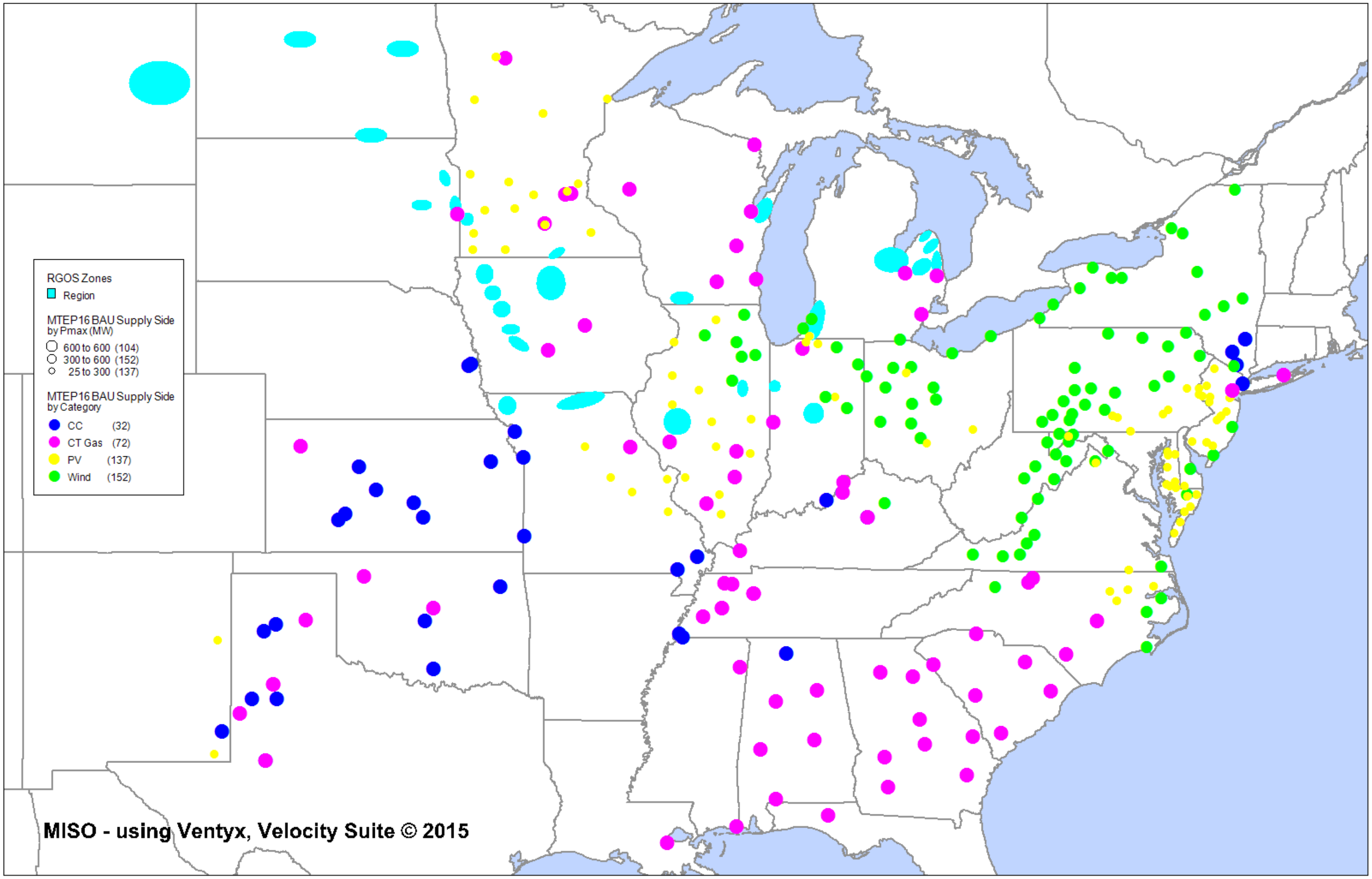


Figure E2.7: MTEP16 Business as Usual future generation siting map

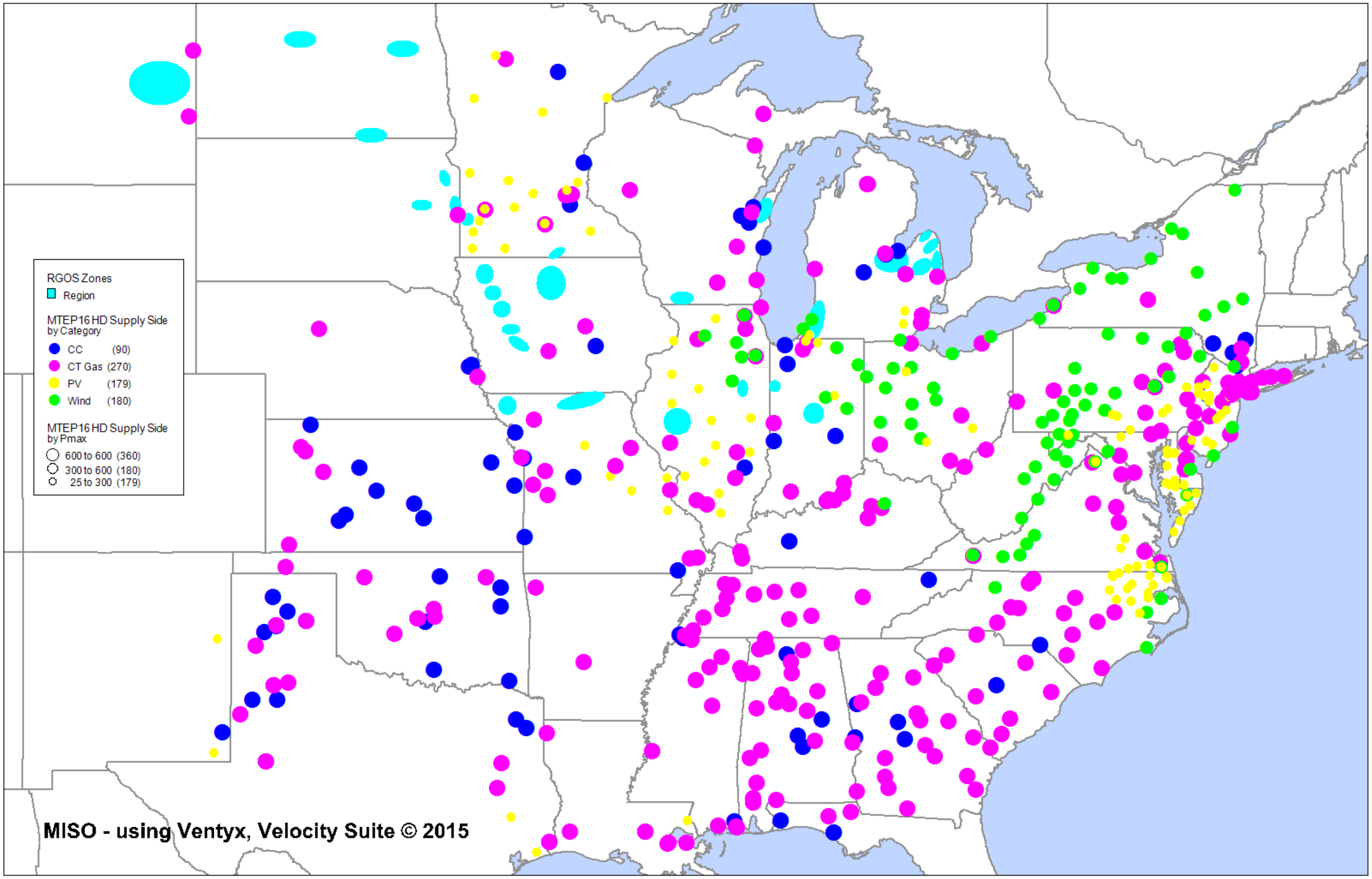


Figure E2.8: MTEP16 High Demand supply-side resource siting map

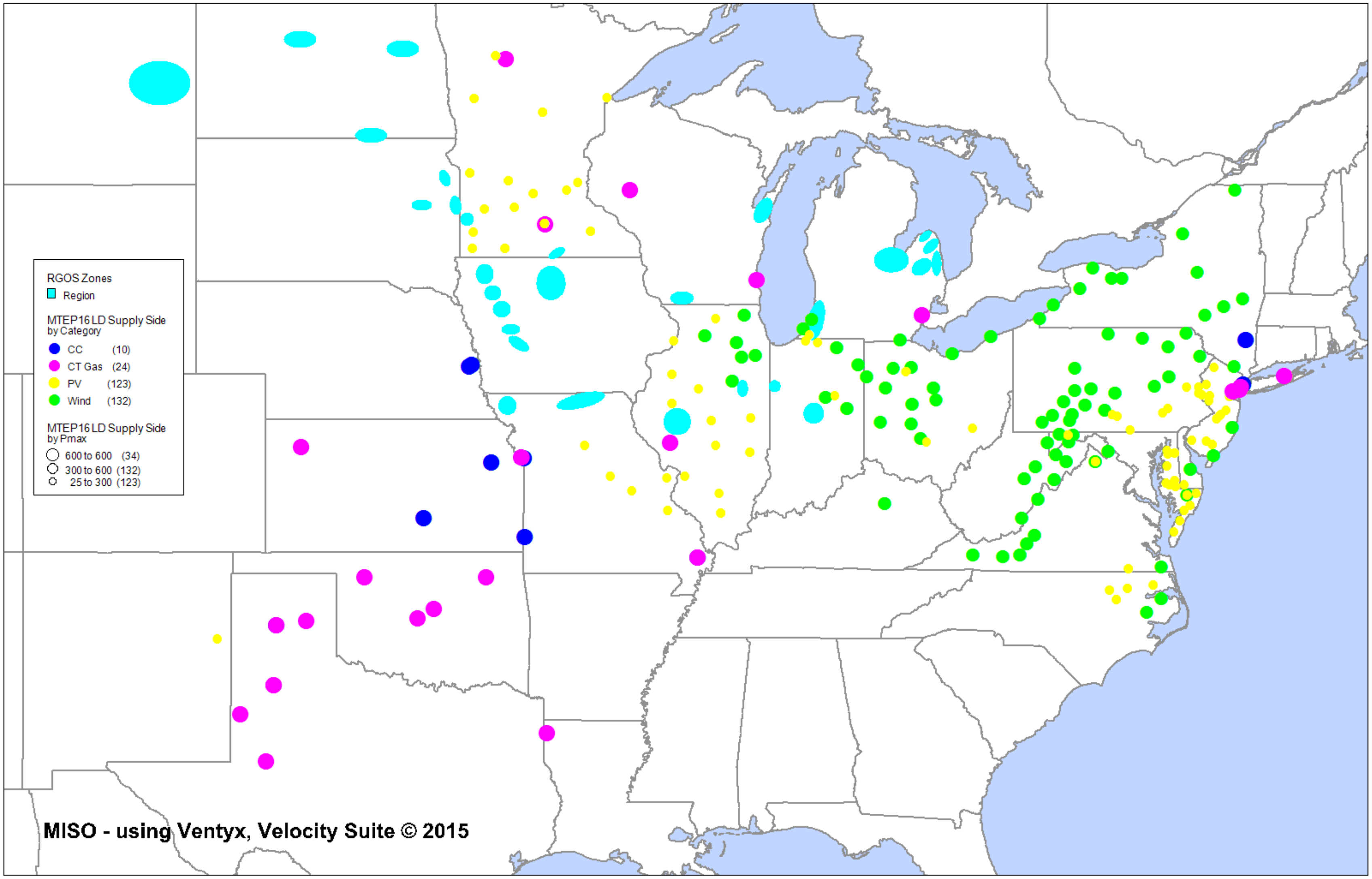


Figure E2.18: MTEP16 Limited Demand supply-side resource siting map

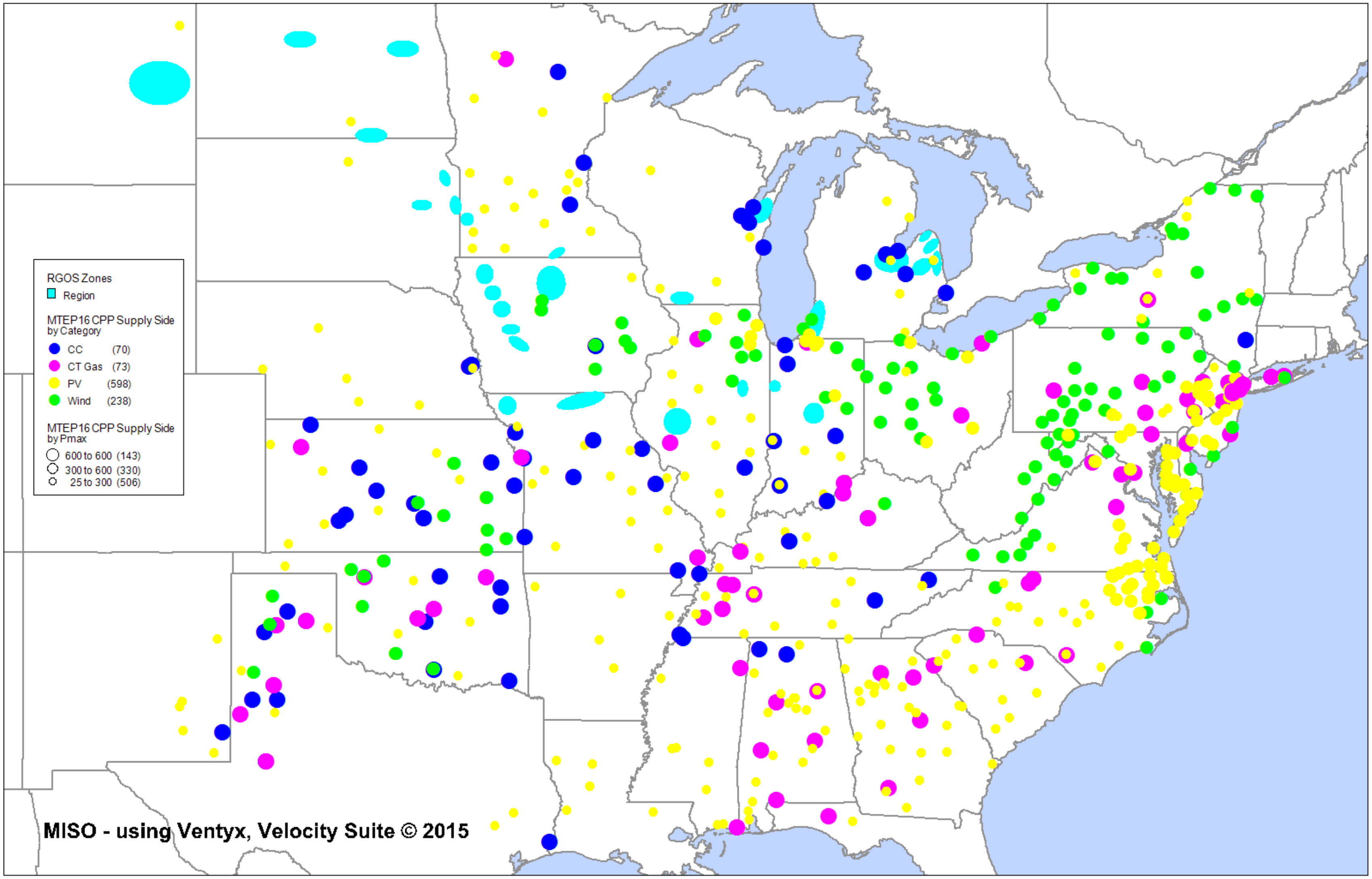


Figure E2.19: MTEP16 Clean Power Plan supply-side resource siting map

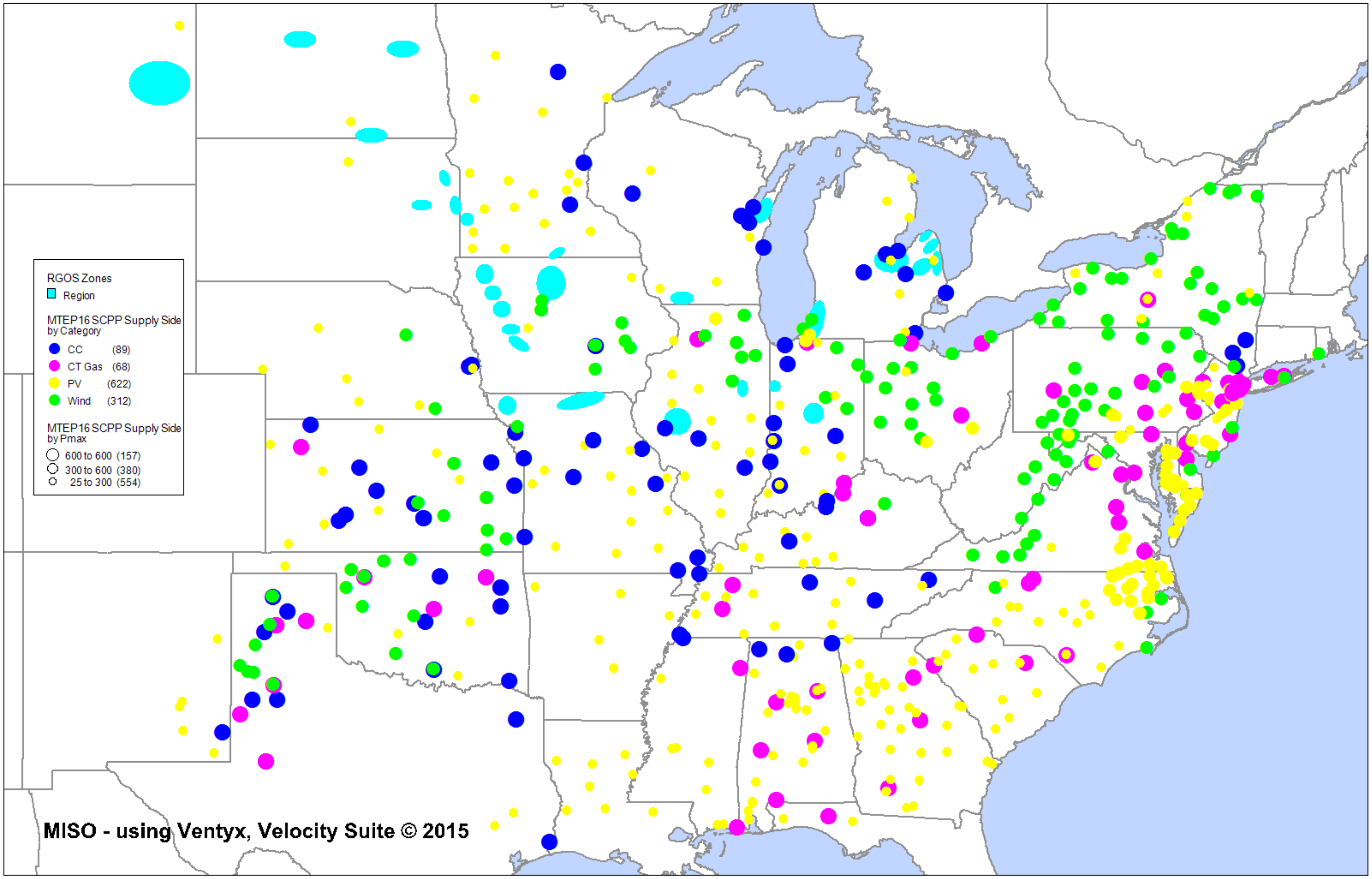


Figure E2.9: MTEP16 Subregional Clean Power Plan supply-side resource siting map

E2.4.6 Demand Response Siting

For MTEP16, demand response requirements for the Business as Usual, High Demand, and Limited Demand scenarios were calculated based only on the expected amounts needed to meet state mandates and goals. The resulting demand response is then sited at the top five to ten load buses in each LSE within the state having the mandate.