Holland Board of Public Works

Power Supply Study

B&V Project No. 165966

March 2010

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Acronym List

ABWR	Advanced Boiling Water Reactor
BACT	Best Available Control Technology
BWR	Boiling Water Reactor
CaO	Calcium Oxide
$CaSO_4$	Calcium Sulfate
CCS	Carbon Capture and Sequestration
CFB	Circulating Fluidized Bed
CO	Carbon Monoxide
CO_2	Carbon Dioxide
COL	Combined Operating License
CPUC	California Public Utilities Commission
CPWC	Cumulative Present Worth Cost
CREBs	Clean Renewable Energy Bonds
CTG	Combustion Turbine Generator
DC	Design Certification
DI	Diffuse Insolation
DNI	Direct Normal Insolation
DOE	Department of Energy
DSM	Demand-Side Management
EE	Energy Efficiency
EIA	Energy Information Administration
EMEC	European Marine Energy Centre
EPRI	Electric Power Research Institute
ESBWR	Economic Simplified Boiling Water Reactor
ESP	Electrostatic Precipitator
FCR	Fixed Charge Rate
FERC	Federal Energy Regulatory Commission
FGD	Flue Gas Desulfurization
FGR	Flue Gas Recirculation
GE	General Electric

HVAC	Heating, Ventilating, and Air Conditioning
HBPW	City of Holland Board of Public Works
HHV	Higher Heating Value
HP	High-Pressure
HRSG	Heat Recovery Steam Generator
IGCC	Integrated Gasification Combined Cycle
IP	Intermediate-Pressure
LNB	Low-NO_x Burner
LP	Low-Pressure
ITC	Investment Tax Credit
LFG	Landfill Gas
MACRS	Modified Accelerated Cost Recovery System
MDEQ	Michigan Department of Environmental Quality
MHI	Mitsubishi Heavy Industries
MISO	Midwest Independent Transmission System Operator
MPPA	Michigan Public Power Agency
MSA	Metropolitan Statistical Area
MW	Megawatts
MWh	Megawatt-Hour
NI	Nuclear Island
NO_x	Nitrogen Oxide
NPHR	Net Plant Heat Rate
NRC	Nuclear Regulatory Commission
O&M	Operations and Maintenance
OWC	Oscillating Water Column
PA	Public Act
PC	Pulverized Coal
PDEA	Project Development and Environmental Analysis
PM	Particulate Matter
PPA	Power Purchase Agreement
PRB	Powder River Basin
PTC	Production Tax Credit

PV	Photovoltaic
PWR	Pressurized Water Reactor
RAP	Realistic Achievable Potential
REAP	Rural Energy for America Program
REPI	Renewable Energy Production Incentive
RH	Relative Humidity
RPS	Renewable Portfolio Standards
SCR	Selective Catalytic Reduction
SDA	Spray Dryer Absorber
SEGS	Solar Electric Generating Station
SNCR	Selective Noncatalytic Reduction
SNL	Sandia National Laboratories
SO_2	Sulfur Dioxide
STG	Steam Turbine Generator
TAPCHAN	Tapered Channel
TI	Turbine Island
ULSD	Ultra-Low Sulfur Diesel
USDA	US Department of Agriculture
USEPA	United States Environmental Protection Agency
WEC	Wave Energy Conversion
WTE	Waste-to-Energy

1.0 Executive Summary

1.1 Study Purpose

Black & Veatch was retained by the City of Holland Board of Public Works (HBPW) to analyze, evaluate, and recommend power supply alternatives to serve the city's future power supply requirements. HBPW generates, purchases, transmits, and distributes electric power to approximately 30,000 residential and commercial customers. HBPW owns baseload generation and peaking generation, purchases wholesale power as a member of the Michigan Public Power Agency (MPPA), and utilizes other resources to meet its needs. Black & Veatch evaluated HBPW's historical load and energy growth, planned commercial expansions, and other data to develop a load forecast that incorporates demand-side management (DSM) and energy efficiency (EE) measures. On the basis of the load forecast and existing resources, HBPW will have a need for additional capacity beginning in approximately 2016.

The purpose of this study was to determine the best long-term resource plan for HBPW that considers cost, reliability, and lower emissions technologies. The need for future resources was determined on the basis of available existing resources and the expected growth in future demand. Several conventional technologies, including supercritical pulverized coal (PC), nuclear, and circulating fluidized bed (CFB) boiler alternatives, were also considered. In addition, renewable energy alternatives, including wind, solar photovoltaic (PV) and solar thermal, biomass, biogas, wave energy, and hydroelectric, were evaluated for the power supply study.

Various factors, such as resource availability, cost and performance characteristics, and environmental impacts, were considered in the analysis. For the fossil generation alternatives, market purchases, fuel price volatility, and emissions profiles were considered in addition to cost. Potential legislation related to the reduction of greenhouse gases, such as carbon dioxide (CO_2), were considered by evaluating fossil fuels and market purchases with a "carbon tax." These and other factors were considered to develop feasible plans with the appropriate balance of cost, long-term reliability, and sustainability with minimal environmental impact.

1.2 Overview of the HBPW System

HBPW currently has a mix of generation fuel types, as shown on Figure 1-1. Approximately 40 percent of the resources are considered baseload, which is lower than what Black & Veatch would typically expect. Black & Veatch would typically expect baseload resources to comprise at least 50 percent of the resources, considering that HBPW's system load factor is approximately 56 percent; this is as discussed further in Section 3.0.

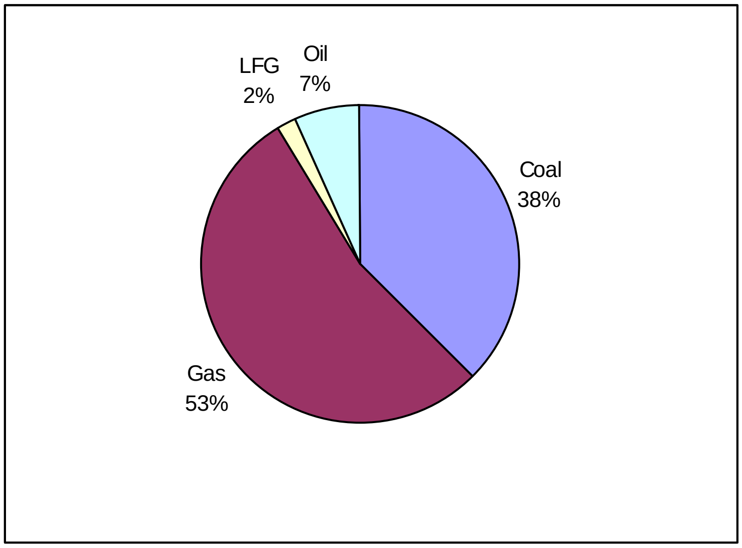

Figure 1-1
HBPW 2010 Capacity Breakdown by Fuel Type

1.3 Study Approach

The HBPW Power Supply Study approach consisted of several key stages including data collection, data analysis, data modeling, analysis of the findings, and documentation of the study in this report. Data were collected from HBPW, Black & Veatch, and a variety of publicly available sources. Separately, HBPW provided information related to several purchases from planned units that may be available to meet future needs. Throughout this process, data for generic supply-side alternatives were compiled, reviewed, screened for appropriateness, and modeled using typical power supply study methods and tools, taking into account special considerations and sensitivities to derive the least-cost expansion plan for HBPW, while also considering environmental impacts, other community benefits, and the need to comply with Michigan Public Act (PA) 295 requirements.

1.3.1 Data Collection

The data collection stage included the compilation and review of both historical and forecast data. This information consisted of historical peak demand and energy data, customer data, heating and cooling-degree data, forecast peak demand and energy data, previous power supply studies, hourly energy profiles, DSM forecasts and programs, details of existing plants and current power purchase agreements (PPAs), historical operating costs and performance characteristics for owned resources, historical energy sources and emissions, power supply alternatives available to HBPW, and other data and assumptions. This information was requested, reviewed, and used as input assumptions for the Power Supply Study.

1.3.2 Data Analysis and Modeling

After being collected, the data were analyzed and used as a basis for developing an optimization expansion planning model in Strategist™ to evaluate a variety of alternative expansion scenarios. Strategist, an optimization expansion planning tool, was developed and licensed by Ventyx; it enables determination of the least-cost plan as well as competing plans with a given set of system parameters and available resources. In developing expansion plans, the model considers the load forecast, existing resources, emissions constraints and allowance prices, fuel prices, cost and performance characteristics of new alternatives, and other factors to estimate the total system cost. Several available generation alternatives were screened, and then various expansion plans were created and evaluated. Generating alternatives that were evaluated included landfill gas, wind, biomass, natural gas combined cycle and combustion turbine, supercritical coal, CFB, and market purchases. As a result, a variety of technologies, including low and zero emissions type resources, were evaluated. The costs of these expansion plans were then evaluated and compared.

1.4 Findings and Conclusions

Based on its analyses and evaluations, Black & Veatch has developed the following findings and recommendations for HBPW's consideration:

- HBPW has a resource need capacity starting in 2016. Based on the resources selected for all cases, this appears to be an intermediate to baseload need rather than a peaking need.
- It appears that HBPW has more than sufficient peaking resources at this time.
- Several peaking, intermittent, intermediate, and baseload resource alternatives appear to be available to HBPW to meet its resource needs including partial ownership purchases, market purchases, natural gas fired combined cycle and simple cycle, supercritical pulverized coal, CFB, landfill gas, hydroelectric, biomass, solar PV, wave, and wind.
- The recent cooler summers and reduced energy consumption from the economic slowdown were not anticipated when the previous forecasts were developed. In addition, new industrial loads are expected in the near term. As a result, Black & Veatch developed a load forecast to account

for these factors as well as historical growth rates, potential reductions in energy intensity within the economy, and potential DSM and EE savings to meet Michigan PA 295.

- Viable resources for new baseload capacity and energy include the proposed HBPW 70 MW (net) CFB, participation in a supercritical coal project, and partial ownership in natural gas combined cycle facilities.
- HBPW's James De Young Generating Station consists of three coal fired electrical generating units, referred to as the JDY Units 3, 4 and 5. These units have capacity of 11 MW, 20 MW, and 25 MW, respectively. In addition, these units are currently 59 years, 48 years, and 41 years, respectively. At the end of the study period, these units will be in the 60 to 80 year old range, and at or near the end of their expected useful life. Although these units are not planned to be retired during this study, except in the case of adding the CFB unit, it would be prudent for HBPW to plan for this contingency.

2.0 Description of Existing System

The HBPW is a community-owned enterprise that provides utility services to the Holland area. HBPW provides reliable and economical electric, water, and wastewater treatment services in an environmentally responsible manner, serving nearly 30,000 customers. HBPW's existing conventional generation resources, environmental commitment, PPAs, and renewable energy projects are discussed in the following section.

2.1 Existing Conventional Generation Resources

The existing generating resources available to HBPW are summarized in Table 2-1. As discussed further in this section, HBPW's generating capacity includes jointly and wholly owned units fueled by coal, natural gas, and distillate fuel oil. HBPW's present summer net ownership capacity is approximately 267 MW[1]. HBPW's generating resources include three self-owned coal fired electric generating units, three natural gas fired simple cycle combustion turbines, and one combustion turbine that operates on distillate fuel oil. In addition, HBPW subscribes to MPPA's partial ownership of two other coal fired electric generating plants.

The wholly owned HBPW generating resources are located at three different sites:

- The James De Young Generating Station consists of three coal fired electrical generating units. These units are referred to as the JDY Units 3, 4 and 5 in subsequent sections of this report.
- The 48th Street Generation Station consists of three natural gas fired simple cycle combustion turbines, two of which are capable of burning distillate fuel oil as a secondary fuel source, if required. These units are referred to as CT7, CT8, and CT9 in subsequent sections of this report.
- The 6th Street Generation Station consists of a simple cycle combustion turbine that operates on distillate fuel oil. This unit is referred to as CT6 in subsequent sections of this report.

In addition to the units described above, HBPW owns shares of coal fired generating Unit 3 at the J.H. Campbell Complex (Campbell) (operated by Consumers Energy Company) and the Units 1 and 2 of the Belle River Plant (Belle River) (operated by Detroit Edison Company).

[1] Including the capacity from the renewable resources discussed in subsequent subsections, HBPW's current summer net generating capability is 273 MW.

Table 2-1
Existing Conventional Generating Units

Plant Name	Unit No.	Commercial Online Date (MM/YYYY)	Primary Fuel	HBPW Share of Net Summer Capacity (MW)	Full Load Net Plant Heat Rate (btu/kWh, Higher Heating Value [HHV])	Sulfur Dioxide (SO_2) Emissions Rate (lb/MBtu)	Nitrogen Oxide (NO_x) Emissions Rate (lb/MBtu)	CO_2 Emissions Rate (lb/MBtu)	Scheduled Outage Rate (%)	Forced Outage Rate (%)
Campbell		09/1980	Subbituminous Coal	10.57	10,414	0.55	0.07	209.5	7.70	4.00
Belle River		08/1984	Subbituminous Coal	35.65	9,870	0.56	0.24	208.3	7.70	4.00
CT6	1	05/1974	Distillate Fuel Oil	18.00	14,680	0.10	0.80	165.70	3.80	4.00
CT7	7	05/1992	Natural Gas	36.00	11,931	0.0006	0.14	118.0	3.80	4.00
CT8	8	05/1992	Natural Gas	36.00	11,931	0.0006	0.14	118.0	3.80	4.00
CT9	9	04/2000	Natural Gas	75.00	11,733	0.0006	0.04	118.0	3.80	4.00
JDY	3	04/1951	Blend Bit/Subbit Coal	11.00	14,492	1.6	1.0	205.1	7.70	4.00
JDY	4	05/1962	Blend Bit/Subbit Coal	20.00	13,047	1.6	1.0	205.1	7.70	4.00
JDY	5	06/1969	Blend Bit/Subbit Coal	25.00	13,191	1.6	0.45	205.1	7.70	4.00

2.1.1 Unit Retirements

No retirements of existing units are scheduled for the base case during the term of this power supply study. However, two of the expansion plan scenarios will require retirements of existing units. To implement the self-build 70 MW (net) CFB alternative, the JDY Unit 3 would need to be retired and demolished at the end of 2013 to allow space for this new unit. In addition, CT9 would need to be retired as a simple cycle unit at the end of 2013 to allow another alternative under consideration to be converted to combined cycle.

2.1.2 Environmental Quality and Protection

HBPW is committed to improving and maintaining the environmental quality of the community. HBPW's Electric Production Department maintains compliance with all environmental emissions and control standards that have been promulgated by the United States Environmental Protection Agency (USEPA) and the Michigan Department of Environmental Quality (MDEQ).

HBPW has taken steps that are consistent with its environmental commitments, having achieved various environmental accomplishments that have helped to improve the environmental quality of the community. Highlights of these accomplishments include the following:

- 65 percent reduction of nitrogen oxide (NO_x) emissions on JDY Unit 5 in 2000.
- Utilization of natural gas fired ignitors on JDY Units 3 through 5 to reduce particulate matter emissions upon startup.
- Utilization of low sulfur coal to reduce emissions of sulfur dioxide (SO_2) and maintain compliance with environmental standards.
- Use of electrostatic precipitators at the James De Young Generating Station, which operates at more than 99.5 percent efficiency to control particulate matter emissions.
- Discontinuing the use of hazardous chlorine gas for the chlorination process, which eliminated the potential for a hazardous chemical release.
- Utilization of state-of-the-art NO_x control equipment at the 48th Street Generation Station, reducing NO_x emissions significantly below current environmental emissions standards.

2.2 Power Purchase Agreements

HBPW traditionally uses various sources of purchased power, both short-term and long-term, to help satisfy demand for power. HBPW typically tries to balance the amount of purchased power with owned generation to minimize market price impacts. HBPW's existing PPAs for calendar year 2010 are summarized below. Each of the power purchases has been entered into with wholesale suppliers through MPPA.

- Purchase 15 MW in calendar year 2010.
- Purchase 25 MW in calendar year 2010.
- Sale of 26 MW (capacity only, no energy) through May 31, 2010.

Additional purchases are discussed below.

2.3 Renewable Energy

Among the requirements of the Michigan Legislation's *Clean, Renewable, and Efficient Energy Act* (Act 295 of 2008) is that certain providers of electric service must establish renewable energy programs. Part 2, Section 25 of Act 295 of 2008, requires municipal utilities to file a 20 year plan to achieve renewable energy credit portfolio standards that are specified in Section 27. HBPW has satisfied that requirement with the filing of its *Renewable Energy Plan* (U-15866). The following is a summary of HBPW's existing and potential future renewable energy sources. Future expansion plans include wind resources, which may come from the planned projects discussed in the following subsections or other projects to be developed.

2.3.1 Grayling Generating Station (Operating)

Grayling Generating Station Limited Partnership provides energy to HBPW under a PPA. The power is provided by a biomass fueled power plant. The annual allocation of energy to HBPW from this PPA is approximately 9,461 MWh. This plant provides only energy to HBPW at a fixed cost of $68.00/MWh, but does not provide any capacity value. The PPA will expire in 2014.

2.3.2 Granger Landfill Energy (Operating)

HBPW, through MPPA, has entered into a long-term contract with Granger Landfill Energy to purchase capacity, energy and renewable energy credits generated at several landfill gas energy projects owned by Granger. The PPA is effective for 20 years, beginning in February 2010. HBPW's power purchase will increase from 780 kW in 2010 to 3.4 MW in 2014.

2.3.3 North American Natural Resources (Operating)

HBPW has entered into a long-term contract with North American Natural Resources (NANR) to purchase capacity, energy and renewable energy credits generated at the Southeast Berrien County landfill gas energy project owned by NANR. The PPA is effective for 20 years, beginning in January 2010. HBPW's power purchase will increase from 4.3 MW in 2010 to 6.4 MW by 2018.

2.3.4 Civic Center Wind (Operating)

This project consists of a 1.5 kW wind turbine mounted to the Holland Civic Center roof and a 1.9 kW wind turbine mounted on a monopole located on the grounds of the Holland Civic Center. The project is assumed to have a 20 percent capacity factor.

2.3.5 HBPW Service Center Wind (Operating)

This project consists of a 1.5 kW wind turbine mounted on the HBPW Service Center roof. The project is assumed to have a 20 percent capacity factor.

2.3.6 Wyandotte Wind Project (Evaluated)

HBPW, through MPPA, evaluated partnering with Wyandotte Municipal Services in a project that would have installed four to five 1.65 MW wind turbine generators within the city limits of Wyandotte, Michigan. However, after further evaluation, the wind resource was determined to be poor and HBPW abandoned this project.

2.3.7 Windmill Island Wind Project (Planned)

HBPW has installed a meteorological equipment tower (MET) at Windmill Island, which is located within the city limits of Holland. If the wind resource is sufficient to make wind energy economical, HBPW would proceed with installing at least one and potentially three wind turbines in the 1.65 MW class, for a total generation potential of 4.95 MW, or approximately 11,274 MWh per year.

2.3.8 Stone Mountain Wind Project (Evaluated)

HBPW has obtained an option to purchase 1,500 acres of land in Chippewa County, Michigan. HBPW has installed a MET to evaluate the wind resource. MET data indicated that the wind resource was poor and the project would not be economic. As a result, HPBW abandoned this project.

2.3.9 NS Wind Project (Evaluated)

HBPW evaluated the option to develop a wind project south of Muskegon, Michigan. HBPW evaluated installation of two or three wind turbines in the 1.65 MW class, providing 3.2 MW of capacity. After further review of the wind resource, this project was determined to not be economic.

3.0 The City of Holland Load Forecast

3.1 Econometric Load Forecast

A load forecast through 2030 for the city of Holland was developed for use in this planning study. The load forecast utilizes an econometric model using historical utility, economic, and weather data series. The load forecast produced projections of Total Energy Requirements, Total Energy Sales, Peak Demand, and System Load Factor. The data from 1981 to 2008 are historical, while the data from 2009 to 2030 are forecasted. The general form of the forecast is discussed below:

- *Total Energy Requirements* were calculated based on the total electrical sales plus an additional requirement to cover system losses (Total Energy Requirements = Total Energy Sales * (1+Losses)). Losses are projected at 3.6 percent of energy requirements and have ranged from 0.9 percent to 6.2 percent over the period from 1990 to 2008.
- *Total Energy Sales* were calculated by summing the residential energy sector, the commercial and industrial energy sector, the other energy sector, and future additions. The residential, commercial and industrial, and other energy sectors were forecast based on regression equations that are further explained below. New electrical additions in the commercial and industrial sector for planned lithium ion battery manufacturing plants were developed, in part, by using information from the city of Holland. Expected demand and energy requirements for these plants have been provided to HBPW for planning purposes.
- *Peak Demand* values were calculated by dividing the energy requirements by the load factor multiplied by the total hours (8,760) in a year (Peak Demand = (Total Energy Requirements)/(Load Factor*8,760)).
- *System Load Factor* is projected to be 56.4 percent and has ranged from 53.7 percent to 59.5 percent over the period from 1990 to 2008.

3.1.1 Energy Sales by Sector

Energy sales grew at an average annual rate of 4.94 percent from 1981 to 2008 and at a rate of 0.7 percent from 1999 to 2008. The forecast values for 2009 to 2030 are based upon normal weather conditions. Each sector is discussed below.

3.1.1.1 Residential Energy Sector. Residential energy sales were projected on the basis of an analysis that examined historical utility data, economic data, and weather conditions over the period from 1981 to 2008. The historical utility data used were the number of residential customers. Economic conditions were modeled on the basis of nominal per capita personal income for the Holland-Grand Haven metropolitan statistical area (MSA). The actual per capita personal income statistics were acquired from Global Insights Inc. and were based on statistics from the Bureau of Economic Analysis. Weather conditions were modeled through the use of two series that summarize the daily changes in temperature: heating and cooling degree-days. The equation used to project residential energy sales is shown below:

$$ResMWH = (ß0 + ß1\ ResCus + ß2\ HDD + ß3\ CDDt + ß4\ PCPI)$$

where:

ResMWH	=	Residential Energy Sales.
ResCus	=	Number of Residential Customers.
HDD	=	Heating Degree-Days.
CDD	=	Cooling Degree-Days.
ResP	=	Residential Price (Nominal Dollars).
PCPI	=	Per Capita Personal Income (Nominal Dollars).

3.1.1.2 Commercial and Industrial Sector. Commercial energy sales were combined with industrial energy sales for projection purposes because of the recent reclassification of commercial and industrial accounts. Since the primary driving forces that affect commercial and industrial customers are similar, this approach should be satisfactory until a longer history under the new classification system is available.

The independent variables used in the regression equation to forecast the industrial and commercial megawatt-hour usage include the gross state product of Michigan, the commercial and industrial megawatt-hours lagged one period, energy intensity[2], and a variable accounting for economic recessions. The equations used to project commercial energy sales are shown in the following equation:

$$I\&C\ MWH = (ß0 + ß1\ GSP + ß2\ CI\ MWH_{t-1} + ß3\ Eng\_Int + ß4\ Dum\_Rec)$$

where:

I&C MWH	=	Commercial and Industrial Energy Sales.
GSP	=	Gross State Product of Michigan.
CI MWH $_{t-1}$	=	Commercial and Industrial Energy Sales Lagged One Period.

[2]Energy intensity is a measure of energy consumption per dollar of gross domestic product (GDP), or stated differently, energy intensity is the ratio of the amount of energy consumed to an indicator of the amount of goods produced or services provided.

Eng_Int = Energy Intensity.
Dum_Rec = Variable Representing the Current Recession.

3.1.1.3 Other Energy Sector. Other energy sales (primarily street lighting) were projected on a basis comparable to that used for the commercial and industrial class; both use the lagged dependent variable as an independent variable (the auto-regressive technique). The other energy sales category is dependent on the number of residential customers, assuming that, as the number of residential customers increases, the number of street lights will increase. Lastly, there is a variable to account for 1998. The equation used to project other energy sales is shown below:

$$OMWH = (ß0 + ß1\ ResCus + ß2\ OMWH_{t-1} + ß3\ Dum\_98)$$

where:

OMWH = Other Energy Sales.
ResCus = Number of Residential Customers.
$OMWH_{t-1}$ = Other Energy Sales Lagged One Period (MWH).
Dum_98 = Variable for 1998.

3.1.2 Results

The forecast results are presented in Table 3-1, which indicates that the total energy requirement is forecast to increase from 947,569 MWh in 2009 to 1,526,194 MWh in 2030, representing an annual average growth rate of 2.30 percent. Total MWh sales are projected to increase from 916,726 MWh in 2009 to 1,476,626 MWh in 2030, an average annual growth rate of 2.30 percent.

Peak demand is projected to increase from 204.5 MW in 2009 to 310.9 MW in 2030, an average annual growth rate of 2.01 percent during the forecast period. These forecast values include a relatively large increase in the demand requirements over the next few years; this is linked to specific new commercial and industrial loads identified by the city of Holland.

The historical and forecast total energy and demand for the city of Holland are shown on Figures 3-1 and 3-2.

Table 3-1
Forecast Results

Year	Res MWH	Industrial and Commercial MWH	Other MWH	Future Additions (MWH)	Required MWH	Annual % Change	Total MWH	Annual % Change	Losses	Peak	Annual % Change	LF
1981	71,934	200,824	2,458		298,160		275,216		7.7%	65.8		51.7%
1982	73,570	211,059	2,488		315,688	5.9%	287,117	4.3%	9.1%	66.0	0.30%	54.6%
1983	74,497	227,842	2,509		329,708	4.4%	304,848	6.2%	7.5%	72.0	9.09%	52.3%
1984	81,259	267,073	2,457		376,960	14.3%	350,789	15.1%	6.9%	76.5	6.25%	53.6%
1985	82,250	292,051	2,481		403,312	7.0%	376,782	7.4%	6.6%	82.4	7.71%	55.9%
1986	84,361	323,728	2,486		424,731	5.3%	410,575	9.0%	3.3%	86.6	5.10%	56.0%
1987	89,493	359,440	2,511		480,200	13.1%	451,444	10.0%	6.0%	96.8	11.78%	56.6%
1988	97,092	395,787	2,612		524,666	9.3%	495,491	9.8%	5.6%	107.8	11.36%	55.6%
1989	103,691	446,286	2,639		582,983	11.1%	552,616	11.5%	5.2%	119.1	10.48%	55.9%
1990	105,554	473,648	2,705		613,956	5.3%	581,907	5.3%	5.2%	119.1	0.00%	58.8%
1991	109,044	488,686	2,727		636,023	3.6%	600,457	3.2%	5.6%	126.2	5.96%	57.5%
1992	114,749	509,744	2,759		656,832	3.3%	627,252	4.5%	4.5%	133.9	6.10%	56.0%
1993	109,246	527,192	2,794		680,829	3.7%	639,232	1.9%	6.1%	131.8	-1.57%	59.0%
1994	118,003	575,627	2,790		732,262	7.6%	696,420	8.9%	4.9%	151.1	14.64%	55.3%
1995	119,193	622,872	2,860		786,049	7.3%	744,926	7.0%	5.2%	164.4	8.80%	54.6%
1996	132,799	677,968	2,929		864,189	9.9%	813,696	9.2%	5.8%	179.0	8.88%	55.1%
1997	131,103	709,667	3,100		892,768	3.3%	843,869	3.7%	5.5%	183.0	2.23%	55.7%
1998	134,961	756,030	3,827		941,326	5.4%	894,818	6.0%	4.9%	195.0	6.56%	55.1%
1999	143,929	803,264	3,381		1,012,987	7.6%	950,573	6.2%	6.2%	204.2	4.72%	56.6%
2000	149,951	884,128	3,457		1,075,940	6.2%	1,037,535	9.1%	3.6%	214.3	4.95%	57.3%
2001	153,121	936,569	3,463		1,102,833	2.5%	1,093,152	5.4%	0.9%	221.0	3.13%	57.0%
2002	156,331	903,926	3,573		1,092,351	-1.0%	1,063,830	-2.7%	2.6%	231.0	4.52%	54.0%
2003	167,390	910,928	3,616		1,110,762	1.7%	1,081,933	1.7%	2.6%	225.9	-2.21%	56.1%
2004	162,698	898,653	3,612		1,105,962	-0.4%	1,064,962	-1.6%	3.7%	222.7	-1.43%	56.5%
2005	162,669	901,126	3,610		1,120,248	1.3%	1,067,404	0.2%	4.7%	215.1	-3.40%	59.5%
2006	175,858	902,401	3,650		1,122,704	0.2%	1,081,908	1.4%	3.6%	222.9	3.63%	57.5%
2007	172,599	879,751	3,615		1,106,526	-1.4%	1,055,964	-2.4%	4.6%	235.4	5.60%	53.7%
2008	174,402	834,137	3,567		1,046,506	-5.4%	1,012,106	-4.2%	3.3%	213.4	-9.33%	55.8%
2009	165,507	747,614	3,605		947,569	-9.45%	916,726	-9.42%	4.0%	204.5	-4.19%	56.4%
2010	168,625	783,398	3,633	7,008	987,735	4.24%	955,656	4.25%	3.4%	201.2	-1.58%	56.0%
2011	169,132	810,048	3,647	13,140	1,015,818	2.84%	982,826	2.84%	3.4%	207.0	2.84%	56.0%
2012	170,611	860,744	3,656	98,988	1,106,087	8.89%	1,070,163	8.89%	3.4%	225.4	8.89%	56.0%
2013	173,000	894,777	3,665	156,642	1,168,155	5.61%	1,130,216	5.61%	3.4%	238.0	5.61%	56.0%
2014	174,586	920,193	3,674	190,124	1,204,409	3.10%	1,165,292	3.10%	3.4%	245.4	3.10%	56.0%
2015	175,996	942,204	3,683	190,124	1,228,626	2.01%	1,188,723	2.01%	3.4%	250.3	2.01%	56.0%
2016	177,432	961,437	3,693	190,124	1,249,999	1.74%	1,209,402	1.74%	3.4%	254.7	1.74%	56.0%
2017	179,048	980,181	3,704	190,124	1,271,054	1.68%	1,229,773	1.68%	3.4%	259.0	1.68%	56.0%
2018	180,994	998,435	3,716	190,124	1,291,944	1.64%	1,249,984	1.64%	3.4%	263.2	1.64%	56.0%
2019	182,882	1,017,167	3,729	190,124	1,313,270	1.65%	1,270,617	1.65%	3.4%	267.6	1.65%	56.0%
2020	184,572	1,035,186	3,742	190,124	1,333,654	1.55%	1,290,339	1.55%	3.4%	271.7	1.55%	56.0%
2021	186,272	1,052,249	3,755	190,124	1,353,061	1.46%	1,309,116	1.46%	3.4%	275.7	1.46%	56.0%
2022	188,050	1,068,985	3,769	190,124	1,372,211	1.42%	1,327,644	1.42%	3.4%	279.6	1.42%	56.0%
2023	189,916	1,085,849	3,783	190,124	1,391,583	1.41%	1,346,387	1.41%	3.4%	283.5	1.41%	56.0%
2024	191,762	1,102,603	3,798	190,124	1,410,823	1.38%	1,365,002	1.38%	3.4%	287.4	1.38%	56.0%
2025	193,740	1,120,081	3,812	190,124	1,430,947	1.43%	1,384,472	1.43%	3.4%	291.5	1.43%	56.0%
2026	195,658	1,137,180	3,827	190,124	1,450,618	1.37%	1,403,505	1.37%	3.4%	295.5	1.37%	56.0%
2027	197,595	1,153,505	3,841	190,124	1,469,508	1.30%	1,421,781	1.30%	3.4%	299.4	1.30%	56.0%
2028	199,736	1,169,683	3,857	190,124	1,488,457	1.29%	1,440,115	1.29%	3.4%	303.3	1.29%	56.0%
2029	201,849	1,185,735	3,872	190,124	1,507,247	1.26%	1,458,295	1.26%	3.4%	307.1	1.26%	56.0%
2030	203,946	1,201,954	3,886	190,124	1,526,194	1.26%	1,476,626	1.26%	3.4%	310.9	1.26%	56.0%

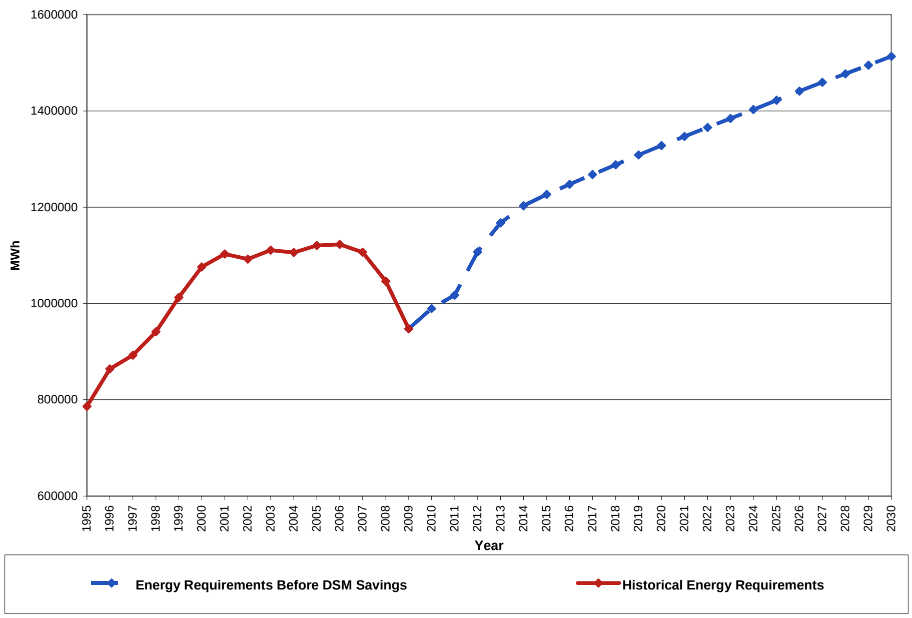

Figure 3-1
Historical and Forecast Total Energy

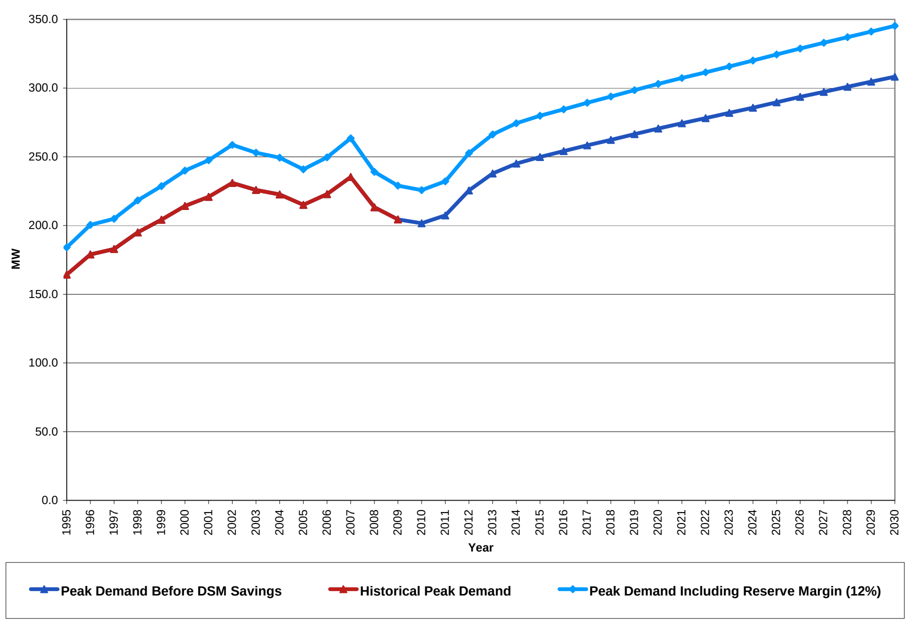

Figure 3-2
Historical and Forecast Peak Demand

3.1.3 Results Versus the Previous Forecast

The values determined in this load forecast were compared with the most recent prior projections, made by R.W. Beck, Inc. (Beck) in its Integrated Holland Load Forecast (2003). Overall, the current projection is lower than that of 2003. For example, the current projection for total energy requirements is approximately 30.9 percent less than the Beck projection in 2020, the last year of the Beck forecast. Similarly, the Beck peak load forecast of 393.4 MW in 2020 is well above the 310.9 MW peak demand figure in the current forecast. A few of the primary reasons for the differences in growth rates are that the previous forecast overestimated the energy requirements in the period from 2003 to 2008. Consequently, the historical energy requirements for 2008 were approximately 30 percent below that of the Beck projected data. In addition, the Beck projections did not account for the current economic recession, while the current forecast assumes that the economy will not fully recover until the 2012 time frame.

3.2 City of Holland IRP - Demand-Side Strategy

3.2.1 Short-Term Strategy and Projections

In April 2009, the HBPW submitted to the Michigan Public Service Commission an Energy Optimization Plan that projected savings of up to 9,169 MWh by the year 2012. The optimization plan was designed to provide energy savings through a portfolio of proven cost-effective measures consistent with the industry's practices, specifically designed to minimize free-ridership by motivating the public to pursue higher efficiency projects that would not be implemented in the absence of the measures, or to accelerate their implementation in case the measure had been considered and saved for a future opportunity. The proposed plan includes a series of EE measures that can be grouped in three EE modules: Residential Low Income Programs, Residential Solutions Programs, and Business Solutions Programs.

The Residential Low Income Program is designed to provide funding to support electric EE upgrades to customers with limited incomes. The program will be implemented with the support of local weatherization and faith-based agencies and will serve a diverse customer base whose income is estimated at 200 percent above the poverty level. This program will account for 8 percent of the overall plan budget and is expected to deliver savings of up to 186,954 kWh by 2012.

For the remainder of the residential customers, HBPW is offering efficient lighting, refrigerator/freezer turn-in and recycling, high efficiency appliances and electronics incentives, high efficiency HVAC (heating, ventilating, and air conditioning) incentives, and education measures. HBPW also has offerings for multi-family units and will continue to monitor the market in order to pilot emerging technology programs. All of the residential measures (low-income included) are expected to provide savings of up to 2,873,753 kWh in 2012.

For commercial customers, HBPW offers incentives to increase the market share of 126 well-known commercial high efficiency technologies in the areas of lighting, HVAC, motors, drivers, and food services. Additionally, HBPW will support site-specific unique EE technologies and/or process improvements. Finally, HBPW will undertake education measures to provide EE information to the business community and will continue to monitor the market for emerging technologies that could be implemented in pilot programs. All commercial measures are expected to provide savings of up to 6,296,148 kWh in 2012.

HBPW will use implementation contractors to administer these programs and will use a contractor for the evaluation, measurement, and verification in support of this initiative.

3.2.2 Long-Term Strategy and Projections

A detailed specific DSM and EE study for the city of Holland was beyond the scope of this study. As a result, Black & Veatch considers it to be reasonable for HBPW to use the Electric Power Research Institute (EPRI) Assessment of Achievable Potential from EE and Demand Response Programs in the US for 2010-2030 (EPRI Report) to forecast projected savings over the long term in the HBPW service territory. The EPRI report states that DSM programs have the potential to reduce the annual growth rate of summer peak demand from a historical 2.1 percent growth rate per year from 1996 to 2006 to a realistically achievable growth rate of less than 1.0 percent per year from 2009 to 2030. Achieving these savings in electricity consumption and peak demand will require significant industry investment in EE and demand response programs. In addition, it is likely that EE legislation will need to be adopted for Michigan state building codes so that certain performance metrics can be achieved with new construction.

The EPRI Report, released in 2009, describes the EE potential of the entire nation for the years 2010, 2020, and 2030. That study focuses on types of measures instead of proposing specific programs or equipment adoptions, and reaches its conclusions by considering likely expectations on adoption, potential emerging efficiencies, and the energy intensities of the technologies affected by these emerging alternatives. The study was structured to address specific savings potentials for the residential, commercial, and industrial sectors.

One of the advantages of using the EPRI Report for projecting HBPW savings over the long-term scenario is that EPRI goes beyond estimating the technical potential of DSM measures by determining the economic potential, the maximum achievable potential, and the realistic achievable potential (RAP). The RAP results are used in this study for forecasting EE savings after 2015, as discussed below. Specifically, EPRI concludes that, for 2010, it is realistic to expect 0.5 percent electricity load reductions due to DSM measures. By 2020, EPRI expects that percentage to grow to 4.8 percent, and eventually reach 8.2 percent by 2030. Table 3-2 lists the potential savings estimates over the next 20 years.

Table 3-2
Energy Efficiency Potential Estimates as Percentage of Energy Requirements

Year	2010	2020	2030
RAP	0.5	4.8	8.2

Source: EPRI Report.

The percentages shown in Table 3-2 are for total energy requirements and, as such, this study assumes that these reductions will apply directly to the HBPW load forecast beyond 2015. Table 3-3 breaks down the savings by the three major customer categories.

Table 3-3
Sector of Origin for DSM Savings under RAP

Year	2010	2020	2030
Residential	0.8	3.9	7.8
Commercial	0.4	5.1	8.7
Industrial	0.2	4.0	7.1

Source: EPRI Report.

According to the EPRI Report, the average US household in 2008 consumed 12,500 kWh of electricity. The majority of this electricity was consumed by cooling and "other" applications. It is expected that the "other" uses (including small appliances, device chargers, and plug loads) will be better understood as the result of current and future research on these end-uses, and that this understanding will open a door to future efficiency opportunities. EPRI estimates for commercial applications show that the lighting intensity per square foot is expected to diminish between 2010 and 2030, but that this effect will be dampened by an increase in the intensity of other commercial office equipment.

In the Energy Information Administration (EIA) Annual Energy Outlook 2009, the EIA has forecast a steady decline in energy use per dollar of GDP, which is also supported by historical energy intensity decline. This projection of energy intensity was also incorporated into the baseload forecast for commercial and industrial loads, as discussed previously. Figure 3-3 shows the projected energy intensity for each year up to 2030.

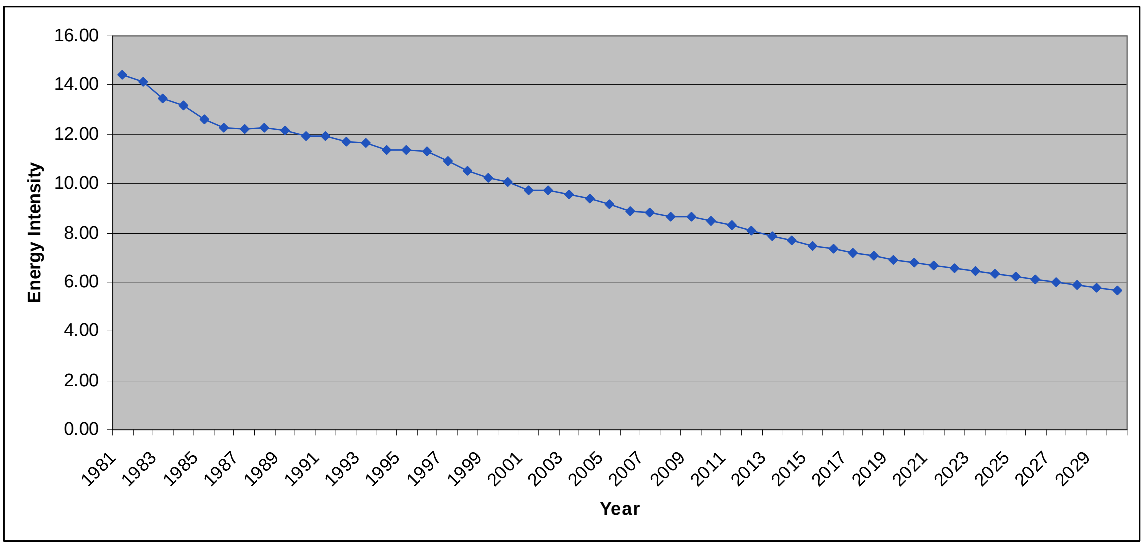

Figure 3-3
Historical and Forecast Energy Intensity

The industrial sector is the only one studied by EPRI that is expected to experience a decline in its electricity intensity baseline between 2008 and 2030. This decline is most likely associated with new environmental and economic constraints. In spite of the declining trend, EPRI expects that the industrial sector will obtain even greater reductions in its electric intensity through the implementation of EE measures.

3.2.3 Consideration of Michigan Public Act 295 (PA 295)

The state of Michigan passed an act that became effective on October 6, 2008. This act requires certain providers of electricity, including HBPW, to establish renewable and EE programs. This "clean, renewable, and efficient energy act" sets regulated guidelines for DSM programs. Accordingly, these DSM programs must achieve the following minimum energy savings:

- Annual incremental energy savings in 2010 equivalent to 0.5 percent of total annual retail electricity sales in MWh in 2009.
- Annual incremental energy savings in 2011 equivalent to 0.75 percent of total annual retail electricity sales in MWh in 2010.
- Annual incremental energy savings in 2012, 2013, 2014, and 2015 equivalent to 1 percent of total annual retail electricity sales in MWh in the preceding year.

When developing the net demand and energy forecast, these energy savings amounts were assumed to be achieved each year as required.

3.2.4 Resulting Net Energy Forecast

The PA 295 savings requirements were used to reduce the baseline net energy forecast through 2015. Thereafter, DSM savings for years 2016 to 2030 were assumed to achieve EPRI's forecast RAP DSM savings each year. Figure 3-4 shows the effects of the MAP, RAP DSM savings, and EE requirements of PA 295 on the base energy forecast discussed previously.

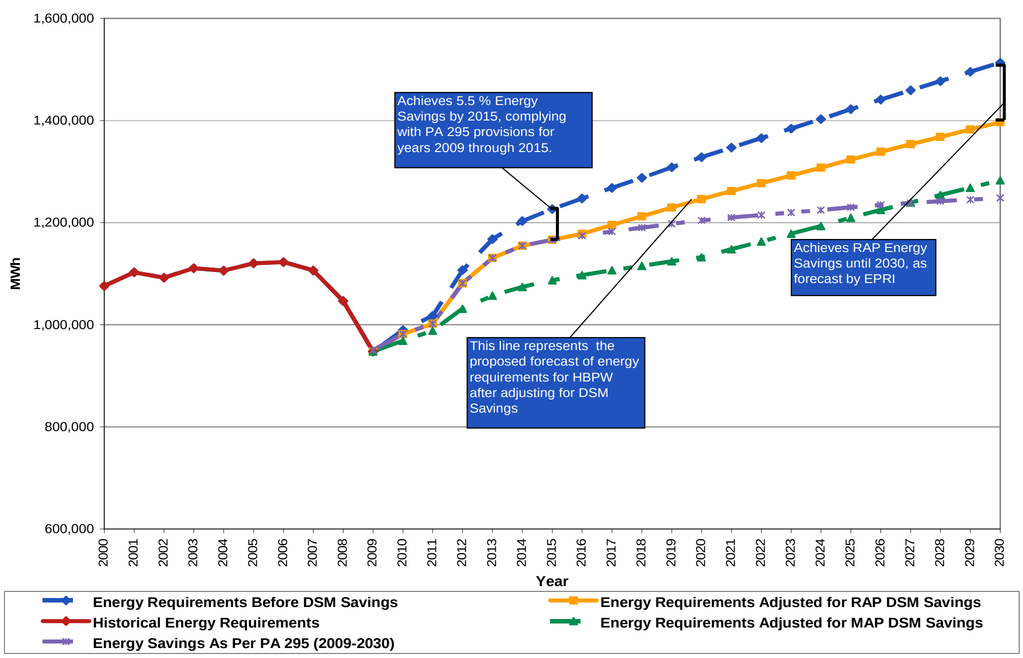

Figure 3-4
Net System Energy Requirements for HBPW after MAP, RAP DSM Savings and Energy Savings Proposed by Michigan PA 295

3.2.5 Resulting Net Peak Demand Forecast

The peak demand, described as the maximum energy required to service the utility's load during its busiest hour, must be accounted for when planning to maintain a reserve margin requirement. The peak demand model incorporates peak savings corresponding to the energy saving requirements of PA 295 from 2010 to 2015 by keeping the system load factor constant at the 2009 level. Beyond 2015, the model incorporates EPRI's RAP DSM savings forecast for peak demand. Peak demand for the years 2010 to 2015 was estimated by holding the load factor for 2009 constant and utilizing the following relationship:

$$LoadFactor = \frac{YearlyTotalDemand}{PeakDemand * 8760 Hours}$$

Figure 3-5 shows the resultant peak load forecast used in the analysis, including the effects of MAP and RAP DSM savings on peak demand and a system reserve margin of 12 percent. This reserve margin requirement is consistent with Midwest Independent Transmission System Operator (MISO) planning reserve margins.

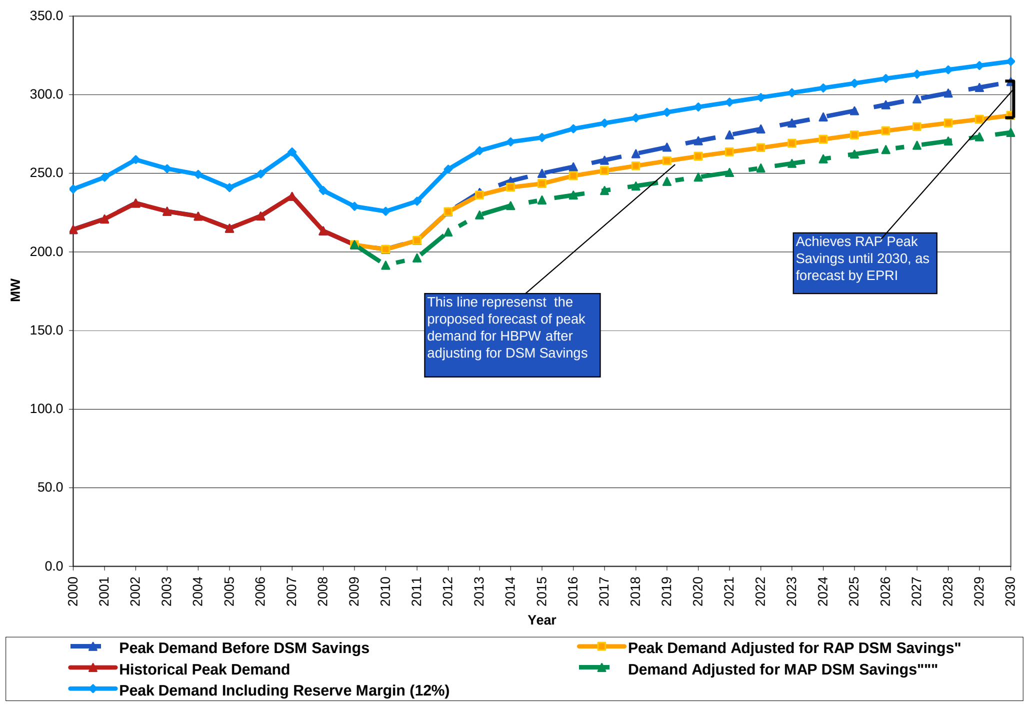

Figure 3-5
MAP and RAP DSM Savings on Peak Demand and System Reserve Margin

4.0 Need for Capacity

HBPW requires a plan to achieve desired levels of capacity in upcoming years to meet its peak demand. HBPW must maintain an additional margin of capacity should unforeseen events result in higher system demand or lower than anticipated available capacity. This section presents the development and analysis of the reliability criteria used by HBPW.

HBPW has historically used a 12 percent reserve margin of capacity. For this Power Supply Study, HBPW will use the 12 percent reserve margin for planning in the summer season. The planning reserve margin covers uncertainties such as extreme weather, forced outages for generators, and uncertainty in load projections. HBPW plans to maintain the 12 percent reserve margin for firm load obligations.

4.1 Development of Reliability Criteria

The most commonly used deterministic method to calculate a utility's system reliability is the reserve margin method, which is calculated as follows:

$$\frac{\text{System Net Capacity} - \text{System Firm Peak Demand (After Interruptible Load)}}{\text{System Firm Peak Demand (After Interruptible Load)}}$$

If the net capacity or the firm peak demand deviates from predicted levels, the actual reserve margin will vary. For a relatively small or isolated utility system, an unanticipated plant outage or higher than expected growth in system demand can quickly reduce or eliminate the planned reserve margin. This formula calculates the reserve margin at a given point in time, but it does not indicate what the appropriate reserve margin is for a given system.

4.2 Reliability Need

To determine HBPW's need for power, a forecast of system peak demand was developed. The forecast of system peak demand was developed through 2030, as discussed in Section 3.1. The baseline forecast was adjusted for potential DSM savings, which is discussed in Section 3.2. The resultant net peak forecast after adjusting for the DSM savings is assumed to be the final peak forecast for HBPW.

As discussed in Section 2.0, HBPW will have about 273 MW of available summer capacity in 2010 from its existing resources and PPAs. Additional incremental capacity from the NANR and Granger landfill gas PPA will increase the total available summer capacity to approximately 278 MW by 2018.

If no new units are added to the HBPW portfolio, the required 12 percent reserve margin will be maintained up until 2015. A yearly breakdown of peak demand, total available capacity, and reserve margins are shown in Table 4-1. The table shows that HBPW would need additional capacity from 2016 onward to meet its reliability criteria. If no units are added between now and 2027, the installed capacity on the HBPW system will fall below its system peak requirements in 2027. Figure 4-1 breaks down the existing resources according to the different primary fuels burned by them.

The capacity balance establishes that HBPW would need additional capacity in 2016 to meet its forecast reliability needs. Based on this assessment, Black & Veatch considered various scenarios, which are discussed in subsequent sections of this report.

Table 4-1
HBPW Capacity Balance Based on Summer Capacity of Existing and Committed Resources

Year	Forecast Peak Demand Before DSM (MW)	DSM Peak Savings (MW)	Peak Demand After DSM (MW)	12.0% Reserves (MW)	Total Peak + Reserves (MW)	Total Existing Coal Fired Capacity (MW)	Total Existing Natural Gas Fired Capacity (MW)	Total Existing Distillate Fuel Oil Fired Capacity (MW)	Total Existing PPA Capacity from Landfill Gas Units(MW)	Capacity Bought (MW)	Capacity Sold (MW)	Total Available Capacity (MW)	Excess/ (Deficit) Capacity to Maintain 12% Reserve Margin (MW)	Reserve Margin
2010	201.6	0.0	201.6	24.2	225.8	102.7	147.0	18.0	5.1	0.0	0.0	272.8	47.0	35.3%
2011	207.3	0.0	207.3	24.9	232.2	102.7	147.0	18.0	6.3	0.0	0.0	274.0	41.8	32.2%
2012	225.5	0.0	225.5	27.1	252.6	102.7	147.0	18.0	7.6	0.0	0.0	275.3	22.7	22.1%
2013	237.9	1.8	236.1	28.3	264.4	102.7	147.0	18.0	7.9	0.0	0.0	275.6	11.1	16.7%
2014	245.1	4.0	241.1	28.9	270.0	102.7	147.0	18.0	8.7	0.0	0.0	276.4	6.4	14.7%
2015	249.9	6.4	243.5	29.2	272.7	102.7	147.0	18.0	9.0	0.0	0.0	276.7	4.0	13.6%
2016	254.2	5.7	248.5	29.8	278.3	102.7	147.0	18.0	9.3	0.0	0.0	277.0	(1.3)	11.5%
2017	258.3	6.7	251.6	30.2	281.8	102.7	147.0	18.0	9.6	0.0	0.0	277.3	(4.5)	10.2%
2018	262.4	7.7	254.7	30.6	285.3	102.7	147.0	18.0	9.8	0.0	0.0	277.5	(7.8)	8.9%
2019	266.6	8.7	257.9	30.9	288.8	102.7	147.0	18.0	9.8	0.0	0.0	277.5	(11.3)	7.6%
2020	270.6	9.7	260.9	31.3	292.2	102.7	147.0	18.0	9.8	0.0	0.0	277.5	(14.7)	6.4%
2021	274.4	10.8	263.6	31.6	295.3	102.7	147.0	18.0	9.8	0.0	0.0	277.5	(17.8)	5.3%
2022	278.2	11.9	266.3	32.0	298.3	102.7	147.0	18.0	9.8	0.0	0.0	277.5	(20.8)	4.2%
2023	282.0	13.0	269.0	32.3	301.3	102.7	147.0	18.0	9.8	0.0	0.0	277.5	(23.8)	3.2%
2024	285.8	14.2	271.6	32.6	304.2	102.7	147.0	18.0	9.8	0.0	0.0	277.5	(26.7)	2.2%
2025	289.7	15.4	274.4	32.9	307.3	102.7	147.0	18.0	9.8	0.0	0.0	277.5	(29.8)	1.1%
2026	293.6	16.6	277.0	33.2	310.3	102.7	147.0	18.0	9.8	0.0	0.0	277.5	(32.8)	0.2%
2027	297.3	17.8	279.5	33.5	313.1	102.7	147.0	18.0	9.8	0.0	0.0	277.5	(35.6)	-0.7%
2028	301.0	19.0	282.0	33.8	315.8	102.7	147.0	18.0	9.8	0.0	0.0	277.5	(38.3)	-1.6%
2029	304.6	20.3	284.4	34.1	318.5	102.7	147.0	18.0	9.8	0.0	0.0	277.5	(41.0)	-2.4%
2030	308.3	21.6	286.7	34.4	321.2	102.7	147.0	18.0	9.8	0.0	0.0	277.5	(43.7)	-3.2%

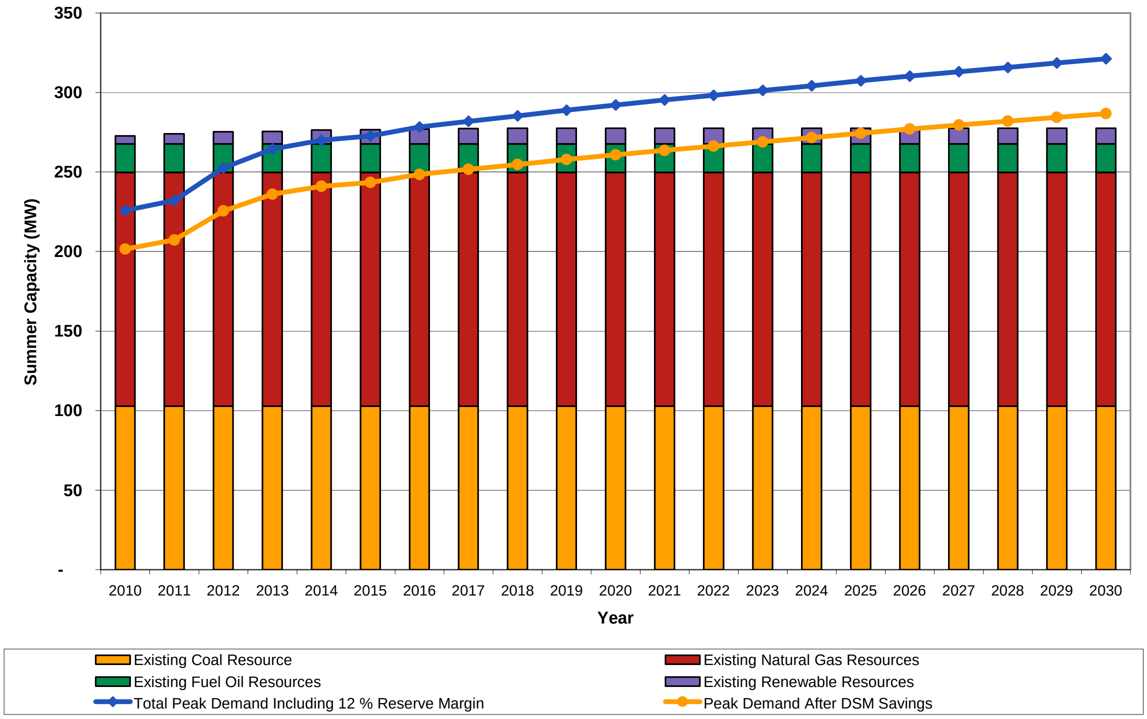

Figure 4-1
Existing and Committed Capacity Resources by Fuel Type

5.0 Technology Screening

This section provides an overview and analysis of various renewable and conventional energy technologies, including the following:

- Solid biomass (direct-fired and co-firing).
- Landfill gas (LFG).
- Wind (onshore and offshore).
- Solar (solar thermal and solar PV).
- Hydroelectric.
- Wave energy.
- Simple cycle.
- Combined cycle.
- Supercritical coal.
- CFB.
- Nuclear.

Generally, each technology is described with respect to its operating principles, applications, resource availability in Michigan, cost and performance characteristics, and environmental impacts. Estimates for costs and performance parameters were based on Black & Veatch project experience, past vendor inquiries, and a literature review. Capital costs are in 2009 dollars and reflect the total project cost, including direct and indirect costs, plus an allowance for owner's costs.

5.1 Renewable Technologies

Renewable energy technologies are diverse; they include wind, solar, biomass, biogas, geothermal, hydroelectric, and ocean energy. The technical feasibility and cost of energy from nearly every form of renewable energy has improved since the early 1980s. However, most renewable energy technologies struggle to compete economically with conventional fossil fuel technologies and, in most countries, the renewable fraction of total electricity generation remains small. Nevertheless, the field is rapidly expanding from occupying niche markets to making meaningful contributions to the world's electricity supply.

Available Federal Incentives

A number of financial incentives are available for the installation and operation of renewable energy technologies. The following discussion summarizes the federal tax-related incentives that are available to new renewable energy facilities. Entities that are not subject to taxes, such as HBPW, are not able to directly take advantage of many incentives. However, there are some incentives that apply to tax-exempt entities. By working with taxable entities via co-ownership or PPAs, HBPW may be able to find optimal ways of utilizing the incentives to lower the cost of energy.

Tax-Related Incentives

The predominant incentive offered by the federal government for renewable energy has been through the US tax code in the form of tax deductions, tax credits, or accelerated depreciation. An advantage of this form of incentive is that it is defined in the tax code and is not subject to annual congressional appropriations or other limited budget pools (such as grants and loans). Tax-related incentives include the Section 45 Production Tax Credit (PTC), Section 48 Investment Tax Credit (ITC), and accelerated depreciation. The ability to utilize tax credits is limited not only by specific legal considerations, but also by practical considerations. For example, it can be difficult to line up the risks and benefits of a specific transaction with the appropriate participants and their tax status.

With the recent passage of the American Recovery and Reinvestment Act (also known as the Stimulus Package) in February 2009, many of these benefits were either extended and/or expanded. In addition, a grant is available, valued up to 30 percent of the cost of a project, that is paid to the developer at the beginning of a project. For wind projects, many of these benefits will apply to projects that come on line by the end of 2012. As a result, there will be an urgency to site, permit, and develop such projects within the next 3 years.

American Recovery and Reinvestment Act of 2009

The key provisions of the Stimulus Package are focused on moving renewable projects ahead in the next 3 years by expanding development incentives to a wider range of investors. Investors will be able to choose from one of three large incentive mechanisms described below to offset the cost of renewable energy projects:

1. **PTC Time Frame--**The time frame by which projects must be placed into service to take advantage of the PTC incentive ($10 to $21/MWh, depending on the renewable resource) has been extended by 3 years. Projects in operation by the end of 2012 (wind) or 2013 (most others) can claim this credit.
2. **ITC to Include More Resources--**In lieu of the PTC, renewable energy developers can opt to use the ITC, equal to 30 percent of the capital cost of the project. Although this option was historically only available to solar projects, most other renewable resources (including wind, biomass,

geothermal, and anaerobic digestion) can now apply it toward their projects. Developers will be able to take full advantage of this funding option regardless of whether other subsidies, typically at the state level, are being utilized. This has the same project development time line as the PTC.

3. **30 Percent Grant Program--**A major issue with the ITC was that it was only appealing to investors with a large tax burden that could apply the credit. With the economic downturn, the number of these types of investors has decreased considerably. The Stimulus Package includes a new grant program equal in size to the ITC (30 percent of the capital cost) that US taxpayers can apply for in lieu of the PTC or ITC, expanding interest to a much broader set of investors. To qualify, projects must begin "construction" by the end of 2010, although the parameters of "construction" are still being defined. Grants will come from the Treasury Department and will not be distributed until the project is placed into service. The details of the grant program are still being developed, so any restrictions associated with the grant program are unknown at this time.

In addition to these Stimulus Package incentives, to help counter the difficulties facing the financial sector, renewable projects will be able to benefit from an expanded loan guarantee program. An estimated $60 to $150 billion of loans could stem from this US Department of Energy (DOE)-administered program to support renewables. Secretary of Energy Chu has already announced a planned overhaul to the loan guarantee system to more rapidly mobilize funding. The impact will be to reduce the interest rate for renewable projects.

Other Tax Benefits

In addition to the direct incentives that projects can receive, special tax treatment for renewable energy projects will also help improve project economics:

1. **5 Year MACRS (Modified Accelerated Cost Recovery System, i.e., Accelerated Depreciation)--**This allows projects that are normally depreciated over 20 years to be depreciated at an accelerated rate and over only 5 years, which helps to improve project returns.
2. **50 Percent Bonus Depreciation for 2009--**As part of the Stimulus Package, wind projects that come on line by 2009 can also benefit from a 50 percent bonus depreciation during the first year of the project. MACRS will apply to the remaining tax basis.

Tax-Exempt Entities — Structures and Incentives

For tax-exempt entities, such as municipals and cooperatives, that cannot directly take advantage of incentives to reduce income taxes, there are alternative programs and incentives offered by the federal and state government, albeit with certain funding caps.

Clean Renewable Energy Bonds (CREBs)

The Energy Improvement and Extension Act of 2008 allocated $800 million for new CREBs.[3] The American Recovery and Reinvestment Act of 2009 allocated an additional $1.6 billion for CREBs. The Internal Revenue Service has yet to announce dates for accepting new applications for the new allocations. Key features of CREBs for purposes of financial modeling are as follows:

- CREBs are essentially equivalent to zero-interest loans for financing qualified energy projects.[4]
- The maximum term of the bond is calculated through a formula developed by the Treasury Department and is updated daily on the following Web site: https://www.treasurydirect.gov/SZ/SPESRates?type=CREBS.
- At current interest rates, the maximum term is approximately 15 years.
- The payments are equal annual installments based on the term of the bond, and repayment begins during the first year following bond issuance—not when the project comes on line.
- Although CREBs are issued without interest costs, there may be transaction costs and discounts necessary, depending on the market's perception of the underlying credit of the borrower or issuer. Note: These costs may add 1 to 2 percent to the project cost that is paid back each year.
- Ninety-five percent of the CREB proceeds must be spent on qualifying capital expenditures and within 5 years of receiving the allocation.
- The allocation of funds will be based on ranking eligible projects from smallest to largest dollar amount of CREBs requested, with the smallest getting first priority.[5] The maximum allocation to a single project for the last round of applicants was $30 million. This means that larger projects (>$30 million) will likely not be able to be fully funded through CREBs alone.

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[3] The Energy Improvement and Extension Act of 2008 also extended the deadline for previously reserved allocations until December 31, 2009.
[4] The value of the CREB to a bondholder for any year is equal to the credit, less the amount of tax payable on the credit.
[5] For the 2007 allocations, refer to http://www.irs.gov/pub/irs-tege/creb_2007_disclosure.pdf.

Other

In addition to CREBs, tax-exempt entities could possibly qualify for the following additional incentives, although the allocation to any single project is limited for larger renewable energy projects:

- **Federal Renewable Energy Production Incentive (REPI)--**REPI provides incentive payments for electricity produced and sold by new qualifying renewable energy facilities. Qualifying systems are eligible for annual incentive payments of 1.5¢ per kilowatt-hour (in 1993 dollars and indexed for inflation) for the first 10 year period of their operation, subject to the availability of annual appropriations in each federal fiscal year of operation. Eligible electric production facilities include not-for-profit electrical cooperatives; public utilities; state governments; commonwealths; territories; possessions of the United States, the District of Columbia, Indian tribal governments, or a political subdivision thereof; and Native Corporations. Two significant limits to the REPI include (1) the production payment applies only to the electricity sold to another entity, and (2) while REPI mirrors the PTC in concept, REPI payments will be for a portion of requested incentives because they are subject to annual appropriations. In 2007, the payout to applicants totaled less than 20 percent of total requests.
- **Rural Energy for America Program (REAP)--**REAP promotes EE and renewable energy for agricultural producers and rural small businesses through the use of (1) grants and loan guarantees for EE improvements and renewable energy systems, and (2) grants for energy audits and renewable energy development assistance. Congress has allocated funding for the new program in the following amounts: $55 million for fiscal year 2009, $60 million for fiscal year 2010, $70 million for fiscal year 2011, and $70 million for fiscal year 2012. The REAP is administered by the US Department of Agriculture (USDA). Since the annual funding allocation is small, the USDA is likely not to fund large wind projects.

5.1.1 Biomass

Biomass is any material of recent biological origin; the most common form is wood. Electricity generation from biomass is the second most prolific source of renewable electric generation after hydroelectric power. Solid biomass power generation options include direct-fired biomass, co-fired biomass, and biomass gasification. Direct and co-fired biomass are described in the following subsections.

5.1.1.1 Direct-Fired Biomass. According to the US DOE, there is approximately 35,000 MW of installed biomass combustion capacity worldwide.[6] Combined heat and power applications in the pulp and paper industry comprise the majority of this capacity.

Operating Principles

Direct biomass combustion power plants in operation today use the same steam Rankine cycle that was introduced commercially 100 years ago. In many respects, biomass power plants are similar to other solid fuel plants. When burning biomass, pressurized steam is produced in a boiler and then expanded through a turbine to produce electricity. Prior to its combustion in the boiler, the biomass fuel may require processing to improve the physical and chemical properties of the feedstock. Furnaces used in biomass combustion include spreader stoker fired, suspension fired, fluidized bed, cyclone, and pile burners. Advanced technologies, such as integrated biomass gasification combined cycle and biomass pyrolysis, are currently under development; however, there are no integrated gasification combined cycle (IGCC) plants currently operating with biomass as a primary fuel.

Applications

Although wood is the most common biomass fuel, other biomass fuels include agricultural residues such as bagasse (sugar cane residues), dried manure and sewage sludge, black liquor from pulp mills, and dedicated fuel crops such as fast growing grasses and eucalyptus.

Biomass plants usually have a capacity of less than 50 MW because of the dispersed nature of the feedstock and the large quantities of fuel required. As a result of the smaller scale of the plants and lower heating value of the fuels, biomass plants are typically less efficient than modern fossil fuel plants. In addition to being less efficient, biomass is generally more expensive than conventional fossil fuels on a $/MBtu basis, if sited over 75 miles from the fuel source, because of added transportation costs. These factors usually limit the use of direct-fired biomass technology to inexpensive or waste biomass sources.

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[6]US Department of Energy, Oak Ridge National Laboratory, "Biomass Frequently Asked Questions," available at: http://bioenergy.ornl.gov/.

Resource Availability

To be economically feasible, dedicated biomass plants are generally located either at the source of a fuel supply (such as a sawmill) or within 100 miles of numerous suppliers. Wood and wood waste are the primary biomass resources and are typically concentrated in areas of high forest product industry activity. In rural areas, agricultural production can often yield significant fuel resources that can be collected and burned in biomass plants. These agricultural resources include bagasse, corn stover, rice hulls, wheat straw, and other residues. Energy crops, such as switchgrass and short rotation woody crops, have also been identified as potential biomass sources. In urban areas, biomass typically consists of wood wastes such as construction debris, pallets, yard and tree trimmings, and railroad ties. Locally grown and collected biomass fuels are relatively labor-intensive and can provide substantial employment benefits to rural economies. In general, the availability of sufficient quantities of biomass is less of a feasibility concern than the high costs associated with the transportation and delivery of the fuel.

Like other Midwestern states, Michigan has a relatively strong supply of biomass resources, including large amounts of urban wood waste in more heavily populated areas. The expected cost of clean wood residues can vary by up to 50 percent, depending on the type of residue, quantity, and hauling distance. A base delivered value of $3.00/MBtu was assumed in this analysis.

Cost and Performance Characteristics

Table 5-1 presents the typical characteristics of a 30 MW boiler biomass plant with a Rankine cycle using wood waste as fuel.

Environmental Impacts

Biomass power projects must maintain a careful balance to ensure long-term sustainability with minimal environmental impact. Most biomass projects target the use of biomass waste material for energy production, saving valuable landfill space. Biomass projects that burn forestry or agricultural products must ensure that both fuel harvesting and collection practices are sustainable and do not adversely affect the environment.

Unlike fossil fuels, biomass is viewed as a carbon-neutral power generation fuel. While CO_2 is emitted during biomass combustion, a nearly equal amount of CO_2 is absorbed from the atmosphere during the biomass growth phase. Further, biomass fuels contain little sulfur compared to coal and, therefore, produce less SO_2. Finally, unlike coal, biomass fuels typically contain only trace amounts of toxic metals, such as mercury, cadmium, and lead. However, biomass combustion still must include technologies to control emissions of NO_x, particulate matter (PM), and carbon monoxide (CO) to maintain Best Available Control Technology (BACT) standards.

Table 5-1
Direct Biomass Combustion Technology Characteristics

Performance	
Typical Duty Cycle	Baseload
Net Plant Capacity (MW)	35 to 75
Net Plant Heat Rate (HHV, Btu/kWh)	14,500
Capacity Factor (percent)	80 to 90
Economics ($2009)	
Total Project Cost ($/kW)	4,500 to 5,100
Fixed O&M ($/kW-yr)	100
Variable O&M ($/MWh)	3
Levelized Cost(1) ($/MWh)	
Municipal	100 to 150
PPA(2)	120 to 150
Applicable Federal Incentives	Open loop: $10/MWh PTC or 30% ITC or 30% grant, 7 yr MACRS; Closed loop: $21/MWh PTC or 30% ITC or 30% grant, 7 yr MACRS
Technology Status	
Commercial Status	Commercial
Installed US Capacity (MW)	7,000

(1)The low ends of the levelized costs are based on a 90 percent capacity factor and a capital cost of $4,500/kW. The high ends of the levelized costs are based on a 70 percent capacity factor and a capital cost of $5,100/kW. Fuel cost is assumed to be $3.00/MBtu.
(2)Assumes that the project can take advantage of federal tax incentives to reduce the cost of energy.

5.1.1.2 Biomass Co-firing. One of the most economical methods to burn biomass is to co-fire it with coal in existing plants. However, burning biomass with coal does not increase the capacity of the existing plants. It only helps in reducing the quantity of coal burned in the plant and also reduces the carbon emissions from the plant. Co-fired projects are usually implemented by retrofitting a biomass fuel feed system to an existing coal plant, although greenfield facilities can also be designed to accept a variety of fuels.

As discussed in the previous subsection, a major challenge to biomass power is that the dispersed nature of the feedstock and high transportation costs can preclude plants larger than 50 MW. In comparison, coal power plants rely on the same fundamental power conversion technology, but can have much higher unit capacities, exceeding 1,000 MW. As a result of this larger capacity, modern coal plants are able to obtain higher efficiencies at lower cost. Through co-firing, biomass benefits from this higher efficiency through a more competitive cost than a stand-alone, direct-fired biomass plant.

Applications

Several methods of biomass co-firing can be used to produce energy on a commercial scale. Provided that they were initially designed with some fuel flexibility, stoker and fluidized bed boilers generally require minimal modifications to accept biomass. For these types of boilers, simply mixing the fuel into the coal pile may be sufficient to co-fire the biomass.

Cyclone boilers and PC boilers (the most common in the utility industry) require smaller fuel sizes than stokers and fluidized beds and may necessitate processing of the biomass before combustion. There are two basic approaches to co-firing in this case: co-feeding the biomass through the coal processing equipment or separately processing and then injecting the biomass into the boiler. The first approach blends the fuels and feed them together to the coal processing equipment (crushers, pulverizers, etc.). In a cyclone boiler, up to 10 percent of the coal heat input can be replaced with biomass using this method. Pulverizers in a PC boiler are not designed to process relatively low density biomass, and fuel replacement is generally limited to around 2 or 3 percent if the fuels are mixed. The second approach (separate biomass processing and injection) allows higher co-firing percentages (10 to 15 percent) in a PC unit, but costs more than processing a fuel blend.

Even at these limited co-firing rates, plant owners and operators have raised numerous concerns about the negative effects of co-firing on plant operations. These include the following:

- Reduced plant capacity.
- Reduced boiler efficiency.

- Ash contamination decreasing the quality of coal ash.
- Increased O&M costs.
- Minimal NO_x reduction potential (usually proportional to biomass heat input).
- Boiler fouling/slagging because of the high alkali in biomass ash (more of a concern with fast growing biomass, such as energy crops).
- Potentially negative effects on selective catalytic reduction (SCR) air pollution control equipment (catalyst poisoning).
- Reopening of existing air permits.

These concerns have hampered the widespread adoption of biomass co-firing by electric utilities in the United States. However, these concerns can often be addressed through proper system design, fuel selection, and limits on the amount of co-firing.

Coal and biomass co-firing can also be considered in the design of new power plants. Designing the plant to accept a diverse fuel mix allows the boiler to incorporate biomass fuel, ensuring high efficiency with low O&M impacts. Fluidized bed technology is often the preferred boiler technology for co-firing since it has inherent fuel flexibility. There are many fluidized bed units around the world that burn a wide variety of fuels, including biomass. An example is a 240 MW CFB in Finland, which burns a mixture of wood, peat, and lignite. This unit is capable of burning various fuels, ranging from 100 percent biomass to 100 percent coal.

Resource Availability

For viability, the candidate coal plant should be located within 100 miles of suitable biomass resources. The United States has a larger installed biomass power capacity than any other country in the world. US-based biomass power plants provide 7,000 MW of capacity to the national power grid. Coal power generation accounted for 2 trillion kWh in 2005, which comprised 49.7 percent of the total generation in the United States. Conversion of as little as 5 percent of this generation to biomass co-firing would increase electricity production from biomass by nearly 400 percent. Again, biomass co-firing does not produce new capacity; it changes the source of generation from coal to biomass.

Cost and Performance Characteristics

Table 5-2 presents the typical characteristics for a biomass and coal co-fired plant. The characteristics are based on co-firing 35 MW of biomass (separate injection) in a PC power project. Except for fuel, the characteristics are provided on an incremental basis (changes that would be expected compared to the coal plant). The primary capital cost for the project would be related to the biomass material handling system. As with direct-fired biomass, biomass fuel cost was assumed to be $3.00/MBtu for forestry residues.

Analysis of the range of levelized costs presented in Table 5-2 indicates that the costs to co-fire biomass with coal would be relatively small.

Table 5-2
Biomass Co-firing Technology Characteristics

Performance	
Typical Duty Cycle	Baseload
Net Plant Capacity (MW)	35
Net Plant Heat Rate (HHV, Btu/kWh)	Increase 0.5 to 1.5 percent
Capacity Factor (percent)	Unchanged
Economics ($2009)	
Total Project Cost ($/kW)	300 to 500
Variable O&M ($/MWh)	0 to 3
Fuel Cost ($/MBtu)	3.00
Levelized Cost(1) ($/MWh)	
Municipal	40 to 50
PPA(2)	30 to 40
Applicable Federal Incentives	None
Technology Status	
Commercial Status	Fully Commercial

(1)The low end of the levelized cost is based on a capital cost of $300/kW and O&M cost of $0/MWh. The high end is based on a capital cost of $500/kW and O&M cost of $3/MWh.
(2)Assumes that the project can take advantage of federal tax incentives to reduce the cost of energy.

Environmental Impacts

As with direct-fired biomass plants, the biomass fuel supply must be collected in a sustainable manner. Assuming this is the case, co-firing biomass in a coal plant generally has overall positive environmental effects. The clean biomass fuel typically reduces emissions of SO_2, CO_2, NO_x, and heavy metals such as mercury. Further, compared to other renewable resources, biomass co-firing directly offsets fossil fuel use. It may also provide an alternative to landfilling wastes, particularly wood wastes.

5.1.2 Landfill Gas

Operating Principles

LFG is produced by the decomposition of the organic portion of landfill waste. LFG typically has a methane content in the range of 45 to 55 percent. There is increased political and public pressure to reduce air and groundwater pollution and, as a result, many landfills already collect LFG. From a generating perspective, LFG is a valuable resource that can be burned as fuel by reciprocating engines, small gas turbines, or other devices. LFG energy recovery is currently regarded as one of the more mature and successful waste-to-energy (WTE) technologies. Currently, more than 600 LFG energy recovery systems have been installed in 20 countries.

Applications

LFG can be used to generate electricity and process heat or can be upgraded for pipeline sales. Power production from an LFG facility is typically less than 10 MW. Several types of commercial power generation technologies can be easily modified to burn LFG. Internal combustion engines are by far the most common generating technology choice. Approximately 75 percent of the landfills that generate electricity use internal combustion engines.[7] Depending on the scale of the gas collection facility, it may be feasible to generate power via a combustion turbine or a boiler and steam turbine. Testing with microturbines and fuel cells is also under way, although these technologies do not appear to be economically viable for power generation.

Resource Availability

Gas production at a landfill is dependent on the depth and age of the waste in place and the amount of precipitation received by the landfill. In general, LFG recovery may be economically feasible at sites that have more than 1 million tons of waste in place, more than 30 acres available for gas recovery, a waste depth greater than 40 feet, and at least 25 inches of annual precipitation.

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[7] EPA Landfill Methane Outreach Program, http://www.epa.gov/lmop/proj/index.htm.

Cost and Performance Characteristics

The economics of installing an LFG energy facility depend heavily on the characteristics of the candidate landfill. The payback period of an LFG energy facility at a landfill that has an existing gas collection system can be as short as 2 to 5 years, especially if environmental credits are available. However, the cost of installing a new gas collection system at a landfill can prohibit installing an LFG facility. Table 5-3 presents cost and performance estimates for typical LFG projects using reciprocating engines, the most common LFG technology. Fuel costs are assumed to be $2/MBtu.

Table 5-3
LFG Technology Characteristics

Performance	
Typical Duty Cycle	Baseload
Net Plant Capacity (MW)	0.2 to 15
Net Plant Heat Rate (HHV, Btu/kWh)	11,500
Capacity Factor (percent)	70 to 90
Economics ($2009)	
Total Project Cost ($/kW)	1,700 to 2,800
Fixed O&M ($/kW-year)	27
Variable O&M ($/MWh)	15
Levelized Cost(1) ($/MWh)	
Municipal	70 to 85
PPA(2)	60 to 90
Applicable Federal Incentives	$10/MWh PTC *or* 30% ITC *or* 30% grant
Technology Status	
Commercial Status	Commercial
Installed US Capacity (MW)	1,100

(1)The low end of the levelized cost is based on a net plant capacity of 15 MW, a 90 percent capacity factor, and a capital cost of $1,700/kW. The high end is based on a net plant capacity of 0.2 MW, a 70 percent capacity factor, and a $2,800/kW capital cost.
(2)Assumes that the project can take advantage of federal tax incentives to reduce the cost of energy.

Environmental Impacts

LFG combustion releases pollutants similar to many other fuels, but it is generally perceived as environmentally beneficial. Since LFG is principally composed of methane, if not combusted, LFG is released into the atmosphere as a greenhouse gas. As a greenhouse gas, methane is 23 times more harmful than CO_2. Collecting the gas and converting the methane to CO_2 through combustion greatly reduces the potency of LFG as a source of greenhouse gas emissions.

5.1.3 Wind

Operating Principles

Wind power systems convert the movement of air to power by means of a rotating turbine and a generator. Wind power has been the fastest growing energy source of the last decade, in percentage terms, with around 30 percent annual growth in worldwide capacity over the last 5 years. Cumulative worldwide wind capacity is now estimated to be more than 93,000 MW. Total installed wind capacity in the United States exceeded 21,000 MW as of October 2008. The US wind market has been driven by a combination of growing state mandates and the PTC, which provides an economic incentive for wind power. The PTC has been renewed several times and is currently set to expire on December 31, 2012.

Applications

Typical utility-scale wind energy systems consist of multiple wind turbines that range in size from 1 to 3 MW for onshore and up to 6 MW for offshore applications. Wind energy system installations may total 5 to 300 MW, although the use of single, smaller turbines is also common in the United States for powering schools, factories, water treatment plants, and other distributed loads. Furthermore, offshore wind energy projects are now being built in Europe and are planned in the United States, encouraging the development of larger turbines (up to 5 MW) and larger wind farm sizes.

Wind is an intermittent resource, with average capacity factors generally ranging from 20 to 40 percent. The capacity factor of an installation depends on the wind regime in the area and the energy capture characteristics of the wind turbine. Capacity factor directly affects economic performance; thus, reasonably strong wind sites are required for cost-effective installations. Since wind is intermittent, it cannot be relied upon as firm capacity for peak power demands at its nameplate capacity. To provide a dependable resource, wind energy systems may be coupled with some type of energy storage to provide power when required; however, this is not common and adds considerable expense to a system.

Resource Availability

Turbine power output is proportional to the cube of wind speed, which makes small differences in wind speed very significant. Wind strength is rated on a scale from Class 1 to Class 7, as shown in Table 5-4. Michigan is not a national leader in wind energy installations as a result of the available wind resources. Michigan has approximately 143 MW of installed wind power capacity, but large wind farms have been proposed. Wind resources are best in the coastal areas of the state. There are also significant offshore resources in Lake Michigan, Lake Superior, and Lake Huron, but offshore wind development to date is very rare in the United States. Winds in these areas are generally Class 5 and 6.

Table 5-4
US DOE Classes of Wind Power

Wind Power Class	Height Above Ground: 50 m (164 ft)[1]	
	Wind Power Density (W/m^2)	Speed[2] (m/s)
1	0 to 200	0 to 5.60
2	200 to 300	5.60 to 6.40
3	300 to 400	6.40 to 7.00
4	400 to 500	7.00 to 7.50
5	500 to 600	7.50 to 8.00
6	600 to 800	8.00 to 8.80
7	800 to 2000	$\geq$ 8.80

[1]Vertical extrapolation of wind speed based on the 1/7 power law, as defined in Appendix A of the *Wind Energy Resource Atlas of the US, 1991.*
[2]Mean wind speed is based on Rayleigh speed distribution of equivalent mean wind power density. Wind speed is for standard sea level conditions. To maintain the same power density, wind speed must increase 3 percent per 1,000 meters (5 percent per 5,000 ft) of elevation.

Cost and Performance Characteristics

Table 5-5 provides the typical characteristics for a 100 to 200 MW wind farm. Substantially higher costs are necessary for wind projects that require grid upgrades or long transmission tie lines. After several years of high price escalation, capital costs for new onshore wind projects have stabilized. Although the PTC has been extended recently, there is always some uncertainty regarding future extensions. Significant gains have been made in recent years in identifying and developing sites with better wind resources and improving turbine reliability. As a result, the average capacity factor for newly installed wind projects in the United States has increased from approximately 24 percent before 1999 to around 32 percent currently.

Environmental Impacts

Wind is a clean generation technology from the emissions perspective. However, there are still environmental considerations associated with wind turbines. Opponents of wind energy frequently cite visual impacts and noise as drawbacks. Turbines are approaching and exceeding heights of 400 feet and, for maximum wind capture, tend to be located on ridgelines and other elevated topography. Turbines can cause avian fatalities and other wildlife impacts if sited in sensitive areas. To some degree, these issues can be partially mitigated through proper siting, environmental review, and public involvement during the planning process.

5.1.4 Solar Thermal

Operating Principles

Solar thermal technologies convert the sun’s energy to electricity by capturing heat. Technological advances have expanded solar thermal applications to high magnitude energy collection and power conversion on a utility scale. The leading solar thermal technologies include parabolic trough, parabolic dish, power tower (central receiver), and solar chimney.

With adequate resources, solar thermal technologies are appropriate for a wide range of intermediate- and peak-load applications, including central station power plants and modular power stations in both remote and grid-connected areas. Commercial solar thermal parabolic trough plants in California currently generate more than 350 MW.

Most solar thermal systems (parabolic trough, parabolic dish, and central receiver) transfer the heat in solar insolation to a heat transfer fluid, typically a molten salt or heat transfer oil. By using thermal storage or by combining the solar generation system with a fossil fired system (a hybrid solar/fossil system), a solar thermal plant can provide dispatchable electric power.

Table 5-5
Wind Technology Characteristics

	Onshore	Offshore
Performance		
Typical Duty Cycle	As Available	As Available
Net Plant Capacity, MW	2.5	2.5
Capacity Factor, percent	28 to 35(1)	30 to 40
Economics ($2009)		
Total Project Cost, $/kW	2,400 to 3,000	5,000 to 6,000
Fixed O&M, $/kW-yr	50	60
Variable O&M, $/MWh	(included with Fixed O&M)	(included with Fixed O&M)
Levelized Cost(2) ($/MWh)		
Municipal	90 to 110	140 to 170
PPA(3)	100 to 150	160 to 260
Applicable Federal Incentives	$21/MWh PTC or 30% ITC or 30% grant, 5 yr MACRS	$21/MWh PTC or 30% ITC or 30% grant, 5 yr MACRS
Technology Status		
Commercial Status	Commercial	Early Commercial
Installed US Capacity, MW	21,000	0(4)

(1)Representative of existing projects in Michigan.
(2)The low end of the levelized cost is based on net plant capacity of 200 MW, capacity factor of 35 percent, and capital cost of $2,400/kW. The high end of the levelized cost is based on net plant capacity of 50 MW, capacity factor of 28 percent, and capital cost of $3,000/kW.
(3)Assumes that the project can take advantage of federal tax incentives to reduce the cost of energy.
(4)European installations total approximately 1500 MW, according to the European Wind Energy Association, 2008.

Unlike the three other solar thermal technologies, solar chimneys do not generate power using a thermal heat cycle. Instead, they generate and collect hot air in a large (several square mile) greenhouse. A tall chimney is located in the center of the greenhouse. As air in the greenhouse is heated by the sun, it rises and enters the chimney. The natural draft produces a wind current that rotates a collection of air turbines.

Applications

The larger solar thermal technologies (parabolic trough, central receiver, and solar chimney) are currently not economically competitive with other central station generation options (such as natural gas fired combined cycle units). Parabolic dish engine systems are small and modular and can be placed at load sites, directly offsetting retail electricity purchases. However, these systems have not been used in commercial applications.

Of the four technologies, parabolic trough represents the vast majority of installed capacity, primarily in the southwestern US desert. Nine Solar Electric Generating Station (SEGS) parabolic trough plants are located in the Mojave Desert, with a combined capacity of 354 MW. Other parabolic trough plants are being developed, including a 64 MW plant in Nevada and several 50 MW plants in Spain.

Parabolic dish engine systems of approximately 25 kW have been developed and are now being actively marketed. Recently, installation was completed on a six-dish test deployment at Sandia National Laboratories (SNL) in Albuquerque, New Mexico. If large deployments of dish/Stirling systems materialize, they are expected to drastically reduce capital and O&M costs and increase system reliability.

The US government has funded two utility-scale central receiver power plants: Solar One and its retrofit, Solar Two. Solar Two was a 10 MW installation near Barstow, California; however, it is no longer operating because of reduced federal support and high operating costs.

The first commercial chimney project has been proposed in Australia. Originally, this project was planned to be 200 MW with a 1 kilometer (km) (0.62 mile) tall chimney and a 5 km (3.1 mile) diameter greenhouse. More recently, the project has been scaled down to 50 MW.

Resource Availability

Solar radiation reaching the earth's surface, often called insolation, has two components: direct normal insolation (DNI) and diffuse insolation (DI). DNI, which typically comprises about 80 percent of the total insolation, is that part of the radiation which comes directly from the sun. DI is the part that has been scattered by the atmosphere or is reflected off the ground or other surfaces. On a cloudy day, all of the radiation is diffuse. The vector sum of DNI and DI is termed global insolation. Systems that concentrate solar energy use only DNI, while nonconcentrating systems use global insolation. Concentrating solar thermal systems (troughs, dishes, and central receivers) use DNI. Lower latitudes with minimum cloud coverage offer the greatest solar concentrator potential. In Michigan, DNI ranges from about 2.8 $kW/m^2/day$ to about 4.0 $kW/m^2/day$. Some locations in the southwestern United States can have DNI as high as 8.5 $kW/m^2/day$.

A general feature of solar thermal systems and solar technologies is that peak output typically occurs on summer days when electrical demand is high. Solar thermal systems that include storage allow dispatch which can improve the ability to meet peaking requirements. Land requirements for solar thermal systems are about 5 to 8 acres/MW.

Cost and Performance Characteristics

Because the solar trough technology is by far the most commercial form of solar thermal energy systems, it was further analyzed for performance characteristics in southwestern Michigan. Representative characteristics for the parabolic trough, solar thermal power plant technology that was described previously are presented in Table 5-6. As a result of the high capital cost of solar thermal plants and lower DNI in Michigan (in comparison to the southwestern United States), solar thermal generation is not likely to be competitive within Michigan.

5.1.5 Solar Photovoltaic

Solar PV technology has achieved considerable consumer acceptance over the last few years. PV module production has experienced significant growth over the last 10 years. In recent years, PV systems as large as 51 MW_{ac} have been installed in Europe, a 12.8 MW_{ac} system was installed at Nellis Air Force Base in Nevada, and a 7 MW_{ac} system was installed in Alamosa, Colorado. PV installations reached a projected worldwide capacity of approximately 14,000 MW_{ac} in 2009. The majority of these installations were in Japan, Germany, and other European countries where strong subsidy programs have made the economics of PV attractive. Annual US PV installations increased from 120 MW_{ac} in 2006 to an approximate 800 MW_{ac} in 2009.

Table 5-6
Parabolic Trough Performance Characteristics[1]

Performance	
Typical Duty Cycle	Peaking - Intermediate
Net Plant Capacity (MW)	100
Integrated Storage	3 hours
Capacity Factor (percent)	14
Economics ($2009)	
Total Project Cost ($/kW)	7,000 to 9,000
Total O&M ($/MWh)	67
Levelized Cost[2] ($/MWh)	
Municipal	550 to 700
PPA[3]	300 to 400
Applicable Federal Incentives	30% ITC or 30% grant, 5 yr MACRS
Technology Status	
Commercial Status	Commercial
Installed US Capacity (MW)	415

R&D = Research and Development.

(1)Parabolic trough cost estimates have a high degree of uncertainty for near-term applications.
(2)The low ends of the levelized costs are based on the higher capacity factors and the lower capital and O&M costs. The high ends of the levelized costs are based on the lower capacity factors and higher capital and O&M costs.
(3)Assumes that the project can take advantage of federal tax incentives to reduce the cost of energy.

Operating Principles

The amount of power produced by PV installations depends on the material used and the intensity of the solar radiation incident on the cell. Single or polycrystalline silicon cells are most widely used today. Single crystal cells are manufactured by growing single crystal ingots, which are then sliced into thin cell-sized material. The cost of the crystalline material is significant. The production of polycrystalline cells can cut material costs, with some reduction in cell efficiency. Thin film cells significantly reduce cost per unit area, but result in lower efficiency cells. Gallium arsenide cells are among the most efficient solar cells and have other technical advantages, but they are also more costly and typically are used only where high efficiency is required even at a high cost, such as space applications or in concentrating PV applications.

Applications

The modularity, simple operation, and low maintenance requirements of solar PV make it ideal for distributed, remote, or off-grid applications. Most PV applications are smaller than 1 kW, although larger, utility-scale installations are becoming more prevalent.

Resource Availability

Most PV systems installed today are flat-plate systems that use global insolation. Concentrating PV systems, which use DNI, are being developed, but are not considered commercial at this time. Global insolation on latitude tilt surfaces in Michigan ranges from about 3 kW/m^2/day in the northern part of the state up to about 4 kW/m^2/day in the southern edge of the state, compared with up to 7 kW/m^2/day in the southwestern United States. In the vicinity of Holland, global insolation is generally close to 4 kW/m^2/day.

Cost and Performance Characteristics

Table 5-7 presents cost and performance characteristics of a 20 MW utility-scale PV energy center, comparing crystalline single-axis tracking and thin film modules.

Environmental Impacts

A key attribute of solar PV cells is that they have virtually no emissions after installation. Some thin film technologies have the potential for discharge of heavy metals during manufacturing; however, proper monitoring and control can adequately address this issue.

Table 5-7
Solar PV Technology Characteristics

	Crystalline, Single-Axis Tracking	Thin Film
Performance		
Typical Duty Cycle	As Available, Peaking	As Available, Peaking
Net Plant Capacity (kW)	20	20
Capacity Factor (percent)	15	14
Economics ($2009)		
Total Project Cost ($/kW)	6,400 to 7,000	3,600 to 4,000
Total O&M ($/kW-yr)	65	55
Levelized Cost[2] ($/MWh)		
Municipal	450 to 550	300 to 350
PPA[3]	250 to 300	180 to 220
Applicable Federal Incentives	30% ITC or 30% grant, 5 yr MACRS	
Technology Status		
Commercial Status	Commercial	
Installed US Capacity (MW)	800	

[1]Includes inverter replacement after 10 years.
[2]The lower levelized costs are based on the low ends of the total project costs, and the high levelized costs are based on the high ends of the total project costs.
[3]Assumes that the project can take advantage of federal tax incentives to reduce the cost of energy.

5.1.6 Hydroelectric

Operating Principles

Hydroelectric power is generated by capturing the kinetic energy of water as it moves from a higher elevation to a lower elevation by passing it through a turbine. The amount of kinetic energy captured by a turbine is dependent on the head (distance the water is falling) and the flow rate of the water. Often, the water is raised to a higher potential energy by blocking its natural flow with a dam. If a dam is not feasible, it is possible to divert water out of the natural waterway, through a penstock, and back to the waterway. Such "run-of-river" applications allow for hydroelectric generation without the impact of damming the waterway. The existing worldwide installed capacity for hydroelectric power is by far the largest source of renewable energy at 740,000 MW.[8]

Applications

Hydroelectric projects are divided into a number of categories on the basis of their size. Micro hydroelectric projects generate below 100 kW. Systems generating 100 kW and 1.5 MW are classified as mini hydroelectric projects. Small hydroelectric systems generate between 1.5 MW and 30 MW. Medium hydroelectric projects generate up to 100 MW, and large hydroelectric projects generate more than 100 MW. Medium and large hydroelectric projects are good resources for baseload power generation if they have the capability of storing a large amount of potential energy behind a dam and releasing it consistently throughout the year. Small hydroelectric projects generally do not have large storage reservoirs and are not dependable as dispatchable resources.

Resource Availability

A hydroelectric resource can be defined as any flow of water that can be used to capture kinetic energy. Projects that store large amounts of water behind a dam can regulate the release of water through turbines and can generate electricity regardless of the season. These facilities can generally serve baseload needs. Run-of-river projects do not impound the water but, instead, divert a part or all of the current through a turbine to generate electricity. At "run-of-river" projects, power generation varies with seasonal flows and can sometimes help serve summer peak loads.

All hydroelectric projects are susceptible to drought. In fact, the variability in hydropower output is rather large, even when compared to other renewable resources. The aggregate annual capacity factor for all hydroelectric plants in the United States has ranged from about 31 percent to 53 percent over the last decade.[9]

[8] International Energy Agency, 2002.
[9] Based on an analysis of reported data from Global Energy Solutions, 2006.

Michigan currently has about 209 MW of developed small hydropower resources, with an estimated 133 MW of additional potential capacity.[10]

Cost and Performance Characteristics

Hydroelectric generation is regarded as a mature technology that is unlikely to advance measurably. Turbine efficiency and costs have remained somewhat stable, but construction techniques and costs continue to change. Capital costs are highly dependent on site characteristics and vary widely. Table 5-8 provides ranges for performance and cost estimates for new hydroelectric projects. These values are for representative comparison purposes only. Capacity factors are highly resource dependent and can range from 10 to more than 90 percent. Capital costs also vary widely with site conditions.

Environmental Impacts

The damming of rivers for small- and large-scale hydroelectric applications may have significant environmental impacts. One major issue involves the migration of fish and disruption of spawning habits. For dam projects, one of the common solutions to this problem is the construction of “fish ladders” to aid the fish in bypassing the dam when they swim upstream to spawn.

A second issue involves flooding existing valleys that often contain wilderness areas, residential areas, or archaeologically significant remains. There are also concerns about the consequences of disrupting the natural flow of water downstream and disrupting the natural course of nature.

5.1.7 Wave Energy

Operating Principles

The energy of ocean and large lake waves can be converted to electric power using a wave energy conversion (WEC) system. Many hundreds of WEC technologies have been suggested, but only a very small proportion of these have been evaluated beyond the concept stage. Of these, only a small number have been developed beyond laboratory testing to deployment as prototypes in real sea conditions. Most of the developing work is being performed in Europe, although there is ongoing work in the United States, India, Australia, and the Far East countries. WECs are generally categorized as shore-based (onshore and near-shore) or offshore systems.

[10] Idaho National Engineering and Environmental Laboratory, “Feasibility Assessment of the Water Energy Resources of the United States for New Low Power and Small Hydro Classes of Hydroelectric Plants,” January 2006.

Table 5-8
Hydroelectric Technology Characteristics

	New Hydro Installations
Performance	
Typical Duty Cycle	Varies with Resource
Net Plant Capacity (MW)	25 to 50
Capacity Factor (percent)	50
Economics ($2006)	
Total Project Cost ($/kW)	4,000 to 5,000
Fixed O&M ($/kW-yr)	50
Variable O&M ($/MWh)	(included in Fixed O&M)
Levelized Cost(1) ($/MWh)	
Municipal	90 to 110
PPA(2)	115 to 140
Applicable Federal Incentives	$10/MWh PTC
Technology Status	
Commercial Status	Commercial
Installed US Capacity (MW)	79,842

(1)The low end of the levelized cost is based on the higher capacity factors and the lower capital and O&M costs. The high end of the levelized cost is based on the lower capacity factors and the higher capital and O&M costs.
(2)Assumes that the project can take advantage of federal tax incentives to reduce the cost of energy.

Onshore and Near-Shore Applications

There are two basic shore-based wave energy designs: oscillating water column (OWC) devices and overtopping-tapered channel (TAPCHAN) devices. Examples of these two shore-based technologies are shown on Figure 5-1.

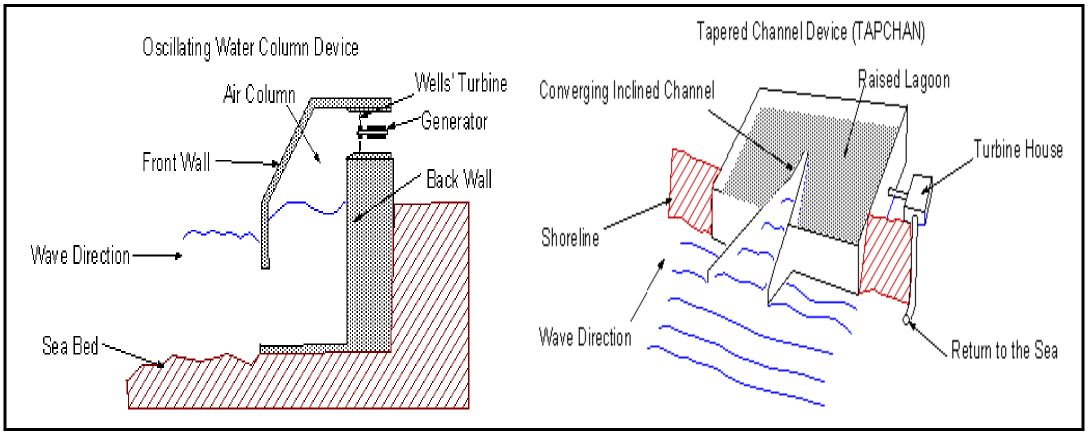


Figure 5-1
Onshore Wave Energy Devices
(Source: EU's Atlas Project)

OWC devices generate electricity from the wave-induced rise and fall of a water column. The energy in this water column is extracted via a moving air column using an air turbine. The main disadvantage with onshore systems, such as the OWC, is that the construction is dependent on local conditions and the available wave power is low at the shoreline. Onshore systems have an advantage over near-shore and offshore systems because of their accessibility for maintenance and transmission. The most developed example of this design is Wavegen's 500 kW LIMPET device, which has been operating since 2001.

TAPCHAN devices generate electricity using conventional low head hydropower turbines. A tapering channel concentrates and funnels waves up a channel and increases their height so that they then spill into a reservoir. Since these devices are driven by water flowing from a reservoir back to the sea, this device produces a more stable power output. Onshore devices such as TAPCHAN also require a small tidal range and a suitable shoreline with a reservoir location.

Near-shore systems that can be built around existing breakwater structures include the Energetech device, which uses a parabolic wall to focus wave energy onto the collector and a Dennis-Auld turbine, which uses variable pitch blades. In general, near-shore devices have the advantage that they can access higher wave power without the need for extensive electricity transmission. However, like onshore devices, their shoreline location may affect their adoption because of their aesthetically displeasing appearance.

Offshore Applications

There is much greater diversity in offshore WECs than near-shore systems. The most common offshore WECs are pneumatic devices, overtopping devices, float-based devices, and moving body devices. In general, offshore devices can access the greatest amount of wave power, but require extensive power transmission and maintenance since they are located in a more extreme environment.

Pneumatic devices generate electricity using air movement, often using an OWC concept similar to that of shore-based devices. Overtopping devices generate electricity using the same basic methodology as the shore-based versions. Float-based devices generate electricity using the vertical motion of a float rising and falling with each wave. The float motion is reacted against an anchor or other structure so that power can be extracted. Moving body devices use a solid body moving in response to wave action to generate electricity. Float-based devices are the most common of all proposed designs.

Well developed designs that are still under consideration include a 1 MW demonstration plant consisting of four 250 kW Finavera Renewables AquaBuOY units at Makah Bay, Washington. In May 2008, the project had completed a successful Project Development and Environmental Analysis (PDEA) and had received a Federal Energy Regulatory Commission (FERC) license to construct the Makah Bay Project. In October 2008, the company was nevertheless denied a PPA with PG&E by the California Public Utilities Commission (CPUC).

The most developed of the offshore wave devices is undoubtedly the Pelamis, from Pelamis Wave Power Ltd. A commercial ocean wave project off the northern coast of Portugal consists of three 750 kW Pelamis machines.

A PowerBuoy float-based device from Ocean Power Technologies is under development. In October 2005, the New Jersey Board of Public Utilities installed a 40 kW PowerBuoy near Atlantic City. Iberdrola S.A. is developing a PowerBuoy project off the coast of Santona, Spain, the first device of which was deployed in 2008; a device was also deployed off the coast of Hawaii during 2008. In addition, Ocean Power Technologies has received a total of $5 million in funding, $3 million of which was from the US Navy, who has continually supported the development.

One fully submerged device is the Archimedes Wave Swing from AWS Ocean Energy Ltd.; a 1.5 MW prototype was installed in Portuguese waters in May 2004. In February 2007, AWS Ocean Energy Ltd. secured £2.1 million in funding from the Scottish Executive, which will be used to develop a pre-commercial prototype and test it at the European Marine Energy Centre (EMEC).

Much of the wave device development is concentrated around the UK, especially since the Scottish Executive has recently provided grants (worth more than £13 million) to marine energy projects, including Pelamis, AWS, and PowerBuoy. The AquaBuOY, Archimedes Wave Swing, PowerBuoy, and Pelamis devices are shown on Figure 5-2.

Figure 5-2
AquaBuOY, Archimedes Wave Swing, PowerBuoy, and Pelamis Devices
(Sources: AquaEnergy Group Ltd., AWS BV, Ocean Power Technologies, and Pelamis Wave Power)

Cost and Performance Characteristics

Since no large-scale commercialization exists for any of these technologies, there is a wide range of projected costs. These costs and performance estimates were based on theoretical calculations and are highly uncertain. These speculative costs are summarized in Table 5-9.

Environmental Impacts

WECs are generally not considered to be environmentally harmful. However, there are some concerns with WECs, including degradation of marine habitat and adverse visual impacts; the installation of WECs often raises issues with surfers due to the extraction of energy from the waves. These concerns may be mitigated through careful siting of projects.

Table 5-9
Wave Energy Technology Characteristics

Performance	Wave
Typical Operating Life (years)	--[1]
Typical Duty Cycle	Intermediate
Net Plant Capacity, MW	10
Capacity Factor, percent	30
Economics ($2009)	
Capital Cost, $/kW	3,500 to 8,300
Total O&M, $/MWh	66 to 157
Technology Status	
Commercial Status	Demonstration
Installed World Capacity, MW[3]	5 to 10

[1] Due to its developmental status, typical useful life data for wave energy technology is not available.
[2] It is estimated that the operating life of a device would be 20 years by this point.
[3] Estimated installed capacity based on the extractable energy that is economically and technically feasible.

5.1.8 Levelized Cost of Energy Comparison - Renewable Energy Technologies

Figure 5-3 illustrates how the renewable energy technologies compare on a levelized cost of energy basis in the vicinity of Holland, Michigan.

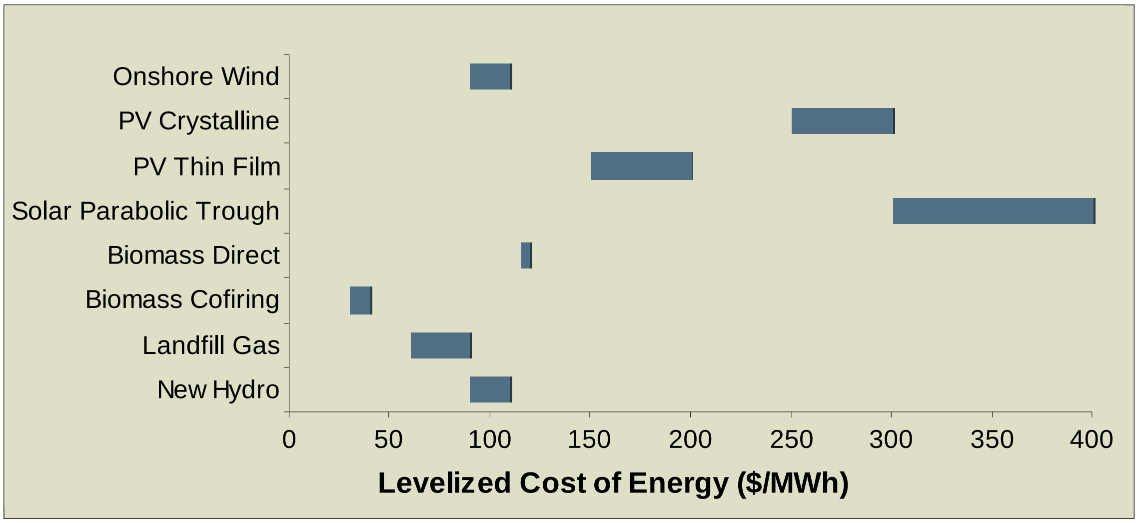


Figure 5-3
Comparison of the Levelized Cost of Energy of Renewable Energy Technologies

5.2 Conventional Technology Options

5.2.1 Simple Cycle Combustion Turbine (LMS100)

Operating Principles

The LMS100 is currently the most efficient simple cycle combustion turbine in the world. In simple cycle mode, the LMS100 has an efficiency of 46 percent, which is 10 percent greater than the LM6000. It has high part-load efficiency, cycling capability (without increased maintenance cost), better performance at high ambient temperatures, modular design (minimizing maintenance costs), the ability to achieve full power from a cold start in 10 minutes, and it is expected to have high availability, although this availability must be commercially demonstrated before the LMS100 can be considered a conventional alternative.

The LMS100 is an aeroderivative turbine and has many of the same characteristics of the LM6000. The former uses off-engine intercooling within the turbine's compressor section to increase its efficiency. The process of cooling the air optimizes the performance of the turbine and increases output efficiency. At 50 percent turndown, the part-load efficiency of the LMS100 is 40 percent, which is a greater efficiency than most simple cycle combustion turbines at full load.

There are two main differences between the LM6000 and the LMS100. The LM6000 uses the SPRINT intercooling system to cool the compressor with a micro-mist of water, while the LMS100 cools the compressor air with an external heat exchanger after the first stage of compression. Unlike the LM6000, which has a high-pressure (HP) turbine and a power turbine, the LMS100 has an additional intermediate-pressure (IP) turbine to increase output efficiency.

As a packaged unit, the LMS100 consists of a 6FA turbine compressor, which outputs compressed air to the intercooling system. The intercooling system cools the air, which is then compressed in a second compressor to a high pressure, heated with combusted fuel, and then used to drive the two-stage IP/HP turbine described above. The exhaust stream is then used to drive a five-stage power turbine. Exhaust gases are at a temperature of less than 800º F, which allows the use of a standard SCR system for NO_x control.

Cost and Performance Characteristics

Table 5-10 presents the operating characteristics of the LMS100 combustion turbine at a winter temperature of 28º F (relative humidity of 75 percent), a summer temperature of 80º F (relative humidity of 70 percent), and an annual average temperature of 48º F (relative humidity of 72 percent). Standard SCR will be used to control NO_x to 2 ppmvd while operating on natural gas. Water injection and SCR will be used to control NO_x while operating on ultra-low sulfur diesel (ULSD).

Table 5-10
GE LMS100 Combustion Turbine Characteristics

Ambient Conditions	Net Capacity (MW)[1, 2]	Net Plant Heat Rate (Btu/kWh, HHV)[1, 2]
Winter (28º F) (Full Load)	99.9	8,919
Summer (80º F) (Full Load)	93.8	9,172
Average (48º F and 72% RH) (Full Load)	100.8	8,978
Average (48º F and 72% RH) (50% Load)	49.9	10,458

RH = Relative Humidity

(1)Net capacity and full load net plant heat rate exclude degradation factors; evaporative cooling is not considered.
(2) Net capacity and heat rate assume operation on natural gas.

Table 5-11 presents the cost characteristics of the LMS100 unit.

Table 5-11 LMS100 Cost Characteristics	
Economics ($2009)	
Total Project Cost ($/kW)	1,060[1]
Fixed O&M ($/kW-yr)	11
Variable O&M ($/MWh)	3
Levelized Cost[1] ($/MWh)	
10% Capacity Factor	224
50% Capacity Factor	117
[1]Based on average annual output.	

Environmental Impacts

Table 5-12 presents the estimated emissions for the LMS100. All performance and emissions estimates presented in Tables 5-10 through 5-12 are preliminary.

Table 5-12 GE LMS100 Estimated Emissions[1]	
NO_x, ppmvd at 15% O_2	2
NO_x, lb/MBtu	0.0072
SO_2, lb/MBtu	0.0005
Hg, lb/TBtu	Negligible
CO, lb/MBtu	0.025
CO_2, lb/MBtu	114.8
[1]Emissions are at full load at 70º F and include the effects of SCR and CO catalyst.	

5.2.2 Combined Cycle Combustion Turbine (2x1 7EA)

Operating Principles

Combined cycle configurations have several advantages over simple cycle combustion turbines. Advantages include increased efficiency and the ability to quickly boost output through the use of duct burners. Disadvantages include a small reduction in plant reliability, higher capital cost, and an increase in the overall staffing and maintenance requirements due to added plant complexity. Combined cycle generators typically require at least three additional hours to cold startup than simple cycle generators.

The 2x1 combined cycle generating unit would include two GE 7EA combustion turbine generators (CTGs), two heat recovery steam generators (HRSGs), one steam turbine generator (STG), and a cooling tower. Each combustion turbine will include evaporative cooling.

Cost and Performance Characteristics

Table 5-13 presents the operating characteristics of the 2x1 7EA combined cycle generating unit with supplemental firing at a winter temperature of 28º F (relative humidity of 75 percent), a summer temperature of 80º F (relative humidity of 70 percent), and an annual average temperature of 48º F (relative humidity of 72 percent).

Table 5-13
GE 2x1 7EA Combined Cycle Designed for
Supplemental Firing Performance Characteristics

Ambient Condition	Net Capacity (MW)[1, 2]	Net Plant Heat Rate (Btu/kWh, HHV)[1, 2]
Winter (28º F) (Full Load not fired)	271	7,605
Summer (80º F) (Full Load, fired)	311	8,394
Average (48º F and 72% RH) (Full Load, unfired)	256	7,627
Average (48º F and 72% RH) (50% Load, unfired)[3]	151	8,546

RH = Relative humidity.

[1]Net capacity and net plant heat rate exclude degradation factors; evaporative cooling is considered at full load cases above 60º F.
[2]Net capacity and heat rate assume operation on natural gas.
[3]Part-load performance percentage load is based on combustion turbine load point.

Table 5-14 presents the cost characteristics of the 2x1 7EA unit.

Table 5-14
GE 2x1 7EA Cost Characteristics

Economics ($2009)	Greenfield	Unit 9 Conversion
Total Project Cost ($/kW)	1,167*	909*
Fixed O&M ($/kW-yr)	12	12
Variable O&M ($/MWh)	3	3
Levelized Cost ($/MWh)		
25% Capacity Factor	136	118
70% Capacity Factor	98	92

*Based on average annual output.

Environmental Impacts

Table 5-15 presents the estimated emissions for the 2x1 GE 7EA combined cycle generating unit with supplemental firing.

Table 5-15
GE 2x1 7EA Combined Cycle with
Supplemental Firing Estimated Emissions(1)

NO_x, ppmvd at 15% O_2	2
NO_x, lb/MBtu	0.0072
SO_2, lb/MBtu	0.0002
Mercury (Hg), lb/TBtu	Negligible
CO, lb/MBtu	0.0028
CO, ppmvd at 15% O_2	1.7
CO_2, lb/MBtu	114.8

(1)Emissions are at full load at 70º F, reflect operation on natural gas, and include the effects of SCR and CO catalyst.

5.2.3 Supercritical Coal (without Carbon Capture and Sequestration [CCS])

Operating Principles

Coal is the most widely used fuel for the production of power, and most coal-burning power plants use PC boilers. PC units utilize a proven technology with a very high reliability level. These units have the advantage of being able to accommodate up to 1,300 MW, and the economies of scale can result in low busbar costs. PC units are relatively easy to operate and maintain.

New-generation PC boilers can be designed for supercritical steam pressures of 3,500 to 4,500 psig, compared to a steam pressure of 2,400 psig for conventional subcritical boilers. The increase in pressure from subcritical (2,400 psig) to supercritical (3,500 psig) generally improves the net plant heat rate (NPHR) by about 200 Btu/kWh (higher heating value [HHV]), assuming the same main and reheat steam temperatures and the same cycle configuration. This increase in efficiency comes at a cost, however, and the economics of whether to use subcritical and supercritical technology depend on the cost of fuel, expected capacity factor of the unit, environmental factors, and the cost of capital.

Newly constructed supercritical PC boilers are currently being designed to provide main and reheat steam at 1,050° F or higher. Advancements in metal alloys now allow main steam temperatures of 1,112° F and reheat temperatures of 1,148° F. Future advancements in the use of high-nickel alloys could allow main steam temperatures to reach 1,292° F, with a reheat temperature of 1,328° F.

The supercritical PC generating unit characterized here would include a single supercritical STG and supercritical PC boiler fueled by coal. Air quality control systems would include low-NO_x burners (LNBs), flue gas recirculation (FGR), and SCR for NO_x control; wet limestone flue gas desulfurization (FGD) for SO_2 control; and wet electrostatic precipitator (ESP) for particulate control. Auxiliary power is assumed to be 9 percent of gross plant output. The boiler feedwater system is expected to include turbine driven boiler feed pumps and eight feedwater heaters – three HP, four low-pressure (LP), and one deaerator. Heat rejection will be accomplished by a wet, mechanical draft cooling tower.

Cost and Performance Characteristics

Table 5-16 presents the operating characteristics of the supercritical PC generating unit. Table 5-17 presents the cost characteristics of the 2x1 7EA unit.

Table 5-16
Supercritical PC Full-Load Thermal Performance Estimates

Ambient Conditions	Net Capacity (MW)[1, 2]	Net Plant Heat Rate (Btu/kWh, HHV)[1, 2]
Winter (28º F)	830	9,134
Summer (80º F)	830	9,134
Average (48º F and 72% RH)	830	9,134

RH = Relative humidity

(1)Net capacity and net plant heat rate exclude degradation.
(2)Net capacity and heat rate assume operation on subbituminous coal.

Table 5-17
Supercritical PC Cost Characteristics

Economics ($2009)	
Total Project Cost ($/kW)	3,429
Fixed O&M ($/kW-yr)	35.06
Variable O&M ($/MWh)	2.41
Levelized Cost ($/MWh)	
70% Capacity Factor	78
90% Capacity Factor	67

Environmental Impacts

Table 5-18 presents the estimated emissions for the supercritical PC generating unit. All performance and emissions estimates presented in Tables 5-16 through 5-18 are preliminary.

Table 5-18
Supercritical PC Estimated Air Emissions(1)

NO_x, lb/MBtu	0.04
SO_2, lb/MBtu	0.06
Hg, lb/TBtu	1.4
CO_2, lb/MBtu	211
CO, lb/MBtu	0.1
PM_{10}, lb/MBtu	0.012

(1)Emissions are at full load at 70º F, and reflect operation on a subbituminous coal. All estimates are presented on the basis of HHV.

5.2.4 Supercritical Coal with CCS

Operating Principles

For a supercritical PC generation facility, the likely near-term approach for CO_2 capture would be an amine-based, post-combustion CO_2 capture process.

In CO_2 capture, the CO_2 concentration and the CO_2 partial pressure in the flue gas stream are important variables. Higher concentrations and higher partial pressures of CO_2 facilitate its capture. The concentration of CO_2 in the flue gas is relatively low and the CO_2 capture process is inefficient. A chemical amine solvent that requires thermal stripping would be used to absorb the CO_2. The CO_2 capture plant would consist of flue gas preparation, CO_2 absorption, and CO_2 stripping. The captured CO_2 would then be dehydrated, transported, and sequestered.

The flow process would begin at the flue gas discharge from the plant emissions controls equipment, where a blower with a cooler would be used to pass the flue gas upward through an absorber. Amine solution would be distributed evenly downward through the absorber onto packing material, allowing the solvent to selectively capture CO_2 from the gas. The resulting flue gas, containing 10 percent of the original CO_2 content, would be discharged from the top of the absorber to the atmosphere. The solvent with the captured CO_2 (CO_2-rich solution) would be collected at the bottom of the absorber, cooled, and pumped into the top of a stripper. CO_2 would be stripped from the solvent by the hot steam, resulting in a 99.9 percent volume CO_2, which could then be dehydrated, compressed, and transported to storage. The resulting CO_2-lean solvent would be cooled and pumped back into the absorber.

Cost and Performance Characteristics

Table 5-19 presents the operating characteristics of a supercritical PC generating unit with post-combustion CCS. Table 5-20 presents the cost characteristics of the supercritical PC generating unit with post-combustion CCS.

Table 5-19
Supercritical PC with Post-Combustion CCS
Full-Load Thermal Performance Estimates

Ambient Conditions	Net Capacity (MW)(1, 2)	Net Plant Heat Rate (Btu/kWh, HHV)(1, 2)
Average (68º F and 72% RH)	580	13,360

(1)Net capacity and net plant heat rate exclude degradation.
(2)Net capacity and heat rate assume operation on a subbituminous coal.

Table 5-20
Supercritical PC with CCS Cost Characteristics

Economics ($2009)	
Total Project Cost ($/kW)	10,290
Fixed O&M ($/kW-yr)	63
Variable O&M ($/MWh)	5.90
Levelized Cost ($/MWh)	
70% Capacity Factor	184
90% Capacity Factor	153

Environmental Impacts

Table 5-21 presents estimated emissions for a supercritical PC generating unit with post-combustion CCS.

Table 5-21
Supercritical PC with Post-Combustion CCS
Estimated Air Emissions[1]

NO_x, lb/MBtu	0.07
SO_2, lb/MBtu	0.10
Hg, lb/TBtu	1.3
CO_2, lb/MBtu	20.5
CO, lb/MBtu	0.1
PM_{10}, lb/MBtu	0.012

[1]Emissions are at full load at 70º F and reflect operation using a subbituminous coal. All estimates are presented on the basis of HHV.

5.2.5 Circulating Fluidized Bed

Operating Principles

The primary coal fired boiler alternative to a PC boiler is a CFB boiler. In a CFB unit, a portion of the combustion air is introduced through the bottom of the bed. The bed material normally consists of fuel, limestone sorbent (for sulfur capture), and ash. The bottom of the bed is supported by water-cooled membrane walls with specially designed air nozzles that uniformly distribute the air. The fuel and limestone sorbent are fed into the lower bed. In the presence of fluidizing air, the fuel and limestone quickly and uniformly mix under the turbulent environment and behave like a fluid. Carbon particles in the fuel are exposed to the combustion air. The balance of combustion air is introduced at the top of the lower, dense bed. Staged combustion and low combustion temperature limit the formation of thermal NO_x.

The bed fluidizing air velocity is greater than the terminal velocity of most of the particles in the bed and, therefore, fluidizing air elutriates the particles through the combustion chamber to the cyclone separators at the furnace exit. The captured solids, including any unburned carbon and nonutilized calcium oxide (CaO), are re-injected directly back into the combustion chamber without passing through an external recirculation. The internal solids circulation provides longer residence time for fuel and limestone, resulting in good combustion and improved sulfur capture.

Commercial CFB units offer greater fuel diversity than PC units, operate at competitive efficiencies and, when coupled with a polishing SO_2 scrubber, operate with emissions below current levels mandated by federal standards. Compared to conventional PC technology, which has been used since the 1920s, CFB is a commercially proven technology that has been in reliable electric utility service in the United States for the past 25 years.

By the late 1980s, small industrial sized boilers had transitioned to several electrical utility reheat boilers in the size range from 75 to 165 MW. Several reheat boilers over 300 MW are currently in service, and boiler suppliers are offering boiler designs that will provide steam generation sufficient to support up to 600 MW with full commercial guarantees. Fuels for these applications include petroleum coke (petcoke), coal, high ash refuse from bituminous coal preparation and cleaning plants, high moisture fuels such as lignite, and biomass.

An environmentally attractive feature of CFB is that SO_2 can be removed in the combustion process by adding limestone sorbent to the fluidized bed. The CaO formed from the calcination of limestone reacts with SO_2 to form calcium sulfate ($CaSO_4$), which is removed from the flue gas with a conventional particulate removal device. The CFB combustion temperature is controlled at approximately 1,600º F, compared to approximately 2,500 to 3,000º F for conventional PC boilers. Combustion at the lower temperature has several benefits. First, the lower temperature minimizes the sorbent (typically limestone) requirement, because the required calcium to sulfur (Ca/S) molar ratio for a given SO_2 removal efficiency is minimized in this temperature range. Second, 1,550 to 1,600º F is well below the ash fusion temperatures of most fuels, so the fuel ash never reaches its softening or melting points. The slagging and fouling problems that are characteristic of PC units are significantly reduced, if not eliminated. Finally, the lower temperature reduces NO_x emissions by nearly eliminating thermal NO_x.

The CFB generating unit includes a single condensing STG and a subcritical CFB boiler. Air quality control systems include a limestone sorbent injection and polishing semi-dry spray dryer absorber (SDA) for SO_2 control, selective noncatalytic reduction (SNCR) for NO_x control, ACI injection for mercury control, and a fabric filter for particulate control. Auxiliary power is assumed to be 10 percent of gross plant output. The boiler feed water system includes seven feedwater heaters – two high-pressure, four low-pressure, and one deaerator. Heat rejection is accomplished by wet, mechanical draft cooling towers.

Black & Veatch characterized three different CFB unit options:

- 2 x 300 MW CFB facility at Rogers City (to be built by Wolverine).
- 70 MW CFB facility (self-build).
- 40 MW Oxy-Fuel CFB facility with oxy-coal (self-build).

Cost and Performance Characteristics

Tables 5-22 through 5-24 present the operating characteristics of the three different CFB generating unit alternatives. Tables 5-25 through 5-27 present the cost characteristics of the three different CFB generating unit alternatives.

Table 5-22
2 x 300 MW CFB Full Load Thermal Performance Estimates

Ambient Condition	Net Capacity (MW)(1, 2)	Net Plant Heat Rate (Btu/kWh, HHV)(1, 2)
Winter (28º F)	600	9,439
Summer (68º F)	600	9,439
Average (48º F and 72% RH)	600	9,439

RH = Relative humidity

(1)Net capacity and net plant heat rate exclude degradation.
(2)Net capacity and heat rate assume coal operation.

Table 5-23
70 MW CFB Full Load Thermal Performance Estimates

Ambient Condition	Net Capacity (MW)(1, 2)	Net Plant Heat Rate (Btu/kWh, HHV)(1, 2)
Winter (28º F)	70	11,148
Summer (68º F)	70	11,148
Average (48º F and 72% RH)	70	11,148

RH = Relative humidity

(1) Net capacity and net plant heat rate exclude degradation.
(2)Net capacity and heat rate assume coal operation.

Table 5-24
40 MW Oxy-Fuel CFB Full Load Thermal Performance Estimates

Ambient Condition	Net Capacity (MW)(1, 2)	Net Plant Heat Rate (Btu/kWh, HHV)(1, 2)
Winter (28º F)	40	19,220
Summer (68º F)	40	19,220
Average (48º F and 72% RH)	40	19,220

RH = Relative humidity

(1) Net capacity and net plant heat rate exclude degradation.
(2)Net capacity and heat rate assume coal operation.

Table 5-25
2 x 300 MW CFB Cost Characteristics

Economics ($2009)	
Total Project Cost ($/kW)	3,413
Fixed O&M ($/kW-yr)	46.12
Variable O&M ($/MWh)	2.95
Levelized Cost ($/MWh)	
70% Capacity Factor	82
90% Capacity Factor	70

Table 5-26
70 MW CFB Cost Characteristics

Economics ($2009)	
Total Project Cost ($/kW)	3,828
Fixed O&M ($/kW-yr)	28.91
Variable O&M ($/MWh)	5.18
Levelized Cost ($/MWh)	
70% Capacity Factor	91
90% Capacity Factor	79

Table 5-27 40 MW Oxy-Fuel CFB Cost Characteristics	
Economics ($2009)	
Total Project Cost ($/kW)	14,935
Fixed O&M ($/kW-yr)	52.31
Variable O&M ($/MWh)	7.90
Levelized Cost ($/MWh)	
70% Capacity Factor	256
90% Capacity Factor	214

Environmental Impacts

Table 5-28 presents estimated emissions for the CFB generating unit. All performance and emissions estimates presented in Tables 5-22, 5-23, 5-24, and 5-28 are preliminary.

Table 5-28 CFB Estimated Emissions[(1)]	
NO_x, lb/MBtu	0.09
SO_2, lb/MBtu	0.13
Hg, lb/TBtu	0.70
CO_2, lb/MBtu	115
CO, lb/MBtu	0.15
PM_{10}, lb/MBtu	0.011
[(1)]Emissions are at full load at 68º F and reflect operation using coal. All estimates are presented on the basis of HHV.	

5.2.6 Nuclear

5.2.6.1 Operating Principles. A uranium-fueled nuclear fission process has been used for several decades to create energy in the United States. Inside a nuclear reactor, uranium atoms are bombarded by neutrons. Each time a neutron is absorbed by a uranium atom, the atom becomes unstable and splits, in a process known as fission. During this process, the atom produces additional neutrons, usually on the average of two and a half for each fission. These neutrons split more uranium atoms, creating more neutrons. This scenario perpetuates, resulting in a chain reaction. The fission process generates heat in the reactor core, and the generated heat is transferred to water, which is circulated to the steam generator.

Currently, nuclear power in the United States faces challenges related to public perception, capital costs, and environmental issues concerning disposal of spent fuel. Combined, these factors explain why nuclear plants have fallen out of favor as generating resources. However, rising fuel prices, greenhouse gas emissions concerns, and increasing energy demand may make new nuclear fission plants a viable option for producing power in the future.

Westinghouse, GE, and others (including Areva and Mitsubishi Heavy Industries [MHI]) are currently developing and licensing nuclear units with the Nuclear Regulatory Commission (NRC). The Westinghouse AP-1000 and the GE Economic Simplified Boiling Water Reactor (ESBWR) are described in greater detail in this subsection. (GE and its partners also offer the Advanced Boiling Water Reactor [ABWR].) The AP-1000 was approved by the NRC in 2004, and the Design Certification (DC) amendment is expected to be approved in 2010.

The units consist of a nuclear island (NI), turbine island (TI), radwaste building, cooling tower, and additional yard facilities. The TI consists of the steam turbine and the switchgear building. The switchgear building includes standard electrical equipment and switchgear for a large nuclear unit.

The radwaste building has both liquid and solid radwaste treatment systems. In addition to the treatment systems, costs for the radwaste building include communications, lighting, and security systems.

The cooling tower is one of the major yard facilities and is assumed to be a mechanical draft cooling tower with a pump house and retention pond. Other yard facilities include transformers, fuel and chemical storage systems, a makeup water treatment building, grounding system, radwaste tunnel, and a service building.

The large capacity of a nuclear unit would not be practical for a small utility to build on its own; however, it is possible for a small utility to participate in a share of a nuclear unit if one is built by others nearby.

Westinghouse AP – 1000 (1,140 MW)

The AP-1000 is the safest reactor; it is the only Generation III+ reactor to receive a DC from the NRC. The AP-1000 features proven technology and innovative passive safety systems and offers the following:

- High safety.
- Economic competitiveness.
- Improved and more efficient operations.

The AP-1000 builds and improves upon the established technology of major components used in current Westinghouse-designed plants with proven, reliable operating experience over the past 50 years. These components include the following:

- Steam generators.
- Digital instrumentation and controls.
- Fuel.
- Pressurizers.
- Reactor vessels.

Simplification was a major design objective for the AP-1000. The simplified plant design includes overall safety systems, normal operating systems, the control room, construction techniques, and instrumentation and control systems. The result is a plant that is easier and less expensive to build, operate, and maintain.

The AP-1000 design saves money and time with an accelerated construction time period of approximately 36 months, from the pouring of first concrete to the loading of fuel. The innovative AP-1000 also features the following:

- 50 percent fewer safety-related valves.
- 80 percent less safety-related piping.
- 85 percent less control cable.
- 35 percent fewer pumps.
- 45 percent less seismic building volume.

Improved nuclear power plant performance means more electricity for less money. The following design features of the AP-1000 reactor improve plant production and worker safety:

- Eighteen-month fuel cycle for improved availability and reduced overall fuel costs.
- Significantly reduced maintenance, staging, and testing and inspection requirements.
- Reduced radiation exposure and less plant waste.
- Sixty-year design life.

Operations and Maintenance

Nuclear plants in the United States are already competitive producers of electricity compared to coal fired plants. This is enhanced by the fact that fuel costs account for about 25 percent of production costs for nuclear power, while the remaining 75 percent of the production cost is the fixed costs for O&M. That means that nuclear power production is much less sensitive to changes in fuel costs than fossil fuel powered plants, where fuel costs can account for up to 75 percent of the production costs.

The AP-1000 is a two-loop pressurized water reactor (PWR) with passive safety systems and extensive plant simplifications that improve plant operation and maintenance, while reducing construction cost and schedule. The AP-1000 is based on the standardized AP-600 plant that received a DC from the NRC in December 1999. The AP-1000 was developed in order to reduce capital costs while maintaining the AP-600's design configuration and, to the extent possible, the AP-600's licensing basis. Changes to the original AP-600 design were limited to only those structures, systems, and components affected by the increase in power. The nuclear island footprint remains unchanged; however, the containment height has increased. Proven components are used throughout the plant. The philosophy governing the plant design is identical to the AP-600.

The AP-1000 uses modular construction techniques. The standard plant is comprised of 50 large and 250 small modules. The small modules are rail-shippable units approximately 12 feet high, 12 feet wide, and 80 feet long, weighing 80 tons. These modules are constructed in parallel and independent of one another at a shipyard-like factory and later assembled onsite. This technique reduces construction costs and schedule because (1) construction activities occur in parallel, rather than sequentially, (2) onsite construction is reduced (shop labor costs are substantially lower than field labor), and (3) shop welding and assembly increases quality of work and flexibility in schedule. The simplified plant design, with its reduced building volumes and fewer components and commodities, also contributes to a short construction schedule. Overall, centralized manufacturing and assembly, together with appropriate testing and inspection of the finished modules, will shorten the onsite construction schedule.

Westinghouse and its subcontractors have performed construction studies in Japan and the United States. These studies conclude that site construction can be completed within 36 months, timed from first concrete to fuel load. A 60 month schedule is anticipated from a utility commitment to build to operation (vendor estimate).

Combined operating license (COL) issues (166 total), including control room design, were identified in the AP-1000 Design Control Document and will have to be addressed in the COL application.

General Electric (GE) ESBWR (1,500 MW)

Since developing nuclear reactor technology in the 1950s, GE's BWR technology accounts for more than 90 operating plants in the world today. These plants account for one-third of the United States-installed base and globally provide enough electricity to power nearly 35 million households.

Primary benefits and features of the ESBWR include the following:

- Simplified design features as follows:
    - Passively removes decay heat directly to the atmosphere.
    - 11 systems are eliminated from previous designs.
    - 25 percent fewer pumps, valves, and motors.
- Passive design features reduce the number of active systems and increase safety. It is 11 times more likely for the largest asteroid near the earth to impact the earth over the next 100 years than for an ESBWR operational event to result in the release of fission products to the environment.
- Incorporation of features used in other operationally-proven reactors, including passive containment cooling, isolation condensers, natural circulation, and debris-resistant fuel.
- Natural Circulation in ESBWR Fact Sheet.

In the 1990s, the NRC certified GE's ABWR in the United States, the first advanced Generation III design (a DOE classification) to begin operation globally. Today, four ABWR plants have been completed and put into commercial operation. An additional three ABWR plants are under construction, with four more plants in the planning stages. ABWR is the foundation of GE's advanced reactor portfolio.

The *Energy Policy Act of 2005* included several incentives for new nuclear construction. The incentives included extending the Price-Anderson Act, reauthorizing the Nuclear Power 2010 Program, providing loan guarantees and risk insurance, and extending the PTCs to nuclear energy. The DOE has suggested that the incentives are not mutually exclusive and that companies will be able to apply for more than one of the incentives.

The Price-Anderson Act authorizes methods of insuring the public for damages from nuclear accidents, and the *Energy Policy Act of 2005* extension includes insuring all power reactors issued construction permits through December 31, 2005.

The Nuclear Power 2010 Program was unveiled in February 2002 and is a joint cost-sharing effort between industry and government to identify sites for new nuclear power plants, develop and bring to market advanced plant designs and nuclear plant technologies (Generation III+), evaluate the business case for building new nuclear power plants, and demonstrate untested regulatory processes[11]. The *Energy Policy Act of 2005* reauthorized the program.

On August 4, 2006, the DOE finalized a rule enacting the *Energy Policy Act of 2005* Standby Support Program, which provides developers of new advanced nuclear plants with risk insurance. The program allows the DOE to enter into contracts with a

[11] http://www.ne.doe.gov/NucPwr2010/NucPwr2010.html

maximum of six reactors whereby the first "initial two reactors" are each eligible for indemnification of covered costs, up to $500 million per contract, for losses due to certain litigation or regulatory-related delays, and the "subsequent four reactors" could receive 50 percent of covered costs, up to $250 million each, after a 180 day delay[12]. The *Energy Policy Act of 2005* also authorizes the DOE to enter into loan guarantees for projects that reduce, sequester, or are free of emissions and air pollutants and/or those that use new technologies including advanced nuclear power plants.

The *Energy Policy Act of 2005* extended the PTCs to nuclear energy. The policy permits taxpayers producing electricity at qualified facilities to claim a credit equal to 1.8 cents per kilowatt-hour of electricity produced for 8 years[2]. The national capacity limit is 6,000 MW. Qualifying facilities are those facilities for which construction is proceeding on schedule with an in-service date before 2021[2].

In June 2007, the House Appropriations Committee cut DOE funding requests for the Nuclear Power 2010 Program and the Global Nuclear Energy Partnership. The committee approved $7 billion in loan guarantees for fiscal year 2008, which is $2 billion less than the amount requested by DOE. The entire $7 billion was allocated to loan guarantees for coal plants featuring carbon sequestration, biofuels and "clean" transportation fuel manufacturing, and new technologies for electric transmission facilities and renewable energy power systems. The committee decision, which has yet to be agreed upon by the full House and Senate, would have a detrimental effect on efforts to increase the role of nuclear power in the United States.

5.2.6.2 Cost and Performance Characteristics. The performance estimates for nuclear generation are summarized in Table 5-29.

The capital cost is the estimated EPC cost inclusive of engineering, procurement, construction, and indirect costs for construction of each alternative utilizing a fixed price, turnkey type contracting structure. Owner's costs may include the costs shown in Table 5-30, as well as Owner's costs specific to nuclear units such as NRC filing fees. Additional costs such as escalation, financing fees, and interest during construction would need to be accounted for separately. All costs are in 2009 dollars.

5.2.6.3 Environmental Impacts. There are no fossil emissions from the nuclear reactor directly connected to power generation. However, there are some incidental emissions related to periodic operation of standby equipment. These emissions, expected to remain constant over 20 years, are listed in Table 5-31.

ESBWR emissions are approximately 10 percent more than those listed for AP-1000 technology.

[12] Jenny Weil, Elaine Hiruo, and Michael Knapik, OE Lays Ground Rules for Incentives for New Reactors. *Nucleonics Week*, Vol. 47, No. 32, pg. 1.

Table 5-29
Nuclear Unit - Performance Estimates

	Westinghouse AP-1000	**GE ESBWR**
Commercial Status	Revised Design Certification Approved 3/06; NRC reviewing DC amendment (approval expected middle 2010)	Currently under NRC review for Initial Design Certification (approval expected late 2009).
Construction Period (months)	72	72
Performance		
Net Capacity (MW)	1,140	1,500
Net Plant Efficiency (percent)	33.5	33.5
Capacity Factor (percent)	80-95	80-95

Table 5-30
Nuclear Cost Characteristics

Economics ($2009)	
Total Project Cost ($/kW)	6,000
Fixed O&M ($/kW-yr)	60
Variable O&M ($/MWh)	(included with Fixed O&M)
Levelized Cost ($/MWh)	
80% Capacity Factor	99
95% Capacity Factor	85

Table 5-31
AP-1000 Yearly Emissions

Auxiliary Boiler		
Pollutant Discharged	**Quantity (lb)**	
Particulates	17,250	
Sulfur Oxides	51,750	
Carbon Monoxide	--	
Hydrocarbons	50,100	
Nitrogen Oxides	--	
Diesel Generators		
2 x 4,000 kW Standby DGs (1) (lb) 2 x 35 kW Ancillary DGs (1) (lb)		
Particulates	<800	<10
Sulfur Oxides	<2,500	<5
Carbon Monoxide	<1,000	<30
Hydrocarbons	<600	<11
Nitrogen Oxides	<12,000	<140

Note: Emissions are based on 4 fired-hours/month operation for each of the generators.

5.2.7 Levelized Cost of Energy Comparison: Conventional Energy Technologies

Figure 5-4 illustrates how the conventional energy technologies compare on a levelized cost of energy basis in the vicinity of Holland, Michigan.

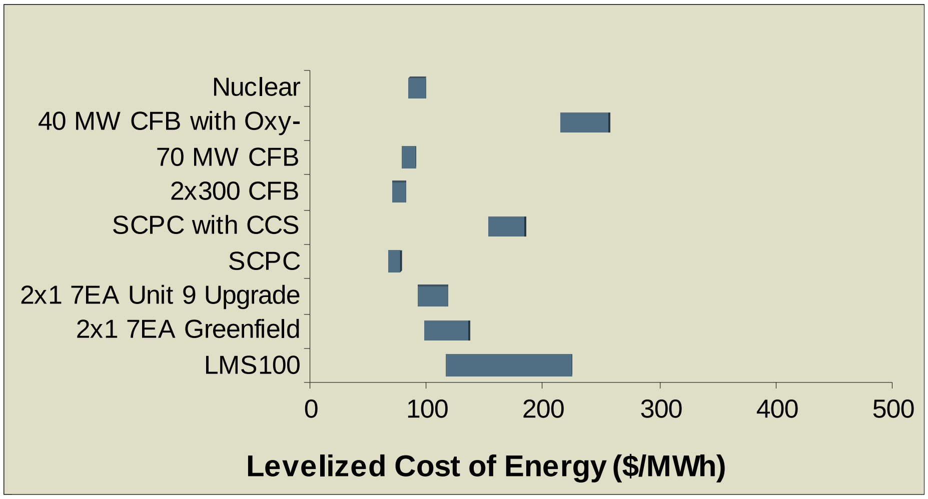


Figure 5-4
Comparison of the Levelized Cost of Energy for Conventional Energy Technologies

6.0 Fuel, Carbon Emission, and Energy Prices

This section summarizes the fuel, potential CO_2 emission allowance, and energy prices used in the expansion model. All prices are presented in nominal terms. The details and assumptions used to develop these price forecasts are contained in Appendix A, Energy Market Perspective.

6.1 Coal

Figure 6-1 illustrates the coal price forecast. The coal prices assumed an all-in delivered price from a Powder River Basin (PRB) source. The coal price forecast was used for all existing coal units, plus the potential PC unit and CFB units.

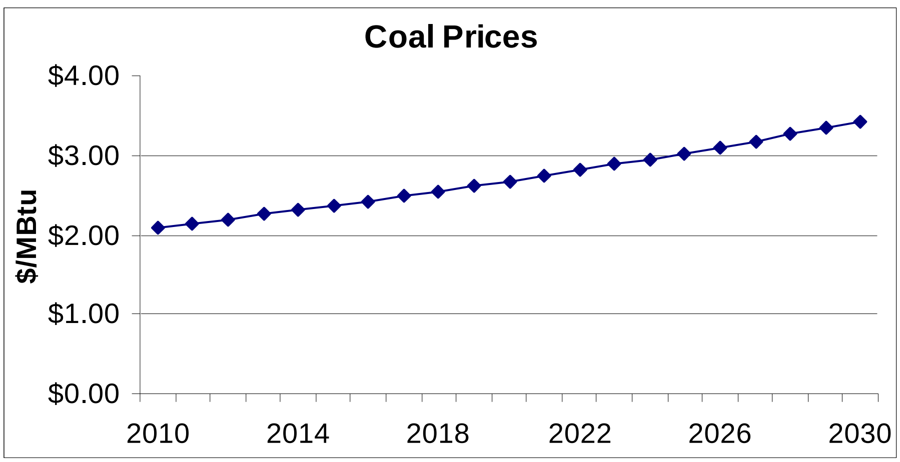


Figure 6-1
Coal Price Forecast (Nominal Dollars)

6.2 Natural Gas

Figure 6-2 illustrates the natural gas price forecast. The natural gas was assumed to be a regional delivered price. The natural gas price forecast was used for all gas fired existing units as well as new combined cycle and simple cycle units.

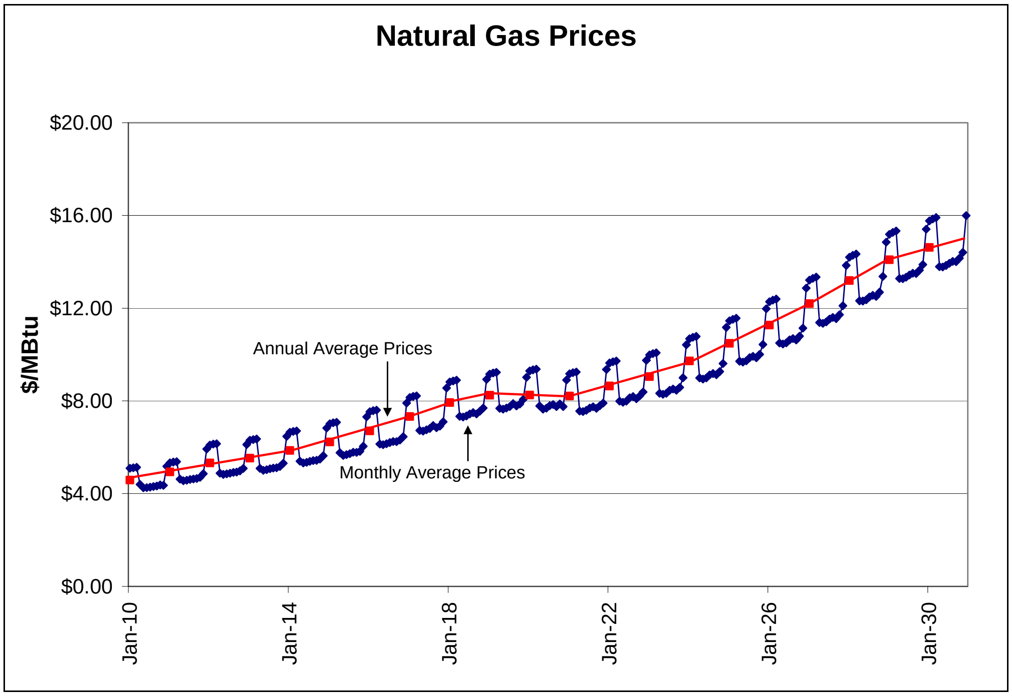


Figure 6-2
Natural Gas Prices Forecast (Nominal Dollars)

6.3 Carbon Emission Allowance

Figure 6-3 illustrates the assumed potential carbon emission allowance price forecast. The emission prices were levied on all units that burn fossil fuels and, hence, emit CO_2.

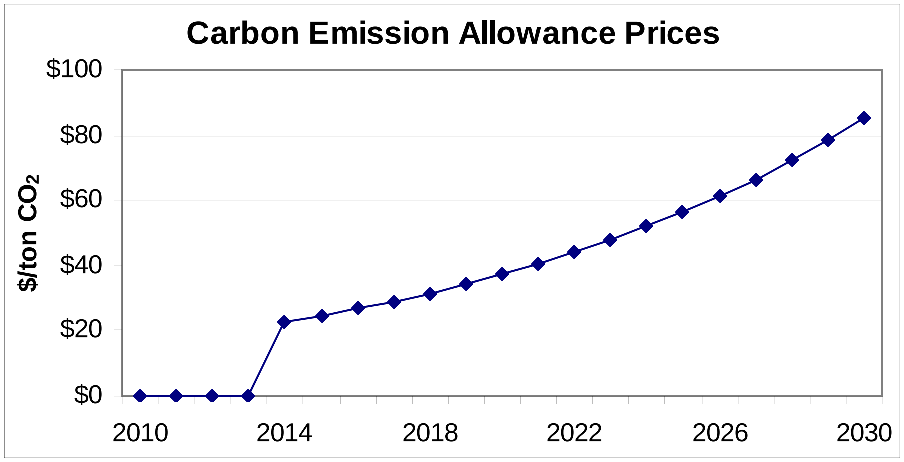


Figure 6-3
Carbon Emission Allowance Price (Nominal Dollars)

7.0 Economic Modeling of Expansion Plan Scenarios

In order to consider the demand and energy forecast, impact of fuel prices, emissions, and other factors, a detailed economic analysis was performed to determine a cost-effective capacity expansion plan to meet HBPW's forecast capacity requirements during the planning horizon. The assumptions and methodology used in the economic analysis, as well as the results of the base case analysis, are presented below.

Black & Veatch used the capacity expansion optimization computer model, Strategist, to evaluate combinations of resources available to HBPW, to meet future demand and energy requirements. Strategist has been used in various public service commission resource planning filings in Colorado, Florida, Ohio, Michigan, and other states. Strategist evaluates a typical week in each month of the year over the analysis period to optimize the least-cost generation alternatives considering peak demand, energy needs, fuel and emissions prices, fixed and variable operating costs, capital costs, and other factors, and estimates annual system costs. The software also has the capability to evaluate renewable resources. Multiple combinations of future resource additions were selected by the model to meet forecast capacity and energy requirements.

As presented in Section 3.0, a forecast of peak demand and system energy requirements was developed and adjusted for recent growth trends for HBPW's system through 2029. The peak load and system energy requirement forecasts were also adjusted for the projected demand and energy savings from different energy efficiency programs. HBPW forecast capacity requirements were developed considering the net peak demand forecast after adjusting for savings from energy efficiency programs, a 12.0 percent reserve requirement, and existing generating resources.

The economic analysis evaluated several different plans as well as sensitivities to determine the impact of various changes to the resource mix of these plans.

7.1 Modeling Assumptions and Methodology

The supply side evaluations of generating resource alternatives were performed using Strategist.

Strategist evaluated all combinations of generating unit alternatives, renewable resources, and purchase power options, in conjunction with existing capacity resources, while maintaining user-defined reliability criteria. All capacity expansion plans were analyzed over a 20 year period from 2010 through 2029.

Historically, HBPW has met more than 90 percent of its peak and energy requirements from self-owned generating resources and has utilized market-priced purchased power transactions to meet its remaining peak demand and energy requirements. Based on the forecast net of DSM and EE measures, and considering existing resources and planned purchases of landfill gas, HBPW does not need additional capacity until 2016. HBPW has indicated that it has procured or is in the process of procuring all resources necessary to meet HBPW's obligations until 2015. As such, Black & Veatch allowed the energy and capacity from market purchases to fulfill all obligations of HBPW until 2015, and no new resources were selected for this period.

Beyond 2015, all resources were available to meet future needs. Black & Veatch then used Strategist to develop capacity expansion plans in which owned and purchased capacity equaled or slightly exceed the projected peak demand plus reserve margin requirements each year.

Strategist utilized emergency energy purchases when the energy requirement exceeded the energy capability of the generating resources due to forced outages. In any given year, emergency energy purchases represent a very small portion of the total annual energy requirement. Emergency energy purchases were priced at a constant $500 per MWh throughout the study period.

Strategist also utilized economy energy purchases from the market to meet the system energy requirements when the energy price in the market was lower than the cost of generating electricity from the most efficient and least-cost available generating resource or purchase agreement available to HBPW. From a modeling perspective, in any given year, the amount of market purchases can be limited to a specified amount. To ensure that adequate supplies are available and reliable service is provided to customers, it is generally not recommended to rely on large amounts of market purchases.

As indicated above, HBPW historically has owned more than 90 percent of its capacity needs. Therefore, Black & Veatch assumed that the spot market purchases would be able to meet up to 10 percent of HBPW's need. Beginning in 2010, Black & Veatch allowed a limited amount of market purchases for every hour in the year for the period.

Strategist estimated annual production costs for each expansion plan and ranked the plans from lowest to highest cumulative present worth cost. Strategist simulated the operation of a power supply system over the 20 year planning period by economically dispatching available resources to meet the projected capacity and energy requirements. Strategist included variable O&M, emission costs, and fuel costs when determining the dispatch order for available generating resources. As a result, renewable resources will be dispatched first, followed by resources with the lowest total variable operating cost.

Required inputs for the model included the performance characteristics of generating units, fuel costs, fixed and variable O&M costs, emission rates and costs, demand and energy charges for purchase power resources, capital costs for future resource additions, system load profile, and projected capacity requirements including reserves.

Strategist summarized each resource's operating characteristics for every year of the planning horizon. These characteristics included, among others, each resource's annual generation, fuel consumption, fuel cost, emissions cost, and variable O&M costs. Fixed O&M costs were included separately for new unit additions. Typically, fixed O&M costs for existing units are generally considered sunk costs that will not vary from one expansion plan to another and are not included in production cost modeling. However, Black & Veatch included total O&M costs (including fixed O&M costs) for existing units. These costs were applied across all plans. Annual capacity charges for HBPW's existing and future power purchases were also included. The cumulative present worth cost (CPWC) of each expansion plan was calculated on the basis of projected total annual costs.

Black & Veatch reviewed the operating and cost data (including emission rates) provided by HBPW for its existing resources and some of the proposed new resources that were considered in the analysis. Black & Veatch provided the operating and cost data for the future new generic generation alternatives. Potential emission allowance costs for CO_2, SO_2, and NO_x were evaluated.

The CPWC calculation accounts for annual system costs (fuel and energy, fixed O&M, variable O&M, emissions, and levelized capital) for each year of the planning period and discounts each back to 2010 at the assumed present worth discount rate of 5.5 percent. The total of these annual present worth costs over the 2010 through 2029 period is the resulting CPWC of the expansion plan being considered. Such analysis allows for a comparison of CPWC between various capacity expansion plans, and the plan with the lowest CPWC is considered the least-cost capacity expansion plan.

Black & Veatch followed a two-step process in conducting these evaluations. In the first step, Black & Veatch identified a few base case scenario expansion plans and applied all the above assumptions to those scenarios. Once the base cases were evaluated, a CO_2 price sensitivity analysis was performed on these plans to estimate the likely impact of potential CO_2 taxes on the system cost and on the selection of new units.

7.2 Committed Resources and Other Specific Resources

In addition to the existing resources of HBPW, Black & Veatch also included some committed units that are expected to come on line during the study period. These units include the two PPAs with Granger Landfill Energy and North American Natural Resources (NANR). These PPAs are assumed to be effective for a period of 20 years, beginning February 2010. The total capacity from these resources increases over times as previously discussed in Section 2.0.

Black & Veatch evaluated the options of buying shares of the proposed 800 MW supercritical PC unit to be built at Karn-Weadock by Consumers Energy in Bay City, Michigan and the 2x300 MW CFB units proposed to be built in Rogers City, Michigan by Wolverine Electric Cooperative. Both these options are in the advanced stages of planning with forecast commercial online dates in 2016. The availability of these units coincides with the needs of HBPW; Black & Veatch evaluated these options for this study.

Black & Veatch also evaluated the option of HBPW building and owning a 70 MW (net) CFB unit on its own. The advantage of building a CFB unit is that it can be designed to burn not only coal but many other fuels like biomass. In doing so, the CO_2 emissions from the plant would be reduced. This option would also provide HBPW and its customers with additional benefits, which were also estimated as part of this analysis. For this option, Black & Veatch looked at two scenarios: burning coal only and burning coal co-fired with 30 percent biomass. Installation of this CFB unit would require that the JDY Unit 3, which has a summer capacity of 11 MW, would be retired at the end of 2013 and the new CFB plant would be built at that site. The CFB plant would be expected to be commercially available in 2016.

As an extension of the self-built CFB unit option, Black & Veatch evaluated the option of installing the CFB unit with a carbon capture and compression system. With this system, the net output of the plant will be reduced to 44 MW and the heat rate of the plant will go up significantly. The capital cost of the CFB with this system increases significantly.

HBPW indicated that this option would be considered only if DOE grant is available for the project. The DOE grant would provide the additional funding required for the carbon retrofit system, so Black & Veatch evaluated this option assuming that the capital cost of the plant would be the same as the 70 MW plant discussed above. As with the 70 MW (net) CFB plant, it was assumed that the JDY Unit 3, which has a summer capacity of approximately 11 MW, would be retired at the end of 2013 and the new CFB plant would be built at that site. The plant is expected to be commercially available in 2016.

Black & Veatch also evaluated an option of converting the existing combustion turbine CT9 into a 2 x 1 combined cycle plant. The existing turbine is a GE 7EA peaking unit and it is assumed that the plant will be converted into a 2 x 1 combined cycle plant by using the existing CT and adding on another GE 7EA CT, two HRSGs, and a steam turbine. The proposed combined cycle plant will be developed at the CT9 site. Since HBPW needs capacity in 2016, it is assumed that the new combined cycle unit would be available in 2016. Since the plant will be located at the CT9 site, the existing unit has to be retired at the end of 2013 for the new plant to be operational in 2016. Because of this unit's size after conversion, additional purchasers would be needed to make this option viable.

7.3 Baseload Resources in Expansion Plan

As discussed previously, HBPW will have predominantly peak load resources in its capacity mix in 2010. The total installed summer capacity for HBPW is 273 MW. Baseload resources comprising coal fired units and landfill gas units make up 40 percent of the installed capacity and the balance of resources are natural gas or fuel oil fired peaking units. Figure 7-1 shows the breakdown of peaking and baseload resources for 2010.

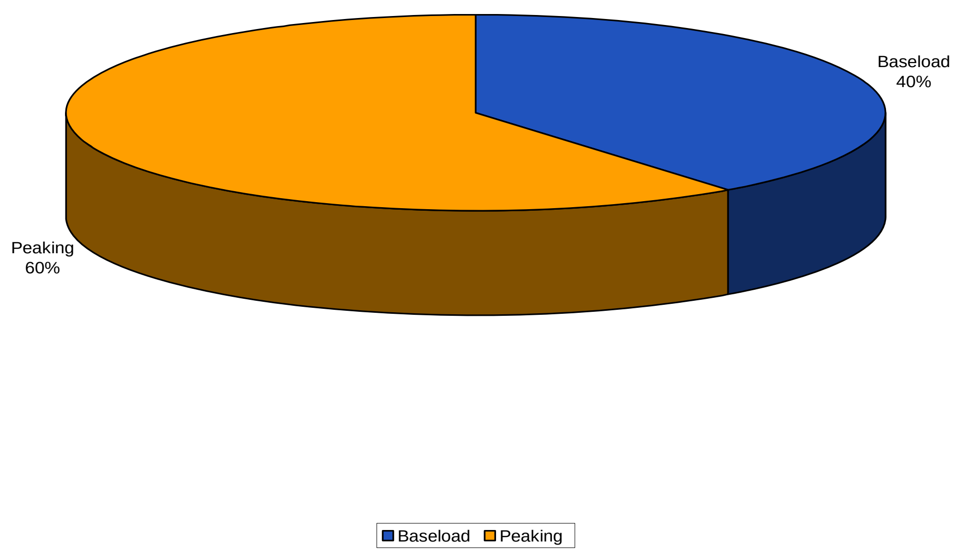


Figure 7-1
Capacity Resources in 2010 by Resource Characteristics

Based on the numbers, Black & Veatch is of the opinion that HBPW has a higher proportion of peaking resources than is usually seen in the resource mix of utilities of similar size. Ideally, utilities prefer to have at least 50 percent baseload and intermediate load resources in their resource mix. Having more baseload resources help in producing energy at a lower cost, which benefits customers of utilities by keeping the electricity rates lower.

7.4 Renewable Portfolio Standards

Black & Veatch considered the requirements of the renewable portfolio standards (RPS) in all the scenarios evaluated. It was assumed that at least 10 percent of the total system energy requirements would be met from renewable resources through 2020, which exceeds the renewable energy standard guidelines in Michigan PA 295. The RPS requirements will be met by energy produced from landfill gas resources of Granger Landfill Energy and NANR, which HBPW is purchasing through two new PPA agreements, a five year PPA from the CMS-Grayling biomass generation plant, and from proposed new wind farms to be developed in the future. Black & Veatch estimated that HBPW would need to acquire 5 MW and 6 MW of wind resources in 2021 and 2027, respectively, in order to comply with the RPS requirements.

In addition, Black & Veatch also evaluated a scenario where 20 percent of system energy needs are supplied from renewable resources by 2020. Under this scenario, Black & Veatch estimated that HBPW would need to acquire about 20 MW of wind in 2020 and an additional 2 MW in 2025. The renewable energy could be supplied from other resources as well.

7.5 Capacity Value for Different Technologies

One of the important decisions in planning for future resources is to consider the firm capacity of each resource. Firm capacity or capacity value of any unit is defined as the generating capacity of any resource to meet the peak load of the system. Conventional units like coal fired steam turbines, natural gas fired units, and some renewable units (such as landfill gas and biomass) can generate at maximum capacity or close to their maximum capacity during any hour, including peak demand hours, as long as the unit has a continuous supply of fuel. Baseload plants generally have a long-term fuel supply plan and/or also have fuel storage facilities onsite, which allow these plants to generate electricity whenever required. As such, baseload units generally have high capacity value (firm capacity) which usually ranges from 80 to 100 percent of its maximum capacity. Adding baseload units to a system gives high-capacity credit, which reduces the need for additional resources to meet the capacity and reliability needs for the system.

However, only some renewable resources have high-capacity credits. Renewable resources like wind, solar, and run-of-the-river hydro are not available at all times. In addition, these resources are also not available in the same quantity for all hours that they are available. Also, some resources such as wind exhibit a general inverse relationship with load (higher generation in off-peak hours and months in comparison to on-peak periods). As such, it is difficult to ascertain how much electricity can be generated from these resources during the peak demand hour.

Figure 7-2 shows the actual average hourly generation for each season in a year from a typical 100 MW wind farm in the Midwest region. Summer months are May through August; shoulder months are March, April, October, and November; and the remaining months are grouped as winter months. As shown on the figure, wind generation is highest during the non-summer months. In addition, on a daily basis, wind generation is higher during evening and early morning hours and lower during the day during the typical peak usage hours. The peak demand hour for most systems in the Michigan region (including the HBPW system) occurs in summer months and during the middle of the day. This shows that the wind generation profile is largely inversely correlated to the demand pattern. As such, adding wind resources to a system gives very little capacity credit to the system compared to baseload resources. Often, wind is given a capacity credit value in the 10 to 20 percent range of nameplate capacity. Black & Veatch assumed a 20 percent capacity credit for wind resource for this planning study, which is consistent with the typical generation profile shown on Figure 7-2. If a lower capacity is achieved from future wind generation resources, then additional capacity will be needed by HBPW than is currently forecast.

7.6 Transmission Cost Adders

Black & Veatch considered transmission cost adders in all the scenarios, where applicable. For the self-built plants, Black & Veatch did not add any transmission cost adders, as these plants would be built somewhere within the HBPW system. For all other resources considered, including the proposed wind resources, Black & Veatch estimated a transmission cost adder.

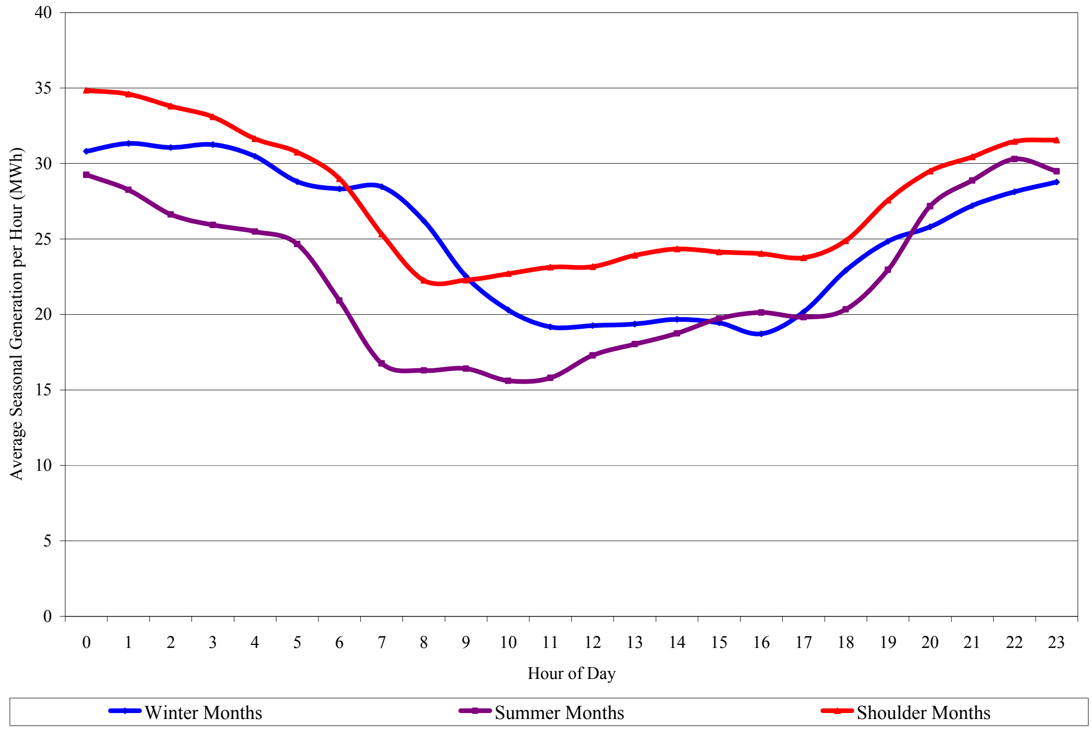


Figure 7-2
Seasonal Average Hourly Generation from a Typical 100 MW Wind Farm in Midwest

7.7 Availability of Resources

As discussed previously in this report, Black & Veatch used Strategist to optimize the expansion plans under the different scenarios. To let the model optimize in an ideal world, resources must be made available at all times throughout the study period so that the model can decide on selecting resources at any time. Keeping this in mind, Black & Veatch ran a fully optimized case, where it allowed the model to pick 5 MW blocks of different resources when needed during the study period. However, in the real world, it is difficult to acquire small capacity blocks of generating resources every year, because whole plants have to be constructed once the decision is made rather than building fractional units. As such, Black & Veatch restricted the availability of these 5 MW expansion units in the model beyond 2016 to be available only in 2018, 2022, 2026, and 2029.

7.8 Capacity Factor for Wind Resources

Black & Veatch assumed that new wind farms would be built in Michigan and assumed a 27 percent capacity factor for these wind farms. The estimation of wind output is based on recent output trends at some of the larger operating wind farms in the state and Black & Veatch's experience with this technology in the Midwest region of the United States.

7.9 Economic Parameters

7.9.1 Inflation and Escalation Rates

Table 7-1 presents the assumed general inflation rate, construction cost escalation rate, and fixed and nonfuel variable O&M escalation rates.

Table 7-1
Assumed Inflation and Escalation Rates

Component	Annual Rate (percent)
General Inflation	2.5
Construction Cost Escalation	2.5
Fixed O&M Escalation	2.5
Nonfuel Variable O&M Escalation	2.5

7.9.2 Debt Interest Rate and Discount Rate

The debt interest rate assumed for 30 year debt is 5.50 percent. The present worth discount rate was assumed to be equal to the debt interest rate of 5.5 percent. Both these values are conservatively high, as current tax exempt interest rates are lower than 5.5 percent.

7.9.3 Levelized Fixed Charge Rate

The fixed charge rate (FCR) represents the sum of a project's annual fixed charges as a percentage of the initial investment cost. When the FCR is applied to the initial investment, the product equals the revenue requirements needed to offset the fixed charges during a given year. A separate FCR can be calculated and applied to each year of an economic analysis, but it is common practice to use a single, levelized FCR that has the same present value as the year-by-year fixed charge rate.

Different technologies evaluated for this study have been levelized across different periods, in accordance with prudent industry practice. The different FCR for different terms are highlighted on Table 7-2.

Table 7-2
Different FCR for Different Time Periods

Bond Financing Period (years)	Bond Interest Rate (%)	FCR
40	5.50	7.23%
30	5.50	7.88%
20	5.50	9.37%

7.10 Capacity Expansion Plans

The previous sections described the assumptions and methodology that were used to select least-cost capacity expansion plans for HBPW. Strategist was used to estimate the total annual system costs and to establish the CPWC associated with each expansion plan. The advantage of using a program such as Strategist is that the CPWC for a large number of plans are developed and the program then ranks the expansion plans from lowest to highest CPWC. In this section, only the system generating costs are discussed. Apart from the system generating costs, HBPW incurs additional administrative and distribution expenses, which are discussed below. These additional expenses are constant across all plans and do not influence the selection of the different plans.

Table 7-3 shows the 10 least-cost plans developed for the HBPW in order of their rank, along with their respective CPWC values and their 20 year levelized cost on a $/MWh basis. From 2010 through 2015, each plan is identical and relies on existing and committed resources and on small amounts of market-based purchases to meet projected demand and energy requirements. The percent cost difference in CPWC between the different cases is shown on Figure 7-3. Table 7-4 shows the detailed expansion plan for four of the ten plans selected on the basis of the results shown in Table 7-3. These four plans were selected on the basis of the different baseload units discussed in Section 7.3.

The least-cost expansion plan for HBPW includes the conversion of the existing CT, CT9, into a 2 x 1 combined cycle plant. The CPWC for the plan is $1,484 million ($62.68/MWh on a levelized cost basis). Once converted, this plant will have a capacity of over 200 MW, and the model only selects a portion of the output. As a result, this plan requires that additional power purchasers are available to participate in the proposed conversion.

Table 7-3
Ranking of Different Expansion Plans with CPWC Values
(System Generation Cost Only)

Plan Description	CPWC Value 2010 Dollars (000s)	Levelized Cost ($/MWh)	Rank	Percent Difference
Unit 9 conversion to 2 x 1 GE 7EA combined cycle. Old CT9 unit retired in 2013. New combined cycle unit available in 2016	1,484,856	62.68	1	0.0%
Fully optimized case. Buying 5 MW blocks of all coal and CFB units (except CCS units), and all generic units are available in 2016	1,498,380	63.25	2	0.9%
Buying 5 MW blocks of 2 x 300 MW CFB unit at Roger City in 2016	1,499,619	63.30	3	1.0%
Buying 30 MW block of 800 MW SCPC unit at Weadock in 2016	1,500,649	63.35	4	1.1%
Buying 5 MW Blocks of 70 MW net CFB unit using 30 percent biomass as fuel to be built by HBPW in 2016	1,502,967	63.44	5	1.2%
Fully optimized case with 20 percent RPS requirements met with additional wind resources only	1,505,064	63.53	6	1.4%
No new units/blocks of units added. Everything is purchased from the market.	1,511,770	63.82	7	1.8%
Buying 5 MW Block of 70 MW net CFB unit to be built by HBPW in 2016. JDY Unit 3 to be retired in 2013.	1,523,441	64.31	8	2.6%
40 MW net CFB unit with CCS (whole plant) to be built by HBPW in 2016. JDY Unit 3 to be retired in 2013.	1,578,367	66.63	9	6.3%
70 MW net CFB unit (whole plant) to be built by HBPW in 2016. JDY Unit 3 to be retired in 2013.	1,591,727	67.19	10	7.2%

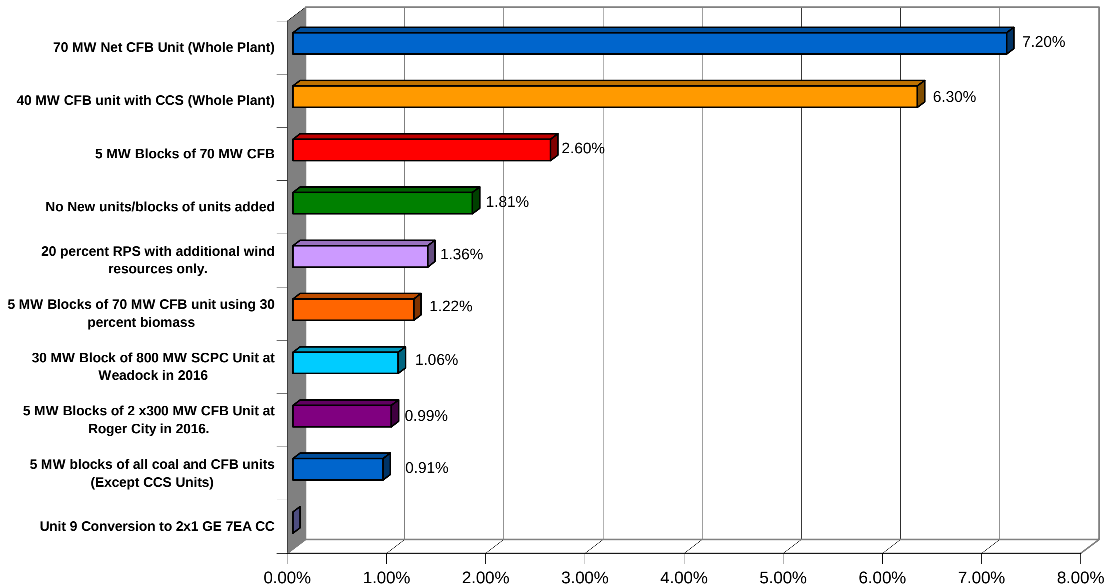


Figure 7-3
Percent Difference in Cost of Different Expansion Plans
Compared to Least-Cost Expansion Plan

Table 7-4
Detailed Expansion Units for Selected Plans

Year	Plan 1			Plan 2			Plan 3			Plan 4		
	30 MW Block of 800 MW SCPC Unit at Weadock in 2016			70 MW CFB Unit (Whole Plant) to be Built by HBPW in 2016			Unit 9 Conversion to 2 x 1 GE 7EA Combined Cycle			5 MW Blocks of 70 MW CFB Unit Using 30 Percent Biomass as Fuel		
	Resource	Units	MW	Resource	Units	MW	Resource	Units	MW	Resource	Units	MW
2010												
2011												
2012												
2013				JDY Unit 3 Retired	1	-11	CT9 Retired	1	-75	JDY Unit 3 Retired	1	-11
2014												
2015												
2016	SCPC Coal	6	30	CFB	1	70	Combined Cycle	20	100	CFB	4	20
2017												
2018										Combined Cycle	4	20
2019												
2020												
2021												
2022	Combined Cycle	3	15				Combined Cycle	1	5	Combined Cycle	3	15
2023												
2024												
2025												
2026	Combined Cycle	2	10				Combined Cycle	2	10	Combined Cycle	3	15
2027												
2028												
2029	Combined Cycle	1	5	SCPC	1	5				Combined Cycle	1	5
	SCPC	1	5							SCPC	1	5
Total Capacity Added			65			64			40			69

The next least-cost expansion plan for HBPW is the fully optimized plan, where HBPW has the option of buying capacity from different resources in increments of 5 MW in all years of the study period. However, as discussed in Section 7.7, this option presents an ideal world case that would be difficult to implement in the real world. However, this plan provides some insight into the types of capacity that might be desirable. The CPWC for the plan is $1,498 million ($63.25/MWh on a levelized cost basis). It is approximately 0.9 percent higher than the least-cost plan.

The next option for HBPW includes buying a 20 MW share of the 2 x 300 MW CFB plant being built at Roger City. This option is contingent on HBPW being allowed to buy only 20 MW of the 600 MW plant and this planned project moving ahead. This optimum share of the plant (20 MW) constitutes only 3.7 percent of the total output from the plant and it may not be possible to procure this small of an ownership share. The CPWC for the plan is $1,500 million ($63.30/MWh on a levelized cost basis). It is approximately 1.0 percent higher than the least-cost plan.

The next option for HBPW includes buying a 30 MW share of the 800 MW SCPC plant being built at Karn-Weadock. This option is contingent on HBPW being allowed to buy only 30 MW of the 800 MW plant. This optimum share of the plant (30 MW) constitutes only about 3.75 percent of the total output from the plant and it may not be possible to procure this capacity. The CPWC for the plan is $1,501 million ($63.35/MWh on a levelized cost basis). It is approximately 1.1 percent higher than the least-cost plan.

The next option for HBPW includes using a 20 MW share of the self-built 70 MW (net) CFB plant with 30 percent of the energy resulting from biomass co-fired with a combination of coal. This option is not contingent upon other external factors and also reduces the carbon footprint of the system compared to the previous two options. The CPWC for the plan is $1,503 million ($63.44/MWh on a levelized cost basis). It is approximately 1.2 percent higher than the least-cost plan. This plan includes other community benefits to the utility and its customers that are not available with other plans. These benefits are discussed in a subsequent section.

The fully optimized scenario, complying with the 20 percent RPS requirement scenario, comes in next with a CPWC of $1,505 million ($63.53/MWh on a levelized cost basis). The option of buying everything from the spot market has a CPWC of $1,512 million ($63.82/MWh on a levelized cost basis) and has the next lowest system cost.

Finally, Black & Veatch evaluated the options of adding the new CFB plant (both with and without sequestration options) and keeping all the output from the plant for HBPW needs. Under these options, HBPW would initially be adding more capacity than required, but would not need to add any more capacity until farther out in the study period. These options were evaluated because it may be beneficial for HBPW to plan for a fully owned and operated new generating resource than buying capacity from others' resources. As indicated above, the CFB plant would provide additional benefits for the community, which would offset some of the costs associated with this plan. The option of installing a 40 MW (net) CFB plant with carbon sequestration by availing DOE funding has a CPWC value of $1,578 million ($66.63/MWh on a levelized basis). It is approximately 6.3 percent higher than the least-cost plan. This plan was only viable if DOE funding could be obtained.

The CPWC of the option of owning a 70 MW net CFB unit (without sequestration and without DOE funding) is $1,591 million ($67.19/MWh on a levelized cost basis). It is approximately 7.2 percent higher than the least-cost plan.

In all the above plans, the first new generating resource is added in 2016 and generic units are subsequently added as required in 2018, 2022, 2026, and 2029.

As can be seen from the discussion of the results, the cost difference between the least-cost and the most expensive plans is only about 7.2 percent on a 20 year net present value basis. This difference is not very significant, and so based on this economic analysis, none of these options clearly stand out as the best option for HBPW. Under the circumstances, it is prudent to select a few of these options based on realistic considerations and evaluate them further for other advantages and disadvantages. In addition, by pursuing multiple plans, HBPW will have options if any of these alternatives cease to be viable.

Four of these plans were selected for further evaluations. These plans are not necessarily the least-cost plans, but have other advantages which are discussed later in this report. The following plans were selected for further analysis:

- Plan 1: Buying 30 MW of the 800 MW SCPC unit at Karn-Weadock in 2016.
- Plan 2: Owning the entire 70 MW CFB plant to be built by HBPW in 2016.
- Plan 3: Converting the Unit 9 CT into a 2x1 combined cycle unit in 2016.
- Plan 4: Owning 5 MW blocks (20 MW) of the 70 MW CFB Plant to be built by HBPW that would burn 30 percent biomass fuel.

Table 7-4 shows the detailed expansion units for these four plans.

7.11 Non-generating Expenses

HBPW provided Black & Veatch with detailed cost estimates for fixed administrative, distribution, and depreciation expenses for the system. These expenses were assumed to be constant across all options evaluated. Black & Veatch estimated that the 20 year CPWC of these costs were $219.013 million. A summary of these expenses is provided in Table 7-5. This system cost was added to the generating costs shown in Table 7-3 to generate the total system cost for each of the plans evaluated.

When the different plans are compared on the total system cost, the difference between the least-cost plan and the most expensive plan is 6.3 percent compared to a 7.2 percent difference when the generating costs are considered. This demonstrates that all the options evaluated are close to one another in terms of cost prior to consideration of the community benefits associated with the CFB alternative.

7.12 Benefits Analysis

As discussed earlier, Black & Veatch selected four plans for further analysis of other benefits. The plans that include building the 70 MW CFB plant include additional community benefits to HBPW and the community it serves. These benefits will be effective from 2016, when the proposed new plant becomes operational, and are summarized in Table 7-6.

The community benefits include a waste heat source for the City's snow melt system and potential expansion of this system into supplemental or direct building heat, funding for harbor dredging, and wastewater treatment solids beneficial use. The City's current snow melt system relies on cooling water discharge from JDY Unit 3, which is planned to be retired with the CFB option. It is likely that this unit would be retired before the end of the study period due to the unit's current age. Upon retirement, new gas fired boilers would need to be installed to keep the snow melt system operational. As a result of installing the CFB unit, the snow melt system could use the CFB's cooling water discharge for the snow melt system. Because the CFB is larger in size than Unit 3, this system could also be expanded over the 2016 to 2030 time frame.

The CFB unit would receive coal deliveries from the harbor. As a result of the harbor usage, the City should be able to retain harbor dredging federal funding support that will lower the harbor costs to the City.

Lastly, the CFB will be able to burn the City's wastewater treatment plant biosolids to offset fuel usage. By beneficially using these biosolids, the City will also save the expense of landfilling or land applying these solids, as is the current practice. CFB fuel use will also be slightly reduced and the biosolids would qualify as a renewable resource under PA 295.

Table 7-5
Summary of Non-Generating Expenses

Description	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
System Fixed Component	4,868	4,989	5,114	5,242	5,373	5,507	5,645	5,786	5,931	6,079	6,231	6,387	6,546	6,710	6,878	7,050	7,226	7,407	7,592	7,782
Other Cost Contribution to HBPW	3,984	4,169	4,611	4,943	5,173	5,355	5,545	5,768	5,995	6,233	6,475	6,720	6,971	7,231	7,499	7,780	8,067	8,359	8,660	8,969
Depreciation	8,146	8,128	6,829	6,344	6,115	5,766	5,588	5,375	5,288	5,199	3,691	3,595	3,696	3,791	3,766	3,619	3,695	3,805	3,859	3,890
Total Annual Non Generating Costs	16,997	17,286	16,554	16,529	16,660	16,629	16,778	16,928	17,214	17,511	16,397	16,701	17,214	17,732	18,143	18,449	18,988	19,571	20,111	20,641
Discount Rate	5.50%																			
PV Of Annual Non Generating costs	16,997	16,385	14,873	14,076	13,449	12,723	12,168	11,637	11,217	10,815	9,599	9,268	9,054	8,840	8,574	8,264	8,062	7,876	7,672	7,463
NPV	219,013																			

Table 7-6
Benefit Credits ($000s) for Building the 70 MW (net) CFB Plant

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Snow Melt Assumed	12,798	995	1,208	1,411	1,599	1,797	2,065	2,350	2,692	3,072	3,486	3,950	4,460	4,997
Dredged Harbor Funding	2,260	553	570	587	1,433	623	2,699	661	681	701	1,711	744	3,223	789
Wastewater Solids Beneficial Use	(3,079)	506	532	560	590	621	654	689	727	767	808	852	899	949
Total CFB Community Benefits	11,979	2,055	2,311	2,558	3,621	3,041	5,418	3,700	4,100	4,539	6,004	5,545	8,582	6,735
Discount Rate	5.50%													
NPV (2016$)	47,245													
NPV (2010$)	34,264													

The CPWC of the benefits stream (2016-2029) is $34.264 million (in 2010 dollars). The details of the benefits credit calculations are shown in Table 7-7. This benefit credit would offset some of the generating costs associated with the CFB plans. Applying the community benefits credit to the CPWC of total system costs, reduces the net total system cost for the plan that includes building and owning the entire 70 MW CFB plant (fired with coal only) to $1,776 million. As a result, the difference in cost from the least-cost plan on a 20 year CPWC basis is 4.26 percent.

The CPWC of the plan that includes owning 20 MW of the 70 MW CFB plant fired with 30 percent biomass fuel will reduce to $1,688 million after consideration of the community benefits. This makes this plan the least-cost plan as the cost becomes lower than the plan that includes conversion of CT9. Moreover, this plan will look even more attractive if HBPW is able to have other utilities participate in this project. As this plant would be co-firing biomass fuel, some generation from this plant will qualify for renewable energy credits, which may be traded in the future. This plan will also enable HBPW to exceed the minimum RPS requirements specified in Michigan P.A. 295.

The plan that includes buying a 30 MW block of the proposed 800 MW SCPC plant at Karn-Weadock and the plan that includes the conversion of CT9 will not have these benefits, so these total system costs are not adjusted for these benefits.

7.13 Sensitivity Analysis

In order to further evaluate the four cases, additional sensitivities were evaluated as some of the variables may show high variation with the projected values. Based on experience, the most significant potential impact is from the potential for CO_2 allowance costs.

The alternatives evaluated included various mixes of renewable resources, gas fired resources, coal fired resources, or direct market power purchases with a fixed energy and capacity cost. These alternatives were evaluated with the potential impact of possible CO_2 legislation. In the base case, alternatives were evaluated assuming a CO_2 price forecast as discussed previously, which has a significant impact on energy prices. As a result, the four different plans were evaluated where no CO_2 allowance prices were considered. The percent difference in cost for the four different plans is shown on Table 7-8 and Figure 7-4.

Table 7-7
Ranking of Different Expansion Plans with CPWC Values
(Total System Cost)

Plan Description	CPWC Value 2010 Dollars (000s)	Levelized Cost ($/MWh)	Rank	Percent Difference
Unit 9 conversion to 2x1 GE 7EA combined cycle. Old CT9 unit retired in 2013. New combined cycle unit available in 2016	1,703,869	71.93	1	0.0%
Fully optimized case. Buying 5 MW blocks of all coal and CFB units (Except CCS units), and all generic units are available in 2016	1,717,393	72.50	2	0.8%
Buying 5 MW blocks of 2 x 300 MW CFB unit at Roger City in 2016	1,718,632	72.55	3	0.9%
Buying 30 MW block of 800 MW SCPC unit at Weadock in 2016	1,719,662	72.59	4	0.9%
Buying 5 MW blocks of 70 MW net CFB unit using 30 percent biomass as fuel to be built by HBPW in 2016	1,721,980	72.69	5	1.1%
Fully optimized case with 20 percent RPS requirements met with additional wind resources only	1,724,077	72.78	6	1.2%
No new units/blocks of units added. Everything is purchased from the market.	1,730,783	73.06	7	1.6%
Buying 5 MW blocks of 70 MW net CFB unit to be built by HBPW in 2016. JDY Unit 3 to be retired in 2013.	1,742,454	73.55	8	2.3%
40 MW net CFB unit with CCS (whole plant) to be built by HBPW in 2016. JDY Unit 3 to be retired in 2013.	1,797,380	75.87	9	5.5%
70 MW net CFB unit (whole plant) to be built by HBPW in 2016. JDY Unit 3 to be retired in 2013.	1,810,740	76.44	10	6.3%

Table 7-8
Ranking of Selected Expansion Plans With No CO_2 Allowance Costs
(System Generation Cost Only)

Plan Description	CPWC Value-2010 Dollars (000s)	Levelized Cost ($/MWh)	Rank	Percent Difference
Buying 30 MW block of 800 MW SCPC unit at Weadock in 2016	1,056,668	44.61	1	0.0%
Buying 5 MW blocks of 70 MW net CFB unit using 30 percent biomass as fuel to be built by HBPW in 2016	1,093,011	46.14	2	3.4%
Unit 9 conversion to 2x1 GE 7EA combined cycle. Old CT9 unit retired in 2013. New combined cycle unit available in 2016.	1,094,288	46.19	3	3.6%
70 MW net CFB unit (whole plant) to be built by HBPW in 2016. JDY Unit 3 to be retired in 2013.	1,105,908	46.68	4	4.7%

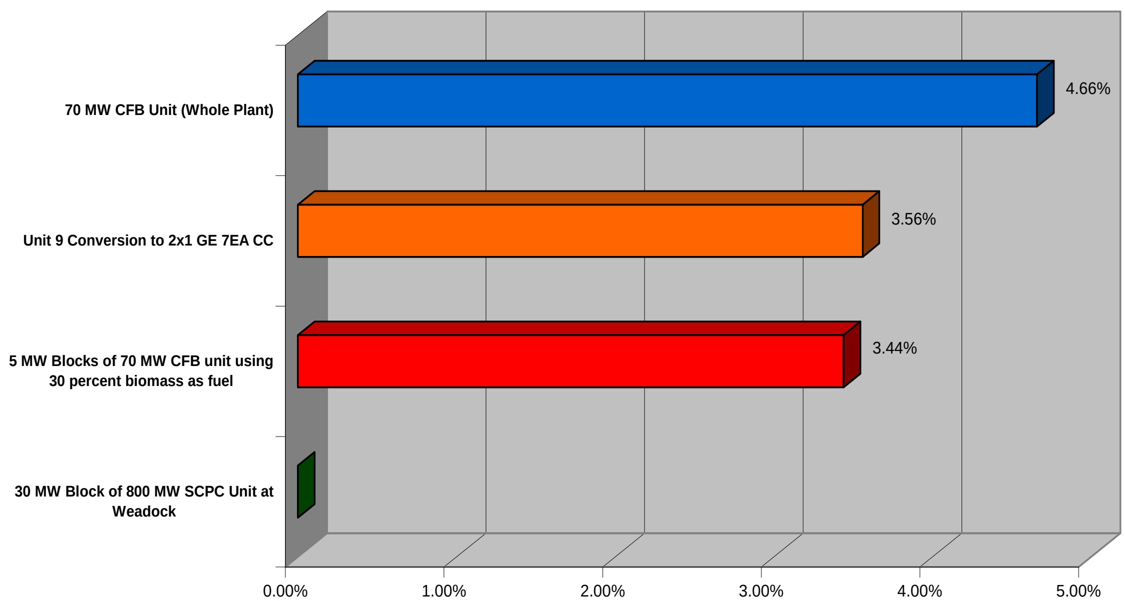


Figure 7-4
Expansion Plan Cost Differentials without Impact of Potential CO_2 Allowance Cost

Under this scenario, the ranking of the plans does change. As expected, the plan that is impacted the most is the plan that includes the 30 MW block purchase of the 800 MW SCPC unit at Karn-Weadock. This plan is the most carbon intensive plan as there are no carbon sequestration measures. This plan now becomes the least-cost plan. Compared to the base case, where CO_2 taxes were assumed, the total change in the CPWC for this plan is $444 million, which equates to a levelized cost difference of $18.85/MWh.

The plan that includes buying 20 MW of the CFB plant co-firing biomass comes in next with a CPWC of $1,093 million. This plan is not as carbon intensive as the previous plan, so the cost difference under the two scenarios is $410 million, which equates to a levelized cost difference of $17.30/MWh

As expected, the conversion plan (converting CT9 to a combined cycle plant in 2016) has a lower CPWC under this scenario as compared to the base case, although its cost savings is not as much as the other cases. The smaller CPWC reduction is a result of this plan's lower CO_2 emission profile. The CPWC of this plan is $1,094 million and is $391 million less expensive than the plan with the CO_2 scenario. Natural gas fired units are generally considered to be highly reliable, with a lower CO_2 emissions profile compared to market or coal purchases. However, natural gas units can experience price volatility associated with changes in gas prices.

The plan that includes owning 70 MW of the CFB plant has the greatest impact in cost under the two scenarios. This is because this plant has a much higher capacity than the other plans discussed in this section. The CPWC of this plan under this scenario is $1,106 million and is $486 million less expensive compared to the CPWC with the CO_2 taxes scenario. However, this plan still remains the most expensive plan.

The above discussion was based on the system generation cost only. However, when the non-generating cost ($219.031 million) is added to the system generation cost for all the plans and the benefit credits ($34.264 million) are deduced from the system generation cost, the ranking of the plans under this scenario does not change. The rankings of the plans and their CPWC are shown in Table 7-9. However, the cost of the least-cost plan (buying a 30 MW block of the 800 MW SCPC unit at Karn-Weadock) and the plan that includes buying 20 MW of the 70 MW CFB plant co-firing 30 percent biomass fuels has now decreased to only 0.2 percent.

Table 7-9
Ranking of Selected Expansion Plans with No CO_2 Allowance Costs
(Total System Cost after Adjusting for Community Benefits Credits)

Plan Description	CPWC Value-2010 Dollars (000s)	Levelized Cost ($/MWh)	Rank	Percent Difference
Buying 30 MW block of 800 MW SCPC unit at Weadock in 2016	1,275,681	53.86	1	0.0%
Buying 5 MW blocks of 70 MW net CFB unit using 30 percent biomass as fuel to be built by HBPW in 2016	1,277,760	53.94	2	0.2%
70 MW net CFB unit (whole plant) to be built by HBPW in 2016. JDY Unit 3 to be retired in 2013.	1290,657	55.94	3	1.2%
Unit 9 conversion to 2x1 GE 7EA combined cycle. Old CT9 unit retired in 2013. New combined cycle unit available in 2016.	1,313,301	55.44	4	2.9%

7.14 Conclusion from Benefits Analysis

As discussed previously, the total annual community benefit credits for building the CFB plant have a CPWC of $34.264 million (in 2010 dollars) over the period 2016 to 2029. These benefits would offset some of the generating costs associated with the CFB plans. Applying this credit to the CPWC of total system costs, the net total system cost for the plan that includes building and owning the entire 70 MW CFB plant (fired with coal only) is $1,776 million. The difference in cost from the least-cost plan on a 20 year CPWC basis is 5.26 percent. The cost of the other three plans after accounting for CO2 taxes, community benefits and other system costs is shown in Table 7-10.

The CPWC of the plan that includes owing 20 MW of the 70 MW CFB plant fired with 30 percent biomass fuels decreases to $1,688 million, which makes this plan the least-cost plan, as the cost becomes lower than the plan that includes conversion of the existing CT9 combustion turbine. This plan assumes that HBPW is able to have other utilities participate in the project. As this plant would be co-firing biomass fuel, a portion of the generation from this plant may qualify for renewable energy credits, which may be traded in the future. This plan will also enable HBPW to exceed the minimum RPS requirements specified in Michigan P.A. 295.

In addition, HBPW will also be benefited by owning this plant and relying less on the MISO grid to provide power to its system.

Table 7-10 summarizes the results of these plants including the community benefits.

Table 7-10
Ranking of Selected Expansion Plans Based on Net System Cost after Adjusting for Benefit Credits and With CO_2 Allowance Costs

Plan Description	CPWC Value-2010 Dollars (000s)	Levelized Cost ($/MWh)	Rank	Percent Difference
Buying 5 MW blocks of 70 MW net CFB unit using 30 percent biomass as fuel to be built by HBPW in 2016	1,687,716	71.24	1	0.0%
Unit 9 conversion to 2x1 GE 7EA combined cycle. Old CT9 unit retired in 2013. New combined cycle unit available in 2016.	1,703,869	71.93	2	0.9%
Buying 30 MW block of 800 MW SCPC unit at Weadock in 2016	1,719,662	72.59	3	1.9%
70 MW net CFB unit (whole plant) to be built by HBPW in 2016. JDY Unit 3 to be retired in 2013	1,776.476	74.98	4	5.26%

8.0 Emissions Profile

This section summarizes the emissions profile of the four key expansion plans discussed in Section 7.0. Historical annual emissions quantities have been estimated and compared to projected emissions for selected plans, to show the expected future level of emissions in these cases. Forecast emissions are based on the output results from the Strategist model runs. Emission rates for existing generating units were provided by HBPW and reviewed by Black & Veatch, while emission rates for alternative generating units were estimated by Black & Veatch.

8.1 Emissions Overview

Coal generation has the greatest impact on the emissions profile of the region as it typically has the highest rate of emissions for every unit of fuel burned. In contrast, natural gas fired resources have the lowest emission rates amongst all fossil fuels. Renewable resources including wind, solar, and hydro units do not have any emissions at all. Landfill gas and biomass will have emissions of various pollutants, but are generally considered carbon neutral with no CO_2 emissions.

Nuclear units also do not emit any of the above mentioned emissions, except for minor emissions from support or backup systems. The emission rates of CO_2 gases are dependent on the quality of the fuel burned. In general, the CO_2 emission rate for coal based generation usually varies between 200 to 220 lb/MBtu. In comparison, the CO_2 emission rate for gas and oil based generation usually varies between 115 to 120 lb/MBtu and 155 to 170 lb/MBtu, respectively.

8.2 Historical Emissions Overview for the State of Michigan

Black & Veatch estimated the historical emissions for the HBPW system based on available information for the state of Michigan. In doing so, Black & Veatch needed to estimate system wide emission rates for CO_2, NO_x, and SO_2 to estimate emissions from the on-the-spot market or from the long-term market purchase contracts.

According to the EPA's eGRID database, the emission rates of CO_2, NO_x, and SO_2 (on a lb per MWh basis) were 1,854.9, 2.9, and 8.8, respectively. Black & Veatch used these average emission rates to estimate the historical emissions from 2004 through 2009 that were attributed to spot market and long-term market purchase contracts.

Recent declines in historical emissions are the result of a decline in energy use over the last few years caused by the recession.

8.3 CO_2 Emissions Profile

The CO_2 emissions profile for the four key expansion plans discussed in Section 7.0 was analyzed. Figure 8-1 shows the historical and projected CO_2 emissions for HBPW for the different expansion plans considered.

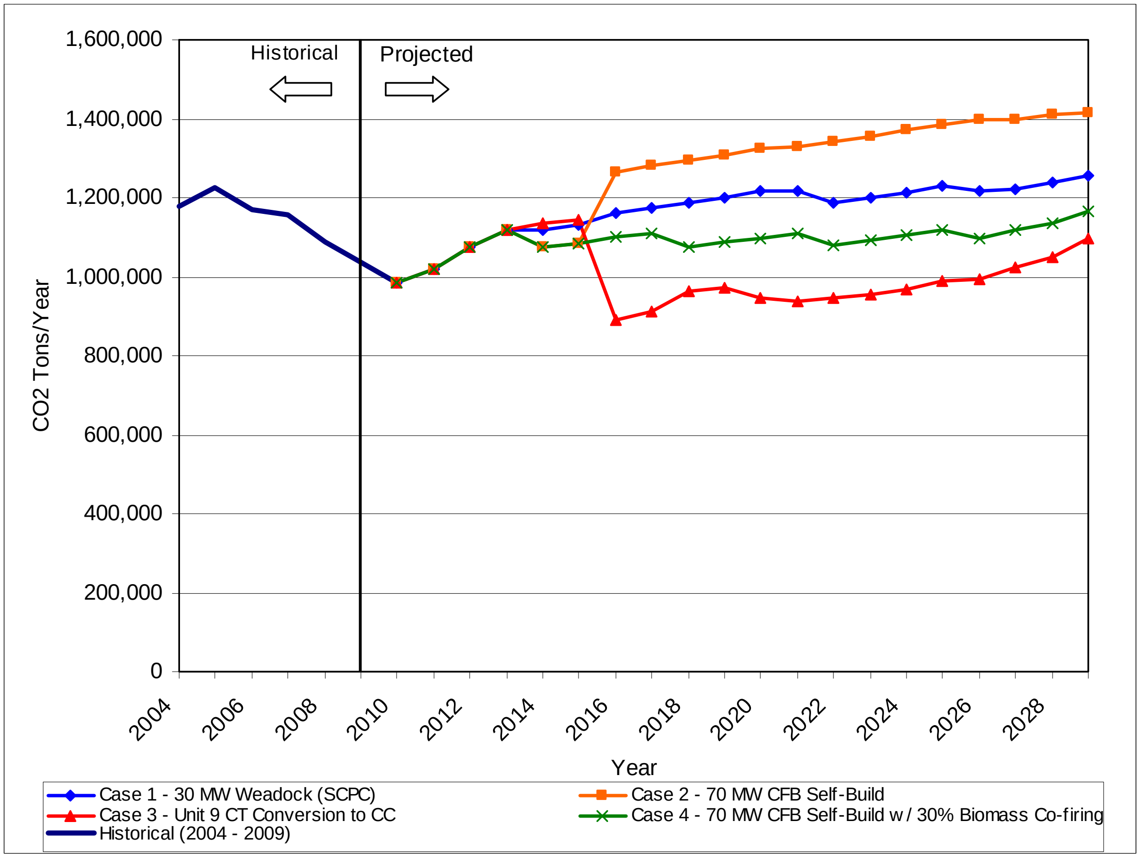


Figure 8-1
Historical and Projected CO_2 Emissions

The emissions profile is similar for all plans until 2014, as no new resources are added in any of the plans for the period 2010 to 2014. Beyond 2014, the plan that includes the 7EA 2 x 1 combined cycle conversion has the greatest reduction in CO_2 emissions after the new resource comes online in 2014. The total reduction is forecast to be 28 percent compared to the previous year. As expected, the addition of gas fired generation has the lowest CO_2 emissions profile, followed by the CFB with biomass co-firing.

8.4 SO_2 Emissions Profile

The SO_2 emissions profile for the four key expansion plans discussed in Section 7.0 was also evaluated. Figure 8-2 shows the historical and projected SO_2 emissions for HBPW for the different expansion plans considered.

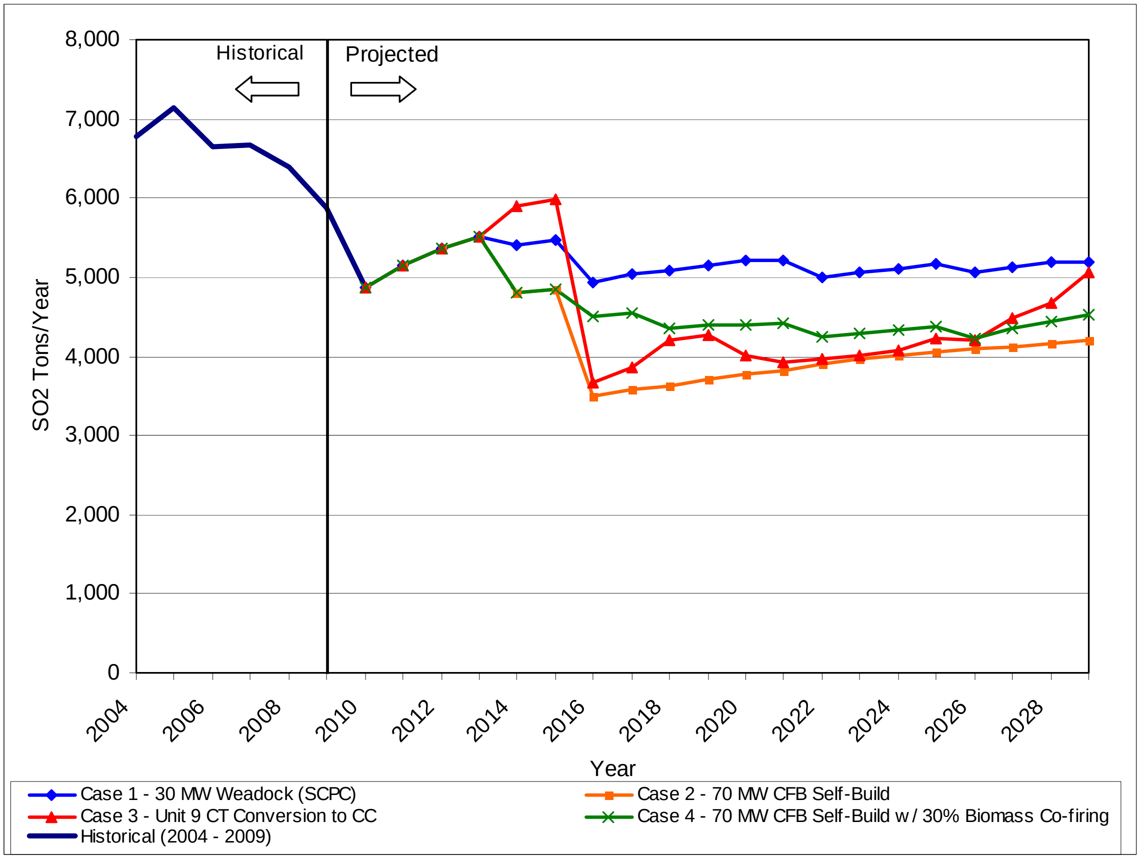


Figure 8-2
Historical and Projected SO_2 Emissions

The emissions profile is similar for all plans until 2014, as no new resources are added in any of the plans for the period 2010 to 2014. Beyond 2014, the plan that includes the 7EA 2 x 1 combined cycle conversion has the greatest reduction in SO_2 emissions after the new resources come online in 2014. The total reduction is forecast to be 21 percent compared to the previous year. However, the plan with the lowest SO_2 emissions profile throughout the study period is the 70 MW CFB self-build option as a result of replacing an older coal unit without SO_2 controls with a newer unit. The plan with the 30 MW supercritical pulverized coal capacity has the highest emissions profile for the period.

8.5 NO_x Emissions Profile

The NO_x emissions profile for the four key expansion plans discussed in Section 7.0 was also analyzed. Figure 8-3 shows the historical and projected NO_x emissions for HBPW for the different expansion plans considered.

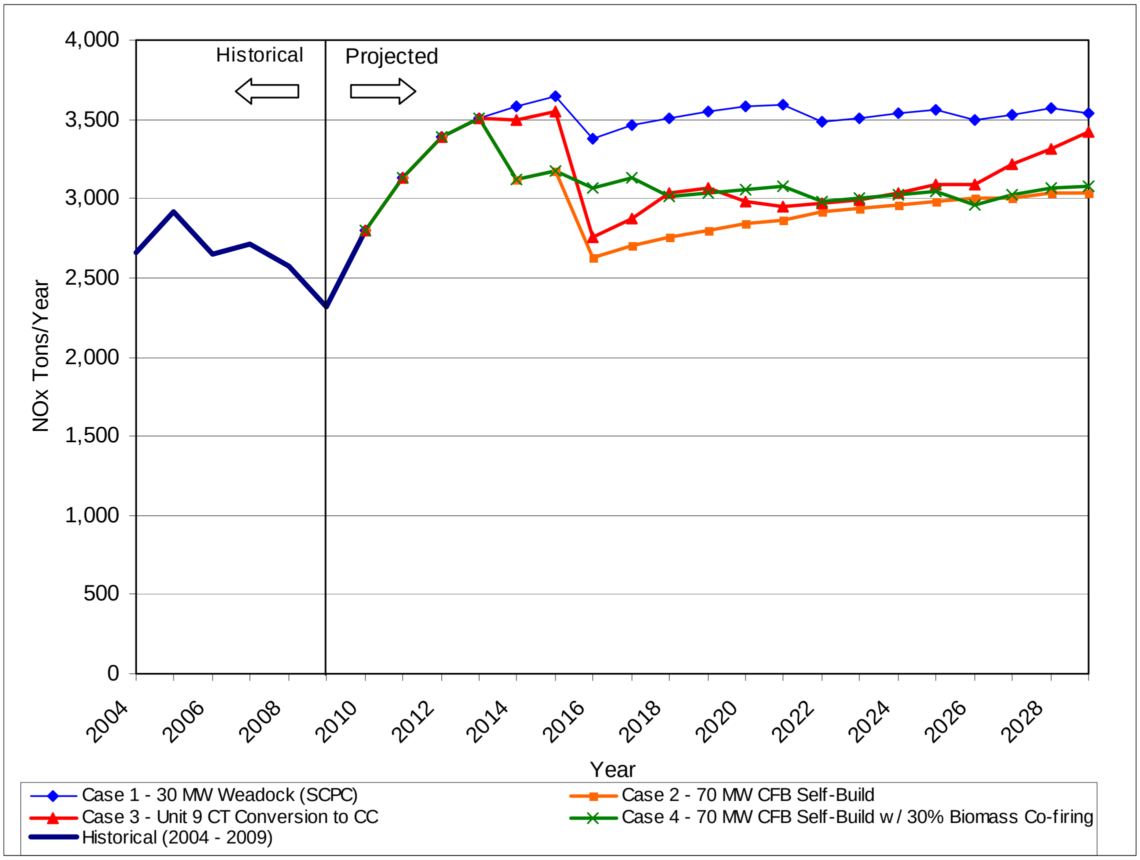


Figure 8-3
Historical and Projected NO_x Emissions

The emissions profile is similar for all plans until 2014, as no new resources are added in any of the plans for the period 2010 to 2014. Throughout most of the planning period beyond 2014, the 70 MW CFB self-build option has the greatest reduction in NO_x emissions. As shown on the graph, the plan does not emerge as the lowest NO_x emission plan until 2016. In 2016, the total reduction is forecast to be 14 percent compared to the previous year. The 30 MW Weadock supercritical PC plan has a slight increase in NO_x throughout the study period.

9.0 Conclusions

Based on the analyses and evaluations, Black & Veatch has reached the following conclusions for HBPW to consider in procuring capacity and energy resources needed in the near term:

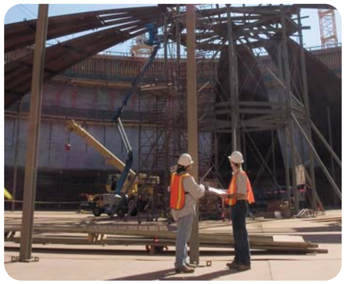
- HBPW has a resource need capacity starting in 2016. Based on the resources selected for all cases, this appears to be an intermediate to baseload need rather than a peaking need.
- It appears that HBPW has more than sufficient peaking resources at this time.
- Several peaking, intermittent, intermediate, and baseload resource alternatives appear to be available to HBPW to meet its resource needs including partial ownership purchases, market purchases, natural gas fired combined cycle and simple cycle, supercritical pulverized coal, CFB, landfill gas, hydroelectric, biomass, solar PV, wave, and wind.
- The recent cooler summers and reduced energy consumption from the economic slowdown were not anticipated when the previous forecasts were developed. In addition, new industrial loads are expected in the near term. As a result, Black & Veatch developed a load forecast to account for these factors as well as historical growth rates, potential reductions in energy intensity within the economy, and potential DSM and EE savings to meet Michigan PA 295.
- HBPW's James De Young Generating Station consists of three coal fired electrical generating units, referred to as the JDY Units 3, 4 and 5. These units have capacity of 11 MW, 20 MW, and 25 MW, respectively. In addition, these units are currently 59 years, 48 years, and 41 years, respectively. At the end of the study period, these units will be in the 60 to 80 year old range, and at or near the end of their expected useful life. Although these units are not planned to be retired during this study, except in the case of adding the CFB unit, it would be prudent for HBPW to plan for this contingency.
- Viable resources for new baseload capacity and energy include the proposed HBPW 70 MW (net) CFB, participation in a supercritical coal project, and partial ownership in natural gas combined cycle facilities.

- The proposed HBPW 70 MW net CFB project has the greatest level of control for HBPW. Other alternatives are heavily dependent upon others for participation and execution, and these alternatives could be abandoned at any time. The CFB project also offers significant community benefits, and is the most fuel flexible of all alternatives considered in that it would be capable of burning coal, petroleum coke, biosolids, biomass, and other fuels. Combustion of biosolids and biomass should qualify as renewable energy fuel sources.
- It is recommended that HBPW continue to pursue the 70 MW CFB alternative and proceed through the permitting process to keep this option viable.
- HBPW should evaluate joint ownership of the 70 MW CFB alternative. It may also be prudent to assess the remaining useful life of the JDY units, as retirement of any of these units will increase the need for base load capacity.
- It is recommended to continue evaluating participation in a gas fired combined cycle alternative if other participants can be found.
- HBPW should evaluate whether participation in the Consumer's supercritical pulverized coal unit is still available, and if so, confirm the level of capacity that may be available to HBPW.

Appendix A
Energy Market Perspective

BUILDING A WORLD OF DIFFERENCE®

BLACK & VEATCH


Energy Market Perspective: Midwest Baseline

Fall 2009

Black & Veatch Statement

- This report was prepared for Client by Black & Veatch Company ("B&V") and is largely based on information not within the control of B&V. As such, B&V has not made an analysis, verified, or rendered an independent judgment of the validity of the information provided by others, and, therefore, B&V does not guarantee the accuracy thereof.
- In conducting our analysis and in forming an opinion of the projection of future operations summarized in this report, B&V has made certain assumptions with respect to conditions, events, and circumstances that may occur in the future. The methodologies we utilize in performing the analysis and making these projections follow generally accepted industry practices. While we believe that such assumptions and methodologies as summarized in this report are reasonable and appropriate for the purpose for which they are used; depending upon conditions, events, and circumstances that actually occur but are unknown at this time, actual results may materially differ from those projected.
- Use of this report, or any information contained therein, shall constitute the user's waiver and release of B&V and Client from and against all claims and liability, including, but not limited to, any liability for special, incidental, indirect or consequential damages, in connection with such use. In addition, use of this report or any information contained therein shall constitute an agreement by the user to defend and indemnify B&V and Client from and against any claims and liability, including, but not limited to, liability for special, incidental, indirect or consequential damages, in connection with such use. To the fullest extent permitted by law, such waiver and release, and indemnification shall apply notwithstanding the negligence, strict liability, fault, or breach of warranty or contract of B&V or Client. The benefit of such releases, waivers or limitations of liability shall extend to B&V and Client's related companies, and subcontractors, and the directors, officers, partners, employees, and agents of all released or indemnified parties. USE OF THIS REPORT SHALL CONSTITUTE AGREEMENT BY THE USER THAT ITS RIGHTS, IF ANY, IN RELATION TO THIS REPORT SHALL NOT EXCEED, OR BE IN ADDITION TO, THE RIGHTS OF THE CLIENT."
- Readers of this report are advised that any projected or forecasted financial, operating, growth, performance, or strategy merely reflects the reasonable judgment of B&V at the time of the preparation of such information and is based on a number of factors and circumstances beyond our control. Accordingly, B&V makes no assurances that the projections or forecasts will be consistent with actual results or performance. To better reflect more current trends and reduce to chance of forecast error, we recommend that periodic updates of the forecasts contained in this report be conducted so more recent historical trends can be recognized and taken into account.
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Table of Contents

Executive Summary

ES.1 About the Energy Market Perspective

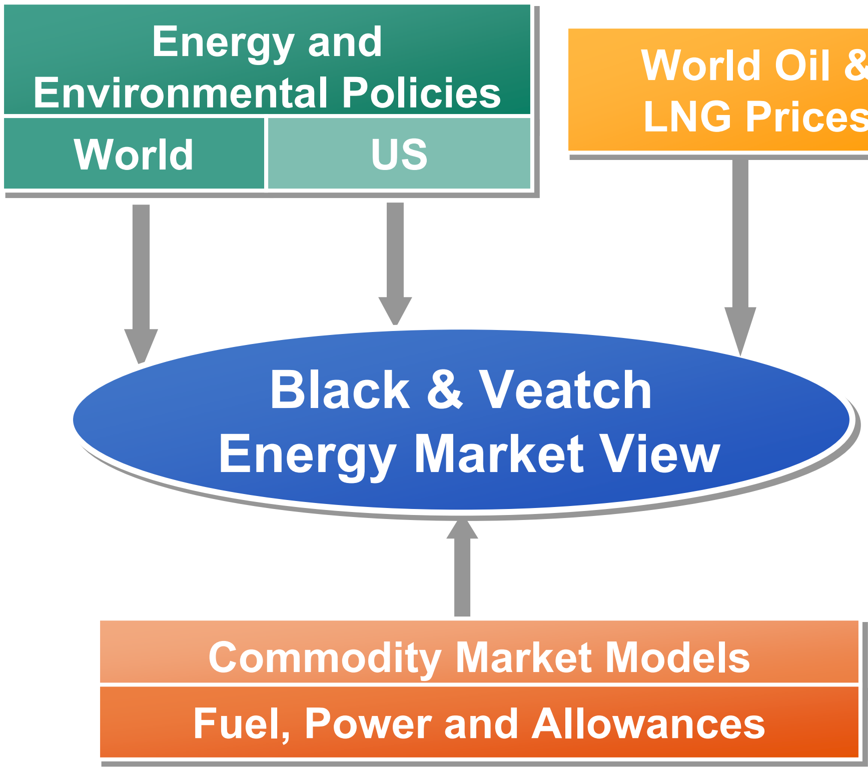
Overview of the Energy Market Perspective

- The Black & Veatch **Energy Market Perspective** is prepared every six months to provide B&V clients with a fresh and insightful assessment of the current state of North American energy markets, and a Base Case long term view of how those markets may function. Critical elements of the Energy Market Perspective include:
  - A thoughtful, transparent and internally consistent approach to analysis of the energy markets and the government policies that influence them.
  - A view of the markets for generation fuel sources.
  - A view of the electric power markets.
  - An Integrated Market Modeling process designed to capture both the broad policy level assumptions and detailed structural market representations to arrive at a consistent market view.
- Key Report Deliverables
  - Energy (power, coal, oil and natural gas) price forecasts at both granular and aggregate levels for a 25-year study period, 2010 – 2034. **All results are in constant beginning of year 2009 US Dollars.**
  - A framework for thinking about a plausible and viable future state of energy industry regulation and infrastructure.
  - Insights on the key value drivers that form value creation opportunities for B&V clients.

Energy Market Price Forecasting

- Black & Veatch's **Energy Market Perspective** is anchored by its **Integrated Market Modeling (IMM)** process, which is used to prepare its integrated long term view on energy markets. In order to arrive at this market view, B&V draws on a number of commercial data sources and supplements them with its own view on a number of key market drivers, for example, power plant capital costs, environmental and regulatory policy, fuel basin exploration and development costs, and gas pipeline expansion.
- B&V uses this data in a series of vendor-supplied and internally-developed energy market models to arrive at its proprietary market perspective; vendor-supplied models include PROMOD (part of the PowerBase Suite).

B&V Energy Market Perspective

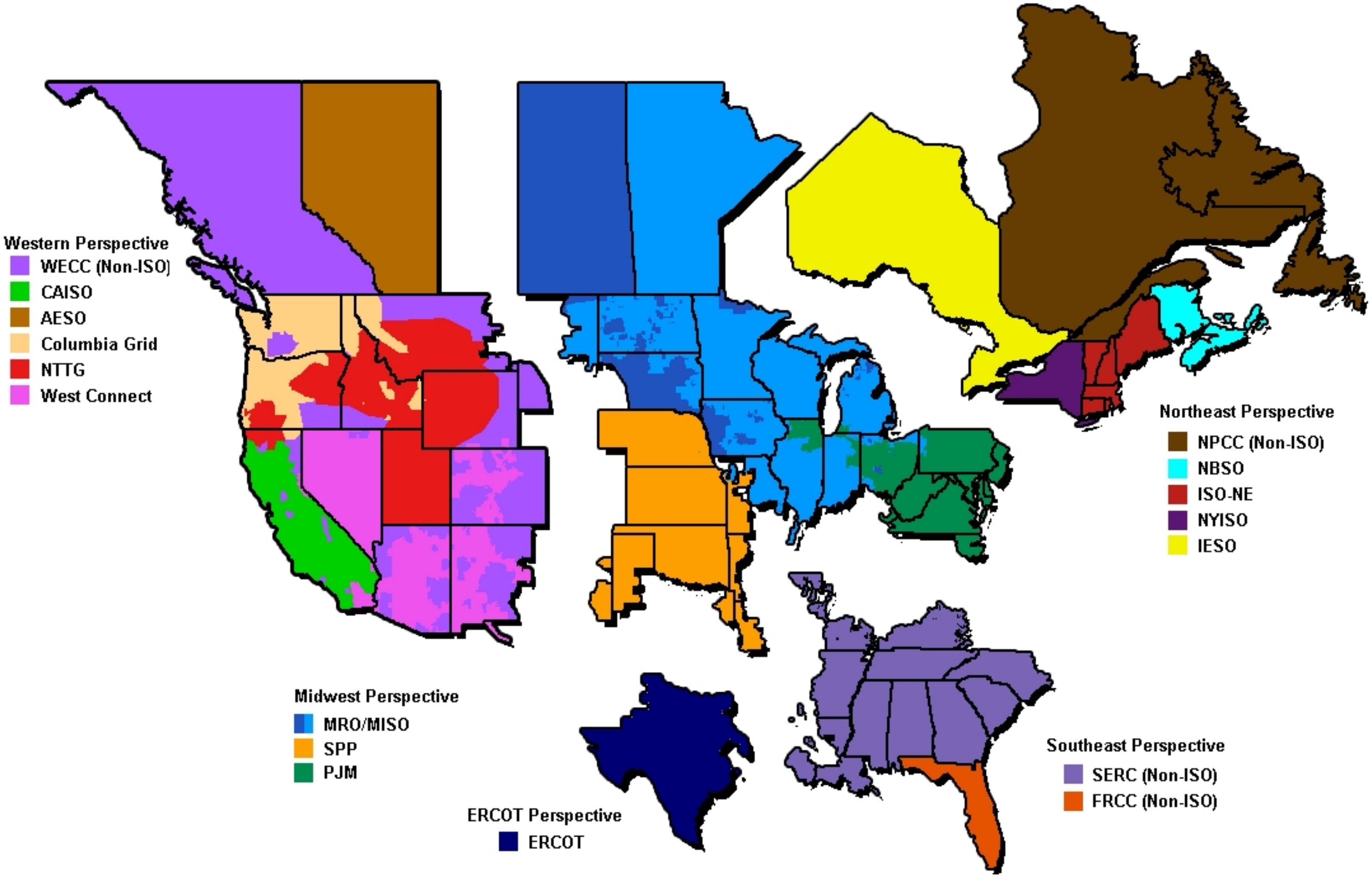


Key Issues (Assumptions) that Influence the Baseline Perspective

- GHG legislation and costs
- RPS requirements and (in)ability to meet
- Power demand
- Future generation construction costs
  - Fossil (gas, coal)
  - Nuclear
  - Renewables (wind, solar, etc.)
- Transmission infrastructure
- Unit retirements
- Gas demand
- Supply F&D costs
- LNG imports
- Oil prices

- Essential criteria for input assumptions
  - **Neutrality:** neither "conservative" nor "aggressive."
  - Chosen to provide a base line or "expected value" forecast around which clients can build their own scenarios.
  - Clearly documented to provide transparency so clients can readily compare input and results to their own world views—**no "black box."**

Power Market Regional Coverage



The B&V Energy Market Perspective is available as a National Service or as one or more Regional Services: Western, Texas (ERCOT), Northeast, Midwest and Southeast.

ES.2 Discussion of the Fall 2009 EMP Baseline View

The Energy Industry—Heading Towards a “New Normal”

- As the world economy begins its recovery from the worst economic downturn since WWII, corporate leaders are all asking the same question--"what does the future hold for my business?" This is never a simple question to answer, particularly this early in any recovery phase, but the range of uncertainties faced by businesses now may never have been greater than they are today. In the past, economic recovery meant returning to some sort of "normal" conditions. In this recovery, the only widespread consensus one can find is that the recovery will not be a return to what was considered to be normal just a couple of years ago; rather, we are headed towards a "New Normal" of uncertain dimensions, risks and opportunities.
- What will be the North American energy industry's "New Normal"? Our industry is caught in the middle of the world's uncertainty, surrounded by currents of market, regulatory and technology forces that all await resolution. Our New Normal will likely include technology changes that simplify communication between energy provider and customer and provide for end use efficiency gains, although the magnitude of the change and the customers' ultimate response is largely unknown at this point. Our New Normal will require the ability to finance new infrastructure investments that today appear greater than our ability to securitize. The New Normal has uncertain government environmental regulations and mandated generation technology choices. The New Normal will require use of technology that today is unproven. At times, our New Normal will seem to be beyond our control.

The Energy Industry—Getting to Where We Are

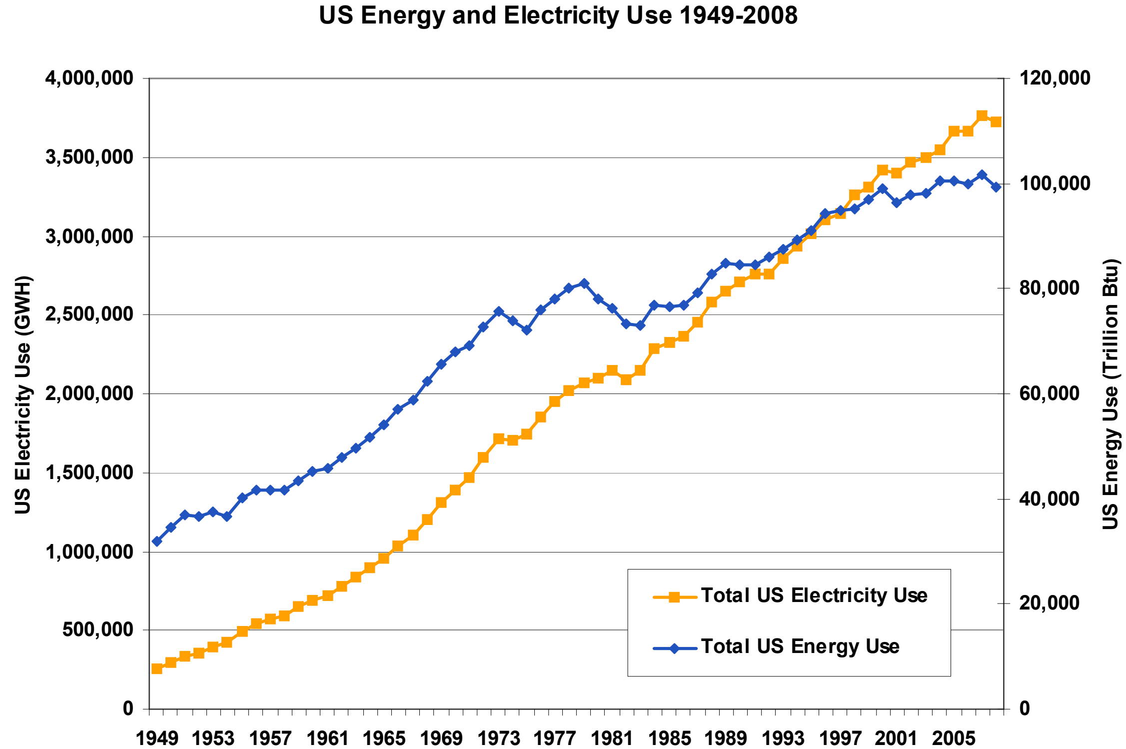
- The dust of this recession has only begun to settle, but it is clear that the energy industry's New Normal faces a series of fundamental risks:
  - Uncertainty in the growth of power demand
  - Uncertainty in input prices, particularly natural gas
  - Uncertainty in GHG control legislation
  - Uncertainty in technological innovation in power, fuel supply and transpiration
- If we are entering a New Normal, what was the Old Normal and what were its key drivers? The Old Normal was based on a nation (and world) of robust growth, and in the US in particular it was driven by consumer spending. In the past 2 decades consumer spending grew rapidly, fueled by a wealth effect emanating from growing stock portfolios, easy credit, and the ability to fund increased spending by borrowing against rapidly inflating real estate values. Ultimately US consumers were highly leveraged, essentially realizing "negative" savings rates. The arrangement was intrinsically unsustainable, and when it collapsed, consumers were hit with plummeting wealth, tighter credit and, as the economy contracted, increased unemployment.
- As the recession deepened, consumers not only cut spending in response to lower income expectations and reduced wealth, they "de-leveraged" themselves, paying down debt, becoming savers again, and thereby amplifying the impact of the recession.

The Energy Industry—Signposts to Watch

- The recovery of the energy industry is tied to the recovery of the overall economy and is thereby dependent upon increased consumer spending. There will be many signposts to watch for in this recovery:
  - Increased stock prices—already in progress
  - GDP growth—early measures of the 3Q09 US GDP indicates a 3% annualized growth rate—when we look back, this could be the point at which the recession ended.
  - Unemployment—has now topped 10% as of October 09 early estimates. The “good news” is that the rate of job loss for the past 3 months has been much less than the previous year.
  - World consumption. Consumers in much of the rest of the world are net savers, in some countries very aggressively so. Reduction in net savings in other countries will mean that their economies are becoming more important in providing a demand pull for the economy, reducing the importance of US consumers “spending” us into a recovery.
- This broad perspective is important because it is clear that the “tide” of the world economy does to some extent “float all boats” including the North American energy industry. The economic events of the past few years has seen the tide go out, with energy sector demand down across the board.

Energy and Electricity Use

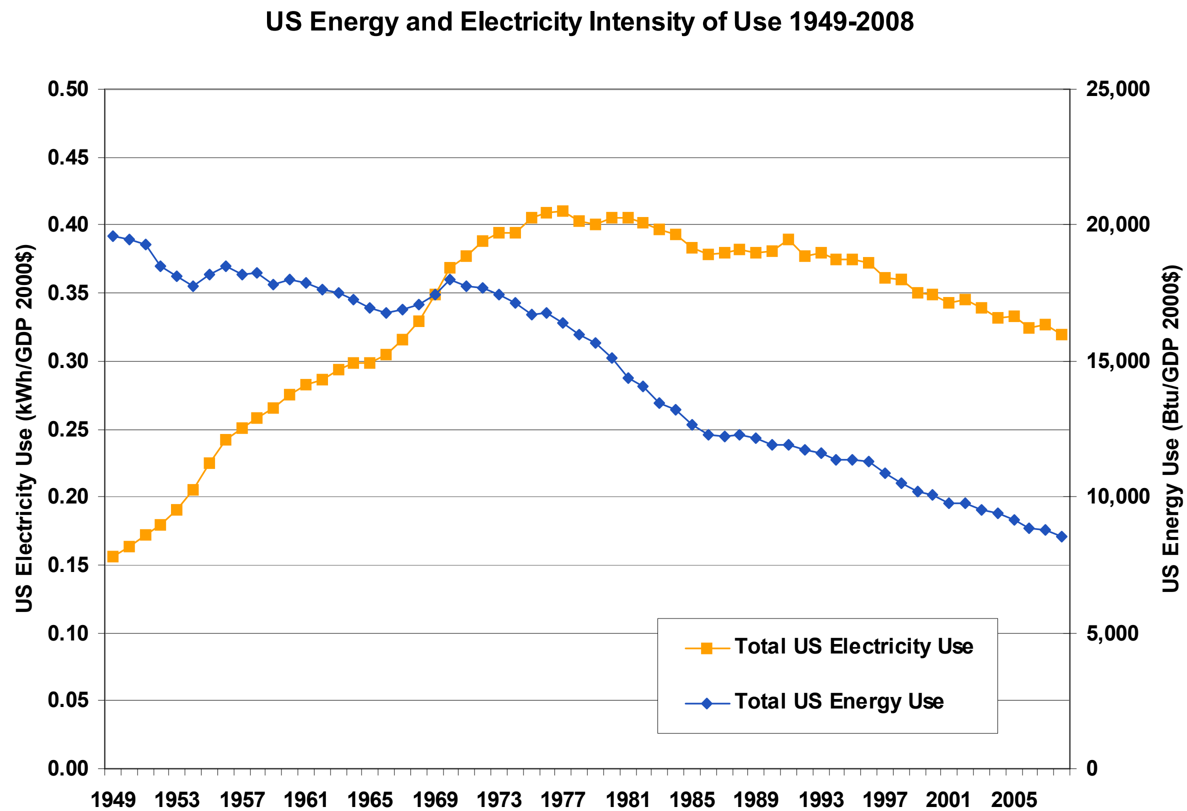
- It is probably not surprising to most in the energy industry to observe that electricity use in the US has been growing faster than overall energy use since the 1970s. The real cost of energy commodities have growth since the first OPEC embargo in 1973, and the shift to a services driven economy has made electricity the more convenient and economical energy source behind much of our economic growth.
- What is probably less well known is that the total consumption of energy in the US has been relatively flat in the past decade. US GDP growth from 1999-2008 averaged 2.5% per year, while total energy demand growth was only 0.4% per year and electricity demand growth was 1.3% per year. Clearly:
  - US economy has become very energy efficient, and
  - Electricity is gaining "market share" relative to all other energy end uses.



Source: B&V Analysis

Energy and the Economy

- The energy efficiency of the US economy (or "intensity of use") is even more dramatic when viewed in terms of consumption per dollar of GDP. In this measure it becomes clear that the energy efficiency of the US economy has improved continually since WWII, and electricity efficiency has been improving since 1970.
  - Overall energy use in the economy per unit of GDP was declining slowly prior to the 1970s, and the rate of decline has increased significantly since then.
- Since 2000, growth in electricity use has been 1.1% lower than GDP growth.

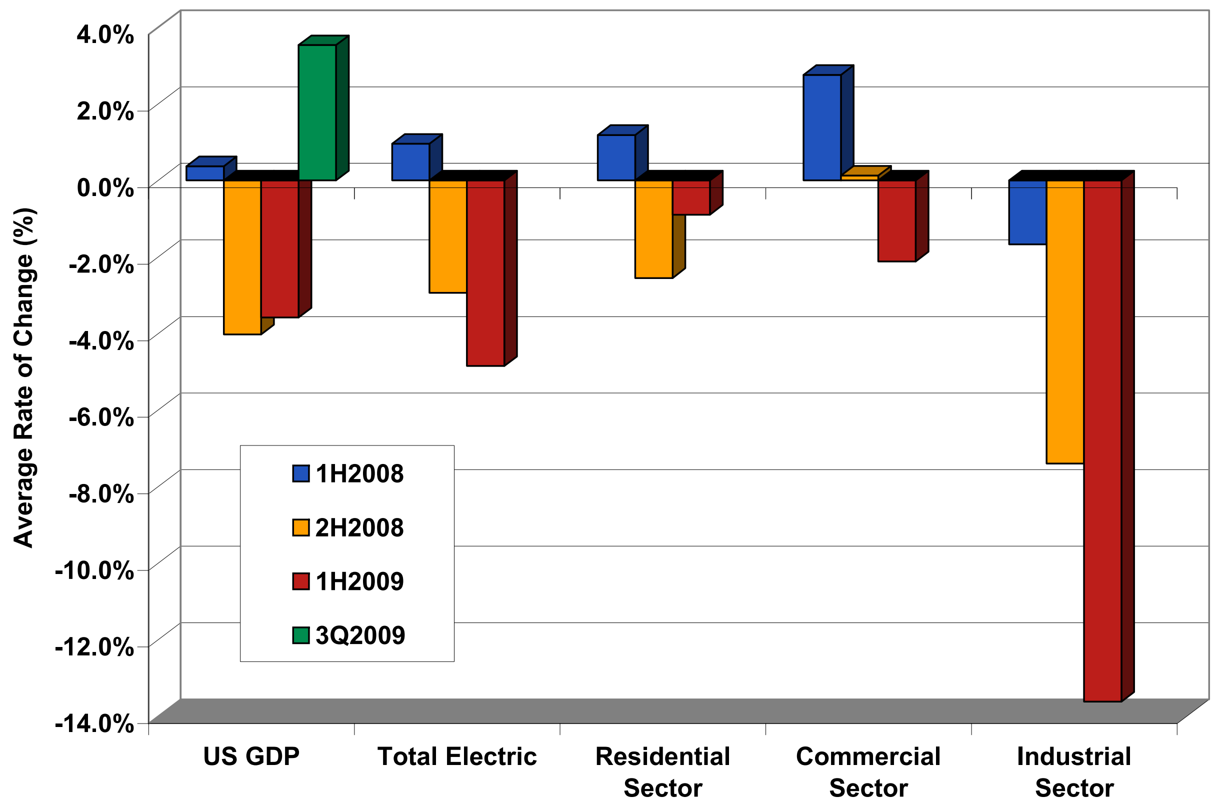


Source: B&V Analysis

Recent Decrease in Electricity Demand

- The preceding discussion provides a backdrop on the impact of the recession on the electric power industry.
- The drop in US electricity demand (using energy, not peak MW) began in August 2008.
- Year over year average growth rates:
  - Jan-Jul 08 = +1.0%
  - Aug-Dec 08 = -3.9%
  - Jan-Jun 09 = -4.9%
- The residential and commercial sectors have seen significant hits, but the biggest decease has been in the industrial sector.
- The industrial sector decline started earlier and has been deeper.
- Combined with increased account delinquencies and defaults, this has constrained revenue and earnings for most electric utilities
- US DOE EIA expects the rate of decline to lessen in the second half of the year, especially in the Southwest, where higher summer temperatures led to higher air conditioning load. The total year decline is expected to be 3.3%.

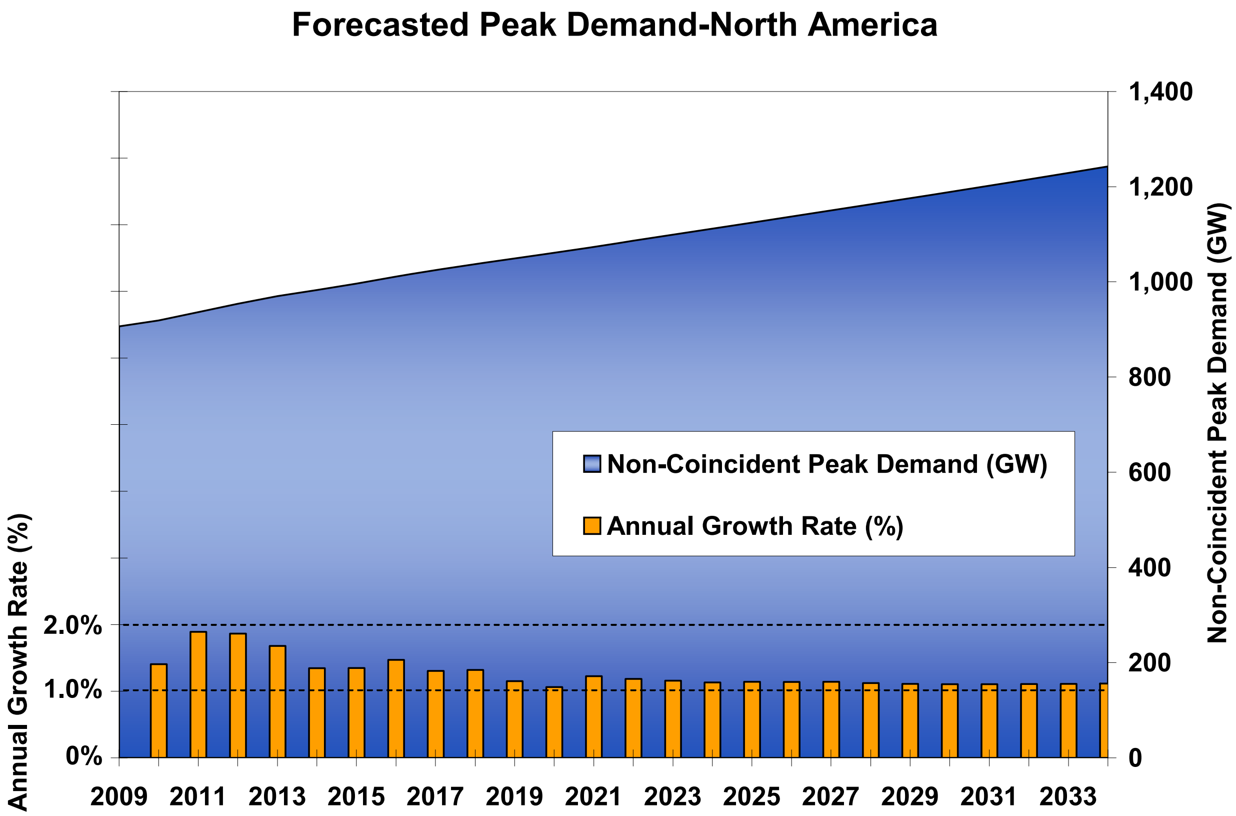
Electricity Consumption by Sector and USD GDP (2008-2009)



Source: B&V Analysis

Forecast for Power Demand

- The apparent start of the US economic recovery in 3Q09 with a 3% annualized growth rate portends a recovery in overall electricity demand in 2010. Expectations are for about 2.5% GDP growth in the US in 2010 (*The Economist, 3 Oct 09, p. 109*).
- Black & Veatch's survey of regional long term forecasts reveals a large amount of regional variation in recovery expectations on all measures: timing, magnitude and long term trend.
- So while averages will mask the important regional variations captured in the EMP analysis, the aggregate impact is an expectation of a moderate economic rebound in 2010-2013 with "1990's style" growth before reverting to a long term growth trend of about 1.1% per year.



Source: B&V Analysis

Long-term natural gas prices are projected to rise with growing demand and new higher cost supply sources.

<u>Short-term (2009 - 2011)</u>

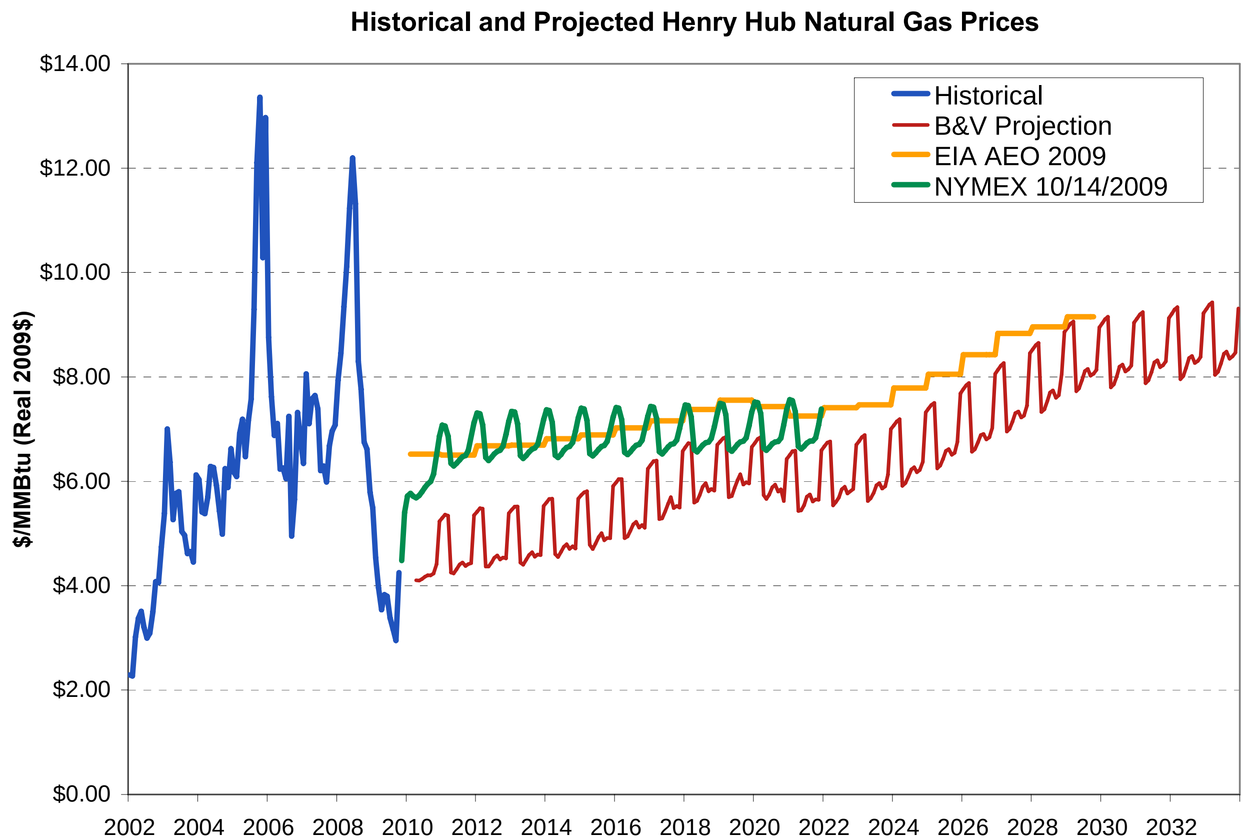
- Demand weakens with global economic climate
- North American natural gas production decreases with lower prices, credit constraints, and reduced drilling activity

<u>Medium-term (2011 – 2019)</u>

- Natural gas prices track upward to an average of $5.50
- Unconventional gas and LNG imports keep pace with demand

<u>Long-term (2019 – 2034)</u>

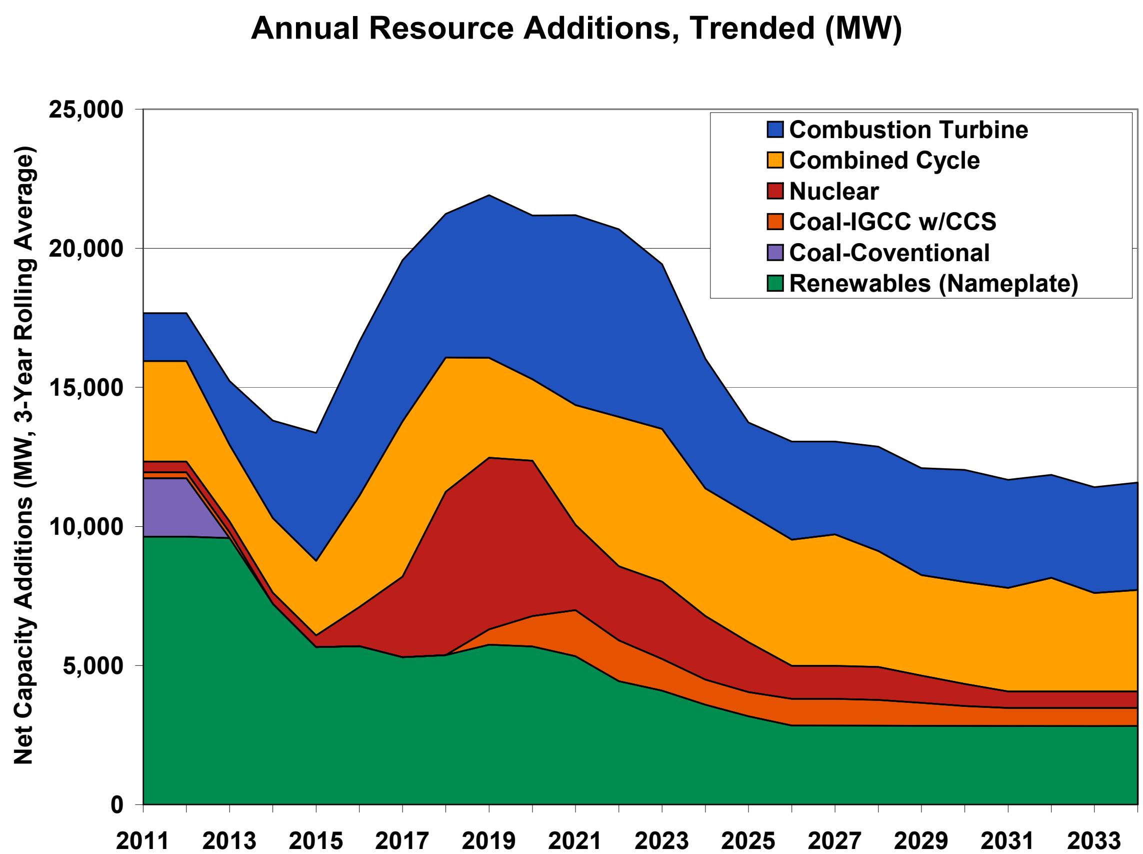
- Power sector demand pushes new consumption
- Alaskan gas enters market in 2020 softening prices for a few years
- Prices then rise as WCSB decline accelerates and current unconventional gas plateaus



Source: EIA, B&V Analysis, NYMEX.com

Resource Implications of the Energy Market Perspective

- Electric power resource additions are driven by:
  - The expectation of a modest near term rebound in power demand.
  - Followed by a sustained longer term growth of about 1.1% per year
  - Continued interest in developing renewable energy to obtain federal tax credits and state RECs.
- Near-term resource additions are dominated by renewable energy due to the incentives, and natural gas resources due to the short development lead time.
- Wind resource additions decline over time as many state RPS standards and guidelines are largely met, with some expectation of extensions.
- Longer-term resource needs are met by natural gas resources, with growing role for nuclear and possibly IGCC w/ CCS for meeting base load growth.



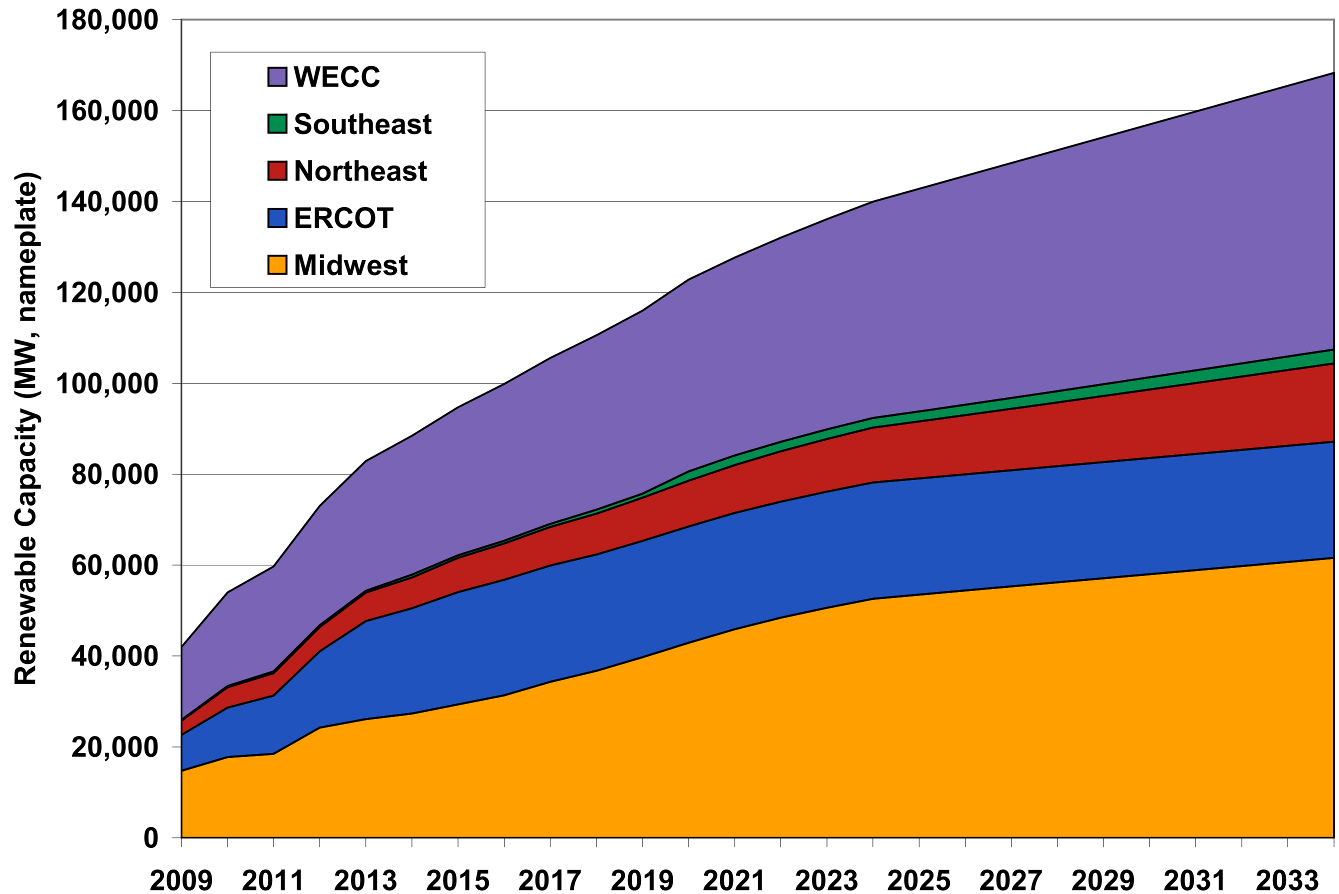
Source: B&V Analysis

Trajectory of Renewables Growth

Issues for Renewables

- Prospects for a Federal RPS.
- Regulation, Spinning Reserve and quick-start requirements.
- Will the transmission be built?
- Improvements in weather forecasting and system operating protocols.
- Modification of Planning Reserve Margin Targets.

Cumulative Renewable Resource Additions (MW)



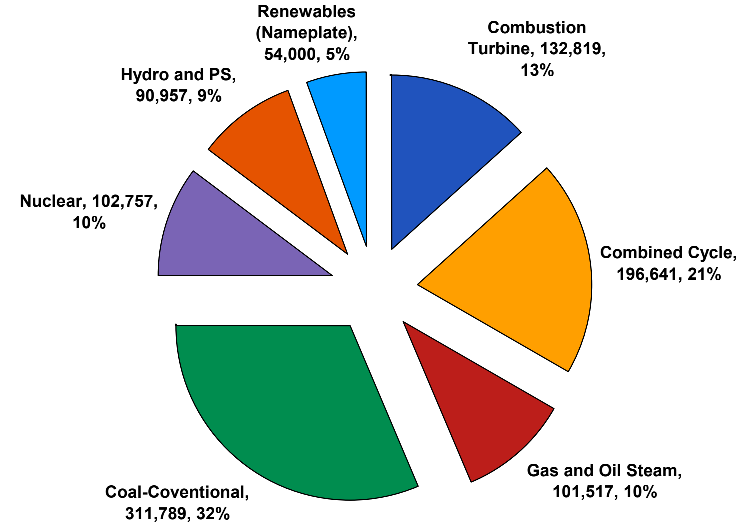
Source: B&V Analysis

The Changing Resource Mix-US

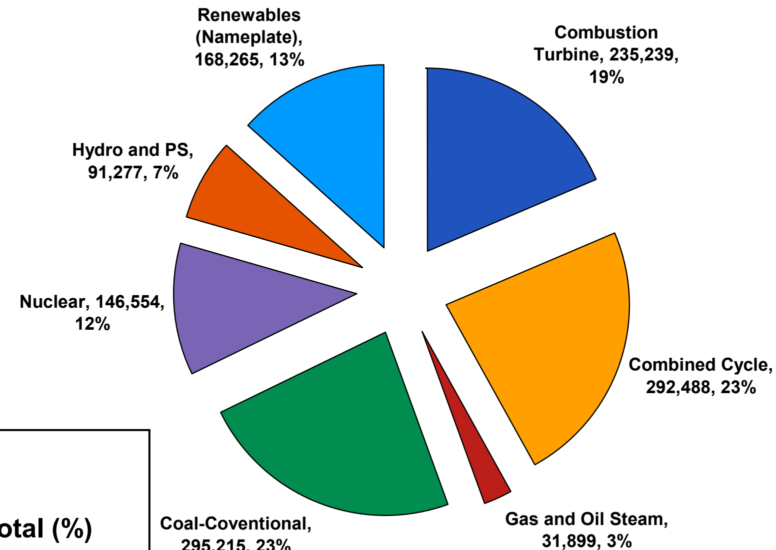
- Over the next 25 years the future mix of electric generation resources will have a notable shift to new gas-fire technologies, as part of a multi-prong power industry strategy that also includes wind, solar, nuclear and some IGCC w/ CCS.
- Combustion turbine and combined cycle capacity gains about 100,000 MW each, while about 70% of gas and oil steam assets are retired for a variety of reasons, such as age, inefficiency, and, on the west coast, limitations on use of ocean water for once-through cooling.
- Renewable capacity more that triples, much of this being wind, with some solar.
- Conventional coal capacity realizes another 8,000 MW of gains in the next few years as projects in advanced development are completed, followed by 25,000 MW of retirements of older, smaller, less efficient resources.

Source: B&V Analysis

Resource Mix—2010



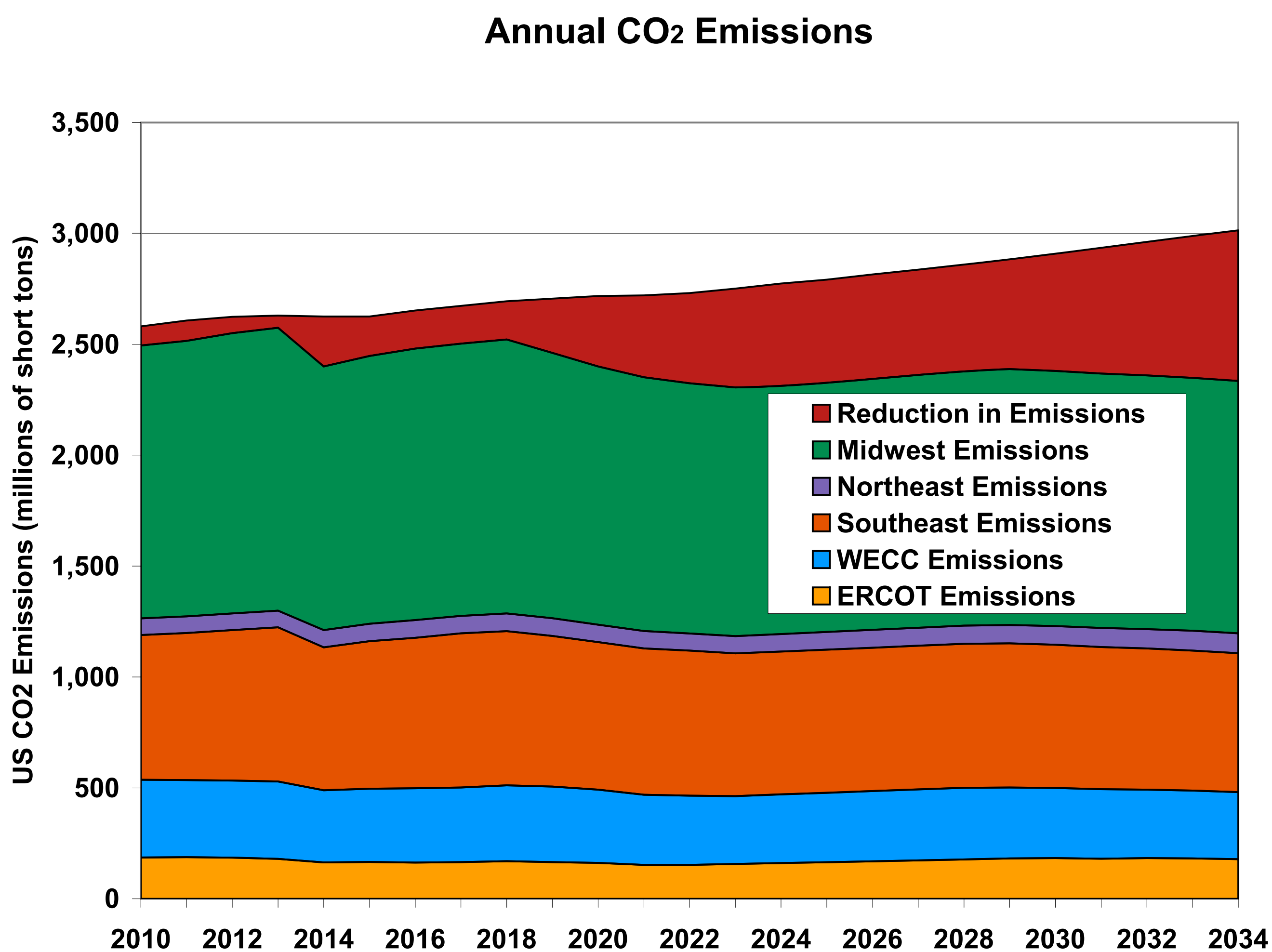
Resource Mix—2034



Data Label Legend:
Technology,
Capacity (MW), Share of Total (%)

Trajectory for CO_2 Emissions

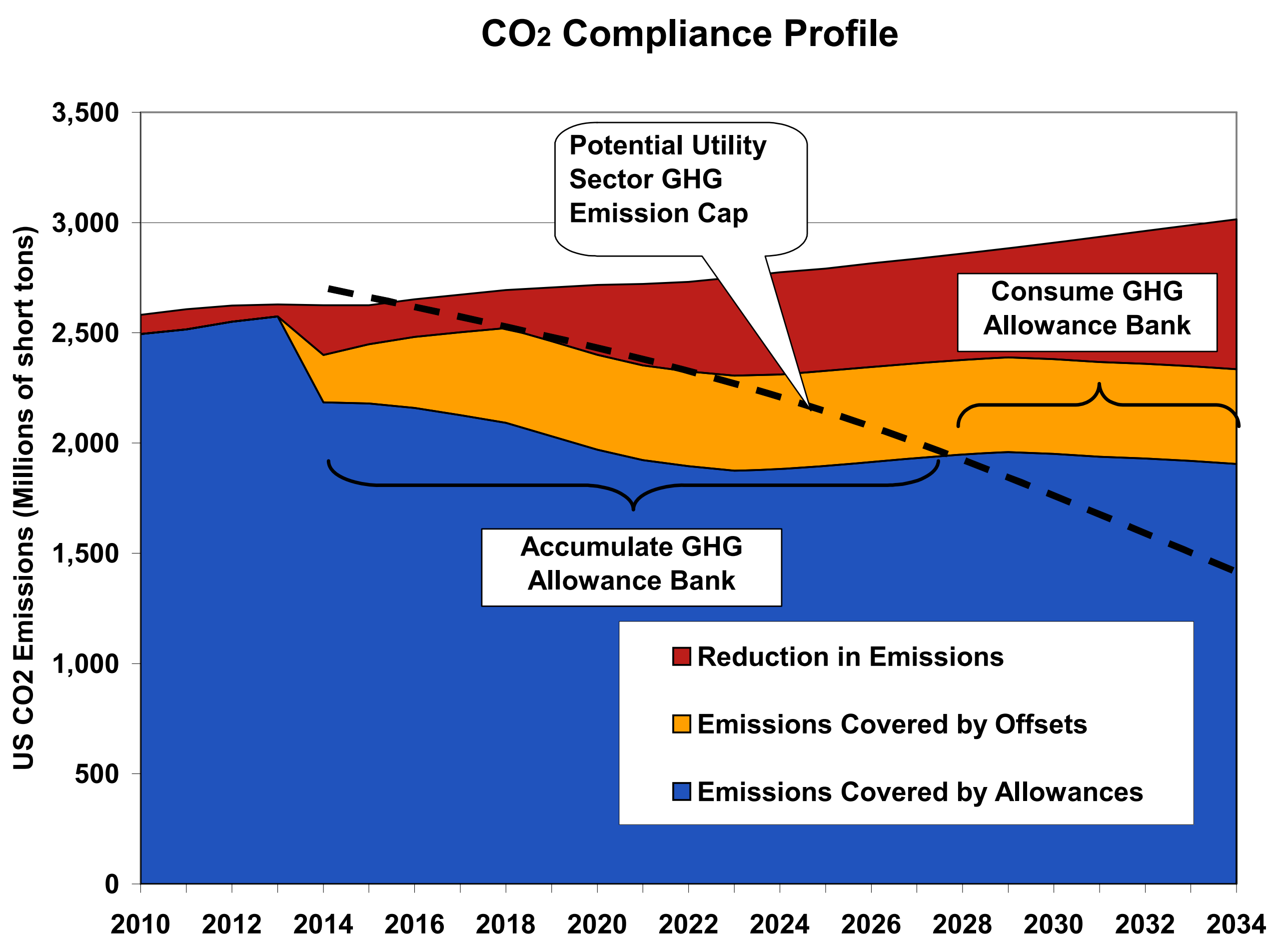
- Compared to a "Business as Usual" case with no GHG legislation, the B&V Base Case has moderate declines in electric power sector CO_2 emissions for 15 years, followed by a period of smaller reductions.
- The reduction in emissions shown in the chart on the chart on this page is the results of increased renewable energy, retirement of less efficient coal units, some re-dispatch of gas ahead of coal, lower demand growth, and utilization of allowances.



Source: USDOE Annual Energy Outlook (for Business as Usual case) and B&V Analysis

Compliance with a CO_2 Emission Cap

- The electric power sector accounts for about 39% of US carbon emissions. A typical presumption is that electric power's GHG compliance costs will be lower than that of many other sectors, so offsets may be used more in other sectors. If so, then the electric power sector may use less than a pro rata share of the 2 billion tpy of offsets allowed under proposed legislation.
- Assuming use of only half of its pro rata share of the 2 billion tpy of offsets, the electric power sector can bank offsets through the late 2020's and consume that bank well into the late 2030's.
- However, as 2040 approaches, additional compliance actions would be needed.

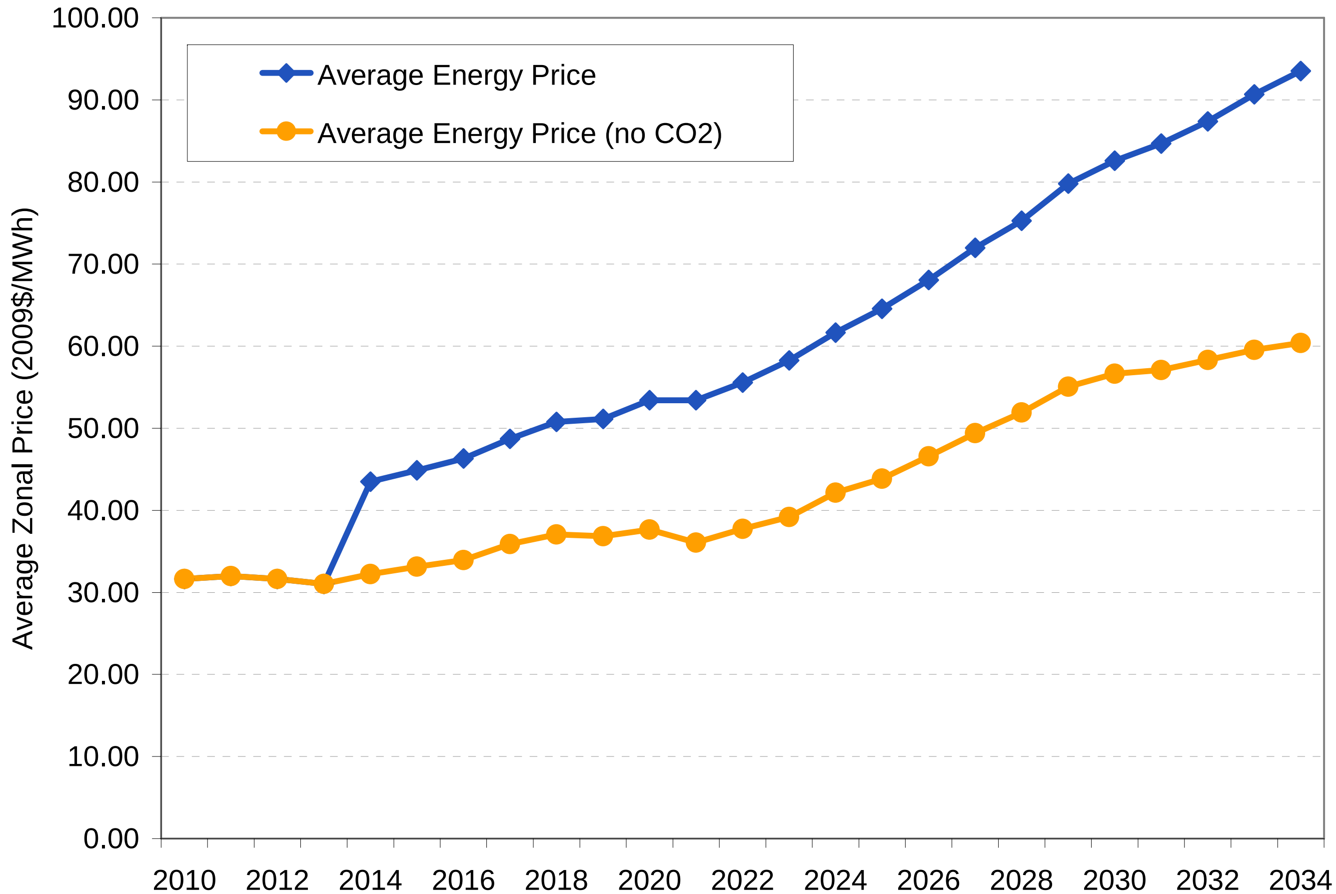


Source: B&V Analysis

Impact of Carbon Allowances on Wholesale Energy Prices

- In markets where natural gas is often the "marginal" fuel, the impact of carbon costs is typically on the order of $0.50/MWh for every $1.00/ton of Carbon Allowance, as illustrated by this comparison from the ERCOT EMP analysis results.

ERCOT Average Power Prices



Source: Black & Veatch

Fall 2009 EMP—Major Assumptions and Findings

- Environmental assumptions:
  - A Green House Gas (GHG) cap and trade system will be implemented in the US in 2014. CO_2 allowance prices will start at $20/ton in 2014 (2009 $'s) and steadily increase to just over $60/ton by 2034.
  - Electricity generation carbon emissions decline throughout the study period, but GHG compliance depends upon offsets.
  - Renewable Portfolio Standards will continue to be managed at the state level.
  - Many states meet existing RPS goals, although often with significant delays in achieving RPS in most states.
- Power demand will rebound somewhat over the next four years, and the 25-year average grow rate will be about 1.2% per year, with wide variation among regions of the US and Canada. The average long term growth rate will be much lower than the historical long term growth rates, reflecting success in energy efficiency programs (including smart grid impacts) and a demand response to higher real energy prices.
- Natural gas prices will trade in the $4 to $6/MMBtu range (2009 $'s) through the early 2020's, after which increased gas demand (motivated by the GHG legislation) will provide steady upward pressure on gas prices, increasing to $8-9/MMBtu by 2030.
- Crude oil prices will increase from a $65-75/BBl (2009 $'s) level in the next three years to about $100/bbl by 2030.
- Cost of new construction of electric generation resources will revert to somewhat lower, sustainable long term levels in the next few years, stabilizing at levels about 10-15% lower than the peak costs realized in 2008.

Midwest Major Findings

- Significant new wind generation is planned and expected to come online in the Midwest. Additional new generation in the next decade will be mostly simple-cycle and combined-cycle natural gas fueled combustion turbines, with some nuclear unit additions starting near the end of the next decade.
- Wind generation has potential to significantly alter market dynamics, but depends on the extent of transmission expansion that can be successfully developed and brought online.
- New resources are needed in MISO in the 2013-2014 timeframe, in the 2015-2016 time frame in PJM, and 2021-2022 time frame in SPP.
- A national GHG cap and trade program will be implemented in 2014, with CO_2 allowance prices forecasted to start at $20/ton, increasing to about $62/ton by 2034. Implementation of the GHG allowance pricing causes a jump in energy prices, and will likely lead to retirement of less efficient coal generation
- Natural gas combined-cycle units will continue to set market clearing prices in the region in on-peak hours of the year. Off-peak prices are frequently set by coal-fueled steam turbines.

ES.3 Discussion of Changes From the Spring 2009 EMP Baseline View

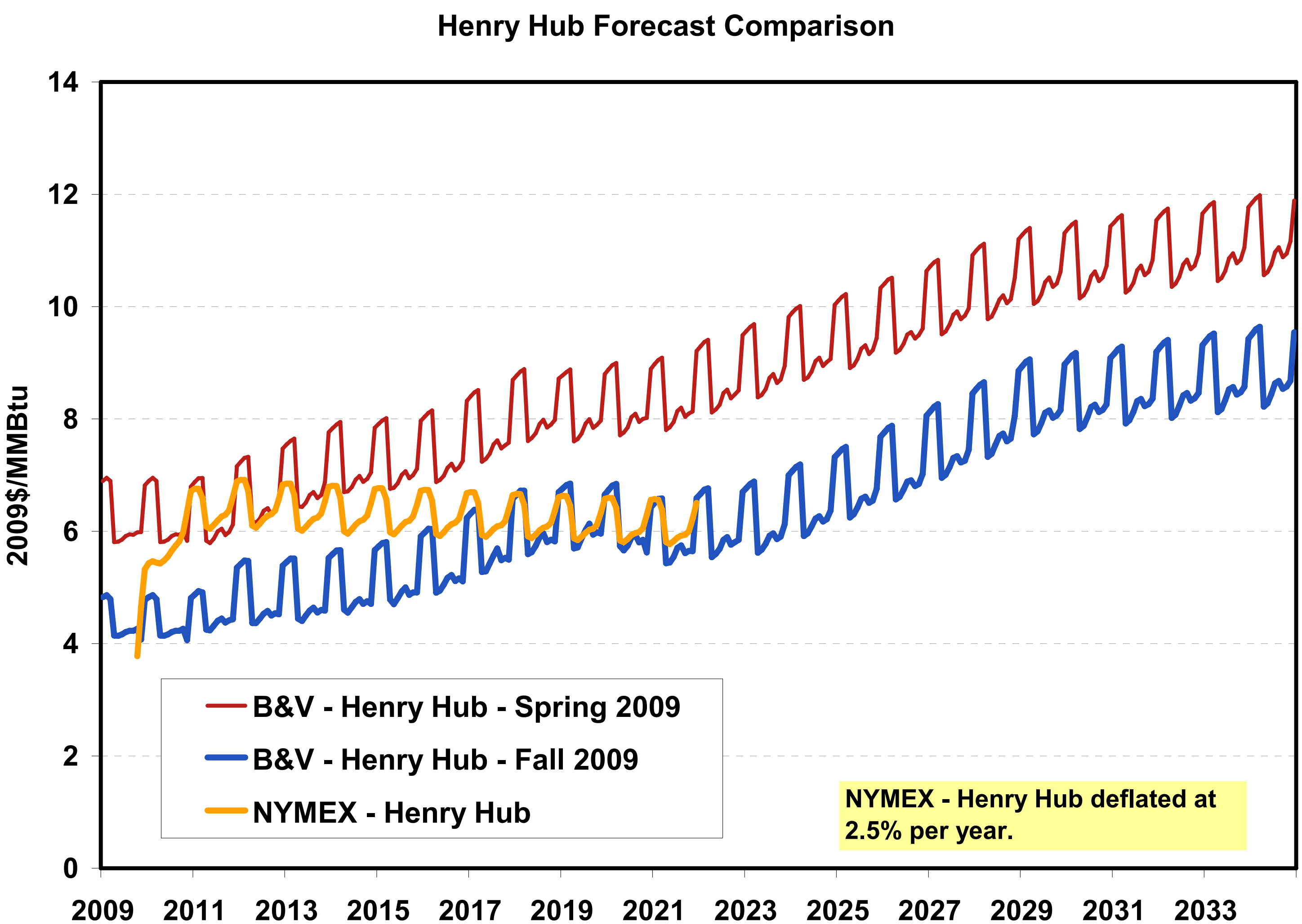
Major Changes from the Spring 2009 Baseline Forecast

- Every edition of the Black & Veatch EMP includes a major input review as a matter of course, updating literally thousand of data points on unit characteristics, retirements, new resources, fuel, power demand, transmission, etc. As the world was particularly volatile in 2009, it seems appropriate to highlight three major changes in the Fall 2009 EMP.

1. GHG assumptions:
   - Implementation of a carbon cap and trade system is delayed from 2012 to 2014 due to likely legislative delays.
   - CO_2 allowance price trajectory starts at a higher point, but rises slower in real terms, and does not hit a "safety valve."
   - GHG emission allowance offsets become a major compliance strategy.
2. Long term power demand growth has declined from about 1.5% to 1.2% per year, reflecting the perspectives of load serving entities on the impact of the recession, long term economic activity, population trends, success in energy efficiency programs and a demand response to higher real energy prices.
3. Natural gas prices rise more slowly and reach about $8/MMBtu by the end of the study period, versus $11/MMBtu in Spring 2009 view, reflecting rapidly expanding evidence on unconventional gas resource development costs, specifically the "gas shales."

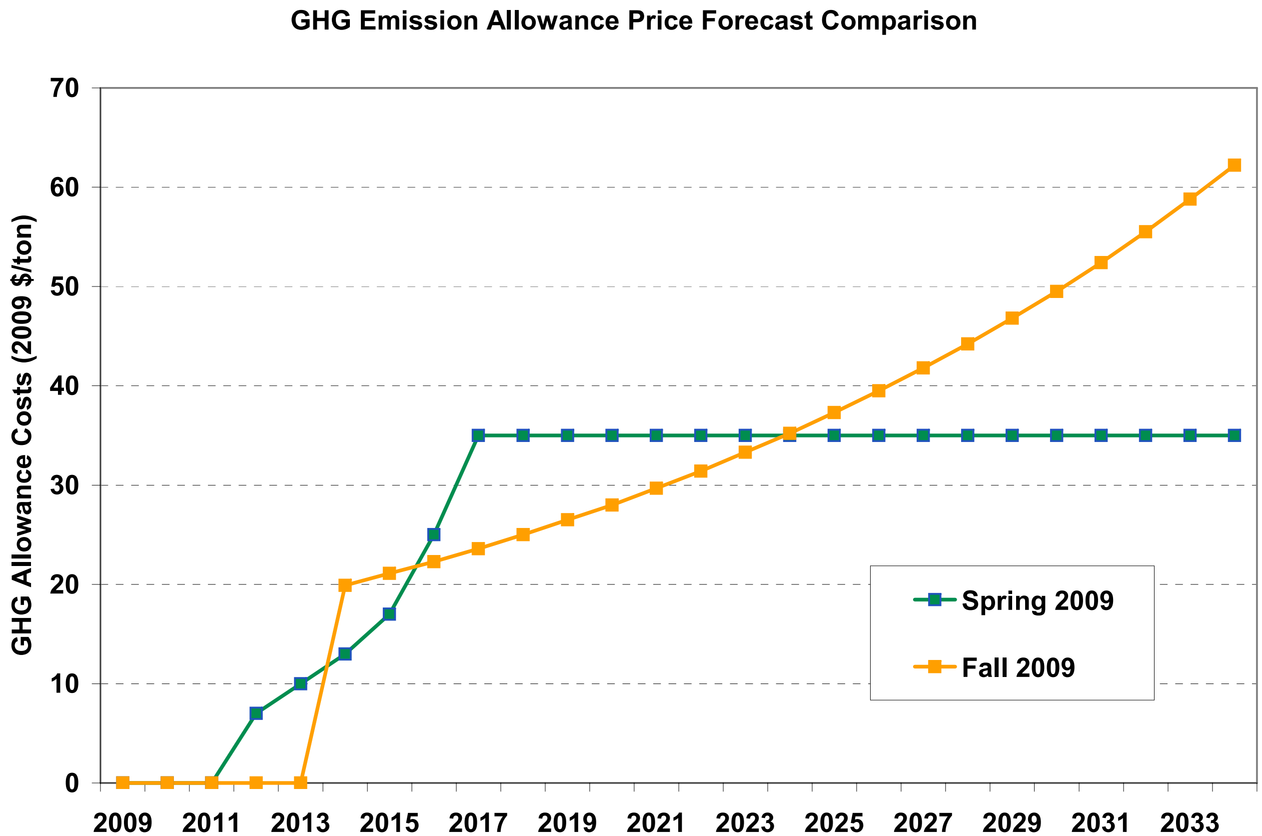
Major Changes from the Spring 2009 Baseline Forecast

- The long term gas price forecast has been lowered in response to recent announcements on shale gas life cycle costs.



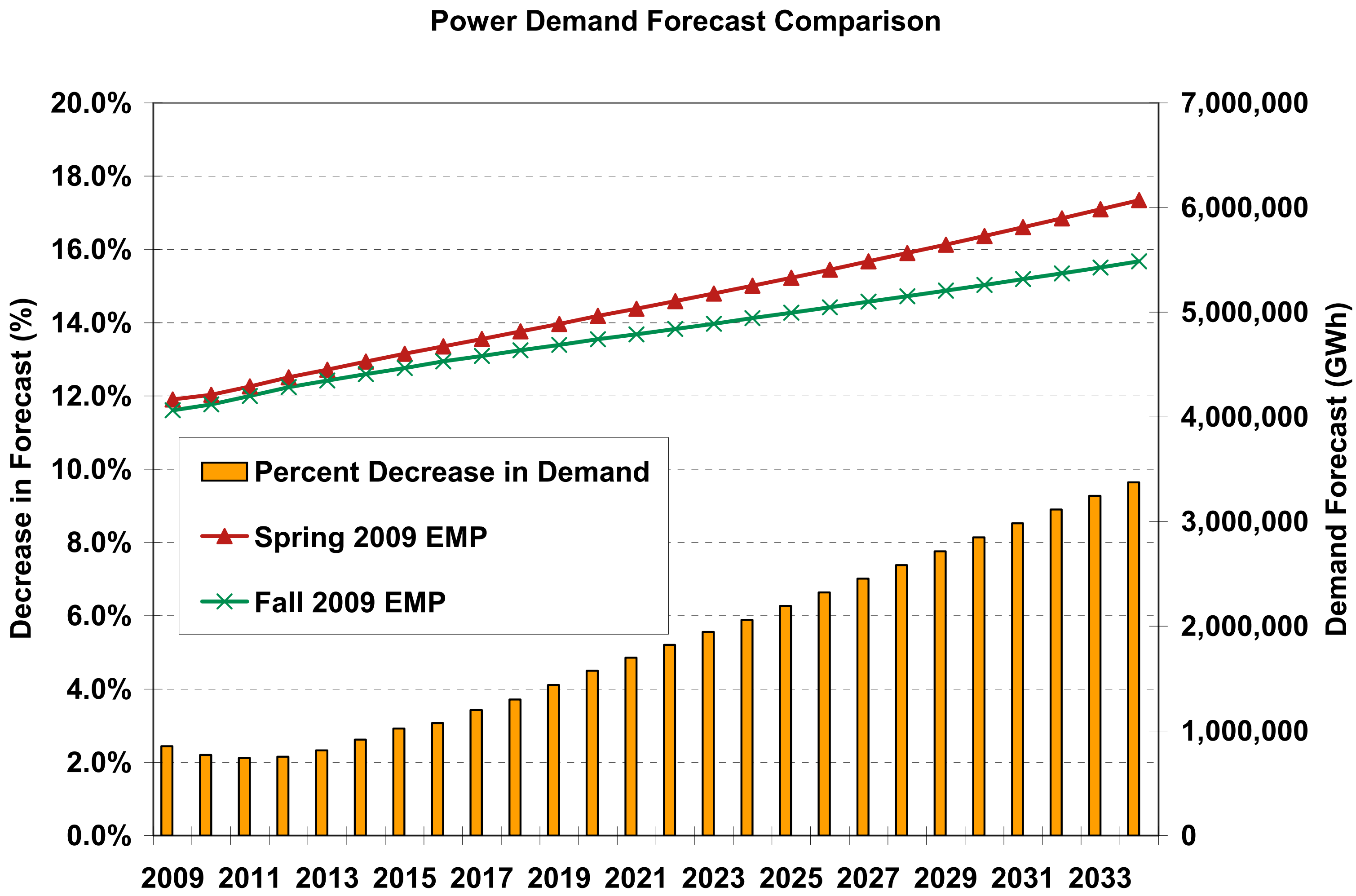
Major Changes from the Spring 2009 Baseline Forecast

- The GHG emission allowance price forecast assumes the first year of compliance is 2014, and US policy allows compliance strategies to include offsets to control the net cost of compliance, removing the need for an explicit "safety valve" or other price ceiling.



Major Changes from the Spring 2009 Baseline Forecast

- The long term energy demand growth rate has been decreased from 1.5% to 1.2%.

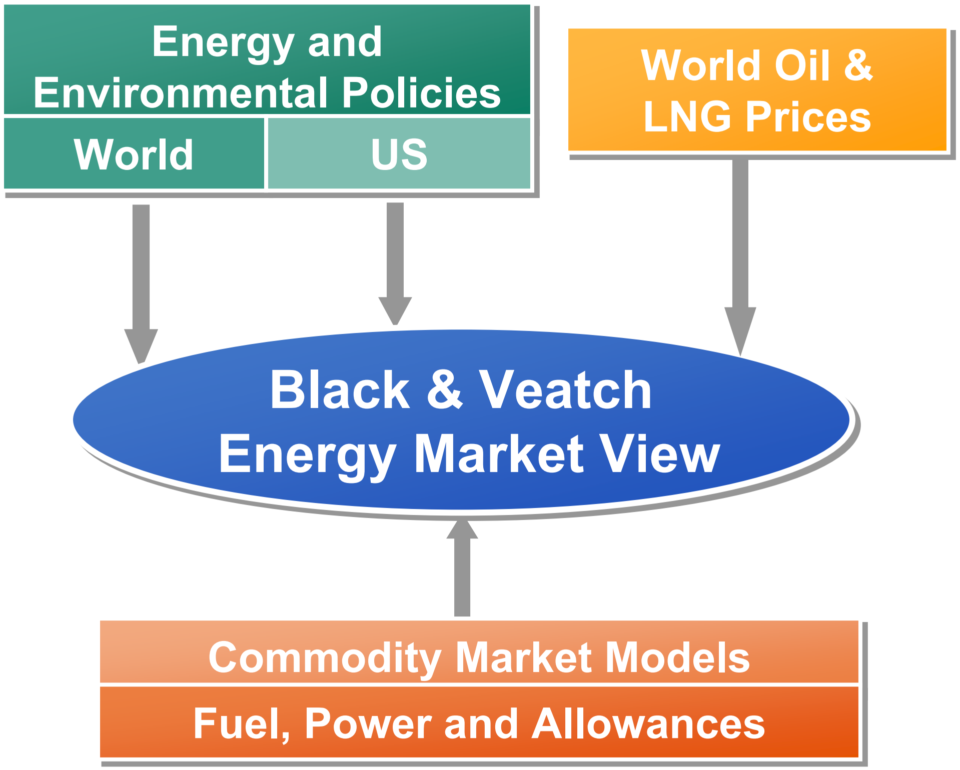


Section 1.
Energy Market Framework

Energy Market Price Forecasting

- Black & Veatch's **Energy Market Perspective** is anchored by its **Integrated Market Modeling (IMM)** process, which is used to prepare its integrated long term view on energy markets. In order to arrive at this market view, B&V draws on a number of commercial data sources and supplements them with its own view on a number of key market drivers, for example, power plant capital costs, environmental and regulatory policy, fuel basin exploration and development costs, and gas pipeline expansion.
- B&V uses this data in a series of vendor-supplied and internally-developed energy market models to arrive at its proprietary market perspective; vendor-supplied models include PROMOD (part of the PowerBase Suite).

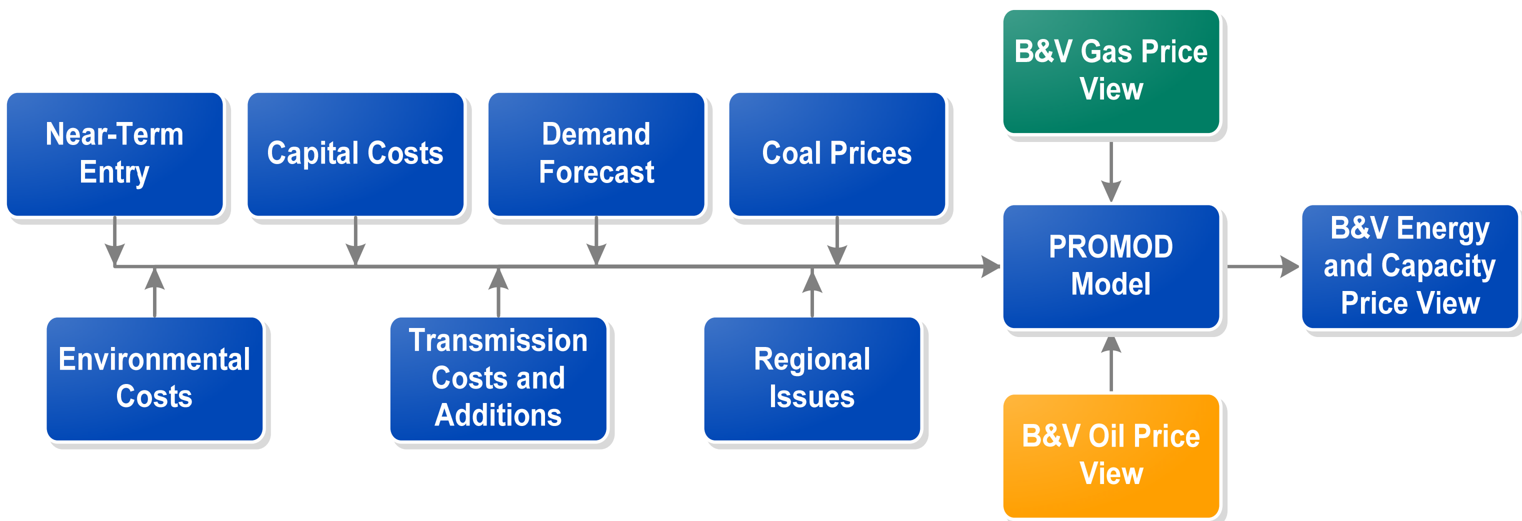
B&V Energy Market Perspective



Electricity Market Price Forecasting

- The electricity price forecasting portion of the IMM process uses the PROMOD structural model to emulate asset-owner market behavior.
  - Execution of this forecasting process requires inputs on various key market drivers, including generation assets, fuel market conditions, electric transmission system operation and improvements and global, national and regional policy issues. The specific inputs assumptions are documented in detail in Sections 2 and 3 of this report.
- The results of the electricity market portion of the IMM process provide long term (25-year) detailed forecasts of **energy and capacity prices** for 71 defined North American market zones. These forecasts are suitable the forecasting merchant assets operations and market revenues, which can in turn drive transactional due diligence, asset portfolio optimization, environmental compliance, risk management and the analysis of business expansion and exit strategies.

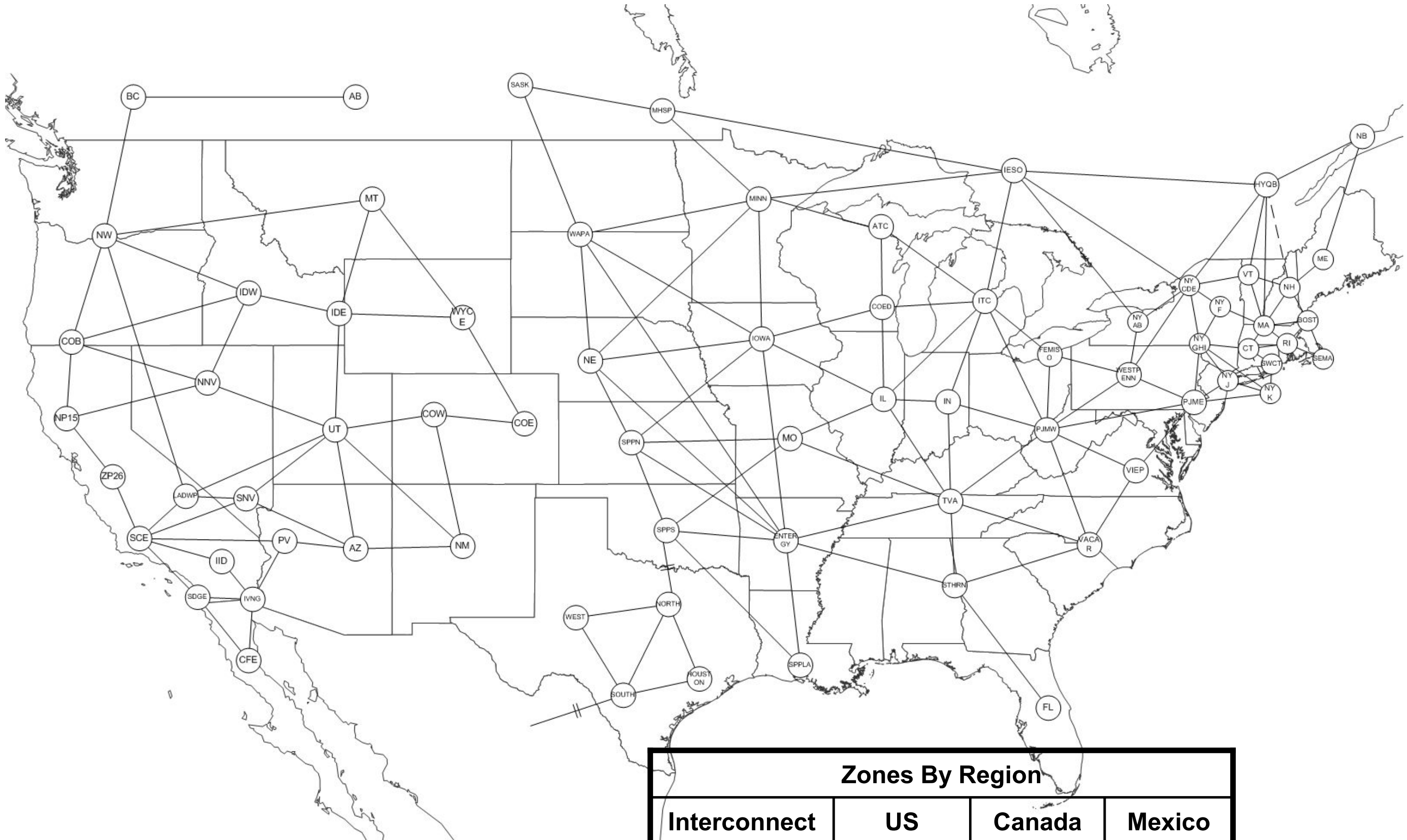
Electricity Market Analytical Structure



Geographic Scope of Energy Market Perspective

EMP North American Market Topology

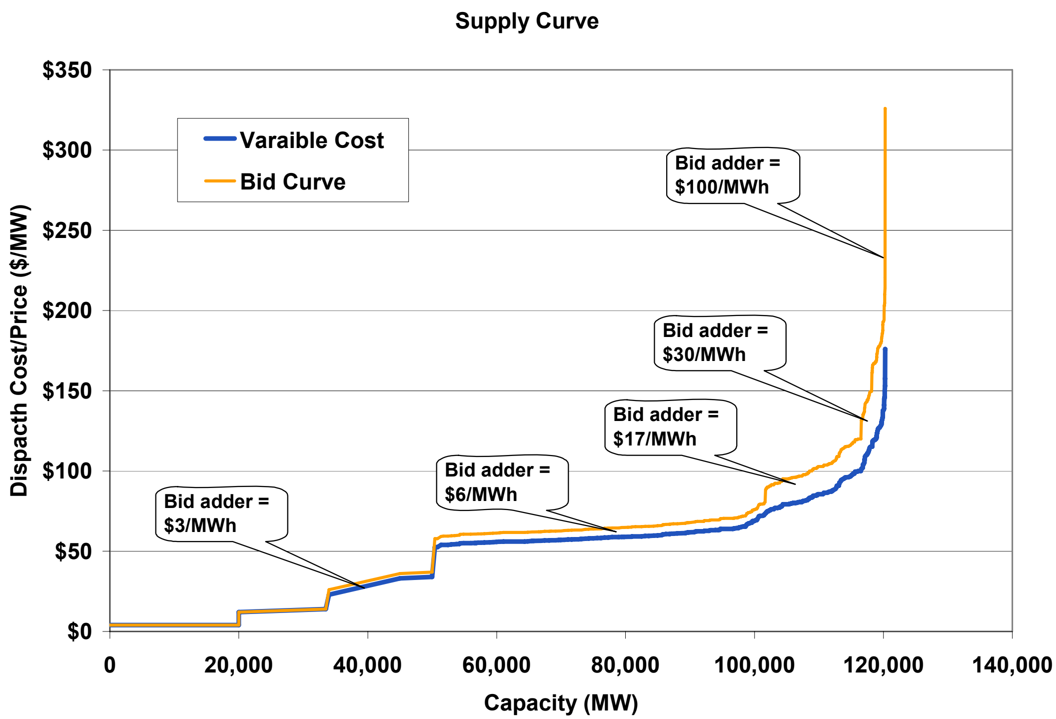
- The B&V Energy Market Perspective covers all of the lower 48 United States, the neighboring provinces in Canada, and northern Baja California in Mexico.
- A total of 71 regional market zones are used to segregate demand and resources so that all principal transmission interfaces and limitations are recognized in the market simulations.



Zones By Region			
Interconnect	**US**	**Canada**	**Mexico**
Eastern	37	5	0
ERCOT	4	0	0
WECC	21	2	1

Energy Price Forecasting—Approach

- An essential element of the energy price forecasting process is the use of a structural market model (sometimes called a “fundamental model”) to simulate electric energy market behavior.
- In general there are two competing approaches used to create market price forecasts from structural models.
  - Variable cost dispatch. In this approach, each asset is assumed to offer its output to the market at its variable costs, typically the cost of fuel plus variable O&M.
  - Dispatch based on “bid adders” or “scarcity premiums.” This second approach recognizes that asset owners will behave in a profit maximizing manner, and when possible will bid prices higher that their variable costs in order to maximize the value of their investment. While organized markets will monitor bidding behavior to restrict this behavior to some “acceptable level,” it is clear from market prices observed in both bilateral and RTO-administered markets that such pricing behavior is common and is considered an acceptable practice.
- B&V’s energy market analysis emulates this profit maximizing behavior in the price forecasting process.

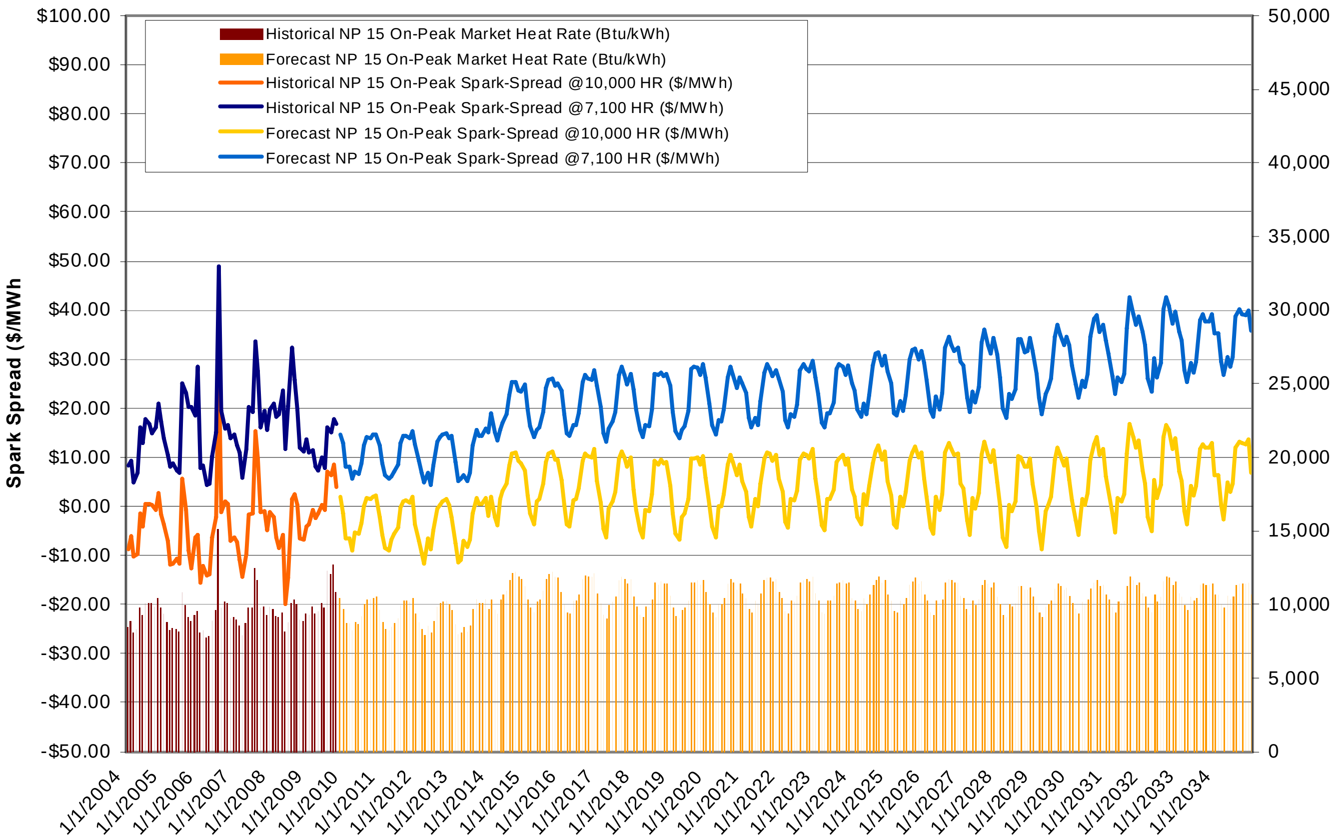


- The cumulative impact of this profit maximizing behavior is illustrated in the figure above. In essence, assets with a relatively low variable cost have little or no capability to bid prices higher than their variable operating costs. However, assets with higher variable operating costs will have opportunities to successfully bid prices above their operating costs.
- The result is that the supply curve seen by the market is “shifted upward” so that at any given demand level, energy market prices are higher than they would otherwise be with a variable cost bid approach.

Resulting Electricity Market Forecasts Are Rational Compared to History

- Near term forecasts are consistent with recent historical observations.
  - This serves to validate B&V's approach to energy price forecasting.
- This comparison is made in terms of spark spreads and market heat rates, which normalizes volatility in natural gas prices.

Northern California (NP-15): Historical and Forecast



Source: Black & Veatch

Interpreting Energy Price Forecast Results (part 1)

- The sample results on the previous page introduced two energy price metrics that are widely used in the power industry:
  - Spark Spread. This is a shorthand calculation of implied profitability for a gas-fired generator given a certain heat rate, such as 7,100 or 10,000 Btu/kWh.
    - Spark Spread ($/MWh) = Power Price ($/MWh) – [Gas Price ($/MMBtu) x Assumed Heat Rate (Btu/kWh) / 1,000]
  - Market Heat Rate ("MHR"). This calculation identifies the "break-even" heat rate of the marginal generator to yield the given energy price, presuming that the generator is gas-fired.
    - Market Heat Rate (Btu/kWh = Power Price ($/MWh) / Gas Price ($/MMBtu) x 1,000
  - Sample calculations follow.

Power Price ($/MWh) = 50
Gas Price ($/MMBtu) = 4.00
Spark Spread @ 10,000 = 50 - [4 x 10,000 / 1,000] = $10/MWh
Market Heat Rate = 50 / 4 / x 1,000 = 12,500 Btu/kWh

- Both Approaches live and die by their simplicity.
  - Spark spreads were created by power traders who needed a quick short hand to identify possible arbitrage opportunities. Asset owners can use spark spreads in the context of knowing, for example, that the Spark Spread @ 10,000 needs to be greater than $4/MWh to cover its variable O&M costs.
  - MHRs can be used in a similar way, in that an asset owner may know for example that the MHR needs to be greater than 8,500Btu/kWh for his asset to cover its fuel and VOM costs.

Interpreting Energy Price Forecast Results (page 2)

- Both metrics have drawbacks when applied to long term forecasts.
  - Spark Spreads are dollar values and are sensitive to assumptions regarding constant versus current dollars. This makes comparisons among differing forecast vintages difficult.
  - Market Heat Rates are not in expressed in dollars, but in a physical unit (Btu/kWh). This makes comparison among forecast vintages easier. But since market heat rates are ratios, differences in the rate of change of the numerator and denominator can give misleading indications. This is particularly noticeable when gas prices are changing rapidly within a forecast, or among vintages of forecasts. An increasing gas price will yield a decreasing market heat rate, even though the spark spread remains constant.
- Sample calculations are in the table at right. While this example was designed to yield a completely unchanging spark spread (which is unlikely), it does illustrate how an increasing gas price creates a decreasing MHR, creating a mistaken impression that asset profitability is dropping in the forecast.
- These metrics have much less meaning for all non-gas-fired assets. Coal-fired assets can look at similar metrics using power and coal prices, but they are asset-specific due to the wide range of efficiencies among these plants and coal's inherent non-fungibility. Assets like hydro, nuclear, wind and solar are focused on the power prices and their own operating costs.

	Natural Gas Price ($/MMBtu)	Power Price ($/MWh)	Spark Spread @ 10,000 ($/MWh)	MHR (Btu/kWh)
2010	4.39	68.94	25.00	15,690
2011	4.58	70.80	25.00	15,459
2012	4.80	73.02	25.00	15,207
2013	4.86	73.61	25.00	15,143
2014	5.01	75.08	25.00	14,992
2015	5.18	76.80	25.00	14,826
2016	5.42	79.16	25.00	14,616
2017	5.79	82.87	25.00	14,320
2018	6.09	85.92	25.00	14,104
2019	6.20	87.01	25.00	14,032
2020	6.09	85.87	25.00	14,107

Source: Black & Veatch

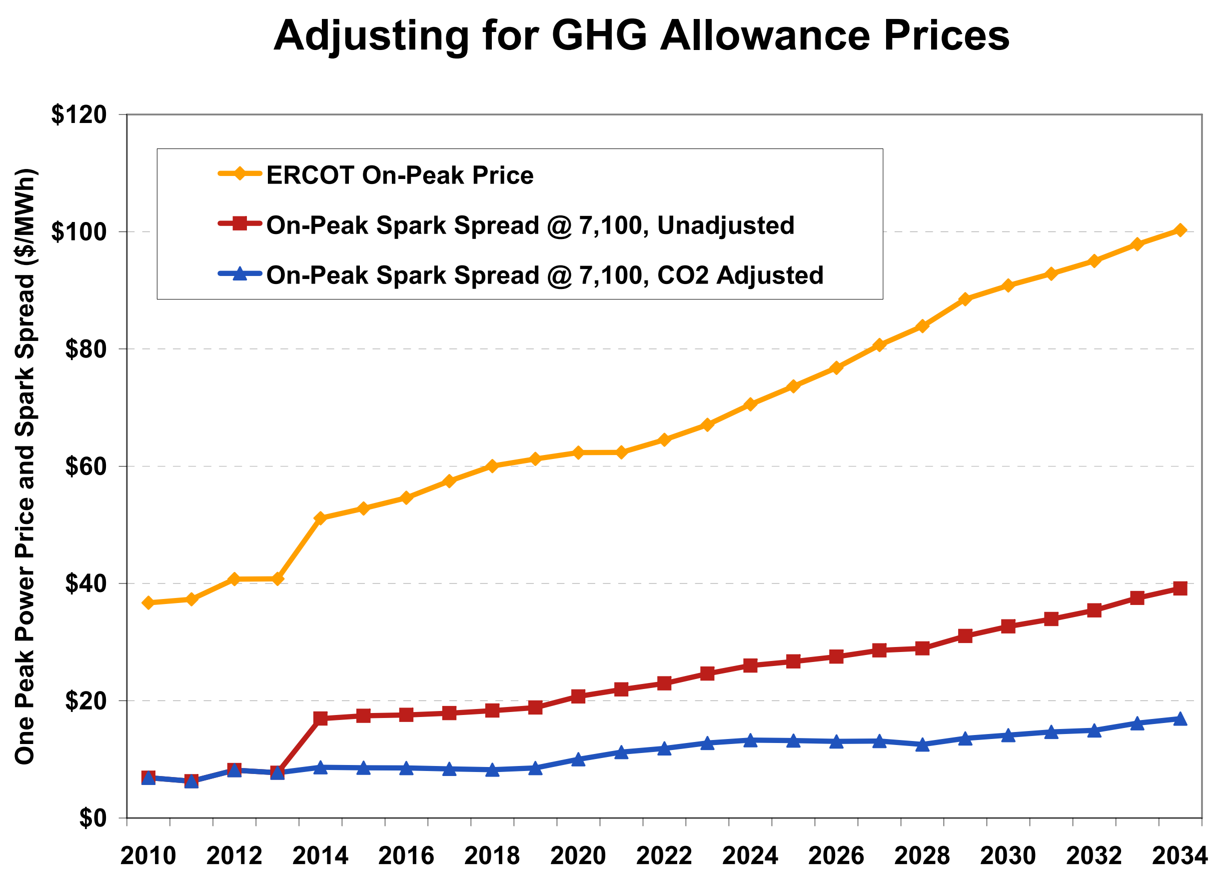
The Impact of GHG prices on the Interpretation of Energy Price Forecast Results (part 1)

- The inclusion of GHG allowance prices introduces a major distortion to both spark spreads and MHRs.
- When other environmental assessments were made, such a SO_2 allowance prices and in some regions NOx allowance prices, the total impact on asset operating costs were small enough that they could be lumped in with other variable O&M costs, and there was no need to re-thing spark spreads and MHRs.
- But GHG allowance prices are forecasted to range in the $20 to $60/ton range. Assuming an average CO_2 content in today's power of roughly 0.75 tons/MWh, this is like adding $15 to $45/MWh to VOM costs. In this dramatic a situation, are the traditional metrics still valid?
- The answer is a clear "maybe." It would be possible to adjust spark spread and MHR calculations by the forecasted mix of CO_2 emissions of marginal (price setting) units each hour each year in an attempt to normalize the metrics for CO_2. This would help somewhat in making forecast comparisons simpler, but would yield a CO_2 adjustment that changes each year in the study period. This does little to help an individual asset owner, with a constant CO_2 emission rate, in quickly relating the meaning of a forecast in terms of asset profitability.
  - Also, the GHG allowance allocation mechanism is still under debate. It is likely that the amount of GHG allowances held by individual asset owners will vary in terms of the proportion of allocated (non-cash cost) versus purchased (cash cost) GHG allowances, and this will vary over time. And allocated GHG allowances will become monetized when assets are sold, so the second owner after allocation will view allocated GHG allowances as a cash cost. Clearly, there is no workable short hand for adjusting forecast prices for GHG impacts.
- For now, Black & Vetch's approach to this issue is to continue to calculate forecast spark spreads and MHRs in the traditional manner. But asset owners need to understand that over time the GHG allowance price is becoming a growing factor in the power price forecast and its impact on assets will vary widely.

Source: Black & Veatch

The Impact of GHG prices on the Interpretation of Energy Price Forecast Results (part 2)

- In this example of on-peak power prices in ERCOT, it is clear to see the impact of the GHG allowance prices in 2014. The overall price trajectory after that is influenced by increases in both the GHG allowance price and natural gas price.
- The unadjusted spark spread increases by a step function in 2014, and tends to rise over time in sympathy with the continued increases in GHG allowance prices.
- Adjusting for the increases in GHG allowance prices (by making a correction based on modeled hourly carbon emissions), the adjusted spark spread rises slowly over time form about \$8.00 to \$17.00 per MWh.



Source: Black & Veatch

Capacity Price Forecasting—Approach

- In the context of long-term price forecasting, capacity prices create an asset revenue stream that supplements the margins received from energy markets.
  - Energy is the output from a power plant (measured in kWh or MWh).
  - Capacity is the ability to generate energy (measured in kW or MW).
- The value of capacity is a function of the value of the energy associated with it.
  - **Reliability capacity** (also called regulatory capacity or naked capacity) entitles the owner of the capacity to receive energy at a market price.
  - Capacity obtained in a **purchased power agreement** (PPA) usually gives the capacity owner the right to obtain energy at the asset's actual cost of production.
    - In effect, it is a physical option.
- PJM, New York and New England have administrative capacity markets, often called ICAP (**I**nstalled **CAP**acity) markets. ICAP is a form of reliability capacity, so the power plant owner can sell ICAP to the ISO and still retain the right to sell energy, although there typically is an obligation to preferentially sell the energy to the ISO.
- In the B&V Energy Market Perspective, we forecast the value of **reliability capacity**, and link it to ICAP in administrative markets
- See "Capacity Markets Demystified," *Public Utility Fortnightly*, March 2008.

Power Plant Owner's Revenue from Capacity Prices

Installed Capacity (ICAP) Markets

- ICAP prices are typically set through an administrative auction process. Rules vary widely by jurisdiction and are discussed in more detail in Section 4 of the Reports covering PJM, NY-ISO and ISO-NE.
- ICAP prices typically are regulated relative to the Cost of New Entry (CONE) for a proxy unit, usually a combustion turbine (CT). CONE will be adjusted by the proxy CT's energy and ancillary serves margins, resulting in a "Net CONE."
- The ISO sets rules for accrediting capacity to assure some level of reliability of service.
- All participating capacity resources receive the ICAP price if they clear in the auction process, regardless of their actual capital costs.
- Assets selling ICAP to an ISO will have to first offer their capability in day ahead energy and/or ancillary services markets sponsored by the ISO, thereby limiting other energy sales opportunities.

Bilateral Capacity Markets

- Bilateral capacity prices are typically set through private negotiation.
- In a PPA type of transaction, all energy and ancillary services (AS) margins are realized by the buyer of the capacity, so from an asset owner's perspective all the revenue comes from the capacity sale.
  - This is a simplification, as some PPAs are structured so that the asset owner realizes additional margin from the structure of the PPA's variable cost pass-throughs.
- In a reliability capacity sale, the capacity revenue would be lower than the revenue stream seen in a PPA under otherwise identical circumstances, and the asset owner would realize energy (and possibly AS) margins.
- This revenue stream will be risky due to the need to contract bilaterally with LSEs (to fulfill resource adequacy requirements) or other potential buyers. It is likely there will be winners and losers in such an activity.

Capacity Prices and Revenue in Non-ICAP Markets

- There are no formal capacity markets in the outside of ISO-NE, NYISO and PJM, and no standard definition of the "capacity" product. At the same time, there are substantial numbers of negotiated power purchase agreements that split revenue for power sales between an energy and a capacity component.
- The forecast energy prices in B&V's Energy Market Perspective Base Case, and in virtually all simulation-based structural electricity price forecasts, are generally below a level that would fully compensate generic new entry for investment costs over their expected operating lives. This is particularly true for new simple-cycle entry included in the forecast process to maintain resource adequacy (minimum planning reserve margin) requirements.
- More efficient generators, likely to earn profit margins from energy sales, may still obtain capacity revenue through bilateral transactions, but it is common for there to be a negotiated trade-off between energy margins and negotiated capacity prices, so that total revenue available to owners is not expected to produce excess investment returns.

B&V Approach to Forecasting Capacity Prices in Non-ICAP Markets

- B&V has implemented an approach to forecasting capacity prices based on a long-run capacity planning algorithm.
- Given the bilateral nature of capacity transactions in non-ICAP markets, there is not a single price of capacity, and not all suppliers are likely to receive capacity revenue. As such, the capacity price forecast developed by B&V should be viewed as “indicative,” and provides a reasonable measure of capacity price/revenue that marginal generators could expect to receive, provided that they are successful bidders in competitive procurement proceedings, and that they are able to negotiate a power sales agreement with a load-serving entity in need of capacity to meet load obligations (including planning reserves).
- In the B&V capacity market analysis, the capacity market “clears” when supply equals annual peak demand, plus planning reserve margins.
- In years and markets where new capacity is not yet needed, the capacity price is determined as shortfall revenue needed for the marginal generator to just recover its variable and fixed operating costs in the upcoming year. Under these conditions, there is no capacity revenue targeted to cover investment-related cost.
- In years and markets where new capacity is needed, and supply is expanding, the capacity price is calculated based on the cost of new entry (net of expected energy market operating revenue) in the upcoming year for two proxy technologies: a simple cycle gas turbine and a combined cycle asset.
- This in turn creates two alternative forecasts for capacity prices, as discussed further on the next page.

Interpretation of Capacity Price Forecasts

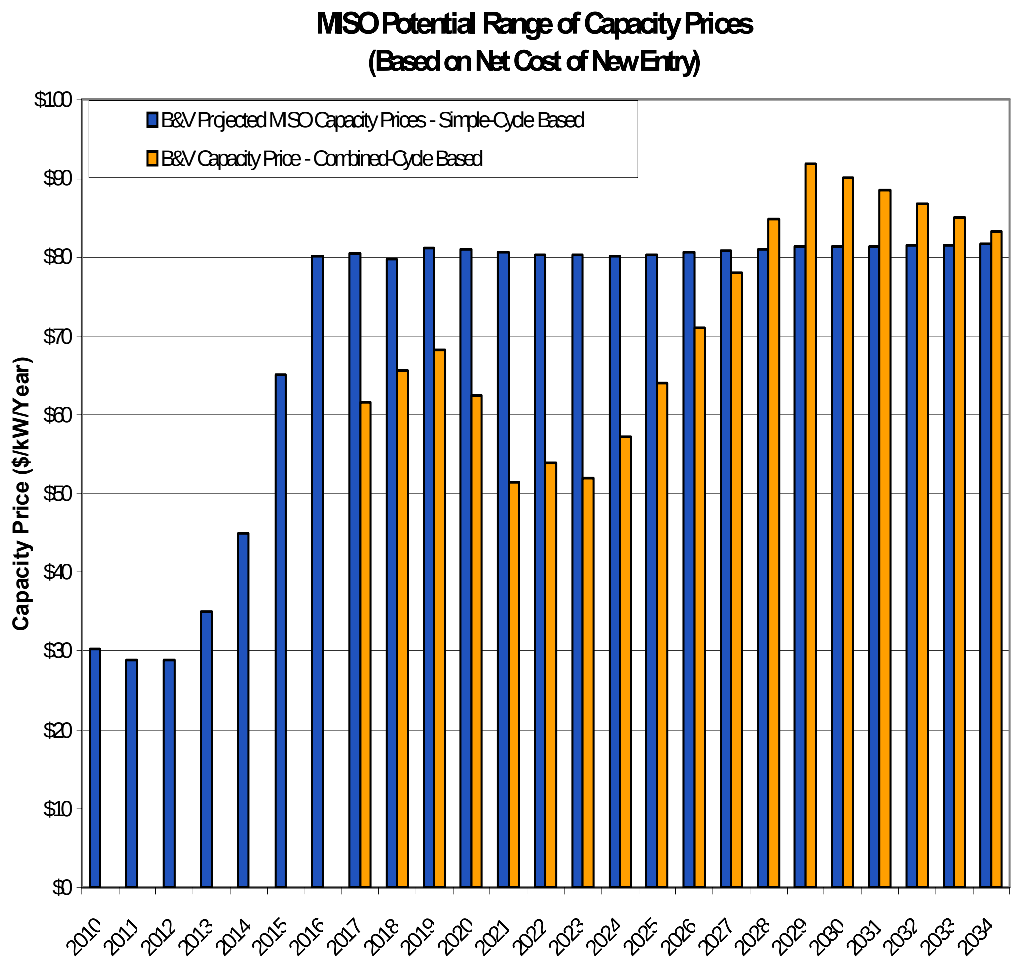
- In this example, which is based on a Fall 2009 forecast result in MISO, there are three capacity price levels to note.

1. When no new capacity is needed to provide adequate planning reserve margins, capacity prices are based upon the revenue shortfall of the region's marginal existing asset which would be needed to provide the regional reserve margin. In this example that value is in the $30-$40/kW/year range. Depending upon the shape of the supply curve this value can be much lower, and in some instances may be zero, indicating that energy revenues do not need to be supplemented by a capacity payment.

- Beginning in 2016-2017, capacity market prices reflect the cost of adding CT or CC capacity. Broadly speaking, the price (or value) of capacity will tend to be competed down to the lower value.

2. The CC-based capacity prices trend lower than the CT-based prices in most of the study period, indicating that CC revenue economics will tend to set capacity prices.
3. If a CT is needed by a specific load serving entity, its energy revenue will need to be supplemented by a capacity price higher than that for the CC asset. This may come from a direct capacity payment to the CT asset, or it may come from sale of ancillary services.

- Later in the study period the CT assets have the lower capacity value. Such changes are driven by changes in the shape of the regional supply curve.



- In ERCOT, the CC and CT net CONE values are very close and only a single capacity price is reported.

Source: B&V analysis

Section 2.
Environmental, Energy Policy and Power Market Assumptions

2.1 Policy Overview

Environmental and Energy Policy and Market Assumptions

- The US electric power industry is again in a state of rapid change and great uncertainty. The following is a discussion (admittedly not exhaustive) of the key policy issues that impact the B&V Market Perspective and influence the value of client investments.
- Key policy issues covered include
  - The 2005 Energy Policy Act
  - The 2009 Economic Stimulus Bill
  - Environmental regulations related to SO2 and NOx emissions
  - Potential green house gas regulations
  - State level renewable portfolio standards (RPS)
- Key electricity market assumptions include
  - Forecasted electricity demand
  - Cost of new generation
  - Resurgence of nuclear power
  - Current resource picture
  - Generation retirements
  - Major transmission projects

Energy Policy Act of 2005

- EP Act 2005 provided for a series of incentives and subsidies to encourage fuel diversity, energy independence, increased efficiency and reduce green house gas emissions. Most initiatives are widely viewed as incremental changes only, and the Act has been criticized (on one hand) for its emphasis on nuclear and fossil fuels, and (on the other hand) for not allowing drilling in the Arctic National Wildlife Refuge.

Topic	Summary of Major Provisions
Coal	•Authorized $200 million per year in clean coal initiatives. •Repeal 160 acre ceiling on federal coal leases.
Network	•Requires DOE to designate National Interest Electric Transmission Corridors where congestion adversely affects the public, and gives FERC federal permitting authority in these corridors. •Sets federal reliability standards
Oil and Gas	•Incentives for development in the Gulf of Mexico •Exempt producers from certain provisions of the Safe Drinking Water Act. •Prohibits drilling in the Great Lakes.
Biofuels	•Increases targets for biofuel blending in gasoline •Authorized $50 million per year biomass grant program
Retail Electricity	•Requires all public utilities to offer net metering to customers. •Tax breaks for home and commercial building efficiency improvements. •Extending daylight savings by 4 to 5 weeks to decrease energy demand.
Renewable Energy	•Expands definition of renewable energy to include wave and tidal power •Authorizes US Department of the Interior to grant leases on Outer Continental Shelf for energy development other than oil and gas.
Green House Gases	•Loan Guarantees for a wide range of innovative technologies to reduce GHG emissions, including clean coal and nuclear

Note: Nuclear industry impact covered later in this section.

2009 Economic Stimulus Bill Contain Significant Energy Industry Provisions

- The American Recovery and Reinvestment Act of 2009 (the "2009 Stimulus Bill") was signed into law on February 17, 2009. It included nearly $50 Billion in energy-related provisions (or more, depending on how you classify some of the programs), including major changes to renewable energy incentives.

Topic	Summary of Major Provisions
Production Tax Credits (PTCs)	•Wind—PTC extended for facilities in service by January 1, 2013. •Biomass, geothermal, solar, landfill gas, municipal solid waste, hydroelectric and marine and hydrokinetic renewable energy facilities—PTC extended for facilities in service by January 1, 2014.
Energy Tax Credits (ETCs)	•For facilities listed above that are placed in service in 2009 or 2010, taxpayers may make an irrevocable election to claim a 30% energy tax credit (ETC) in lieu of the PTC. •ETC now available for assets financed in part or whole by tax exempt bonds or certain other government financing programs
Cash Grants	•Some ETC eligible assets may apply for a cash grant equal to 30% of the tax basis of the asset in lieu of the ETC. Grants will not be taxable income and the depreciation basis will be reduced by 50% of the grant. • Applies to assets (1) placed in service in 2009 or 2010 although construction began earlier, or (2) for which construction began in 2009 or 2010 and are placed in service by the PTC dates listed above, except solar and fuel cells (and technology previously eligible for ETCs) must be in service by January 1, 2017.
Smart Grid and Transmission	•$18.75 billion funding in various programs.
Energy Efficiency	•$22 billion funding in various programs.
Loan Guarantees	•$6 billion funding for guaranteeing $60 billion in loans for renewable energy and transmission projects.
Fossil Energy R&D	•$3.4 billion funding for what is perceived as a re-start of the FutureGen IGCC w/CCS demonstration project.

2.2 Environmental Regulations For Other Than Green House Gas Emissions

Background on SO2 and NOX Emission Regulations

- The Acid Rain Program under the Clean Air Act Amendments of 1990 (CAAA 90)–This was the original "cap and trade" program, designed to reduce the environmental and human health impacts associated with the release of sulfur emissions from coal power plants. Its success is often cited in the debate over future regulation of carbon emissions.
- The Acid Rain Program incorporated a sulfur dioxide (SO_2) emission allowance trading system that employed a tradable permit mechanism. The program allowed market forces to efficiently allocate mitigation resources so that the national emission reduction goal was achieved.
- The Acid Rain Program was implemented through the following steps:
    - Set overall emission limits, subdividing that limit by setting specific limits for each emission source.
    - Assign tradable allowances to each emitter in an amount equal to their specific emission history.
    - Allow trading and track transfers of emission allowances.
- CAAA 90 NOx reductions were set in a two-phased strategy
    - The first phase, finalized in a rulemaking in 1995, was designed to reduce NOx emissions by over 400,000 tons per year between 1996 and 1999.
    - The second phase, which began in 2000, was designed to reduce NOx emissions by over 2 million tons per year. The second phase reduction goal has been surpassed, in part due to additional state-initiated NOx reductions in the Northeast.

Further Regulation of SO2 and NOX Under the Clean Air Interstate Rule (CAIR)

- Clean Air Interstate Rule (CAIR) – In 2005 the EPA announced CAIR, a rule designed to achieve the largest reduction in air pollution in more than a decade.
- Through the use of the proven cap-and-trade approach, CAIR was designed to achieve substantial reductions of sulfur dioxide (SO_2) and nitrogen oxides (NO_x)
- CAIR included a two-phase program with declining power plant emission caps:
  - SO_2 annual caps: 3.6 million tons in 2010 and 2.5 million in 2015
  - NO_x annual caps: 1.5 million tons in 2009 and 1.3 million in 2015
  - NO_x ozone season caps: 580,000 tons in 2009 and 480,000 in 2015
  - Emission caps were divided into State SO_2 and NO_x budgets
- Use of Acid Rain allocations for compliance with CAIR
  - 1:1 ratio for allocations before 2010
  - 2:1 ratio for allocation 2010-2014 (one allowance for Acid Rain and one allowance for CAIR)
  - 2.86:1 ratio for allocation 2015 and after (one allowance for Acid Rain and 1.86 allowance for CAIR)

CAIR's Legal Journey

- The Clean Air Interstate Rule (CAIR) rulemaking prompted utilities in the eastern United States to order billions of dollars of equipment to reduce SO_2 and NO_x emissions, or purchase emission allowances, in anticipation of the annual NO_x trading market scheduled to begin on January 1, 2009, seasonal NO_x trading in May 2009, and SO_2 market in January 2010. The first phase of CAIR was designed to reduce annual SO_2 and NO_x emissions by 45% and 53% respectively, with even greater reductions to begin under a subsequent phase in 2015.
- The rule was challenged by several states and other petitioners, most of whom sought to have only certain provisions of the rule revised or set aside. After ruling in July 2008 that CAIR had "more than several fatal flaws" and vacating the rule altogether, the U.S. Court of Appeals for the District of Columbia Circuit instructed all litigants to file responses to EPA's petition for rehearing in October 2008.
- Based on these responses, the court issued a four-page order on December 23, 2008, that temporarily restored CAIR and essentially reversed its previous decision to vacate the rule while the U.S. Environmental Protection Agency drafts a new rulemaking that addresses the legal problems the court previously identified when it vacated the CAIR rule in July 2008. In its decision, the Court concluded "notwithstanding the relative flaws of CAIR, allowing CAIR to remain in effect until it is replaced by a rule consistent with our opinion would at least temporarily preserve the environmental values covered by CAIR."

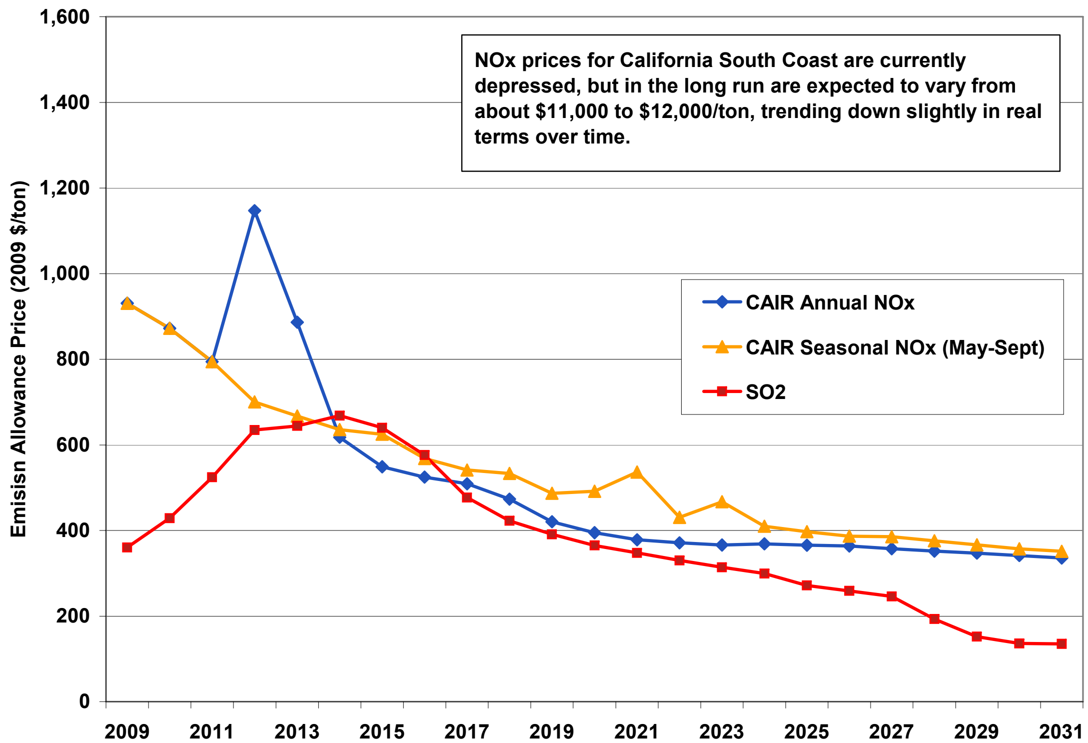
CAIR's Next Steps

- EPA must now promulgate a new CAIR that addresses all the flaws and concerns identified in the court's July 2008 ruling, which realistically could take years to finalize.
  - A Proposed Rule is expected in May 2010, with finalization in 2011. It may or may not include emissions trading as part of allowable compliance strategies.
- Alternatively, Congress could enact legislation that implements CAIR's proposed SO_2 and NO_X emission reduction programs, but EPA would still likely have to develop rules to implement the new legislative program. Bills to accomplish this have been introduced in 2009, but none have passed so far.
- In the meantime, both states and utilities must scramble to distribute allowances and manage emissions to meet the initial phase of CAIR's emission reduction requirements.

SO2 and NOX Emission Allowance Price Assumptions

- In 2008, seasonal NOx Emission Allowances (EAs) varied between $600 - $1,400 per ton, and SO2 EAs varied in a range of about $100 to $500 per ton.
- In the near term significant deviation between actual prices and forecasts is possible because the current market prices are based largely on speculation in the face of regulatory uncertainty, not fundamentals. Once caps are re-established and confirmed, there will be a re-alignment between pricing and fundamentals.
- In the long run, SOx and NOx EA prices will likely decrease due to various GHG regulation impacts:
  - Gas substitution,
  - Few new coal additions,
  - Increased the rate of renewable additions, and
  - Higher power prices pushing demand down.

Forecasted Emission Allowance Prices



Source: PowerBase and B&V Analysis

SO_2 & NO_X Emissions – Other EPA Regulations

- **Fine Particulate Matter ($PM_{2.5}$)** - forms from precursor pollutants such as SO_2 and NO_X
  - EPA designated 225 counties as non-attainment areas for annual standard in 2005 and 120 counties for new 24-hour standard in October 2009.
  - NSR implementation rule issued in May 2008 imposes BACT requirements on new and modified sources, requires SO_2 and presumes NO_X to be treated as a precursor pollutant
  - States have 3 years from each rulemaking to develop State Implementation Plan (SIP) requirements
- **8-hour Ozone** – forms from precursor pollutants NO_X and VOCs
  - EPA stays 2008 standard for attainment designations in September 2009 to reconsider stringency, expects to complete accelerated designation process in August 2011.
  - 2008 standard will continue to be implemented for permitting, and 1997 standard for non-attainment designations

Regional Haze Program

Regulates emissions of $PM_{2.5}$, SO_2 and NO_X from older (1962-1977) plants that contribute to reduced visibility

- Original 1999 Regional Haze rule vacated by courts in May 2002
- Final rule and guidance for Best Available Retrofit Technology (BART) determinations issued in June 2005
- EPA issues finding in January 2009 that 37 states have failed to submit complete State Implementation Plans (SIPs) with BART determinations and long term “reasonable progress” strategies
  - AL, AR, DE, IA, KY, LA, MS, MO, NC, SC, TN, UT, WV and Albuquerque/Bernalillo County New Mexico have submitted complete SIPs
- EPA to issue Federal Implementation Plan (FIP) by January 2011, which will establish basic requirements for each state that has not by then completed an approved SIP

Mercury (Hg) Emissions

- Final Clean Air Mercury Rule **(CAMR)** published May 2005
  - Nationwide cap-and-trade program regulating Hg emission from coal-fired units >25 MW
  - Reduction goals of 38 tons beginning in 2010 (AQC co-benefits) and 15 tons beginning in 2018 (~70%)
  - Performance standards by category of fuel/technology (bituminous, subbituminous, lignite, coal refuse & lignite) for units built or modified after January 30, 2004.
- States asked to adopt federal CAMR - Multiple states adopt more stringent Hg requirements (which remain in effect today)
- CAMR vacated by DC Circuit Court in February 2008 due to unlawful delisting of EGUs from regulation under Clean Air Act §112. Supreme Court denies petition for certiorari (review) in February 2009.
- March 2008 state agencies begin regulating Hg emissions on a case-by-case basis
- October 22, 2009: consent decree issued as settlement of December 2008 lawsuit brought by the Natural Resources Defense Council and others to compel EPA to regulate Power plant air toxics emissions under the Clean Air Act. In this consent decree EPA is to finalize Maximum Available Control Technology (MACT) standard for Hg and other hazardous air pollutant emissions from new and existing coal and oil fired units (likely 90% reduction or greater) by November 2011.

New Source Review

Modifications to existing sources that result in emission increases may trigger requirement to install state-of-the-art air pollution control equipment

- **Reform Rules**
  - Only two of ten proposed by Bush administration in effect today – past actual to future projected actual calculation test; and plant-wide 10 year cap
- **Enforcement Actions**
  - 16 federal cases settled over past decade, lawsuits against Cinergy, Duke and Alabama Power still active
  - Supreme Court upheld EPA's annual (vs. hourly) emission increase trigger in April 2007
  - New lawsuits filed by Obama administration against Westar, Louisiana Energy and Midwest Generation in 2009
  - New 114 letters requesting information on past modifications mailed out

Non-Air Regulatory Actions Affecting Utilities

- **Combustion Waste Management**
  - December 2008 spill from TVA ash pond prompts new EPA Administrator to announce agency will propose coal-ash regulations and determine whether to reclassify coal combustion byproducts as hazardous waste by end of 2009
- **Wastewater Discharges**
  - EPA to propose revised rule including limits on toxic metal discharges in mid-2012
- **Cooling System Intake Structures**
  - EPA promulgates Phase I rule for new facilities in 2001 and Phase II rule for existing facilities in 2004
  - EPA suspended its Phase II rule for existing facilities in 2007 after Second Circuit Court of Appeals vacates provisions
  - April 2009 US Supreme Court upholds EPA authority to use cost-benefit analysis to determine “best technology available for minimizing environmental impact” in Phase II rule

2.3 Green House Gas Regulations

Green House Gas (GHG) Regulations

- According to the World Resources Council, baseline (uncontrolled) carbon emissions are expected to grow at 2.5% per year. Seven Bills in the 110th Congress addressed Federal Greenhouse Gas (GHG) Legislation all targeting significant decreases in total emissions by 2050. None were passed.
- During the campaign, now-President Obama proposing to target the 1990 emissions level by 2020 and an additional 80% reduction by 2050.
- The Obama administration has pledged to establish a national CO_2 cap & trade program which will include an economy-wide cap on CO_2 emissions.
- In the summer of 2009, much attention was focused on HR 2454, the American Clean Energy and Security Act of 2009 (ACESA), drafted by Reps. Henry Waxman and Ed Markey. The US House of Representatives passed the bill on June 26, 2009. The Senate has not yet passed a companion bill, although bills have been introduced.
- Intended to reduce domestic emissions of greenhouse gases, ACESA contains four main mechanisms for reducing greenhouse gas emissions in the economy:
  - A cap and trade emissions trading system geared at the electric utility sector and large emitters of greenhouse gases;
  - EPA enforced equipment performance standards for all other CO_2 emitters;
  - A mandatory federal renewable electricity standard requiring electric utilities to generate 20 percent of their power from renewable sources and through efficiency gains by 2020;
  - Various energy efficiency standards for buildings, equipment, and appliances.

Main Provisions of ACES (Waxman-Markey)

- Reduce greenhouse gas (GHG) emissions by 17% in 2020 compared to 2005 levels; 42% by 2030, and 83% by 2050.
- 85% of the GHG allowances will be allocated to retail electric companies and generation owners; 15% will be auctioned.
- Combines DSM/EE and RPS in a single program called Combined Efficiency and Renewable Electricity Standard (CERES). Sets a combined target of 6% in 2012 rising to 20% in 2020.
  - Up to 25% of target can be met with DSM/EE:
    - In that case 15% of electricity to come from renewable energy sources and there is a 5% demand reduction from energy efficiency measures.
  - Generation from new nuclear, new CCS and existing hydro are deducted from retail sales for calculating the CERES requirement.
  - Creates RECs which can be banked for 3 years after generation.
  - REC prices capped by an Alternative Compliance Payment (ACP) of $25/MWh.
  - Retailers selling less than 4,000,000 MWh/yr are exempt.

The Boxer-Kerry Bill (S. 1733)

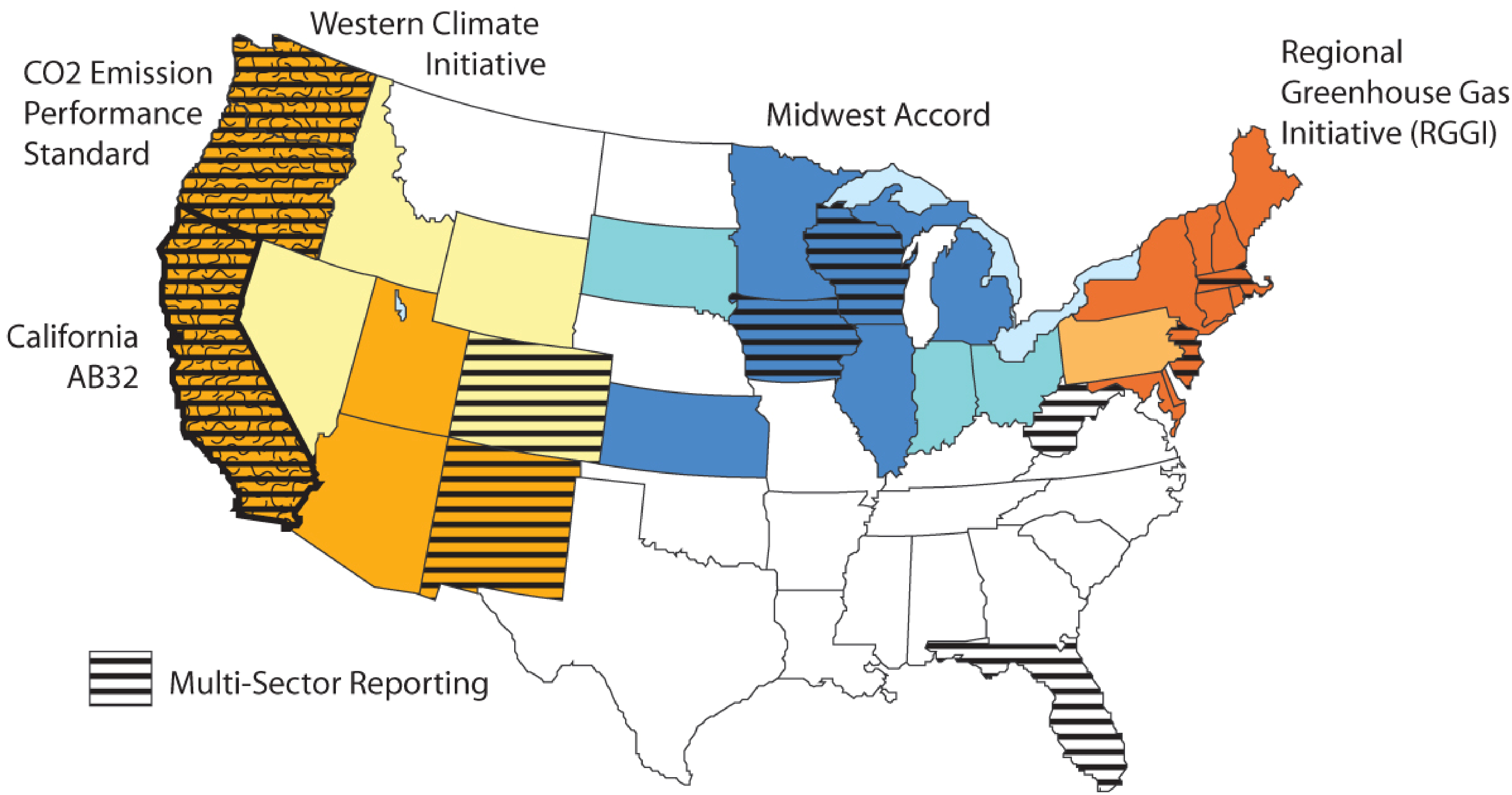
- As the Fall 2009 EMP approached completion, another new bill, the Clean Energy Jobs and American Power Act (S. 1733) was introduced on September 30 by Senators Barbara Boxer and John Kerry. It is likely that various additional bills will be introduced in the Senate, and all will need to go through the committee process before they ever get to a floor vote. Once a Senate bill is passed, then the bill will need to go to conference committee before having a chance at becoming law.

Waxman-Markey "American Clean Energy & Security Act" (Passed by House June 2009)	**Kerry-Boxer "Clean Energy Jobs & American Power Act"** (Introduced to Senate September 2009)
• Reduction Goals – 17% by 2020, 42% by 2030, 83% by 2050 • Economy-wide cap-and-trade with unlimited banking, borrowing with interest, detail distribution scheme • Offsets - 2 billion tons annually, 1 billion domestic & 1 billion international (international can be increased to 1.5 billion by EPA Administrator) • National RPS 20% by 2020 • New coal plant CO_2 performance standards • Prohibits EPA regulation under Clean Air Act provisions	• Reduction Goals – 20% by 2020, 83% by 2050 • Economy-wide "pollution reduction & investment" with unlimited banking, borrowing with interest, distribution details yet to be negotiated • Offsets - 2 billion tons annually, 1.5 billion domestic & 0.5 international (international can be increased to 1.25 billion by EPA Administrator) • New coal plant CO_2 performance standards • Silent on EPA regulation under Clean Air Act provisions

GHG Regulations – EPA Actions

- **Endangerment Finding** – proposed April 2009 that GHG emissions from motor vehicles "cause or contribute to pollution that endangers public health & welfare" (in response to 2007 Supreme Court ruling)
  - Finding would give EPA authority to regulate GHG emissions from mobile and stationary sources under the Clean Air Act
  - Expected to be finalized by end of 2009
- **GHG Mandatory Reporting Rule** – final issued September 2009 for sources emitting 25,000 tons CO_{2e} annually
  - Specifies industrial categories, defers others to 2011
  - Begins January 1, 2010 with first report due March 31, 2011.
- **GHG Tailoring Rule** – proposed September 2009, would subject new sources (and modification of existing sources) emitting 25,000 tons per year or more to Best Available Control Technology (BACT) requirements under Clean Air Act PSD program

Regional & State GHG Programs (in effect by 2012)



Baseline GHG Regulation Assumptions for EMP

- Based on Waxman-Markey bill, assuming compliance is centered on a cap and trade program.
- Covers electric generation, transportation and other fossil fuels used by residential, commercial and industrial sectors.
- CO_2 emission caps are:
  - 6.5% of 2005 GHG emission levels by 2014 (2.7 billion short tons – 2.5 billion metric tons)
  - 17% by 2020 (2.4 billion short tons – 2.2 billion metric tons)
  - 42% by 2030 (1.7 billion short tons – 1.5 billion metric tons)
  - 83% by 2050 (0.5 billion short tons – 0.45 billion metric tons)
- Allowances can be banked for future use.
- Technical assumptions inherent in B&V Baseline Forecast
  - A CO_2 cap & trade program will induce the application of the most cost-effective avoidance and abatement measures first and additional measures in order of increasing cost until total emissions are under the targeted cap – Allowance prices are determined by the marginal cost of control of the last measure required to meet the cap.
  - The cost of control in the industrial, transportation and domestic sectors are sufficiently similar to the costs for the electric industry such that the trading of allowances between the electric and other sectors is minimal. Therefore, electric industry caps and use of offsets are in proportion to economy-wide caps. [Currently electric generation contributes 39% of covered emissions.]
- *Offsets* are permanent greenhouse gas emission reductions or avoidance (including sequestration) not required by any law or regulation or commenced prior to 2009. According to Waxman-Markey, the offset project developer is issued one credit for each CO_2e that the project reduces, avoids or sequesters.
- Allows for 2 billion metric tons (2,204,623 short tons) in offsets.
- Electric power industry uses only 50% of it “pro-rata share” of offsets, on the presumption that other sectors will have more difficulty in compliance and therefore need more than their share.
- Legislative delays make 2014 the first year of implementation.

GHG Regulation Compliance Measures

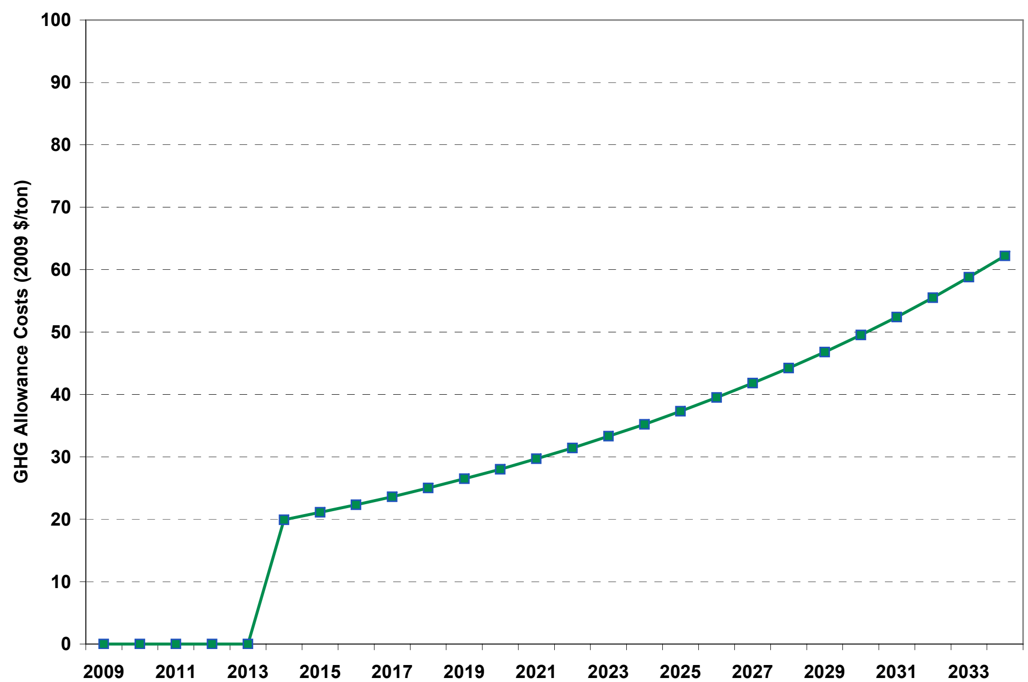
- Compliance with GHG regulations can be met from a variety of measures. The current avoidance and abatement measures applicable to the electric industry include the following:

Compliance Measure	Advantage(s)	Disadvantage(s)
Offsets	Allows for compliance with less reduction in carbon-based fuel use	Uncertain Availability and Costs
Nuclear	Cost effective based on today's costs	Siting and permitting difficult; ability to raise adequate capital
Coal IGCC w/ CCS	Abundant domestic energy source	Expensive and still in demonstration stage; uncertain environmental impacts
Retrofitted Carbon Capture and Sequestration	Reduces carbon emissions of existing carbon-based generation assets.	Existing assets were not designed for CCS, so retrofitting casts are relatively high and technology is uncertain
Wind	Zero Carbon, abundant resource, favorable economics	Needs PTC/ITC and/or RPS/REC; Intermittency
Solar	Zero Carbon, abundant resource	Cost; Regional resource; intermittency
Natural Gas	Proven technologies, short development lead time; less carbon than conventional coal	Exposure to volatile commodity pricing
DSMEE	Uses proven technology	Regulatory risk related to revenue de-coupling and proof of negawatts

Implications of the B&V Baseline GHG Assumptions

- GHG allowance prices will lead to retirement of some of the smaller, older, less efficient coal fired units. The development of nuclear power, wind, solar and natural gas resources will also all be part of the compliance stew.
- Wind energy offers a very large opportunity to further reduce CO_2 emissions in the US. However, the cost of transmission to tap that opportunity is currently unknown.
- International Offsets are vital for compliance at reasonable costs.
- Available CO_2 allowances will be distributed with a combination of auction and allocation processes to current and future producers. Over time, more will be auction and fewer will be allocated. **The implication is that over time the cost of CO_2 emission allowances becomes a cash operating cost for all carbon-emitting entities.** This is in sharp contrast to the SO_2 cap and trade system in the 1990 Acid Rain Program, in which SO_2 emission allowances were allocated at zero cost to existing emitters.

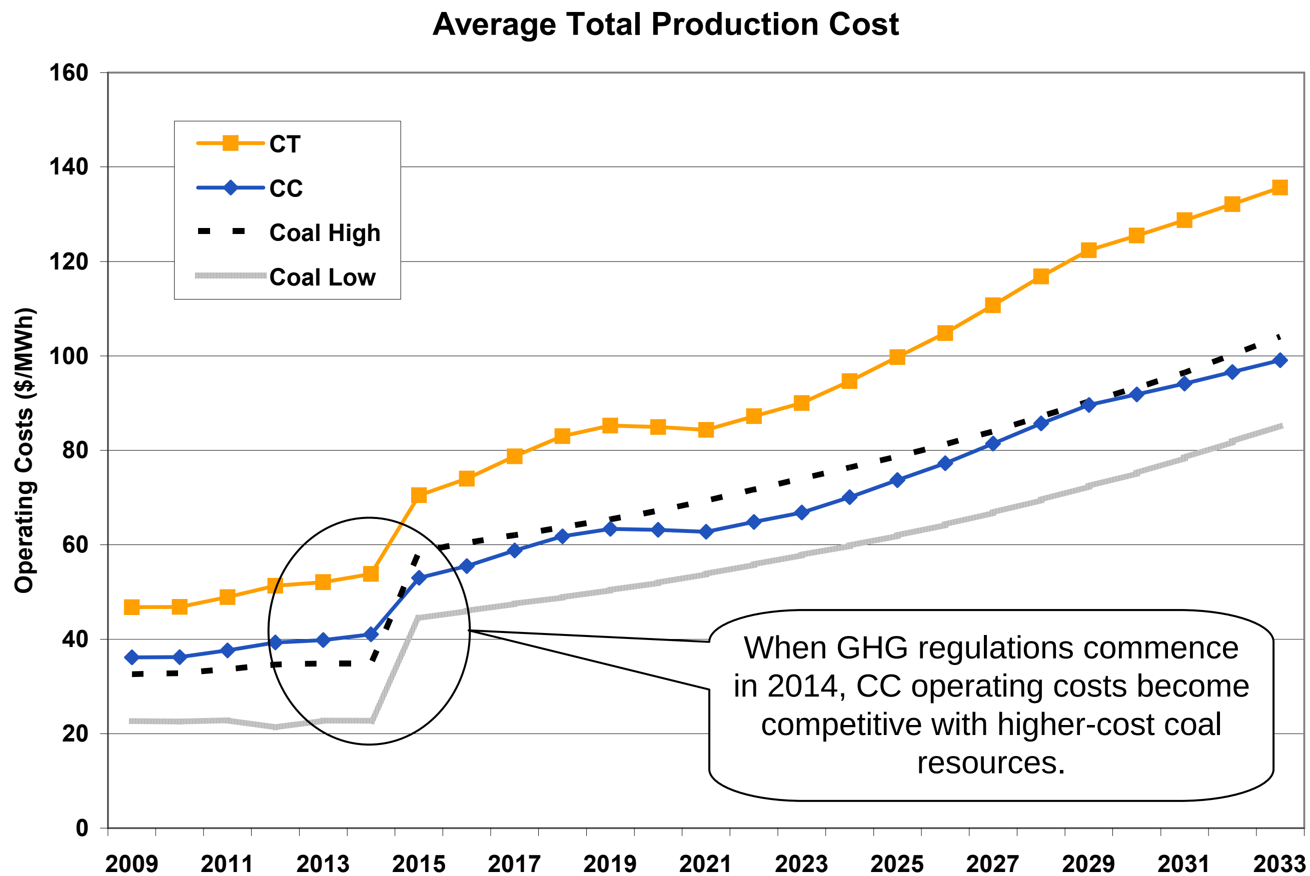
Forecasted CO_2 Emission Allowance Prices



Source: B&V Analysis

Carbon Forecast Likely to Marginally Change Dispatch

- The level of GHG emission allowance costs assumed in this forecast lead to some dispatch substitution from coal to natural gas, depending upon regional delivered fuel costs and the shape of the supply curve.
- Regional average coal capacity factors drop up to 20% during study period.

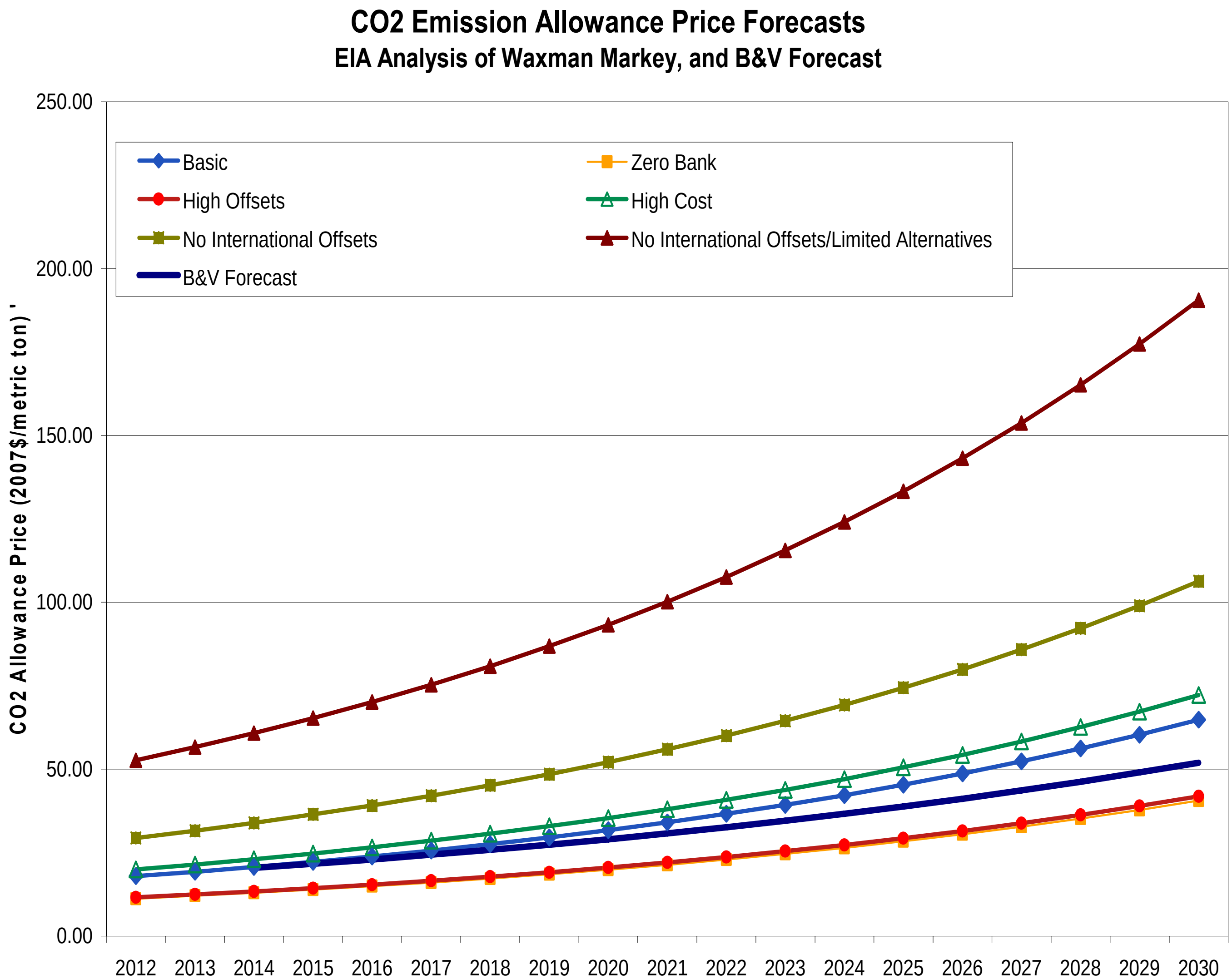


Assumptions:
Natural Gas prices are national average delivered prices in Baseline Forecast.
CC and CT heat rates are 7,200 and 10,300 Btu/kWh, respectively.
"Coal Low" has a heat rate of 9.200 Btu/kWh and an average delivered price of $2.28/MMBtu.
"Coal High" has a heat rate of 11,500 Btu/kWh and an average delivered price of $2.90/MMBtu.

Source: B&V Analysis

Offsets Are Essential for Cost-Effective Compliance

- International Offsets are vital for compliance at reasonable costs.
- Studies by both the US EPA and US DOE-EIA clearly demonstrated that GHG allowance prices would be much higher if the availability of international offsets is limited. This seems to be the key risk driver for GHG allowance prices.



Source: B&V Analysis

2.4 Renewable Portfolio Standards

Renewable Portfolio Standards (RPS)

- Majority of State RPS targets typically include:
  - A percentage (usually 15% to 25%) of annual retail sales to be met by renewable resources.
  - Phased implementation, typically 1% per year.
  - Allow Renewable Energy Credit (REC) trading to meet RPS targets and most allow those RECs to come from out-of-state.
  - A penalty for non-compliance with the RPS (or Alternative Compliance Payment).
    - Most States' penalty is around $50/MWh.
    - This is a barrier to achieving the RPS targets.
- Many States include in their RPS a cost cap of a certain percentage of retail revenue. If a utility determines that the cost of meeting the RPS target is more than a certain percentage of retail revenue (e.g., 2%), then the utility is not required to spend more on additional renewables.
  - For the States where a cost cap or cost test is applicable, the methodology for determining the comparative cost of meeting RPS standards is largely untested. This issue could become a large one for regulated investor-owned utilities evaluating investment in renewable generation to meet the RPS targets.

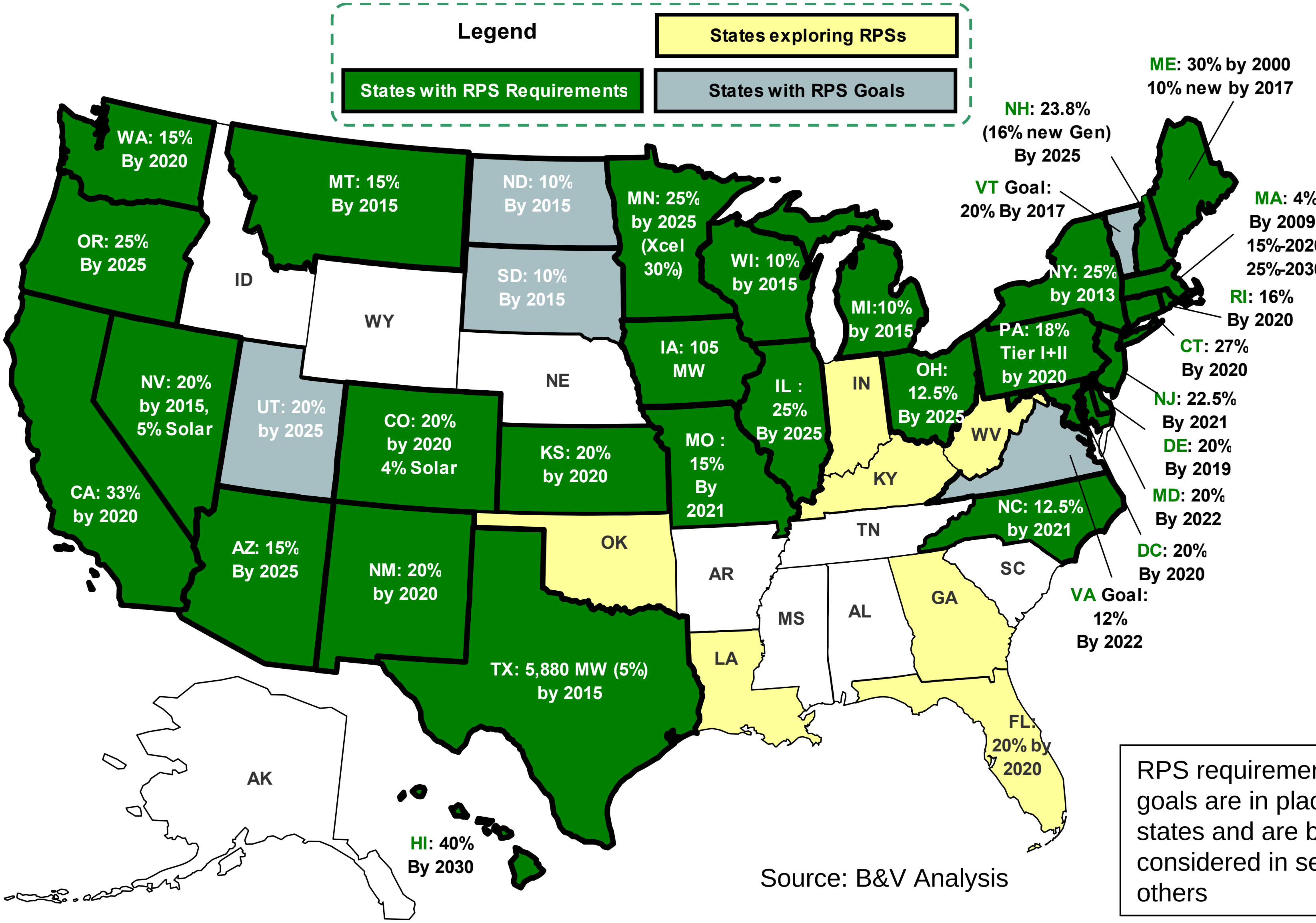
Potential Barriers to Achieving RPS targets: Cost Caps and Alternative Compliance Payments

- Most states with an RPS target have either an explicit alternative compliance payment provision, or some form of cost effectiveness consideration in enabling legislation.

State	Penalty	ACP ($/MWh)	Cost Cap (% annual retail sales or rev req)	Notes
Arizona	Yes			
California	Yes	$50		Annual Penalty Cap of $25m.
Colorado	Yes		2%	
Connecticut	Yes	$55		
Delaware	Yes	$80*		* Ramp up from $25/MWh in 2009 to $80/MWh in 2011
District of Columbia	Yes	$50		
Illinois	No		2%	Ramp up of cost cap to 2.015% in 2011 as compared to 2007.
Kansas	Yes			Penalties not specified.
Maine	Yes	$57		
Maryland	Yes	$40	10%	
Massachusetts	Yes	$59		
Michigan	No			Cost Caps are Customer Class Specific.
Minnesota	Yes			ACP not set. Rate impact language included but not explicitly defined.
Missouri	Yes		1%	Penalty is 2x cost of RECs.
Nevada	Yes			$1000 per day with $100k cap.
New Hampshire	Yes			ACP not set.
New Jersey	Yes	$50		$300/MWh Solar ACP.
New Mexico	Yes		2%	
North Carolina	No			Cost Caps are Customer Class Specific.
North Dakota	No			Cost Effective Test in Bill Language.
Ohio	Yes	$45	3%*	*3% above 'market rates'
Oregon	Yes	TBD	4%	ACP to be set by PUC.
Pennsylvania	Yes	$45		
Rhode Island	Yes	$50		
South Dakota	No			Cost Effective Test in Bill Language.
Texas	Yes	$50		
Washington	Yes	$50	4%	
Wisconsin	No			Compliance exceptions for rate impacts.

Source: B&V Analysis

Renewable Portfolio Standards by State

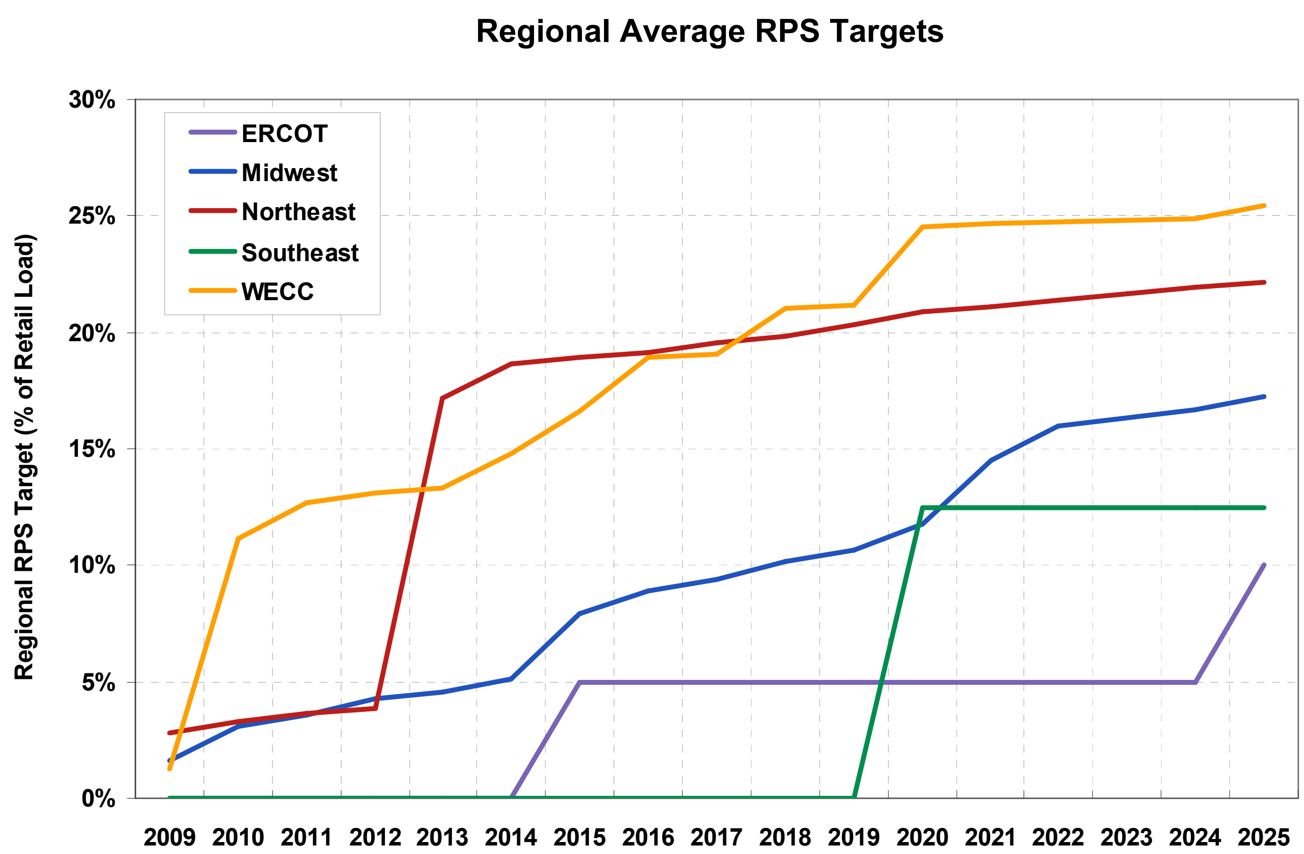


Source: B&V Analysis

RPS requirements or goals are in place in 34 states and are being considered in several others

RPS Targets by Region

- Analysis of RPS targets by regions illustrates the persistent upward migration of targets through 2025.
- Northeast and Western States have most aggressive short term and long term RPS targets.
- Most Southeast states do not have an RPS.
- Regional averages based on State RPS targets, weighed by historical (2007) retail sales for each State. Only states shaded in green on previous page are included in averages: states with no RPS targets are excluded from the averages.



Notes: Midwest includes MISO, MRO, PJM, SPP States. Southeast consists of NC and VA.

Source: B&V Analysis

Transmission expansion and access are an inhibitor to quickly ramping up renewable generation

- Significant investment in transmission upgrades and additions are needed across the country to make RPS goals a reality.
  - These investments are costly, and the siting and permitting process is time-consuming.
- ‘Not In My Back Yard’ (NIMBY) is another issue that delays both transmission investment and new renewable additions. Several wind projects nationwide have been delayed due to local push-back on project siting.
- Billions of dollars of transmission investment will be needed to facilitate the integration of the large amount of renewables required to meet the various State RPS targets.
  - In today’s uncertain credit markets, access to this type of capital is constrained, which will slow down the growth in renewable additions.

Potential for a Federal RPS could spur additional renewable generation development

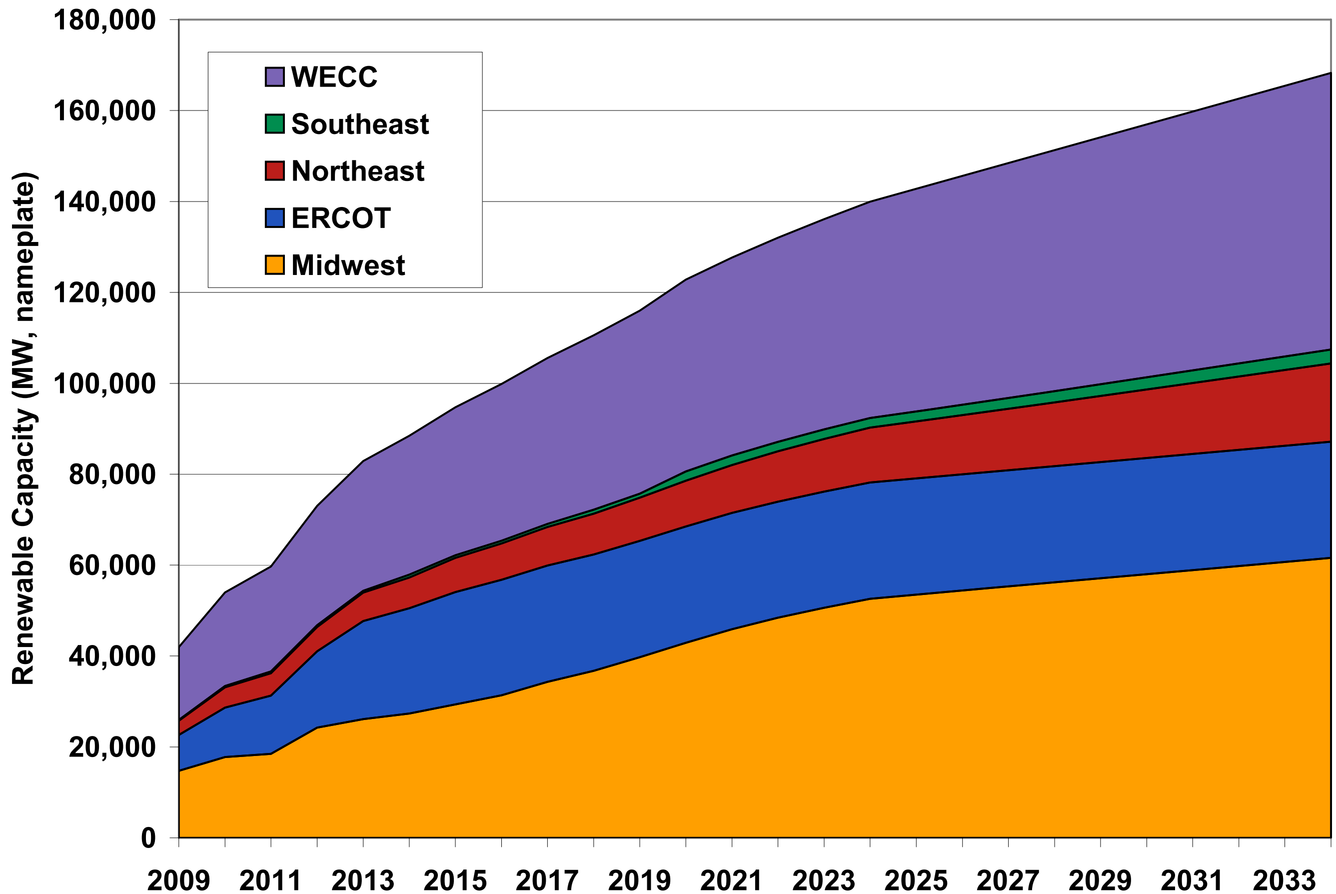
- Congress, the public, and the Obama administration are discussing the development of a Federal Renewable Portfolio Standard in 2009-10.
  - A Federal RPS would have a large effect on Southern States, many of whom do not have an RPS law or goal in place. At issue is the fact that Southern states do not have great resources of wind like some regions of the country do. REC markets will play a significant role in meeting these States' targets and would likely lead to significantly more investment in wind additions in resource-rich areas such as the Midwest and Texas.
  - This would lead to a ripple-effect of impacting states that already have an RPS in place, by putting greater demand on available renewable resources through ownership and trading of RECs.
    - A Federal RPS requirement would impact the States' existing RPS targets – in some cases additional renewables would be required, and the timing of meeting those targets shifted.

Trajectory of Renewables Growth

Issues for Renewables

- Prospects for a Federal RPS.
- Regulation, Spinning Reserve and quick-start requirements.
- Will the transmission be built?
- Improvements in weather forecasting and system operating protocols.
- Modification of Planning Reserve Margin Targets.

Cumulative Renewable Resource Additions (MW)

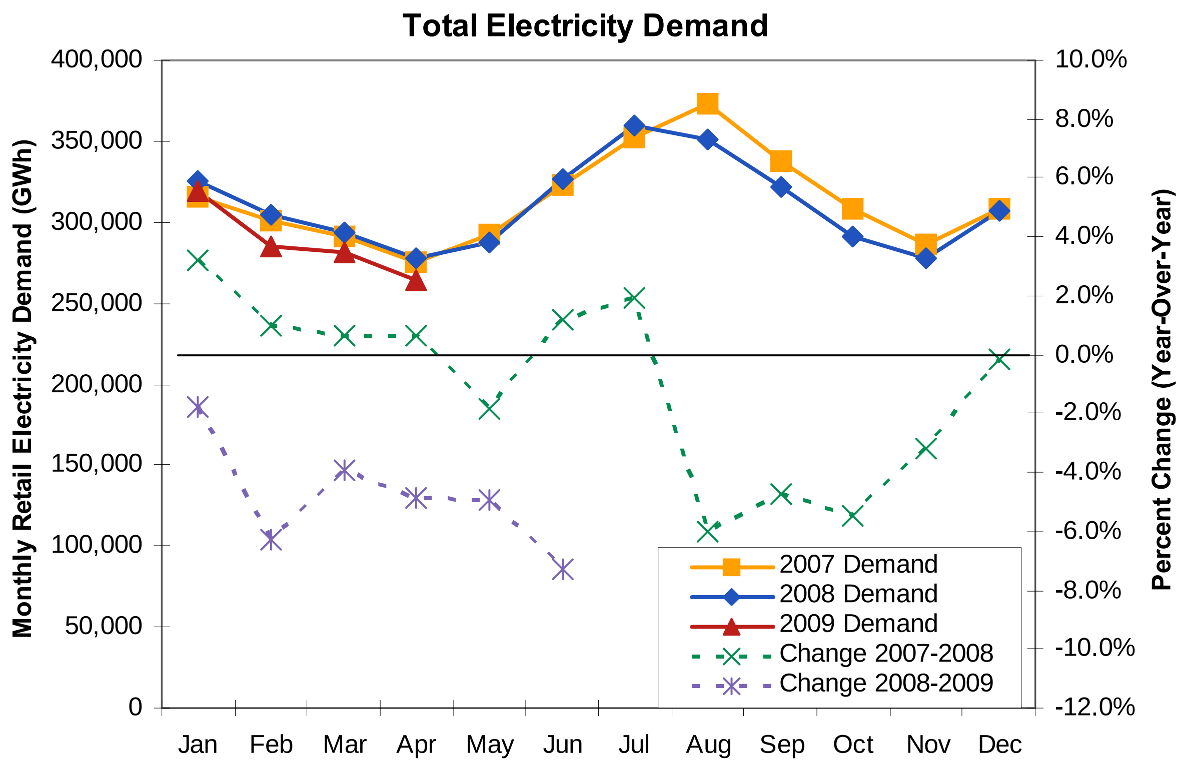


Source: B&V Analysis

2.5 Electricity Market Assumptions

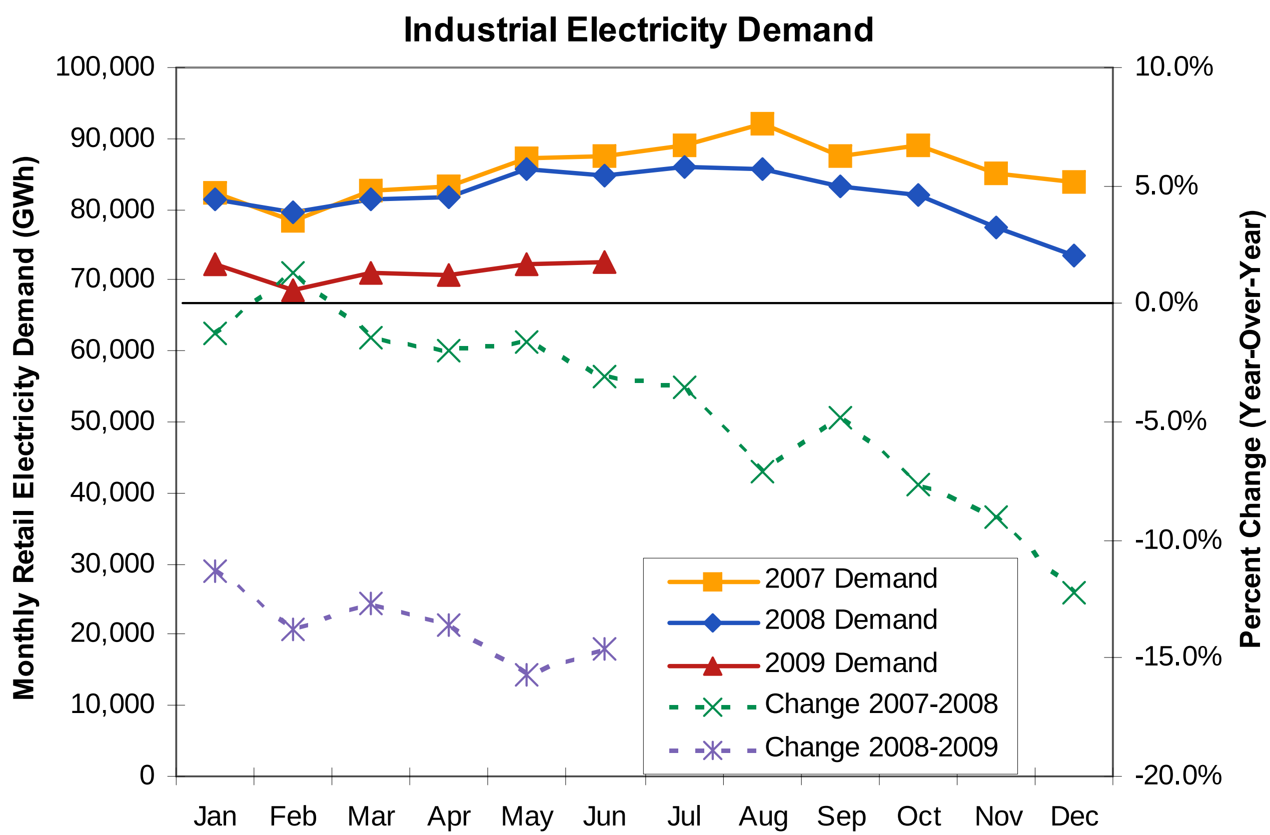
Recent Decrease in Electricity Demand

- The drop in US electricity demand (using energy, not peak MW) began in August 2008.
- Year over year average growth rates:
  - Jan-Jul 08 = +1.0%
  - Aug-Dec 08 = -3.9%
  - Jan-Jun 09 = -4.9%
- Combined with increased account delinquencies and defaults, this has constrained revenue and earnings for most electric utilities.
- US DOE EIA expects the rate of decline to lessen in the second half of the year, especially in the Southwest, where higher summer temperatures led to higher air conditioning load. The total year decline is expected to be 3.3%.



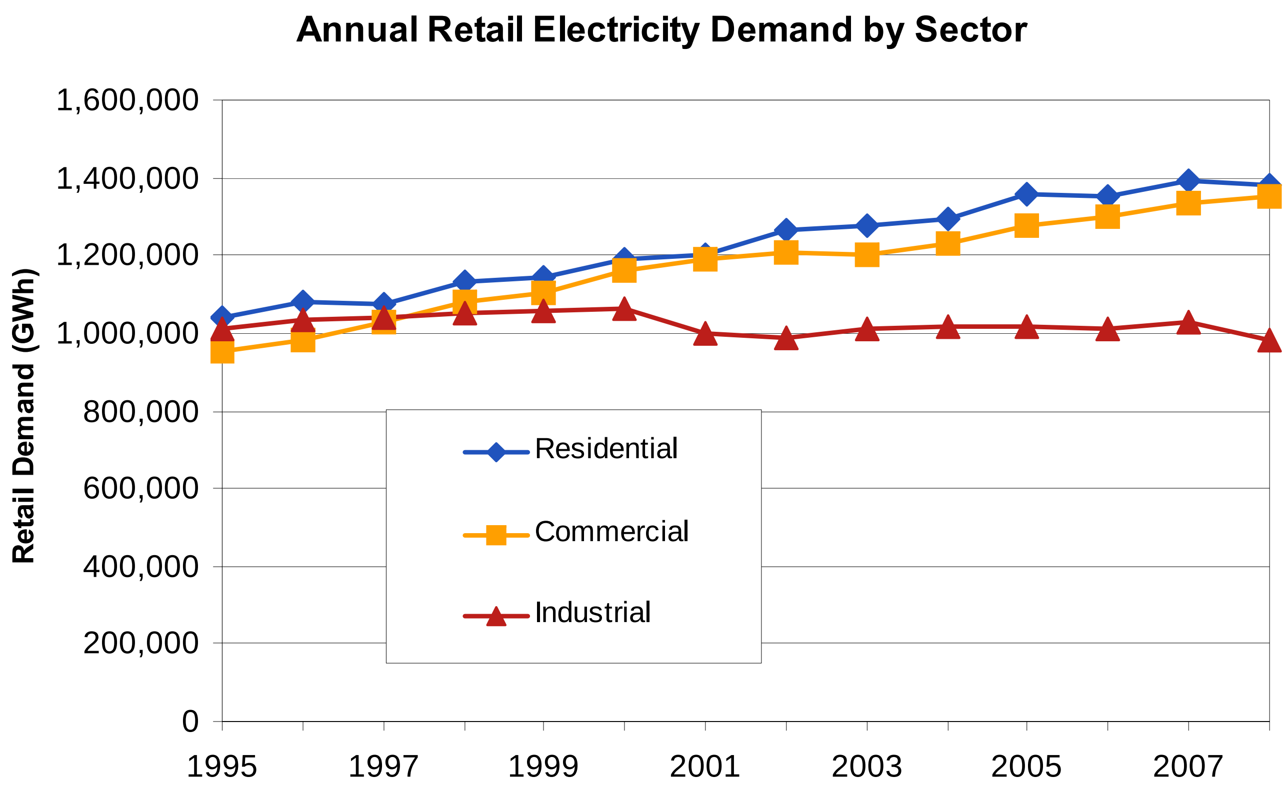
Industrial Electricity Demand is Getting Hit Hardest

- The residential and commercial sectors have seen significant hits, but the biggest decease has been in the industrial sector.
- Industrial year over year average growth rates:
  - Jan-Jul 08 = -1.7%
  - Aug-Dec 08 = -8.2%
  - Jan-Jun 09 = -13.6%
- The industrial sector decline started earlier and has been deeper. Utilities dependent upon industrial revenue have been hit the hardest.



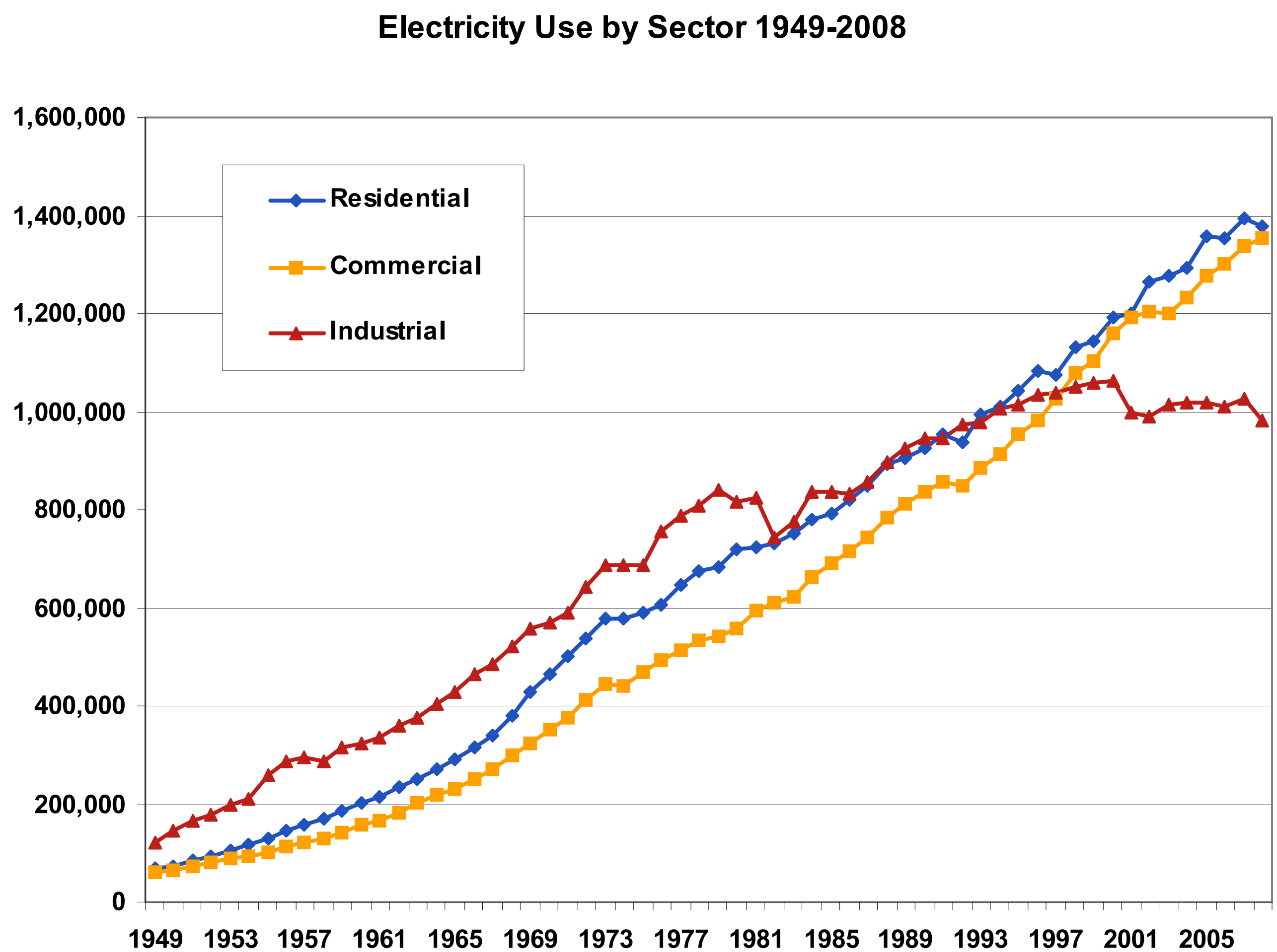
Will Industrial Recover?

- The industrial sector took the hardest hit from the 2001 energy market downturn.
- This is consistent with the idea that industrial facilities recover slowly or not at all after a down turn—the capacity is permanently lost or is at least is exported.
  - Example: aluminum smelters in the Pacific Northwest shut down in 2001 and mostly were never re-started.



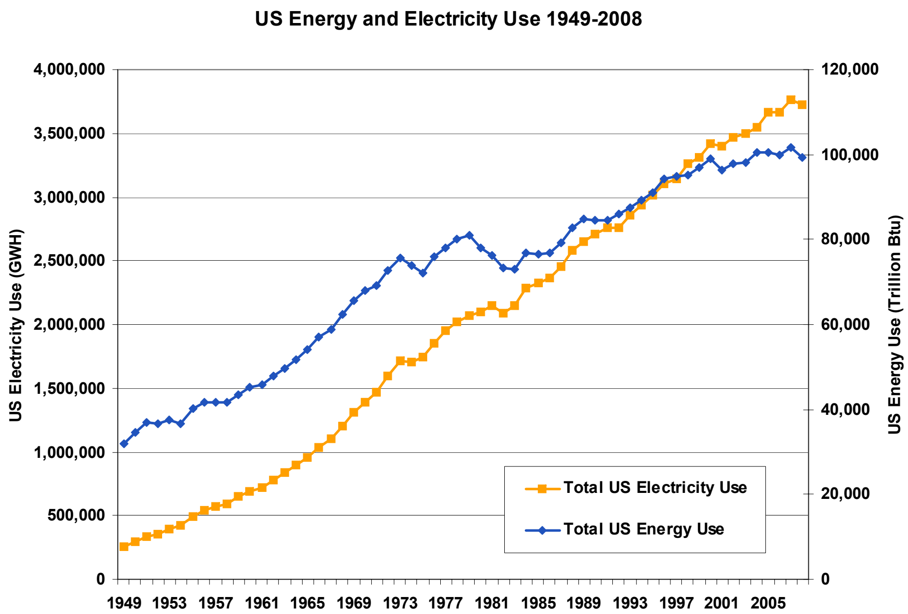
Will Industrial Recover?

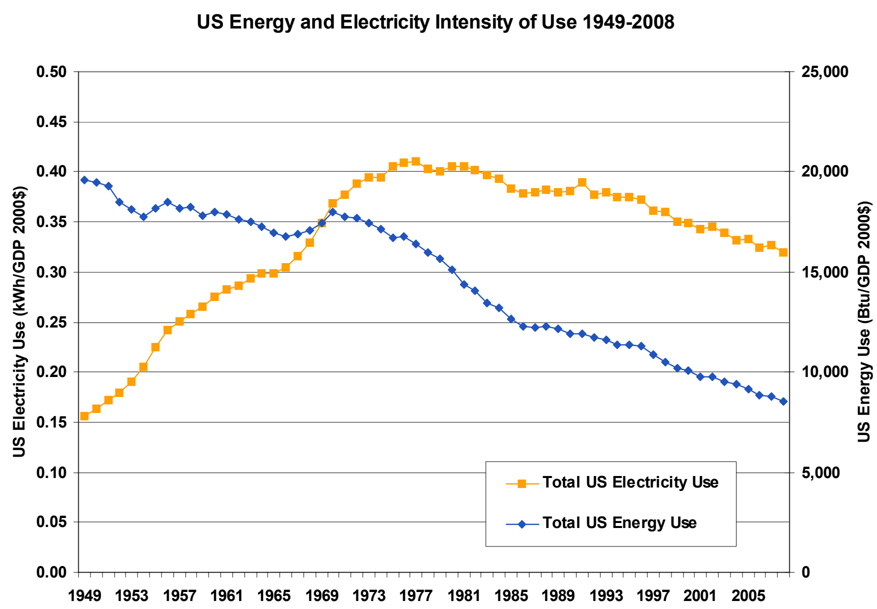
- In a long term view it becomes clearer that industrial electricity demand is diminishing in importance relative to the other sectors.
- The industrial sector was hit hard by the general increases in energy prices after OPEC I and II in the 1970s, and growth has been sluggish since then.



Energy and Electricity Use

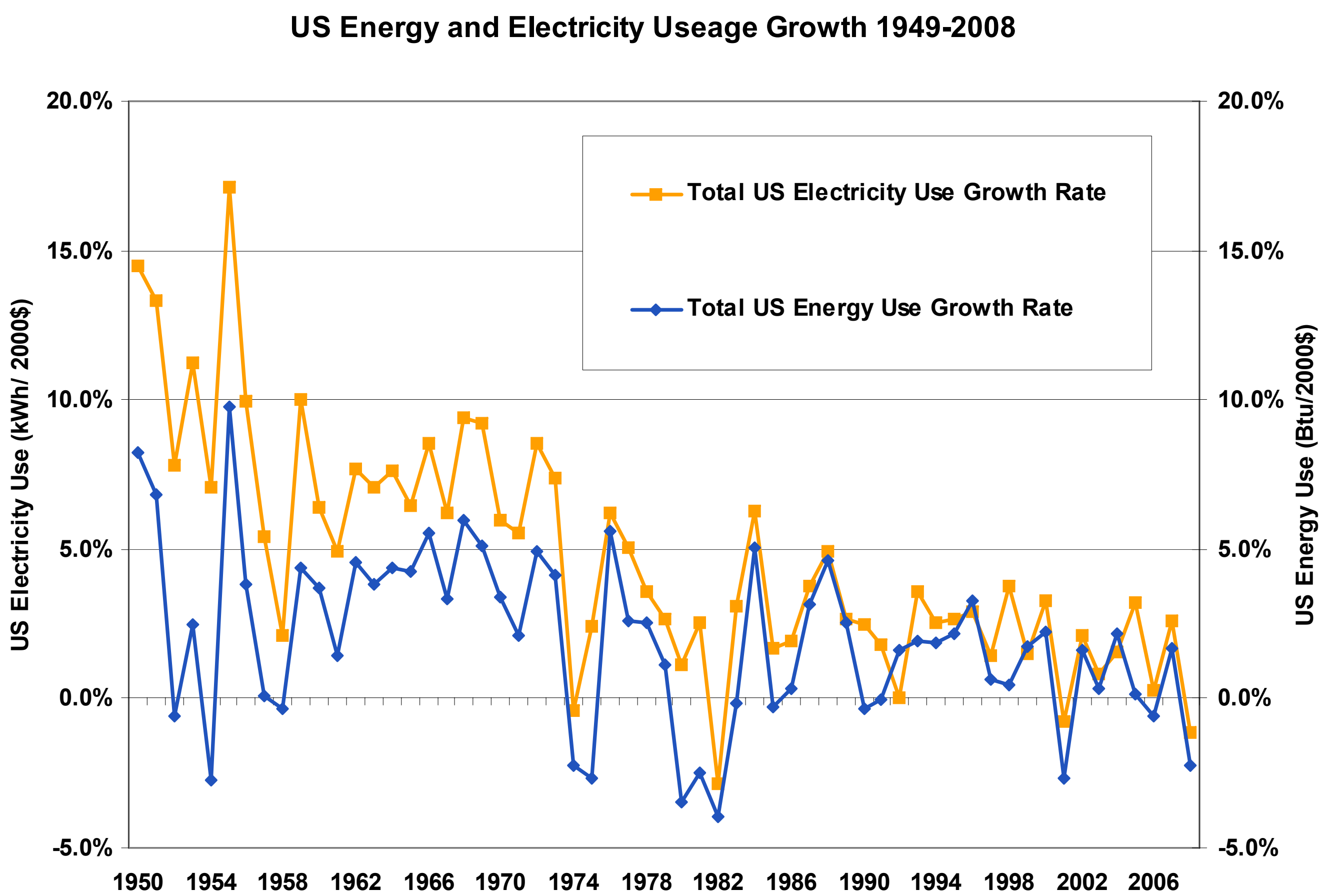
- Electricity use in the US has been growing faster than overall energy use since the 1970s.
- Overall energy use in the economy per unit of GDP was declining slowly prior to the 1970s, and the rate of decline has increased significantly since then.
- Electricity use per GDP$ was rising until the 1970s but has declined since then.
- Since 2000, growth in electricity has been 1.1% lower than GDP growth.





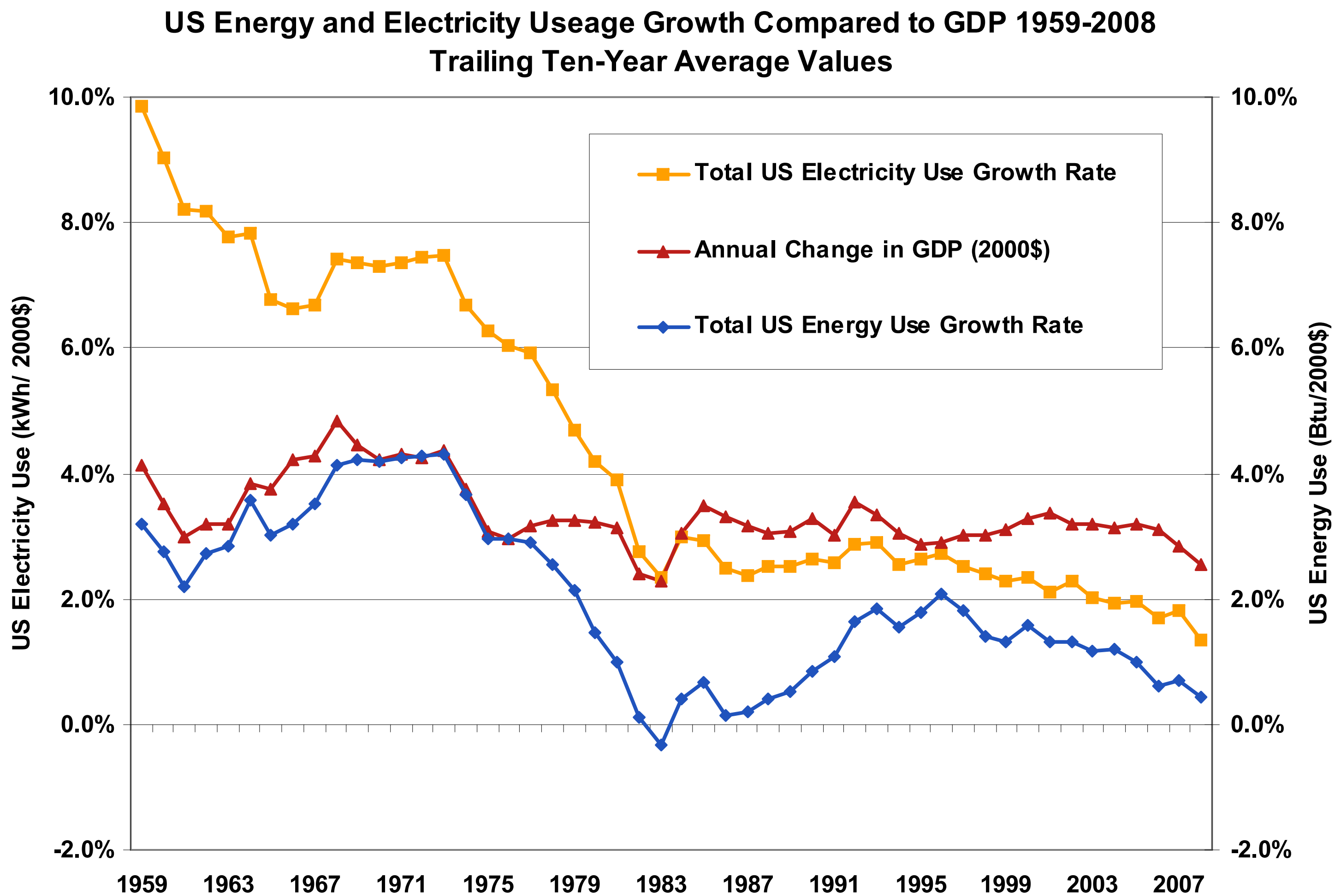
Energy and Electricity Use

- Annual changes in energy and electricity use vary due to both economic and weather conditions.
- In the current decade there are clearly two years (2001 and 2008) with noticeable negative electricity use growth.



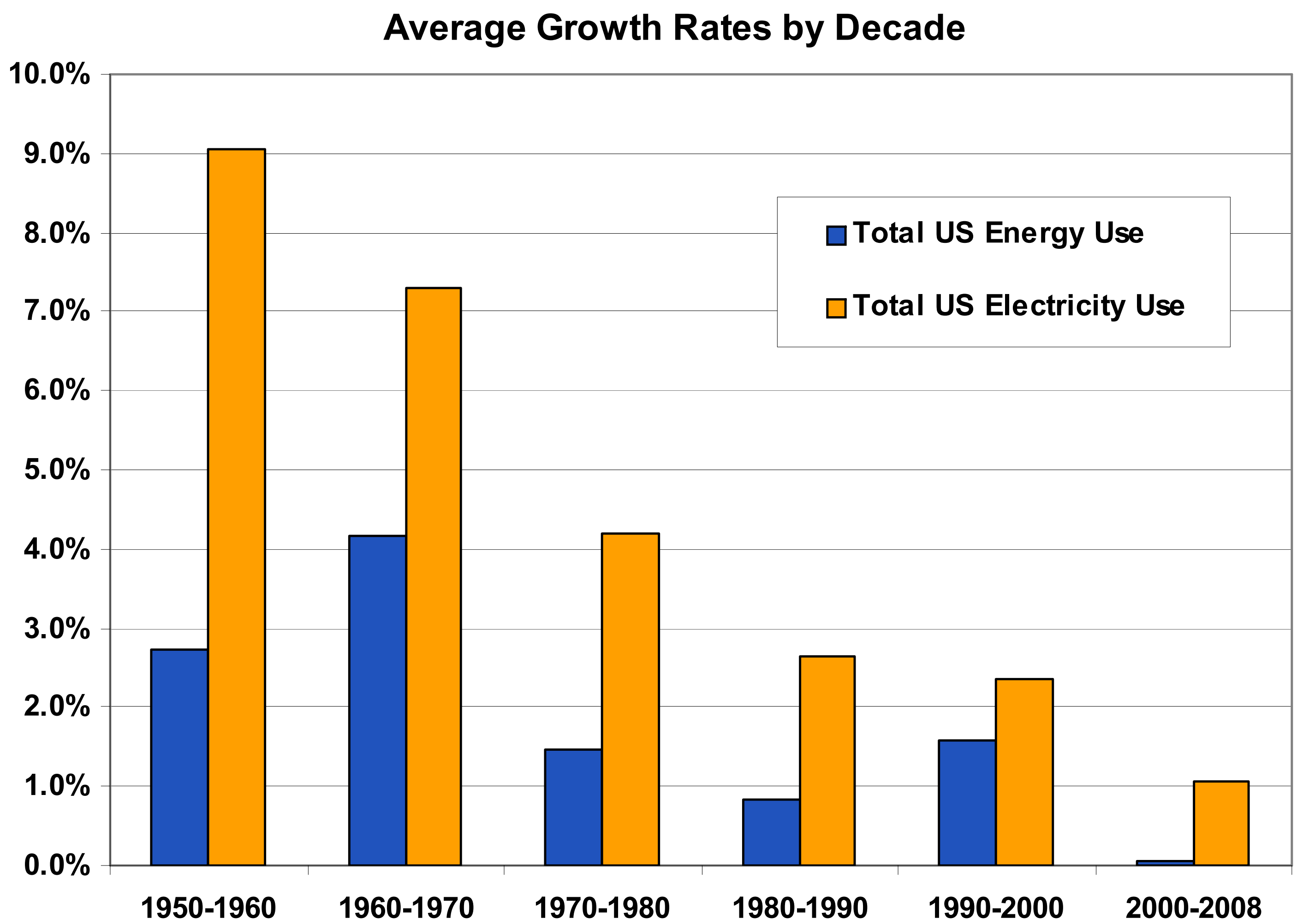
Energy and Electricity Use

- Trends are more clearly seen when looking at 10-year trended growth rate data.
- Clearly, both energy and electricity use growth rates have sharply declined over time.
- The biggest decline occurred in the 1970s—more fallout from OPEC I and II.



Energy and Electricity Use

- The relationship between economic activity and electricity consumption has been slowly changing over the past 60 years, with electricity becoming a proportionately smaller part of overall economic activity.
- In the 1950s, average annual growth in electricity demand was about 9% per year. In the current decade the growth has been only 1.1% per year.



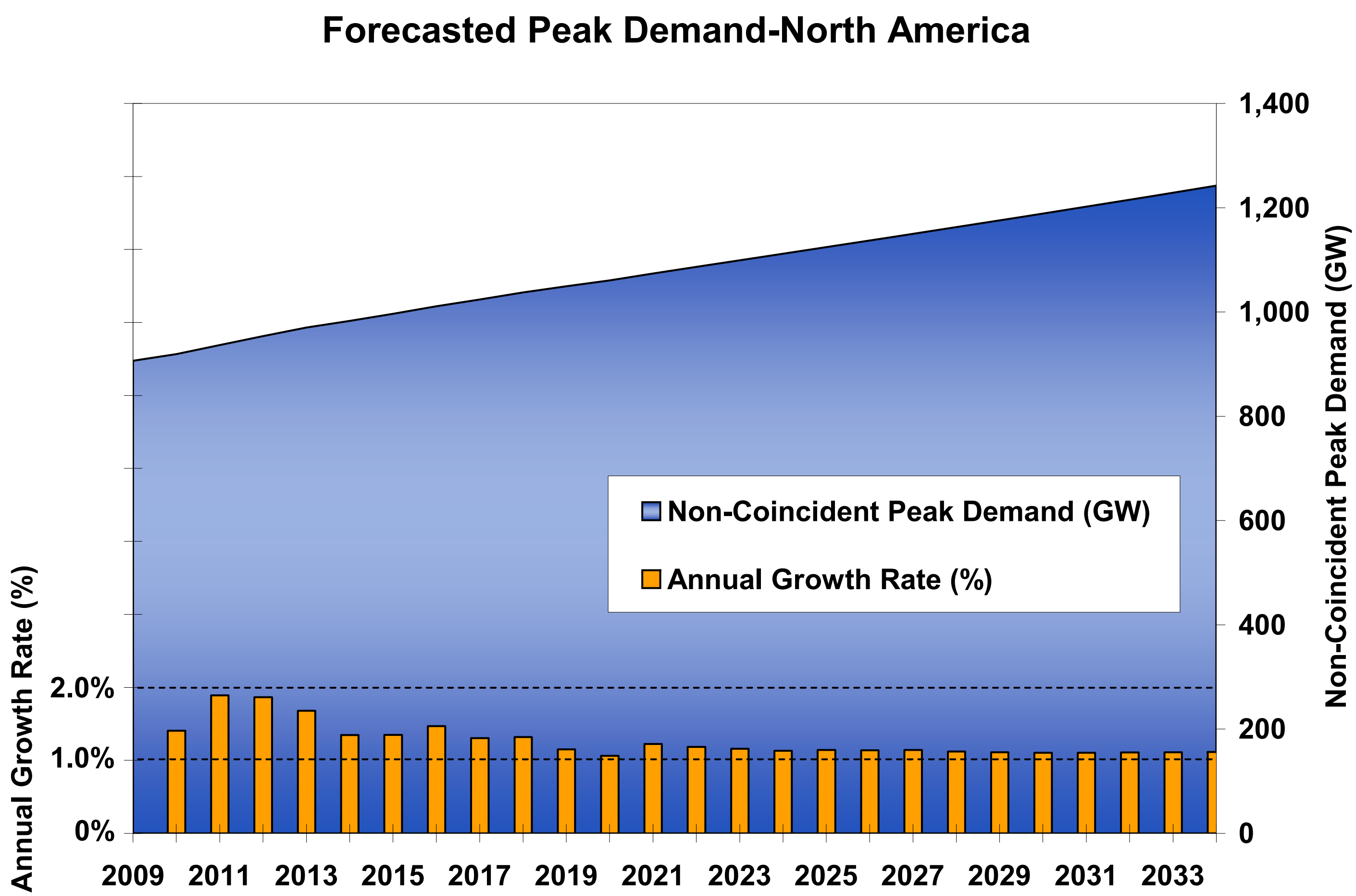
Power Demand Forecast Methodology

- The first approximately ten years of forecasted energy and peak demand data is developed from a combination of:
  - FERC 714 filings,
  - ISO and RTO publications and data,
  - Intelligence gathered directly from contacts at NERC regions and ISOs,
  - Modifications to reflect recessionary impacts not included in public sources due to reporting lags.
- Some agencies report more than 10 years of data and that is used when available.
- Data is reviewed for consistency and to eliminate possible double counting of demand reports.
- Extrapolation beyond the reporting periods assumes that peak demand and energy grow at 80% of the average energy growth rate over the last several years of the forecast reporting period.
  - Acknowledges long term economic trends, including increased social and political emphasis on DSM, and real dollar increases in retail electricity prices due to natural gas prices and GHG emission costs.
- Regional trends vary widely (see next page) but the aggregate impact is an expectation of a moderate economic rebound in 2010-2013 before reverting to a long term growth trend of about 1.1% per year.

Source: B&V Analysis

Forecast for Power Demand

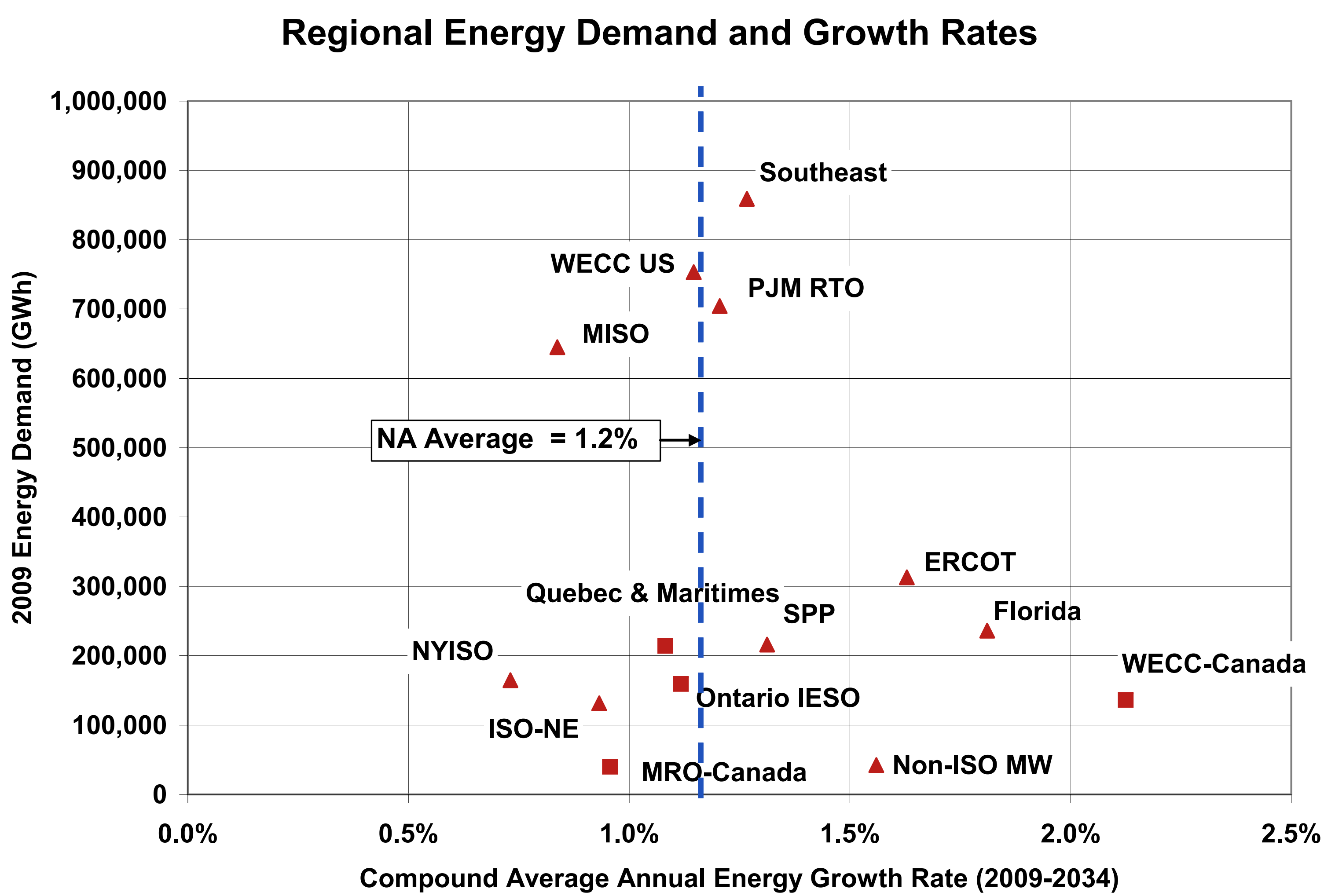
- That background on long term trends provides context for the Energy Market Perspective power demand forecast.
- Regional trends vary widely (see next page) but the aggregate impact is an expectation of a moderate economic rebound in 2010-2013 with “1990’s style” growth before reverting to a long term growth trend of about 1.1% per year.



Source: B&V Analysis

Dramatic Regional Variations in Power Demand Growth

- Regional growth rates vary widely based upon long term expectations of:
  - Population migration (from Snow Belt to Sun Belt), and
  - Regional industrial growth (such as energy production development in western Canada).



Source: B&V Analysis

Outlook for Nuclear Power

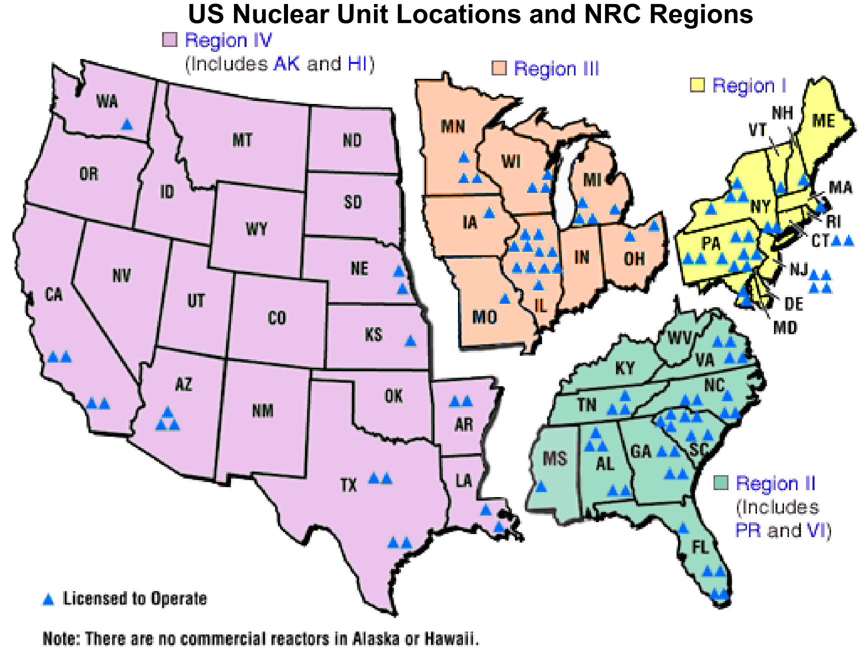
The First Nuclear Build-Out

- The first commercial nuclear power unit in the US was the Shippingport Atomic Power Station located outside Pittsburgh Pennsylvania. It went on line in December 1957, was dedicated in May 1958, and ceased operations in October 1982. This 60 MW unit was a prototype for both commercial electric generation units and for nuclear aircraft carrier units. Notable is that the unit was built in 32 months.
- US nuclear generation expanded rapidly in the 1960s and 1970s but was ultimately stopped due to public anxiety over technology safety and ultimate fuel disposal.
- Currently there are 104 licensed operating nuclear generating units in the US, accounting for about 97,000 MW of generation capacity and about 20% of the energy generated. In addition, there are 16 fully-operating units in Canada with a total capacity of about 11,300 MW (there are several other inactive units that are planned for re-starting).

Nuclear Resurgence

- Nuclear power in the US is now entering a period of resurgence, prompted by growing concerns over green house gas emissions from fossil fueled technologies and the difficulty experienced by industry in the permitting of new coal-fired capacity.
- The US federal government is facilitating nuclear development through two major policy initiatives:
  - Nuclear Power 2010 Program, and
  - Energy Policy Act of 2005.

US Nuclear Unit Locations and NRC Regions



Sources: US Nuclear Regulatory Commission and the OECD Nuclear Energy Agency.

Nuclear Power 2010 Program

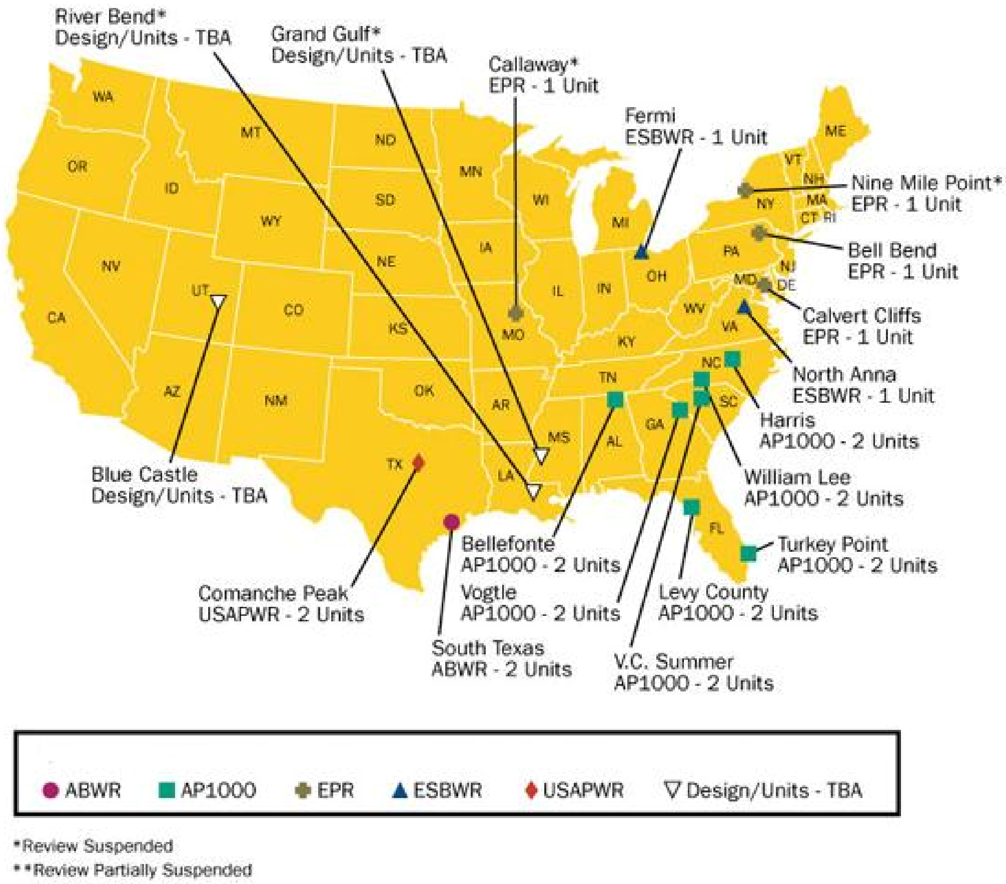
- The Nuclear Power 2010 Program (NP-2010), proposed by the US Department of Energy in February 2002, was designed to reduce technical, regulatory and institutional barriers to the development of new nuclear power plants.
- NP-2010 is focused on demonstrating an advanced light water nuclear generation technology denoted as "Generation III+," to denote that it is an advancement over the "Generation III" technology certified by the NRC in the 1990s. To achieve this goal with NP-2010, the DOE has:
  - Initiated a program with industry to obtain NRC approval of three sites under the Early Site Permit (ESP) process, and
  - Developed application guidance and resolve regulatory issues related to filing combined Construction and Operating Licenses (COL).
- To achieve these goals, DOE has entered into three separate government/industry cost-sharing consortia to identify, permit and develop new nuclear power plant sites.

Energy Policy Act of 2005—Nuclear Provisions

- The EP Act of 2005 contains a number of provisions related to facilitating the development of nuclear power.
- The Price Anderson Nuclear Industries Indemnity Act was extended to apply to all non-military units built before 2026. This act was created to provide a mechanism for insuring against the event of a major nuclear catastrophe, and is still considered a necessity for the development of new units.
- Authorized coverage for cost overruns due to regulatory delays of up to $500 million for the first two units and half the cost of overruns (up to a payout of $250 million) for the next four units.
- Authorized a production tax credit of 1.8 cents/kWh for 6,000 MW of new nuclear units during their first 8 years of operation.
- Authorized $1.25 billion for the USDOE to fund construction of a Next Generation Nuclear Plant at Idaho National Laboratory that produces both electricity and hydrogen.
- Mandated the USDOE to report in one year on how to dispose of high-level nuclear waste.
- Load guarantees for up to 80% of the cost of new “innovative technologies” to reduce green house gas emissions, which could include new advanced design power plants.
- Updated tax treatment of decommissioning fund payments to allow regulated and merchant owned nuclear plants similar tax impacts.
- Updating nuclear power plant security provisions.

Policy Changes and GHG Issues Have Led to a Nuclear Resurgence

- Over the last few years, interest in developing new nuclear power plants has grown substantially. In part this is driven by the need for new base load generation capacity to meet demand growth and replace retiring assets, and in part by the re-characterization of nuclear energy as a green technology due to its lack of green house gas emissions.
- The provisions of the Nuclear Power 2010 program set events in motion as development consortia were pulled together and COLs were prepared. Furthermore, the nuclear provision of the EP Act 2005, in particular the production tax credits for the first 6,000 MW completed, created a "land rush" mentality for the filing of COLs and the beginning of campaigns to design and build the new generation of nuclear plants.
- In 2009 a few plants have at least temporarily left the development queue, including Amarillo and Victoria County in Texas and Hammett in Idaho, and others are reconsidering their technology choice.



Source: US Nuclear Regulatory Commission

- Within the nuclear power and financial industries there is a widely-shared belief that financing a major nuclear resurgence will require more financing capability than sponsors currently have, necessitating greater government support in the form of loan guarantees. Supporters see additional financial support for nuclear power may come from amendments to any Green House Gas legislation that is ultimately passed by Congress.

Modeling Transmission Aspects

- This forecast utilizes a zonal representation of the electric power network or grid. Within this zonal representation, each market zone is connected to a series of other market zones with transmission interfaces that have been assigned bi-directional energy and capacity limits, wheeling charges (when applicable) and losses.
- Within the boundary of an independent system operator (ISO), transmission system charges are typically "socialized," meaning that the cost of the transmission system (including return of and on capital) are recovered through ISO assessments paid by the retail electric customers in their monthly bills. In such a case, there are no wheeling charges (just an allowance for losses) and energy flows within the ISO subject only to the capacity rating in the zonal transmission representation.
  - ISOs may have wheeling charges applied to energy that crosses the ISO's borders.
- Transmission system changes are typically modeled for one of two reasons.
  - **New Announced Projects.** B&V adds new projects based upon an assessment of their likelihood of completion, which will be drawn from a review of permitting status, funding, regulatory approval and political momentum.
  - **Modeled System Congestion.** This forecast uses the addition of new generation resources relatively near load centers as the primary methodology for meeting demand growth and replacing retiring generation assets. However, there are conditions under which the location of generation assets may be remote from the load centers, such as when environmental limitations make local siting very difficult, or when a specific type of resource (such as wind generation) needs to be sited near its prime mover. When transmission system congestion is encountered in the modeling process, B&V considers addition of new transmission based on the magnitude of the congestion and an assessment of the viability of developing new transmission capacity.

New Generation Assets

- New generation data is formulated to be representative for the entire 25-year study period.
- Installed costs include allowances for owner's costs and interest accrued during construction.
- Most technologies include a 10-15% decrease in capital costs from 2008 peak levels to levels considered to be more representative for use in a long term forecast.

Summary of New Entry Assumptions - National Averages

Asset Type	Designation	Installed Costs (2009$/kW, US Typical Value, includes IDC and Owners Costs)	Summer Ratings: Capacity (MW)	Summer Ratings: Full Load Average Heat Rate (Btu/kWh, HHV)
Combustion Turbine	GE 7 FA	680	185	11,000
	LM 6000	1,310	40	10,250
	LMS 100	1,080	86	9,350
Combined Cycle	2 x 1 GE 7FA	1,260	550	6,870
Nuclear	Generic	5,900	1,500	10,000
Coal Steam	Supercritical PC	3,500	800	9,200
Coal IGCC	Without CCS	5,000	720	9,600
	With CCS (@ 90% control)	7,800	510	12,350
Wind	Generic	2,400	1.5	n/a
Solar Thermal	without Storage	5,200	250	n/a

Source: B&V Analysis

Renewable Resource Cost Vary Widely Depending on Critical Assumptions

- Solar and Wind technologies are very capital cost intensive, making energy production assumptions (expressed as capacity factor) key. **Higher capacity factors (CFs) dramatically lower levelized busbar costs.**
- For wind technology typical capacity factors are 25-35%. With current technology, a 40% CF is achieved at only the very best sites. Manufacturers claim that + 40% CFs will be achieved more frequently with the next generating of technology.
- Production tax credits (PTC) for wind and investment tax credits (ITC) for solar significantly improve economics.
  - The current wind PTC is $21/MWh for the first ten years of asset operation, equating to about $12/MWh when levelized over a 20-year life cycle cost.
  - The wind PTC is available for assets completed by the end of 2012.
  - Due to very favorable depreciation allowances, many wind developers do not have a enough near term taxable income to be able to use the PTC. The 2009 Stimulus Bill allows them to substitute a form of ITC instead, called the Energy Tax Credit (ETC). The ETC is also the better economic choice than PTC for lower capacity factor wind regimes (e.g., 25%)
- Due to their generating profiles, solar and wind technology only provide a small contribution to peak capacity, so one way to place them on a level playing field is to “firm” the capacity with a compensating amount of CT gas-fired capacity.
  - For illustration in this report, wind is assumed to be able to contribute 10% to peak capacity and solar contributes 20%. In application, this factor will vary by region and by site.

Technology Cost Impacts of Carbon Allowance Prices

Wind

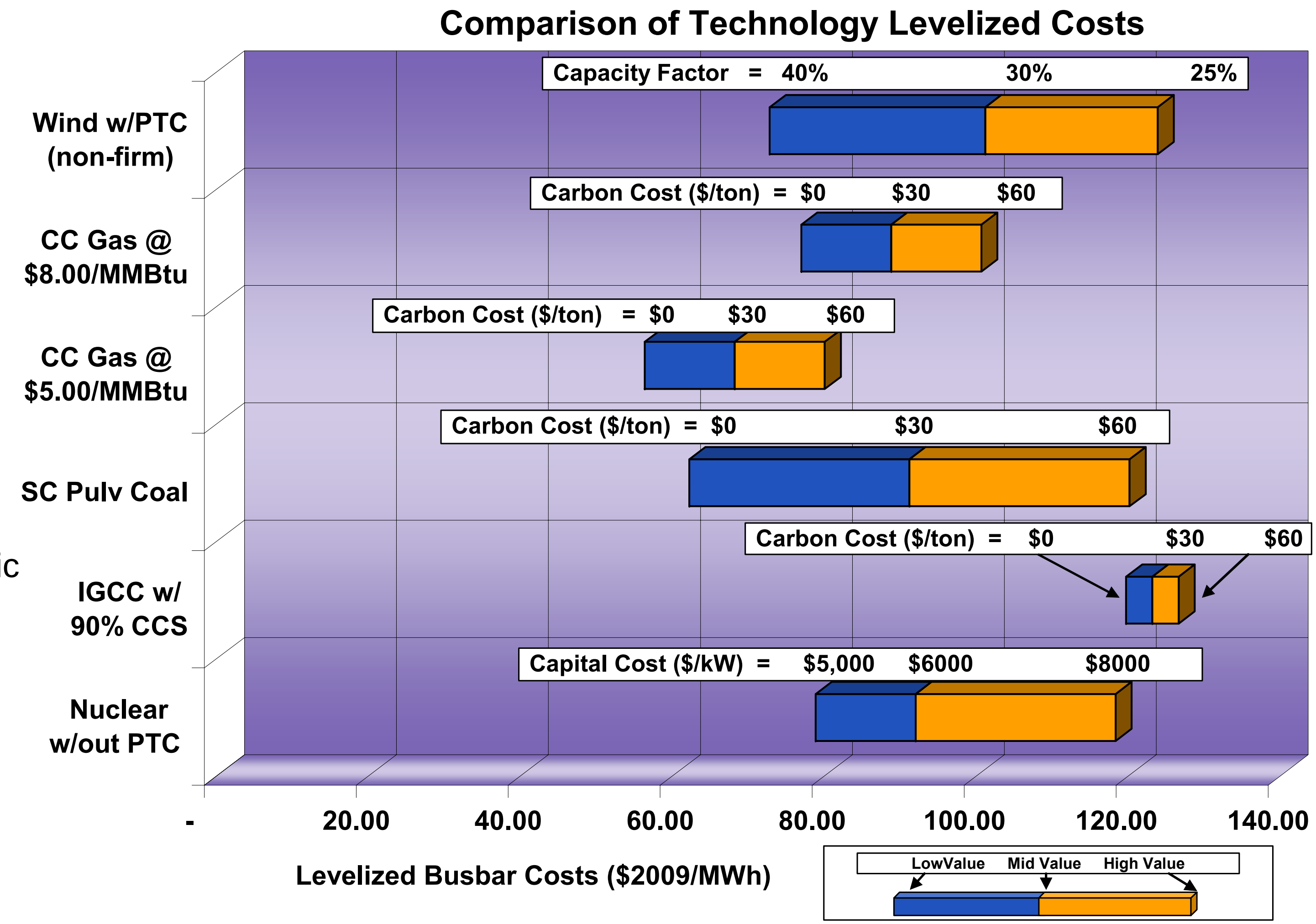
- Highly dependent on site economics (e.g., capacity factor) and availability of RECs (none included here). ITC will improve low CF economics.

Coal and Nuclear Generation

- Conventional coal technology can become less economic than nuclear technology.
- Coal with carbon sequestration is even more expensive.

Natural Gas

- Competitiveness of combined cycle generation depends on gas prices.

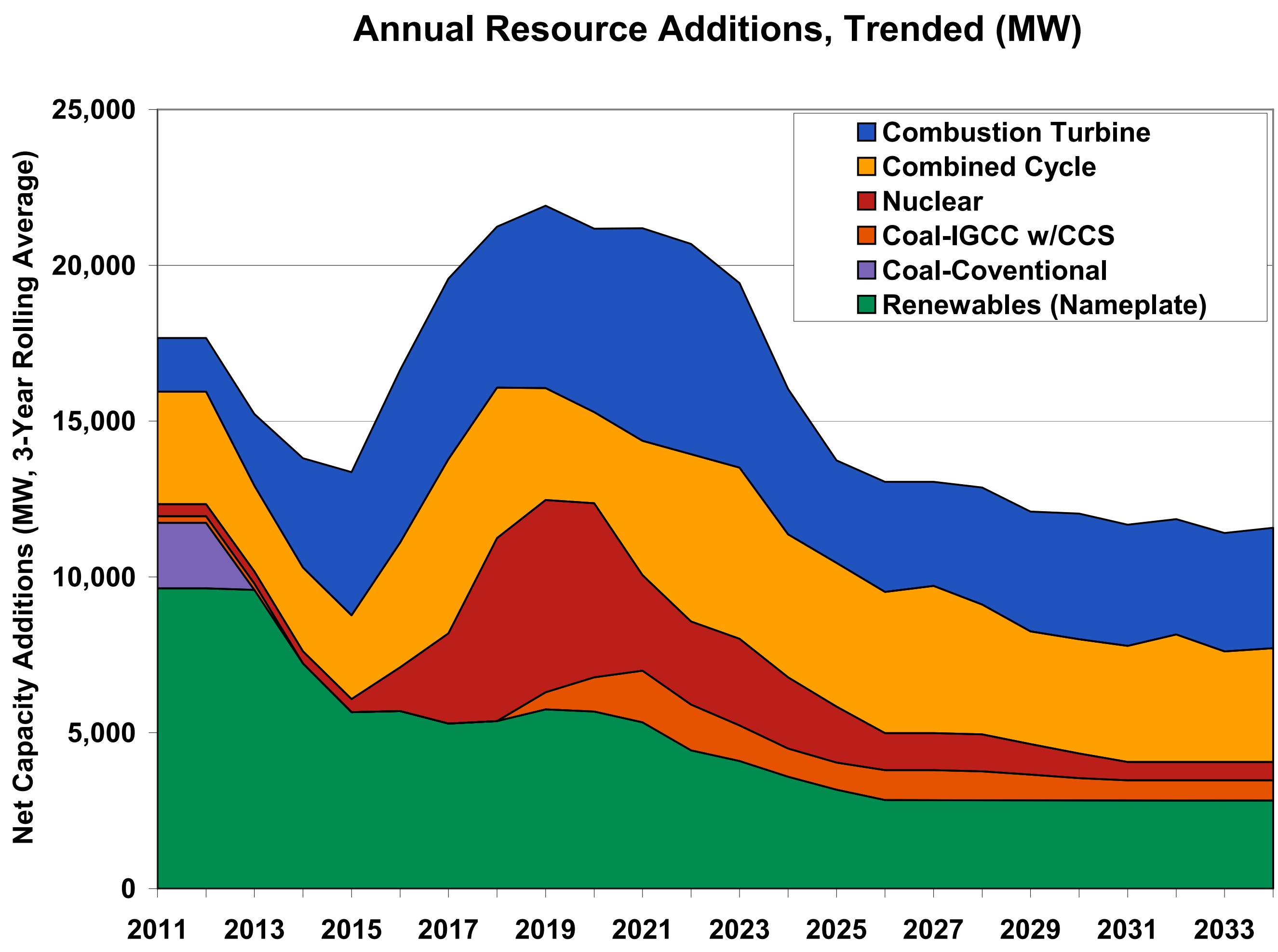


Assumptions:
Capital costs are national average values and will vary widely by region and site.
Coal assumes an average delivered price of $1.50/MMBtu.

Source: B&V Analysis

Resource Implications of the Energy Market Perspective

- Near-term resource additions dominated by renewable energy and natural gas resources.
- Wind resource additions decline over time as many state RPS standards and guidelines are largely (but not totally) met.
- Longer-term resource needs are met by natural gas resources, with growing role for nuclear and possibly IGCC w/ CCS for meeting base load growth.



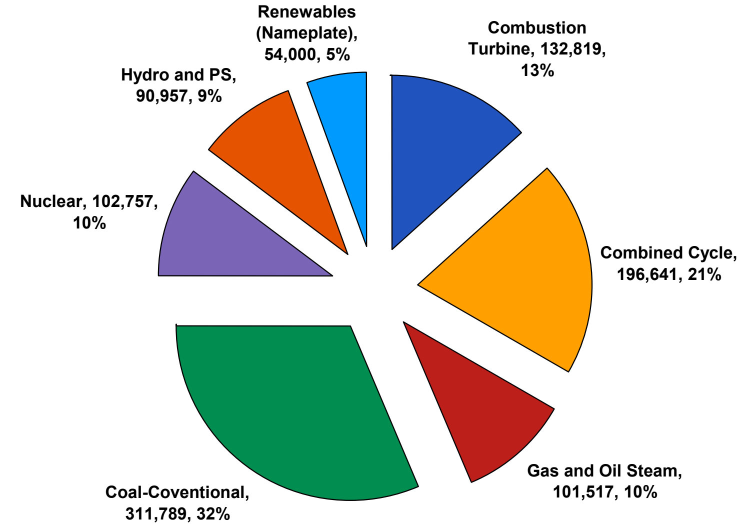
Source: B&V Analysis

The Changing Resource Mix-US

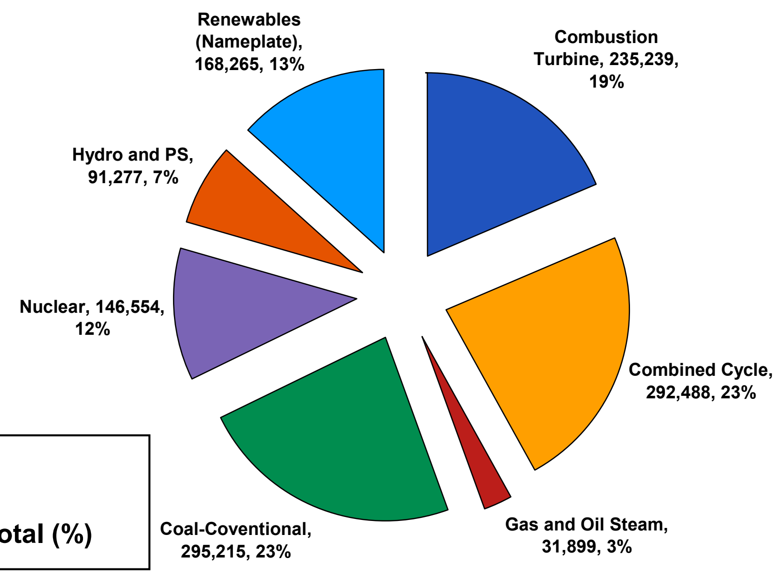
- Over the next 25 years the future mix of electric generation resources will have a notable shift to new gas-fire technologies, as part of a multi-prong power industry strategy that also includes wind, solar, nuclear and some IGCC w/ CCS.
- Combustion turbine and combined cycle capacity gains about 100,000 MW each, while about 70% of gas and oil steam assets are retired for a variety of reasons, such as age, inefficiency, and, on the west coast, limitations on use of ocean water for once-through cooling.
- Renewable capacity more that triples, much of this being wind, with some solar.
- Conventional coal capacity realizes another 8,000 MW of gains in the next few years as projects in advanced development are completed, followed by 25,000 MW of retirements of older, smaller, less efficient resources.

Source: B&V Analysis

Resource Mix—2010



Resource Mix—2034

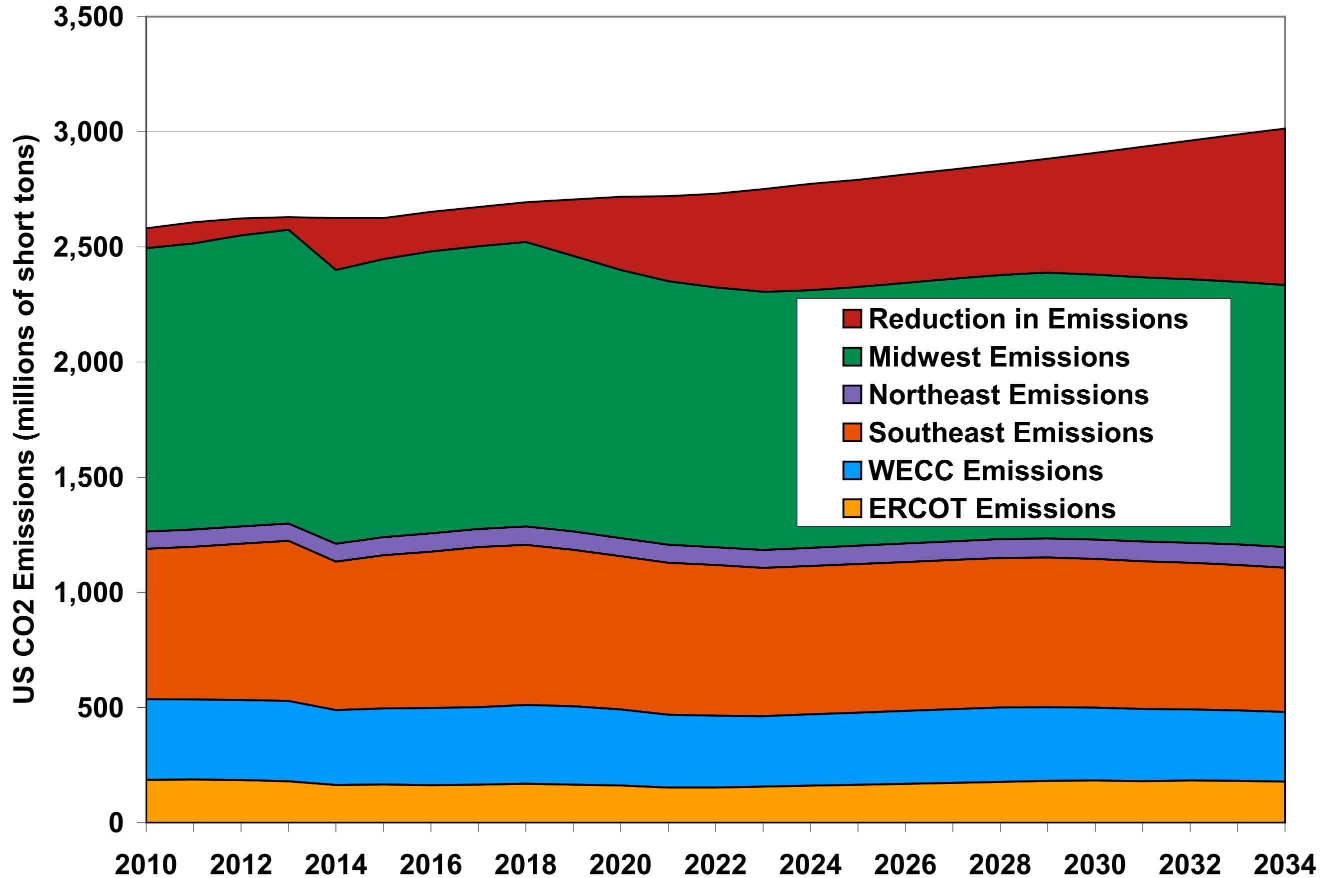


Data Label Legend:
Technology,
Capacity (MW), Share of Total (%)

Trajectory for CO_2 Emissions

- Compared to a "Business as Usual" case with no GHG legislation, the B&V Base Case has moderate declines in electric power sector CO_2 emissions for 15 years, followed by a period of smaller reductions.
- The reduction in emissions shown in the chart on the chart on this page is the results of increased renewable energy, retirement of less efficient coal units, lower demand growth and utilization of allowances.

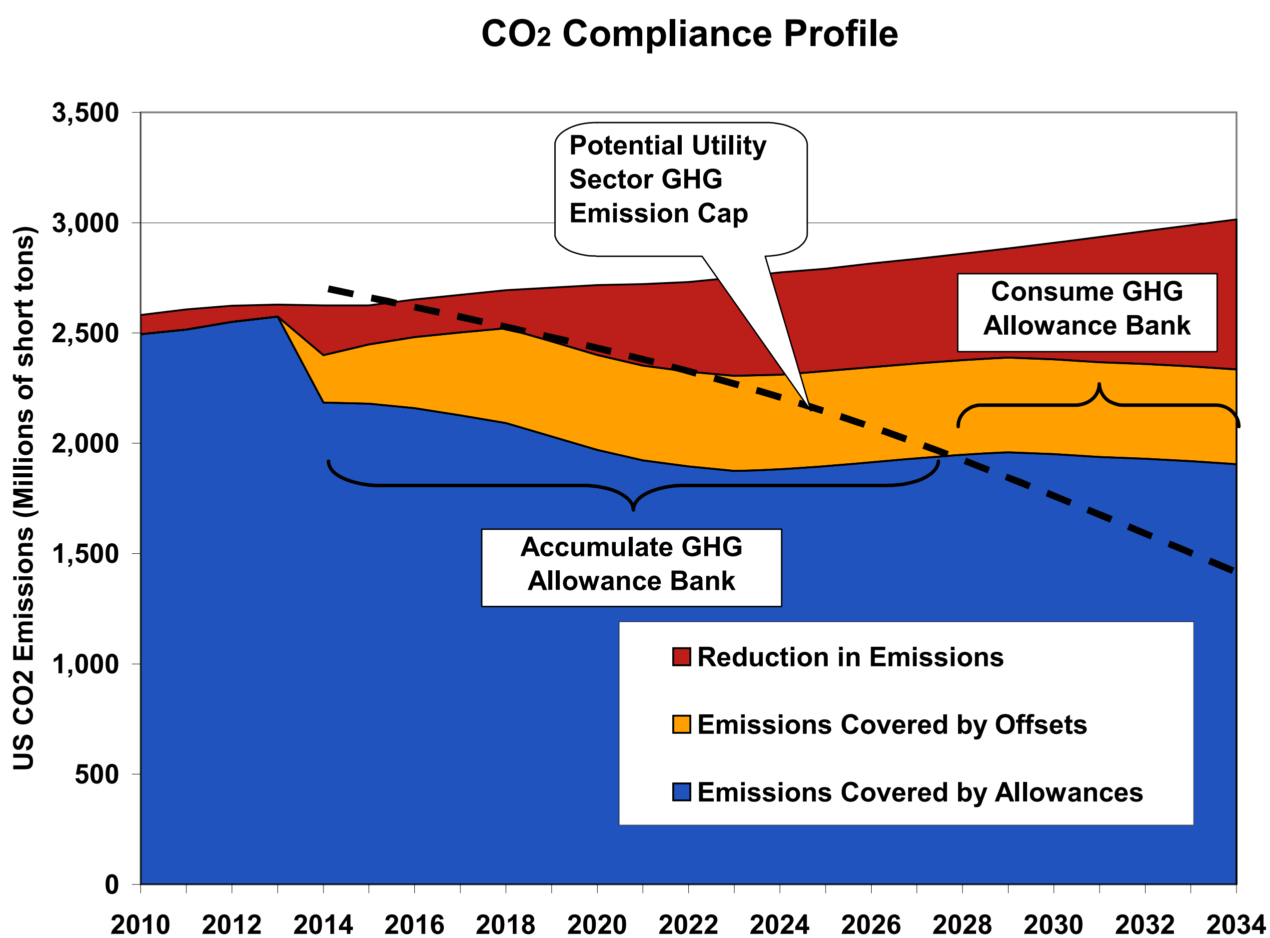
Annual CO_2 Emissions



Source: USDOE Annual Energy Outlook (for Business as Usual case) and B&V Analysis

Compliance with a CO_2 Emission Cap

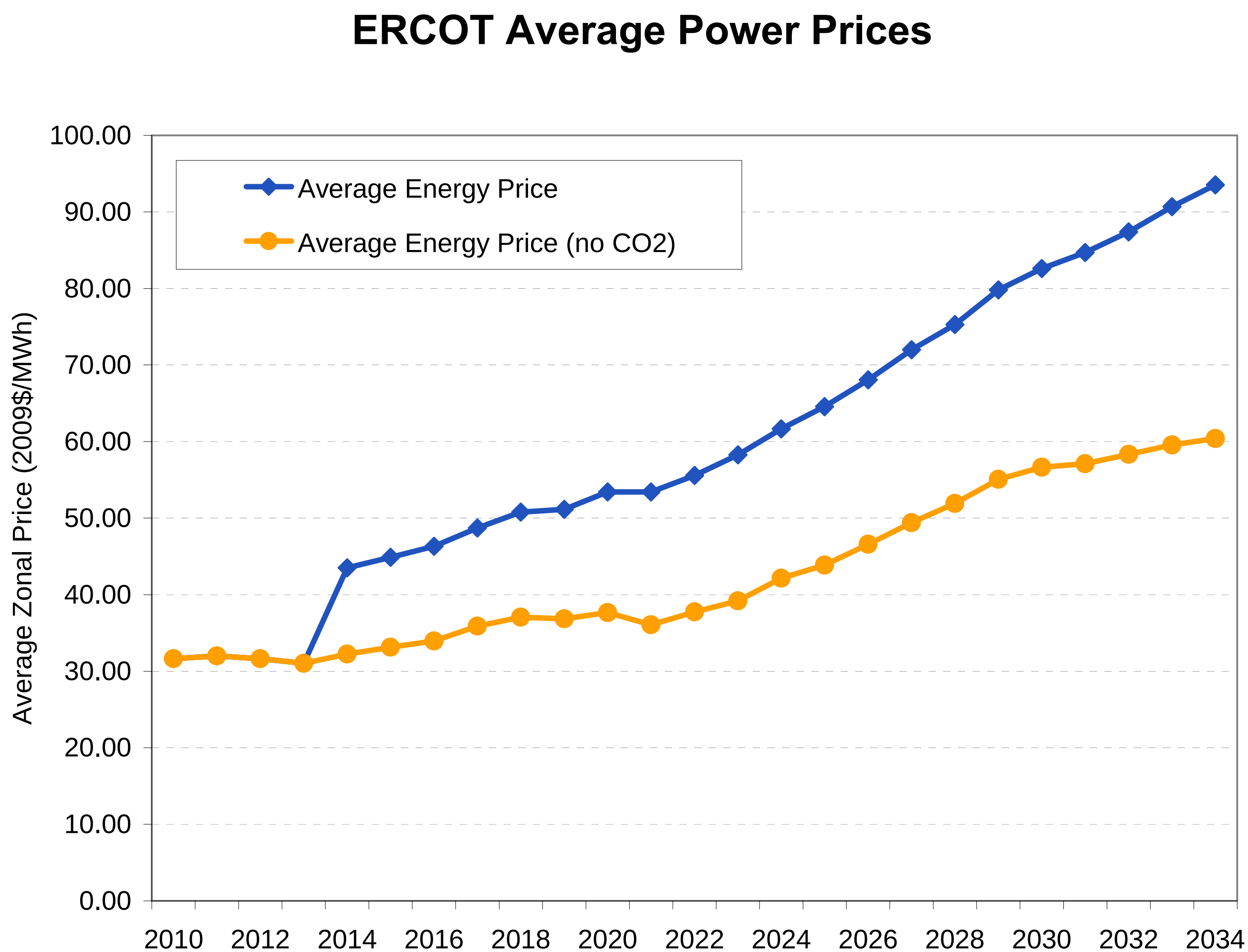
- The electric power sector accounts for about 39% of US carbon emissions. A typical presumption is that electric power's GHG compliance costs will be lower than that of many other sectors, so offsets may be used more in other sectors. If so, then the electric power sector may use less than a pro rata share of the 2 billion tpy of offsets allowed under proposed legislation.
- Assuming use of only half of its pro rata share of the 2 billion tpy of offsets, the electric power sector can bank offsets through the late 2020's and consume that bank well into the late 2030's.
- However, as 2040 approaches, additional compliance actions would be needed.



Source: B&V Analysis

Impact of Carbon Allowances on Wholesale Energy Prices

- In markets where natural gas is often the "marginal" fuel, the impact of carbon costs is typically on the order of $0.50/MWh for every $1.00/ton of Carbon Allowance.
- In regions with more coal the impact is closer to $0.75/MWh per $1.00/ton CO_2.
- In this ERCOT example, increasing CO_2 allowance costs add $12/MWh to the wholesale price of electricity beginning in 2014, increasing to $34/MWh in 2034, just a bit more than $0.50/MWH for every $1.00/ton CO_2.



Source: Black & Veatch

Section 3.
Fuel Market Assumptions

3.1 North American Fuel Overview

Fossil fuel prices, specifically natural gas, will reflect national effects of clean air and renewable energy policies.

- More than seventy percent of US power generation assets use fossil fuels: oil, coal and natural gas
- CO_2 initiatives signal a shift to a lower GHG emissions generating portfolio that drives increases in natural gas demand
- New sources of natural gas will be available to meet rising demand needs in North American regional markets
- Oil prices will increase to $100/bbl by 2030 as demand growth requires more expensive resources to be exploited.
- Natural gas prices (real $2009) rise steadily from $5.00 to $9.00/MMBtu through 2034
- Coal prices nearly flat, with only slight increases, reflecting cost of resource development even as demand is about flat.

Key Assumptions for Fuels Markets

- US and global economy is expected to recover starting in the second half of 2009, remaining flat for 2010 and growing at about 2 percent annually thereafter
- World oil prices will respond to global economic signals and stabilize at lower than levels reached in early 2008
- North American coal-fired generation development remains sharply lower than historical and recent development
- US nuclear and renewables development remains feasible, and contributes to new power capacity and energy needs
- Unconventional gas production remains economic to produce at $5-$6/MMBtu (basin dependent); production levels respond more quickly market price signals than historical production
- Global LNG capacity continues to outpace global demand, particularly in Northern hemisphere summer seasons; drives imports to US markets

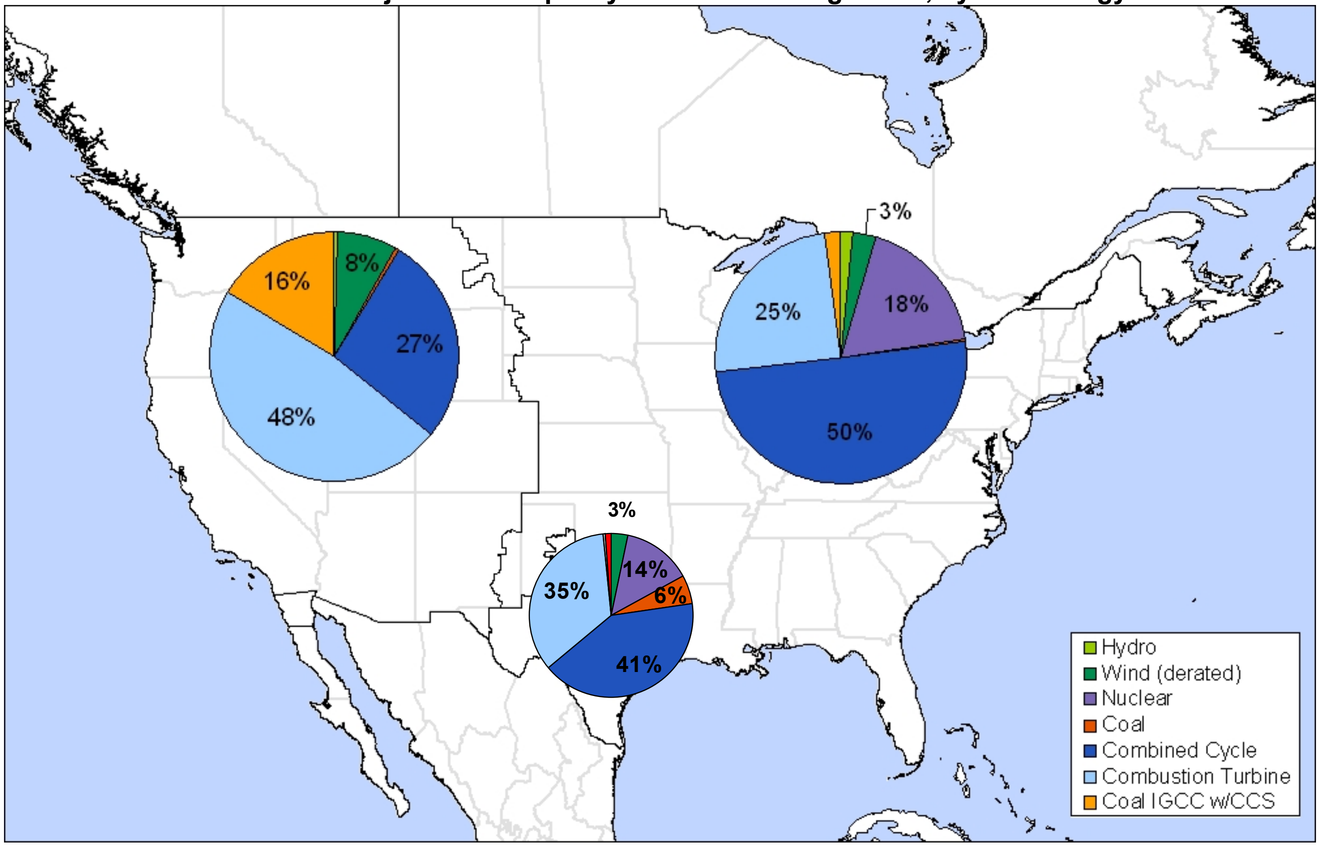
Key Uncertainties in the Fuels Market

- Timing and pace of economic recovery will affect the demand for all fuels. Delayed or slow demand rebound will keep fuel prices relatively low.
- Implementation and format of CO_2 regulation will affect the industries' choice of fuel and their prices. Prolonged debate creates the option of gas as a "filler".
- The production potential and cost of unconventional natural gas resources of North America determines the sufficiency of supply to meet potential demand growth for natural gas.
- LNG import volumes and price are determined by the balance between liquefaction capacity, global demand growth for natural gas and storage capacity.

B&V's fuels outlook is based on expectations for a diversified generation portfolio and increasing gas demand.

- B&V expects general compliance with Renewable Portfolio Standards
- Renewables (wind), nuclear, and IGCC with CCS will play a key role long term in a diversified portfolio
- More than half of new generation capacities will be from natural gas – both for mid-merit and peaking needs
- New gas supply sources will realign to meet demand needs in the East as WCSB production declines

B&V Projection of Capacity Additions through 2030, by Technology



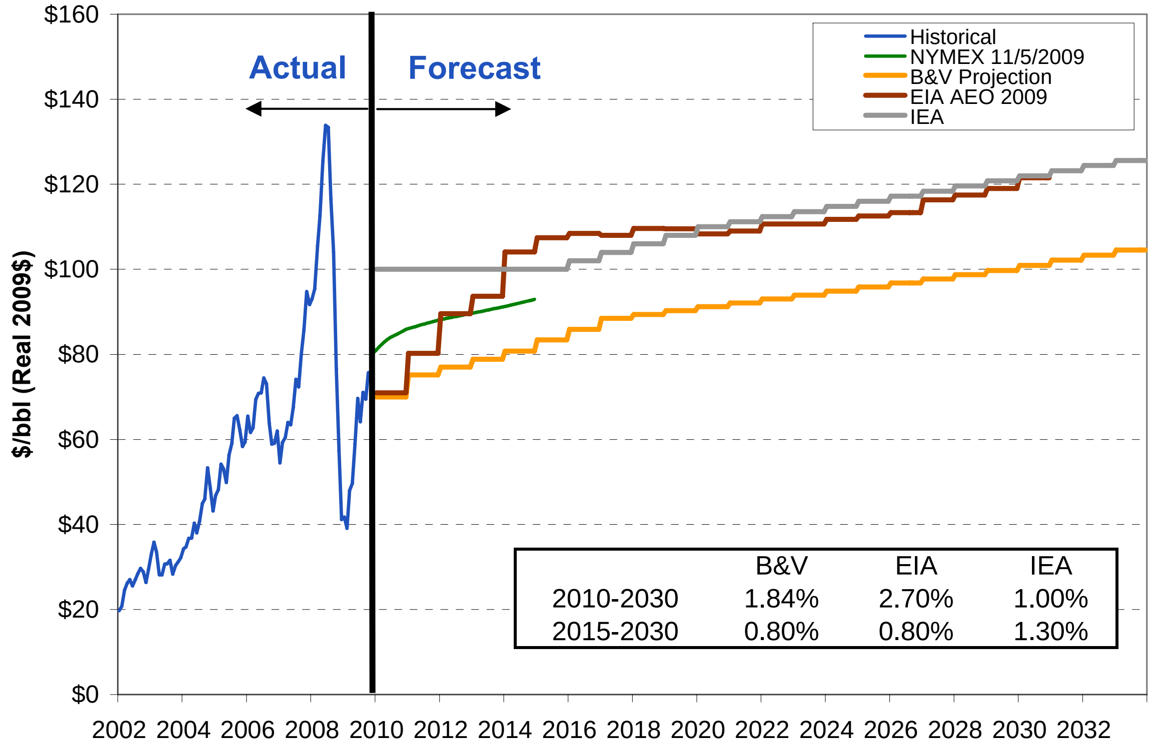
Source: B&V Analysis

3.2 Global Oil Outlook

B&V Expects Continued Oil Price Recovery in the near term

- Short-term oil prices will stabilize at $60-$70/bbl as global economy continues to recover
- Long-term prices will grow to $90-$100/bbl as more expensive production sources meet demand growth
- Low oil prices generally favor increased US LNG imports as Asian and European prices are more closely linked to oil
- Increasing LNG trade creates pressure, but not requirement, on the oil to gas linkage

Historical and Forecasted Oil Prices



	B&V	EIA	IEA
2010-2030	2.7%	2.7%	1.0%
2015-2030	1.5%	0.8%	1.3%

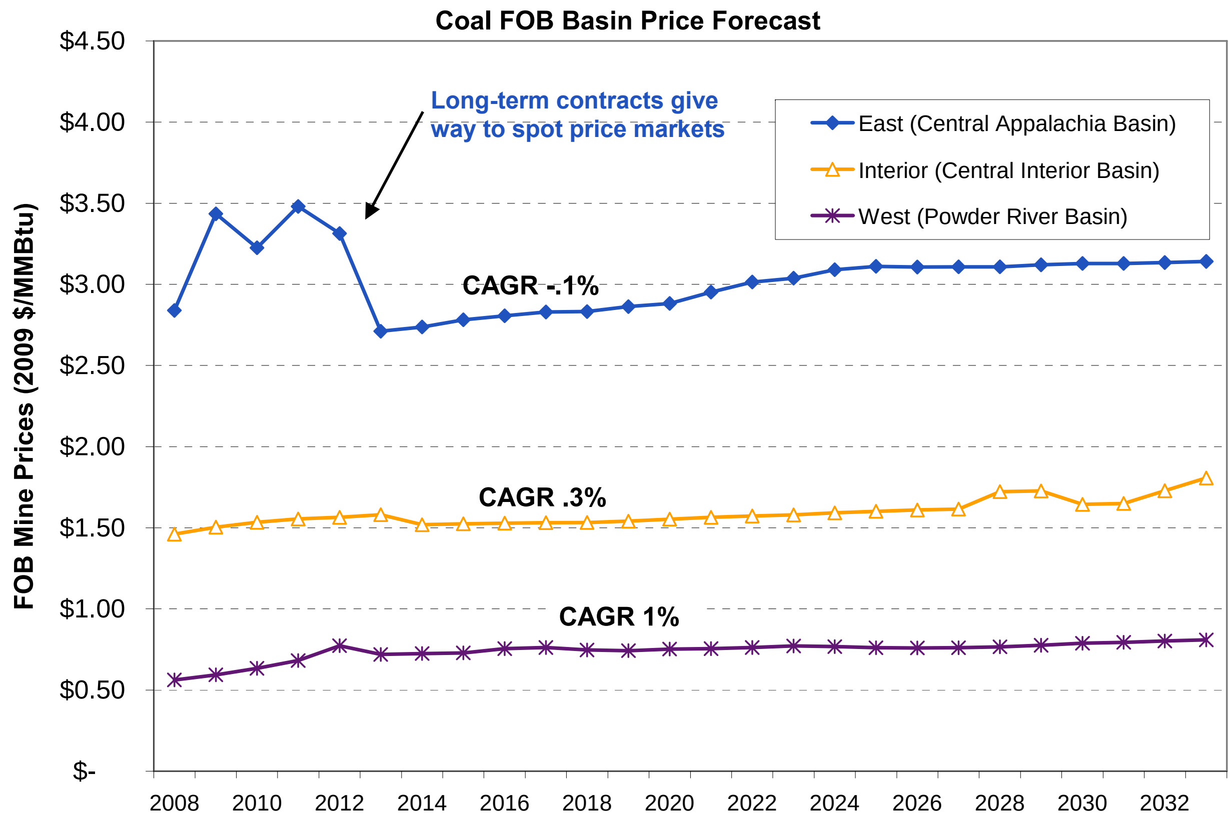
Source: B&V Analysis, EIA, IEA, NYMEX

3.3 North American Coal Outlook

Coal prices are expected to rise gradually through 2030, with lower-sulphur PRB prices outpacing other basins on a CAGR basis.

Although new coal generation development is stagnant, prices at flat to slightly increasing due to:

- Rising mining and labor costs with more stringent mine safety standards
- Tougher geological conditions, especially in the more mature Eastern region
- Slower productivity gains
- Price linkages with oil and gas prices
- Rising oil prices that increase transportation costs
- Demand weakens with global economic climate

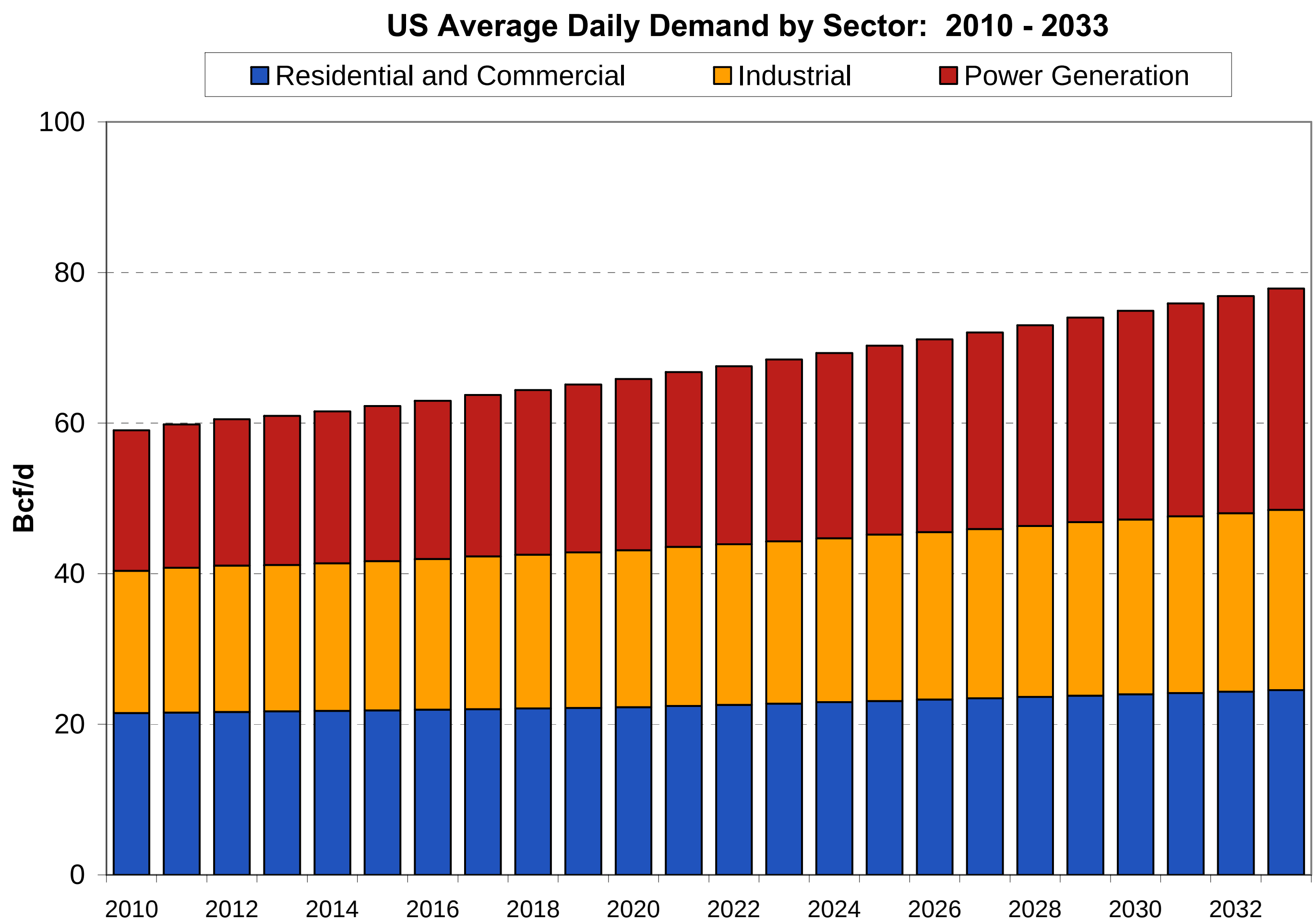


Source: Energy Velocity

3.4 North American Natural Gas Outlook

Power Generation Demand Drives Natural Gas Growth and Offsets More Modest Growth in Traditional Sectors.

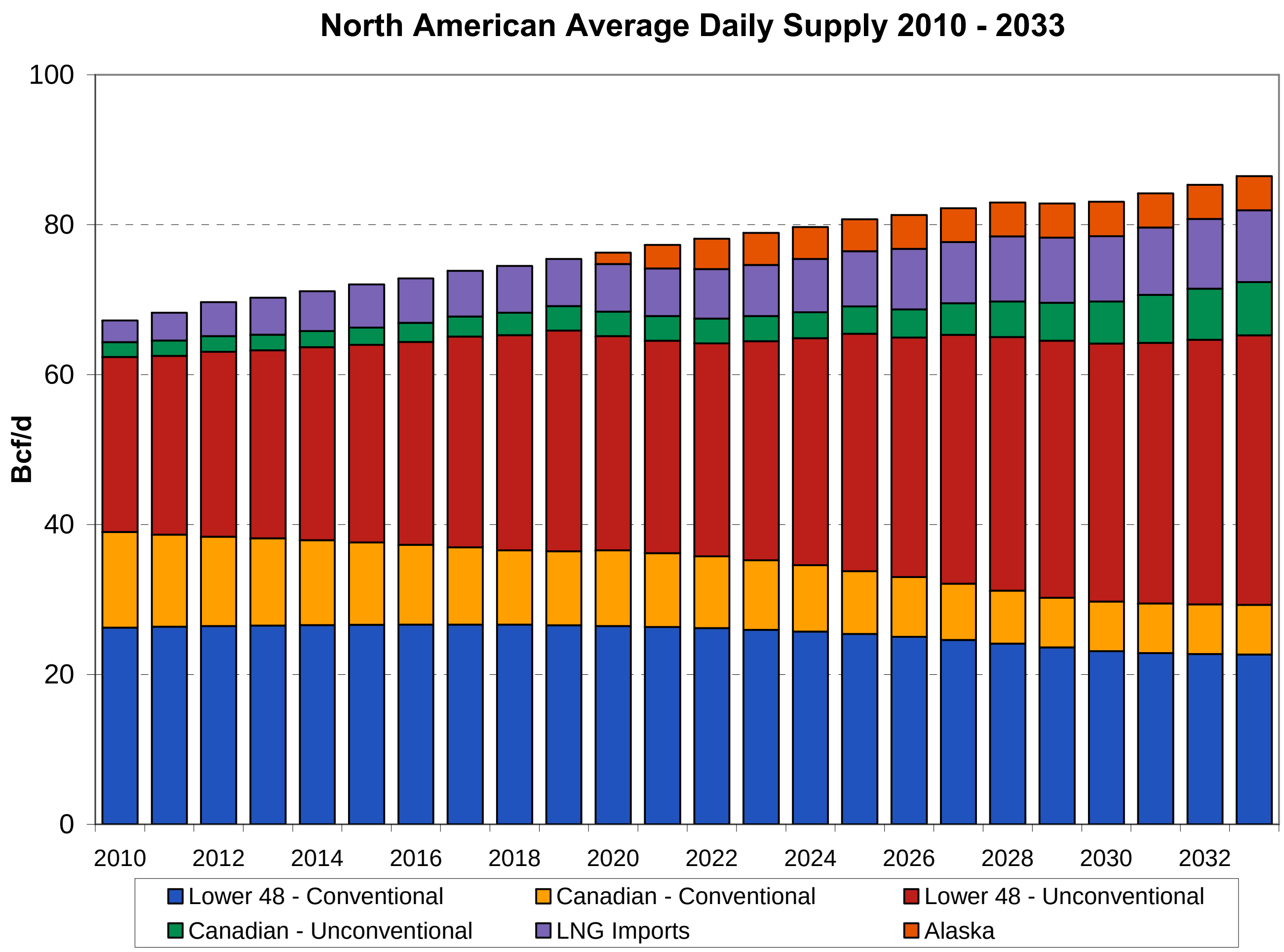
- Demand from the power generation sector is expected to grow at 2.1% per annum through 2030.
- Core (residential/ commercial) and industrial sector growth flattens with increasing efficiencies (CAGR = 0.5%).
- Industrial remains stable due to demand restoration.



Source: EIA, B&V Analysis

Unconventional production, Alaskan gas, and LNG imports will offset declines from conventional North America gas supplies.

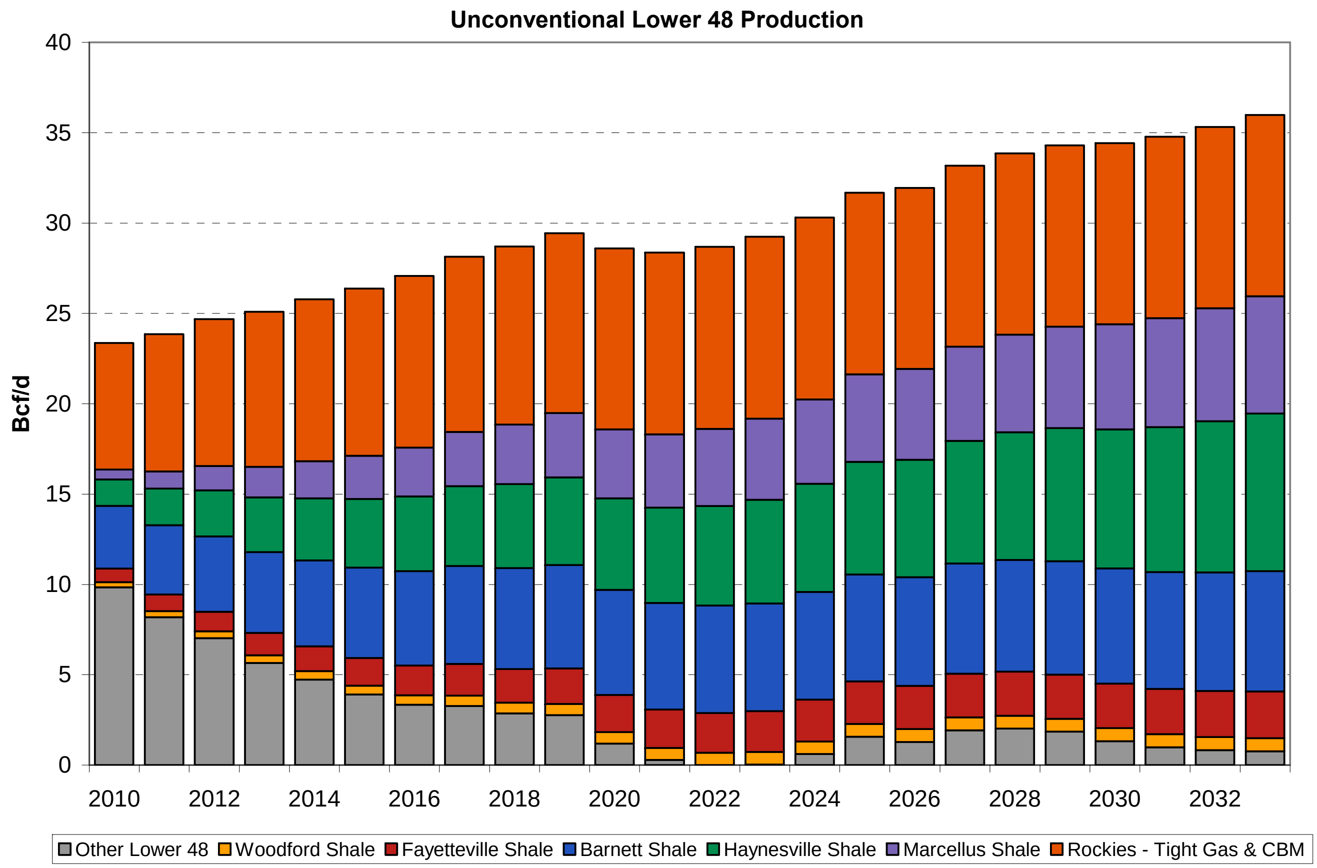
- US/Canadian demand will draw from a common North America resource base.
- Price signals bring new supplies to market: volatility is different than availability.
- LNG and unconventional supply (shale, tight sands and CBM) growth is expected to be adequate for growing demand



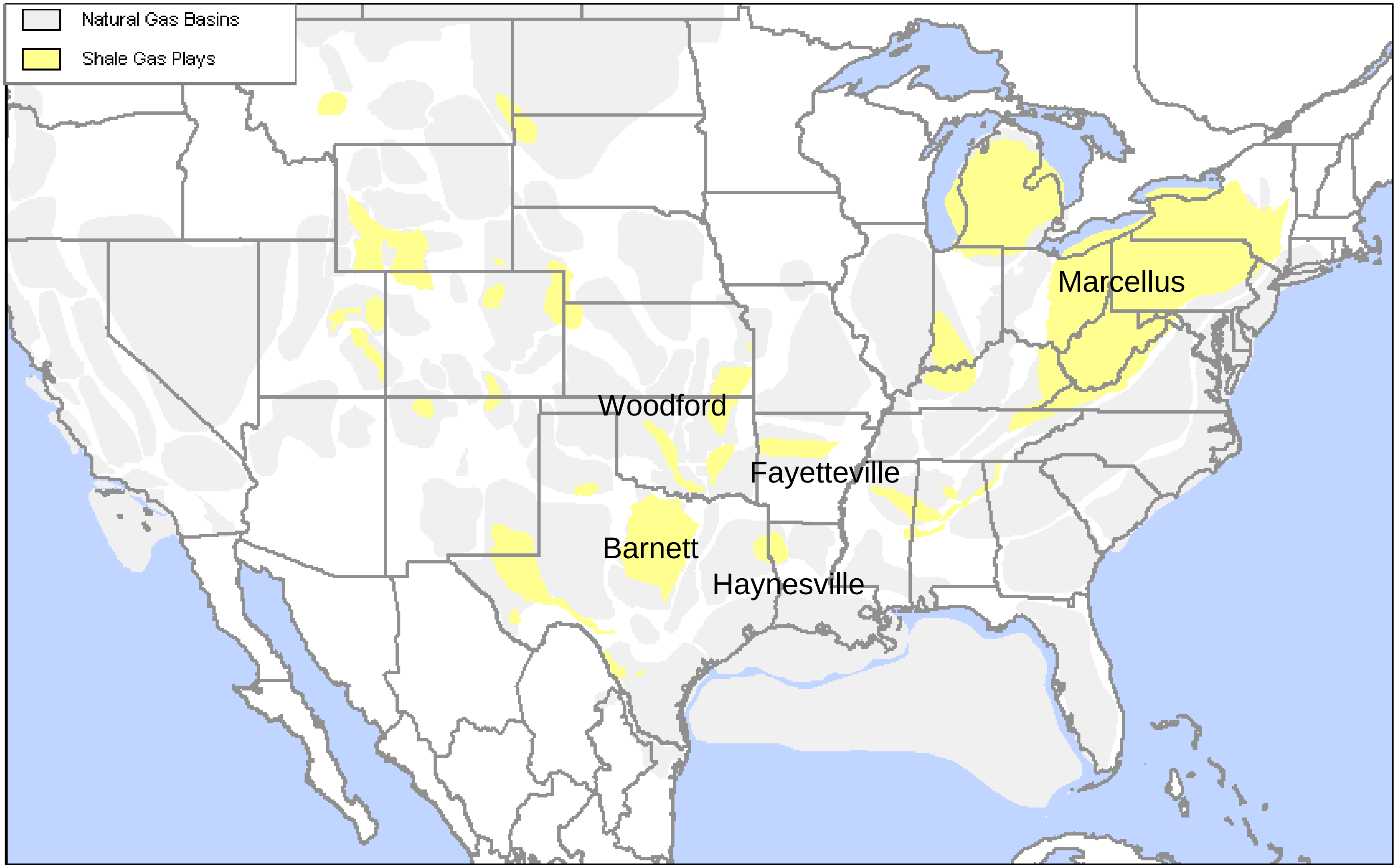
Source: B&V Analysis, National Energy Board

Shales, Rockies Tight Gas and Coal Bed Methane Production Grow to Offset Declining Conventional Supplies

- Gulf Coast Shale production is expected to exceed 17 Bcf/d by 2030; mostly from Barnett and Haynesville Shale
- Rockies TG and CBM production will be mainly from Green River and Powder River basins
- Technical Recoverable Reserve estimates for Marcellus Shale potential to exceed 262 Tcf

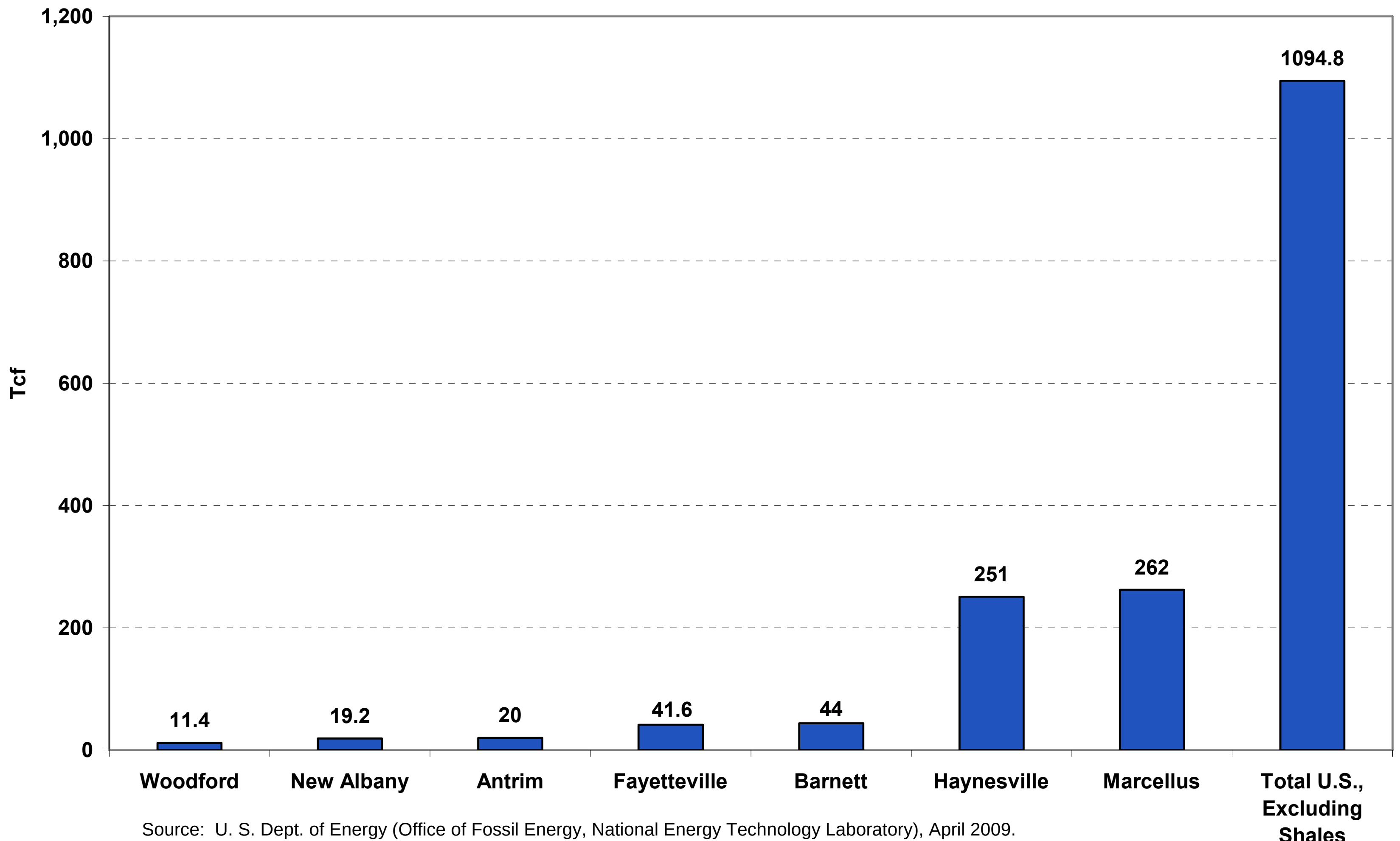


Major Natural Gas Shale Plays in the Lower 48



Technically Recoverable U.S. Shale Reserves Account for Nearly 40% of Total U.S. Reserves

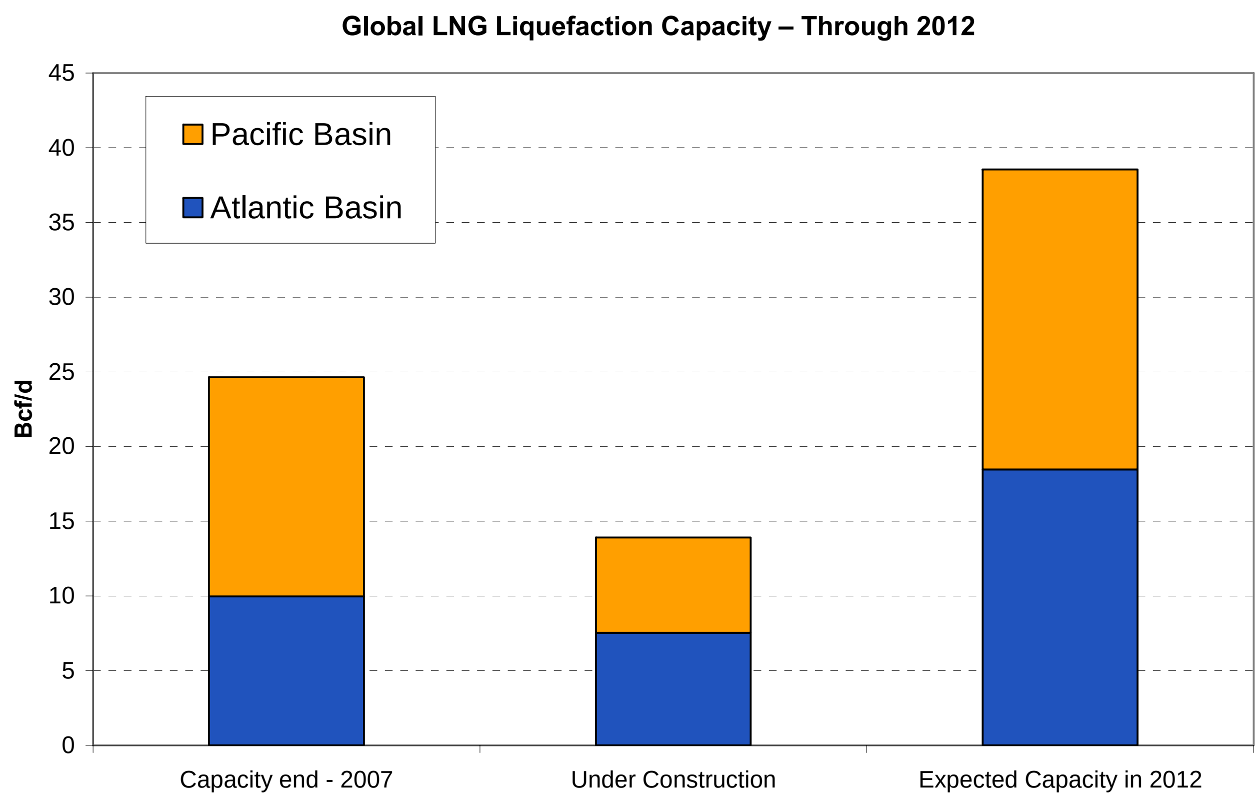
Technically Recoverable Natural Gas Resources in the United States: Shales vs. All other Reserves



Source: U. S. Dept. of Energy (Office of Fossil Energy, National Energy Technology Laboratory), April 2009.

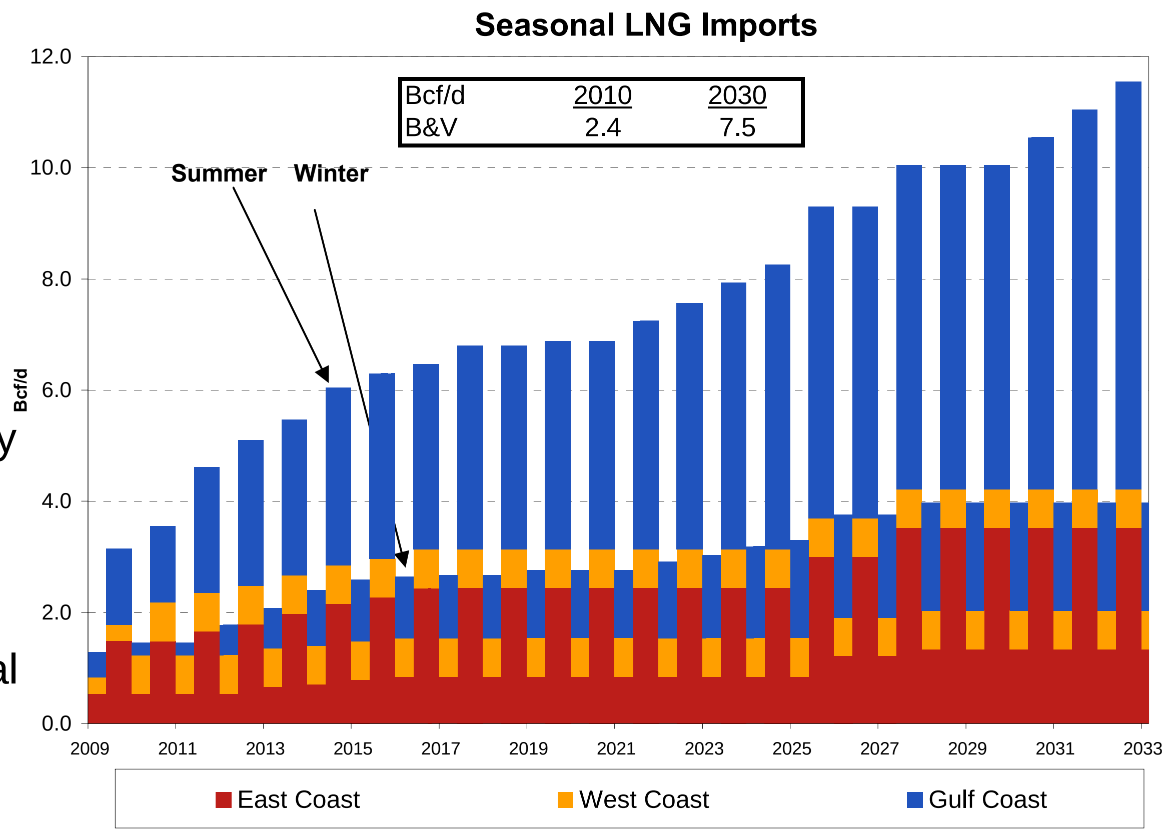
Global liquefaction capacity increases will create new Atlantic Basin supplies that will seek US markets.

- Global liquefaction capacity increases will ease recent supply constraints in all LNG markets
- US power generation demand peaks in summer when LNG supply is least needed in Asia and Europe
- LNG merchants are expected to ship to US markets through new import terminals when prices and demand are stronger than Europe
- Additional liquefaction capacity in Nigeria, Algeria, and Australia are under development post 2012



LNG imports are expected to approach 10 Bcf/d by 2030, but remain highly seasonal with summer peak imports.

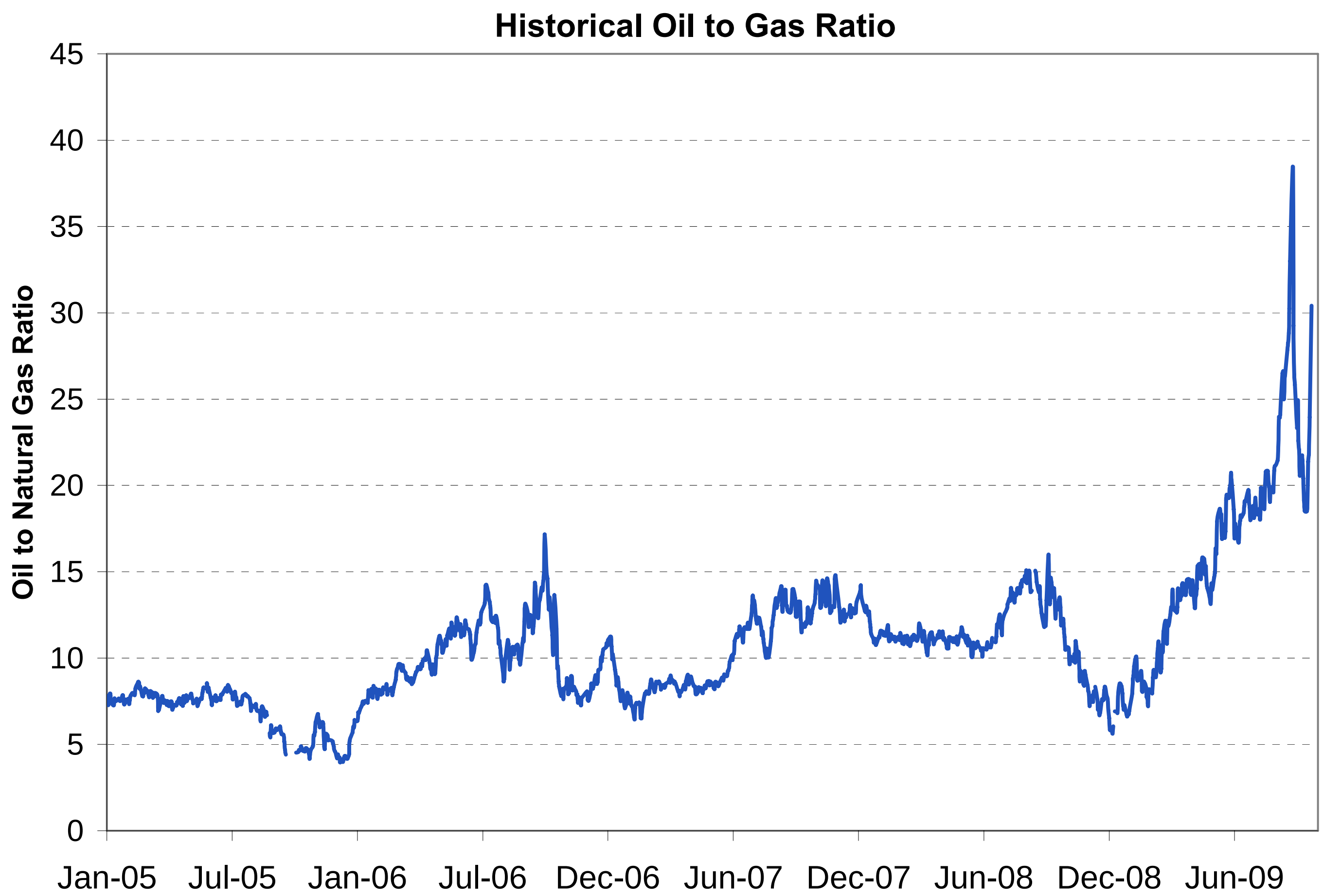
- LNG world market dynamics:
  - Strategic Fuel in Europe and Japan
  - Opportunistic Fuel in US in Summer: Monetization
- Europe:
  - Storage use is smaller in comparison to the US
  - Storage utilized for seasonal demand and to mitigate supply disruptions (e.g. – Russia).
- US LNG
  - East and West Coast LNG terminals rely more on bilateral contracts.
  - Gulf coast terminals expect to be the "swing" importers, with higher summer utilization to monetize LNG cargo.



Source: B&V Analysis

LNG destinations decisions based on Oil to Gas ratio will determine import volumes to Lower 48

- Supply overhang in 2009 contributed historically high oil to gas ratios
- B&V projects oil to gas ratio to moderate between 10 to 15 in the near term
- Market area LNG terminals may receive incremental cargos during peak demand months



Long-term natural gas prices are projected to rise with growing demand and new higher cost supply sources.

Short-term (2009 - 2011)

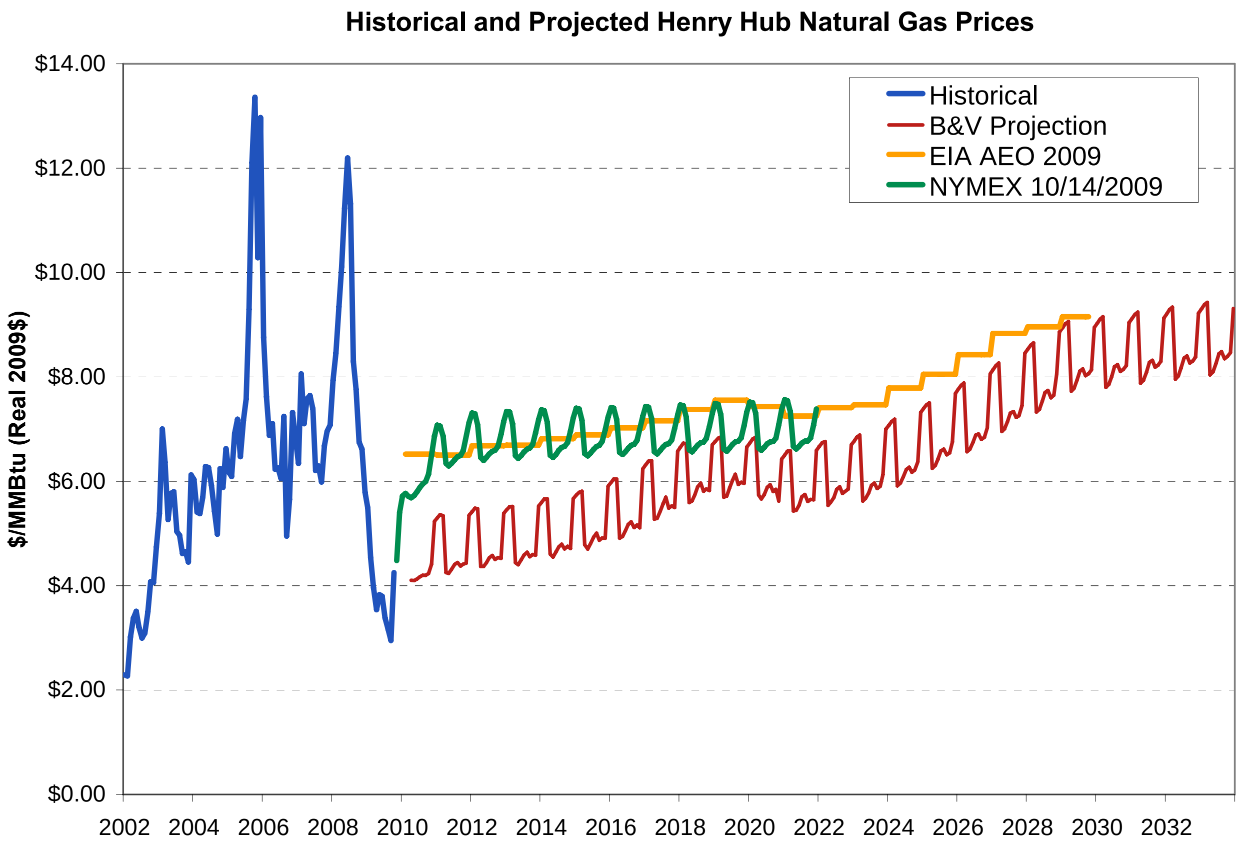
- Demand weakens with global economic climate
- North American natural gas production decreases with lower prices, credit constraints, and reduced drilling activity

Medium-term (2011 – 2019)

- Natural gas prices track upward to an average of $5.50
- Unconventional gas and LNG imports keep pace with demand

Long-term (2019 – 2030)

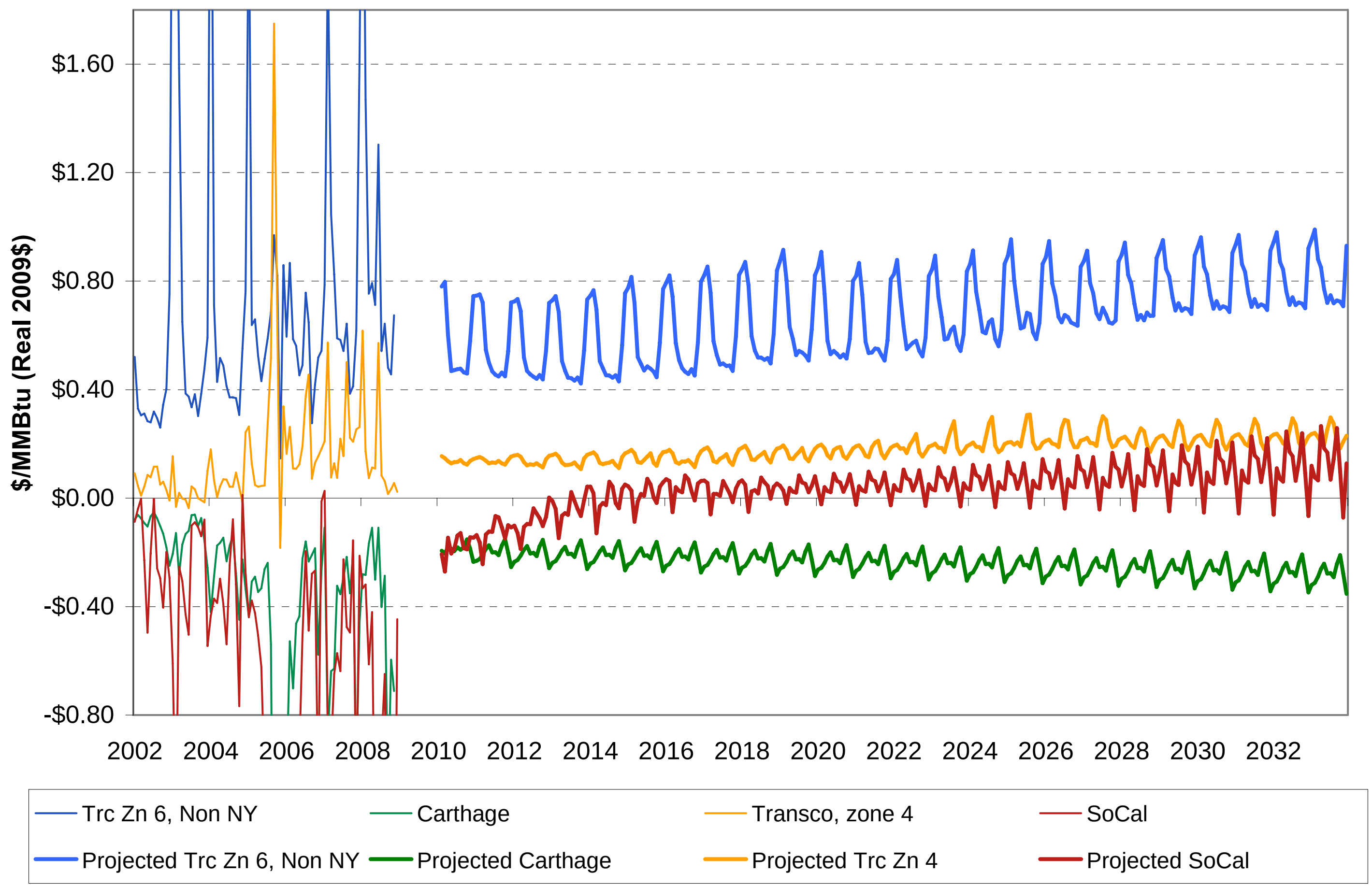
- Power sector demand pushes new consumption
- Alaskan gas enters market in 2020 softening prices for a few years
- Prices then rise as WCSB decline accelerates and current unconventional gas plateaus



Source: EIA, B&V Analysis, NYMEX.com

Selected Regional Basis Price Forecasts Reflect Growing Demand (Basis ↑) and Increased Supply (Basis ↓)

- The Energy Market Perspective incorporates detailed structural modeling of the North American gas industry.
- The result is basis differentials are represented as changing over time in response to shifting regional supply and demand balances.

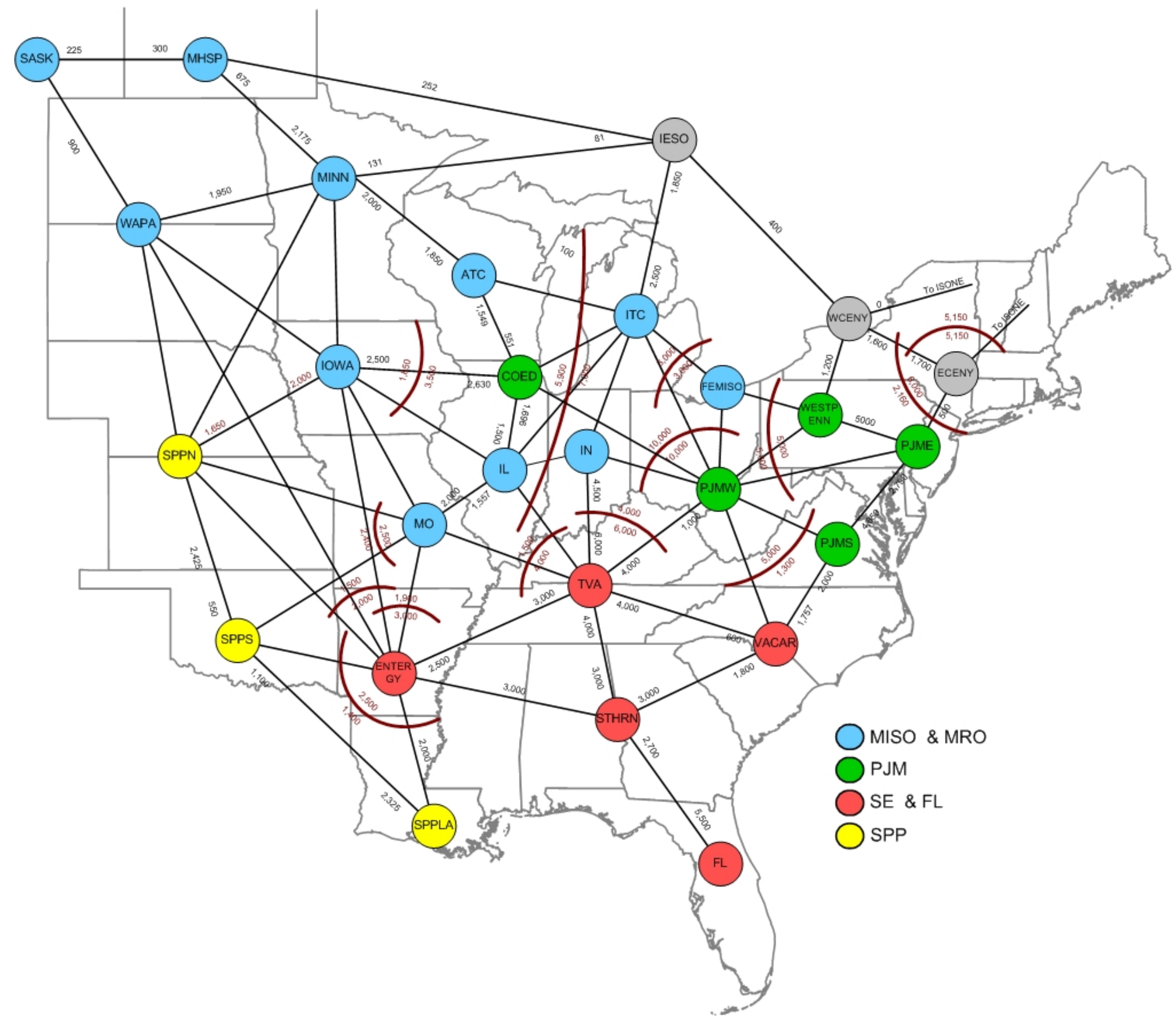


Section 4.
Midwest Regional Market Analysis

4.1 Overview and Key Issues

Midwest/Southeast Energy Market Simulation Topology

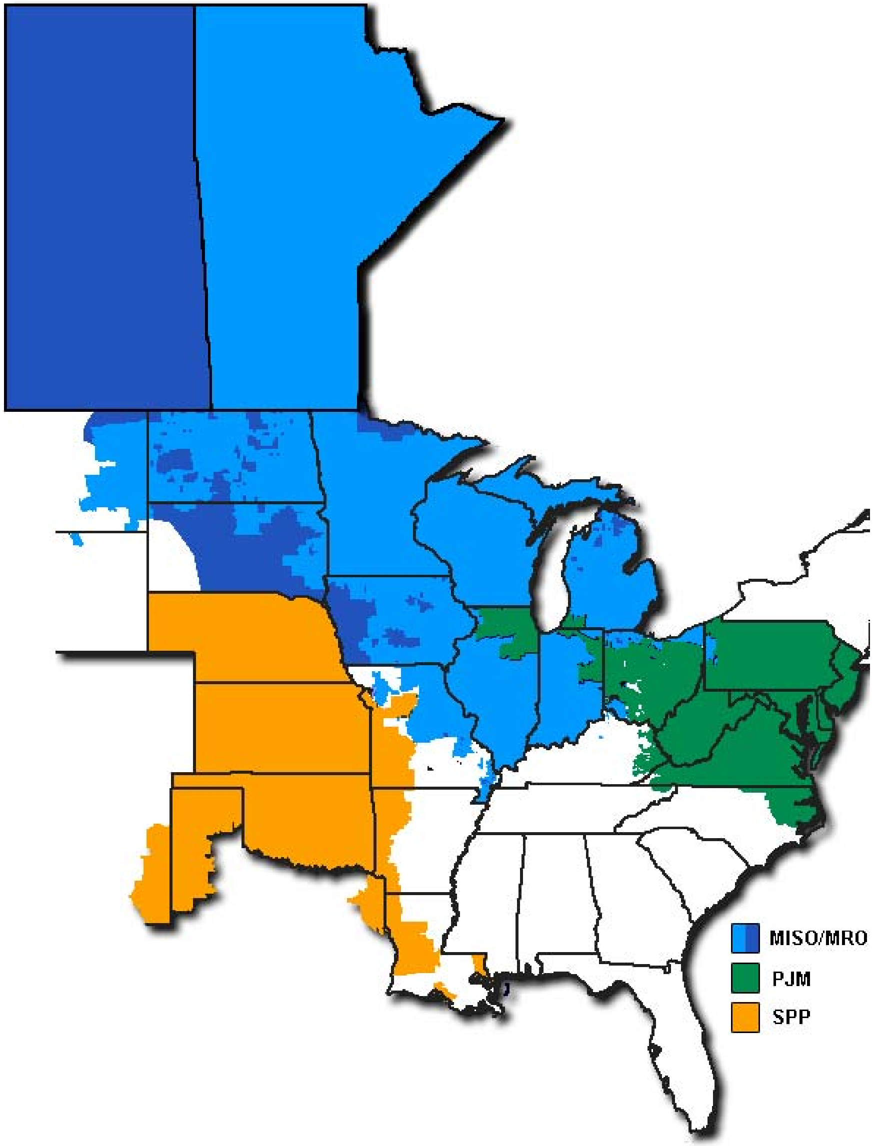
- The Midwest and Southeast market perspectives use a combined model with a topology developed to capture all the key transmission constraints between market areas
- Power flows between market areas are limited by either a link and/or an interface flow constraint
- Links and interfaces are assigned a maximum transfer rating which is the maximum amount of power (MW) that can flow (import/export) from one market area to another
- An interface limit is the cumulative transfer limit across more than one link
- NYISO and IESO footprint were also modeled to capture the power flow interactions between control areas
- 24 Market Areas Modeled



Source: Black & Veatch

The Midwest Energy Market Perspective

- The Black & Veatch Midwest Energy Market Perspective covers MISO and MRO, PJM, and SPP
- 376,000 MW Firm Installed Capacity
- 311,000 MW Frcst Peak Load
- 21 % Reserve Margin

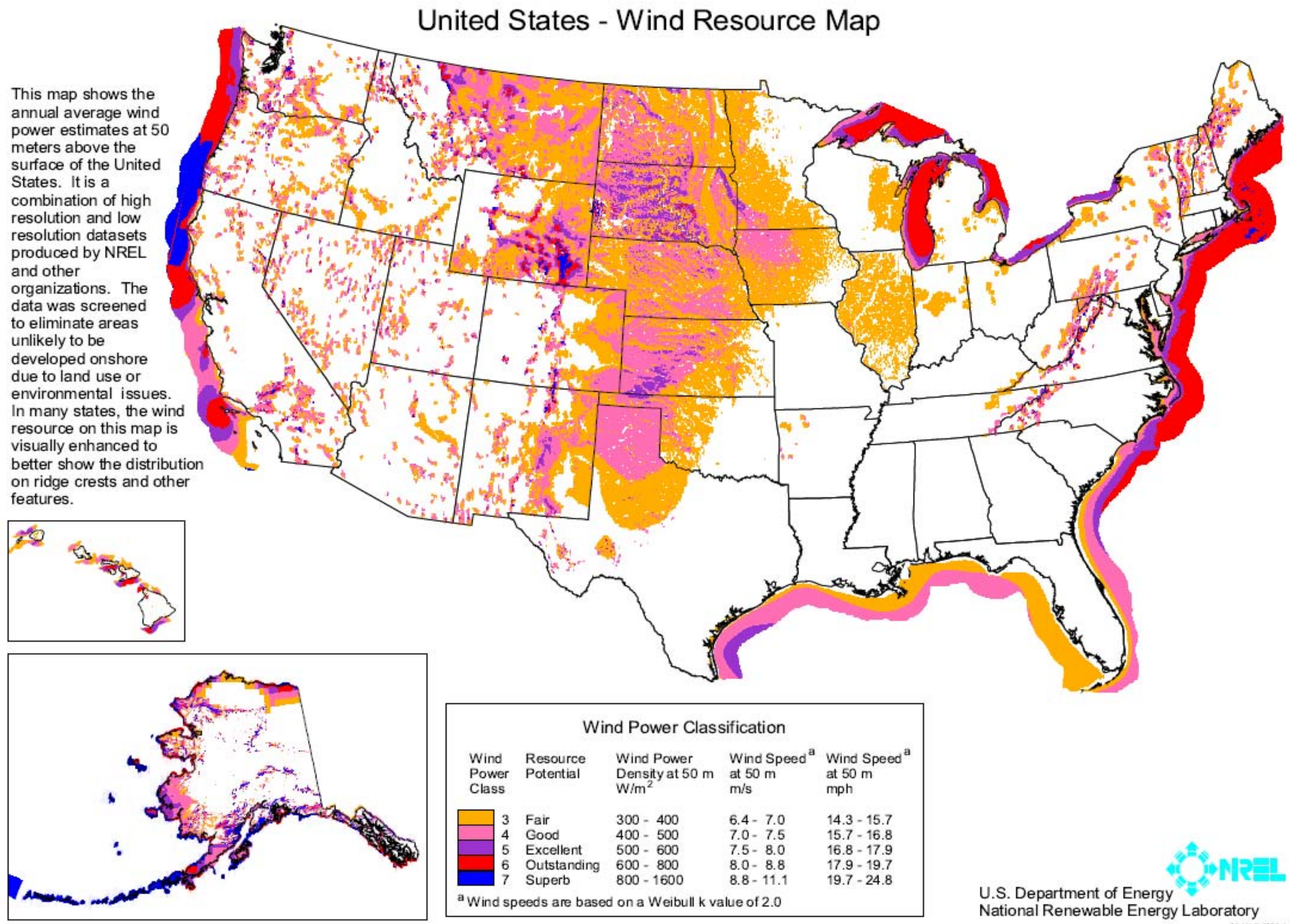


Key Issues Affecting Midwest Power Markets – Focus on Wind Penetration

- Each market region in the Midwest has focused significant planning resources on wind generation development, and the economic and operational impacts of large-scale wind penetration across the region
- Wind interconnection requests have overwhelmed Midwest independent system operators and planning entities:
  - MISO – 60,000 MW
  - PJM – 36,000 MW
  - SPP – 20,000 MW
- A number of projections, driven by higher quality wind resources and lower all-in costs, have significant wind penetration levels in the Upper Midwest Great Plains Area, some of which would be targeted to serve the demand for renewable energy in markets to the south and east
- DOE national wind study and similar studies project 5,000 -10,000 MW of wind in many of the upper midwest states, with concentration in the areas with the most favorable wind regimes
- Midwest entities have completed or are completing wind integration studies, and transmission overlay studies examining transmission infrastructure needs to accommodate large-scale wind penetration

Most Favorable Midwest On-Shore Wind Resources are in Upper Great Plains Region (MISO, MRO, SPP)

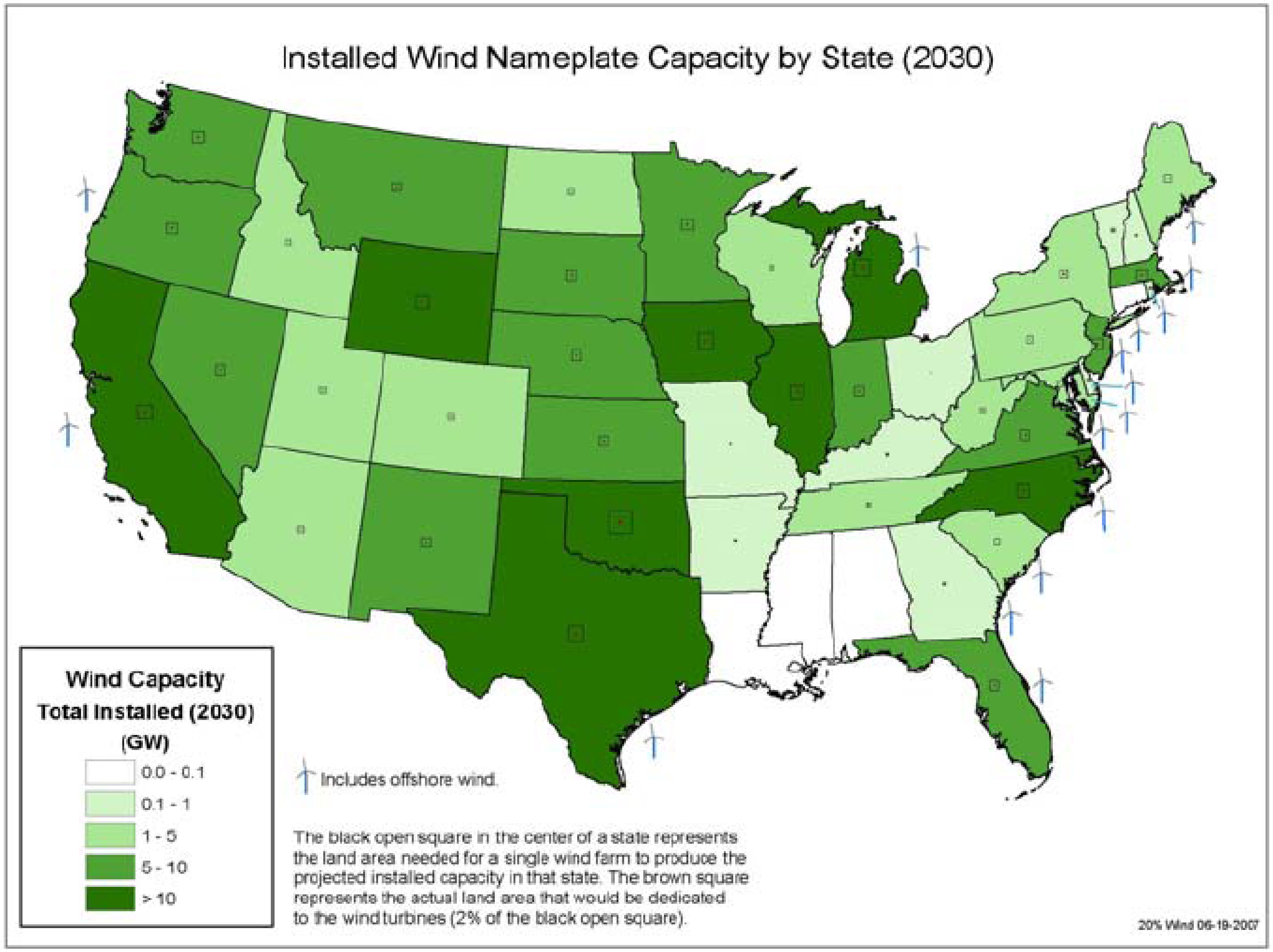
- Highest quality wind regimes in the Midwest are in the Upper Great Plains Region, with concentrations of Class 4 and Class 5 Wind
- Black & Veatch's technical work underlying the DOE 20% Wind Study shows construction and operating cost advantages of locating wind generation in the Upper Great Plains Region
- Transmission upgrades would be required to accommodate large-scale wind penetration



Source: NREL

Achieving High Wind Penetration Levels Could Lead to Significant Wind Generation in Midwest Markets

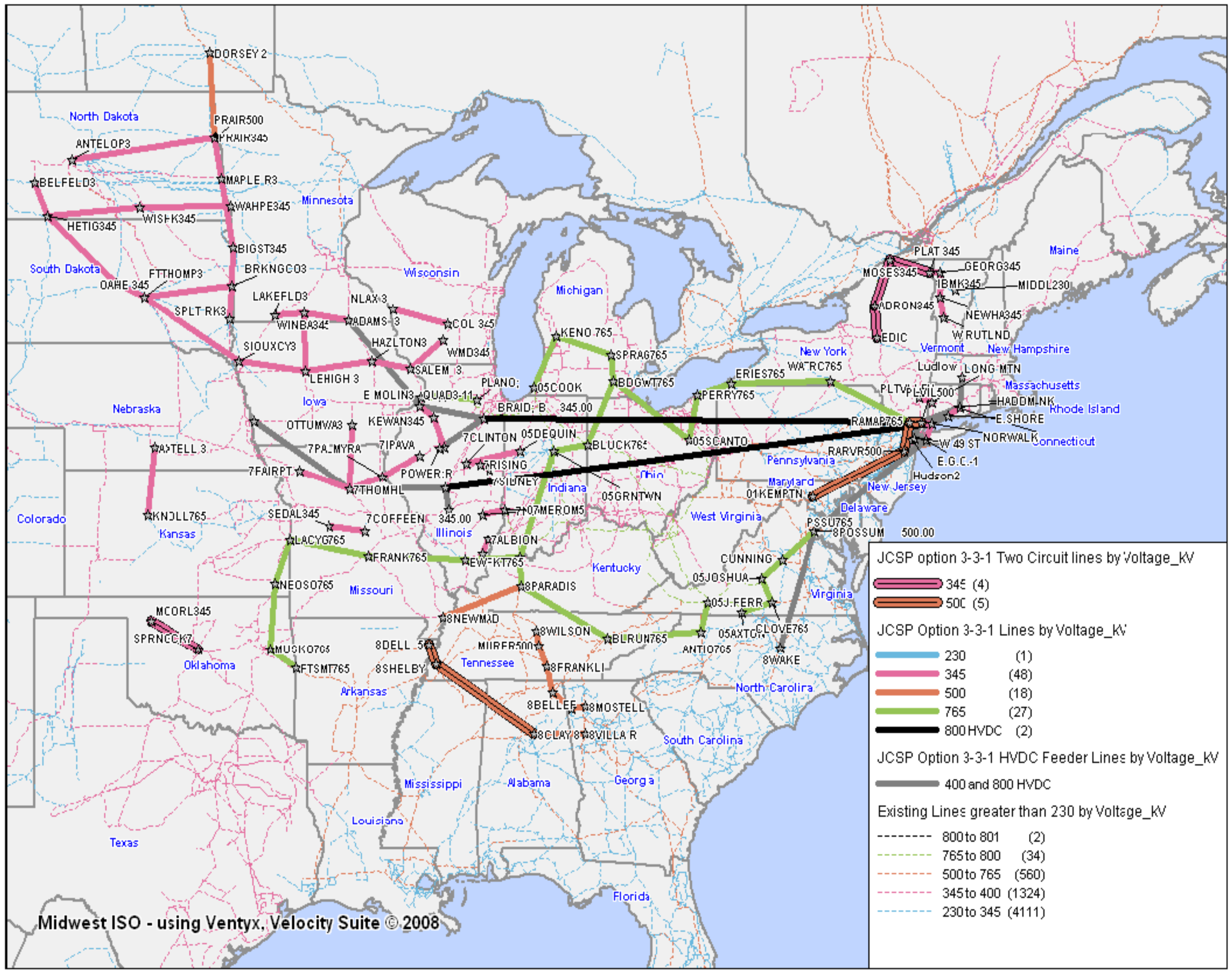
- Consistent with favorable wind regimes, higher concentration of wind resources is likely in the Upper Great Plains Region
- Northeastern, Mid-Atlantic and Southeastern states likely to import a portion of renewable energy supply, and potentially would develop off-shore wind projects



Source: DOE 20% Wind Study

Achieving High Wind Penetration Levels Will Require Significant Transmission System Investment

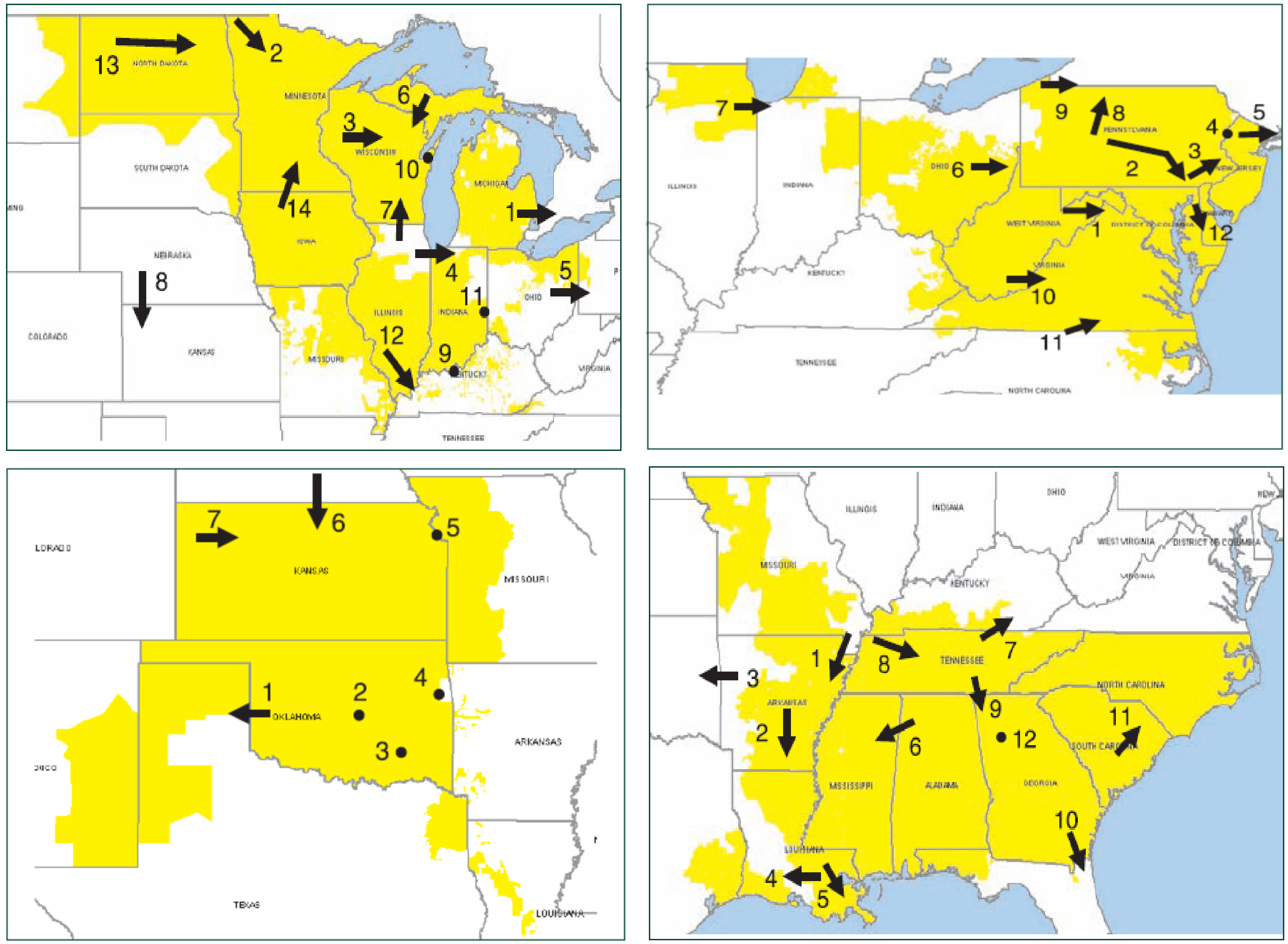
- Joint-Coordinated System Plan (JCSP) study recently completed analysis of high voltage transmission system overlay facilities needed to accommodate facilitate high levels of wind penetration in Midwest and other Eastern Interconnect markets
- JCSP projects $50 billion in transmission investment by 2024 in its reference case scenario, and $80 billion under a 20% wind penetration scenario
- JCSP study was a collaborative planning effort between MISO, PJM, SPP, TVA, MAPP, and several members of SERC



Source: JCSP Reference Case Scenario

Midwest and Southeast Markets Have Areas of Meaningful Transmission Congestion Under Current Conditions

- Significant interaction occurs between Midwest and Southeast markets, and transmission bottlenecks lead to price separation under current market conditions
- Transmission congestion may become significantly more frequent, depending on wind penetration levels in the Midwest, and geographical dispersion of new wind generation



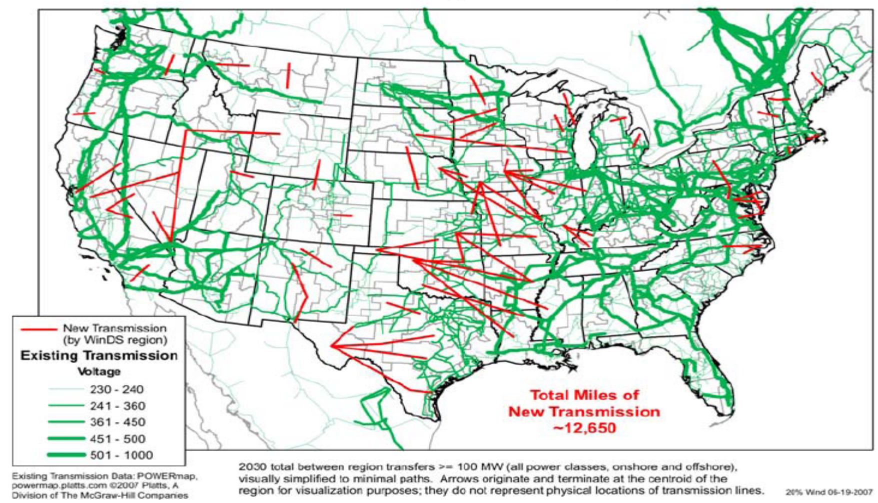
Source: DOE National Congestion Study

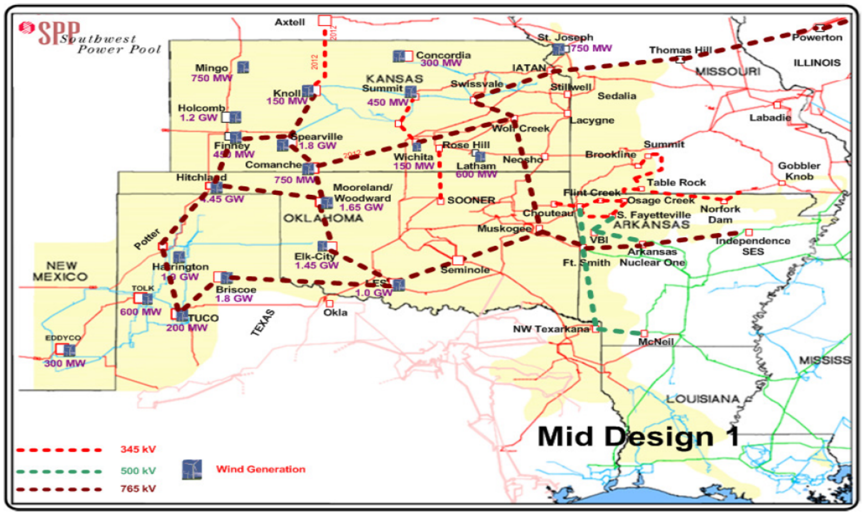
* Number show frequency of congestion, 1 is highest

DOE and SPP Transmission Studies Similarly Identify Need for Transmission Investment to Facilitate Wind Penetration

- The Department of Energy 20% Wind Study also developed projected transmission overlay projects needed to accommodate large scale wind development
- SPP completed its EHV Overlay study and identified potential high voltage transmission projects needed to facilitate 20,000 MW of wind development in the SPP region
- Given the history of transmission system expansion, and difficulty in gaining siting approval for high voltage regional projects, building sufficient new transmission facilities to facilitate wind generation will encounter a number of regulatory approval challenges

2030 - New Transmission Lines - WinDS Region Level - Simplified Corridors >= 100 MW





Source: DOE 20% Wind Study; SPP EHV Overlay Study

Midwest Major Transmission Expansion Projects

The anticipated impact of announced transmission system upgrades on area to area transfer limits were incorporated in the Fall 2009 electric price forecasting model (ProMod). These major projects are summarized below.

- PJM
  - Project Mountaineer
    - AEP Interstate Project : 550 miles, WVa to NJ
    - Trans-Allegheny Interstate Line (TrAIL) : 330 miles, SW PA, across West VA and into Northern VA
    - Potomac-Appalachian Transmission Highline (PATH) : 290 miles, from AEP's John Amos plant in southern West VA to the Kemptown substation in central Maryland
    - Mid-Atlantic Power Pathway (MAPP) : 220 miles, From VA, across Chesapeake Bay, up Delmarva Peninsula to NJ
    - In aggregate the impacts of Project Mountaineer were modeled as a 2000 MW increase in transfer capability between West Penn and PJM East beginning in 2013; a 3000 MW increase in transfer capability between Dominion and PJM East beginning in 2016; and, a 3000 MW increase in transfer capability between West PJM and Dominion beginning in 2016.

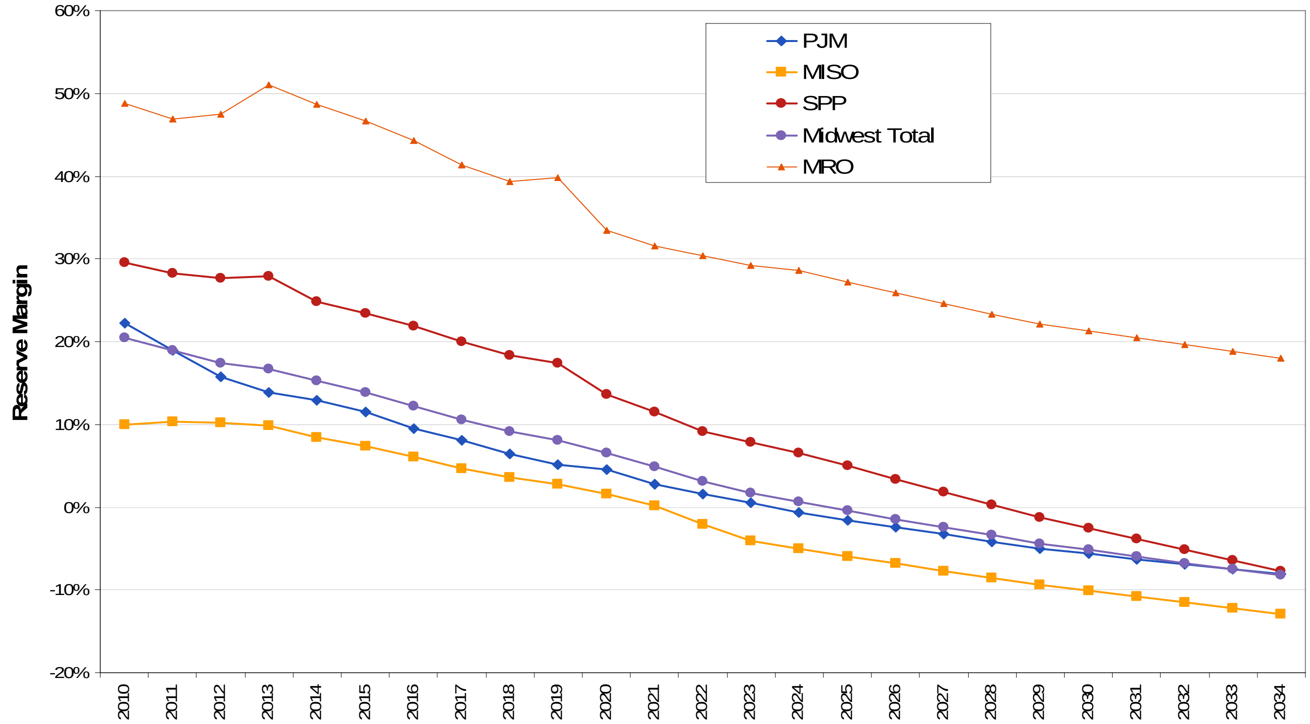
Midwest Market Areas

- The Midwest Energy Market Perspective is comprised of 20 distinct zonal pricing points for electricity
- Locations within each market area are assigned to a corresponding natural gas delivery basin
- Market Area assumptions and results are aggregated to the region level and entire Midwest level.

Region	Abbrev	Market Area	Gas Basin
Midwest ISO (MISO)	ILLINOIS	Illinois	Chicago
	INDIANA	Indiana	Dominion South
			Lebanon
	MISSOU	Missouri	Chicago
	FEMISO	FirstEnergy (MISO)	Lebanon
	ITC	Michigan	Dawn
			Lebanon
	ATC	American Transmission Company - Wisconsin	Ventura
			Chicago
			Dawn
	MINN	Minnesota	Ventura
			AECO
MRO	IOWA	Iowa	Ventura
	MHSP	Manitoba Hydro	AECO
	SASK	SaskPower	AECO
	WAPA	WAPA Control Area	Ventura
PJM Interconnect (PJM)	COED	Commonwealth Edison	Chicago
	EASTPJM	East PJM	Transco Z6 (NNY)
	PJMWEST	PJM West	Dominion South
			Lebanon
	WESTPENN	Western Pennsylvania	Transco Z6 (NNY)
	VIEP	Dominion	Transco Z5
Southwest Power Pool (SPP)	SPPLOUIS	SPP Louisiana	Henry Hub
	SPPN	SPP North	Chicago
			ANR SW
			Ventura
	SPPSOUTH	SPP South	ANR SW

Reserve Margin with No Generic Resource Expansion

- Overall, the Midwest will have healthy reserve margins for the next few years due to excess capacity and lower demand growth
- The chart on the right shows when new capacity maybe needed to come online in order to maintain reliability
- The NERC reliability standard of "1 day in 10 years" translates to about a 15% reserve margin.



Source: Black & Veatch

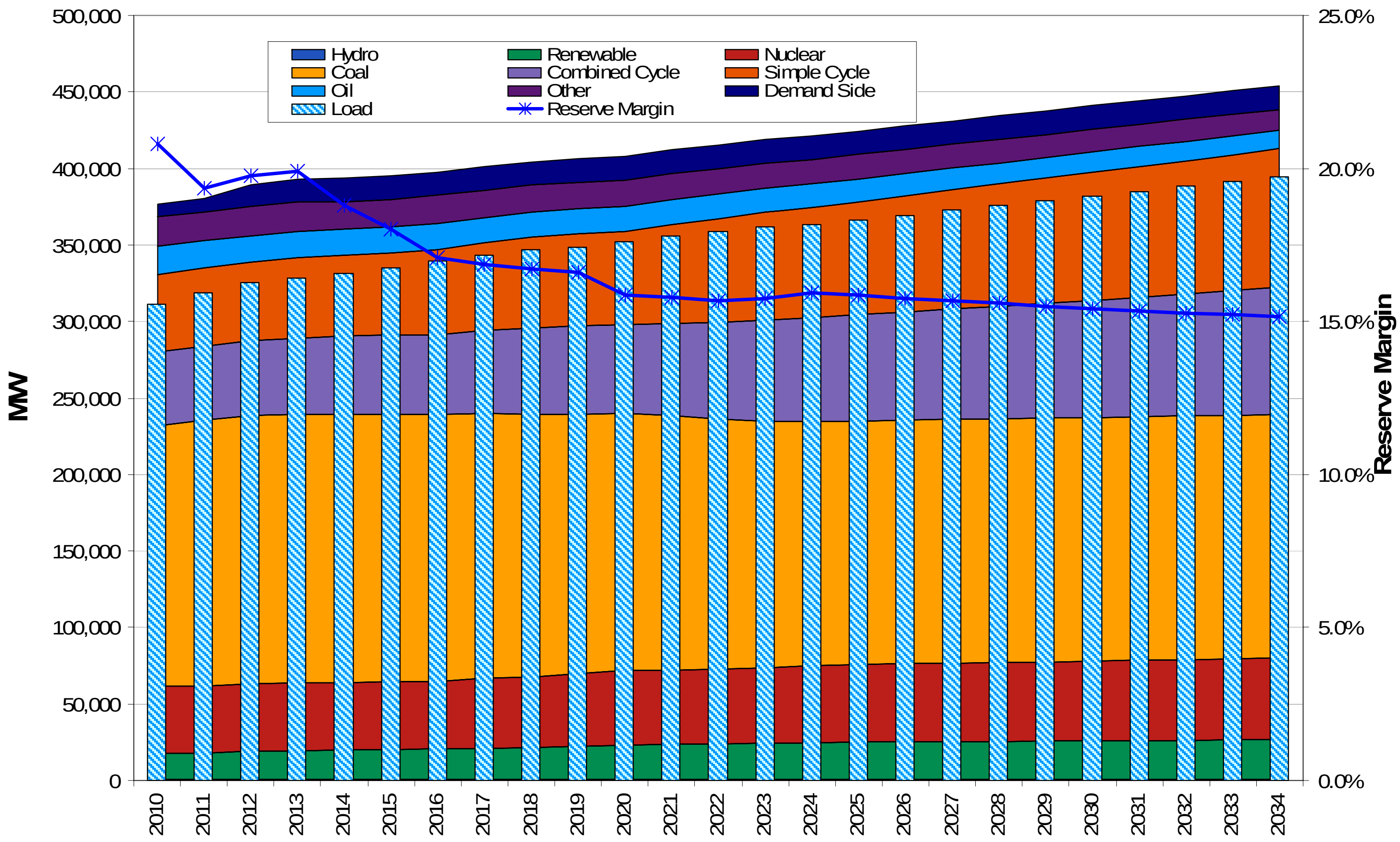
1 Assumes only the plants that are under construction or far enough along in the development process are built. The interconnection queues are much larger.

2. All resources are nameplate capacity except for wind (renewable) which has been de-rated to 20% of nameplate capacity

3. Based on coincident peak demand

4.2 Modeling Input Assumptions

Midwest Loads & Resource Outlook



Source: Black & Veatch

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2 Loads are shown for August peak load
3 Other units include Steam Oil and Gas, and Combustion Turbine Other.
4 After 2024 every 5th year was modeled. Used linear interpolation between 2024 and 2029 and then 2029 and 2034.
5 Renewable category includes all wind units, and all hydro units except for those excluded from being counted towards RPS compliance by state regulation.

Midwest 2010 Capacity Resource Summary

Midwest Resource Summary								
	MISO		MRO		PJM		SPP	
Unit Type	Capacity (MW)	% of Total	Capacity (MW)	% of Total	Capacity (MW)	% of Total	Capacity (MW)	% of Total
Hydro	379	0.3%	0	0.0%	0	0.0%	0	0.0%
Renewable	2,135	1.8%	9,253	34.8%	2,922	1.8%	2,941	4.7%
Nuclear	9,717	8.0%	576	2.2%	31,480	19.0%	2,421	3.9%
Coal	66,732	55.1%	10,623	39.9%	69,168	41.7%	23,596	38.1%
Combined Cycle	11,817	9.7%	1,833	6.9%	23,787	14.3%	10,781	17.4%
Simple Cycle	19,935	16.4%	2,106	7.9%	21,123	12.7%	7,596	12.3%
Oil	4,029	3.3%	800	3.0%	11,484	6.9%	1,604	2.6%
Other	3,295	2.7%	322	1.2%	3,691	2.2%	12,080	19.5%
Demand Side	3,175	2.6%	1,086	4.1%	2,157	1.3%	923	1.5%
Total Capacity	121,214		26,598		165,812		61,943	
Summer Peak Load	110,281		17,881		135,653		47,814	
Reserve Margin	9.9%		48.8%		22.2%		29.5%	

Source: Black & Veatch

- Wind in Renewable Unit Type is de-rated to 20% of nameplate for peak capacity accounting purposes

Midwest Coincident Peak and Energy Load Forecast

- **Demand Side Management is included in Annual Average Growth Rate**

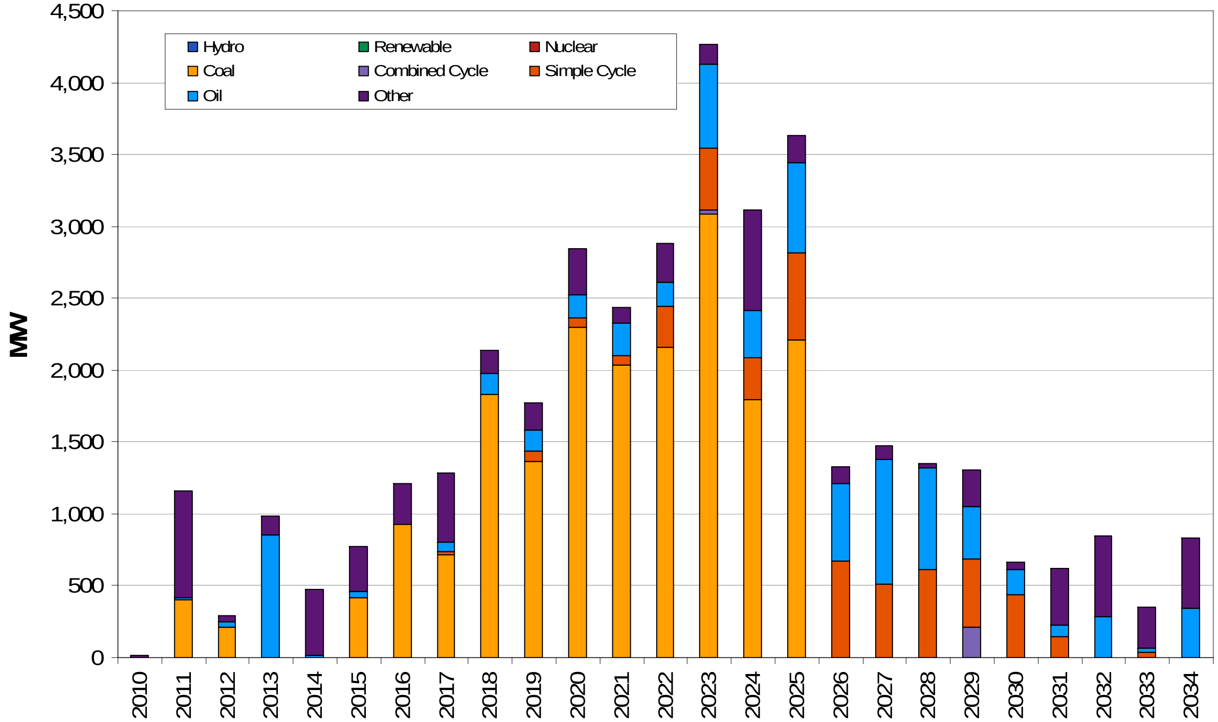
	PJM Interconnect		Midwest ISO		MRO		Southwest Power Pool	
	Peak (MW)	Energy (GWh)	Peak (MW)	Energy (GWh)	Peak (MW)	Energy (GWh)	Peak (MW)	Energy (GWh)
2010	129,850	713,364	110,281	564,848	17,881	110,152	47,814	221,816
2011	134,649	734,203	111,792	573,807	18,102	111,401	48,746	227,060
2012	139,924	759,755	112,539	580,399	18,354	112,521	49,405	231,431
2013	141,934	772,418	112,966	584,805	18,352	113,521	49,339	234,681
2014	141,939	784,242	113,979	586,031	18,656	114,497	50,537	237,698
2015	143,327	794,383	114,890	591,033	18,836	115,703	51,099	240,558
2016	146,879	806,740	115,927	597,131	19,030	116,770	51,634	243,839
2017	148,929	814,315	116,937	602,146	19,212	117,844	52,165	245,485
2018	151,230	824,024	117,612	608,164	19,464	118,944	52,660	249,825
2019	152,342	832,559	118,052	612,422	19,423	119,737	52,523	252,569
2020	151,884	844,518	119,446	616,732	19,665	120,531	53,760	255,357
2021	154,602	850,906	120,249	621,098	19,790	121,335	54,309	258,190
2022	156,621	859,345	121,057	625,520	19,917	122,144	54,858	261,061
2023	158,187	866,917	121,879	629,995	20,035	122,968	55,414	263,981
2024	159,454	876,765	122,089	634,523	20,052	123,796	55,230	266,949
2025	160,674	884,271	123,018	639,224	20,219	124,654	55,951	270,053
2026	161,894	891,777	123,946	643,924	20,386	125,513	56,673	273,158
2027	163,113	899,284	124,875	648,625	20,553	126,372	57,394	276,262
2028	164,333	906,790	125,803	653,325	20,720	127,230	58,116	279,367
2029	165,553	914,296	126,732	658,026	20,887	128,089	58,837	282,471
2030	166,845	922,206	127,711	663,033	21,018	128,996	59,461	285,821
2031	168,136	930,116	128,690	668,040	21,149	129,902	60,086	289,171
2032	169,428	938,027	129,668	673,047	21,280	130,809	60,710	292,522
2033	170,719	945,937	130,647	678,053	21,411	131,716	61,335	295,872
2034	172,011	953,847	131,626	683,060	21,542	132,622	61,959	299,222
Annual Average Growth Rate	1.18%	1.22%	0.74%	0.79%	0.78%	0.78%	1.09%	1.26%

Source: Black & Veatch

* Assumptions are an aggregate of each EMP Area.

Midwest Retirements by Year

- Nuclear units are assumed to get license extensions and have a life span of 75 years
- Coal units over 100 MW are assumed to have a life span of 75 years.
- All relatively inefficient coal units were retired between 2014 and 2024. Total retirements is 19 GW. Assumption based on expectations for future carbon legislation.



Source: Black & Veatch

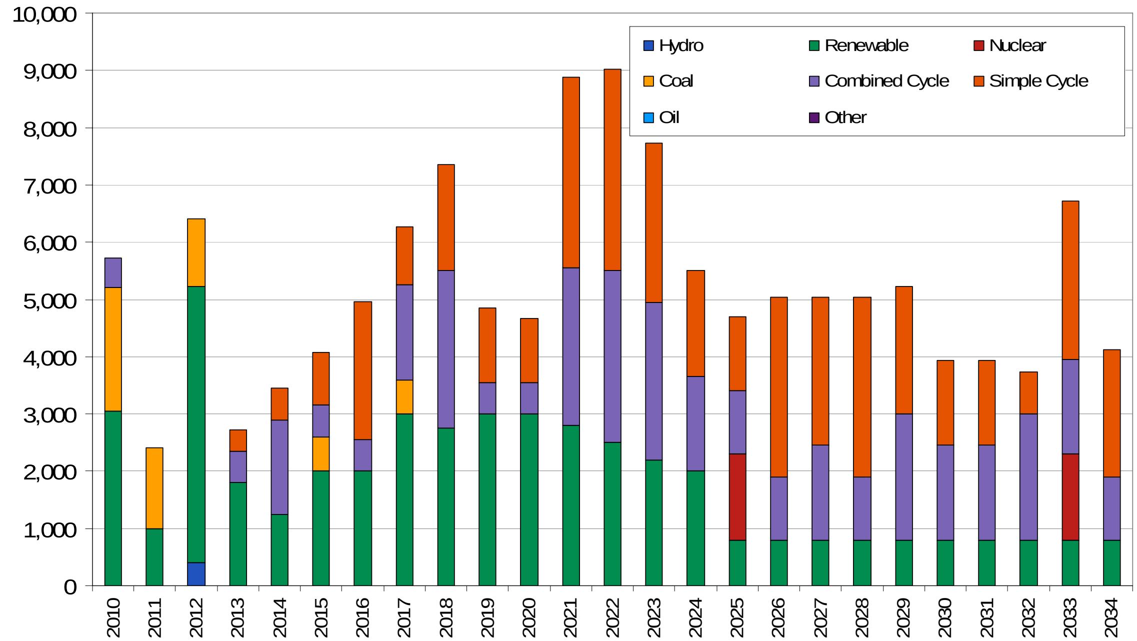
1 Other units include Steam Oil and Gas, and Combustion Turbine Other

2 Assumptions are an aggregate of each EMP Area.

- Large CT over 50 MW, and large CC over 100 MW are assumed to have a life span of 65 years.
- Small CT under 50 MW, CC generators under 100 MW, Diesel generators, and all other fossil fueled units are assumed to retire at 55 years.
- Renewable Generation assumed to not retire or be replaced with like generation.

Midwest Expansion by Year

- For the Midwest generic expansion, in general, generic units were added to maintain an overall 15 percent reserve margin in the Midwest footprint.
- However, the MISO and PJM regions were getting low on capacity in 2013 so units were added to these regions before the broader Midwest reserve margin decreased to 15 percent.
- Resources were added to the ISO areas with the lowest reserve margins first. Within a ISO, resources were added to the Market Areas with the lowest reserve margin first.
- Significant renewable additions to meet RPS.



Source: Black & Veatch
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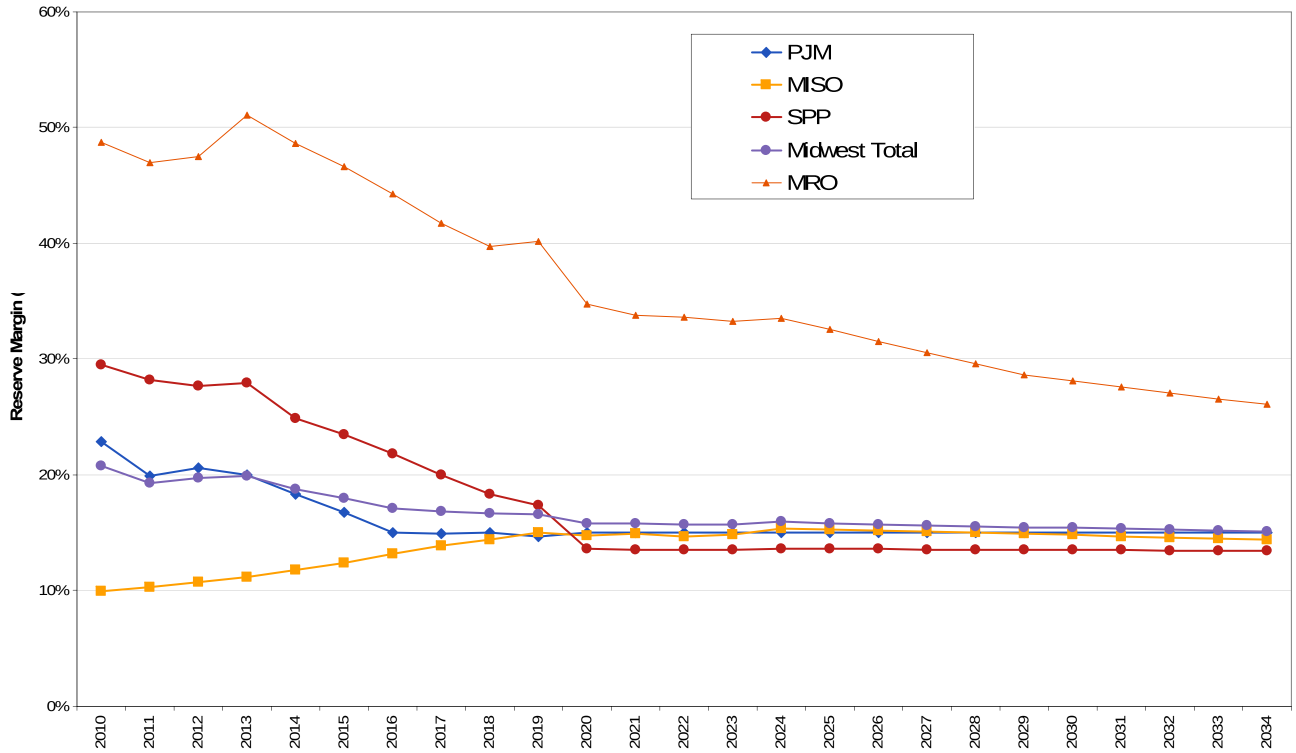
2 Assumptions are an aggregate of each EMP Area.
3 After 2024 every 5th year was modeled. Used linear interpolation between 2024 and 2029 and then 2029 and 2034.
4. All resources are reported as name plate capacity.

Reserve Margin with Resource Expansion

- Overall, the Midwest will have healthy reserve margins for the next few years due to excess capacity and lower demand growth
- The chart on the right shows when new capacity maybe needed to come online in order to maintain reliability
- The NERC reliability standard of “1 day in 10 years” translates to about a 15% reserve margin.

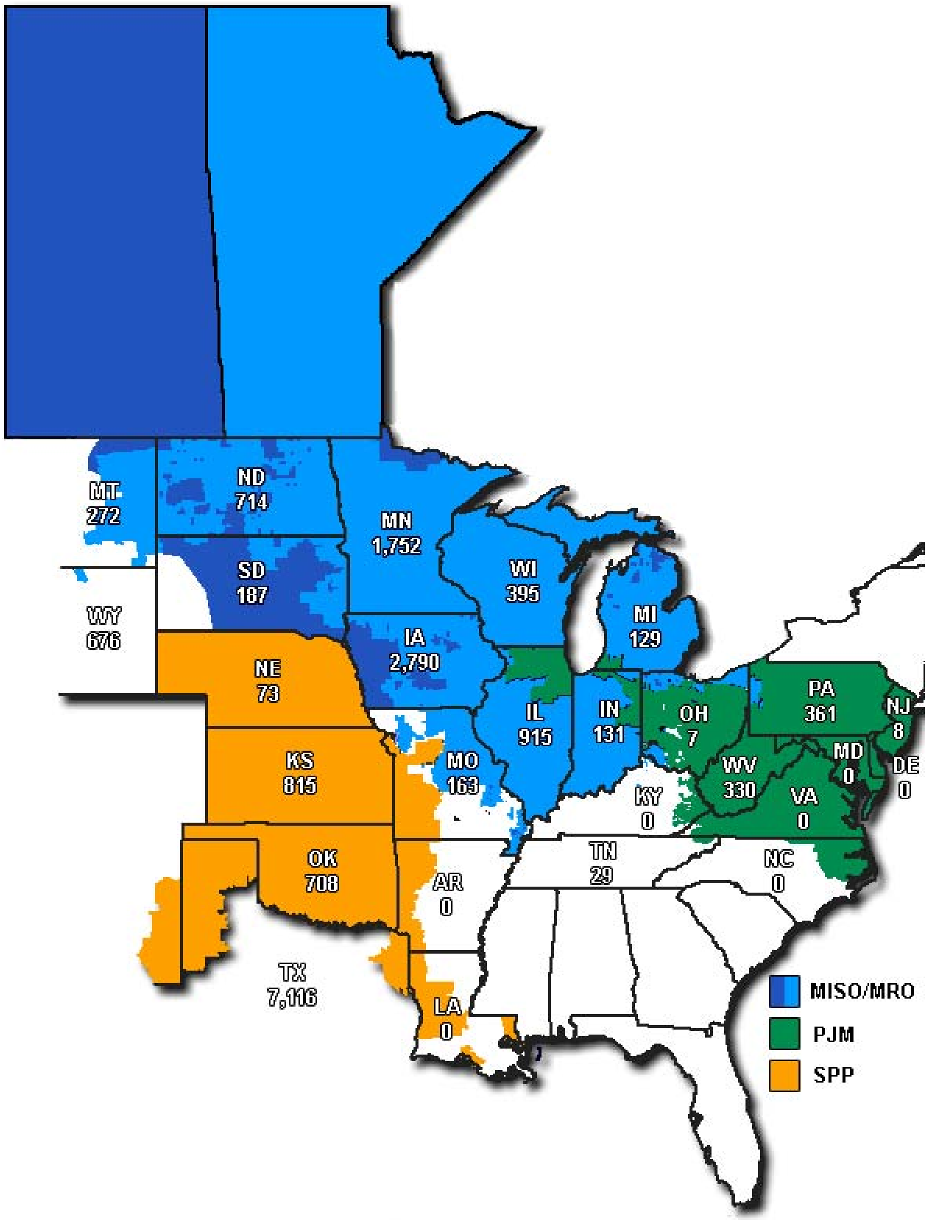


Source: Black & Veatch

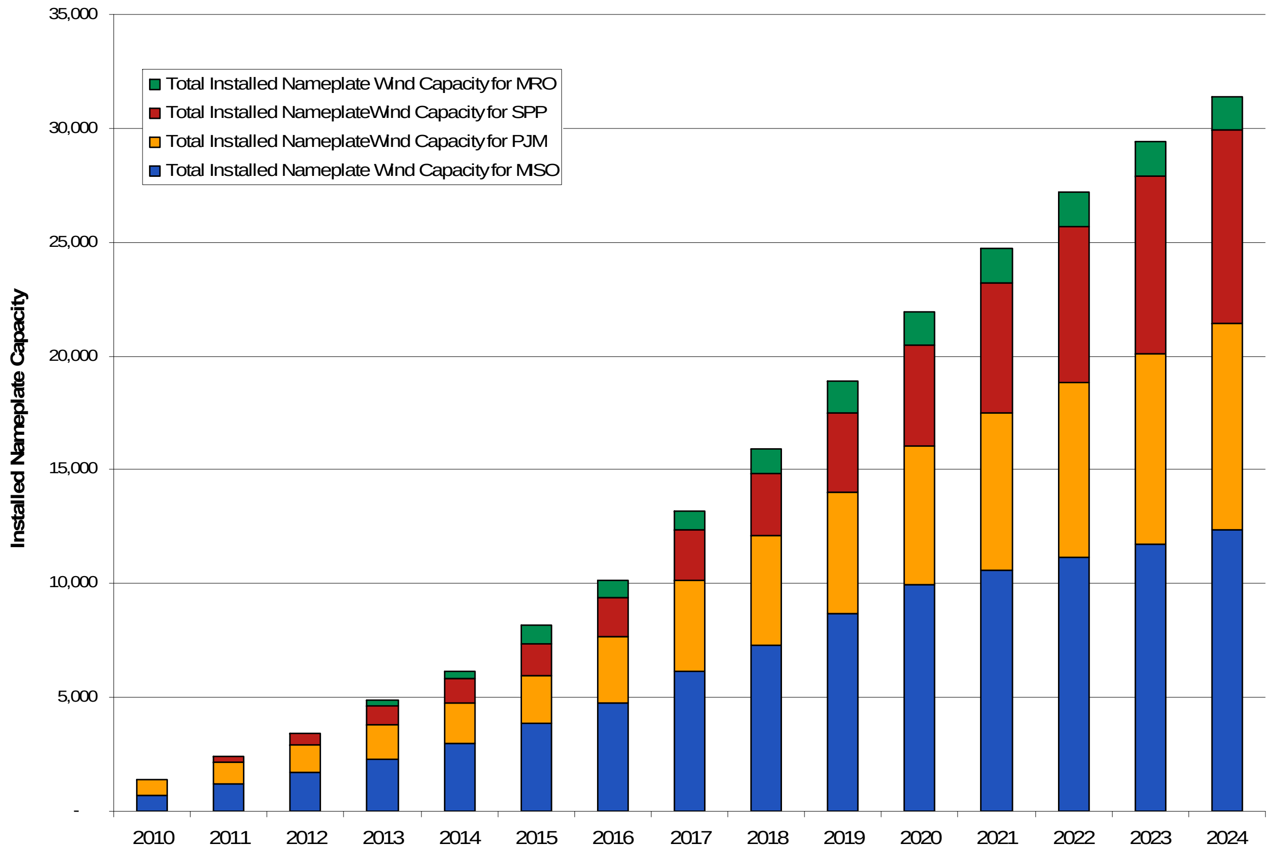
* All resources are nameplate capacity except for wind (renewable) which has been de-rated to 20% of nameplate capacity

Existing Wind Resources

- In the Midwest, Minnesota and Iowa have more than 1000 MW of nameplate wind capacity installed.
- Other states such as Kansas, Illinois, Oklahoma and North Dakota also have significant wind capacities.
- Most of the wind capacity additions were done during the last few years.



Renewable Resources Added in the Last 10 Years (Nameplate Capacity in MW)



Source: Energy Velocity

Wind Potential

- MISO and SPP have the most potential for development of new wind capacity.
- States that have limited potential for in-state renewable resources sites are expected to purchase renewable generation or credits from resources located outside their state to meet RPS.
- Significant transmission infrastructure upgrades would be needed to meet the full wind energy potentials to transfer the energy to the demand areas.

States With Maximum Potential (MW)

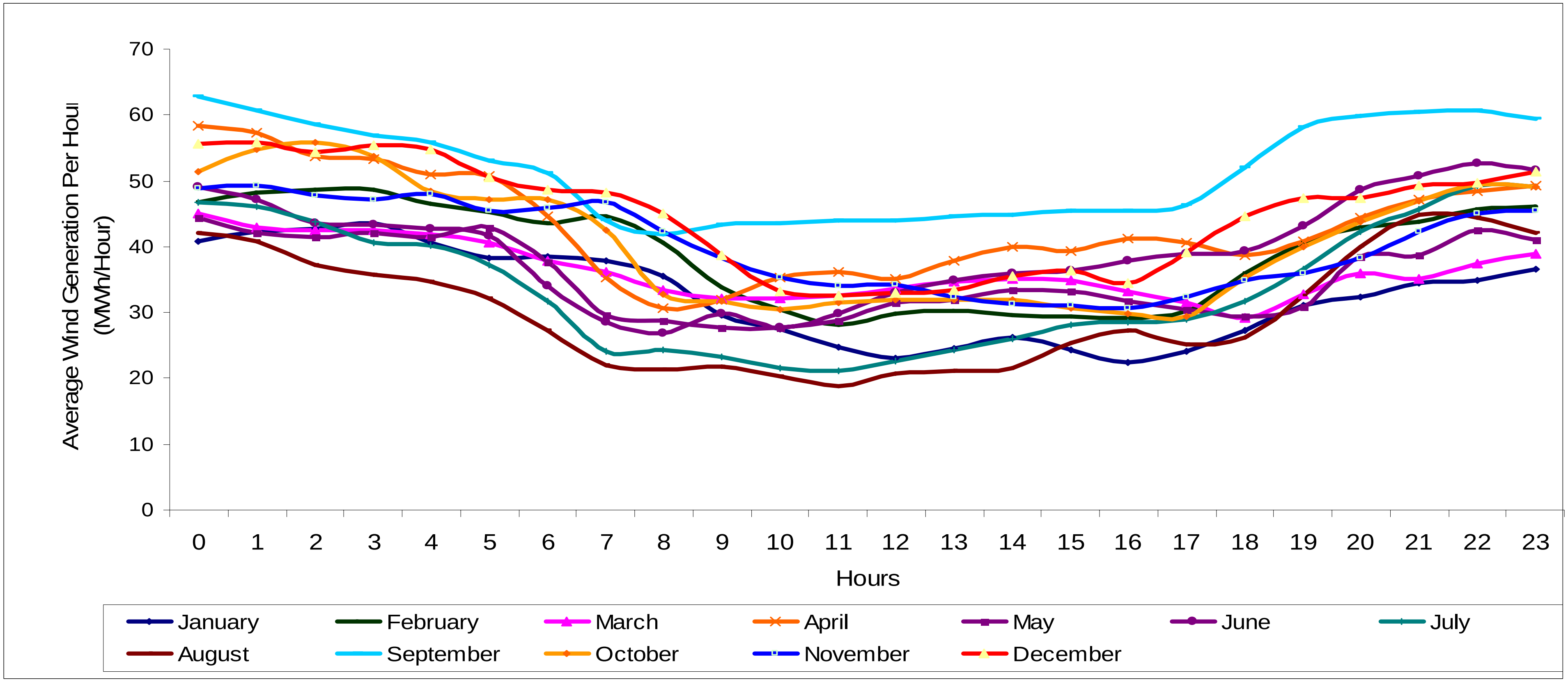
Iowa	62,900
Minnesota	75,000
Illinois	7,000
Kansas	122,000
North Dakota	138,000
Oklahoma	82,700
Wisconsin	6,500
Michigan	7,500

Source: www.awea.org

Assumptions for MW for Meeting the RPS Requirements

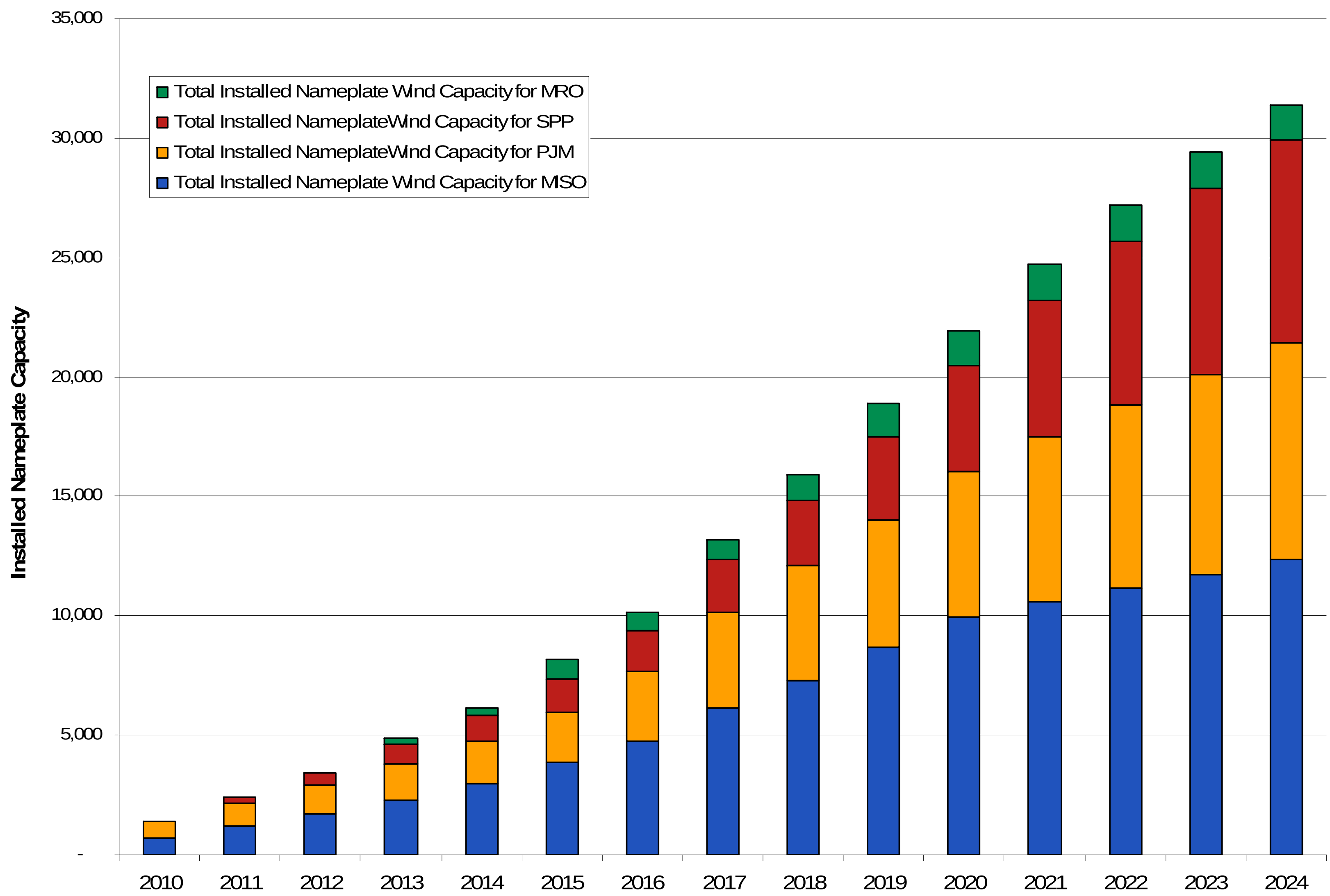
- In 2007 and 2008, the total wind resources added in the MISO region was around 700 MW and 2,400 MW respectively. It is assumed that MISO would be able to add, on average, 2,000 MW of wind energy resources every year for 2014 and onwards.
- Based on historical trends, it is assumed that on average 700 MW and 1000 MW of wind resources can be added in SPP and PJM every year respectively.
- Wind farm additions would be lumpy in regions with most potential; trading of RECs and development of new transmission corridors would enable transfer of energy within regions.
- Average wind capacity factor for the MW/SE region is 35%.
- Operating fixed cost (FOM) excluding capital cost is assumed to be $51/kw-year (2009 dollars) or $17/MWh (approx) at 35% CF.
- Based on the RPS requirements and goals for the different states, it is assumed that the MW region would try to achieve at least 10% generation by 2015 and 15% by 2020 from renewable resources.

Typical Wind Profile for MW



Wind is typically counter cyclic to electricity demand as wind generation tends to be higher in off-peak hours.

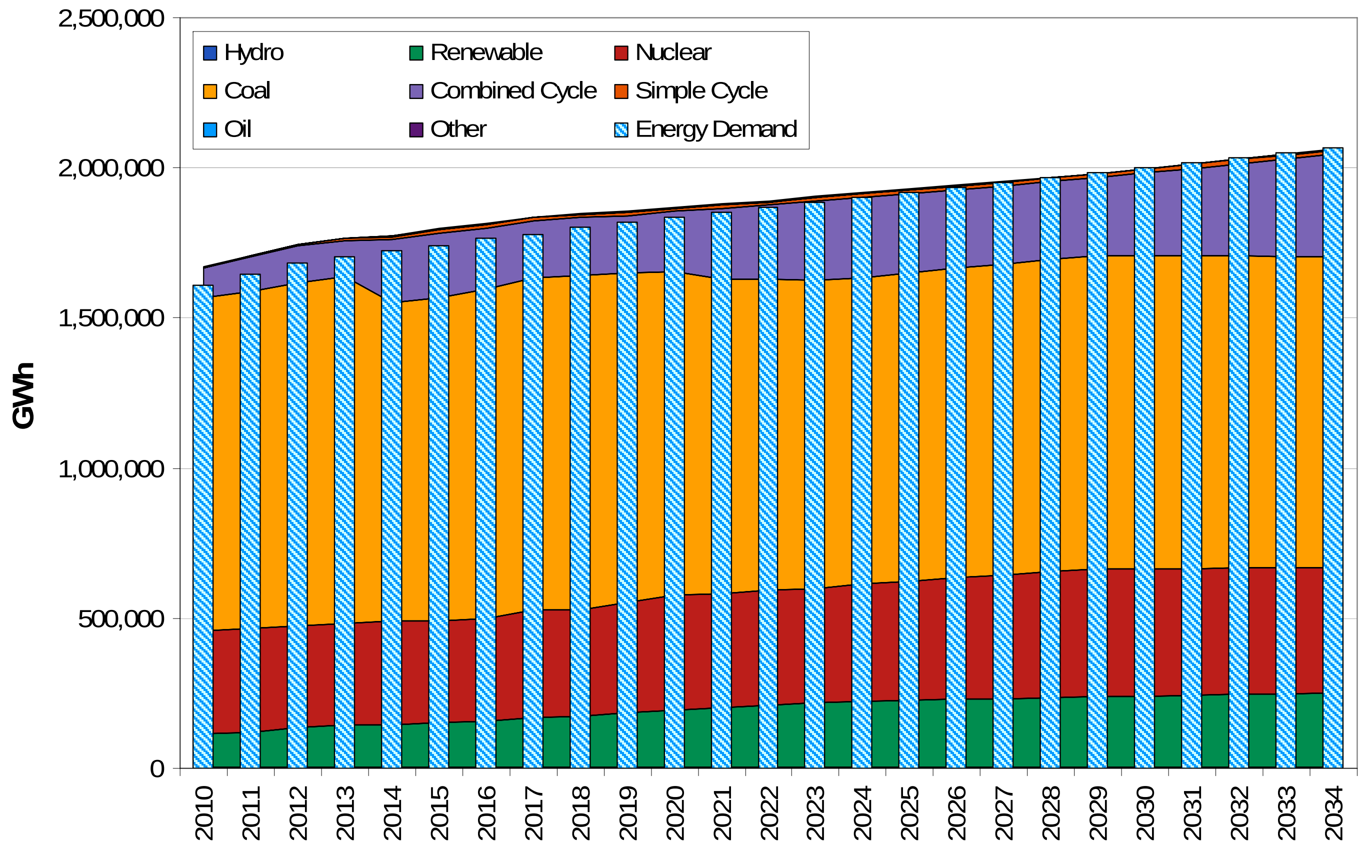
Renewable Resources Additions (Nameplate Capacity, MW)



4.3 Modeling Results and Analysis

Midwest Energy Demand and Generation by Unit Type

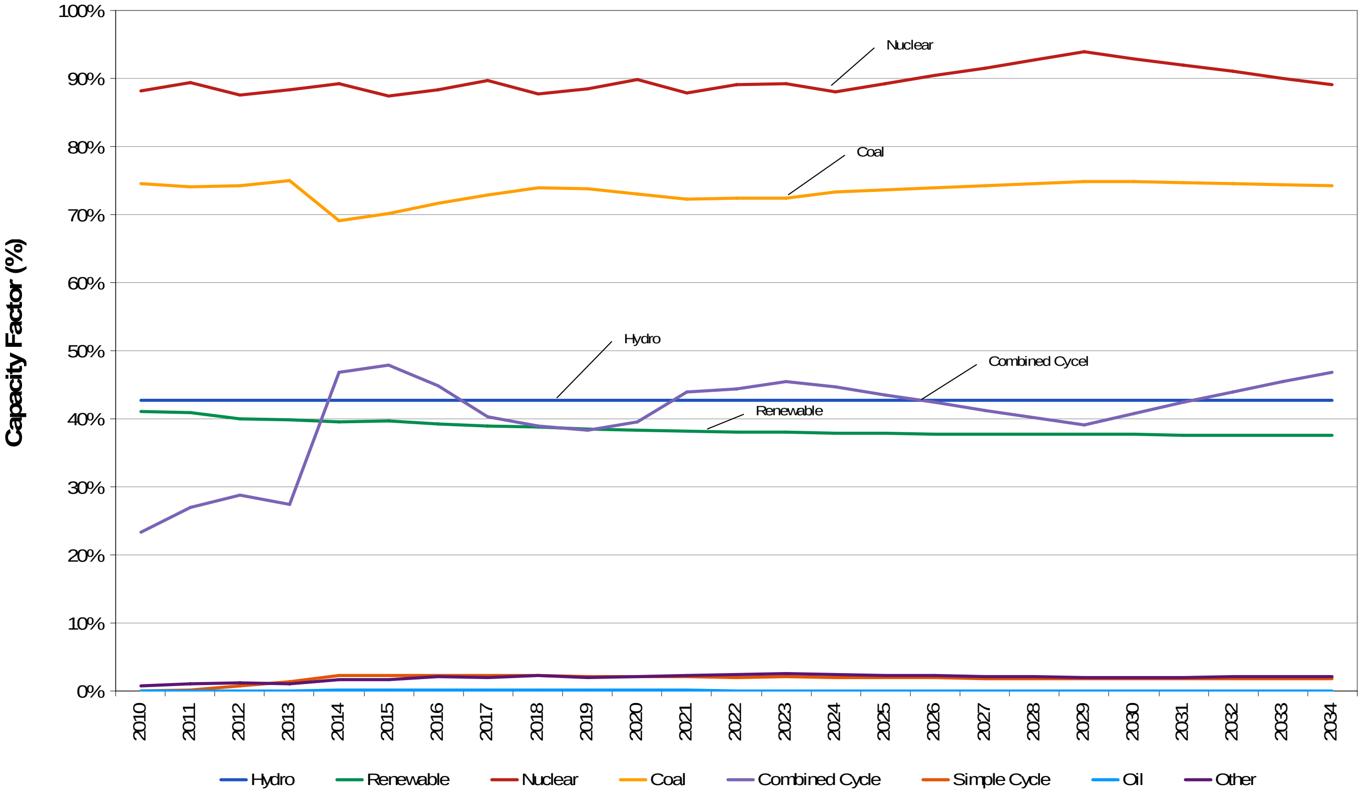
- Coal generation remains the predominant source generation in the Midwest.
- Increase in CC generation in 2014, same year as CO_2 legislation is implemented
- Renewable energy use in the form of wind generation increases to about 12% of the total generation.



Source: Black & Veatch
1 Other units include Steam Oil and Gas, and Combustion Turbine Other
2 Results are an aggregate of each EMP Area.
3 After 2024 every 5th year was modeled. Used linear interpolation between 2024 and 2029 and then 2029 and 2034
4 Renewable category includes all wind units, and all hydro units except for those excluded from being counted towards RPS compliance by state regulation.

Midwest Fleet Average Capacity Factor

- Combined Cycle CF utilization increases over time caused by demand growth.
- Minor drop in CF% for Coal in 2014 caused by CO_2 allowance cost increase to $20/short ton, however coal-fired generation will still be dispatched before natural gas-fired generation



Source: Black & Veatch

1 Other units include Steam Oil and Gas, and Combustion Turbine Other

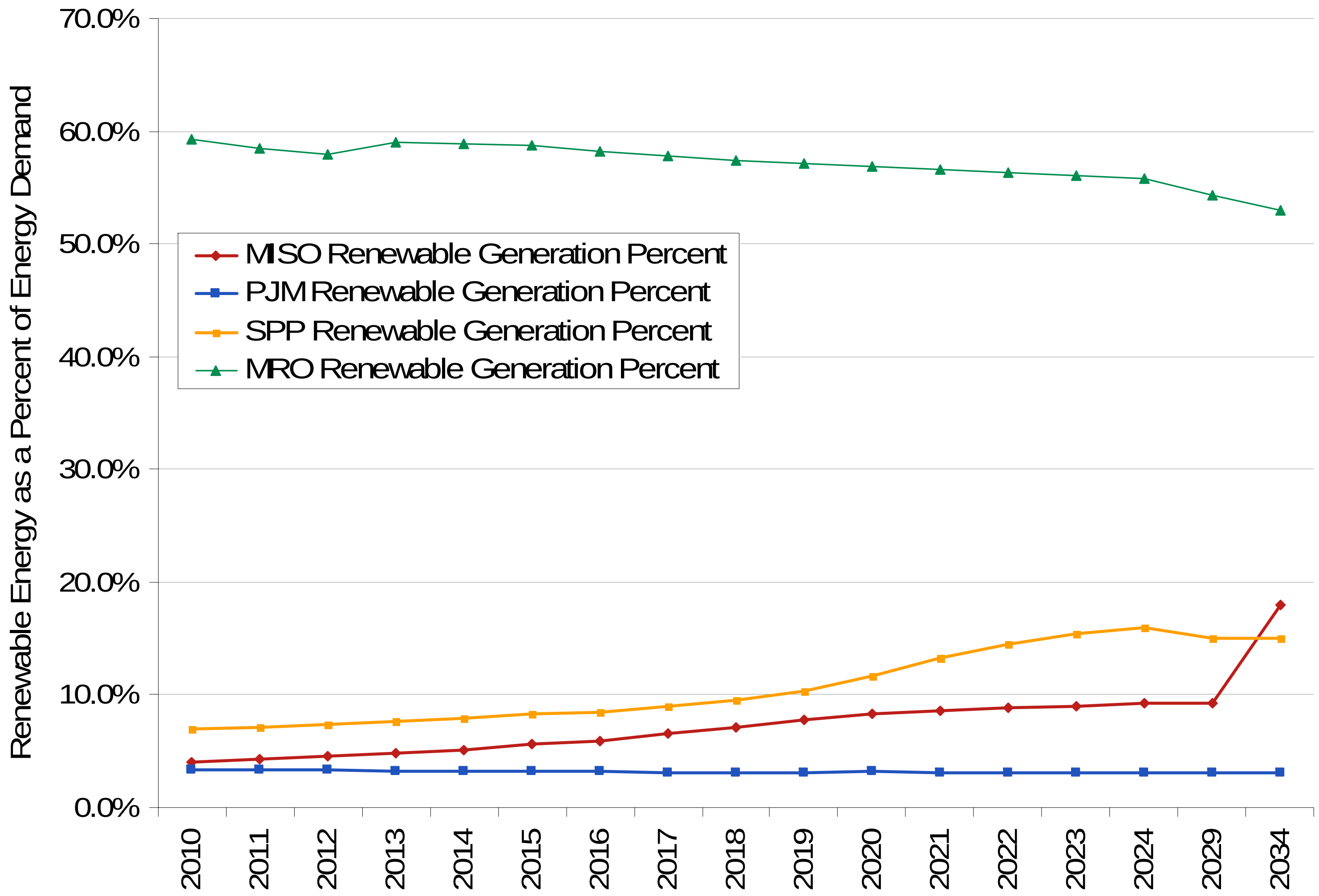
2 Results are an aggregate of each EMP Area.

3 After 2024 every 5th year was modeled. Used linear interpolation between 2024 and 2029 and then 2029 and 2034.

4. Renewable category includes all wind units and hydro units which can be counted towards RPS credits

- Combustion turbines run at 2% CF or less and only operate during the peak hours.
- Wind plants are assumed to produce energy at a 35% capacity factor.

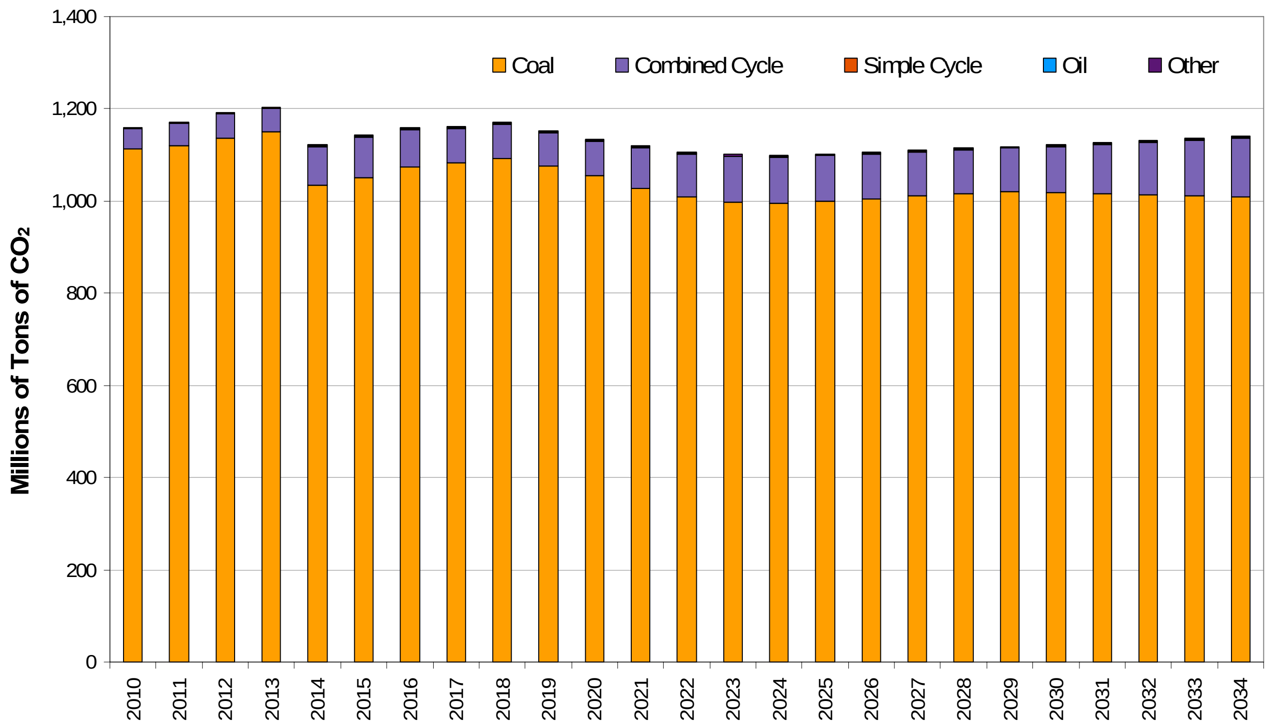
Renewable Energy Generation As a Percent of Energy Demand



Will MW Fulfill RPS Requirements?

- MW/SE region will partially fulfill RPS requirements by 2020.
- Overall the MISO Region is projected to achieve 20% RPS target by 2020. During this time period, SPP will achieve 15%; PJM - 6%.
- To achieve these RPS levels, installed nameplate wind capacity will need to more than tripled from 21,000 MW in 2008 to about 68,000 MW in 2020. (Additional 47,000 MW)
- Adding an additional 47,000 MW of wind resources will only account for 9,400 MW of firm capacity based on a twenty percent firm criteria. Capacity additions through conventional resources would still be required to meet the reliability standards.
- Turbine manufacturing capacity may need to increase to support the build assumed.
- Transmission facilities would also need to be permitted and constructed

Midwest CO2 Emissions by Unit Type



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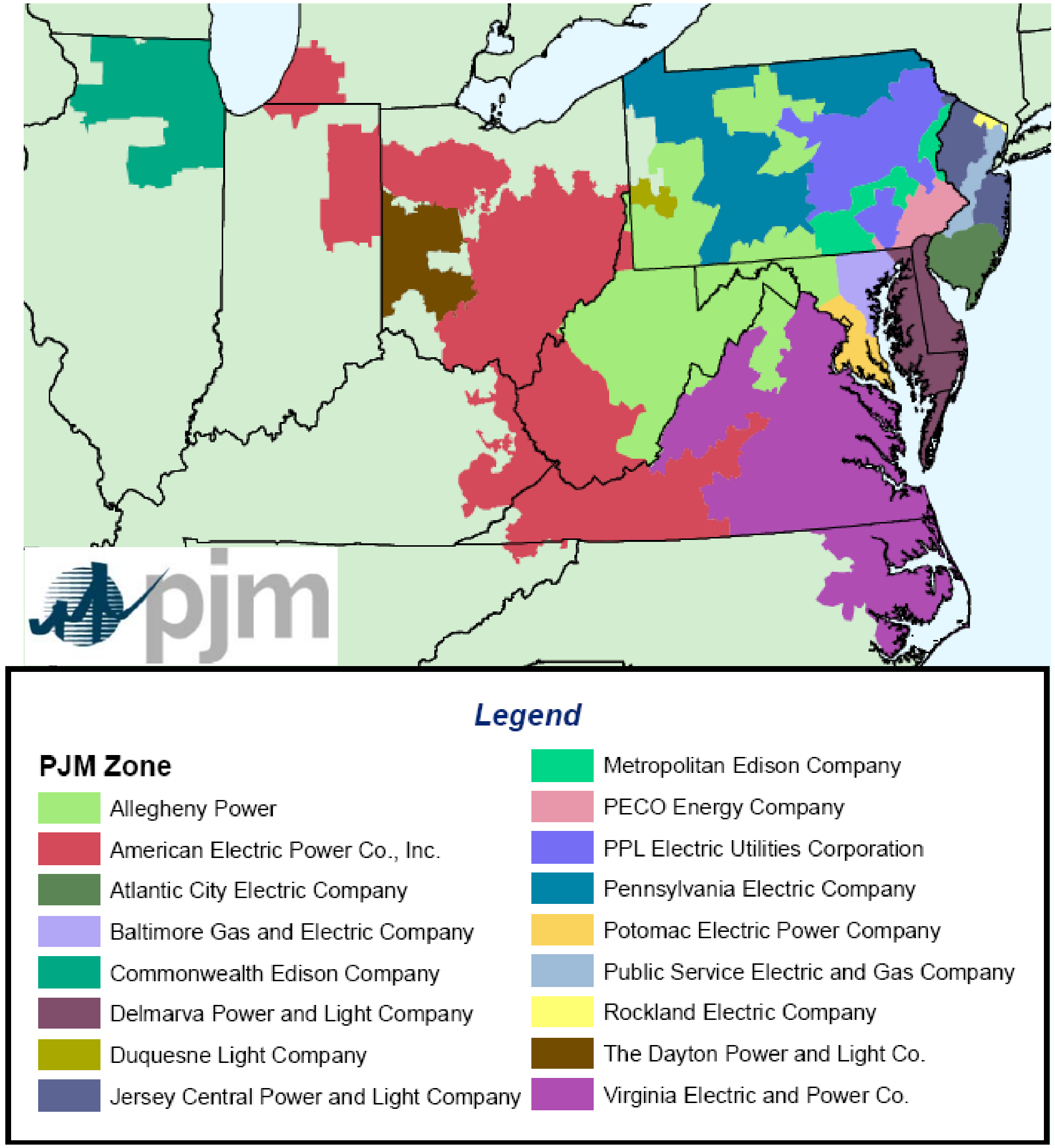
3 After 2024 every 5th year was modeled. Used linear interpolation between 2024 and 2029 and then 2029 and 2034.

- Carbon allowance cost has impact on CO2 for the Midwest
- Most of the drop comes from MISO, MRO and SPP
- PJM CO2 stays about constant

4.4 PJM Interconnect Results

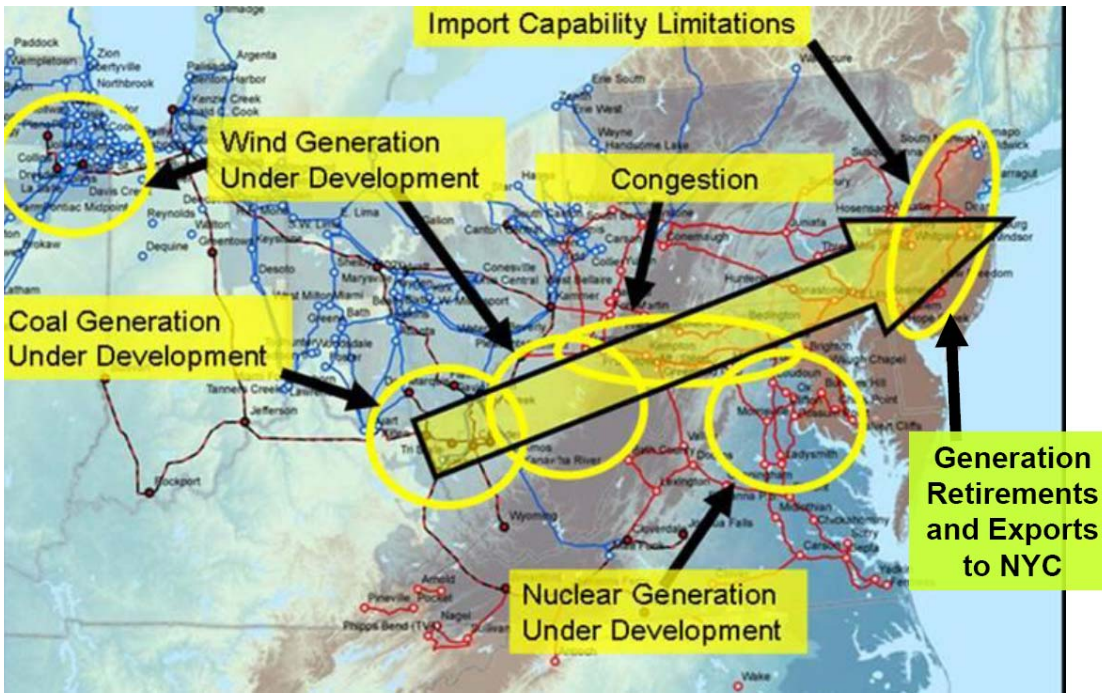
PJM At a Glance

- Regional Transmission Organization (RTO) for 13 states and DC
  - Balances: Generation, Transmission and Demand
  - Functions as data clearinghouse and decision maker
- 163,500 MW of Firm Capacity
- ~1,200 Generation Units
- 56,350 miles of transmission
- 168,500 Sq Miles of Territory



PJM Current Events

- Jan 2009: PJM evaluates the potential impact of climate control legislation and, among many scenarios, considers 15,000 MW of wind by 2013 (1/3 of generation in the interconnection queue)



- Currently about 40% of all projects proposed in PJM involve wind generation
- In Dec 2008 PJM approved $1.6 Billion for Transmission system additions and upgrades including:
  - 500-kV lines in NJ by 2013 (Somerset county to Hudson county, passing through Essex county)
  - HVDC for part of the Mid-Atlantic Power Pathway. (between Clavert Cliffs in Maryland to the Delmarva Peninsula)
- Conduct first long-term FTR Auction in October 2008

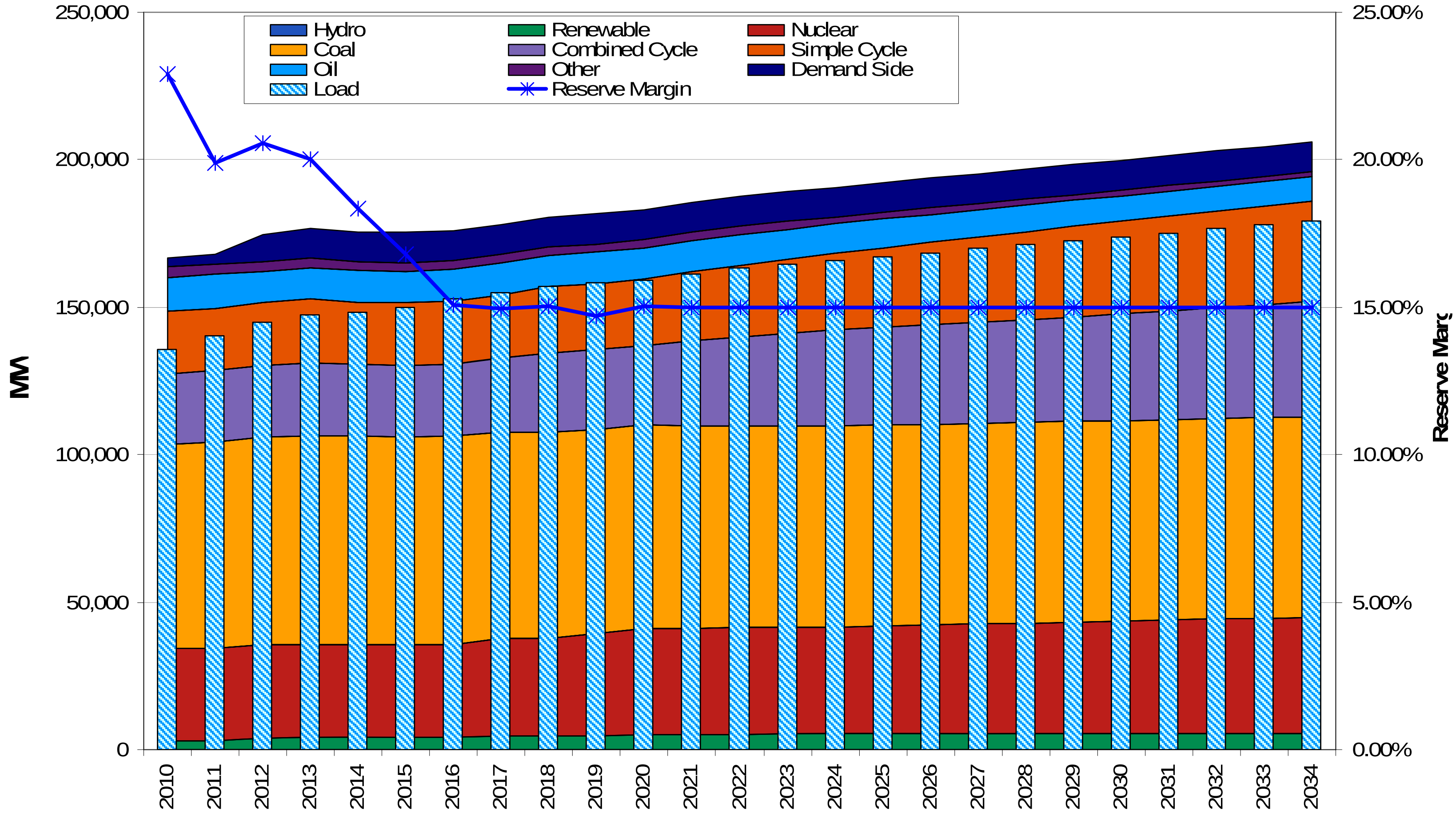
PJM Current Trends

- Demand is expected to grow more than 22,000 MW (16%) in the next decade
- Already shows reliability violations (NJ, PA, Delaware, Maryland, Virginia, and DC)
- PJM supports a Reliability Pricing Model - RPM (3 years forward look for capacity, with locational pricing to attract capacity development)
- Demand Response is being seen as a viable alternative in the area
- PJM is co-sponsoring research into Vehicle to Grid (V2G) connections to use hybrid cars as "batteries on the grid" to supplement the system during peaks in the region. (MAGIC- the Mid-Atlantic Grid Interactive Car)

PJM Markets Features

- RTO/ISO since December 2002
- Nodal Pricing since April 1998
- Real-time and Day-Ahead Energy Markets
- Capacity Credit Market-RPM Since June 2007
- Ancillary Services Markets for Regulation and Spinning Reserves
- Transmission Congestion hedged through FTRs
  - entitle holder to revenues or charges based on the hourly congestion price differences across a transmission path in the Day-Ahead Energy Market

PJM Interconnect Loads & Resource Outlook



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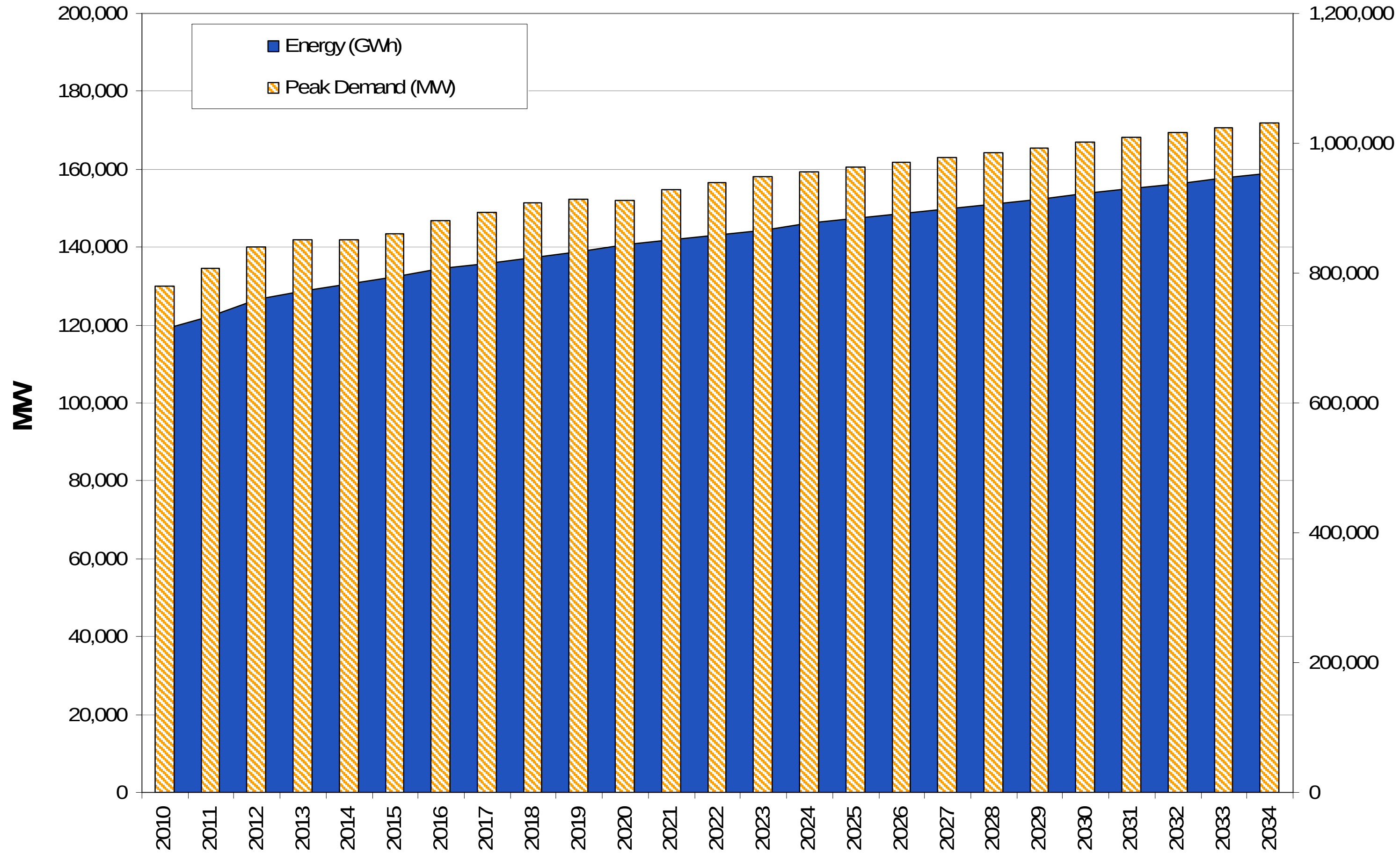
5 Renewable category includes all wind units, and all hydro units except for those excluded from being counted towards RPS compliance by state regulation.

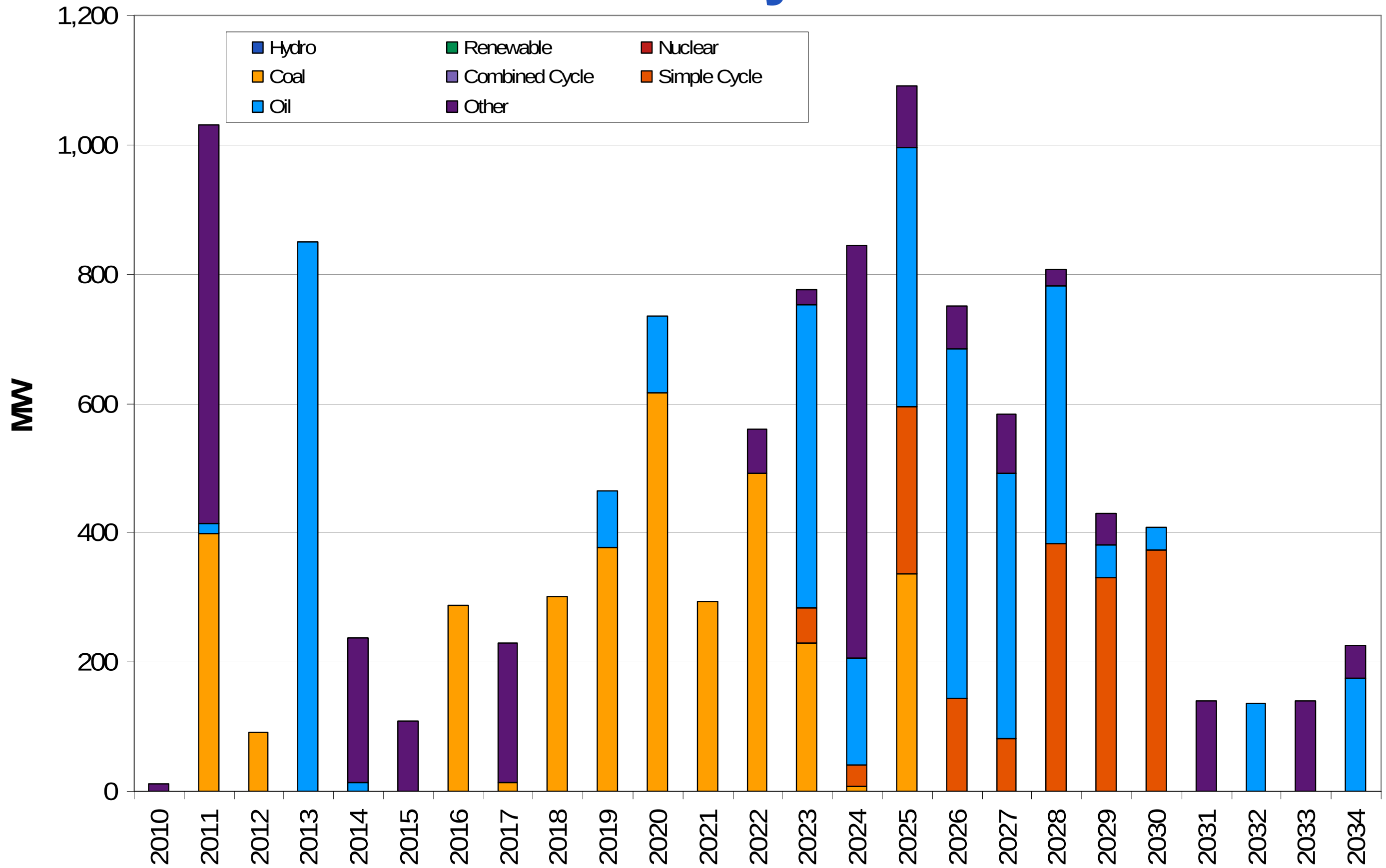
PJM Peak and Energy Load Forecast



Source: Black & Veatch

* Assumptions are an aggregate of each EMP Area.

PJM Interconnect Retirements by Year



Source: Black & Veatch

1 Other units include Steam Oil and Gas, and Combustion Turbine Other.

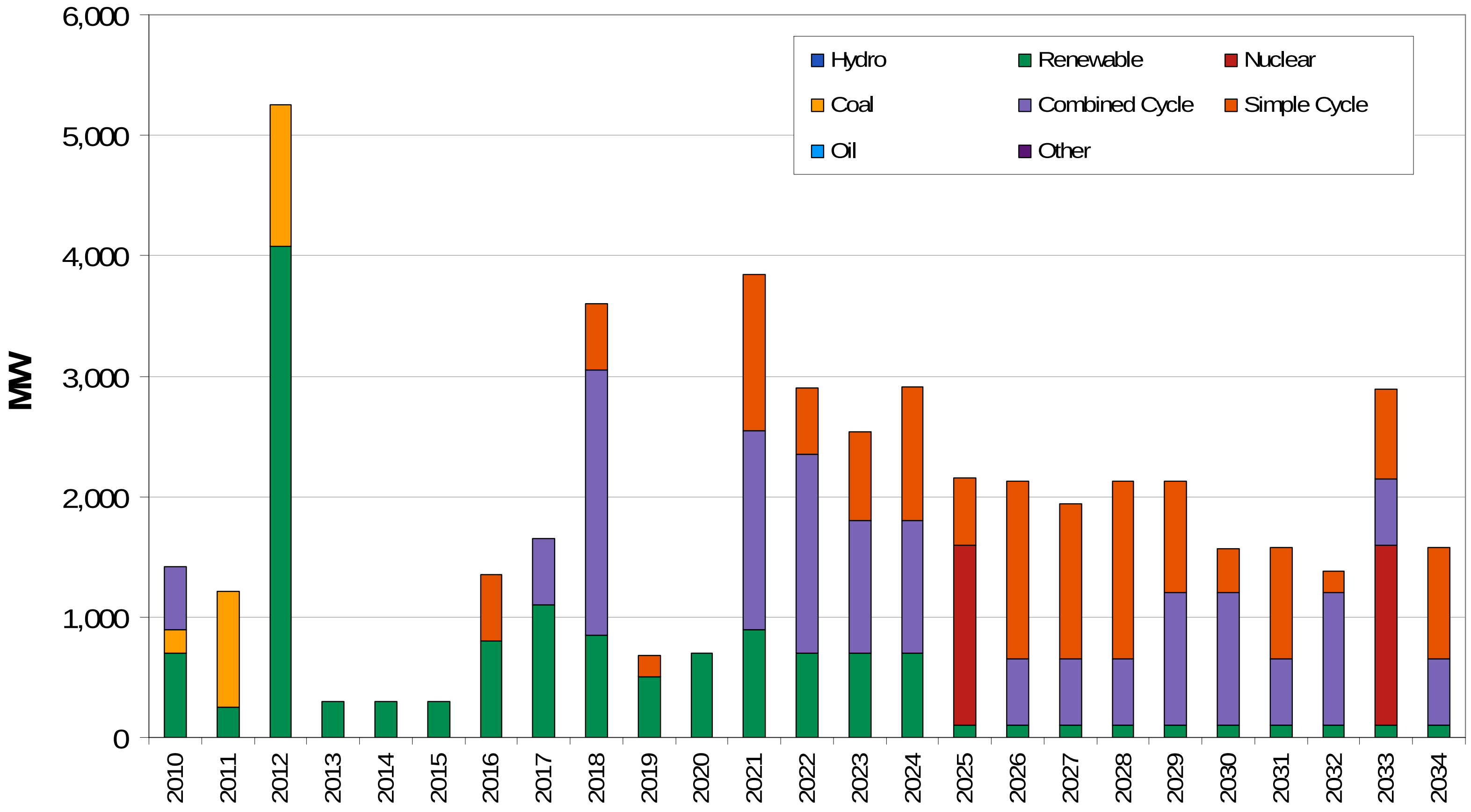
2 Results are an aggregate of each EMP Area.

- Over 11,500 MW of cumulative capacity is retired by 2034

  Coal – 3,500 MWCT – 1,700 MW

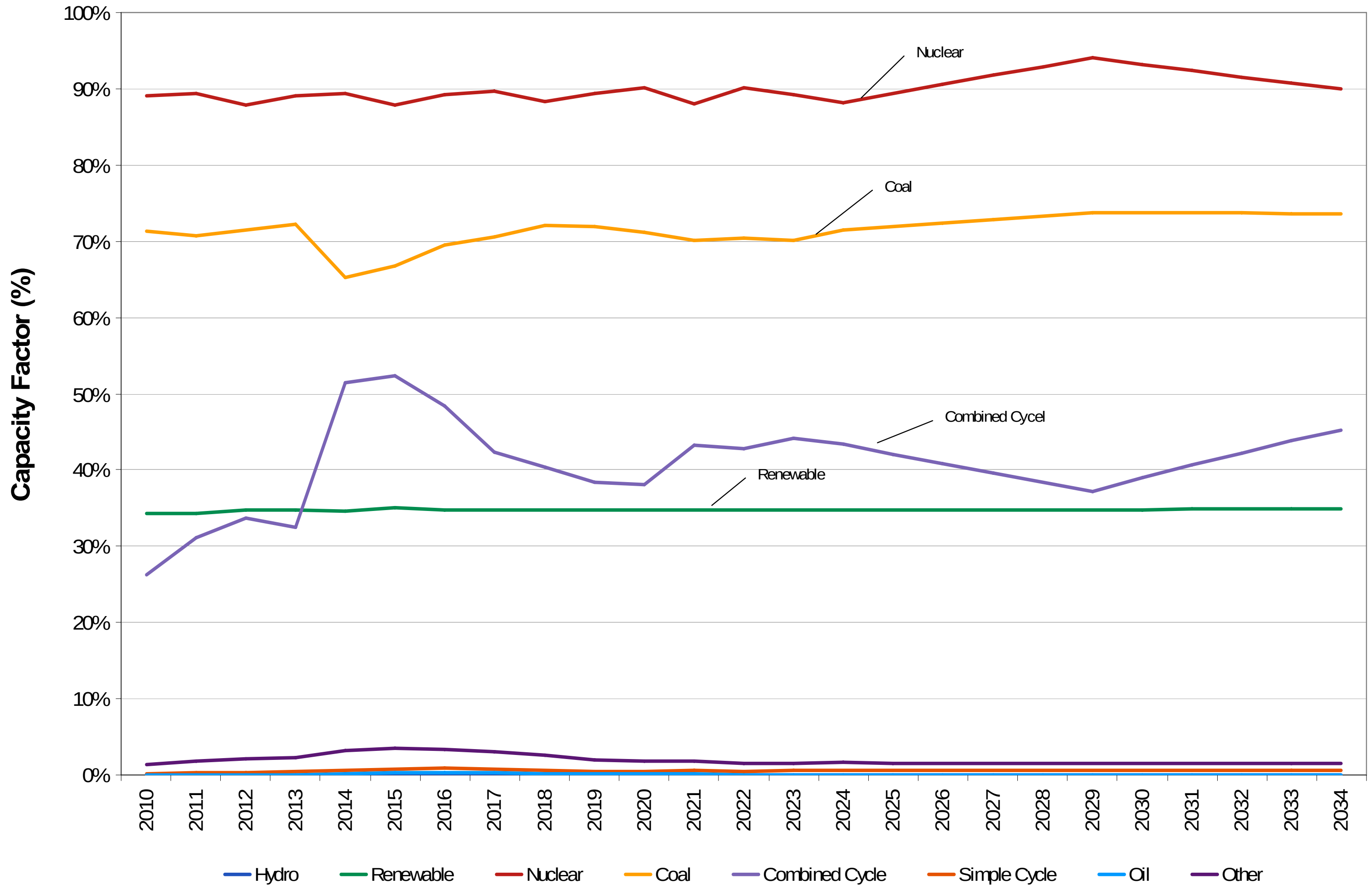
  Oil - 3,900 MW Other –2,500 MW

PJM Expansion by Year



Source: Black & Veatch
1 Other units include Steam Oil and Gas, and Combustion Turbine Other
2 Assumptions are an aggregate of each EMP Area.
3 After 2024 every 5th year was modeled. Used linear interpolation between 2024 and 2029 and then 2029 and 2034.
4. All resources are reported as name plate capacity

PJM Interconnect Fleet Average Capacity Factor



Source: Black & Veatch

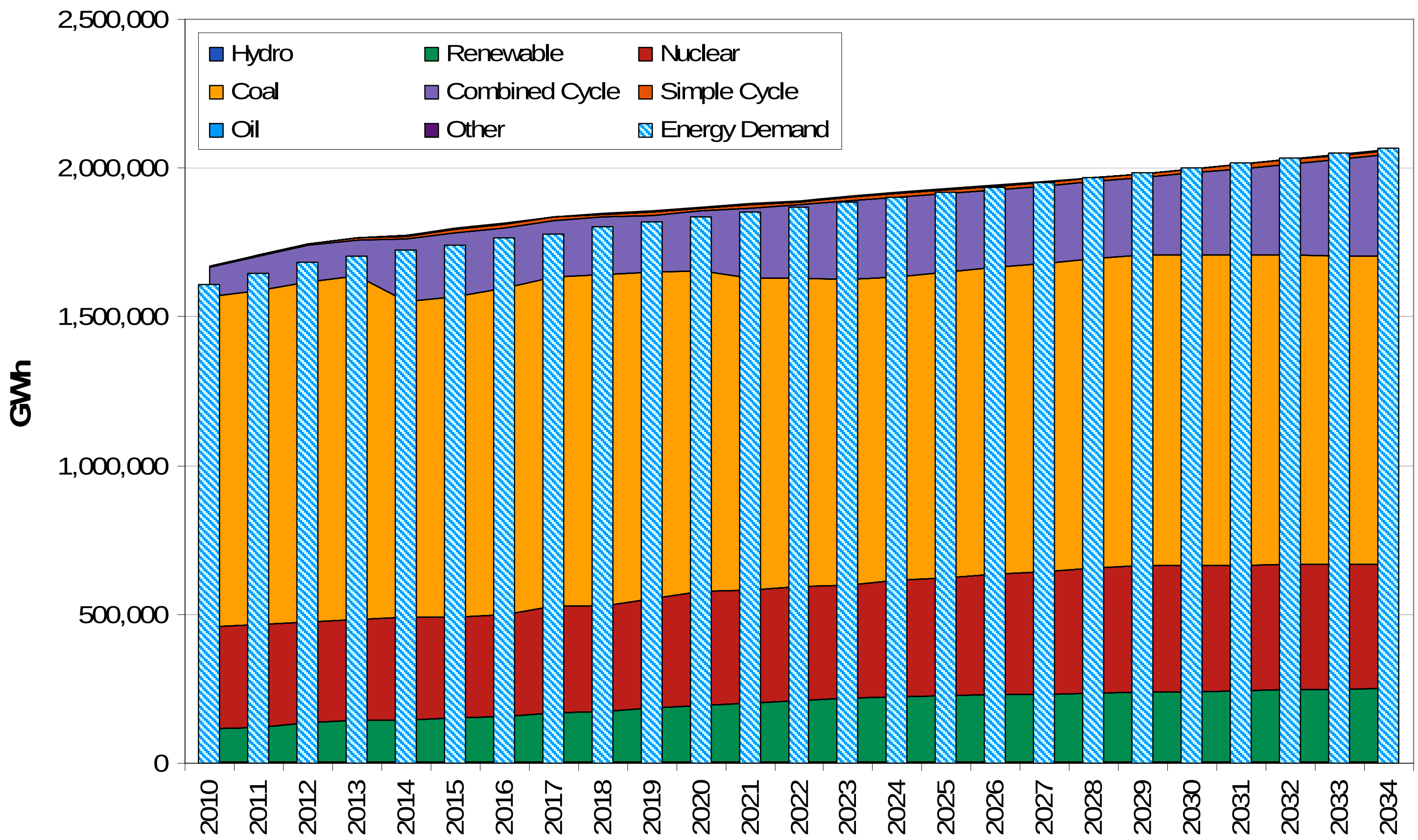
1 Other units include Steam Oil and Gas, and Combustion Turbine Other

2 Results are an aggregate of each EMP Area.

3 After 2024 every 5th year was modeled. Used linear interpolation between 2024 and 2029 and then 2029 and 2034.

PJM Energy Demand and Generation by Unit Type

- Steady Increase in renewable generation
- Nuclear generation increases after 2018
- Minor reduction in coal generation in 2014. Later reductions driven by increased nuclear capacity and higher carbon allowance prices
- CC replaces some coal after 2014



Source: Black & Veatch

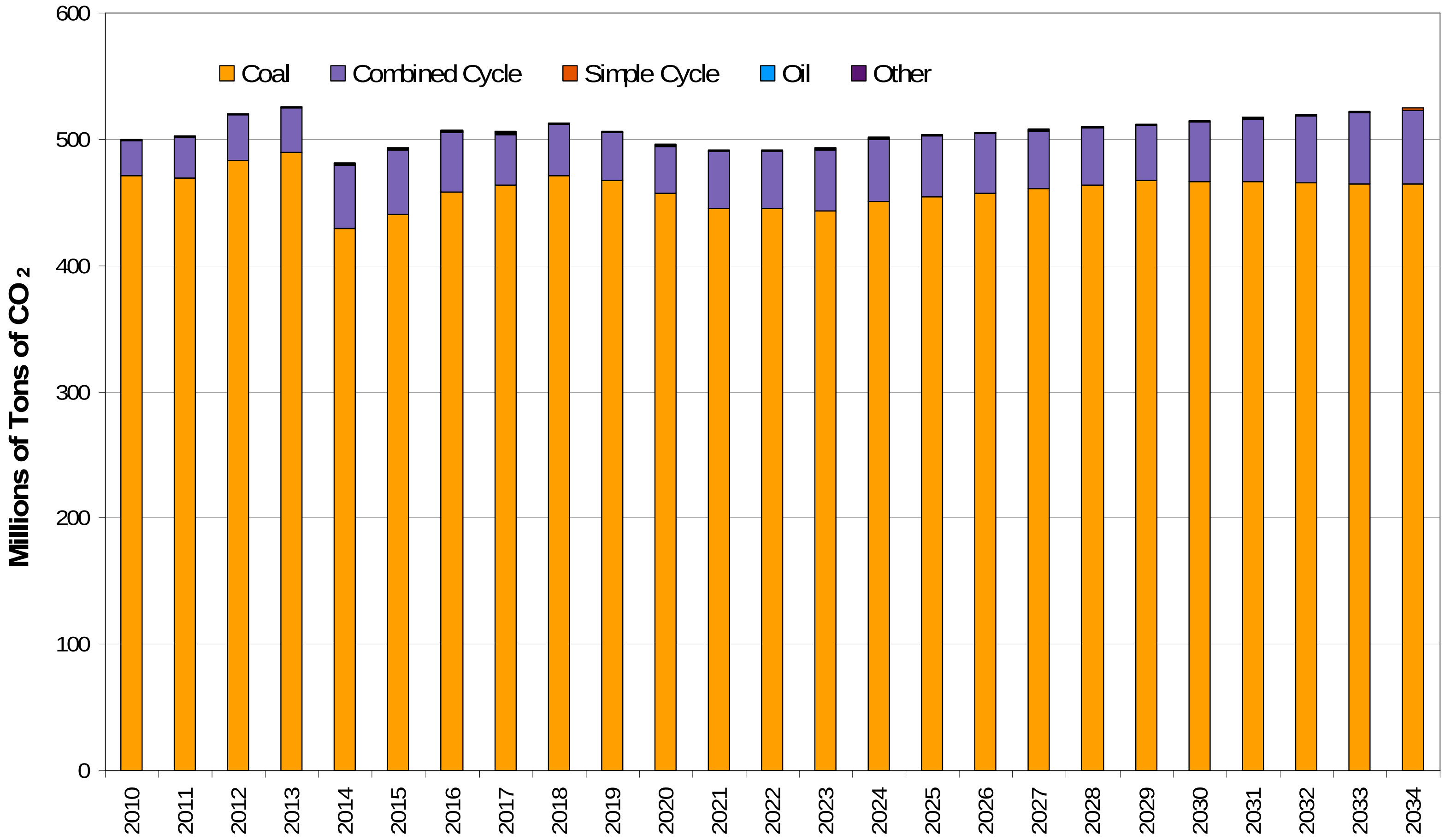
1 All resources are nameplate capacity except for wind (renewable) which has been de-rated to 20% of nameplate capacity

2 Other units include Steam Oil and Gas, and Combustion Turbine Other

3 After 2024 every 5th year was modeled. Used linear interpolation between 2024 and 2029 and then 2029 and 2034.

4 Renewable category includes all wind units, and all hydro units except for those excluded from being counted towards RPS compliance by state regulation.

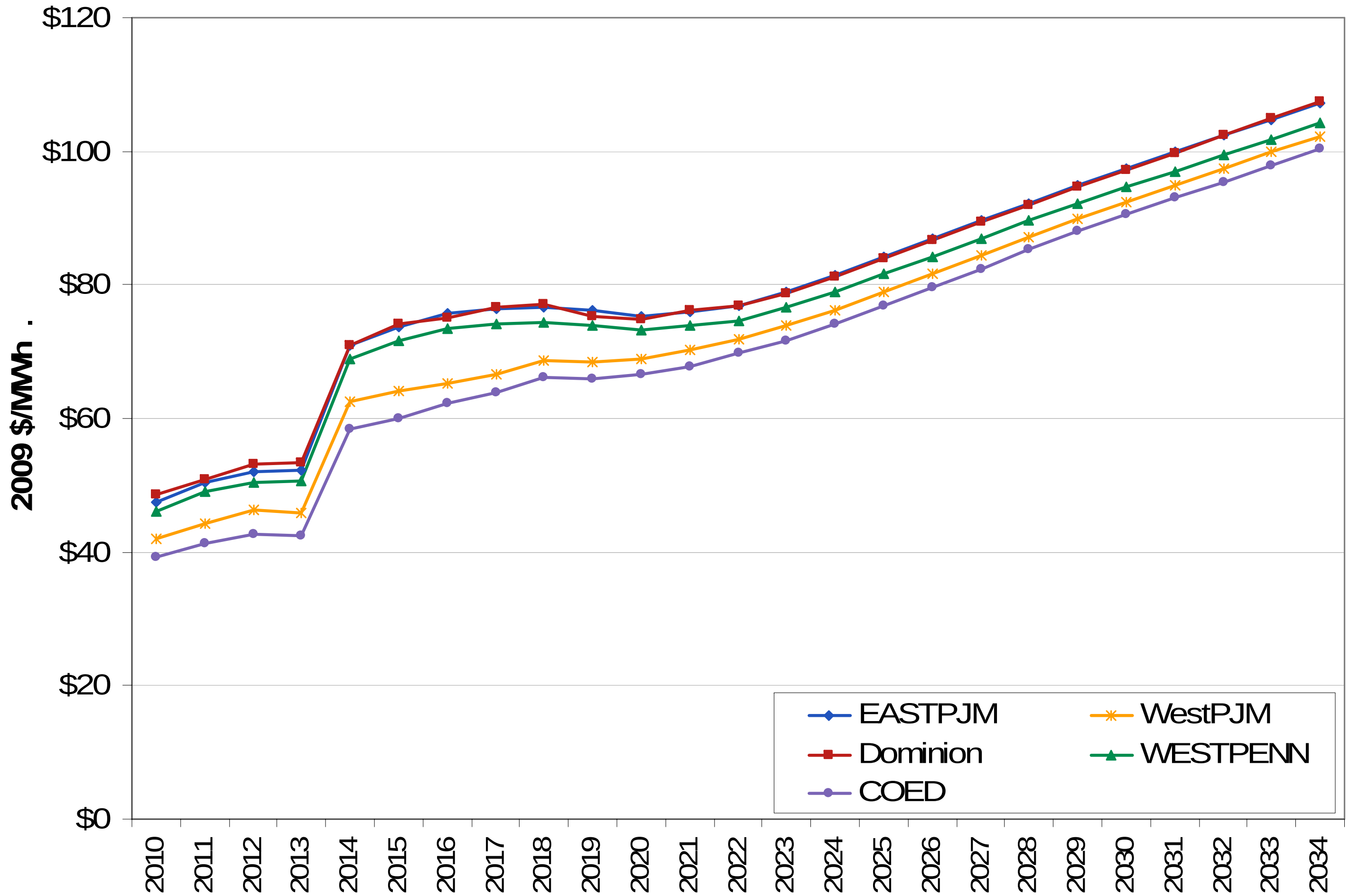
PJM Interconnect CO2 Emissions by Unit Type



Source: Black & Veatch
1 Other units include Steam Oil and Gas, and Combustion Turbine Other
2 Results are an aggregate of each EMP Area.
3 After 2024 every 5th year was modeled. Used linear interpolation between 2024 and 2029 and then 2029 and 2034.

PJM Annual Average Prices

- PJM Prices increase by a step function in 2014 due to the impact of the CO2 allowance prices.
- Prices climb steadily thereafter due to the combined effect of increasing CO2 allowance prices and gas prices.
- Price separation between eastern and western market zones is driven by transmission congestion.

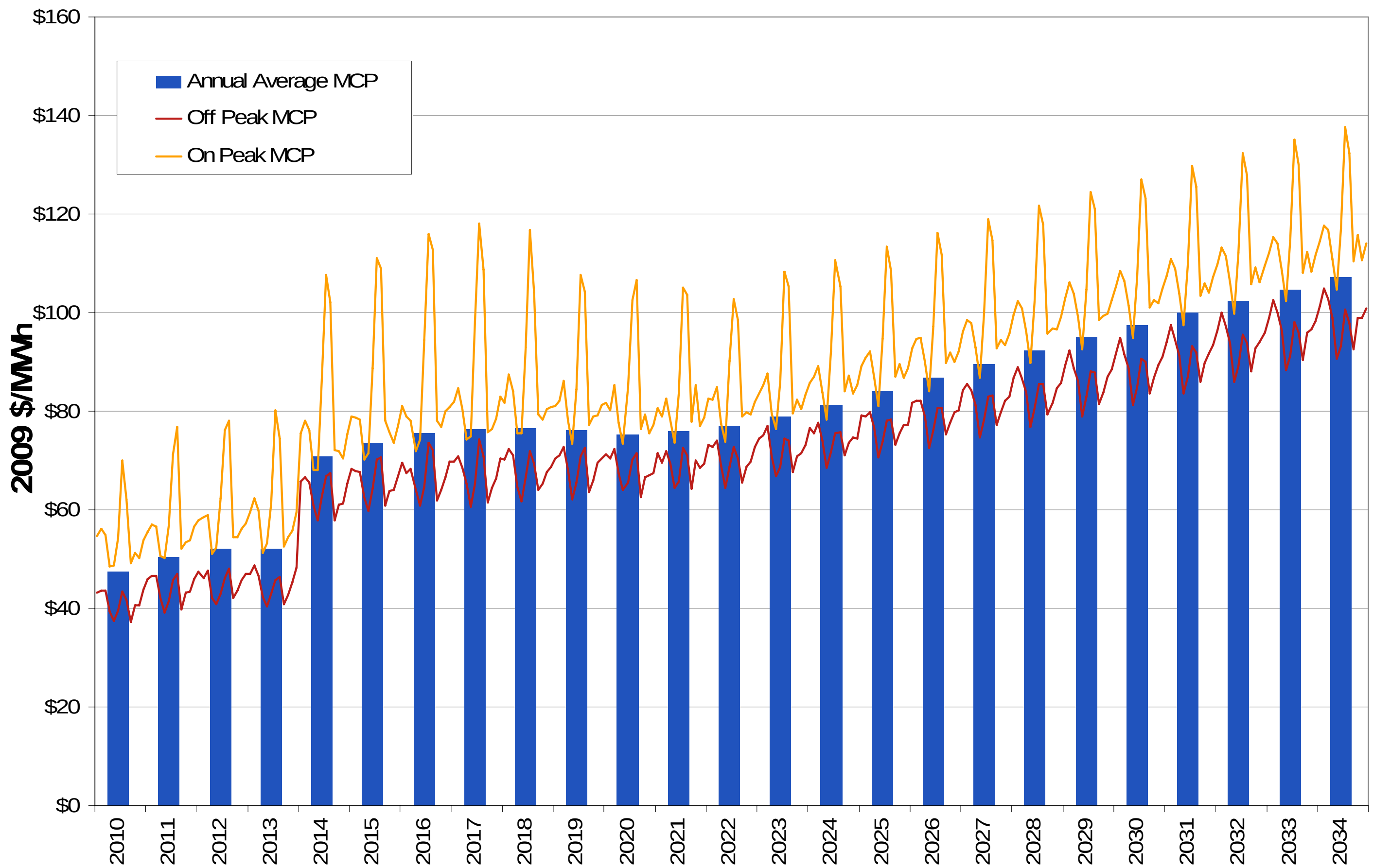


Source: Black & Veatch

* After 2024 every 5th year was modeled. Used linear interpolation between 2024 and 2029 and then 2029 and 2034.

East PJM On and Off Peak Energy Prices

- PJM East prices have a typical pattern of monthly variation and on-peak to off-peak spreads seen in eastern PJM.
- The summer peak prices are elevated relative to markets further west, as transmission congestion compels a greater reliance on local peaking assets.

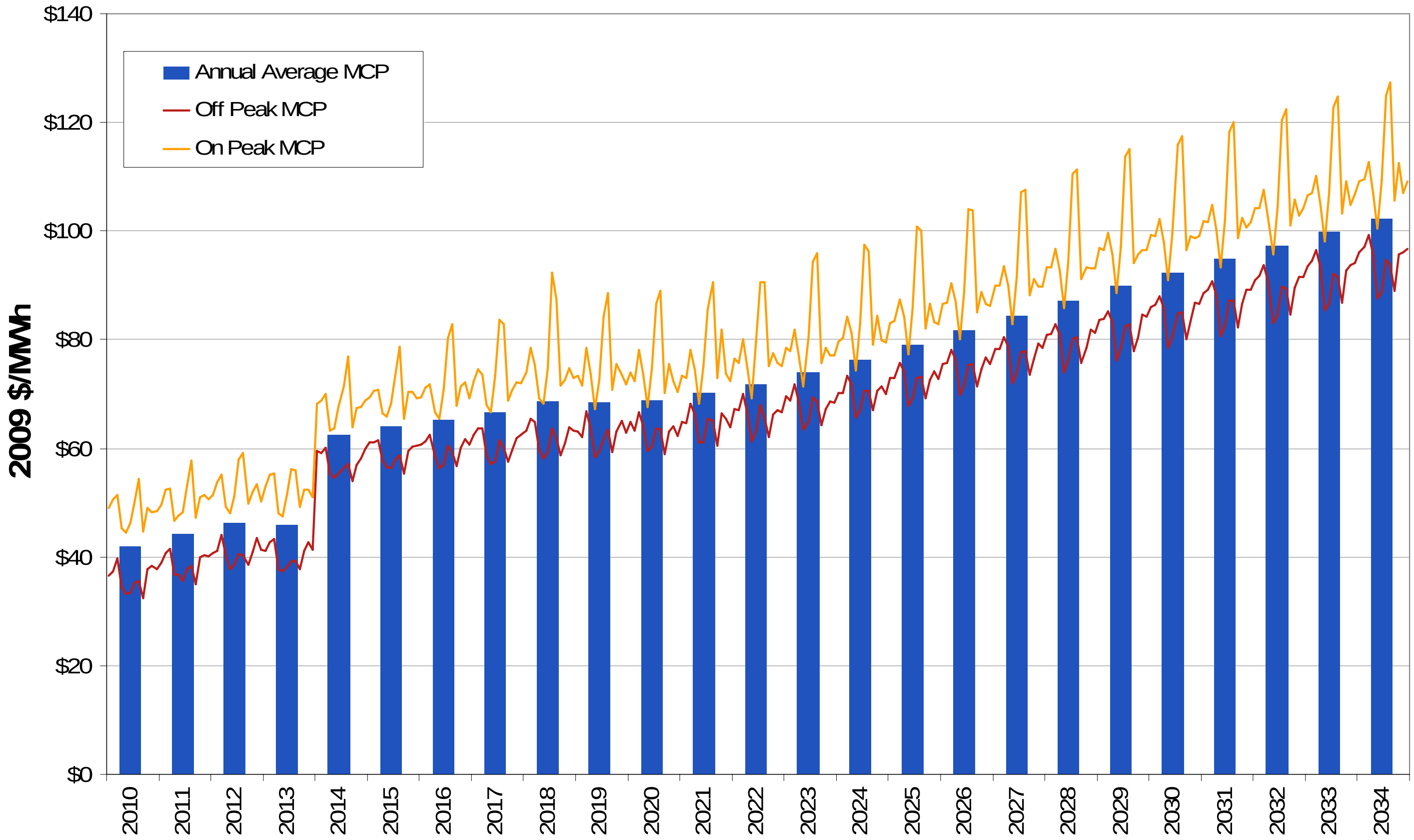


Source: Black & Veatch

* After 2024 every 5th year was modeled. Used linear interpolation between 2024 and 2029 and then 2029 and 2034.

West PJM On and Off Peak Energy Prices

- PJM West prices have a typical pattern of monthly variation and on-peak to off-peak spreads seen in western PJM including ComEd.



Source: Black & Veatch

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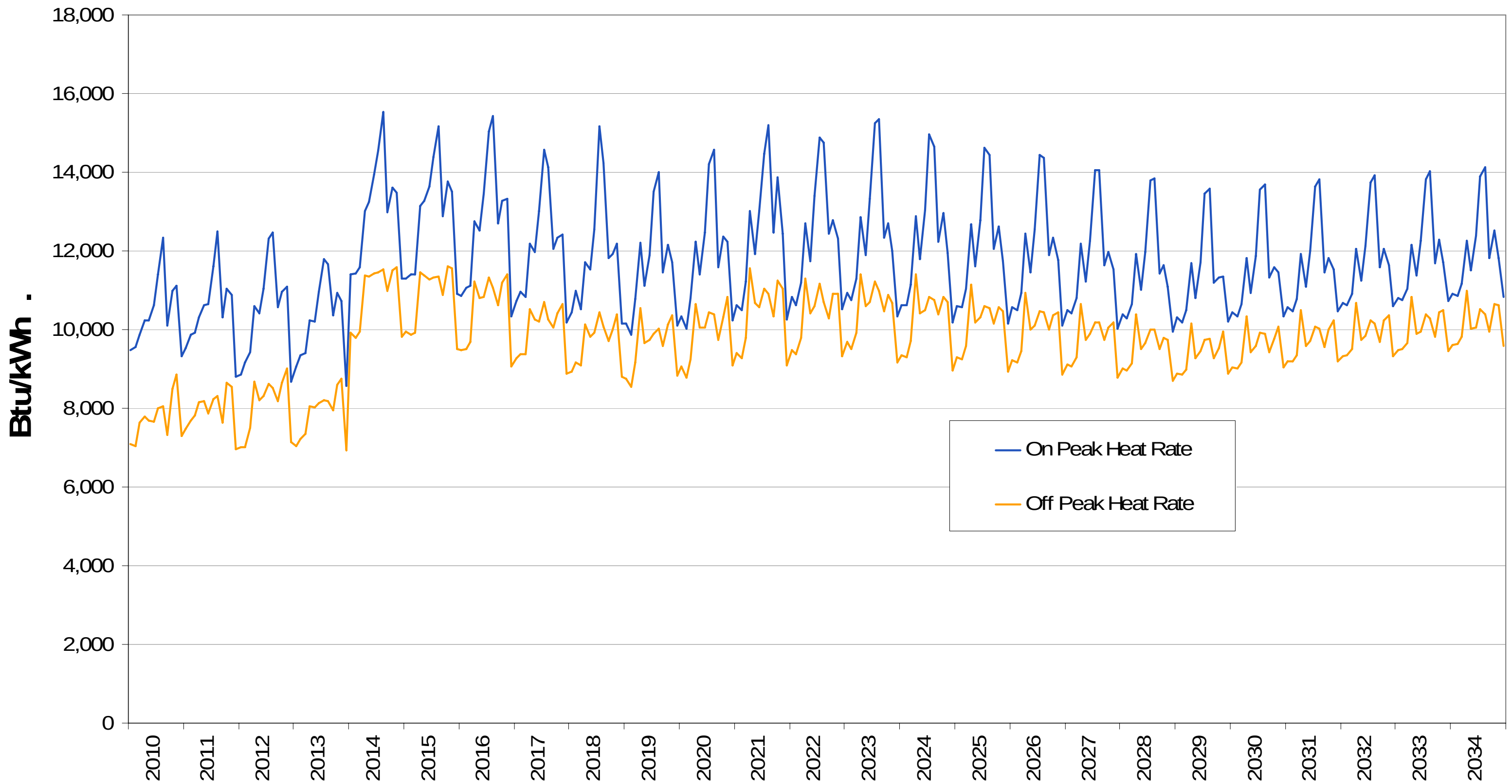
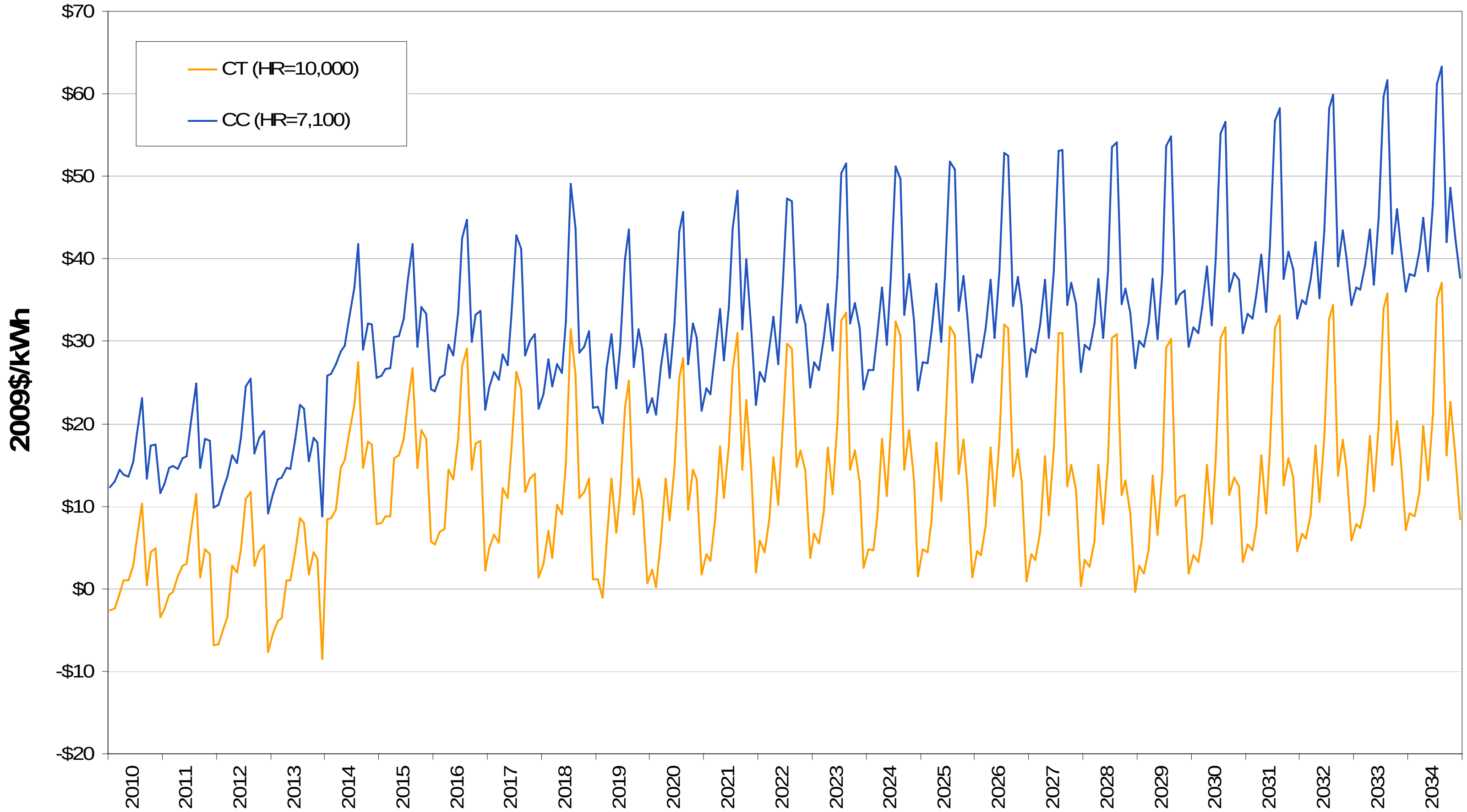
PJM West Heat Rate



Source: Black & Veatch

PJM West Spark Spreads



Source: Black & Veatch

PJM RPM Capacity Market Overview

- PJM conducts annual auctions for a 3-year forward capacity obligation and price
- Residual auctions are held to address changing conditions and to procure replacement capacity
- PJM employs downward sloping demand curves in clearing the capacity market, where the curve is adjusted for different levels of required reserves
- The auction is held on an RTO-wide basis, and locational adjustments are made with separate clearing prices in import-constrained sub-markets
- Capacity prices are capped at the Net Cost of New Entry, which is administratively determined
- Explicit market power rules are in place, including must-offer rules for existing supply

PJM RPM Auction Results

- PJM's Most Recent RPM Auction let to capacity prices that are significantly lower than those cleared in previous auctions
- The 2012/2013 RPM auction saw significant increases in generating capacity and demand response capacity bid into the market, which created downward pressure on capacity prices

PJM RTO Cleared Capacity Prices

	2009/2010	2009/2010	2010/2011	2011/2012	2012/2013
Capacity Clearing Price ($/MW/Day)	$111.92	$102.40	$174.29	$110.00	$16.46
Capacity Clearing Price ($/kW/Year)	$40.85	$37.38	$63.62	$40.15	$6.01
Cleared Capacity (MW)	129,598	132,232	132,190	132,221	136,143
Reserve Margin	17.50%	17.80%	16.50%	18.10%	20.90%

Total Cleared Capacity in PJM RPM Market

	RTO*				
Auction Results (all values in UCAP**)	2008/2009	2009/2010	2010/2011	2011/2012	2012/2013
Generation Offered	131,164.8	132,614.2	132,124.8	136,067.9	134,873.0
DR Offered	715.8	936.8	967.9	1,652.4	9,847.6
EE Offered	-	-	-	-	652.7
Total Offered	131,880.6	133,551.0	133,092.7	137,720.3	145,373.3
Generation Cleared	129,061.4	131,338.9	131,251.5	130,856.6	128,527.4
DR Cleared	536.2	892.9	939.0	1,364.9	7,047.3
EE Cleared	0.0	0.0	0.0	0.0	568.9
Total Cleared	129,597.6	132,231.8	132,190.5	132,221.5	136,143.6
Uncleared	2,283.0	1,319.2	902.2	5,498.8	9,229.7

* RTO numbers include all LDAs

** UCAP calculated using sell offer EFORd for Generation Resources. DR and EE UCAP values include appropriate FPR and DR Factor.

Source: PJM

- In 2012/2013 auction, 9,850 MW of Demand Response was offered, and 7,060 MW cleared the market
- 1,050 MW of the market clearing Demand Response capacity was in the ComEd sub-market area
- The increased demand bidding contributed to lower RPM capacity prices
- There may be some performance risk in PJM relying on this amount of Demand Response in clearing the capacity market

Incremental Cleared Capacity in PJM RPM Market

	RTO*						
Capacity Changes (in ICAP)	2007/2008	2008/2009	2009/2010	2010/2011	2011/2012	2012/2013	Total
Increase in Generation Capacity	602.0	724.2	1,272.3	1,776.2	3,576.3	1,893.5	9,844.5
Decrease in Generation Capacity	-674.6	-375.4	-550.2	-301.8	-264.7	-3,253.9	-5,420.6
Net Increase in Demand Resource Capacity**	555.0	574.7	215.0	28.7	661.7	7,938.1	9,973.2
Net Increase in Energy Efficiency Capacity**	0.0	0.0	0.0	0.0	0.0	632.3	632.3
Net Increase in Installed Capacity	482.4	923.5	937.1	1,503.1	3,973.3	7,210.0	15,029.4

* RTO numbers include all LDAs

** Values are with respect to the quantity offered in the previous year's Base Residual Auction.

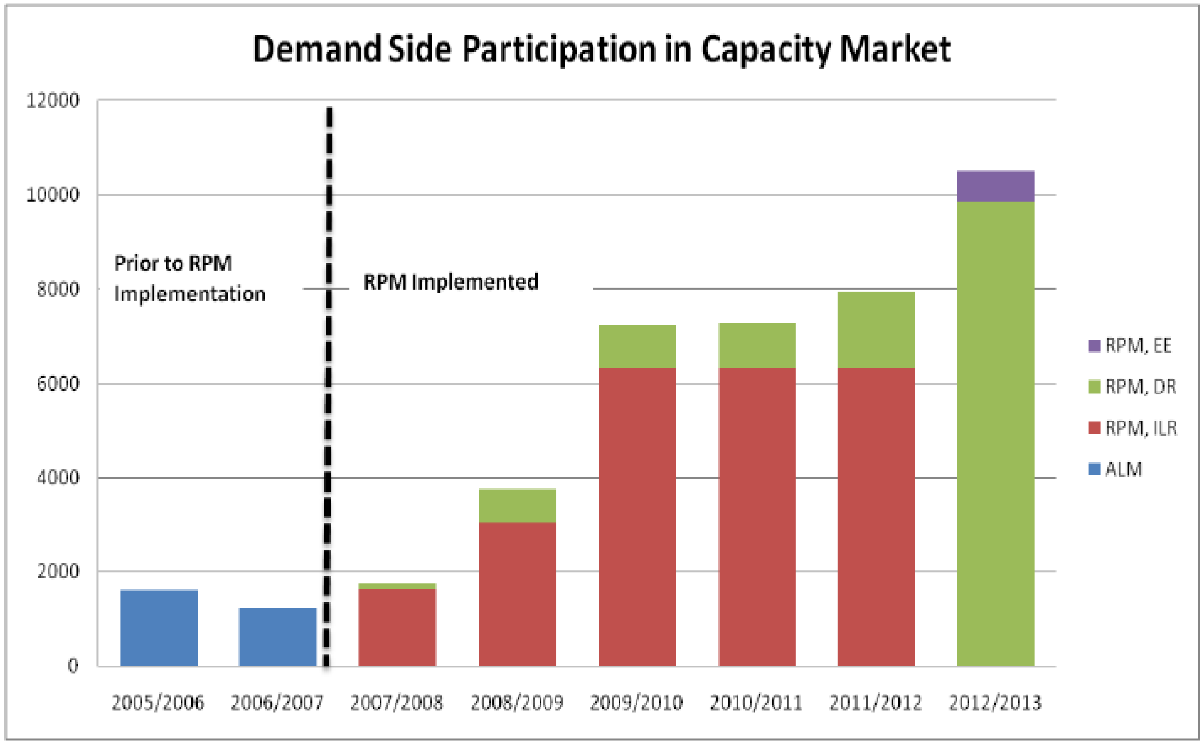
^ Values include 2007/2008 values not posted in this report but available on PJM.com.

Source: PJM

- In addition to the increase in Demand Response, there was also a significant increase in the amount of supply capacity bid into the 2012/2013 RPM auction
- In 2012/2013 auction, there was an increase of 9,844.5 MW of generation capacity bid into the RPM market. This consisted of new power plants being built, and projected upgrades to existing generators
- In combination with the increase in Demand Response, the PJM market saw a net increase in supply of 15,029.4 MW

Demand Response Has Played Increasing Role in RPM

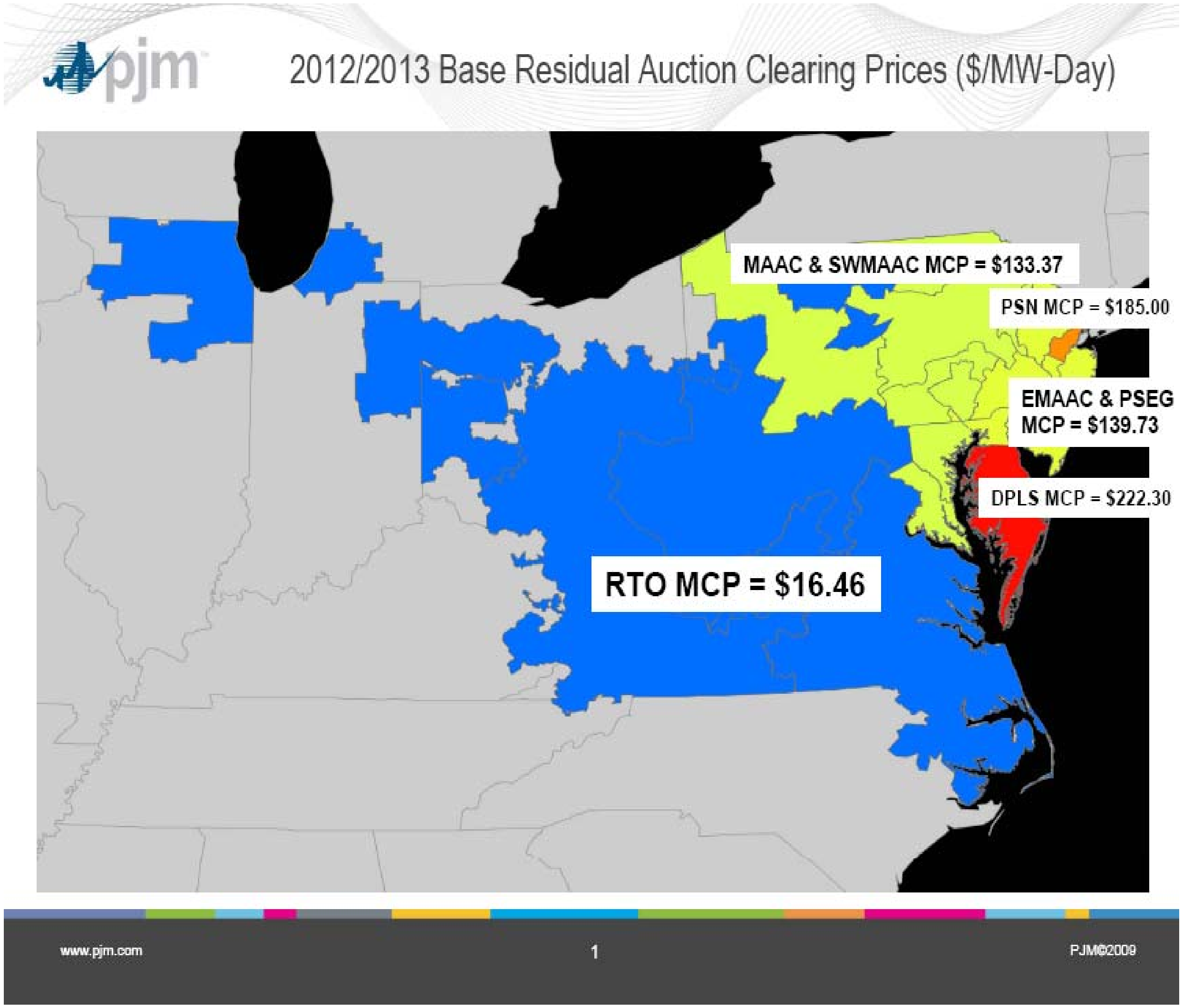
- Demand response bid into the RPM market has increased each year
- In 2012/2013 auction, 9,850 MW of Demand Response was offered, and 7,060 MW cleared the market
- 1,050 MW of the market clearing Demand Response capacity was in the ComEd sub-market area
- The increased demand bidding contributed to lower RPM capacity prices
- There may be some performance risk in PJM relying on this amount of Demand Response in clearing the capacity market



Source: PJM

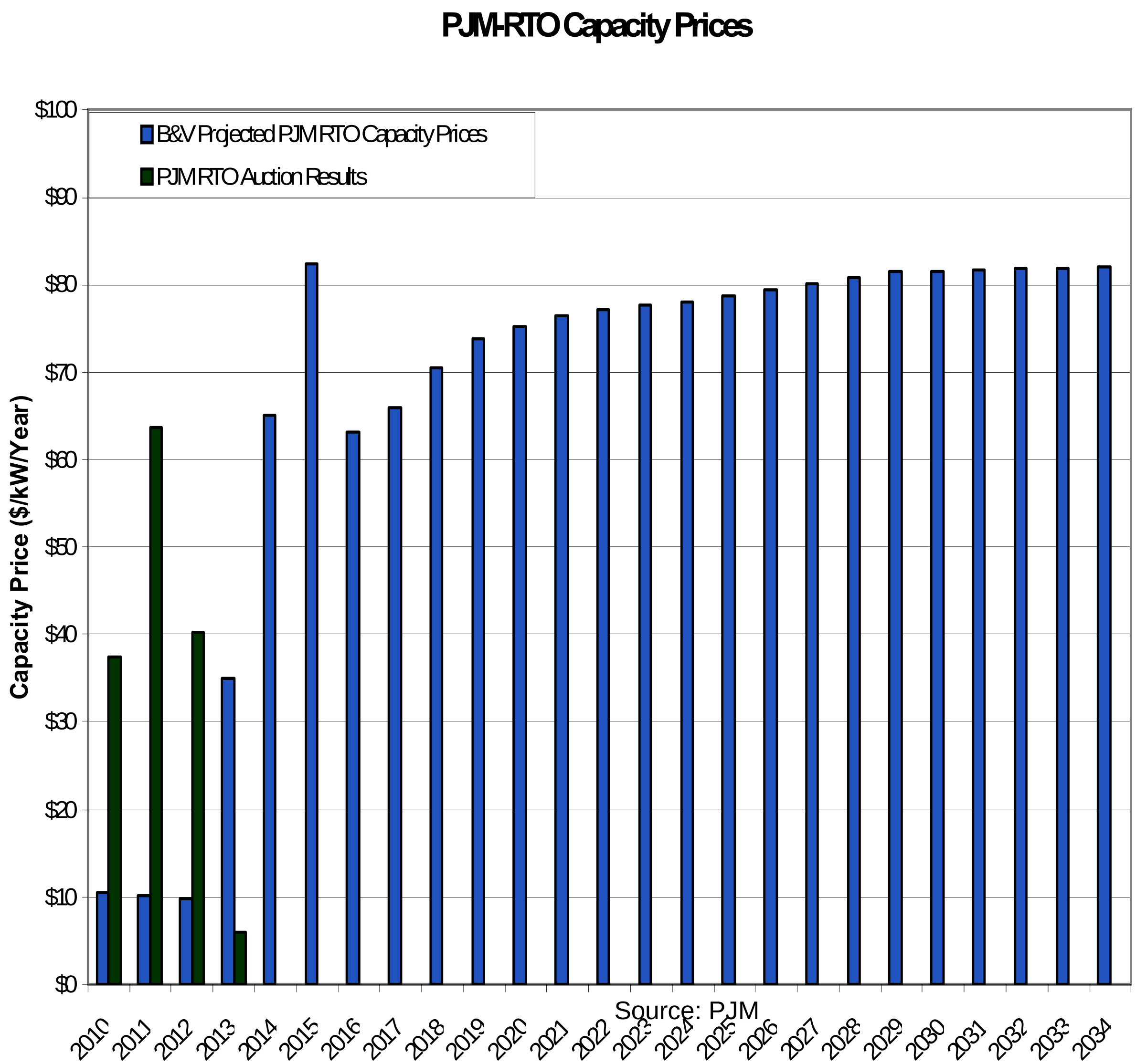
PJM Locational Capacity Markets

- The RPM market results in locational capacity prices, in cases where transmission constraints between sub-markets prevent capacity transfers of a magnitude that would clear the demand requirement in the constrained sub-market
- In sub-markets not constrained by transmission limits, a single clearing capacity price applies across all of those sub-markets
- The Illinois sub-market is not constrained under current conditions, so in recent RPM auctions it has seen the RTO-wide capacity price
- Capacity prices in the RTO-wide region are significantly lower than in the constrained sub-markets



B&V PJM Capacity Price Forecast

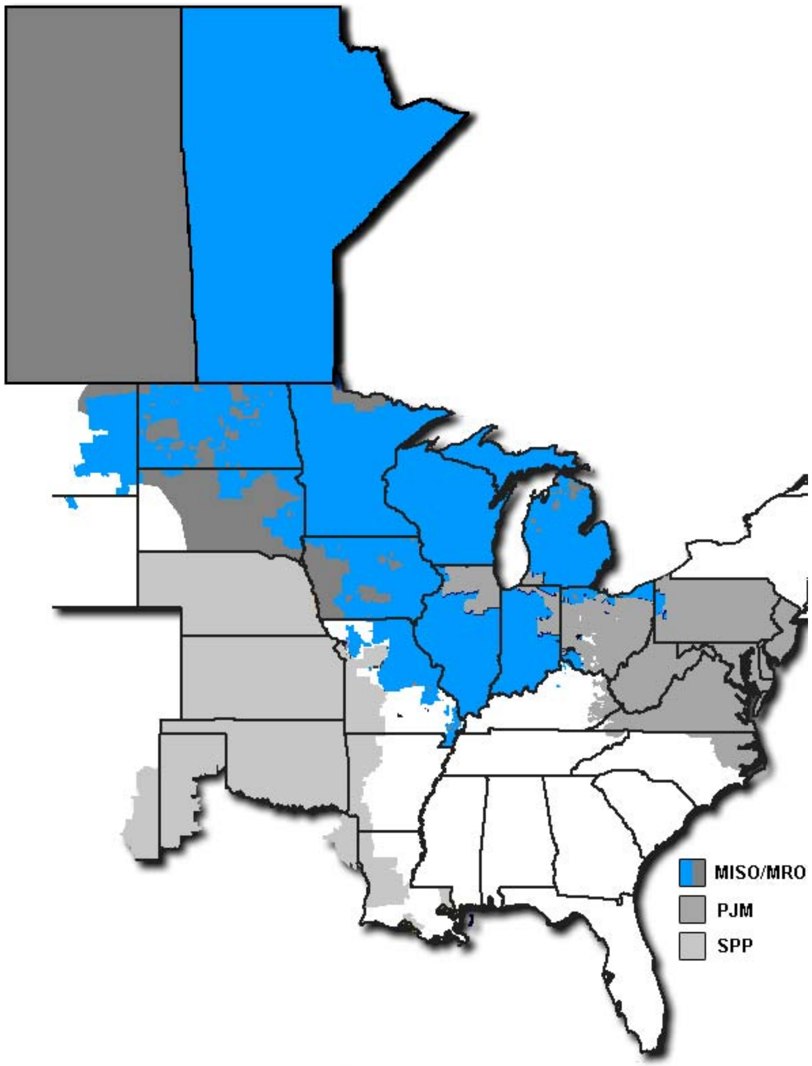
- B&V has prepared a capacity price forecast for the PJM RTO wide region, consistent with the PJM auction
- Capacity offer prices for each generator are based on the amount needed to offset net operating losses for existing generators, and based on the Net Cost of New Entry (CONE) for new generators
- While the B&V capacity price forecast is reflective of our specific supply and demand assumptions, prices generally track those seen in the PJM RPM auctions
- B&V expects equilibrium capacity pricing levels in the PJM RTO in the 2015-2016 timeframe



4.5 MISO Results

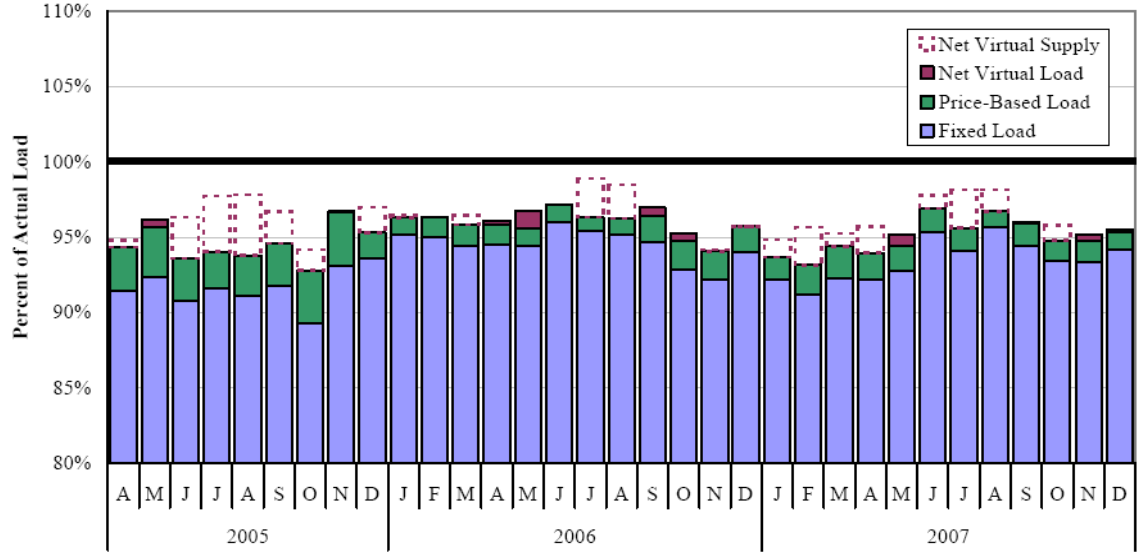
Midwest ISO (MISO) Overview

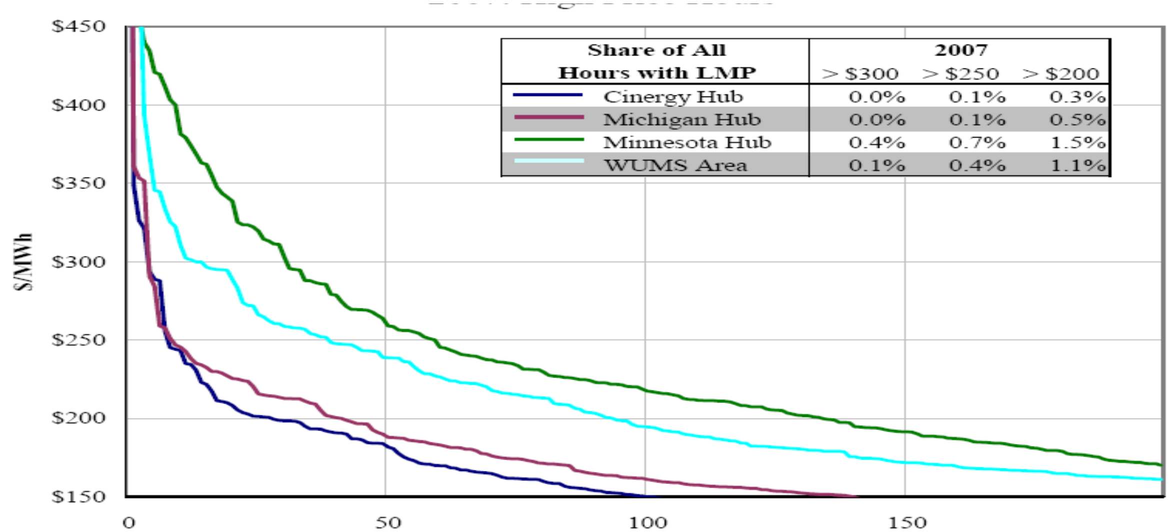
- States covered: All or most of Minnesota, Wisconsin, Illinois, Indiana, Michigan, Missouri, Kentucky, and Ohio.
- Reliability regions: Midwest Reliability Organization (MRO), Southeastern Electric Reliability Council (SERC) and ReliabilityFirst Corporation (RFC)
- Market Hubs: Cinergy, First Energy, Illinois, Michigan, Minnesota
- RTO/ISO: Midwest ISO (MISO) (established 2002) administers a two-settlement (day ahead and real-time) energy market known as the Day-2 market. It produces hourly locational marginal prices that are rolled up into 5 regional hub prices.
- MISO also administers a monthly financial transmission rights (FTR) allocation and auction.
- In 2009, MISO implemented Ancillary Services Markets for regulating, supplemental and spinning reserves
- Midwest bilateral trading is active on the Intercontinental Exchange (ICE) at the Cinergy Hub and Northern Illinois Hub



MISO Market Performance

- A significant portion of MISO load is scheduled through the Day Ahead market (90 to 96% of peak daily load)
- Locational Marginal Prices have been higher in markets affected by transmission import constraints, including the Southeastern Wisconsin WUMS region, and the Minnesota region
- MISO Real-Time Market is a residual demand market, with significantly lower volume than the Day Ahead Market



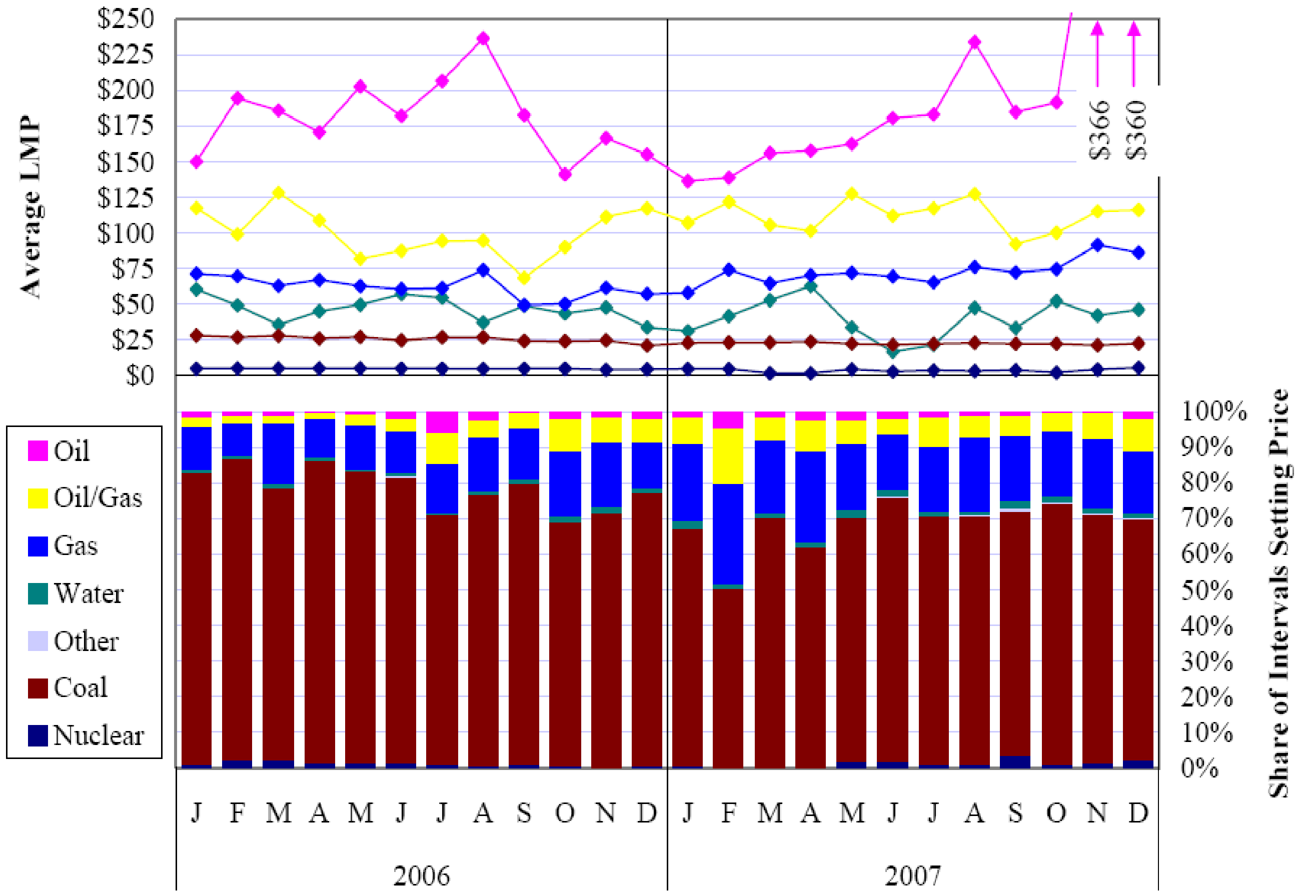


Share of All Hours with LMP	2007 > $300	> $250	> $200
Cinergy Hub	0.0%	0.1%	0.3%
Michigan Hub	0.0%	0.1%	0.5%
Minnesota Hub	0.4%	0.7%	1.5%
WUMS Area	0.1%	0.4%	1.1%

Source: MISO 2007 State of Market Report

MISO Price Setting Resources

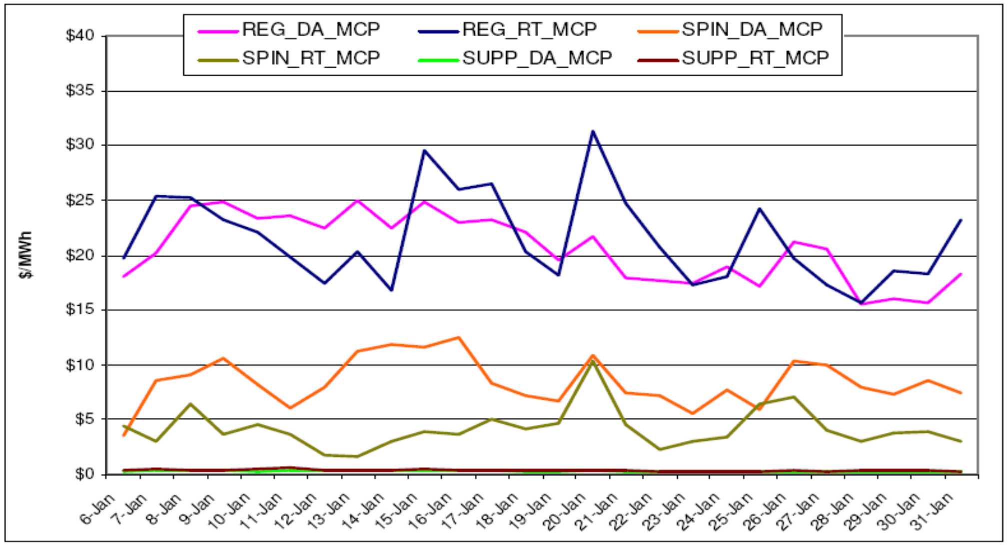
- The MISO region remains dominated by coal-fired generation. Coal-fired resources are typically price-setting 70 to 80 percent of the time
- Natural gas-fired resources are price-setting with the next highest frequency, in the range of 10 to 20 percent of the time
- Oil-fired resources are price setting for a smaller portion of the time, in the range of 1 to 5 percent

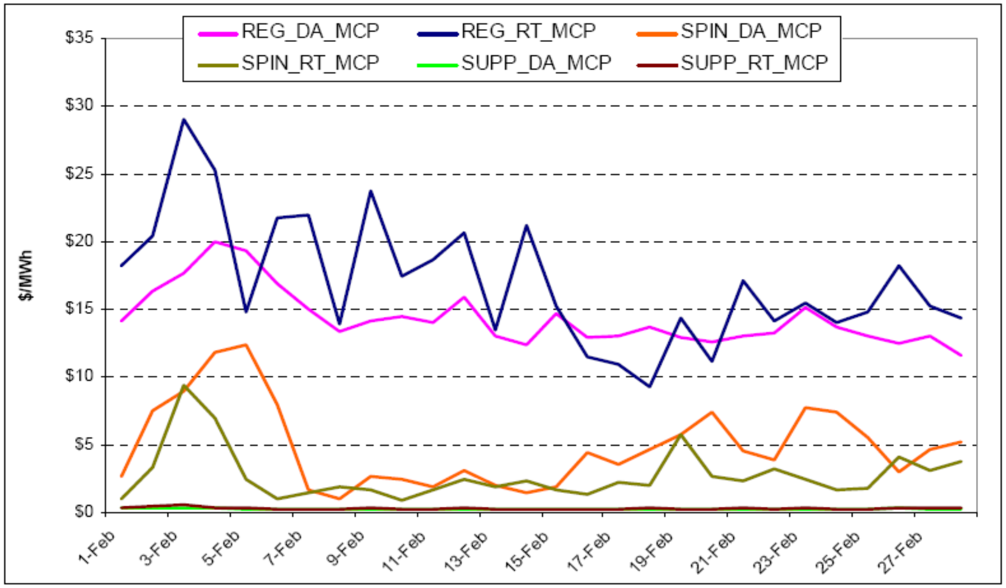


Source: MISO 2007 State of the Market Report

Midwest ISO Ancillary Services Markets

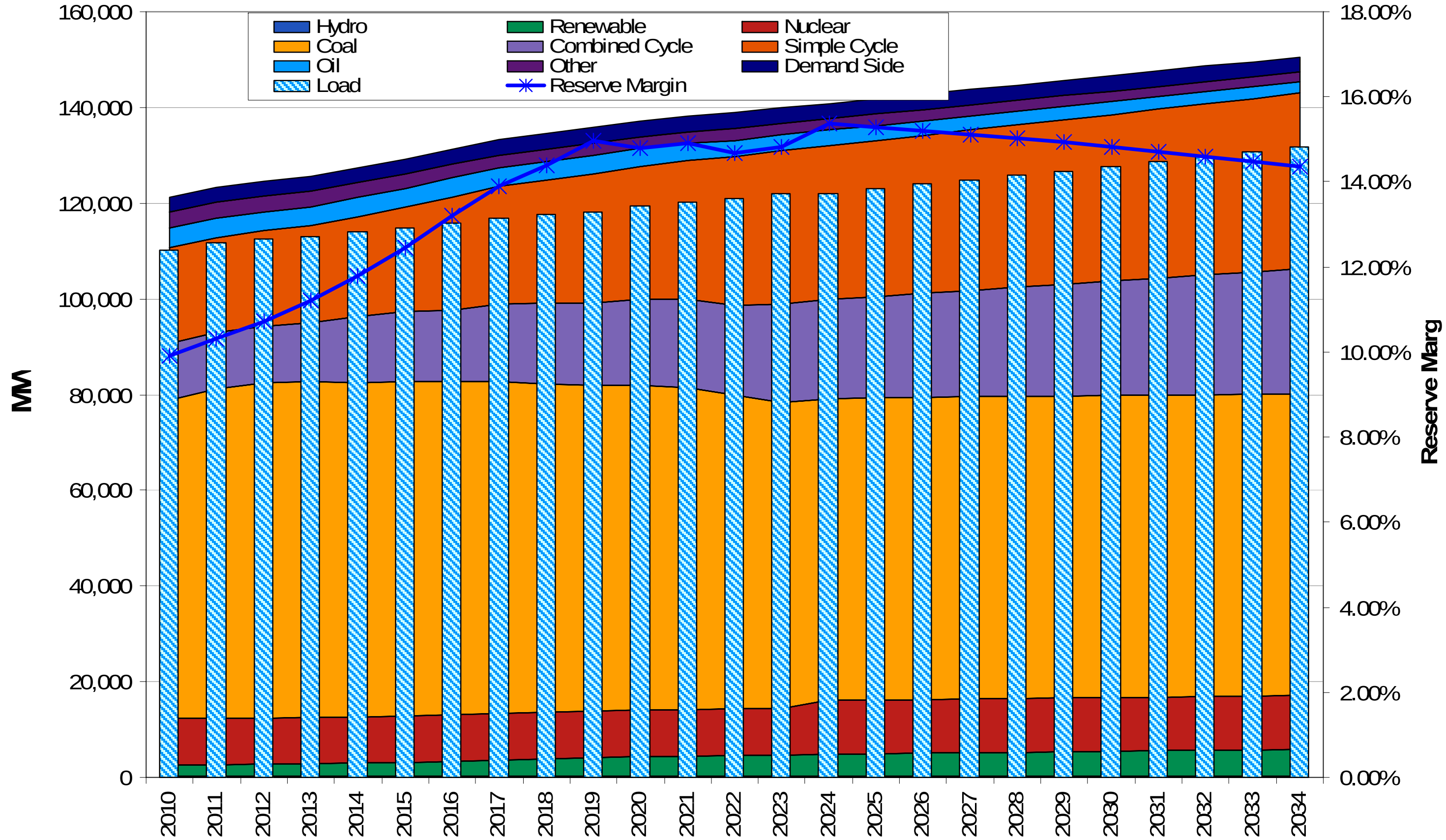
- In January 2009, MISO implemented Ancillary Services Markets for regulating, supplemental and spinning reserves
- MISO reflects seven reserve zones in administering its Ancillary Services market
- Across MISO zones, prices for regulating reserves have generally traded in the $3 to $10 per MWh range.
- Prices for spinning reserve have traded in the $10 to $30 per MWh range, with an apparent downward trend in late February
- Daily demand for spinning and regulating reserves clearing the market have been modest, in the 450 to 600 MW range
- MISO entities are still able to self-provide regulating and spinning reserve services





Source: MISO

MISO Loads & Resource Outlook



Source: Black & Veatch

1 All resources are nameplate capacity except for wind (renewable) which has been de-rated to 20% of nameplate capacity
2 Loads are shown for August peak load
3 Other units include Steam Oil and Gas, and Combustion Turbine Other
4 After 2024 every 5th year was modeled. Used linear interpolation between 2024 and 2029 and then 2029 and 2034.
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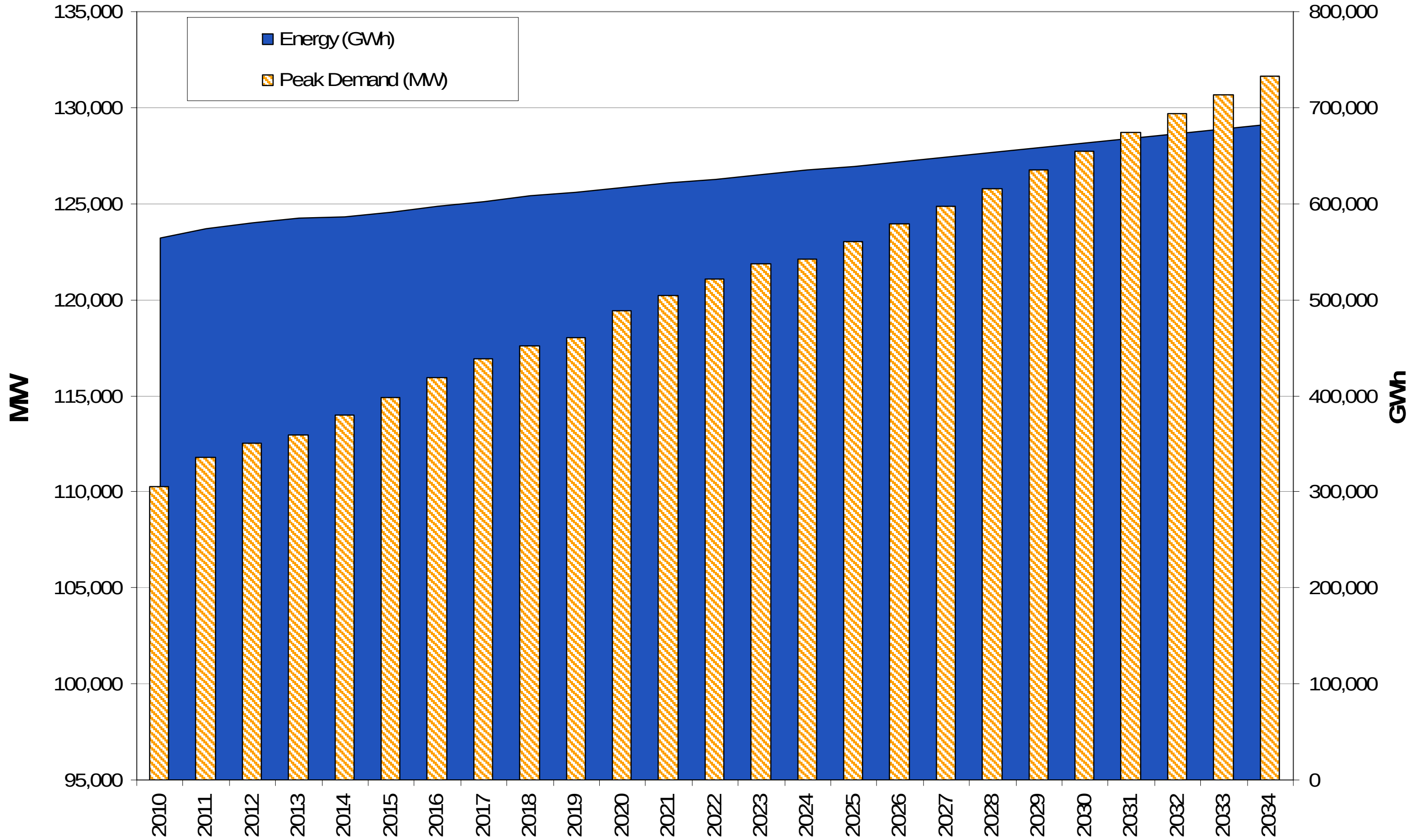
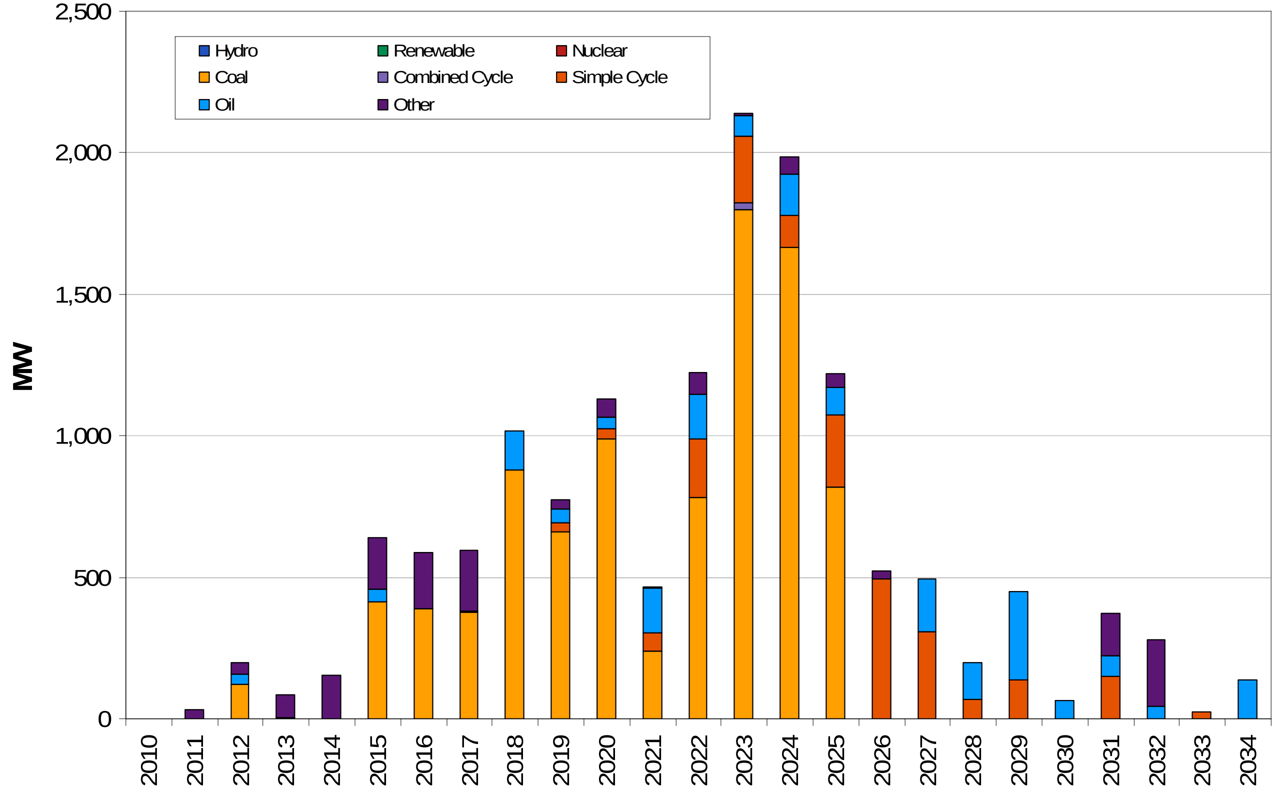
MISO Peak and Energy Load Forecast



Source: Black & Veatch

* Assumptions are an aggregate of each EMP Area.

MISO Retirements by Year



Source: Black & Veatch

*Other units include Steam Oil and Gas, and Combustion Turbine Other

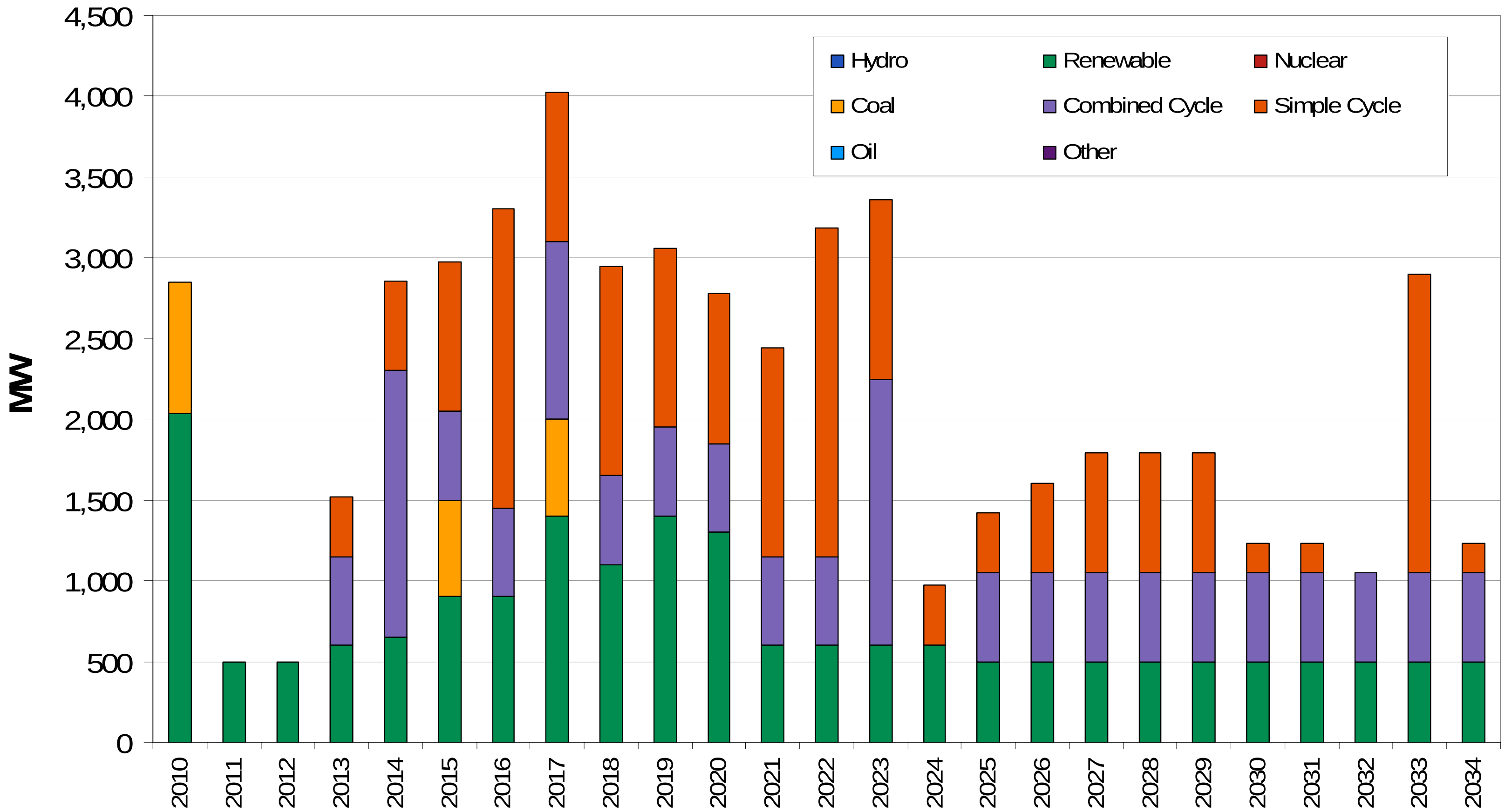
** Assumptions are an aggregate of each EMP Area.

- Approximately 14,800 MW of cumulative capacity is retired by 2034

  Other – 1,600 MW; Oil – 1,900 MW

  Coal – 9,100 MW; CT – 2,100 MW

MISO Expansion by Year



Source: Black & Veatch
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2 Assumptions are an aggregate of each EMP Area.
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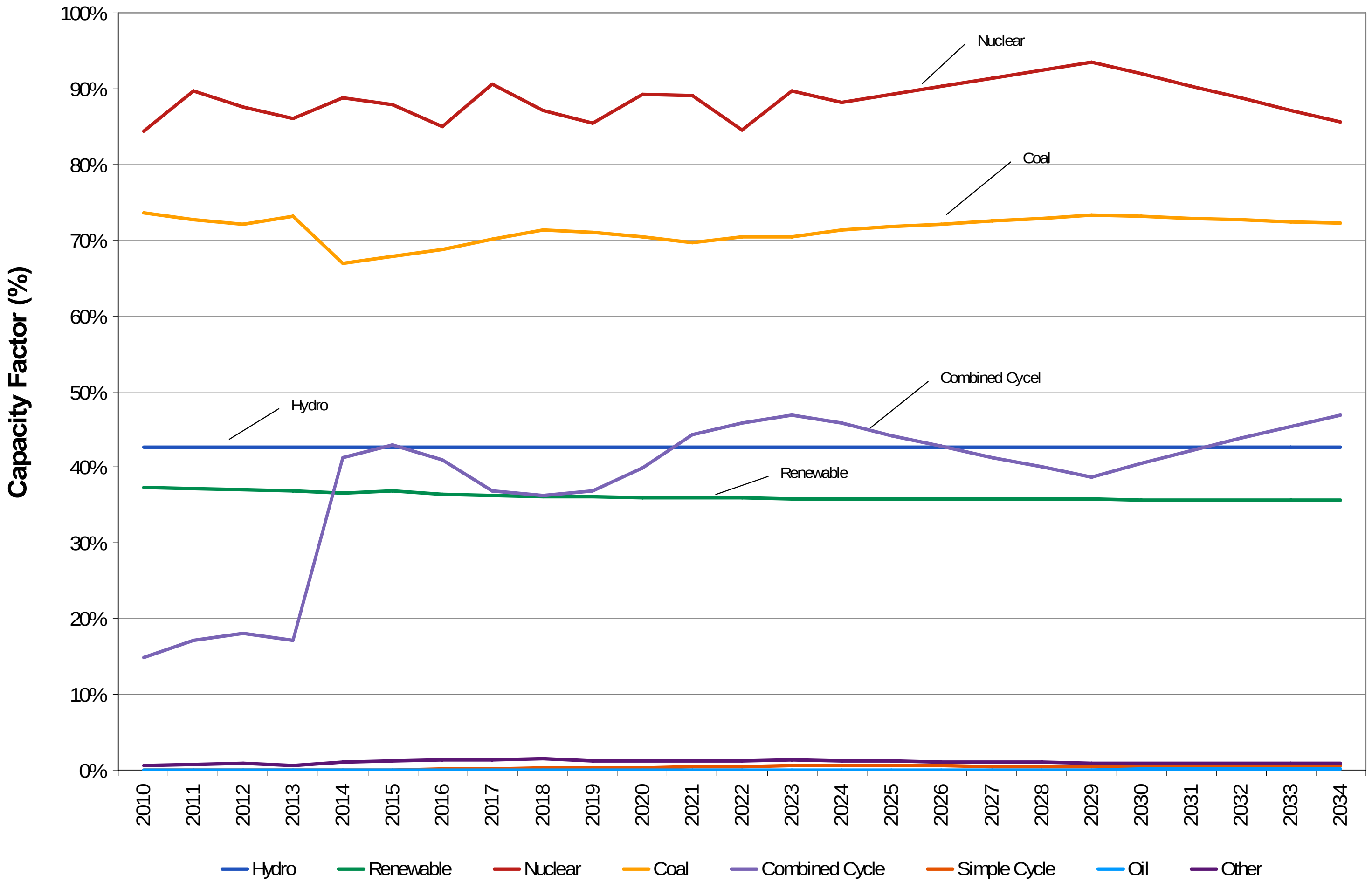
4. All resources are reported as name plate capacity

MISO Fleet Average Capacity Factor



Source: Black & Veatch

1 Other units include Steam Oil and Gas, and Combustion Turbine Other

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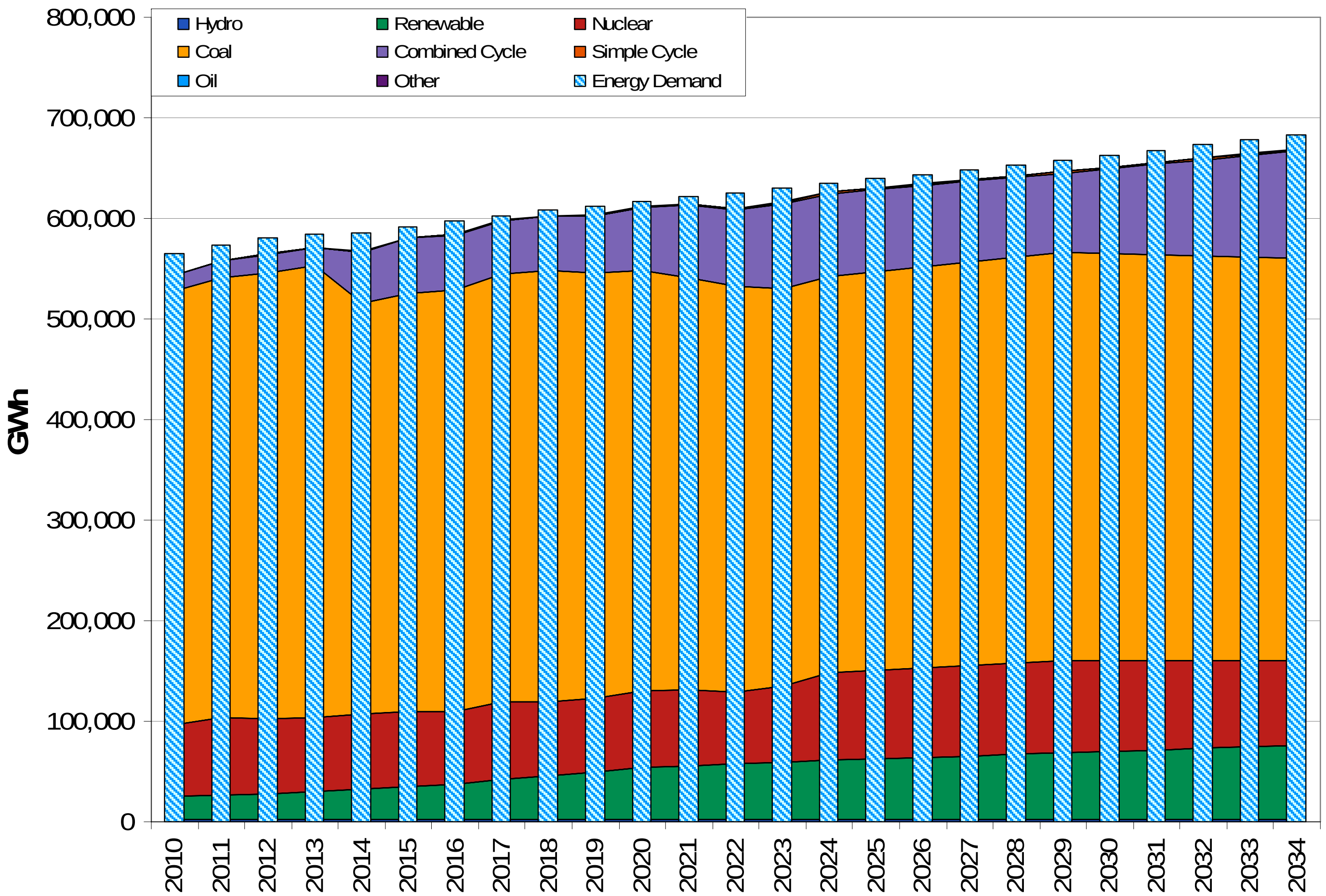
MISO Energy Demand and Generation by Unit Type



Source: Black & Veatch

1 Other units include Steam Oil and Gas, and Combustion Turbine Other

2 Results are an aggregate of each EMP Area.

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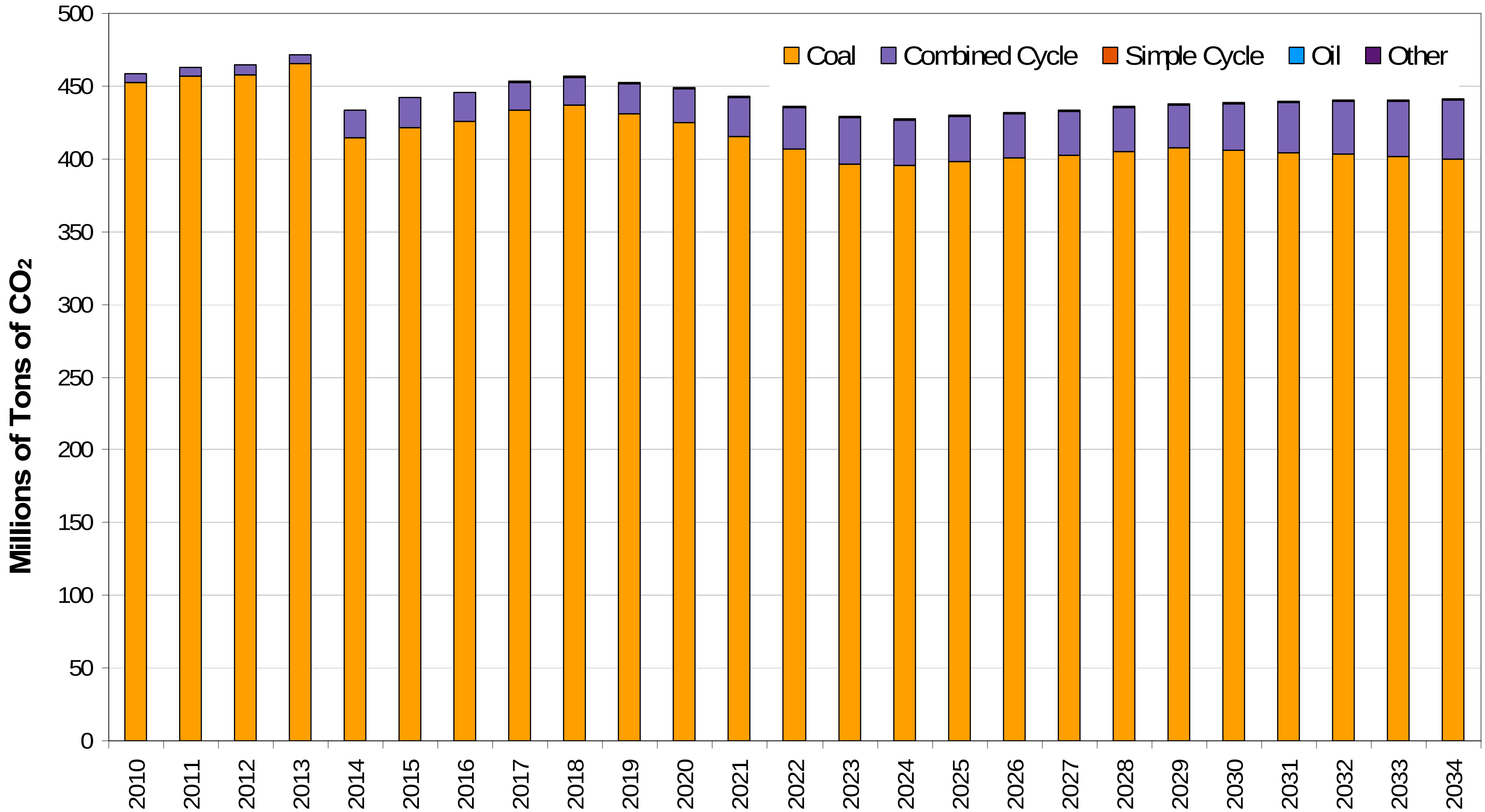
MISO CO2 Emissions by Unit Type



Source: Black & Veatch

1 Other units include Steam Oil and Gas, and Combustion Turbine Other

2 Results are an aggregate of each EMP Area.

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MISO Annual Average Prices

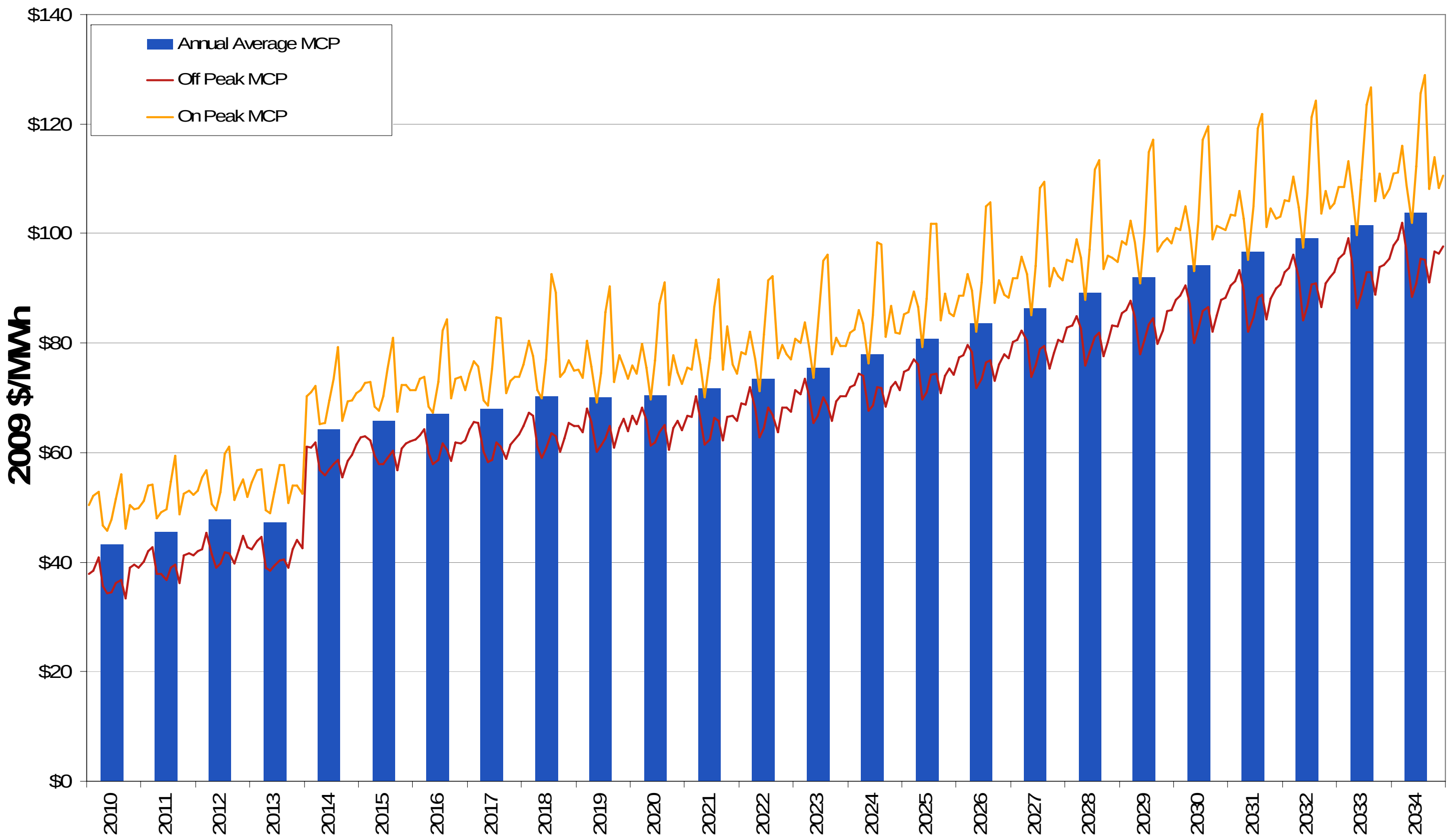
- MISO Prices increase by a step function in 2014 due to the impact of the CO2 allowance prices.
- Prices climb steadily thereafter due to the combined effect of increasing CO2 allowance prices and gas prices.

Source: Black & Veatch

* After 2024 every 5th year was modeled. Used linear interpolation between 2024 and 2029 and then 2029 and 2034.

FirstEnergy (MISO) On and Off Peak Energy Prices

- FirstEnergy prices have a typical pattern of monthly variation and on-peak to off-peak spreads seen throughout MISO.



Source: Black & Veatch

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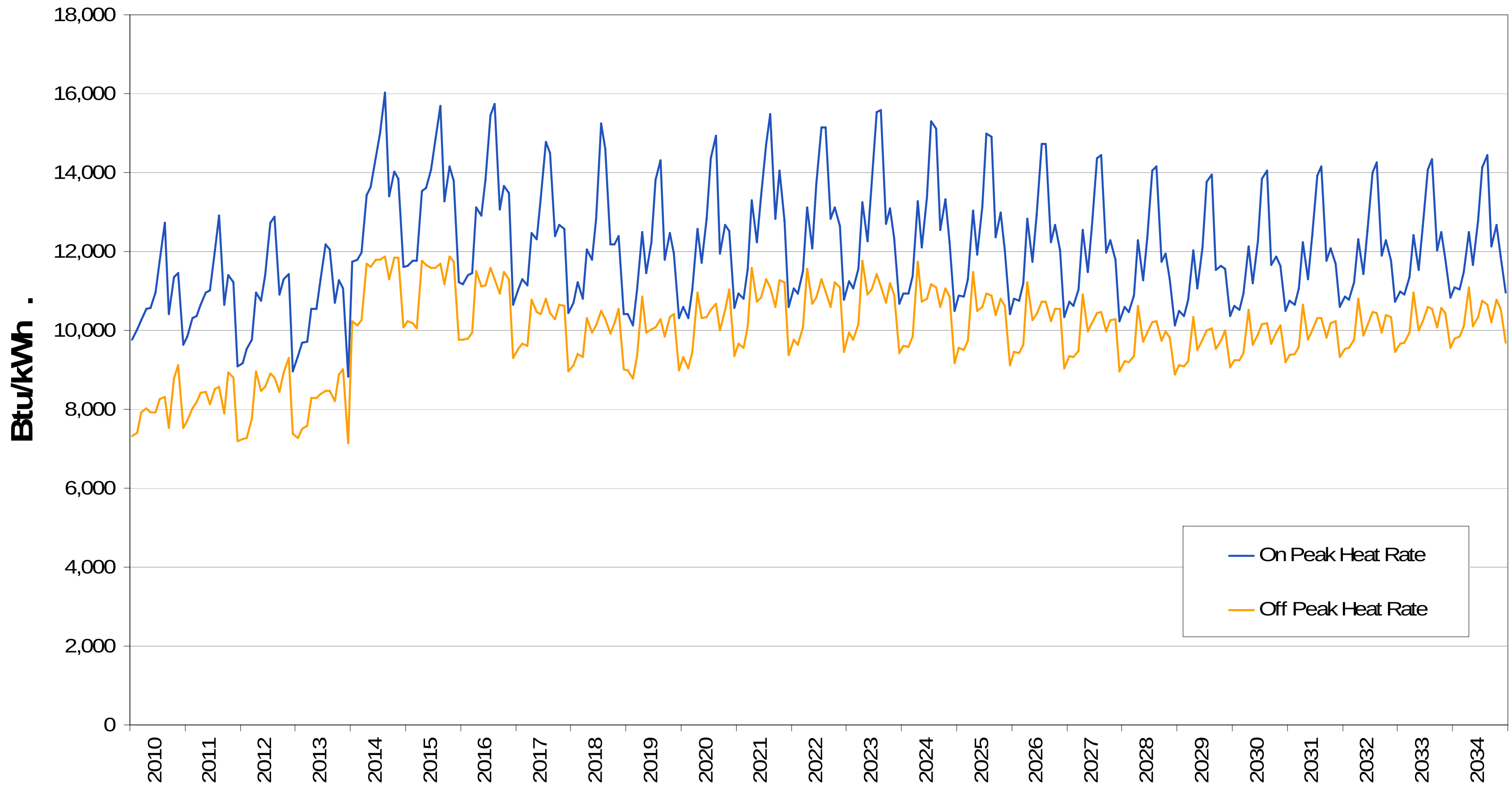
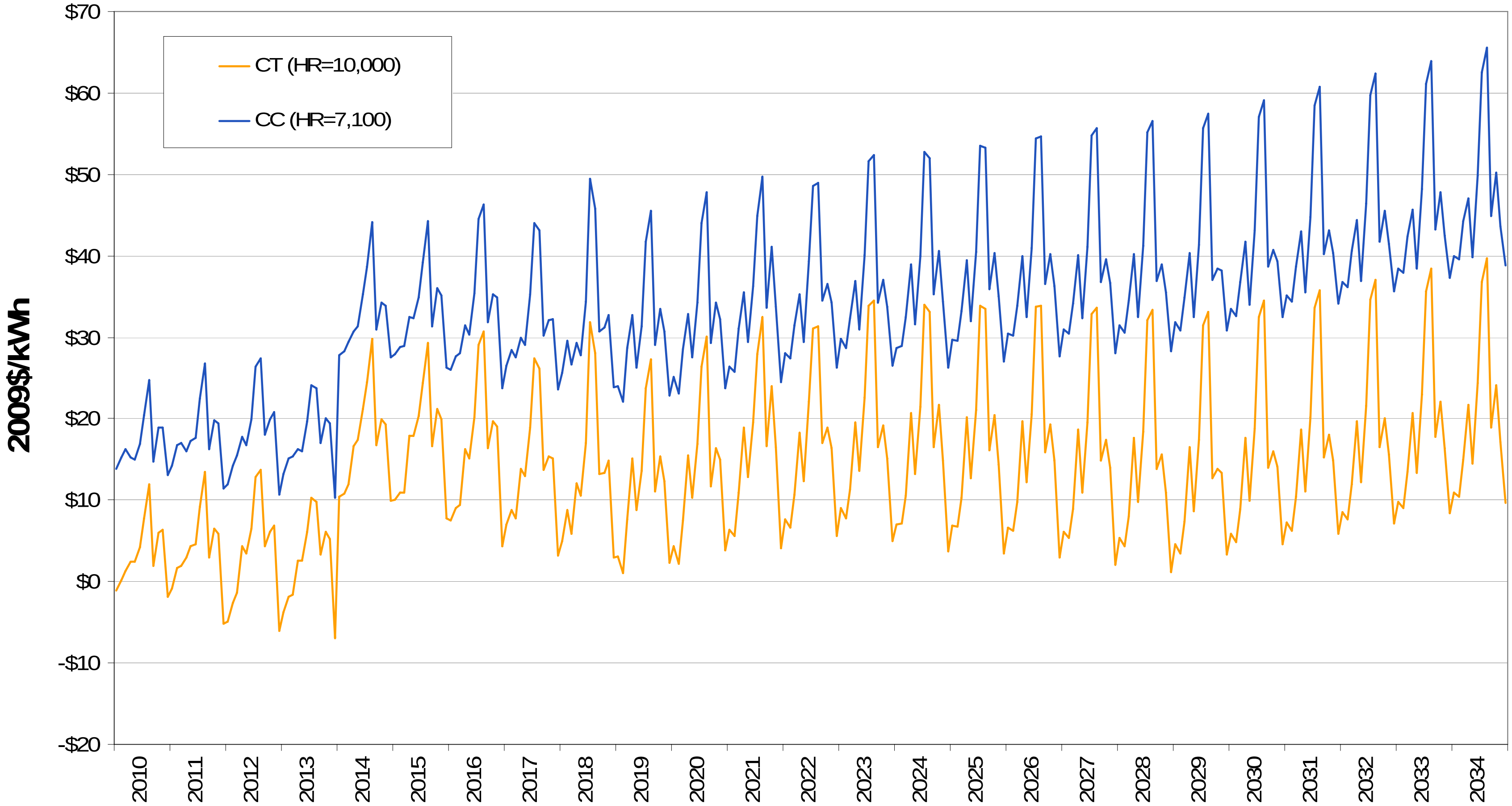
FirstEnergy (MISO) Heat Rate



Source: Black & Veatch

FirstEnergy (MISO) Spark Spreads

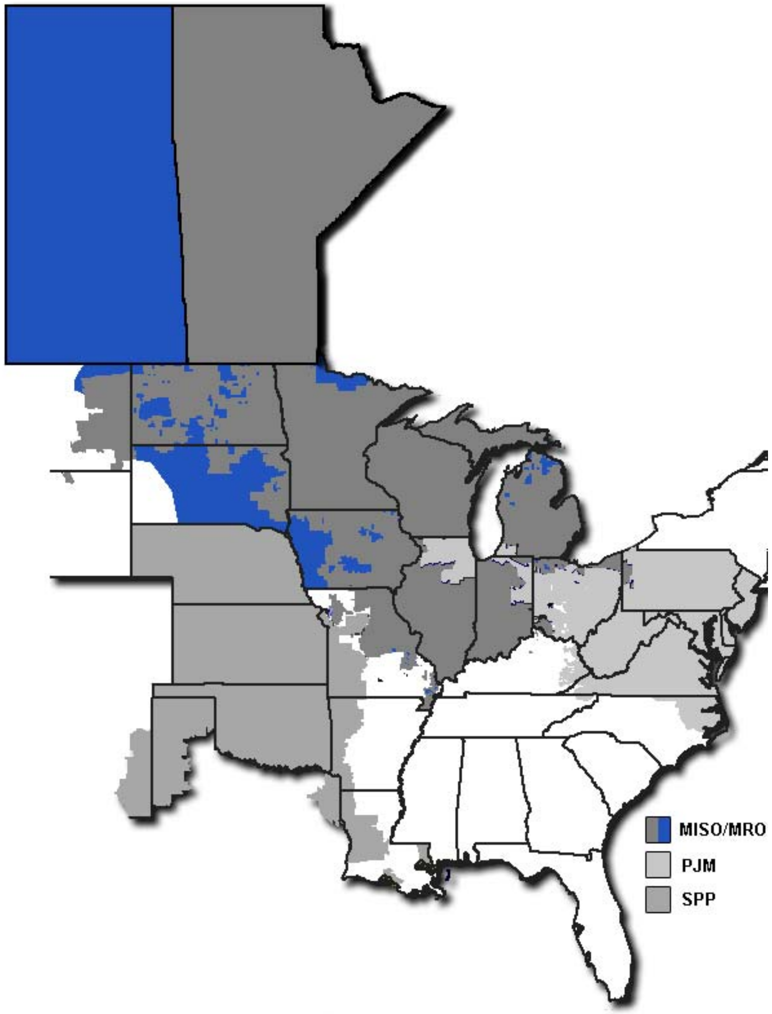


Source: Black & Veatch

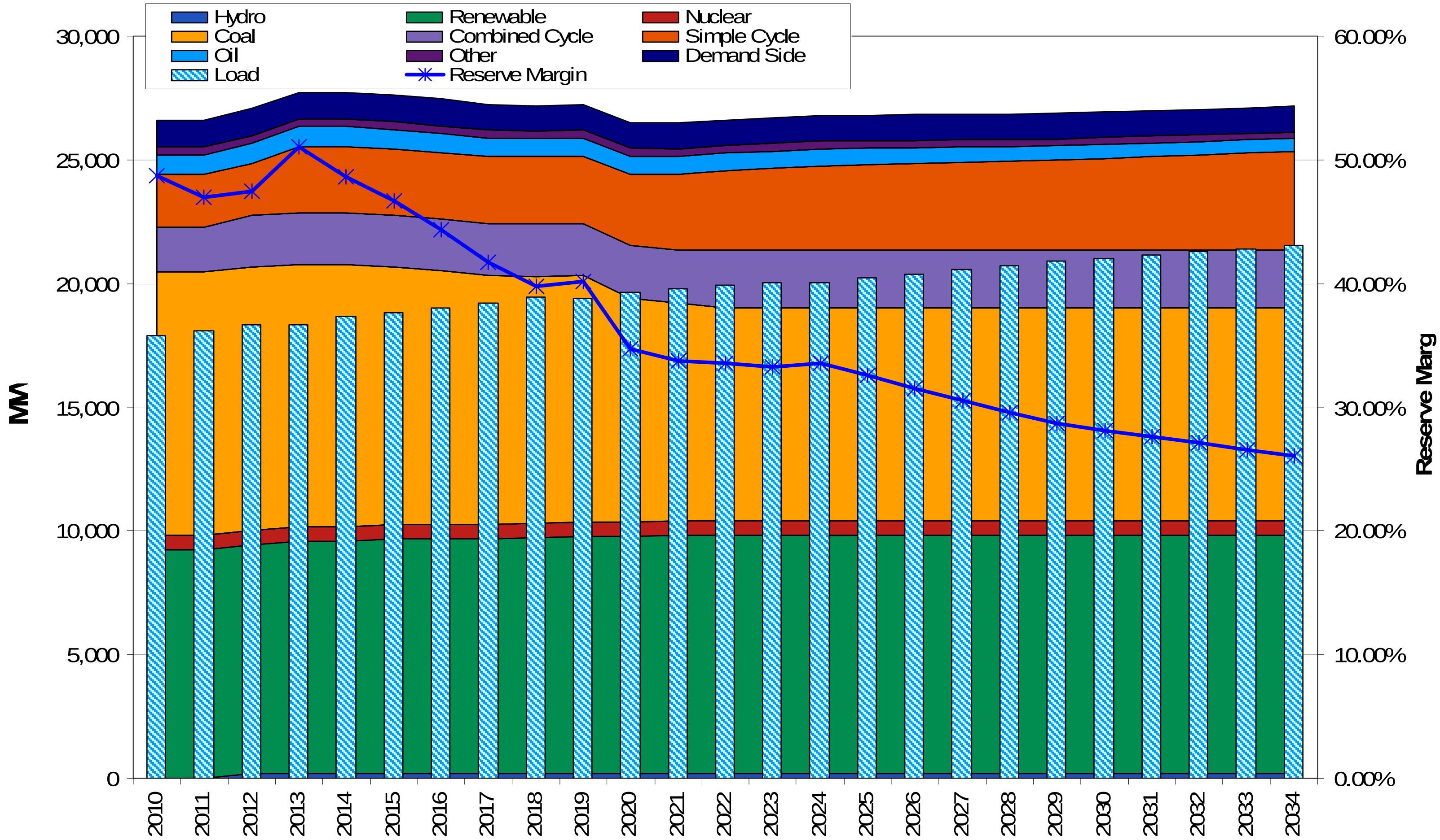
4.6 MRO Results

Midwest Reliability Organization (MRO) Overview

- Area covered: Includes areas of the Midwest Reliability Organization that are not members of MISO
- Includes portions of North Dakota, South Dakota, Montana, Manitoba Hydro, and Saskatchewan



MRO Loads & Resource Outlook



Source: Black & Veatch

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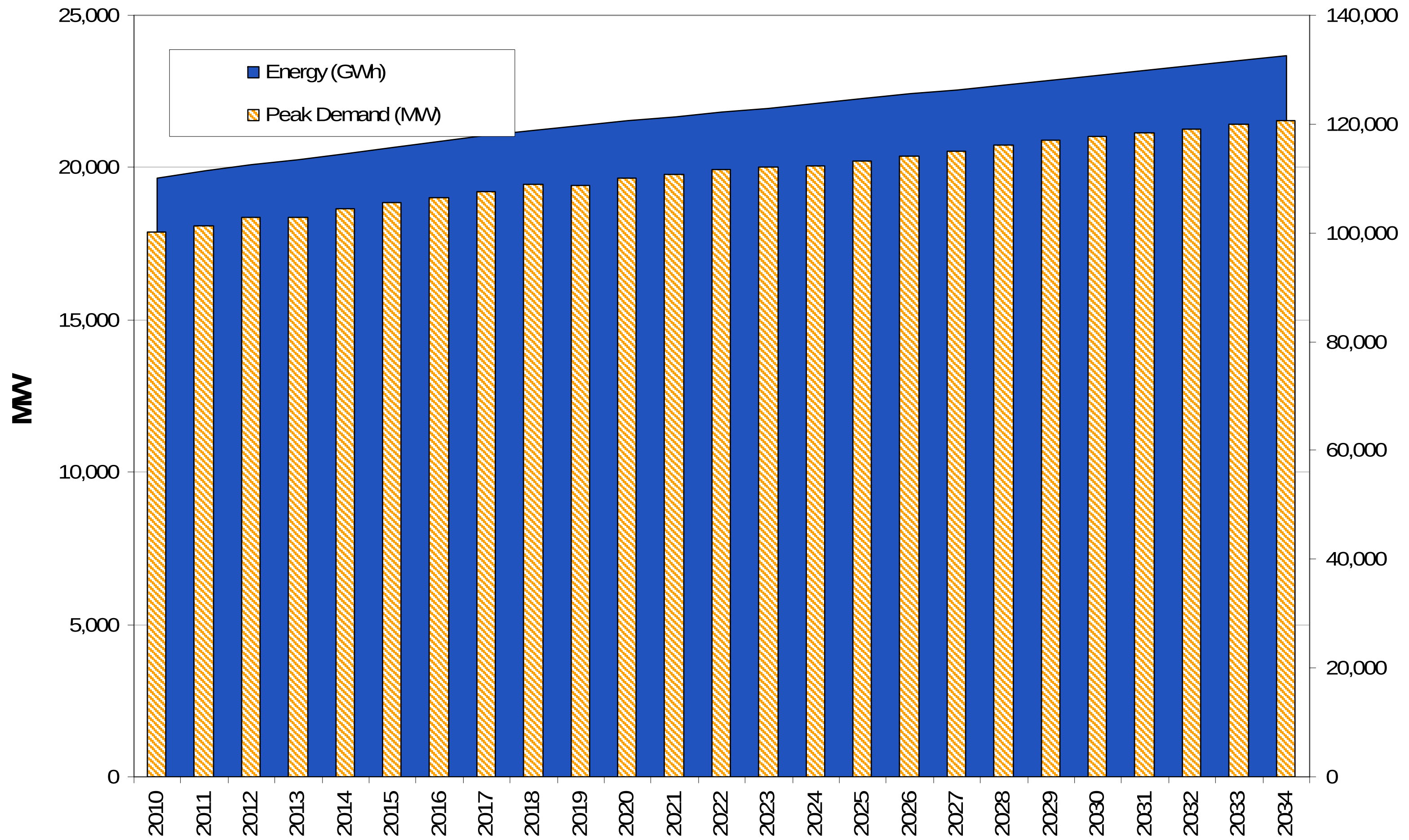
5 Renewable category includes all wind units, and all hydro units except for those excluded from being counted towards RPS compliance by state regulation.

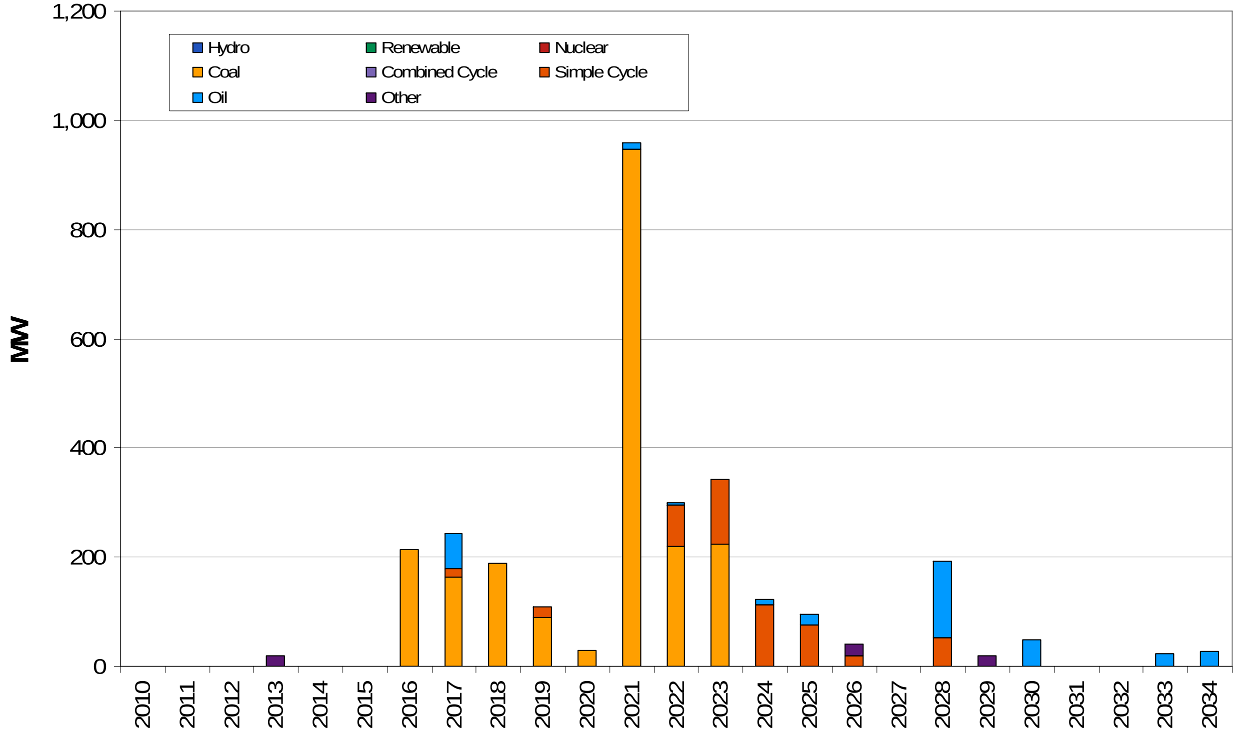
MRO Peak and Energy Load Forecast



Source: Black & Veatch

* Assumptions are an aggregate of each EMP Area.

MRO Retirements by Year



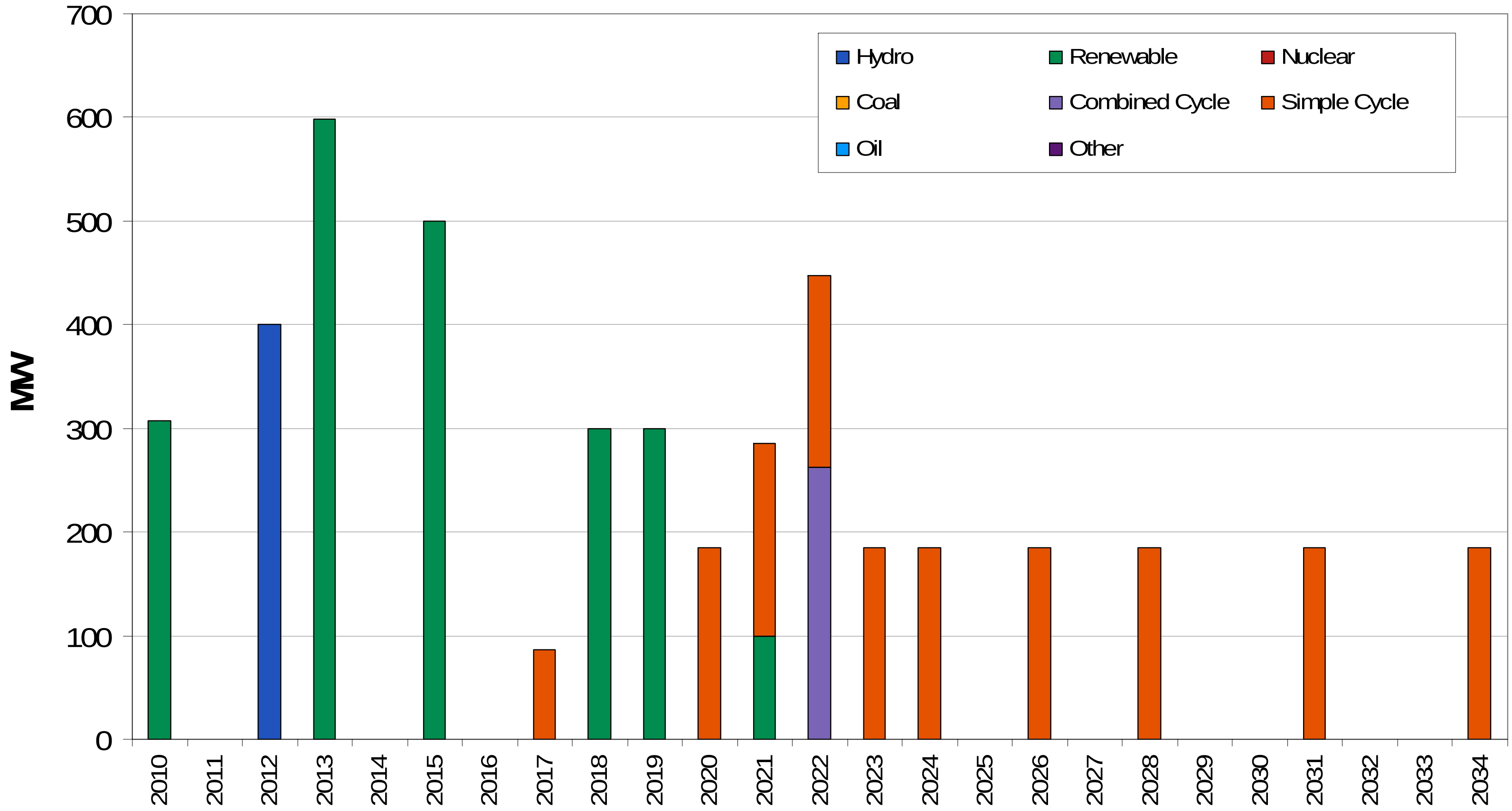
Source: Black & Veatch

*Other units include Steam Oil and Gas, and Combustion Turbine Other

** Assumptions are an aggregate of each EMP Area.

- Over 3,000 MW of cumulative capacity is retired by 2034, of which 2,000 MW is coal.

MRO Expansion by Year



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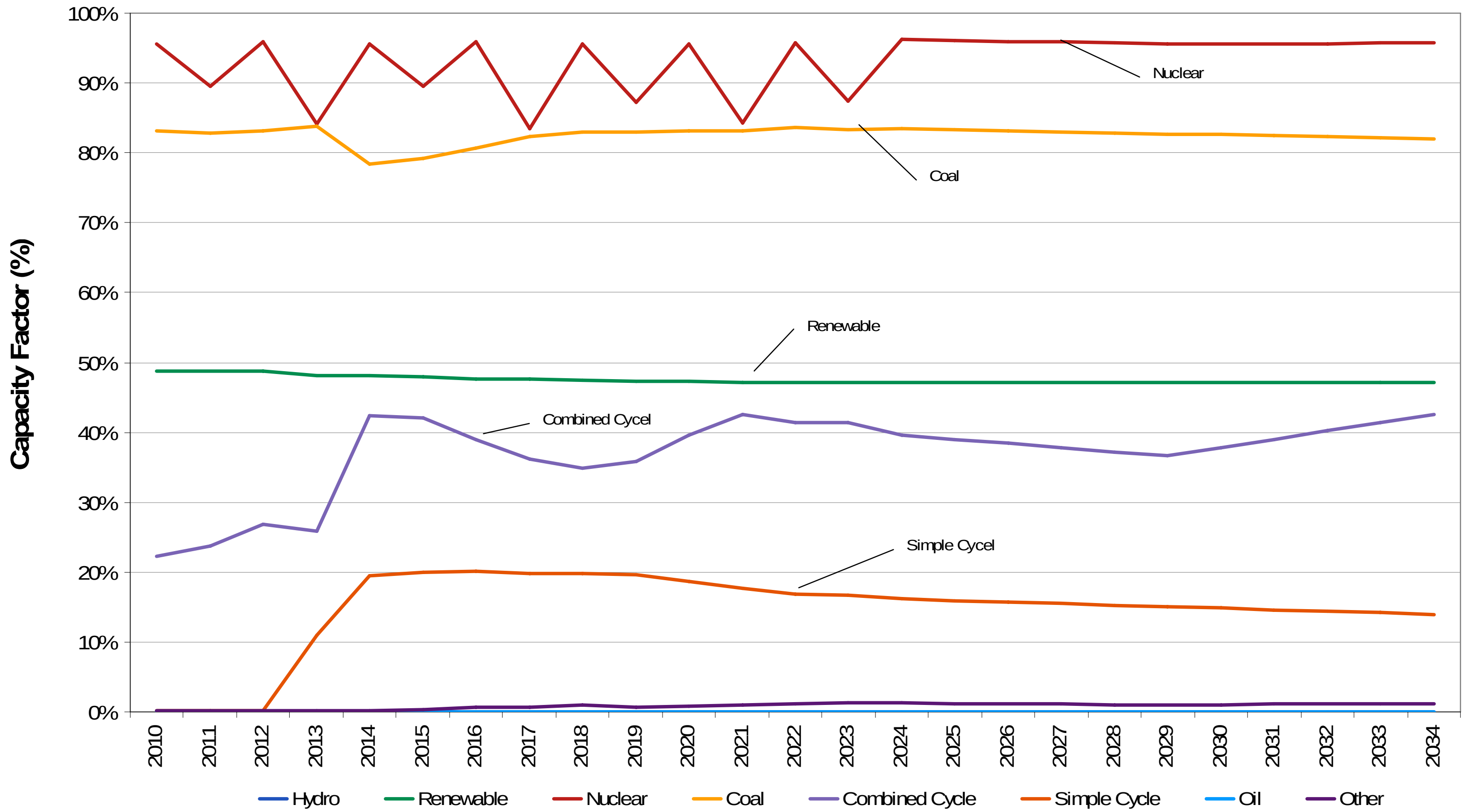
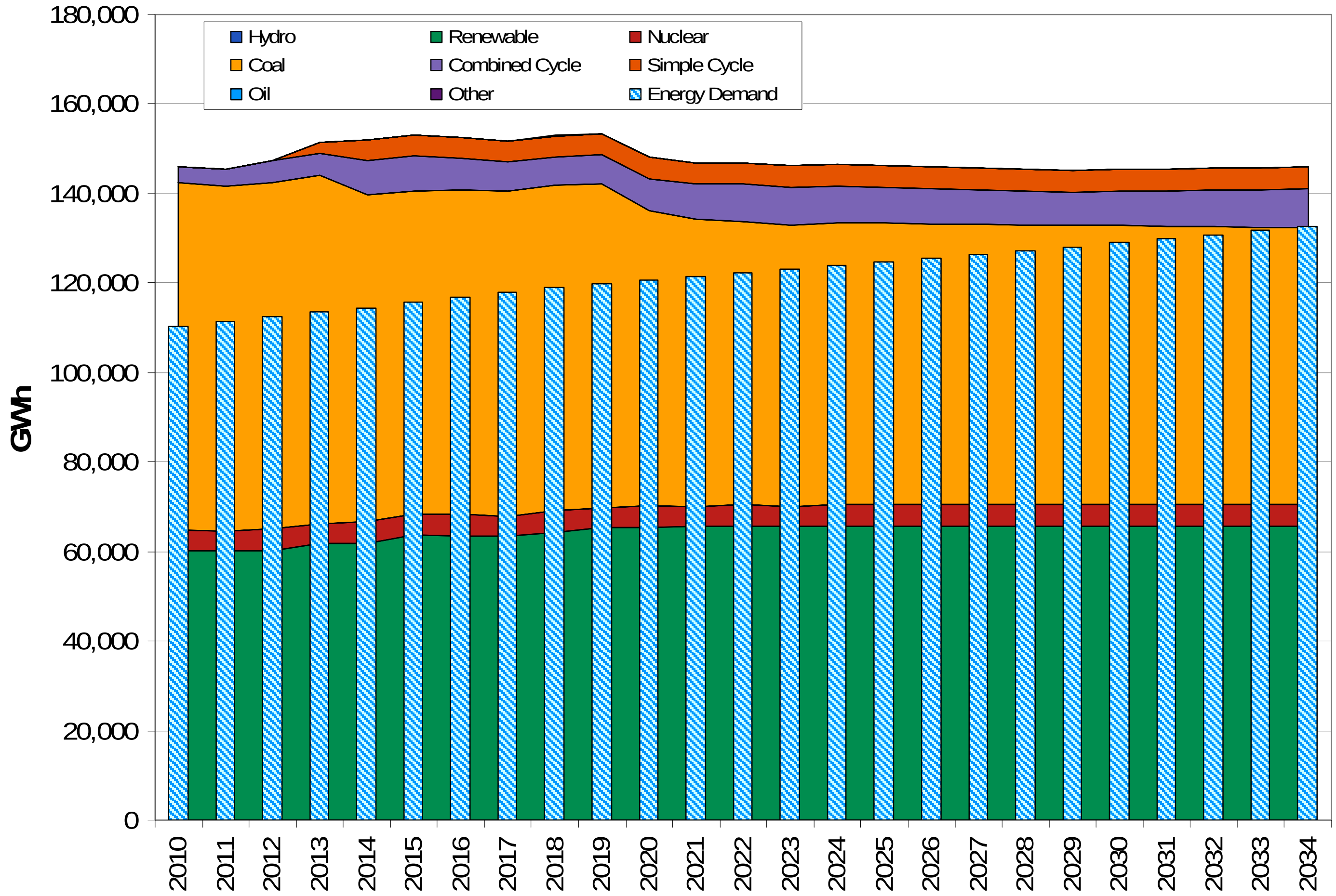
2 Assumptions are an aggregate of each EMP Area.
3 After 2024 every 5th year was modeled. Used linear interpolation between 2024 and 2029 and then 2029 and 2034.
4. All resources are reported as name plate capacity

MRO Fleet Average Capacity Factor



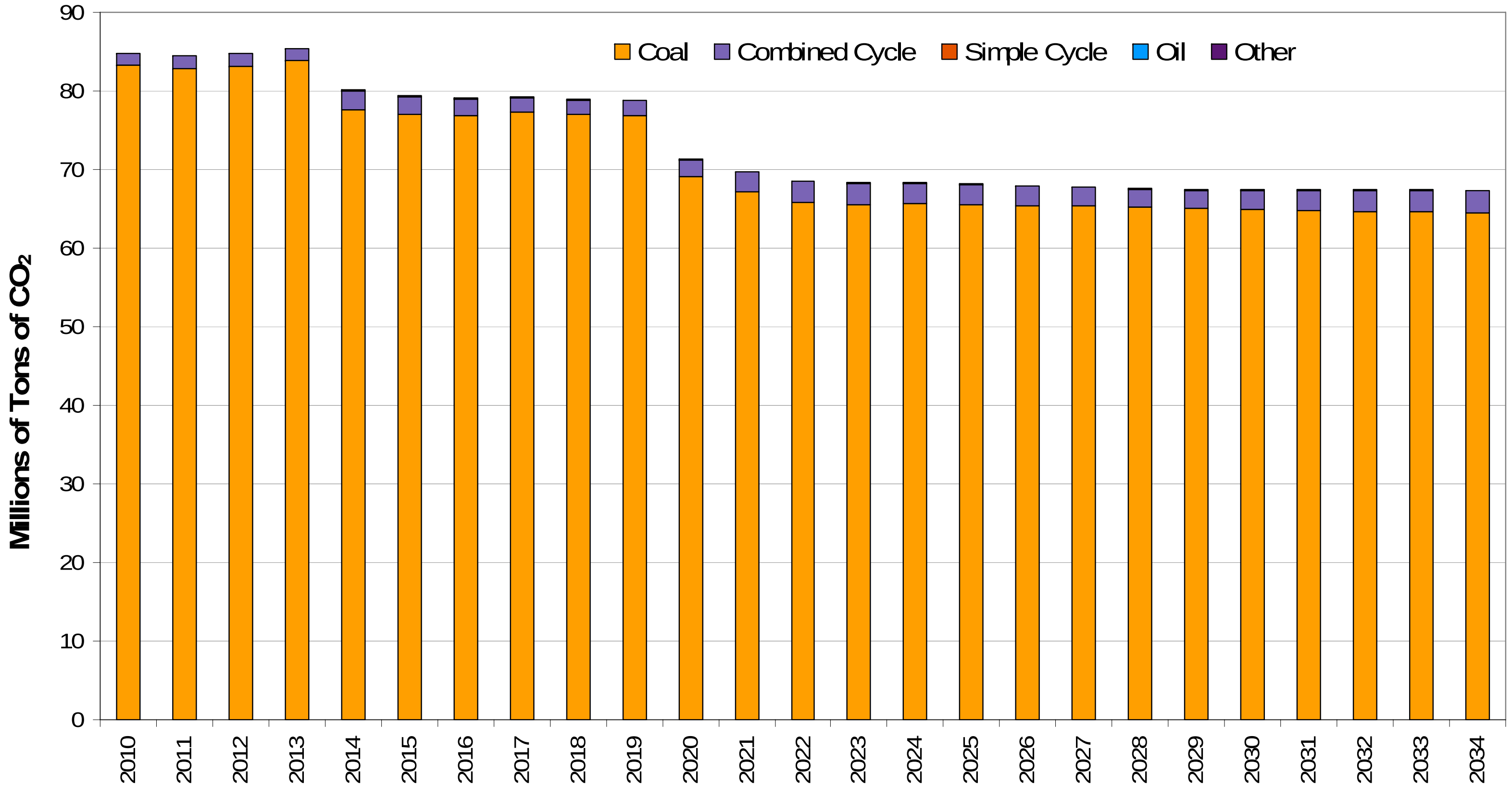
Source: Black & Veatch
1 Other units include Steam Oil and Gas, and Combustion Turbine Other
2 Results are an aggregate of each EMP Area.
3 After 2024 every 5th year was modeled. Used linear interpolation between 2024 and 2029 and then 2029 and 2034.

MRO Energy Demand and Generation by Unit Type



Source: Black & Veatch
1 Other units include Steam Oil and Gas, and Combustion Turbine Other
2 Results are an aggregate of each EMP Area.
3 After 2024 every 5th year was modeled. Used linear interpolation between 2024 and 2029 and then 2029 and 2034.
4 Renewable category includes all wind units, and all hydro units except for those excluded from being counted towards RPS compliance by state regulation.

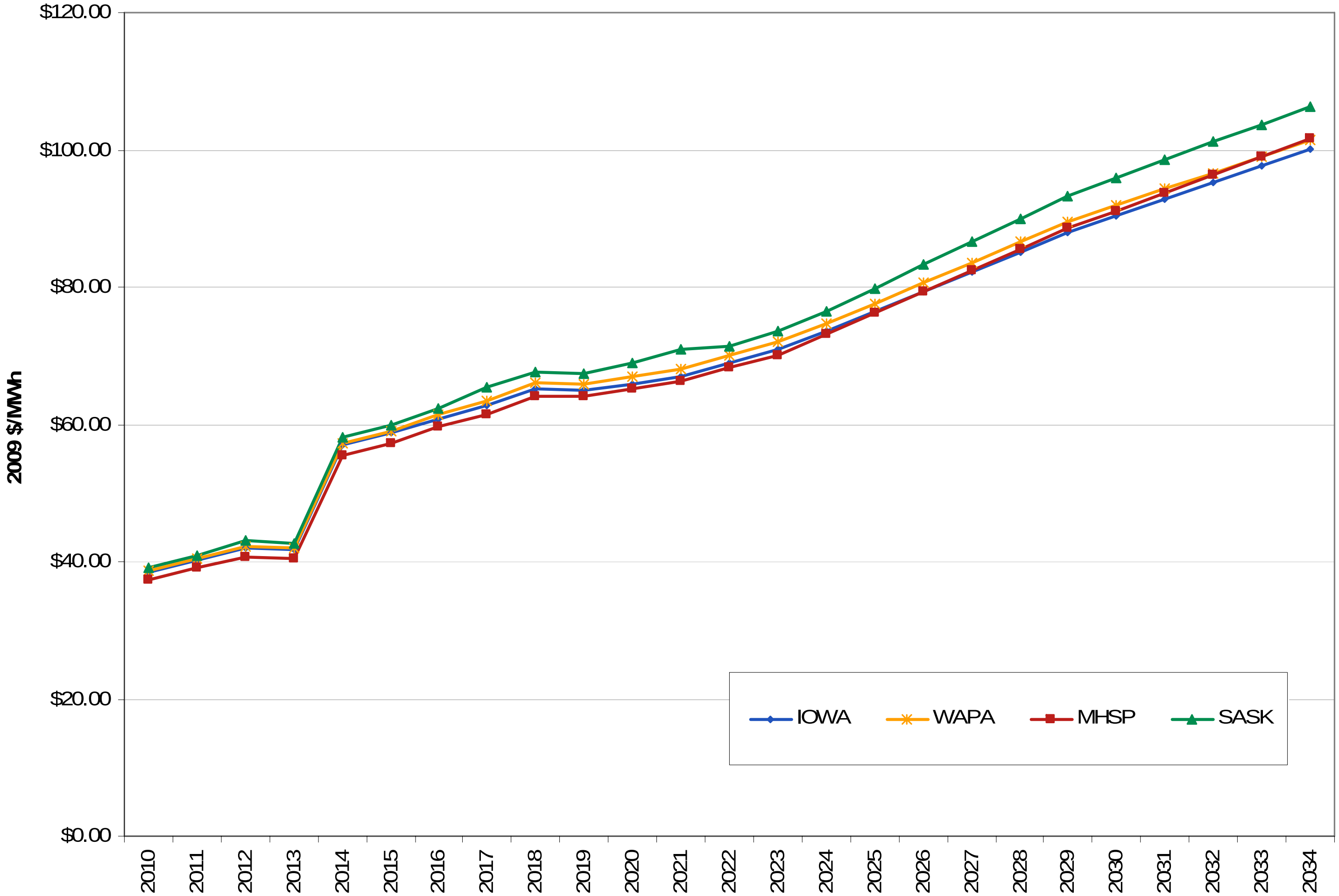
MRO CO2 Emissions by Unit Type



Source: Black & Veatch
1 Other units include Steam Oil and Gas, and Combustion Turbine Other
2 Results are an aggregate of each EMP Area.
3 After 2024 every 5th year was modeled. Used linear interpolation between 2024 and 2029 and then 2029 and 2034.

MRO Annual Average Prices

- MRO Prices increase by a step function in 2014 due to the impact of the CO2 allowance prices.
- Prices climb steadily thereafter due to the combined effect of increasing CO2 allowance prices and gas prices.

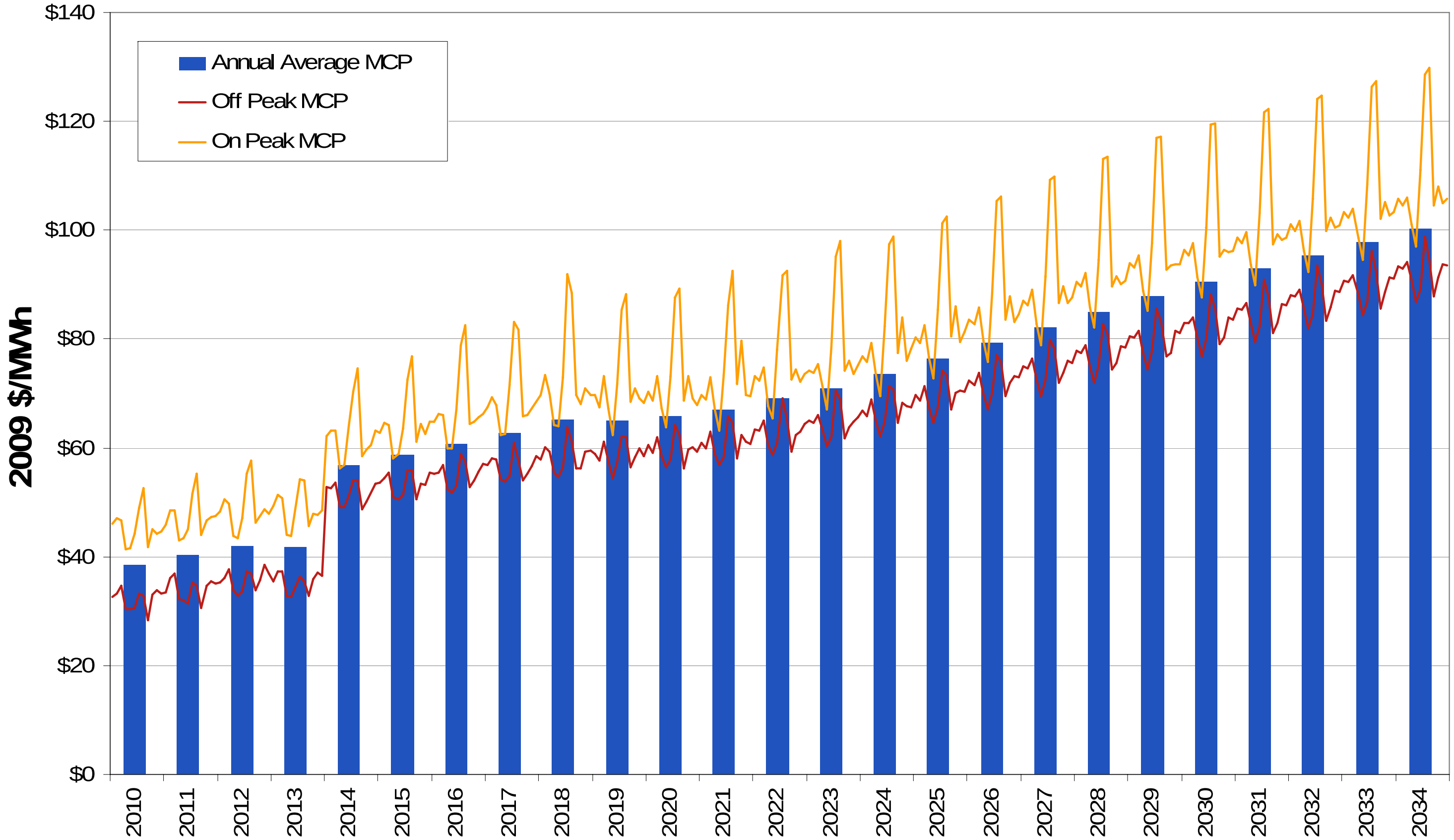


Source: Black & Veatch

* After 2024 every 5th year was modeled. Used linear interpolation between 2024 and 2029 and then 2029 and 2034.

Iowa On and Off Peak Energy Prices

- Iowa prices have a typical pattern of monthly variation and on-peak to off-peak spreads seen throughout MRO.



Source: Black & Veatch

* After 2024 every 5th year was modeled. Used linear interpolation between 2024 and 2029 and then 2029 and 2034.

4.7 SPP Results

SPP Market Structure

SPP Southwest Power Pool

- RTO/ISO since February 2004
- Nodal Pricing Since February 2007
- Real-time (LIPs)
- Ancillary Services Markets being phased-in.
- Working Group formed to address market based congestion management
- Currently no Capacity Markets (LSE required to have 13.6% reserve margin)
- Multi-Control Area Structure

Source: SPP website

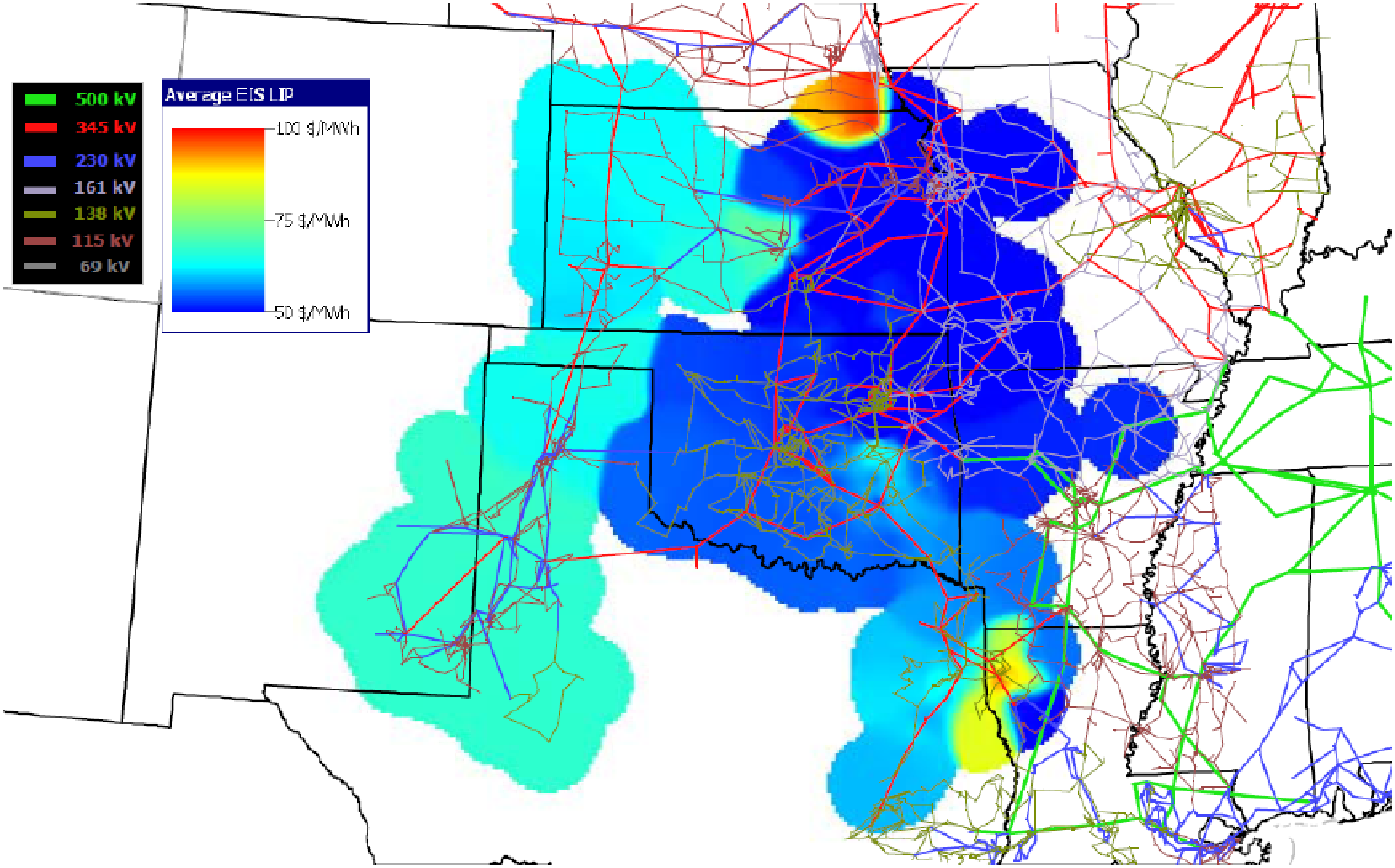
SPP Highlights and Market Structure

SPP Southwest Power Pool

- 2009 System Peak (non-coincident): 47,365 MW
- Net Energy for Load: 210,074 GWh
- Generating Plants: 451
- Capacity/Generation by Fuel Type
  - Coal 39% / 64%
  - Gas/Oil 42% / 26%
  - Nuclear 2% / 6%
  - Wind 1% / 3%
  - Other 11% / 1%
  - Hydro 4% / 1%
- Three Nebraska Utilities (NPPD, OPPD, LES) joined SPP in 2009
- 2008 SPP Transmission Expansion Plan Approved in February 2009

Source: SPP website

SPP Transmission Expansion Plan (Congestion Topology)

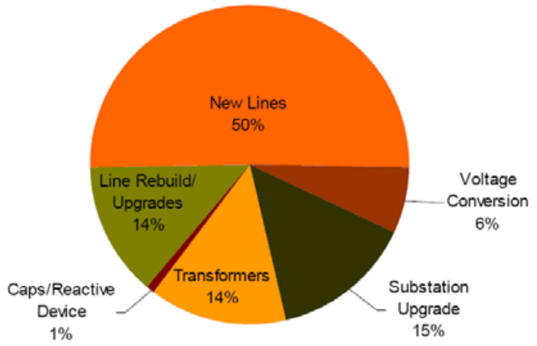


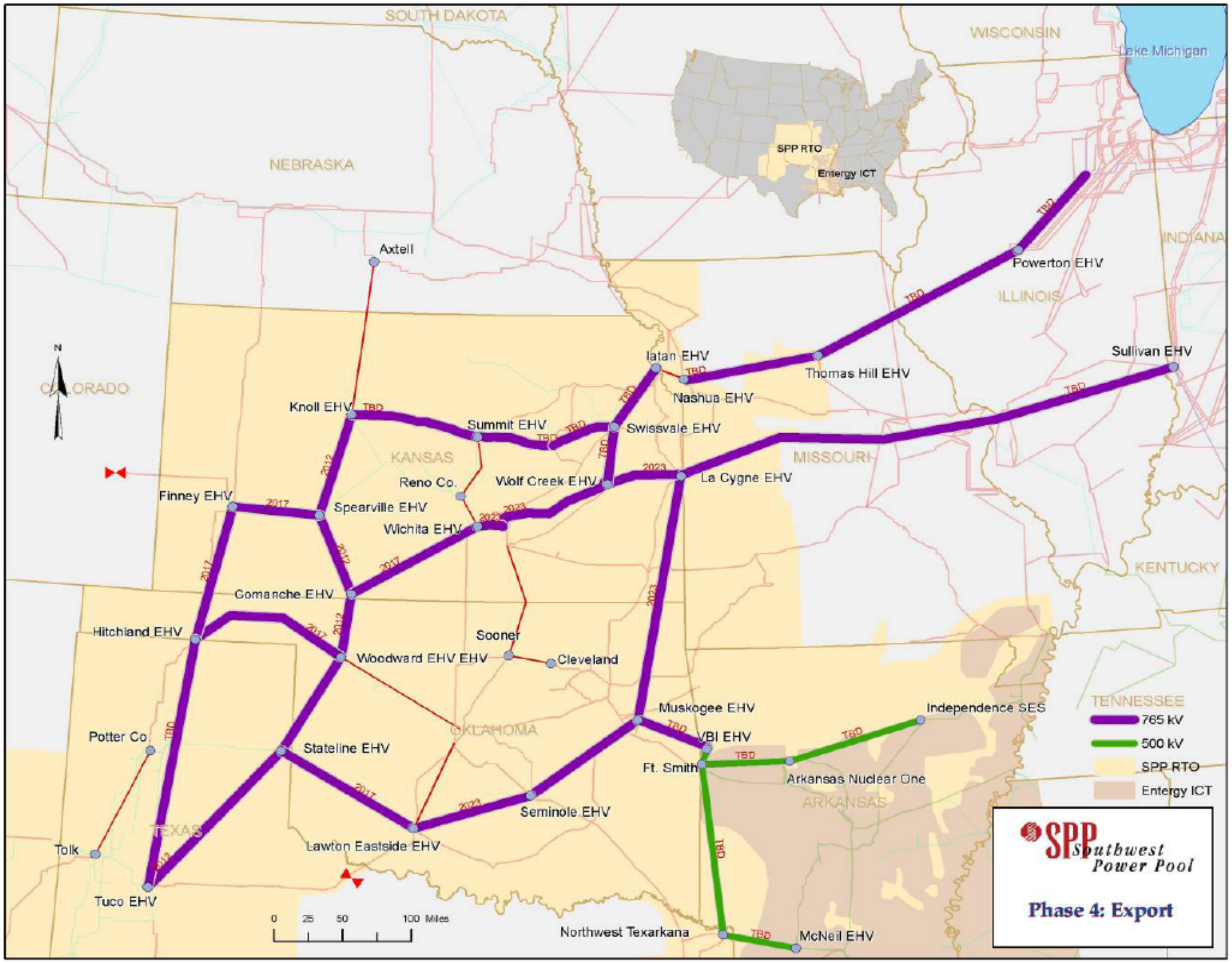
Source: www.spp.org website

SPP Transmission Expansion Plan

- Recommend improvements for 8 state region
- 1753 miles of new transmission
- 80 new or upgraded transmission

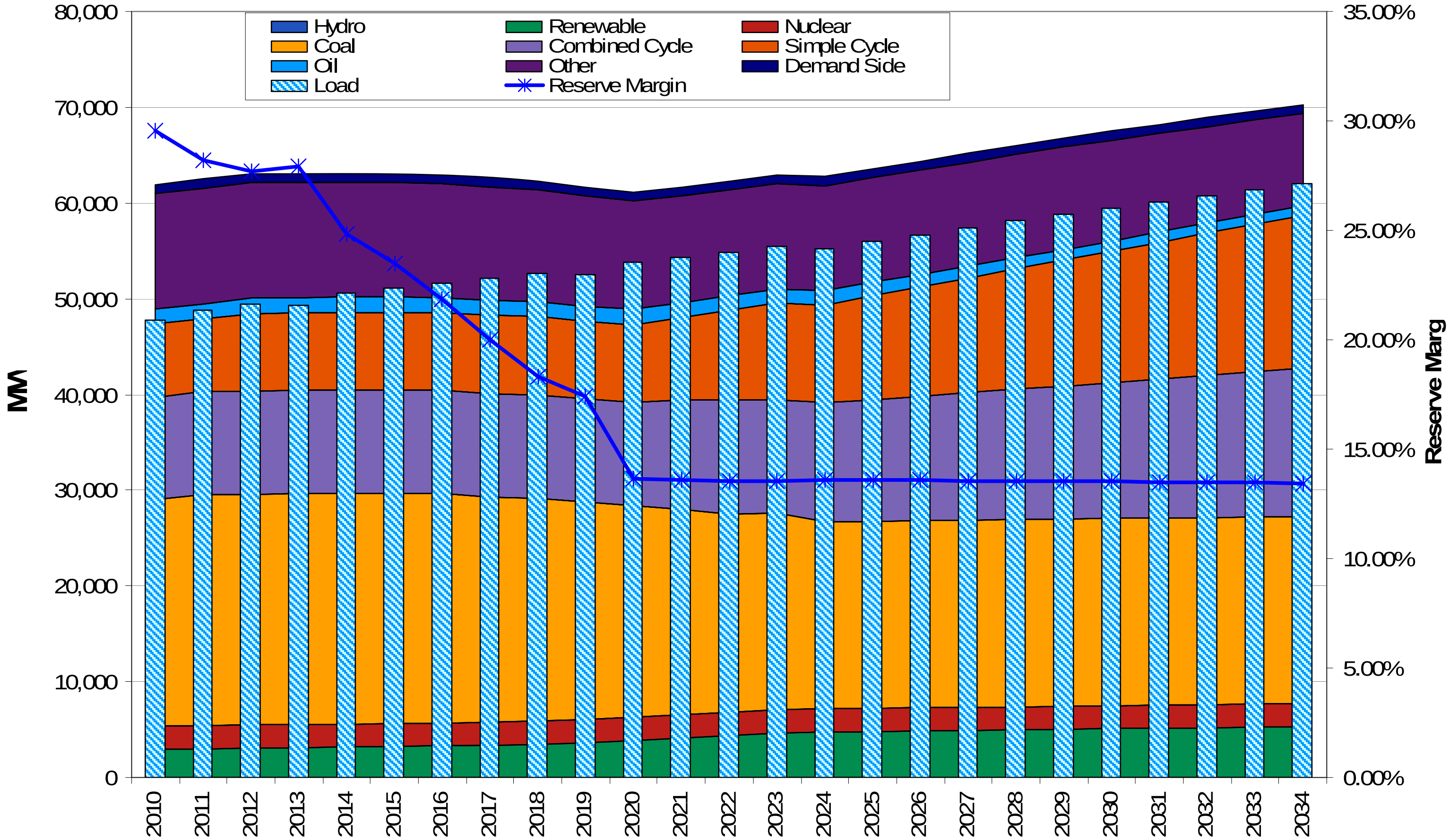
Project Cost by Network Upgrade Type
Total $2.7 Billion





Source: www.spp.org website

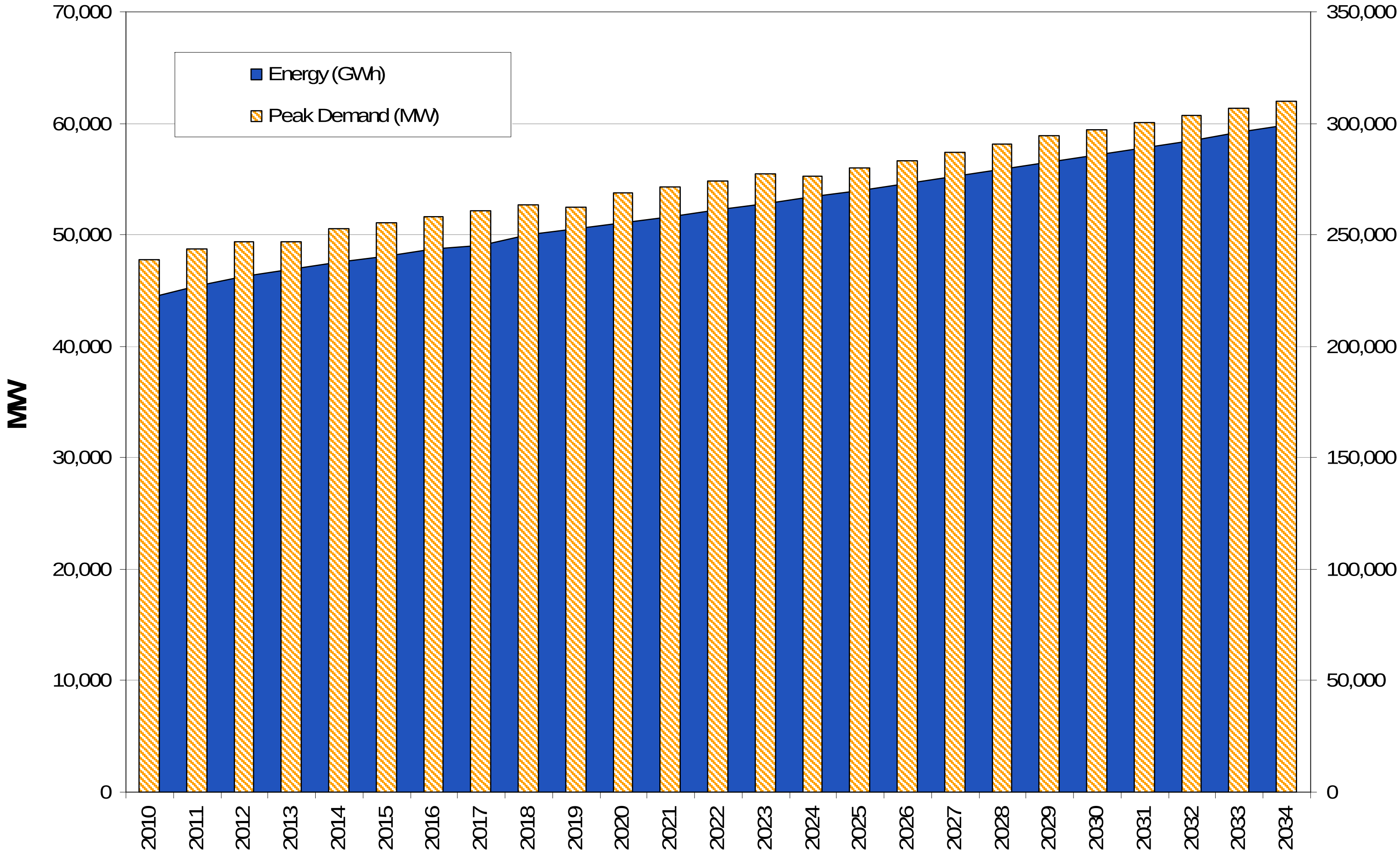
Southwest Power Pool Loads & Resource Outlook



Source: Black & Veatch

1 All resources are nameplate capacity except for wind (renewable) which has been de-rated to 20% of nameplate capacity
2 Loads are shown for August peak load
3 Other units include Steam Oil and Gas, and Combustion Turbine Other
4 After 2024 every 5th year was modeled. Used linear interpolation between 2024 and 2029 and then 2029 and 2034.
5 Renewable category includes all wind units, and all hydro units except for those excluded from being counted towards RPS compliance by state regulation.

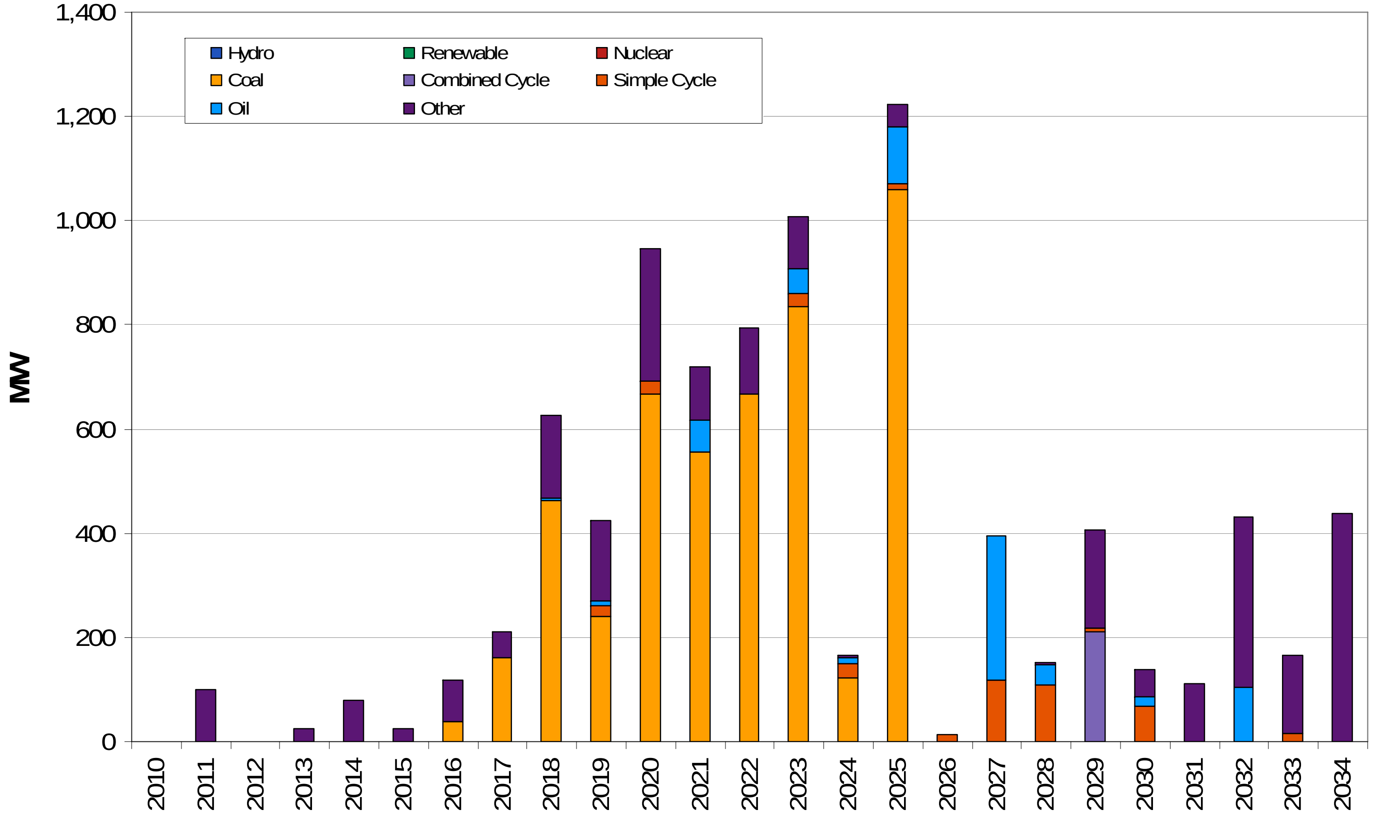
SPP Peak and Energy Load Forecast



Source: Black & Veatch

* Assumptions are an aggregate of each EMP Area.

Southwest Power Pool Retirements by Year



Source: Black & Veatch

*Other units include Steam Oil and Gas, and Combustion Turbine Other

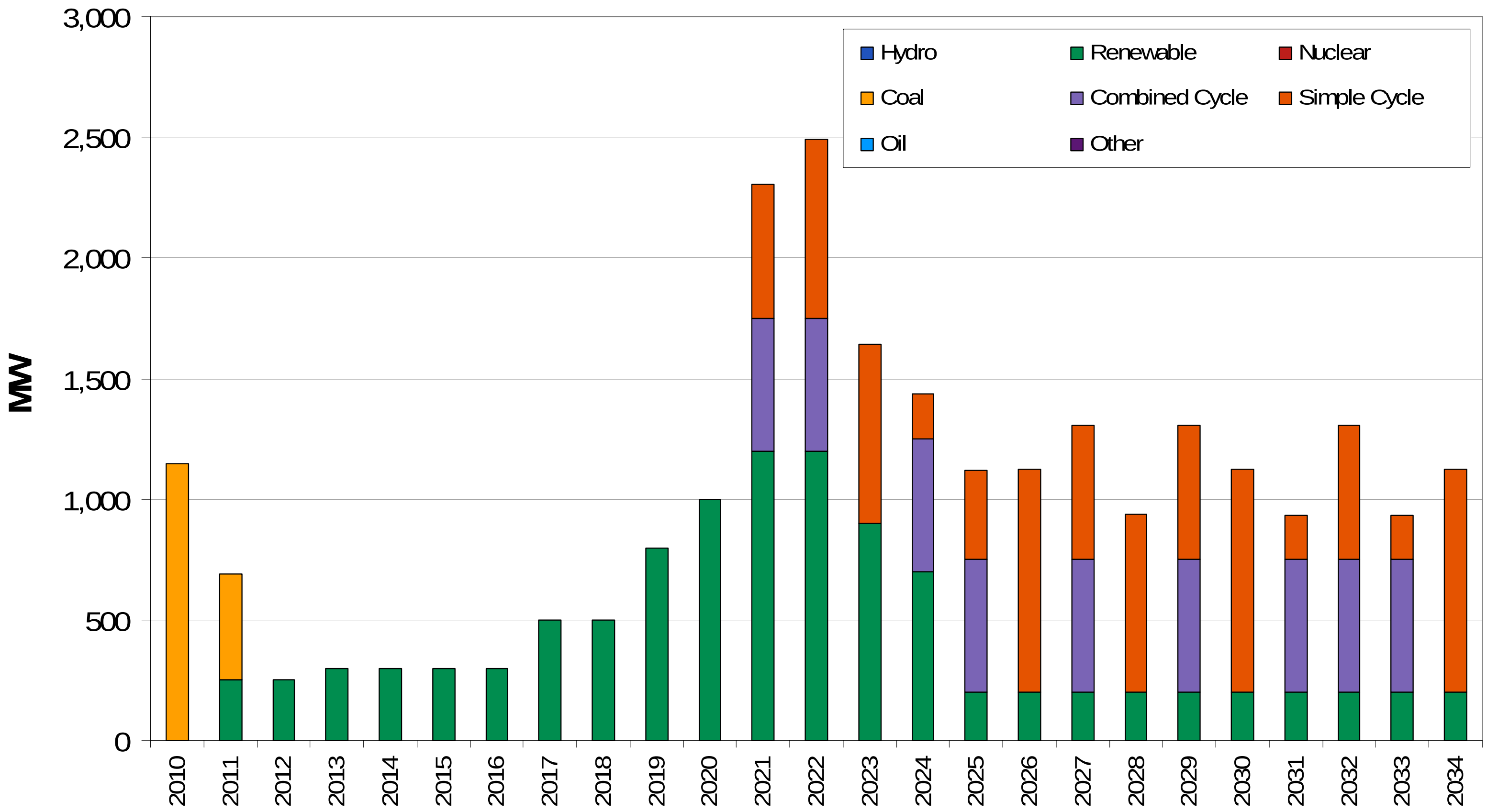
** Assumptions are an aggregate of each EMP Area.

- Over 8,700 MW of cumulative capacity is retired by 2034

  Coal – 4,800 MWCT – 450 MW | Oil – 700 MW

  CC – 200 MW | Other – 2,600 MW

SPP Expansion by Year



Source: Black & Veatch
1 Other units include Steam Oil and Gas, and Combustion Turbine Other
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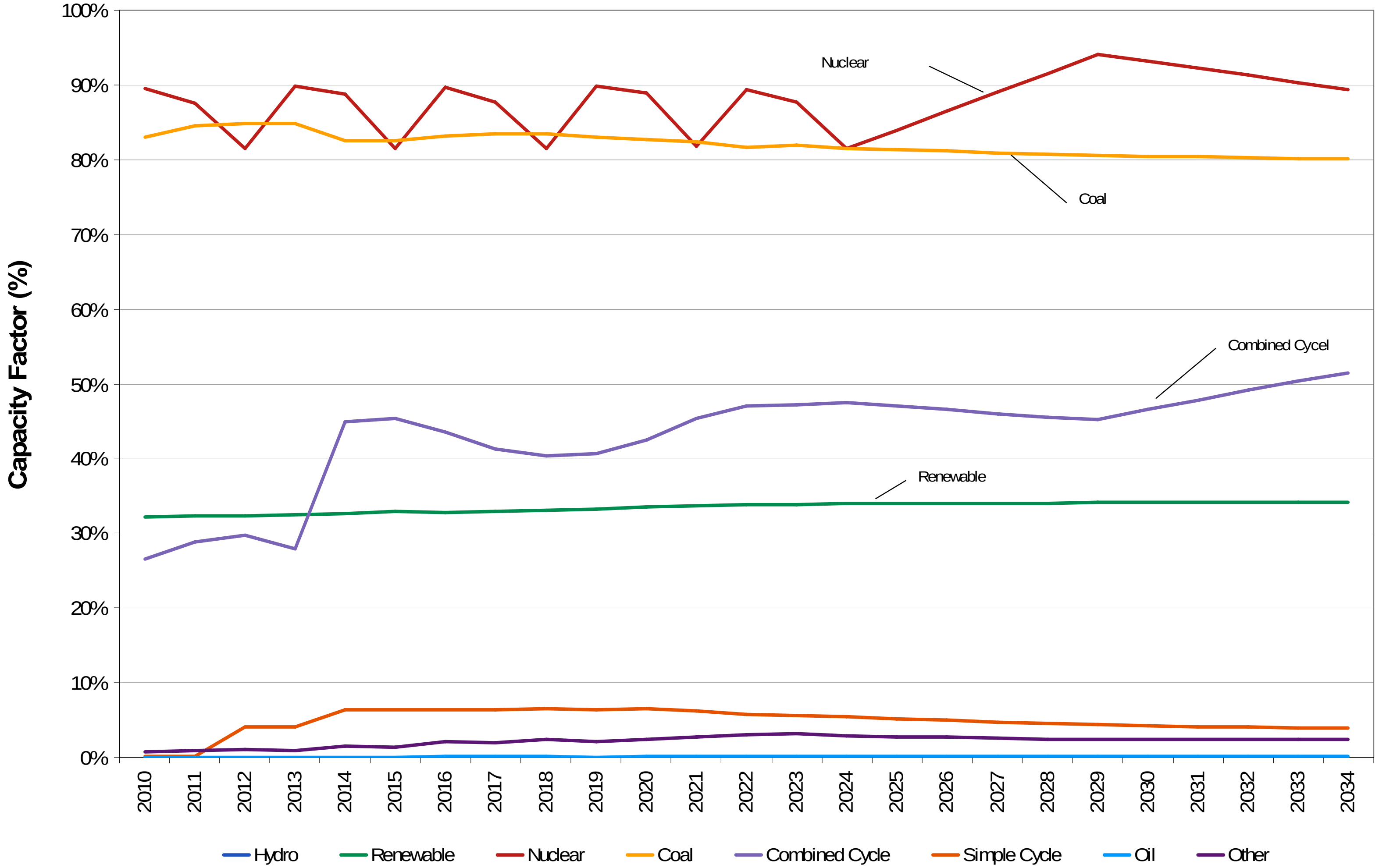
Southwest Power Pool Fleet Average Capacity Factor



Source: Black & Veatch
1 Other units include Steam Oil and Gas, and Combustion Turbine Other
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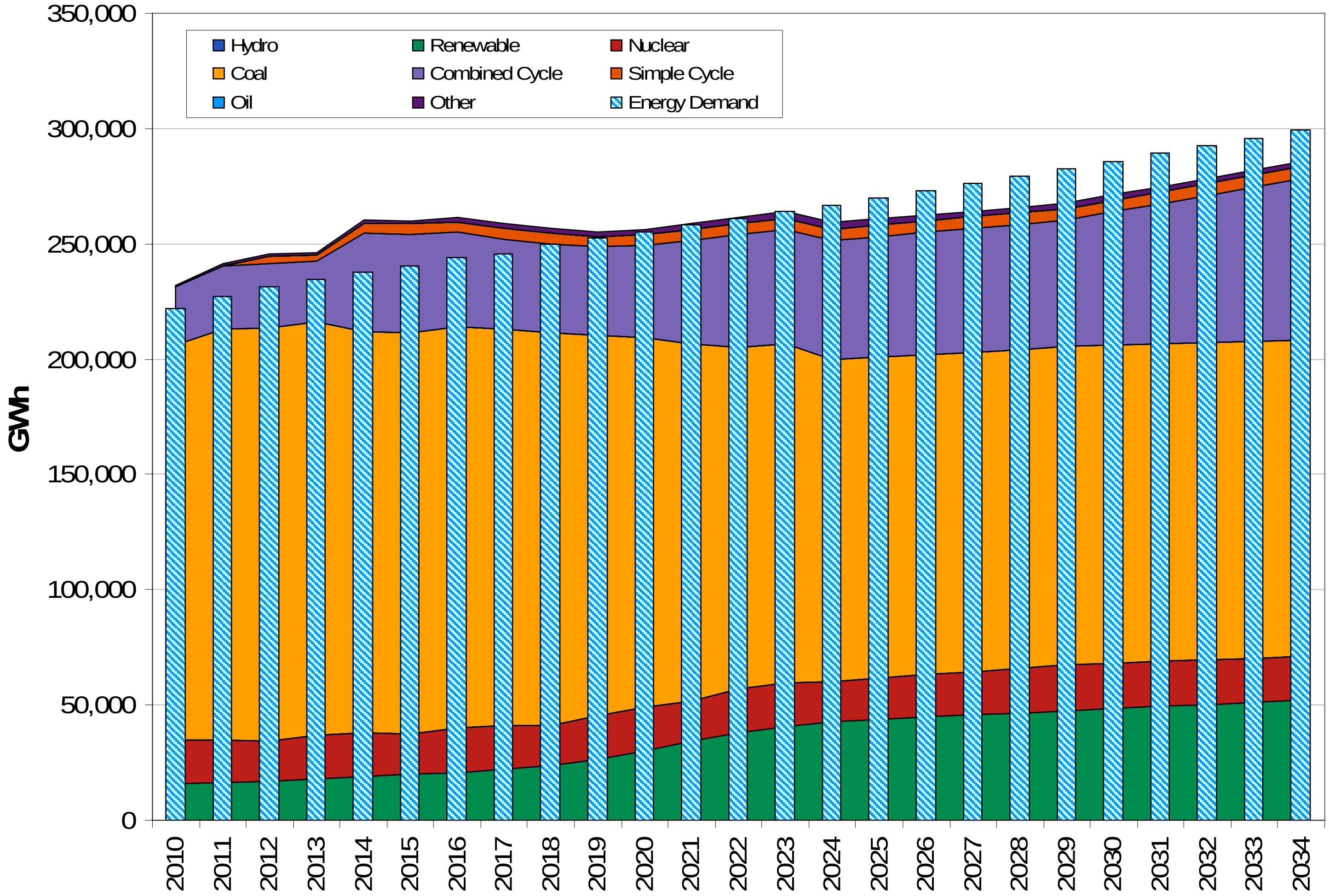
SPP Energy Demand and Generation by Unit Type



Source: Black & Veatch

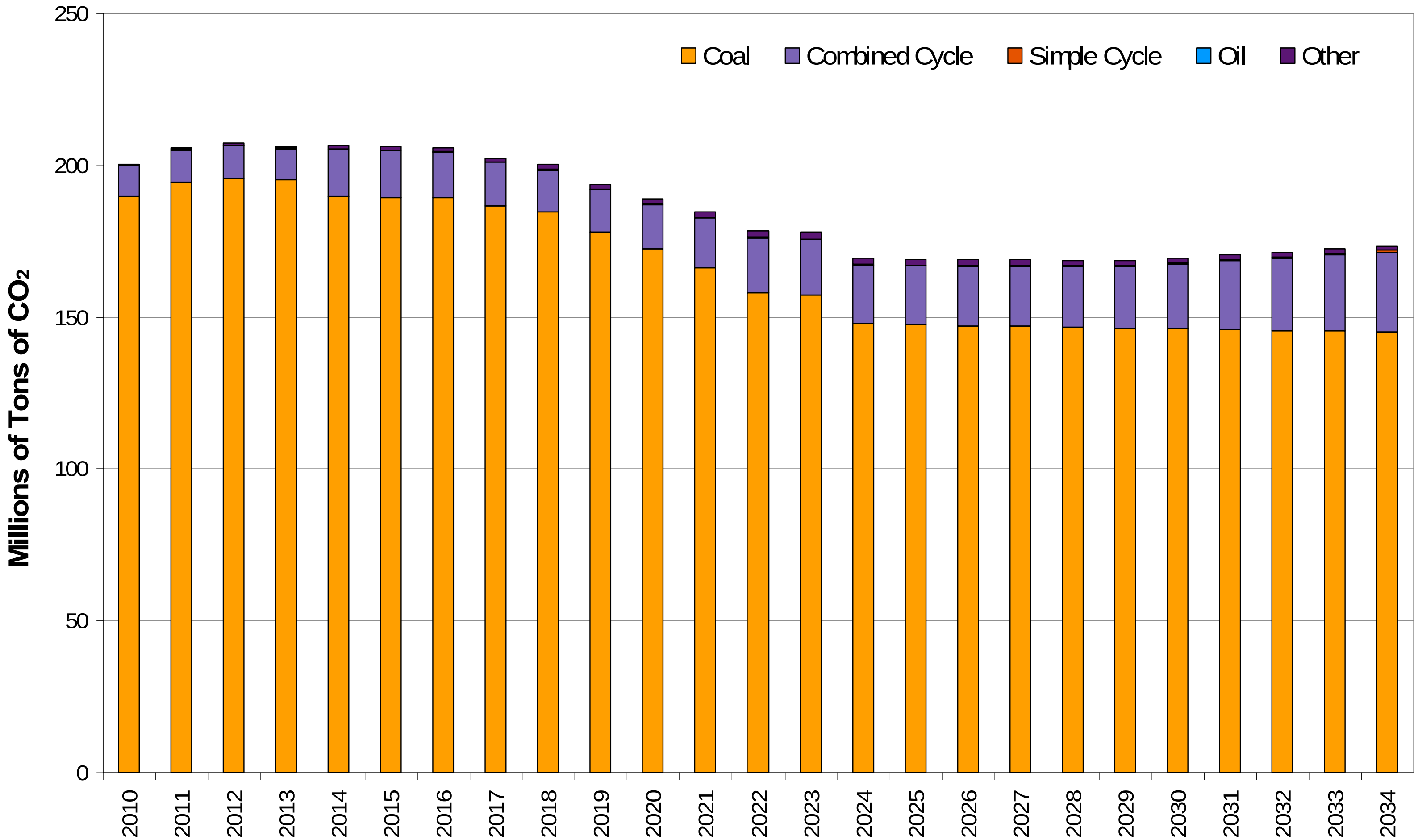
1 Other units include Steam Oil and Gas, and Combustion Turbine Other

2 Results are an aggregate of each EMP Area.

3 After 2024 every 5th year was modeled. Used linear interpolation between 2024 and 2029 and then 2029 and 2034.

4 Renewable category includes all wind units, and all hydro units except for those excluded from being counted towards RPS compliance by state regulation.

SPP CO2 Emissions by Unit Type



Source: Black & Veatch
1 Other units include Steam Oil and Gas, and Combustion Turbine Other
2 Results are an aggregate of each EMP Area.
3 After 2024 every 5th year was modeled. Used linear interpolation between 2024 and 2029 and then 2029 and 2034.

SPP Annual Average Prices

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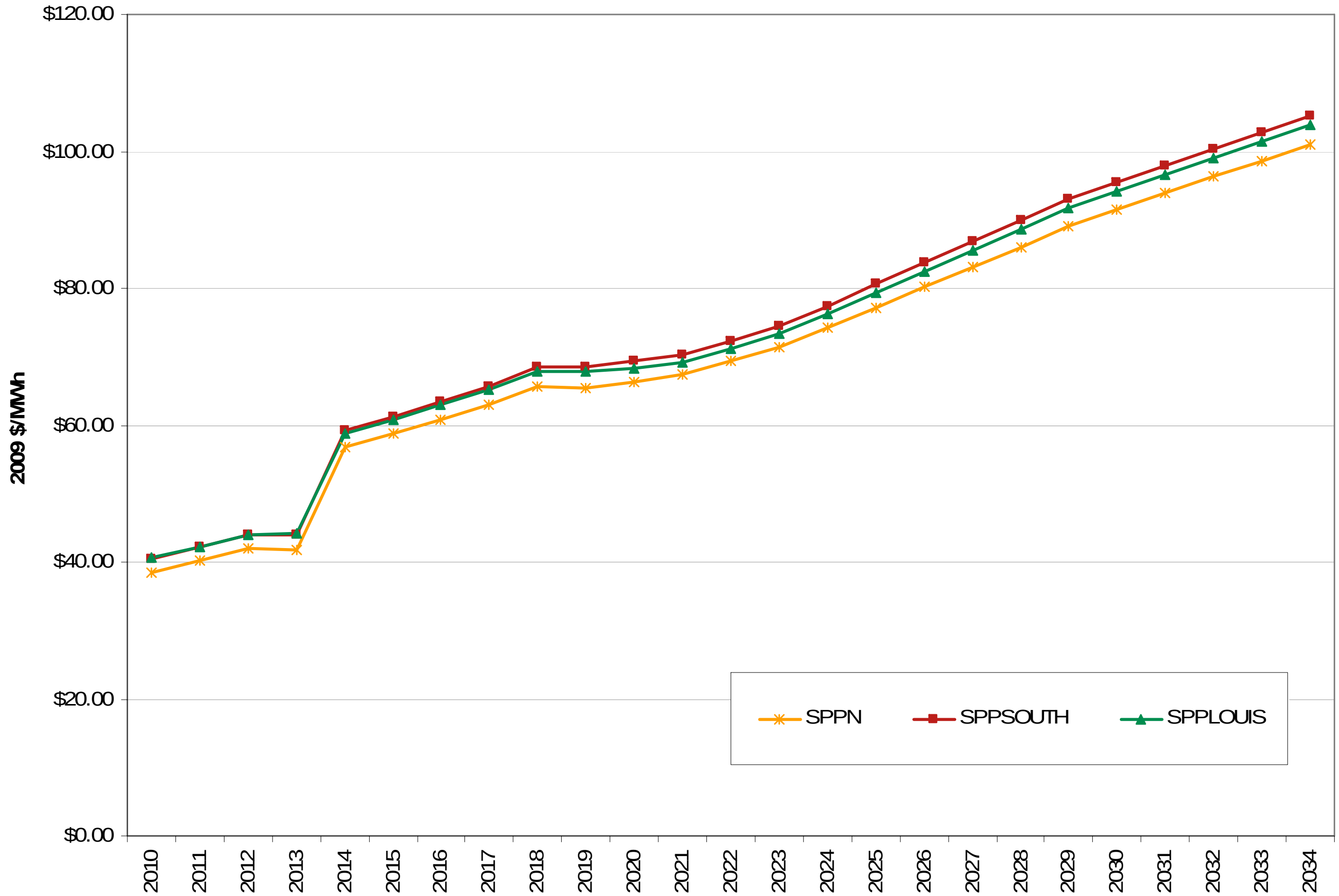
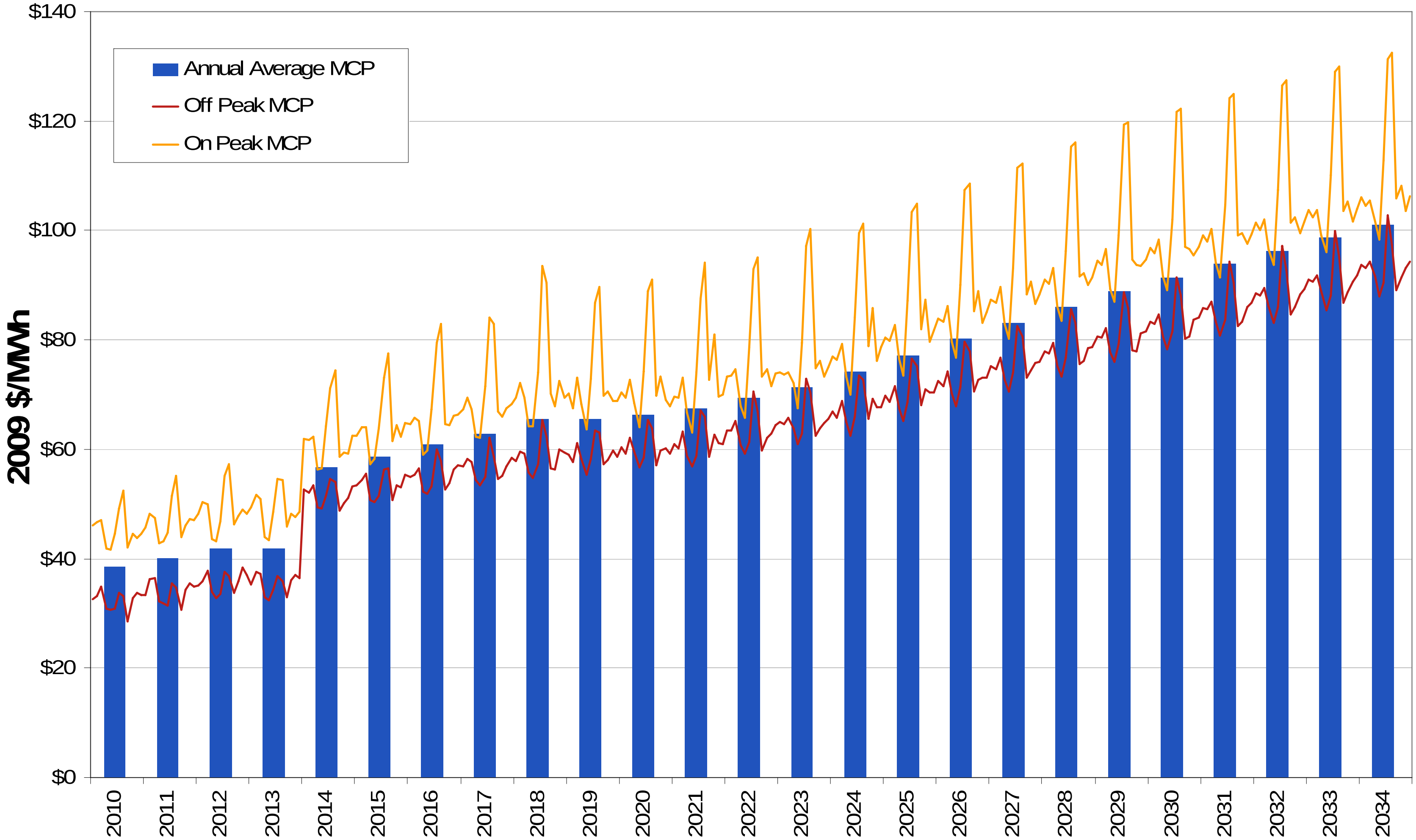


Source: Black & Veatch

* After 2024 every 5th year was modeled. Used linear interpolation between 2024 and 2029 and then 2029 and 2034.

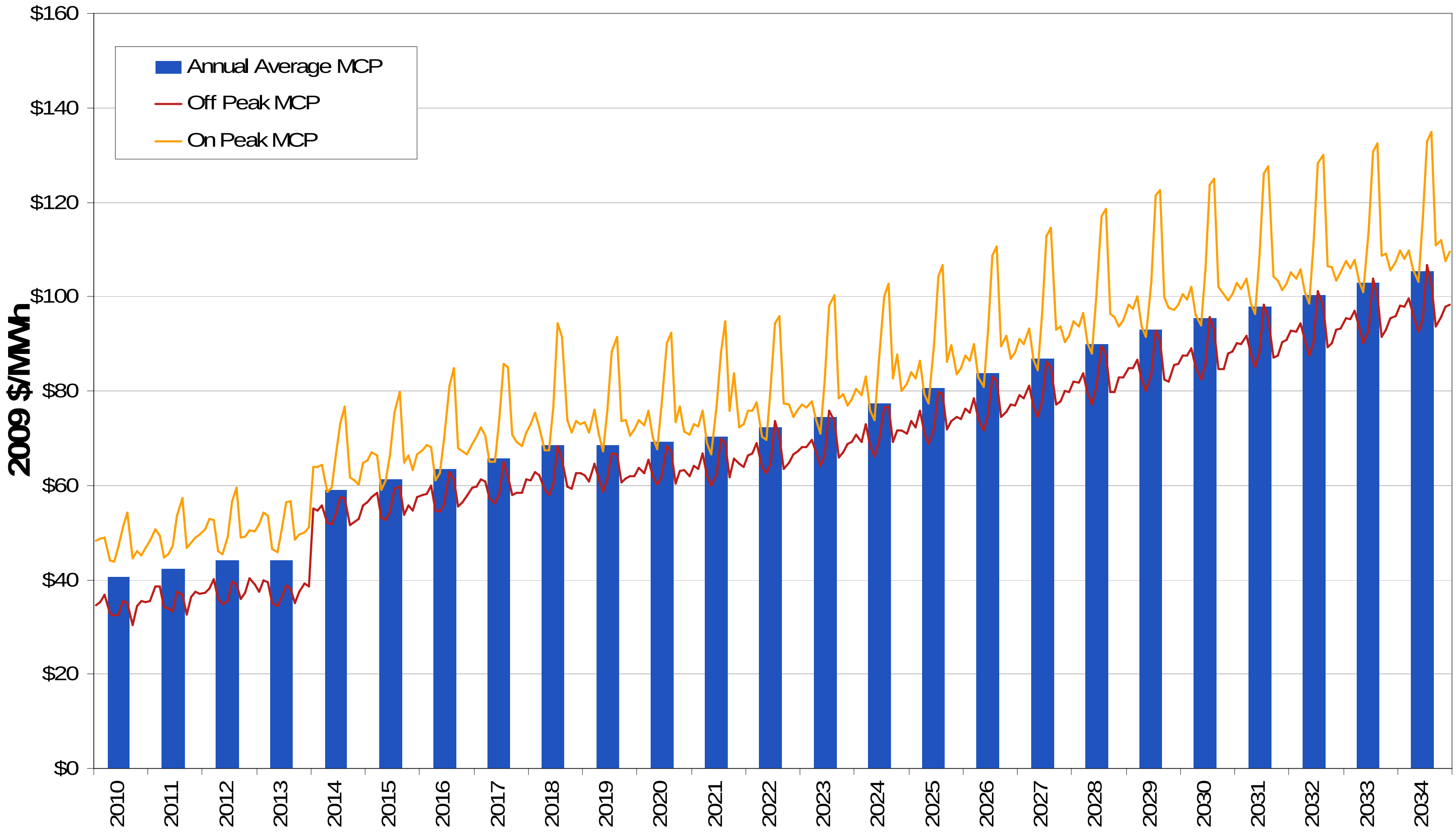
SPP North On and Off Peak Energy Prices



Source: Black & Veatch

* After 2024 every 5th year was modeled. Used linear interpolation between 2024 and 2029 and then 2029 and 2034.

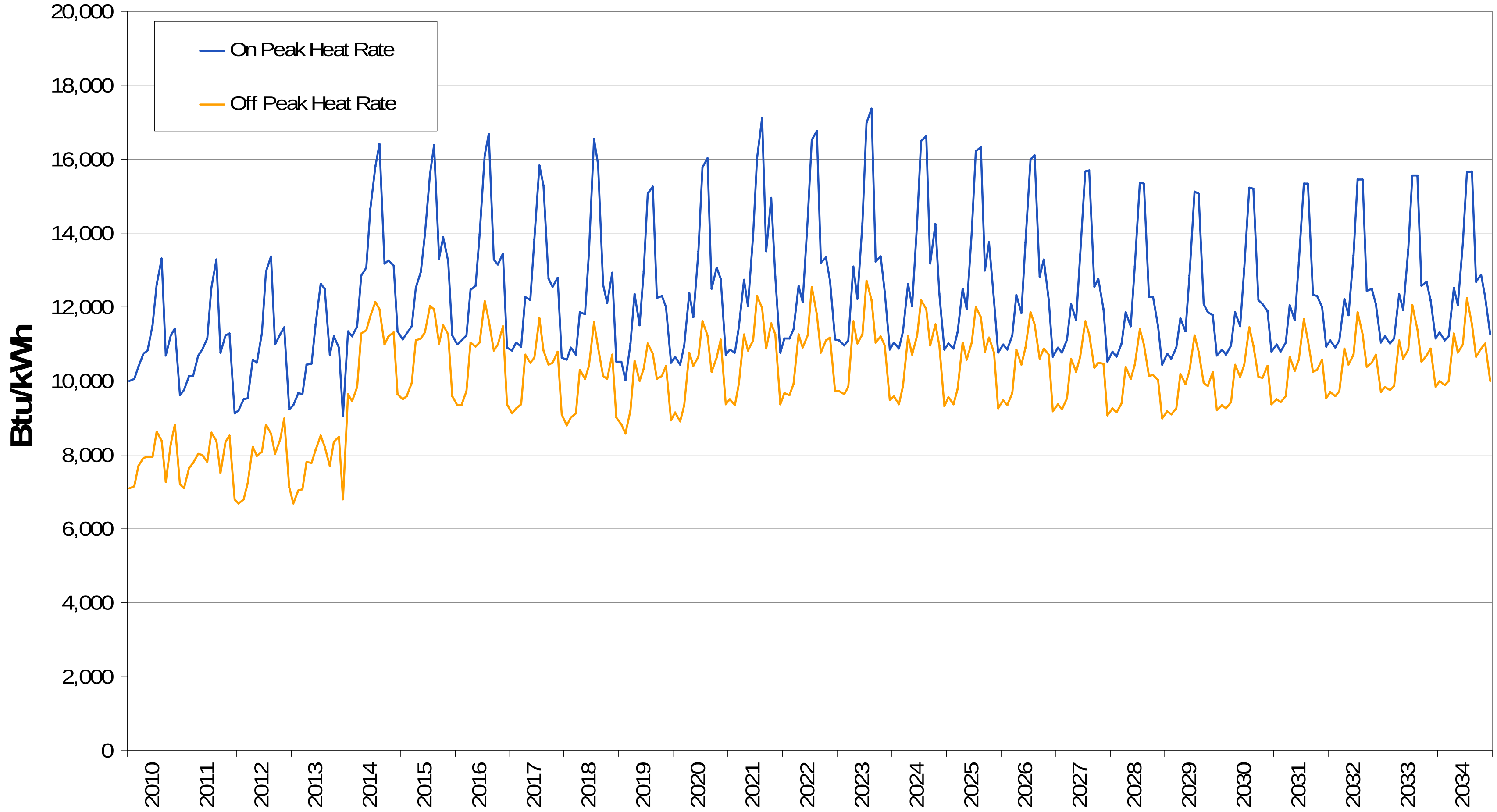
SPP South On and Off Peak Energy Prices



Source: Black & Veatch

* After 2024 every 5th year was modeled. Used linear interpolation between 2024 and 2029 and then 2029 and 2034.

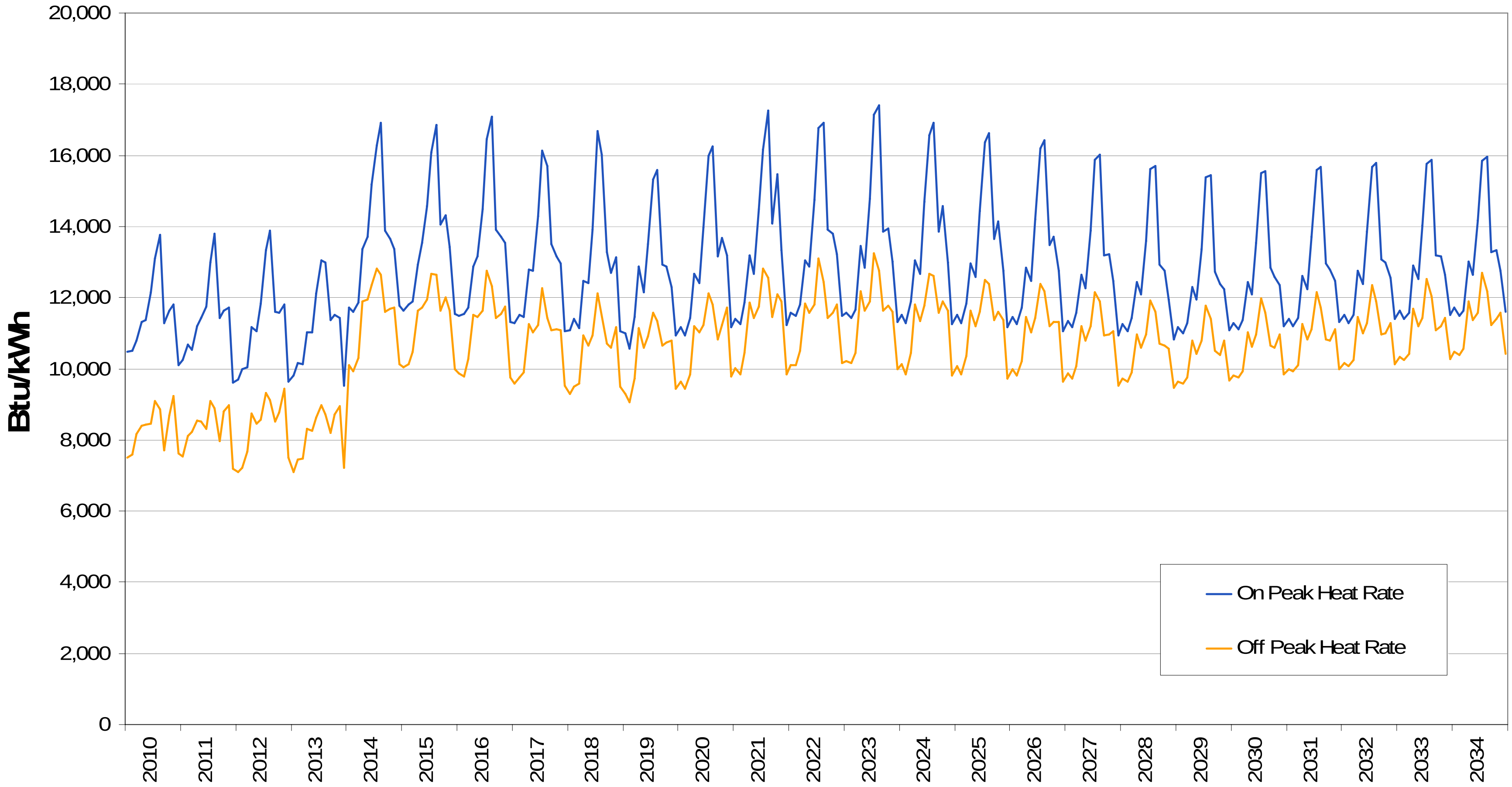
SPP North Heat Rate



Source: Black & Veatch

* No Historical Data Available

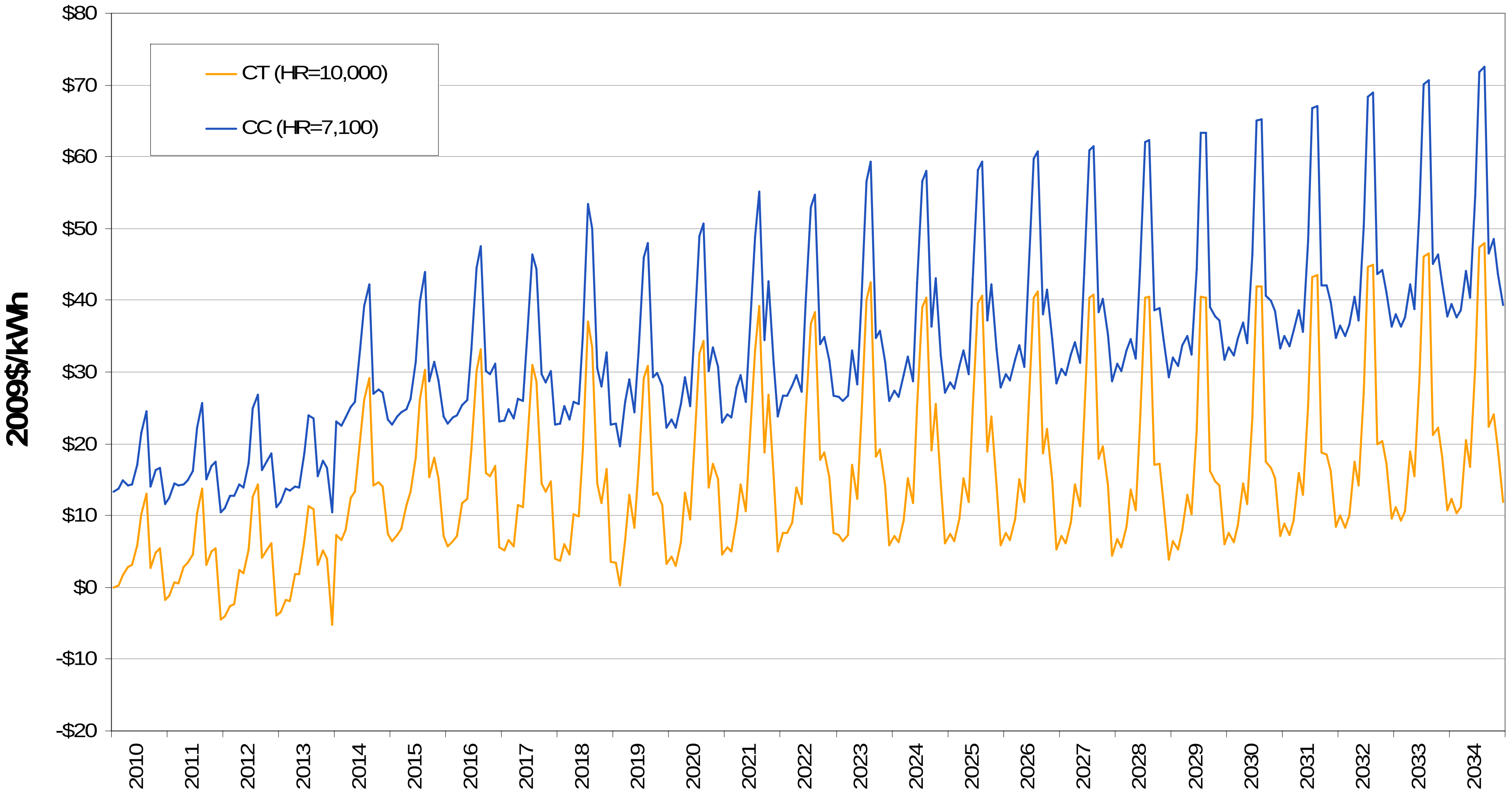
SPP South Heat Rate



Source: Black & Veatch

*No Historical Data Available

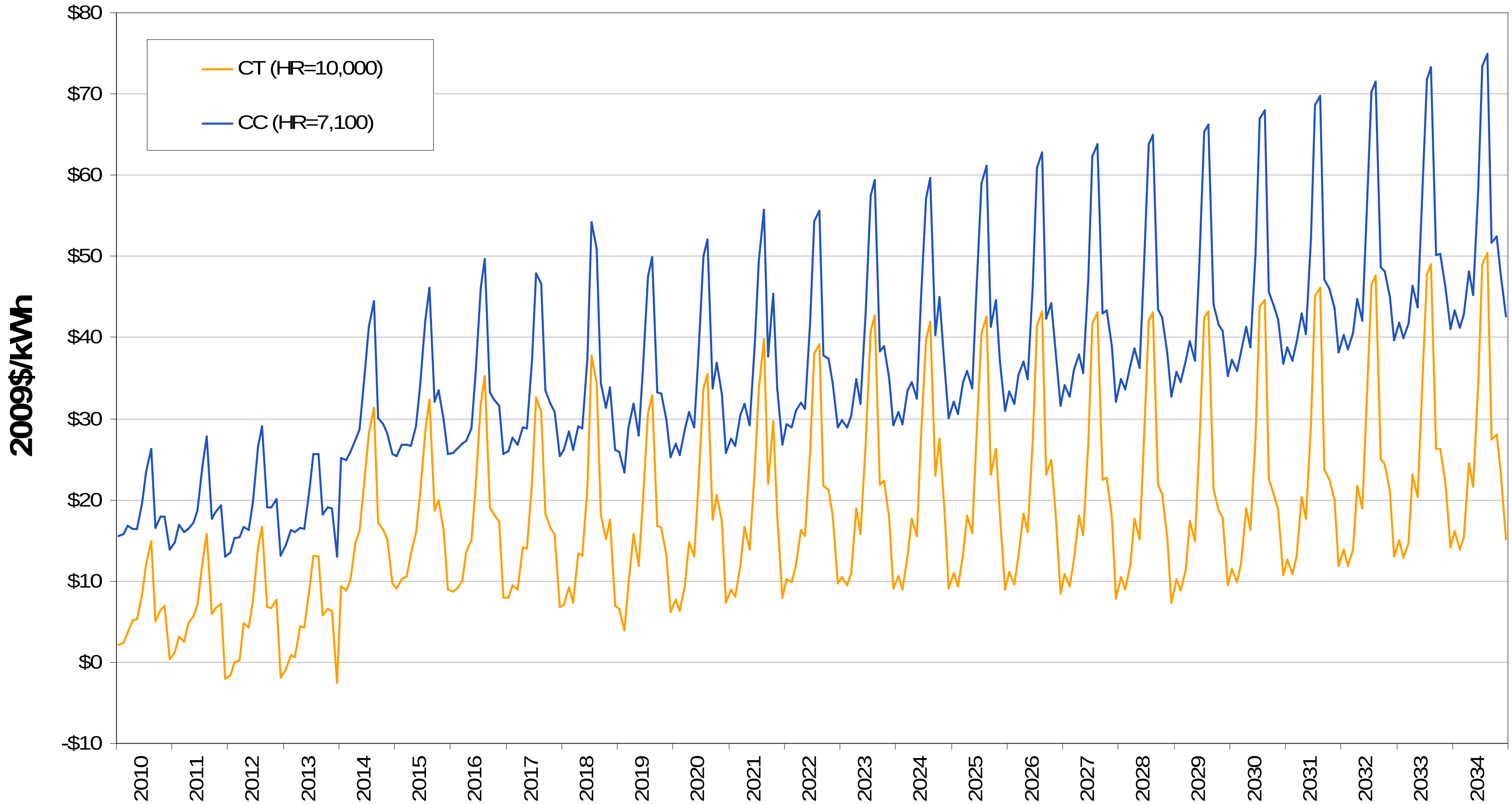
SPP North Spark Spreads



Source: Black & Veatch

*No Historical Data Available

SPP South Spark Spreads



Source: Black & Veatch

*No Historical Data Available

4.8 Capacity Price Forecast

Capacity Prices and Revenue in Southeast/Florida Markets

- With the exception of PJM, there are no formal capacity markets in the Midwest market regions, and no standard definition of the "capacity" product. At the same time, there are substantial numbers of negotiated power purchase agreements that split revenue for power sales between an energy and a capacity component.
- The forecast energy prices in B&V's base line forecast, and in virtually all simulation-based electricity price forecasts, are generally below a level that would fully compensate generic new entry for investment costs over expected operating life timeframes. This is particularly true for new simple-cycle entry included in the forecast process to maintain resource adequacy (minimum planning reserve margin) requirements.
- More efficient generators, likely to earn profit margins from energy sales, may still obtain capacity revenue through bilateral transactions, but it is common for there to be a negotiated trade-off between energy margins and negotiated capacity prices, so that total revenue available to owners is not expected to produce excess investment returns.

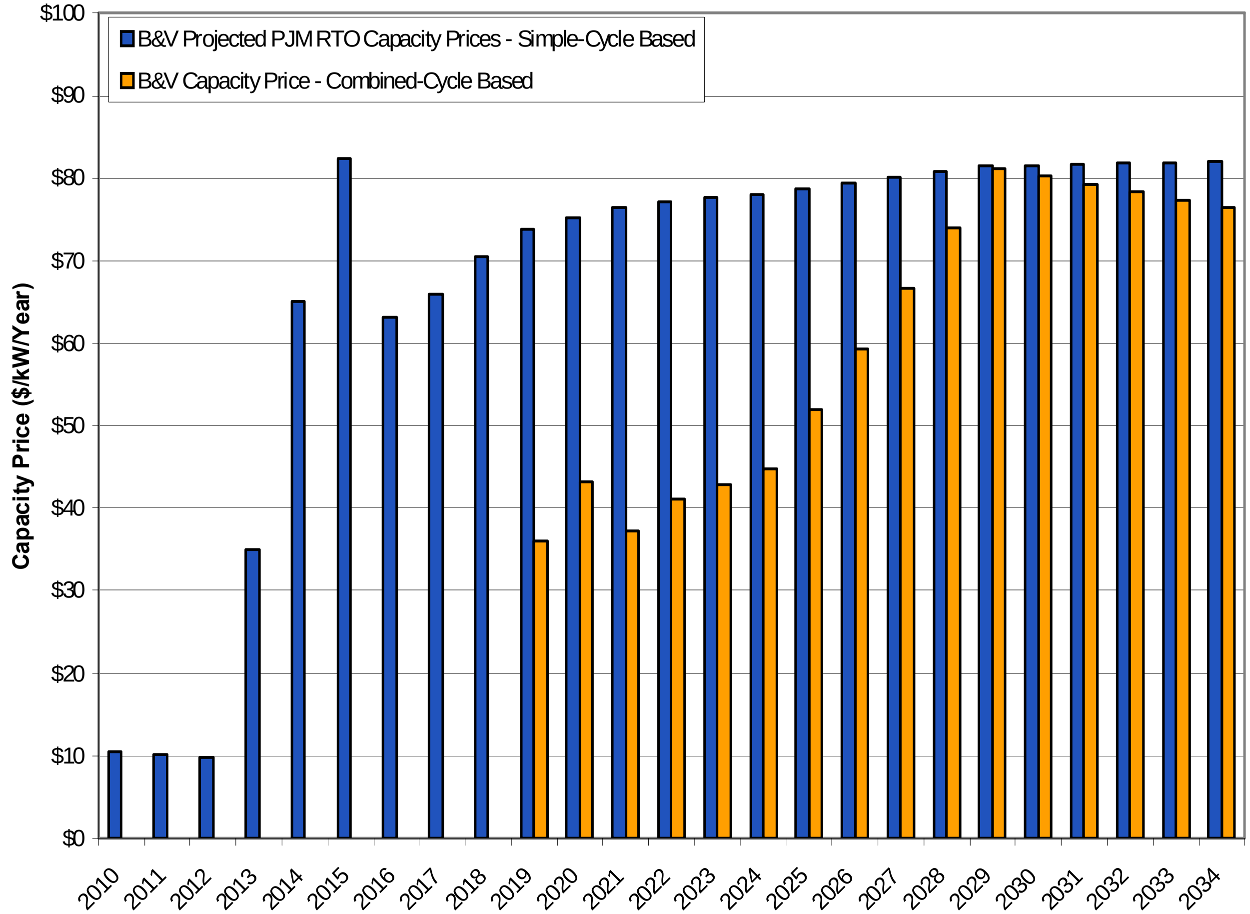
B&V Approach to Forecasting Capacity Prices

- B&V has implemented an approach to forecast capacity prices based on a capacity planning algorithm.
- Given the bilateral nature of capacity transactions in non-PJM Midwest markets, there is not a single price of capacity, and not all suppliers are likely to receive capacity revenue. As such, the capacity price forecast developed by B&V should be viewed as "indicative," and provides a reasonable measure of capacity price/revenue that marginal generators could expect to receive, provided that they are successful bidders in competitive procurement proceedings, and that they are able to negotiate a power sales agreement with a load-serving entity in need of capacity.
- The capacity market clears when supply equals annual peak demand, plus planning reserve margins.
- In years and markets where new capacity is not yet needed, the capacity price is determined as shortfall revenue needed for the marginal generator to just recover its variable and fixed operating costs in the upcoming year. Under these conditions, there is no capacity revenue targeted to cover investment-related cost.
- In years and markets where new capacity is needed, and supply is expanding, the capacity price is generally based on the cost of new entry in the upcoming year for a simple cycle gas turbine, net of expected energy market operating revenue.

PJM Capacity prices

- Based on near-term supply/demand conditions there are no economic signals to add new reliability capacity until 2013-2015
- Prior to that period, projected capacity prices begin in the $10/kW/Year to $25/kW/Year range, reflecting levels needed to cover net operating losses on existing generators
- Beginning 2013, capacity prices increase toward the cost of adding CT capacity in 2013 - 2014.
- Discounting of capacity prices is possible if suppliers choose to build combined-cycle units and offer capacity based on net energy margins
- This model-based result is compared to PJM RMP auction results on page 182.

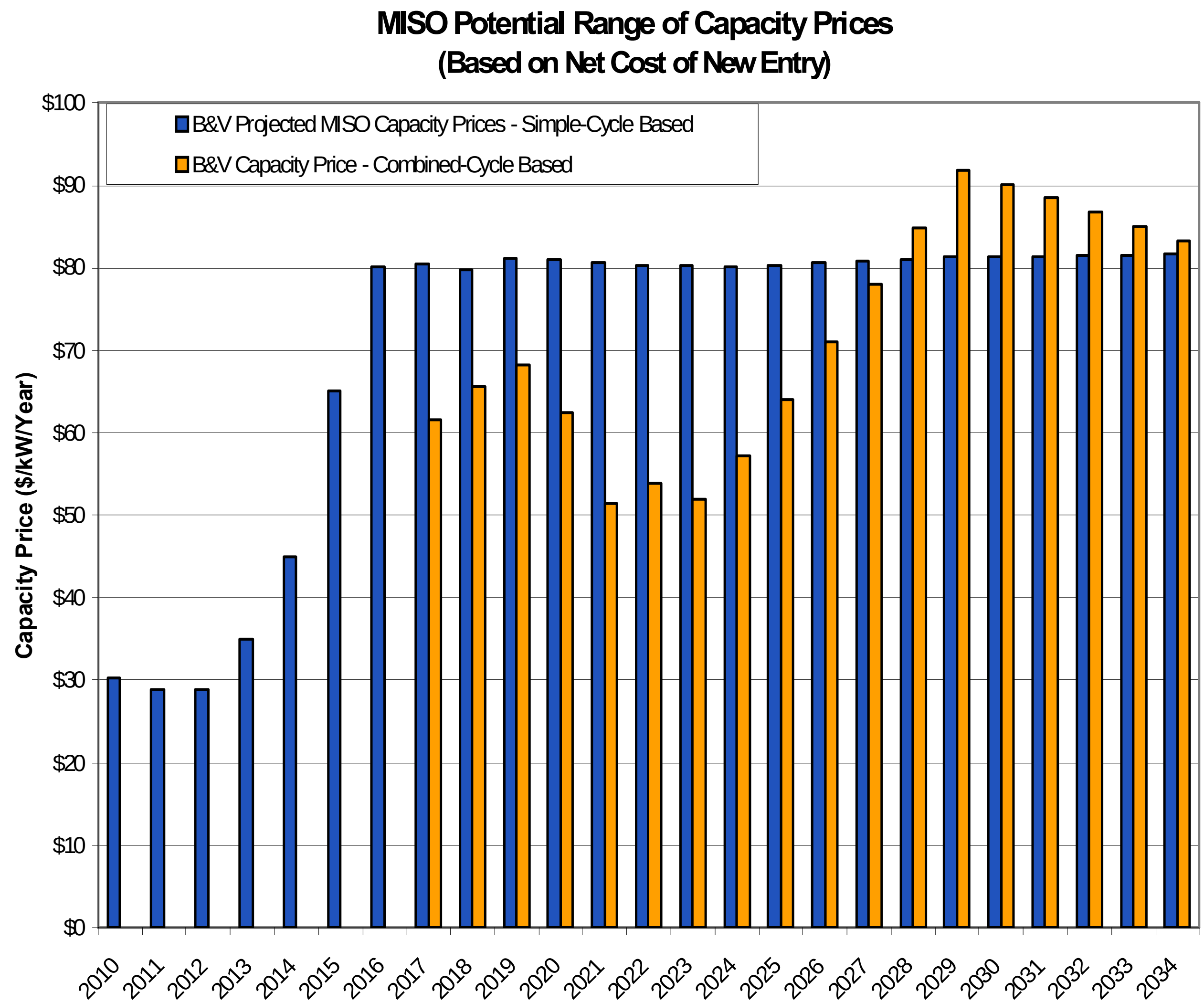
PJM-RTO Potential Range of Capacity Prices
(Based on Net Cost of New Entry)



Source: B&V analysis

MISO Capacity prices

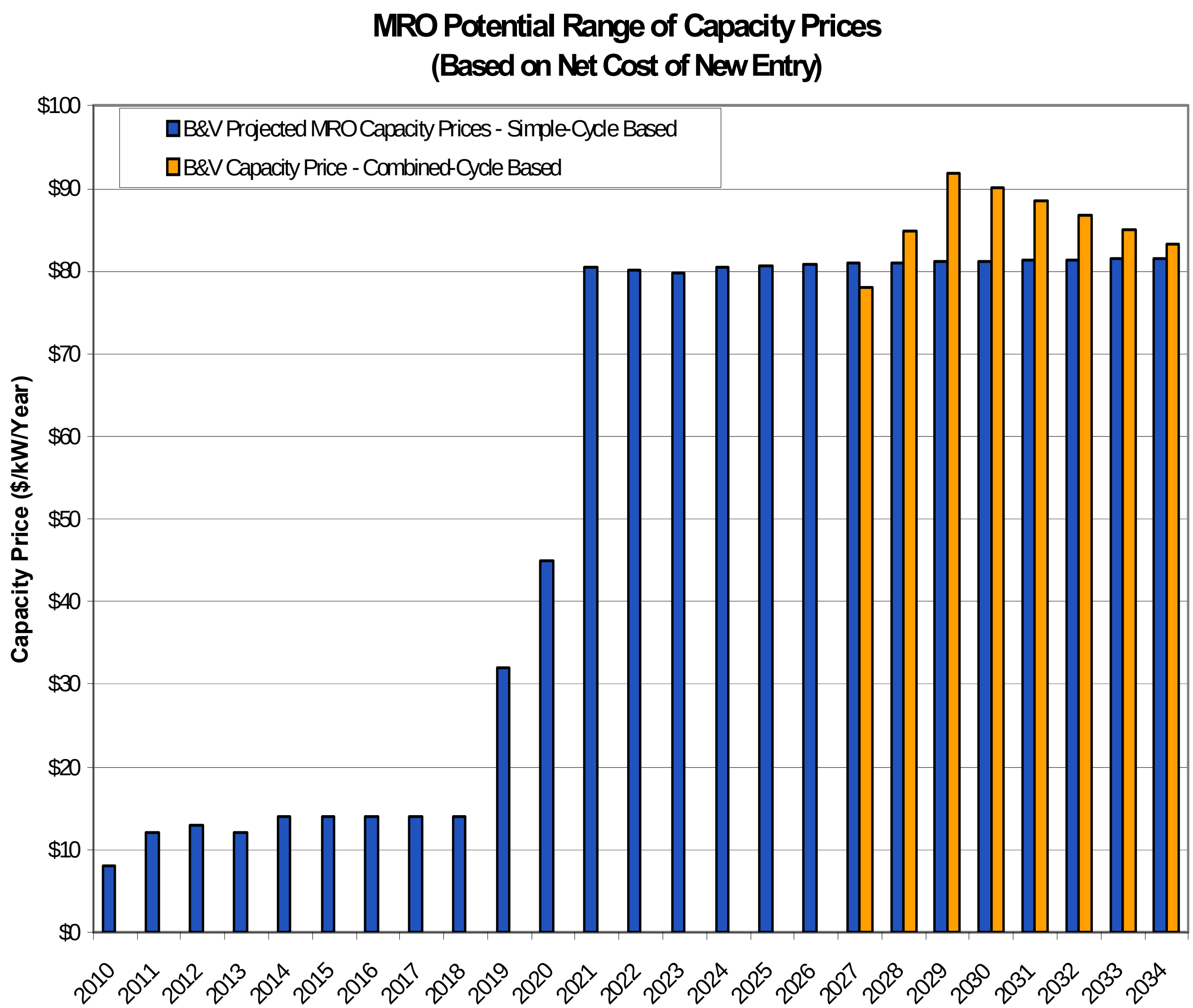
- Based on near-term supply/demand conditions there are no economic signals to add new reliability capacity until the 2015-2017 time frame
- Prior to that period, projected capacity prices begin in the $30/kW/Year range, reflecting levels needed to cover net operating losses on existing generators
- Beginning 2014, capacity prices increase toward the cost of adding CT capacity in 2016.
- Discounting of capacity prices is possible if suppliers choose to build combined-cycle units and offer capacity based on net energy margins



Source: B&V analysis

MRO Capacity prices

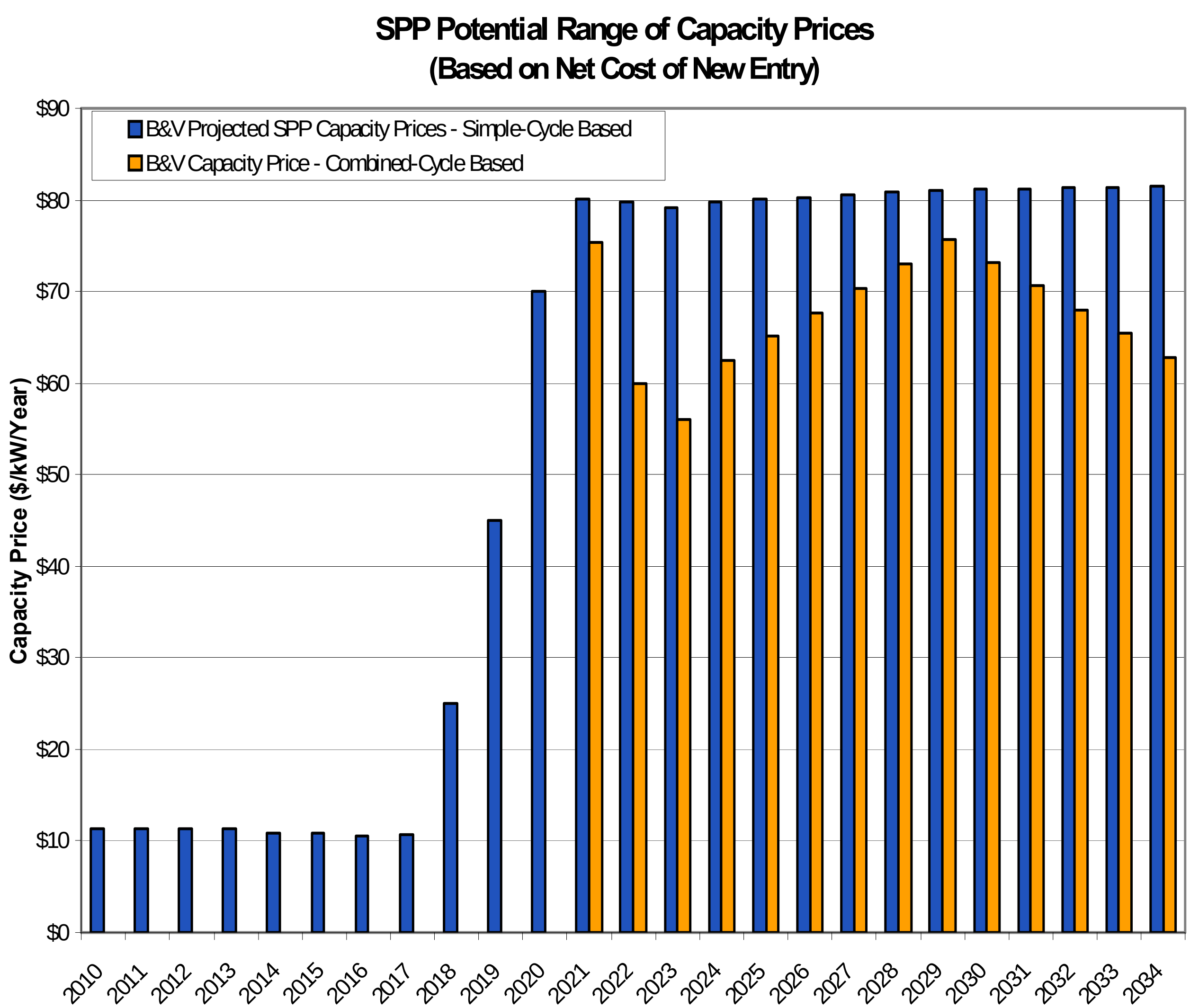
- Based on near-term supply/demand conditions there are no economic signals to add new reliability capacity until the 2020-2021 time frame
- Prior to that period, projected capacity prices begin in the $10-$15/kW/Year range, reflecting levels needed to cover net operating losses on existing generators
- Beginning 2019, capacity prices increase toward the cost of adding CT capacity in 2021.
- Discounting of capacity prices is possible if suppliers choose to build combined-cycle units and offer capacity based on net energy margins



Source: B&V analysis

SPP Capacity prices

- Based on near-term supply/demand conditions there are no economic signals to add new reliability capacity until 2020-2022
- Prior to that period, projected capacity prices begin in the $10-$12/kW/Year range, reflecting levels needed to cover net operating losses on existing generators
- Beginning 2016, capacity prices increase toward the cost of adding CT capacity in 2021.
- Discounting of capacity prices is possible if suppliers choose to build combined-cycle units and offer capacity based on net energy margins



Source: B&V analysis