KANSAS CITY
BPU
THE POWER OF COMMUNITY

Prepared and submitted to meet WAPA IRP filing requirements of October 2019

KANSAS CITY, KANSAS, BOARD OF PUBLIC UTILITIES
INTEGRATED RESOURCE PLAN
2019

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KANSAS CITY, KANSAS, BOARD OF PUBLIC UTILITIES
INTEGRATED RESOURCE PLAN --- 2019

I. INTRODUCTION

The Kansas City Board of Public Utilities' 2019 Electric Integrated Resource Plan (IRP) is a long-term strategic plan used to guide resource acquisition, conservation and demand-side management (DSM) decisions. The IRP process combines technical analysis and public participation to ensure low cost reliable electric supply. Integrated resource planning is a process that considers demand-side options in addition to traditional supply-side options to meet the electric power needs of the electrical system. Integrated resource planning is a continual process that focuses on seeking and evaluating opportunities for demand and energy savings in addition to evaluating traditional supply side resources. It is an on-going and evolutionary process calling for a re-analysis of utility system plans as conditions, prices, costs, technologies, and power requirements change. The integrated resource planning process anticipates the future and considers the many uncertainties a utility faces. An objective of integrated resource planning is to find the lowest cost solution that supplies customers the amount and quality of electric service desired while at the same time supporting the utility's long term financial health. Solid, long-term integrated resource planning takes into account price elasticity of demand, reliability, and quality of service.

Under an agreement with WAPA, the Board of Public Utilities of Kansas City, Kansas (BPU) is required by law to file an Integrated Resource Plan (IRP) with the Western Area Power Administration (WAPA), an Agency of the U.S. Department of Energy, and update the plan every five years. The BPU is also required to submit annual progress reports on the status of its IRP. In return, the BPU receives an annual allocation of approximately 4.8 megawatts (MW) of capacity and about 14,900 megawatt-hours (MWH) of hydroelectric power. Receiving this power is a valuable benefit to BPU. This document is the BPU's 2019 Integrated Resource Plan report and documents the integrated resource planning the BPU currently has in place.

II. BENEFITS OF IRP PLANNING

There are multiple benefits which can be derived from integrated resource planning. A good practical plan manages risks and seeks to minimize long-run costs. It also encourages energy conservation and the use of renewable energy resources and promotes the use of lower cost and more abundant fuels. Furthermore, it provides a forum for diverse interests and disciplines to communicate and develop a common goal and select an acceptable resource option.

These benefits are derived from the change of focus in planning, where studies and reviews search for ways to improve energy utilization and marginal revenues, and to reduce costs. Some of these benefits to the BPU have been that it has:

1. Deferred new generation capacity additions. In general, aided in stabilizing rates and keeping costs down for customers.
2. Assisted in improving the Utility's system load factor allowing better utilization of generating equipment.

3. Increased the use of more efficient generating equipment thus lowering the cost per unit of power generated.
4. Reduced energy use in certain situations by encouraging the use of more efficient appliances and building additions. Consequently, this has decreased load growth in peak periods, while at the same time increased off peak energy uses.
5. Assisted in improving public relations.
6. Aided in energy conservation.

III. BPU ELECTRIC UTILITY OVERVIEW

The Kansas City Board of Public Utilities (BPU) water department was originally created in 1909, and its electric utility was operational in 1912, with the utility officially being established in 1929. The purpose of the utility, then and to this day, is to provide the highest quality electric and water services at the lowest possible cost. Today the publicly owned utility serves approximately 65,000 electric and 51,000 water customers, primarily in Wyandotte County, Kansas. The mission of the utility and its employees is "to focus on the needs of our customers, to improve the quality of life in our community while promoting safe, reliable and sustainable utilities. BPU is a publicly owned administrative agency of the Unified Government of Wyandotte County/Kansas City, Kansas, and is self-governed by an elected six-member board of directors.

The electric utility serves 155.9 square miles of Wyandotte County with its current facilities consisting of three self-owned power stations, one joint-owned combined cycle, 33 substations and approximately 3,000 miles of electrical lines. The four power stations contain generators with the following approximate capacities:

- Nearman Creek Power Station – capacity 326 MW
- Quindaro Power Station – capacity 250 MW
- Kaw Power Station – capacity 98 MW (currently cold standby)
- Dogwood – own 17% of 650 MW capacity unit

Transmission systems consist of 161 kV and 69 kV transmission lines. The 161 kV system is configured in two loops, establishing a "figure eight" over the entire service territory. Interconnection between the 161 kV and 69 kV systems is made at four locations. Highest peak demand was recorded on August 9, 2006, at 529 MW. Electrical lines interconnect to four Kansas City Power & Light (KCPL) locations and one Westar Energy location. KCPL and Westar are currently in the process of merging operations and thus moving forward all tie points will be with one organization, Evergy.

Thanks to the Western Area Power Administration (WAPA), the Board of Public Utilities of Kansas City, Kansas was among the first municipally owned systems to undertake integrated resource planning. WAPA provided the initial exposure of integrated resource planning to the BPU, and from the beginning WAPA staff has provided invaluable assistance in implementing this program. This planning process continues today. As conditions and technologies change, existing programs are modified and new studies are performed and incorporated into updates of BPU electric power resource plans.

The initial IRP by BPU was completed in 1989. The cost of that IRP was shared between WAPA and BPU with BPU receiving over $100,000 to prepare the study. The Energy Policy Act requiring an IRP was adopted in 1992.

IV. LOAD ANALYSIS & FORECAST

The Board of Public Utilities updates its electric load forecast on an ongoing basis. Short–term peak demand energy forecasts are developed for use in revenue forecasting and budgeting. Long–term energy and peak demand forecasts are developed for use in longer term system planning such as to assess the long-term energy and demand requirements of the BPU and for use in performing analyses of various capacity and/or energy purchase options.

A. Methodology

BPU's forecasting method is a bottom-up approach developed by aggregating customer class specific forecasts. Developing customer class specific forecasts allows for the ability to get a refined estimate of total system demand. The estimates for the individual customer classes are aggregated to develop the estimate for the entire system as a whole. In using this method, the forecast for the system as a whole is typically more accurate since it allows for careful consideration of the change in demand for each of the customer classes and then combining these carefully considered estimates rather than merely making one large system forecast estimate which may not as thoroughly consider all of the factors causing both the change in number of customers in each class and the use per customer of each individual customer class.

B. Major Customer Class Historical and Forecast Demand

The individual historical data and forecasts for industrial, commercial, and residential energy consumption are aggregated in the table below:

Table 1
Large Customer Class Data (kWh)

Historical and Forecast Annual Major Customer Class Data (kWh)

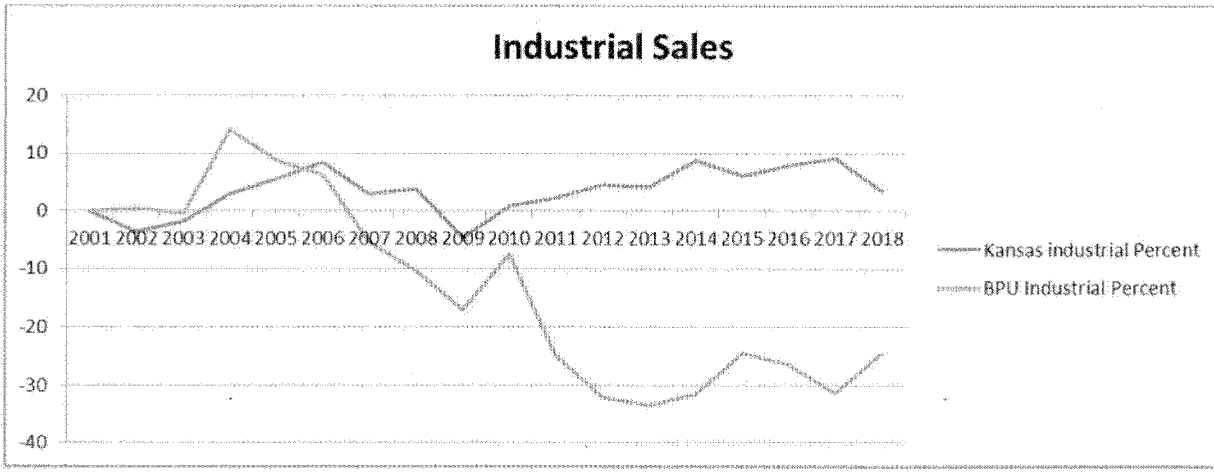
Year	INDUSTRIAL	Percent Change	COMMERCIAL	Percent Change	RESIDENTIAL	Percent Change	Major Customer Classes Summed	Percent Change
1998	803,331,850	0.58%	820,089,166	2.46%	543,913,298	6.38%	2,167,314,314	2.70%
1999	847,643,070	5.52%	821,146,470.0	0.13%	512,421,552	-5.79%	2,191,211,092	1.10%
2000	803,136,767	-5.25%	822,626,899	0.18%	545,307,672	6.42%	2,171,071,338	-0.92%
2001	817,758,956	1.82%	802,679,313	-2.42%	550,869,096	1.02%	2,171,307,365	0.01%
2002	822,335,834	0.56%	806,031,040	0.42%	568,700,840	3.24%	2,193,557,963	1.02%
2003	814,756,414	-0.92%	814,699,133	1.08%	525,368,930	-7.62%	2,131,266,244	-2.84%
2004	932,858,837	14.50%	833,645,939	2.33%	514,886,934	-2.00%	2,222,835,681	4.30%
2005	889,594,504	-4.64%	856,388,086	2.73%	564,944,642	9.72%	2,252,376,120	1.33%
2006	869,655,917	-2.24%	909,404,930	6.19%	564,353,393	-0.10%	2,278,621,843	1.17%
2007	774,211,822	-10.97%	909,219,828	-0.02%	574,127,016	1.73%	2,167,598,240	-4.87%
2008	733,052,531	-5.32%	877,655,653	-3.47%	550,773,920	-4.07%	2,069,014,083	-4.55%
2009	678,327,267	-7.47%	843,231,586	-3.92%	535,690,414	-2.74%	1,964,810,292	-5.04%
2010	757,355,721	11.65%	879,059,973	4.25%	599,167,144	11.85%	2,135,501,779	8.69%
2011	614,559,741	-18.85%	963,117,955	9.56%	588,240,616	-1.82%	2,050,079,776	-4.00%
2012	555,511,201	-9.61%	988,166,817	2.60%	564,029,077	-4.12%	1,973,157,079	-3.75%
2013	544,416,379	-2.00%	963,696,185	-2.48%	556,786,563	-1.28%	1,944,299,731	-1.46%
2014	559,278,599	2.73%	973,384,174	1.01%	564,782,275	1.44%	2,097,445,048	7.88%
2015	617,838,731	10.47%	991,672,581	1.88%	593,132,956	5.02%	2,202,644,268	5.02%
2016	602,395,303	-2.50%	944,569,395	-4.75%	573,461,087	-3.32%	2,120,425,785	-3.73%
2017	561,731,105	-6.75%	903,387,325	-4.36%	549,713,684	-4.14%	2,014,832,114	-4.98%
2018	593,132,956	5.59%	991,672,581	9.77%	617,838,731	12.39%	2,202,644,268	9.32%
2019	587,201,626	-1.00%	971,839,129	-2.00%	580,768,407	-6.00%	2,139,809,163	-2.85%
2020	572,521,586	-2.50%	971,839,129	0.00%	579,897,255	-0.15%	2,124,257,970	-0.73%
2021	557,063,503	-2.70%	974,268,727	0.25%	579,027,409	-0.15%	2,110,359,639	-0.65%
2022	554,835,249	-0.40%	976,704,399	0.25%	578,158,868	-0.15%	2,109,698,516	-0.03%
2023	554,002,996	-0.15%	979,146,160	0.25%	577,291,629	-0.15%	2,110,440,785	0.04%
2024	553,171,992	-0.15%	981,594,025	0.25%	576,425,692	-0.15%	2,111,191,709	0.04%
2025	551,512,476	-0.30%	984,048,010	0.25%	575,561,053	-0.15%	2,111,121,539	0.00%
2026	549,857,938	-0.30%	986,508,131	0.25%	574,697,712	-0.15%	2,111,063,780	0.00%
2027	548,208,364	-0.30%	988,974,401	0.25%	573,835,665	-0.15%	2,111,018,430	0.00%
2028	546,563,739	-0.30%	991,446,837	0.25%	572,974,912	-0.15%	2,110,985,488	0.00%
2029	544,924,048	-0.30%	993,925,454	0.25%	572,115,449	-0.15%	2,110,964,951	0.00%
2030	543,289,276	-0.30%	996,410,268	0.25%	571,257,276	-0.15%	2,110,956,820	0.00%
2031	541,659,408	-0.30%	998,901,293	0.25%	570,400,390	-0.15%	2,110,961,091	0.00%
2032	540,034,430	-0.30%	1,001,398,546	0.25%	569,544,790	-0.15%	2,110,977,766	0.00%
2033	538,414,327	-0.30%	1,003,902,043	0.25%	568,690,472	-0.15%	2,111,006,842	0.00%

The major customer classes' aggregate number is added to the smaller customer classes' energy forecasts. The smaller customer classes are: schools, local government, highway lighting, BPU interdepartmental and borderline customers as well as metered and un-metered city government. Borderline customers' demand is served by BPU through a neighboring utility's distribution system. The customers are billed through the neighboring utility's billing system and BPU is paid by the neighboring utility. The table of historical and forecasted data of the small customer class data appears below:

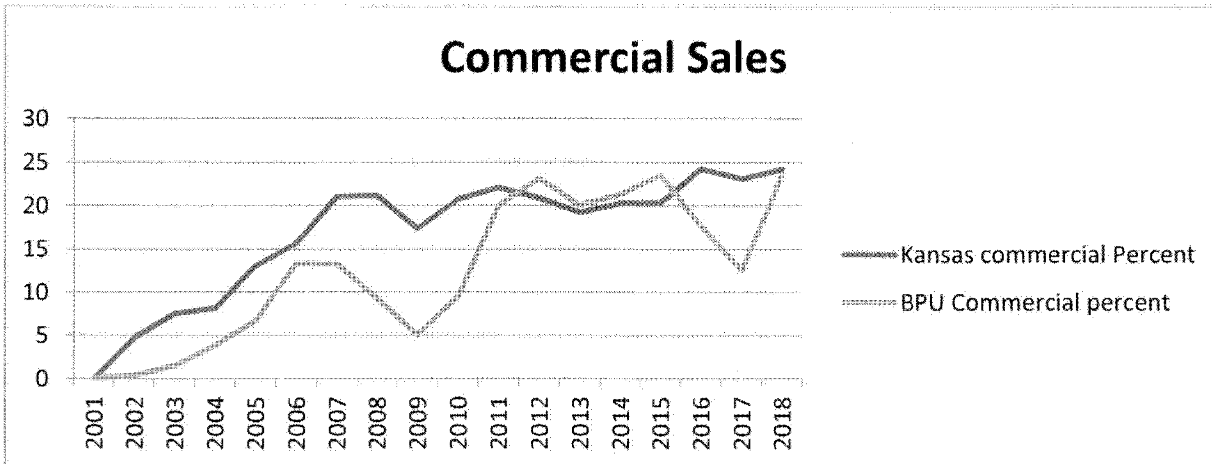
Table 2
Smaller Customer Class Data (kWh)

Smaller Customer Class Data (kWh)								
Year	Schools	Highway Lighting	County	Metered City of KCK	Unmetered City of KCK	BPU Inter-department	Borderline	Village West
1998	53,842,157	3,379,918	9,247,141	34,986,176			15,525,400	
1999	51,810,293	2,972,184	8,911,111	35,355,045			13,925,900	
2000	55,483,018	2,961,610	9,379,719	38,028,632	34,932,504	29,600,000	16,874,842	
2001	60,837,512	2,968,798	9,901,089	35,289,968	34,960,667	33,240,000	16,882,433	
2002	63,612,415	2,973,036	7,871,638	34,794,040	35,181,411	41,911,465	18,221,142	3,509,751
2003	68,937,672	3,072,183	8,620,954	35,052,238	35,663,130	31,387,396	17,338,495	23,558,233
2004	68,937,672	2,665,939	8,438,262	34,401,457	36,041,942	42,938,994	17,805,851	58,556,029
2005	68,272,280	2,665,939	8,756,979	31,743,439	45,027,579	47,626,677	18,765,903	58,551,112
2006	70,866,995	2,665,939	8,782,346	34,427,171	36,782,902	44,616,218	18,678,613	64,792,397
2007	75,577,601	2,664,127	8,663,293	30,522,789	38,716,486	44,996,254	19,313,961	89,960,426
2008	75,239,657	2,646,121	7,864,157	36,320,298	37,424,804	45,882,343	18,482,844	92,468,021
2009	77,430,042	2,556,091	7,637,040	33,103,923	37,433,960	36,999,231	18,429,740	92,438,975
2010	73,706,199	2,556,091	7,965,143	40,639,135	37,754,060	38,331,710	18,625,886	100,081,059
2011	70,174,257	2,556,096	5,768,883	38,462,059	37,640,339	38,405,209	17,381,535	115,838,536
2012	66,077,568	2,556,096	11	42,592,110	38,001,433	37,462,727	17,029,530	134,550,016
2013	69,637,035	2,556,096	-	42,694,440	37,364,538	38,369,477	17,972,281	120,599,396
2014	74,760,541	2,552,091	-	44,791,460	37,364,538	29,444,273	18,873,819	-
2015	72,663,778	2,340,156	-	35,502,105	37,364,538	29,248,043	17,780,671	-
2016	73,304,208	2,306,580	-	36,799,229	37,364,538	29,778,091	17,883,518	-
2017	72,111,223	2,306,580	-	39,229,511	38,093,694	27,728,649	16,486,144	-
2018	83,497,634	2,306,580	-	38,121,254	38,093,695	30,559,491	17,565,564	-
2019	77,652,800	2,306,580	-	38,109,818	38,093,695	30,253,896	17,504,085	-
2020	77,381,015	2,303,120	-	38,098,385	37,712,758	29,951,357	17,442,820	-
2021	77,110,181	2,299,665	-	38,086,955	37,335,630	29,651,844	17,381,770	-
2022	76,840,296	2,296,216	-	38,075,529	36,962,274	29,355,325	17,320,934	-
2023	76,571,355	2,292,772	-	38,064,106	36,592,651	29,061,772	17,260,311	-
2024	76,303,355	2,289,332	-	38,052,687	36,226,725	28,771,154	17,199,900	-
2025	76,036,293	2,285,898	-	38,041,271	35,864,458	28,483,443	17,139,700	-
2026	75,770,166	2,282,470	-	38,029,859	35,505,813	28,198,608	17,079,711	-
2027	75,504,971	2,279,046	-	38,018,450	35,150,755	27,916,622	17,019,932	-
2028	75,240,703	2,275,627	-	38,007,045	34,799,247	27,637,456	16,960,362	-
2029	74,977,361	2,272,214	-	37,995,642	34,451,255	27,361,081	16,901,001	-
2030	74,714,940	2,268,806	-	37,984,244	34,106,742	27,087,471	16,841,848	-
2031	74,453,438	2,265,402	-	37,972,848	33,765,675	26,816,596	16,782,901	-
2032	74,192,851	2,262,004	-	37,961,457	33,428,018	26,548,430	16,724,161	-
2033	73,933,176	2,258,611	-	37,950,068	33,093,738	26,282,946	16,665,626	-

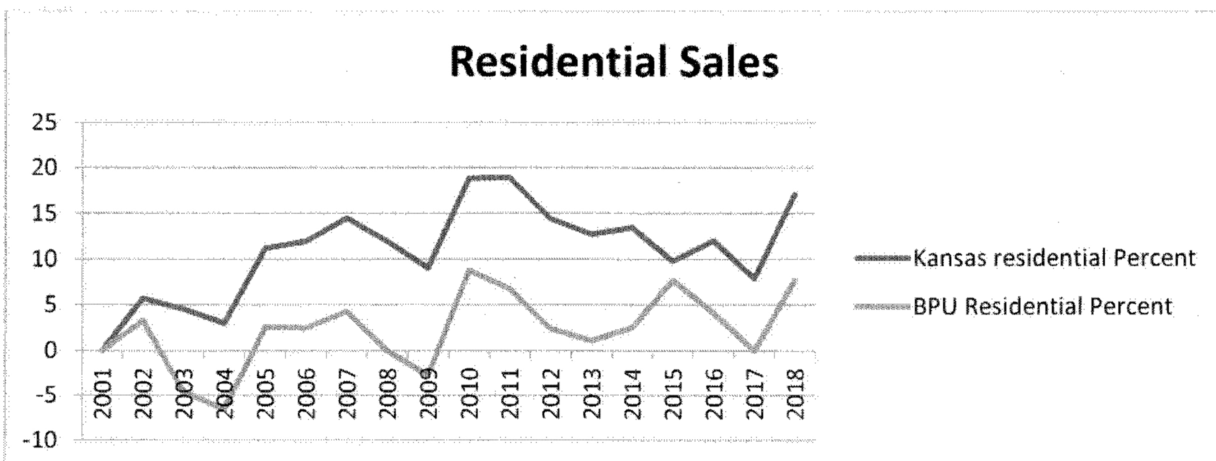
Below are a series of graphs showcasing the comparison between the BPU system and that of the state and national utilization on a percentage basis. Some classes showcase very similar correlation while others vary quite distinctly.



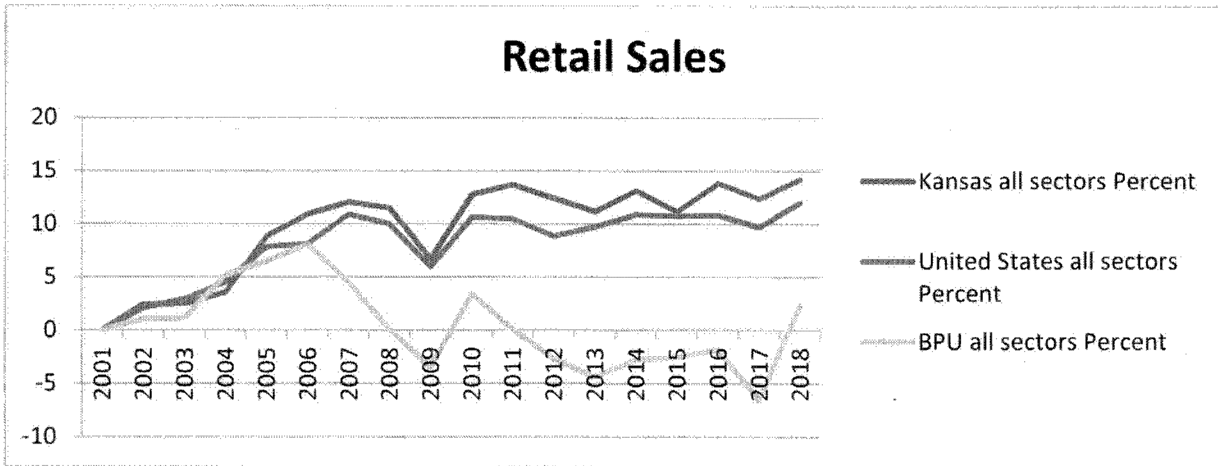
Industrial Sales
20
10
0
-10
-20
-30
-40
2001 2002 2003 2004 2005 2006 2007 2008 2009 2010 2011 2012 2013 2014 2015 2016 2017 2018
Kansas industrial Percent
BPU Industrial Percent



Commercial Sales
30
25
20
15
10
5
0
2001 2002 2003 2004 2005 2006 2007 2008 2009 2010 2011 2012 2013 2014 2015 2016 2017 2018
Kansas commercial Percent
BPU Commercial percent



Residential Sales
25
20
15
10
5
0
-5
-10
2001 2002 2003 2004 2005 2006 2007 2008 2009 2010 2011 2012 2013 2014 2015 2016 2017 2018
Kansas residential Percent
BPU Residential Percent



C. Losses

Losses are estimated based on component losses for transmission, primary, and secondary loads. These loss estimates are applied by customer class as annotated below.

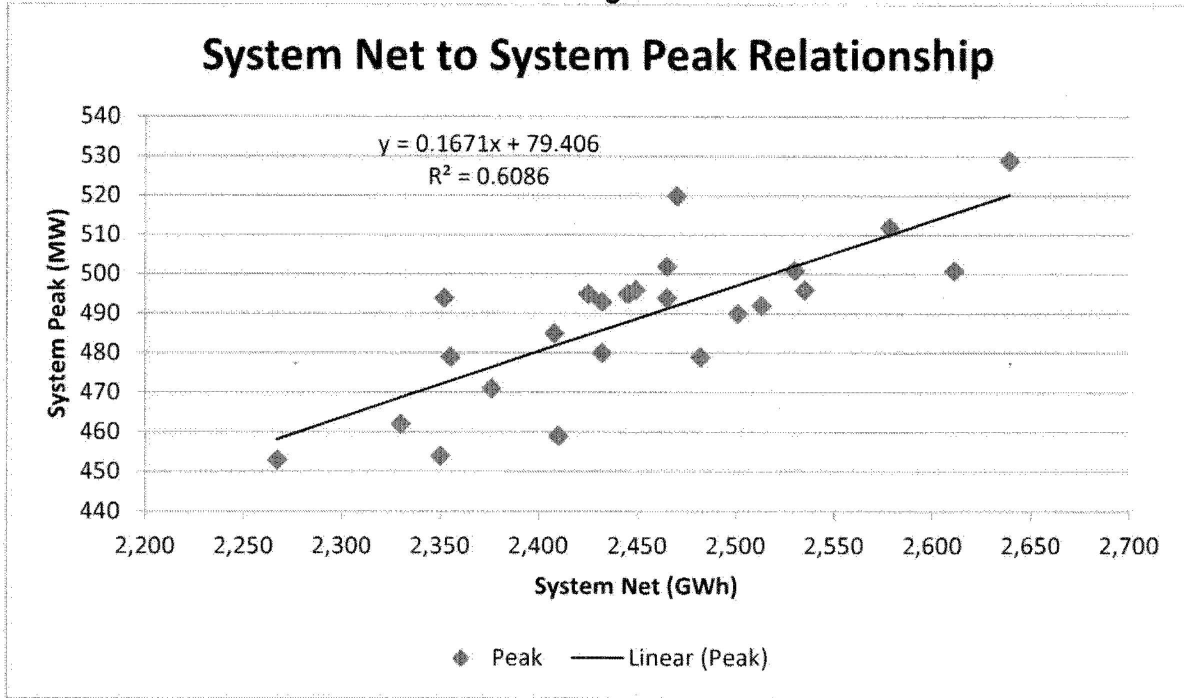
Table 3

	Losses		
Customer Class	**Transmission 0.44%**	**Primary 2.39%**	**Secondary 4.38%**
Industrial	X		
Commercial	X	X	X
Residential	X	X	X
Schools	X	X	X
Hiway Lighting	X	X	X
County	X	X	X
Metered City of KCK	X	X	X
Unmetered City of KCK	X	X	X
BPU Inter-Departmental	X	X	X
Borderline	X	X	
Nearman Participating	X		
Wholesale	X		

D. Peak System Demand

Peak system demand is calculated based on linear regression trend modeling of the historical peak plotted against the associated system net for the years 1995 through 2018. Figure 1 contains a plot of the system annual net energy and system annual peak demand. The black line in Figure 1 shows the historical trend line relationship between system annual net energy and system annual peak demand.

Figure 1



E. Forecast Results

The system load forecast developed by the BPU is shown in Table 5. The forecast includes sales to BPU's retail customers, borderline, city, and the BPU.

Table 5
Load Forecast

Year	System Peak (MW)	System Energy (GWh)	Growth (%)	Load Factor
2000	494	2,465	0.81%	57%
2001	496	2,449	-0.65%	56%
2002	479	2,482	1.33%	59%
2003	520	2,470	-0.49%	54%
2004	490	2,501	1.24%	58%
2005	501	2,611	4.21%	59%
2006	529	2,639	1.06%	57%
2007	512	2,578	-2.37%	57%
2008	492	2,513	-2.59%	58%
2009	471	2,376	-5.77%	58%
2010	501	2,530	6.09%	58%
2011	502	2,465	-2.64%	56%
2012	495	2,425	-1.65%	56%
2013	454	2,350	-3.19%	59%
2014	459	2,410	2.49%	60%
2015	485	2,408	-0.08%	57%
2016	480	2,432	0.99%	58%
2017	494	2,352	-3.40%	54%
2018	496	2,535	7.22%	58%
2019	492	2438	-3.97%	57%
2020	488	2419	-0.80%	57%
2021	485	2403	-0.68%	57%
2022	485	2403	0.01%	57%
2023	485	2402	-0.03%	57%
2024	485	2402	-0.03%	57%
2025	485	2401	-0.03%	57%
2026	484	2400	-0.03%	57%
2027	483	2400	-0.03%	57%
2028	482	2399	-0.03%	57%
2029	481	2398	-0.02%	57%
2030	480	2398	-0.02%	57%
2031	478	2397	-0.02%	57%
2032	475	2397	-0.02%	58%
2033	474	2396	-0.02%	58%

BPU's base energy requirements are expected to modestly decline over the next decade as on-site energy efficiency programs continue to drive further reductions in overall energy demand.

V. CURRENT RESOURCE SUMMARY

The BPU's existing power supply resources are made of a diverse collection of thermal and renewable or green generating assets including 43 MW of hydro capacity purchased from the Southwestern Power Administration (SWPA) and the Western Area Power Administration (WAPA), 250 MW of wind capacity purchased from the Smoky Hills, Alexander, and Cimarron

Bend wind farms, 7 MW of run-of-river hydro off Bowersock, 3 MW of Landfill gas generation purchased from Oak Grove, and a 1 MW solar facility located at the Nearman Station.

BPU's thermal generating plants include Nearman 1, a 250 MW pulverized coal unit operational in 1981, located at the Nearman Station. Also installed at the Nearman Station is CT 4, a 75 MW GE 7EA simple cycle natural gas combustion turbine commissioned in 2006. The Quindaro Station consists of a 72 MW dual fuel steam turbine, Quindaro Unit 1, commissioned in 1966; and a 76 MW dual fuel steam turbine, Quindaro Unit 2, commissioned in 1971.

The Quindaro Station also includes two simple cycle combustion turbines, CT 2 and CT 3 with accredited capacities of 49 and 50 MW, respectively. The online dates for these generators were 1974 and 1977. CT 2 and CT3 both utilize fuel oil for generation.

In addition BPU also purchased a 17% stake in Dogwood in May 2012. The Dogwood plant which became operational in February 2002 is a 650 MW natural gas-fired, combined-cycle electric generation facility consisting of one power train in a 2 x 1 configuration with Siemens Westinghouse 501F D2 Gas Turbines, a Toshiba HRSG, and one Toshiba steam turbine generator. The Dogwood facility is located in Cass County, Missouri, near the town of Pleasant Hill. Westar is currently responsible for handling all market related activities on the unit.

The BPU system also includes the inactive Kaw Station with three coal and/or gas fired steam generating units placed online between 1955 and 1962. All three units are in cold standby and would require extensive capital investment for equipment replacements and additions to be available as reliable generation resources in the future.

The BPU is currently in the process of ceasing operations at Quindaro Unit 1 and Quindaro Unit 2 in 2019 due to a number of factors. Although the BPU will maintain the stated capacity through the summer season of 2019 those units are not expected to provide capacity to the system in 2020. Despite the cessation of operations at those facilities the BPU does not expect to require any additional capacity resources in the immediate future.

Currently, BPU anticipates retiring CT2 and CT3 in December 2027 respectively when they reach 53 and 50 years of age respectively, but those retirement dates are still fluid and will depend on the financial metrics associated with those units versus alternative technologies. Table 6 contains a summary of the operating characteristics of the existing active BPU generators.

Table 6
Summary Operating Characteristics of Existing Active BPU Generators

Generator	Description	COD[1]	Max Net MW[2]	Min Net MW[2]
Nearman 1	Coal Steam	1981	250	120
Quindaro ST1	Coal / Gas	1966	72	64
Quindaro ST2	Coal / Gas	1971	77	48
Quindaro GT2	Oil CT	1974	49	10
Quindaro GT3	Oil CT	1977	50	9
Nearman CT4	Gas CT	2006	76	46
Dogwood [3]	Gas CC	2002	650	150

[1] COD = Commercial Operation Date.

[2] Minimum and Maximum Output Capacities reflect the minimum and maximum continuous rating of the generator, in MW, at the conditions which it is expected to operate.
[3] Dogwood is a 650 MW joint owned unit with the BPU owning a 17% stake in the unit.

In addition to the active generators operated, the BPU also has a number of long-term Purchase Power agreements (PPA) in place. All long-term PPAs currently in place contribute to the diversity of the power supplied, and therefore the energy curves associated with that type of energy, are green energy sources, and provide a hedge against carbon fuel price and wholesale energy volatility as well as future environmental regulations.

A. Wind Power Energy

In the IRP of August 2005 two recommendations were made relating to wind power. The first recommendation was an evaluation of purchasing commercial wind power energy. Toward that end, the BPU entered into a 20 year Renewable Energy Purchase Agreement and began receiving wind generated energy from Smoky Hills Wind Farm in early 2008. BPU has been a leader of Kansas municipals with regard to purchasing Kansas wind energy. Smoky Hills made up approximately 5% of BPU's 2018 system peak demand, based on nameplate capacity; and approximately 3.4% of BPU's 2018 system load. BPU chose to enter into wind energy at this level to gain experience with the issues related to the variability of wind, wind forecasts, and other related wind integration issues. BPU is currently not required by any regulatory agency or mandate to purchase renewable energy; however, BPU management is committed to continuously exploring methods and alternatives to reduce the carbon footprint of the organization while providing our customers with an energy portfolio that meets their reliability needs while providing a lasting reduction in greenhouse gas emissions.

The second recommendation was to evaluate the potential for local wind driven turbines. BPU concluded based on research of both wind options that a commercial scale wind facility was preferable over local community wind because of its lower cost due to wind location and economies of scale. A concern about entering into an agreement to purchase wind energy from a commercial wind facility remote from BPU's service territory was whether the transmission system had the capacity to get the energy to BPU. Therefore, as part of the evaluation of the economics of the wind energy purchase SPP performed an analysis to evaluate the potential for curtailment of flows originating at Smoky Hills and sinking in the KC area. The result of this analysis was that it did not expect the energy flow from Smoky Hills to BPU be curtailed a significant percent of the time.

Since the addition of Smoky Hills, the BPU has been active in obtaining additional and varied renewable resources to complement the existing fleet but also to hedge fuel price volatility and regulatory risk. In addition to Smoky Hills, the BPU purchased an additional 25 MW of wind capacity off the Alexander wind farm from Own Energy, with a commercial operation date of 2015.

In addition to the acquisition of Alexander the BPU further cemented its commitment to Kansas wind through the acquisition of 200 MW of wind energy from Tradewind Energy. The Cimarron Bend wind facility began operations in 2017 and is expected to produce approximately 865,000 MWh annually.

In 2018 BPU's wind facilities produced approximately 1.1 million MWh or approximately 42% of BPU's total system net. All three wind facilities feature a fixed 20 year contractual energy rate which allows the utility a great deal of cost certainty over the life of the contract.

B. Landfill Gas Generation

The 2003 Master Plan recommended evaluation of Landfill Gas Generation as a renewable energy source but was narrowly focused on the potential for landfill gas generation at a local landfill. In 2009, BPU was approached by a project developer who had secured a source of gas at a private landfill in Arcadia, Kansas managed by Waste Corporation of Kansas. After considerable due diligence and contract negotiation BPU entered into a Renewable Energy Purchase Agreement with the developer, Oak Grove Power Producers, LLC. Beginning March 1, 2010 the Land Fill Gas generator began production with a 1.6 MW Caterpillar G3520. In December 2013 the BPU began receiving an additional 1.4 MW of generation from the Arcadia, Kansas landfill, with a total of 3.55 MW coming online in 2014. The LFG generation is expected to be available approximately 90% of the time and is expected to be able to produce its maximum MW output 90% of the time it's available. These figures make it one of the most reliable and dependable base load generation types available.

The negotiated capacity cost for the Arcadia, Kansas landfill gas capacity was comparable, but slightly less than, the annual capital carry costs for a scrubbed new coal plant on a $/kW-yr basis based on Table 8.2 of the U.S. Energy Information Administration's Annual Energy Outlook 2010 as a reference for overnight construction costs. The negotiated energy cost for generation from the Arcadia, Kansas landfill site, was also slightly less than the energy price forecasted by Ventyx in their semi-annual _Power Reference Case Electricity & Fuel Price Outlook_, on a long-term levelized cost basis. Energy deliveries started in March of 2010.
The Oak Grove Landfill Gas Energy purchase agreement is for a period of 20 years. The purchase agreement affords BPU a renewable energy resource without the variability of wind and solar. The methane gas produced in a landfill is a potent greenhouse gas, about 21 times more so than carbon dioxide, so the gases produced in a landfill must be collected and flared off or used to produce heat or electricity preventing the methane from migrating into the atmosphere where it contributes to local smog and global climate change. Using LFG to produce electricity results in beneficial use of the LFG as well as an opportunity to obtain base load generation without the carbon production from fossil fuel combustion. The LFG generation is expected to produce enough power for about 1,000 homes with an annual reduction of GHG attributable to this project of approximately 1,400 passenger cars.

C. Hydro Generation

The BPU has existing contracts in place with three hydro entities, Southwest Power Administration, Western Area Power Administration, and Bowersock. Hydro generation and especially government hydro works as a cost effective alternative to base load fossil fuel generation. Government based hydro is extremely reliable and can be scheduled in much the same way as alternative generation types due to the size and scope of hydro facilities.

Southwestern Power Administration is one of four power marketing administrations within the U.S. Department of Energy whose role is to market and transmit electricity from 24 U.S. Army Corps of Engineers multipurpose dams. By law, Southwestern's power is marketed and delivered primarily to public bodies such as rural electric cooperatives and municipal utilities. The BPU's contract entitles it to 38.6 MW of capacity.

Western Area Power Administration is also one of the four power marketing administrations within the U.S. Department of Energy whose role is to market and transmit wholesale electricity from multi-use water projects. The service area encompasses a 15-state region of the central and western U.S. and consists of 57 hydropower plants, with an installed of capacity of 10,504 MW. The BPU's contract entitles it to 4.8 MW of capacity.

In November 2010, the BPU entered into a contract with the Bowersock Mills and Power Company (BMPC) to purchase the capacity and energy off an existing 2.15 MW run of the river hydroelectric facility on the Kansas River in Lawrence, KS and 4.70 MW of capacity from an expansion of Bowersock's existing hydroelectric facilities. The Bowersock agreement is to provide up to 7 MW of power for a period of 25 years. Bowersock is a low-impact hydro facility and has been supplying electricity to Northeast Kansas on a limited basis since 1905. The dam is owned by Bowersock but maintained by the city of Lawrence, which depends on the dam to pool water for its Kaw River Water Treatment plant. As part of the agreement, Bowersock undertook a plant expansion project, building an additional powerhouse on its existing site while tripling the overall energy production capability. The project is expected to maintain Bowersock's current status as a "low-impact" hydropower plant. The Bowersock hydro purchase provides BPU with a renewable energy source without the variability of wind and solar, additional base generation without the carbon production, and hydro energy from the facility for 25 years. The project is expected to produce 33,000 MWh per year of energy (the equivalent of 188 railcars of coal), enough to supply electricity to 3,300 Wyandotte County homes. Moreover, the project will reduce overall CO2 emissions by more than 44,000 tons.

BPU performed an analysis on the economic feasibility of purchasing energy from the facility that led to the agreement. The expansion will include four turbines that will more than double the amount of electricity produced from the existing plant. Production costs simulations using the ProSym production cost model were used to determine the economics of the hydro generation purchase proposal. The analysis was performed for a combination of future scenarios that assumed two different natural gas price forecasts, and with and without CO2 emission reduction mandates over a 25 year period. The analysis showed a net positive benefit to BPU, assuming equal likelihood of each scenario.

D. Solar Generation

The BPU began incorporating solar into its portfolio in September of 2017 with the incorporation of the 1 MW BPU Community Solar Farm. The solar facility is expected to produce approximately 1.7 GWh annually moving forward. The 1 MW solar facility is a behind the meter generation source located at the Nearman Creek generation facility and was designed to provide solar benefits to those customers who desired greener energy sources for those customers who could not or chose not to place solar at their residence. The design of the program was to provide the benefits of location sourced generation while reducing the risk and maintenance associated with those types of sources.

The program was initially only open to residential customers however has recently been opened up to all customer classes with each customer and customer class capable of taking a certain portion of their power from the solar facility. Although the solar facility is under a 25 year purchase power agreement customers are only required to commit to 12 months of service and the BPU is willing to re-acquire those solar panels for a set price based on the number of months remaining in the program, therefore providing customers the ability to go green without the long-term commitment.

VI. CURRENT DEMAND SIDE PROGRAMS

Screening of demand-side options began at BPU with the first IRP in 1989. Subsequently, XENERGY, INC. of Austin, Texas performed a detail screening and market assessment in 1993. This screening analysis became the implementation guide for many of the programs in place today.

Future Energy Efficiency and Demand Side Management programs are evaluated on a number of factors. The BPU utilizes several standard cost effectiveness test results, including Utility Cost Test, Total Resource Cost Test, Ratepayer Impact Measure Test, and Societal Test. Moreover, these test results are provided for various weather conditions, including weather normal, and under a number of wholesale market conditions. In addition to the standard qualification factors considered the BPU continues to explore new programs and roles based on technology, customer preference and environmental stewardship.

The programs described in this section are a continuation of those started either as a result of IRP or were started earlier as an effort to minimize cost and increase energy efficiency. They continue to be effective and generally require less attention and resources and thus are documented as IRP Programs.

A. System Load Factor Benefits

IRP planning and the programs implemented there under contribute to the system load factor [a quotient of energy used (kWh) divided by the product of peak load (kW) and the number of hours in the year]. Generally speaking, an improvement in system load factor is desirable because it allows for more efficient use of existing equipment and lowers the per unit fuel cost.

An improvement in system load factor occurs when the increase in system energy is greater than the increase in system peak. An improvement in load factor can be due to any number of things, such as: energy management programs that control on-peak use; greater efficiency in appliances; more energy efficient residential, commercial and industrial building additions; increased off-peak use; the addition of large industrial loads with non-coincident peaks or high load factors; and weather factors. Programs implemented since the inception of the integrated resource planning process have aided in obtaining an improved load factor.

Improvements in load factor associated with integrated resource planning result from the fact that some of the programs implemented have increased off-peak use while others have encouraged conservation or the use of more efficient appliances at the time of peak loads. The result is that less fuel is used per kWh generated while at the same time there is an increase in the use of more abundant and less costly fuels – coal versus natural gas. Greater use of more abundant and less costly fuels is primarily due to the reduction of the use of energy in peak periods (because of the increased efficiency of appliances being connected). Reductions in peak demand and use also save in the purchase of off-system power.

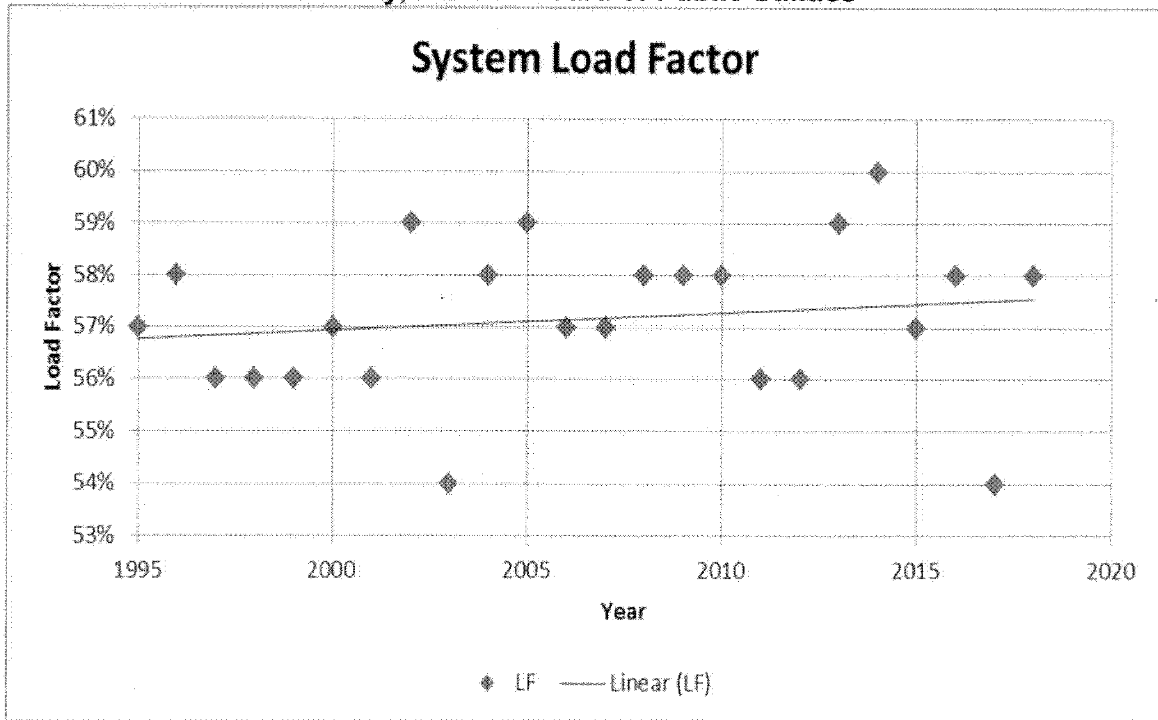
In addition to system load factor benefits various programs have the ability to contribute to the overall reliability of the system as well as reducing the overall environmental conditions that are present when peaking units are dispatched.

Table 7
System Load Factor
Kansas City, Kansas Board of Public Utilities

Year	System Peak (MW)	System Energy (GWh)	Load Factor
2000	494	2,465	57%
2001	496	2,449	56%
2002	479	2,482	59%
2003	520	2,470	54%
2004	490	2,501	58%
2005	501	2,611	59%
2006	529	2,639	57%
2007	512	2,578	57%
2008	492	2,513	58%
2009	471	2,376	58%
2010	501	2,530	58%
2011	502	2,465	56%
2012	495	2,425	56%
2013	454	2,350	59%
2014	459	2,410	60%
2015	485	2,408	57%
2016	480	2,432	58%
2017	494	2,352	54%
2018	496	2,535	58%

Charting the above data yields the graph shown on Figure 2 on the following page. This graph shows a positive load factor trend line that is gradually increasing. This chart also shows variation associated with weather and other factors.

Figure 2
System Load Factor
Kansas City, Kansas Board of Public Utilities



The apparent random variations in the load factor from year to year are due to a multitude of factors with the predominant reasons being shifting load dynamics and weather variations. The general trend of improvement is due to the success of many of the programs undertaken by BPU. Some of the major contributors to this net change in system load factor have been the following:

1. Electric heat pump and all electric home rebate program,
2. Changes in the electric rate structure lowering winter rates thus encouraging winter use and increasing summer rates making energy management programs economically viable.
3. Changes in the standards of the signal light and street light replacement program,
4. Implementation of construction standards emphasizing higher efficiency,

A discussion and documentation of these programs follows.

B. Heat Pump and Hot Water Heater Rebate Programs

This program began in 2001 and continues today. The program is designed for both residential and commercial customers such that rebates are given to customers or builders who install or retro-fit energy efficient heat pumps or hot water heaters. The amount of rebates given to residential and commercial customers is provided on the BPU website, www.BPU.com. The BPU partners with the Energy Star Program and rebates are consistent with Energy Star recommendations.

The Heat Pump and Hot Water Heater Rebate Program is intended to incentivize residential and commercial customers into installing highly efficient electric devices into their homes and businesses therefore allowing those customers to improve the efficiency of those appliances and thereby reducing the amount of energy being consumed in those applications especially during those times when energy and demand is at its highest. It also provides numerous benefits to the electrical system as a whole in a number of ways. These programs work to smooth energy consumption across the year to provide a much more efficient load profile, they also reduce overall demand and energy consumption during those high demand periods that would likely require peaking resources to serve that incremental load, and lastly by trimming the incremental peak it also helps extend the timeline and requirements associated with acquiring additional peaking generation to serve that load.

The BPU program continues to drive demand for highly efficient electrical appliances especially from the residential development community. With the push to a cleaner resource mix and further electrification within the residential and commercial sector it is anticipated that more consumers will consider the program and share in its benefits.

Table 8 summarizes the incremental gains of the rebate program over the last 4 years.

Table 8
Rebate Program Energy Savings
Kansas City, Kansas Board of Public Utilities

Energy Savings	2015	2016	2017	2018
Incremental Annual MWh Savings	330 MWh	564 MWh	348 MWh	203 MWh
Incremental Peak MW Demand Savings	1.0 MW	1.3 MW	0.78 MW	0.41 MW

C. Utility Learning Center

The BPU established an on-site Utility Learning Center to assist customers in the area of energy efficiency. Under this program customers are able to meet with trained energy efficiency staff to review their bills and consumption patterns within the Energy Engage portal while also providing them energy efficiency methods that may be useful and cost effective measures within their residence or business.

This program hopes to alert customers to the tools and technologies that are currently available and how to best use those technologies to track and manage their consumption. It also provides simple cost effective techniques to improve energy usage within their home or business through DIY videos or instructions.

D. Reactive Adjustment Rider

Customers with low power factors impose a burden on the electrical system causing a utility to increase its generation, transmission, distribution, transformer capacities and energy generation. Power factors are functions of real power (kW) and the apparent power (kVA) a utility must supply to the customer. For any given-metered load in kW, the lower the power factor, the greater the amount of power (kVA) a utility must generate and deliver to the customer. For example, in order to supply a load of 100 kW having a power factor of 85% the utility would have to generate and deliver approximately 117.6 kVA. An 85% power factor would require equipment with 17.6% more capacity to meet this demand. Further, since system losses vary as the square of the amperage required to serve the load, there is at the same time a 36% increase in system losses. BPU rates are designed to permit a customer to have a power factor equal to or greater than 90%. Customers with power factors less than 90% are penalized.

In August 2003 the power factor penalty provision was revised because the rate structure did not adequately address the cost of low power factors and customers in this category continued to impose a burden on the system. A customer with a low power factor can correct its power factor by installing corrective equipment or modifying the use of its equipment. When this new reactive adjustment penalty provision was enacted customers were notified of the change and given a six (6) month grace period in which to take corrective action.

Currently customers are notified if they have a low power factor and given an opportunity to correct the problem. If corrective action is not taken within a reasonable period of time then a penalty is added to their bill. The penalty is the difference between 90% and the actual power factor applied to the total customer's monthly electric billing. For example, if a customer has a power factor of 80% then a penalty of 10% is applied to the bill (90% - 80%).

The BPU continues to review rate design and charges under the context of power factor to ensure that those customers that drive additional cost on the system are paying for their share of utilization of the system. Power factor data much like many other customer specific details are adequately analyzed to determine their true cost to ensure subsidization between customers is remediated as much as possible.

E. Net Metering

In May 2009, Kansas passed the Net Metering and Easy Connection Act which is applicable to Investor Owned Utilities (IOU's) only. The BPU, as a municipal utility, was not subject to that regulation, but developed and adopted net metering and connection standards for Large, Medium, and Small Commercial and Residential customers to enable customer owned renewable generation sources. Although regulations surrounding net metering are now required the BPU was actively participating in net metering and providing customers a means to self-generate well before required to do so. Due to the falling prices surrounding solar PV and the robustness of the BPU net metering program the BPU has seen substantial growth over the past five years. In 2014 the BPU had 4 customers on the net metering program, as of the end of 2018 the BPU had a total of 39 net metering customers, a ten-fold growth rate over just the past five years. The BPU continues to monitor regulations and studies from around the country to ensure that the organization is actively pursuing best practices in self-generation while attempting to ensure limited cross-subsidization.

F. Smart Meters

Over the past several years the BPU implemented AMI smart metering technology to all BPU customers. The goal of the Advanced Metering Infrastructure is to improve customer service, lower the BPU's expense structure, and to provide consumers with the ability to monitor and drive efficiencies within their own system. Some of the benefits of AMI technology include immediate leak detection, reducing the need to access a customer's premises, and a real-time viewing of electric and water usage. The new meters are more accurate, and less prone to failure, and eliminate the potential for reader error that existed with the older electro-mechanical meters. In 2015 the BPU rolled out the Energy Engage Portal which allowed customers the ability to access their own individualized data regarding energy and water usage. The AMI smart meters are just another tool that consumers can use that will have a direct impact on their usage and in turn their bill. The BPU continues to explore ways in which to make the data more accessible and more useful to both the customer and the utility.

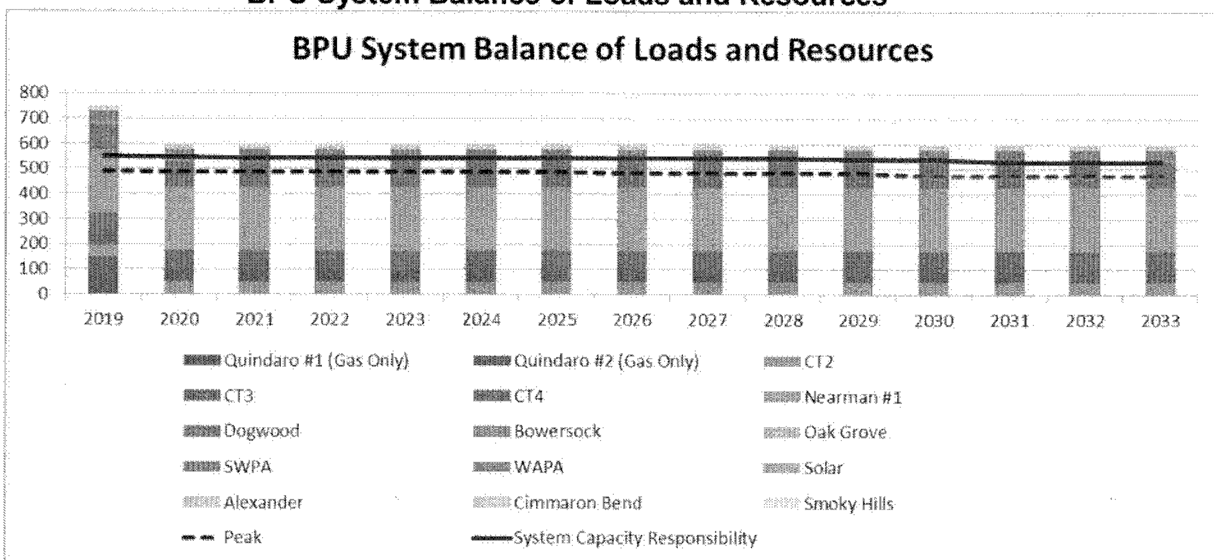
G. FlexPay Program

In August 2017 the BPU rolled out a new payment method called the FlexPay program. The FlexPay program was designed to allow customers more flexibility in the manner in which they view and manage their energy needs as well as when and what payments are made. FlexPay is a program which allows the customer to monitor their electricity and water usage on an as needed basis. This program allows the customer to receive service with no deposit or late fees while providing the customer the ability to view their account balance, daily usage, payment history and more through an App or an online portal. There are currently nearly 1,100 participants in the program with that number continuing to climb.

VII. FUTURE RESOURCE REQUIREMENTS SUMMARY

The graph below in Figure 3 shows the BPU future resource requirements based on current demand and supply forecasts. BPU currently has sufficient capacity to meet the forecast demand through the 2033 evaluation period. Load dynamics will be a major contributor to the future system capacity requirements. Based on the current base case scenario peak load is expected to be flat to slightly lower over the evaluation period as energy efficiency continues to reduce load across the various customer segments.

Figure 3
BPU System Balance of Loads and Resources



The BPU base case scenario does not recognize any expected changes within the current generation fleet outside of the retirement of the Quindaro Steam units in 2019 and the expiration of the Smoky Hills wind purchase power agreement in 2027. The BPU however recognizes that generation pricing, policies, and regulatory requirements are in constant flux and therefore continue to evaluate the cost of new generation both at the point of inception as well as the expected levelized cost over the life of the resource in context with expected market pricing as well as load dynamics and volatility.

The BPU expressly looked out five years for this IRP. The reasons include:

- BPU does not inherently require new resources within this time period.
- The planning horizon for new supply side resources is relatively short in nature based on the expected resource additions under consideration.

- Resource pricing and efficiencies are expected to continue to see material improvements moving forward.
- The nature of the electric industry is in a period of flux with the levels, locations, and types of generation being added to the grid both locally and regionally.
- The environmental regulatory landscape is evolving and may have a significant impact on various types of supply side resources.
- The political policies and incentives are evolving to adapt to new technologies.

Based on the above thoughts the BPU continues to monitor the cost and technologies in the market and how those may impact the organization over the long-term.

VIII. FUTURE RESOURCE OPTION SUMMARY

BPU's integrated resource planning is a continuous process and the selection of programs to apply scarce resources is a dynamic process. One manifestation of the dynamic nature of this planning is that as programs mature (reach a point of diminishing returns) new initiatives are undertaken, which produce better marginal results. With this dynamic nature of the IRP process, it is not to say that existing programs are discontinued, but are simply allowed to continue (either with or without modification), but are de-emphasized with regard to the use of scarce resources. The new initiatives which appear to be fruitful are implemented with sufficient resources so as to make them effective. Once a program is implemented, then planning goes on to evaluate other options. In the process of developing plans, BPU management personnel are always looking for initiatives which will produce the greatest result with the least long-run investment and expense.

Studies done under the IRP umbrella have produced programs that have yielded cost reductions, increased the use of more efficient generating units, enhanced conservation, and improved net revenues. In general these activities have helped hold down rates. Studies have been made which have focused upon increasing the use of renewable or "green" resources as well as improving energy conservation. An example of an energy conserving program is the Street Lighting and Signal Light Replacement Program where more efficient lamps are being utilized to replace older less efficient lamps while providing the same or greater level of lumens to the area or signal brightness.

Initial efforts by the BPU were aimed at improved energy utilization (increased off peak energy use). The more recent plan focuses on assisting customers through energy efficiency measures, as well as long-term green energy initiatives, which act as a hedge against carbon based generation volatility.

Resource options considered viable are screened through cost analysis and penetration studies. Resource options for meeting the power requirements of a system are traditionally screened through a power-supply evaluation program. The equipment to be evaluated for supply-side resource is first screened by an assessment of what options are available and most likely viable. In integrated resource planning demand-side options are also considered. The viable candidates are then placed into the mix of power-supply options for total resource evaluation. This evaluation will indicate what mix of programs should provide the lowest long term cost and will be pursued. The overall evaluation is typically done through the use of a long-term chronological production cost power supply modeling

Resource planning at the Kansas City Board of Public Utilities (BPU) is an ongoing process. As opportunities for acquiring additional resources are presented, the BPU performs studies and analysis, and then decides how to proceed depending on the results of the analysis. The BPU has completed a great deal of analysis over the years to ensure the BPU and its customer base are well insulated from volatility through energy source diversification and hedging while also preparing for inevitable shifts in demand based on population, industry, and technology changes. The following chronicles many of these studies.

In 2006, BPU commissioned a study for an independent review and update of the 2003 Kansas City Board of Public Utilities Electric System Master Plan. A conclusion of the study was that the most economical next new unit for BPU to meet projected demand is a nominal 235 MW pulverized coal unit. Subsequent to the completion of the 2006 Planning Study, in the first half of 2007, in a landmark case, the U.S. Supreme Court ruled that carbon dioxide and other global warming pollutants can be regulated under the Clean Air Act. The court also ruled that the EPA cannot refuse to regulate these pollutants for political reasons. In the first challenge since the ruling, the Sierra Club and Earthjustice petitioned the state of Kansas not to issue a permit for expansion of a coal-fired power plant proposed in Western Kansas unless it requires substantial controls for carbon dioxide. Subsequently, Secretary of the Kansas Department of Health and Environment, Roderick Bremby made an announcement in fall 2007 denying the air quality permit for Sunflower Electric Power Corporation's Holcomb Expansion. Bremby's decision was based on his opinion that additional carbon dioxide in the atmosphere presents a "substantial endangerment" to the public health of Kansans. Current EPA and Kansas regulations did not consider carbon dioxide a pollutant. The Secretary's decision set aside KDHE professional staff's recommendation to issue the permit and disregarded the extensive and exhaustive work completed by the KDHE technical staff to ensure that public health and the environment were protected, public concerns were addressed, and strict state and federal laws were followed.

A consequence of the Bremby decision was concern about the ability to permit a coal fired plant in the state of Kansas. Therefore, in 2008 the Kansas City Board of Public Utilities (BPU) performed a Ten Year Power Supply Plan study which considered natural gas fueled generation future resources capable of meeting the BPU's need for firm generating capacity. One conclusion of the study was that it was less costly to continue to operate Q1 through 2017 rather than to retire it and replace it with a similar amount of combustion turbine based capacity. Of the expansion plans considered, the plans that convert new or existing simple cycle combustion turbines to combined cycle combustion turbines are consistently the most expensive plans because the production cost savings associated with the efficiency of a combined cycle configuration compared to a simple cycle configuration are not sufficient to offset the combined cycle's incremental capital cost. In the least cost plan, BPU could meet its additional load growth with the addition of a 43 MW LM6000 type aero-derivative combustion turbine in 2011. The second least-cost plan also assumed Q1 remained in service and that two smaller (21 MW) LM2500 type combustion turbines were added for growth, one in 2011 and one in 2015. In the third least cost plan, a 75 MW Frame 7EA combustion turbine could be added in 2011.

In 2009, after the completion of the 2008 10-yr Power Supply Plan study, BPU was able to obtain firm transmission service on its SWPA Hydro purchases through the SPP aggregate study process. The ability to obtain firm transmission service from the SWPA Hydro capacity provided 39 MW of accredited capacity to the BPU. Obtaining this capacity moved BPU's need for additional capacity to the year 2016. Therefore allowing BPU the ability to defer capital costs associated with the anticipated generation need.

The following is additional documentation of many of the studies and analysis performed.

A. Electric Master Plan Review and Power Market Assessment

In 2006, BPU commissioned a study for an independent review and update of the 2003 Kansas City Board of Public Utilities Electric System Master Plan. The study was conducted in parallel with a base load generation siting study designed to identify the most feasible site for new base load generation available to the BPU system. A wholesale power market assessment designed to identify neighboring utilities needing additional generation with the common goal of the acquisition of additional generating capacity and energy to meet the needs of a growing service area was performed as a component of this study. The benefits identified in partnering with other utilities are twofold:

- Reduced costs to BPU customers from excess capacity that typically exists in the years immediately following the addition of the next major new generation resource, and

- Potentially significant economies-of-scale associated with the construction of generators larger than would be required to meet BPU's demand alone.

By conducting siting and market assessment studies concurrent with the Master Plan update, the BPU ensured that the costs of new generation resources considered reflect site specific conditions and cost-effective generator unit sizing. The concurrent studies also preserved the lead time required to design, permit, and construct new coal fueled generation for commercial operation in 2012 consistent with what the 2003 Master Plan indicated was needed.

This independent Master Plan review and update of 2006 addressed the future power supply needs of the BPU's native load customers, plus the wholesale power sales commitments under existing contracts through 2021-2022. The study also considered age and ability of the existing BPU generators to continue providing the level of economic and reliable service they have provided over the past 35 or more years. The period of study was the 25-year period 2006 through 2030.

The Master Plan review included the following elements:

- Forecast Need for Power--A review of previous BPU electric load and generating capacity requirement forecasts, a forecast of the capabilities and costs of existing BPU generators and power purchases, and a forecast of the timing and size of additional generating capacity needs.

- Characterization of New Power Supply Resources--Descriptions of the new power supply resources available to the BPU including conventional and renewable supply-side generation options, demand-side management programs designed to reduce the demand for power and possibly delay the need for new generation, and purchased power.

- Supply Side and Demand Side Resource Screening--A qualitative comparison of alternative resources with regard to their applicability to the BPU system along with a lifecycle cost comparison of the applicable options.

- Financial Comparison of Alternative Power Supply Plans--The identification of alternative plans to meet 2006-2030 generating capacity and energy needs and the comparison of these plans on a comparative revenue requirement basis. Includes associated risk and contingency analyses.

- Bilateral Power Market Description--A description of the potential availability of base load purchased power to be acquired in lieu of construction of a new BPU resource, and a description of the initial responses to a bridge power solicitation.

A conclusion of the study was that the most economical next new unit for BPU to meet the projected demand is a nominal 235 MW pulverized coal unit. The Executive Summary from that report is included in Appendix E.

B. 2008 Ten Year Power Supply Plan, updated 12/2012 (The Gas Plan)

Subsequent to the 2006 Master Plan review and update, in late 2008, the Kansas City Board of Public Utilities (BPU) completed a Ten Year Power Supply Plan study. The 10-year power supply study considered natural gas fueled generation resources capable of meeting the BPU's need for firm generating capacity. The need for capacity was identified as the difference between forecast peak demand plus reserve requirements and the capacities of existing power supply resources. The study recognized the expected outputs of existing BPU generators and that the economics of the Quindaro Units' continued operation is a function of potential future environmental regulations, including the Regional Haze Rule and the ozone non-attainment conditions in the Kansas City metropolitan area. The study period was the 10-year period beginning 2008 through 2017. That study identified a need for between 35 and 107 MW of additional firm capacity by 2017, dependent upon whether or not BPU continued to operate Quindaro Unit 1 (Q1). The study consisted of the comparison of ten alternative generation expansion plans. Each plan was based on the use of simple cycle combustion turbines and/or combined cycle units burning natural gas as the primary fuel.

The study objective was to find the power supply plan that minimized overall costs to BPU customers during the ten-year study period under a range of plausible future conditions. The initial set of plan comparisons assumed forecasts of expected fuel prices, power purchase and sales price, load growth, sulfur dioxide ($SO2$) allowance prices and carbon dioxide ($CO2$) allowance prices. In addition, sensitivity analyses were conducted to compare the costs to customers under the following conditions:

- Gain of a large (28 MW) customer, at a load factor similar to the BPU system load factor.
- Loss of a large (28 MW) customer, at a load factor similar to the system load factor.
- High natural gas and electric market prices.
- A high cost for $CO2$ emissions either as a result of a cap & trade program or the application of a carbon tax.
- No purchases of economy energy from the market reflecting an extreme case of transmission congestion.

One conclusion of the study was that it was consistently less costly to continue to operate Q1 through 2017 rather than to retire it and replace it with a similar amount of combustion turbine based capacity. Q1 was assumed to be required to be retrofit with a selective catalytic reduction (SCR) system for nitrogen oxide (NOx) control in order to continue operating through the study period. Of the expansion plans considered, the plans that convert new or existing simple cycle combustion turbines to combined cycle combustion turbines are consistently the most expensive plans because the production cost savings associated with

the efficiency of a combined cycle configuration compared to a simple cycle configuration are not sufficient to offset the combined cycle's incremental capital cost during the 10 year planning period. In the least cost plan, BPU could meet the additional load growth with the addition of a 43 MW LM6000 type aero-derivative combustion turbine in 2011. The second least-cost plan also assumed Q1 remains in service and that two smaller (21 MW) LM2500 type combustion turbines were added for growth, one in 2011 and one in 2015. In the third least cost plan, a 75 MW Frame 7EA combustion turbine could be added in 2011.
Because the NPV costs of the three least-cost plans calling for the addition of an LM6000 turbine, two LM2500 turbines or a 7EA turbine were so close, BPU selected the 7EA plan as the basis of the rate impact analysis in order to accommodate what is likely to be the most capital intensive of the least-cost plans and to allow BPU to maintain needed flexibility in procuring turbines.

C. 2008 - 2009 Kansas Municipal Generation Planning

The BPU participated in a joint resource planning study with Kansas Municipal Utilities (KMU), Kansas Public Power (KPP), and Kansas Municipal Energy Agency (KMEA) to determine a viable power supply plan that meets the power supply needs of all the participants at a cost that is more cost-effective than if the participants develop individual plans.

Power supply data was compiled and analyzed for the KMU membership as a whole as well as an approach to the individual agency power supply needs of KMEA, KPP and Kansas City BPU.

D. 2011 Environmental Regulatory Uncertainty Report

In July 2011, Black and Veatch was commissioned to perform a study related to the current and future environmental regulatory climate and how those regulations may affect BPU generation and the utility industry as a whole. The study focused on regulations associated with air quality, solid waste, as well as potentially new water mandates and how these new or potential mandates would affect the current fleet of generation at the BPU.

The study was divided into the near term (2012 – 2014) and the long term (2015 and beyond) compliance planning to ensure the BPU was taking all necessary steps to be prepared for regulatory changes. In the near term CSAPR or the Cross State Air Pollution Regulations were analyzed, with an expected compliance date of January 1, 2012. Within the CSAPR analysis several alternatives were analyzed including air quality controls on Nearman1, Quindaro1, and Quindaro2, the discontinuation of coal on Quindaro1 and Quindaro2, additional purchase power scenarios including that of the Dogwood combined cycle plant, as well as a discussion related to allowances and the pricing structure that may be established to handle those regulations.

In the long term analysis Black and Veatch reviewed a number of current and potential mandates. Long term compliance planning involved utility MACT or Maximum Achievable Control Technology which anticipated a compliance date of January 1, 2015, the maturing of CSAPR regulations, as well as NAAQS or National Ambient Air Quality Standards which were still pending at the time of the analysis. All potential and upcoming regulations were expected to have moderate to meaningful impacts on the generation side of the BPU and would continue to require continuous monitoring to ensure the BPU is doing everything possible to be compliant under current regulations as well as adapt plans to better position the utility going forward.

E. 2016 Clean Power Plan Study

In 2016 the BPU partnered with the Electric Power Research Institute (EPRI) to analyze the effects and options of various scenarios under the proposed U.S. Environmental Protection Agency's Clean Power Plan (CPP). As part of that analysis EPRI and the BPU evaluated various compliance pathway choices for implementing that plan and the implications of Kansas' options in preparing a CPP required state plan. As part of this review the analysis specifically assessed the mass and rate based pathways under a range of sensitivities. EPRI's U.S. Regional Economy, Greenhouse Gas, and Energy (US-REGEN) model was utilized to compare the various scenarios against the business as usual case. As part of this review the analysis suggested that business as usual within the state of Kansas would be insufficient to meet the required targets and thus various actions would be required to meet the proposed requirements. The analysis indicated that strong cases could be made for both mass and rate based pathways, though neither dominated in all scenarios.

Since the conclusion of the study the CPP underwent a series of reviews at the U.S. EPA as well as being stayed at the D.C. Circuit of Appeals. As of now the CPP is not expected to move forward in a manner consistent with the original proposal.

Although the CPP is not expected to have a material impact on generation requirements moving forward the BPU does expect other regulatory matters to come up in the coming years that will materially impact generation sources and output levels with the newest proposal in the pipeline being the Affordable Clean Energy (ACE) rule, although this plan has yet to be effectively published and therefore is expected to receive substantial review prior to implementation.

IX. PROPOSED FUTURE INITIATIVES

A. General

The Integrated Resource Plan is intended to act as a comprehensive decision support tool and road map for the BPU's objective of providing reliable and least-cost electric service to all of its customers while addressing the substantial risks and uncertainties inherent in the electric utility business. Today's utilities are facing even greater challenges than ever before with likely more challenges and opportunities on the horizon. The analysis and decisions that culminate within the IRP will likely make lasting and substantial advancements in the development of the utility and therefore to its customers. As such BPU is constantly evaluating its options with respect to capacity and or energy additions or modifications in light of the numerous changes within the industry as well as those changes that may affect the industry from a far.

The challenges facing new generation are significant and any deferral or reduction of capacity additions may have worthwhile dividends. BPU will continue to systematically challenge capacity addition decisions using available data on proven renewable and energy efficiency alternatives as well as conventional supply side alternatives.

X. ACTION PLAN

The BPU is devoting considerable resources to the programs either operating or being considered as a part of Integrated Resource Planning. The existing programs are yielding beneficial results. These programs are aiding in holding down rates, conserving energy, improving use of power generating equipment, and reducing the use of limited and more costly fossil fuels.

The BPU is going to continue to analyze the effectiveness of the current programs while continuing to search for additional programs both at the utility level as well as at the customer level. As technology continues to evolve more and more opportunities will become available that allow consumers to make smarter energy choices while also allowing the BPU to make more efficient choices, therefore saving everyone money. All the current ongoing programs are expected to continue over the next year. Future programs are being evaluated and if considered worthy of consideration will be evaluated to determine its cost effectiveness.

Results of the current supply side analysis indicate that the BPU will likely not require additional supply side resources over the next five years. Since the anticipated need for new supply-side resources is greater than five years out, there is sufficient time for the BPU to diligently consider all the options before committing to any action at the current time. Changes to the EPA power plant emission regulations, policies affecting carbon dioxide output levels, or even changes within the economic structure of various generation types will likely influence BPU power supply decisions. Although the BPU does not have immediate plans for additional generation, as either the opportunity or need for additional generation or purchases avails, the BPU will evaluate and consider the opportunities.

Although the BPU does not have immediate need for additional supply-side resources, the BPU will continue to evaluate opportunities for additional supply-side and demand-side resources for environmental and economic benefit. If the resources are of benefit to the BPU and its customers, the resources will be thoroughly analyzed and if the qualifications are met will be integrated into the existing resource mix towards meeting current and future needs.

XI. PUBLIC PARTICIPATION

Communication with its customers has always been a hallmark of the BPU. The IRP is both an art and a science and is an attempt to quantify and qualify the best possible scenarios for the utility and the community it serves. As part of this process the BPU is committed to openly discussing the IRP and all that it entails with those in and of the community to ensure that the voice of the community is heard while providing insight into the process.

In keeping with this tradition and the Federal Regulations, 10 CFR Part 905.11, governing the public participation requirements in developing BPU's IRP, the BPU is initiating this public process starting with this publication of the IRP:

1. Publication in Draft format posted with a downloadable link at the BPU web site, www.BPU.com, with paper or electronic copies available for the public upon request. Requests should be submitted to:

   Electric Supply Planning
   Kansas City Board of Public Utilities
   Electric Supply Administration Office
   PO Box 2409
   Kansas City, KS 66102

   Attention: Andrew Ferris

   Or by e-mail at:

   aferris@bpu.com

2. Upon posting, a notice will be published in the utilities current Publication of Record for official notices. This notice will open a 30 day public comment period and announce the date and time of the public meeting. At the meeting, BPU staff will explain the IRP process, present information in the IRP and receive comments from the public.

3. At the completion of the public comment period the BPU will have 30 days to incorporate the comments into the report with a full copy of all comments included in the appendix of the IRP.

4. Upon the publication of the IRP the elected members of the Board will have 30 days to approve the Integrated Resource Plan - Final Copy. Approval of the document constitutes the passing of a Board Resolution authorizing the General Manager to certify the submittal to Western Area Power Administration that the IRP meets all requirements set forth in 10 CFR Part 905 applicable to the Board of Public Utilities of Kansas City, Kansas.

5. An executed copy of the Board Resolution and one bound copy of the Integrated Resource Plan will be mailed to WAPA at their current address for legal notices. An electronic copy of the IRP will be made available to WAPA for publication on their web site and the current copy of BPU's WAPA-approved IRP will be maintained on BPU's web site during the term of our agreement with WAPA to meet the requirements of current regulations governing WAPA IRP customer transparency.

Appendix A (Tab A)

PUBLIC COMMENTS

KANSAS CITY BOARD OF PUBLIC UTILITIES
OFFICE OF MARKETING & CORPORATE COMMUNICATIONS
540 Minnesota Avenue
Kansas City, KS 66101

Contact: David Mehlhaff
Chief Communications Officer
Phone: (913) 573-9173
E-mail: dmehlhaff@bpu.com
Web site: www.bpu.com
Facebook: www.facebook.com/kckbpu
Twitter: http://twitter.com/kckbpu
YouTube: https://www.youtube.com/user/kckbpu

Date: July 19, 2019

For Immediate Release

BPU Takes Public Comment on 2019 Integrated Resource Plan

(KANSAS CITY, Ks.) — The Kansas City Board of Public Utilities (BPU), in accordance with Federal Regulation, 10 CFR, Part 905.11, is taking public comment and making available for review its draft 2019 Integrated Resource Plan (IRP).

Integrated Resource Planning (IRP) is a process that involves consideration of demand-side options in addition to traditional supply-side options in meeting the power needs of an electrical system. Such planning focuses on the need to seek and evaluate opportunities for savings of demand and energy in addition to evaluating traditional supply resources. It is an on-going planning process that is updated as conditions, price costs, technologies and power requirements change. The object of such planning is to find a least cost solution which will supply customers the amount and quality of electric service they desire while at the same time promoting the utility's long term financial health.

BPU is required by law to file an Integrated Resource Plan (IRP) with Western Area Power Administration, an agency of the U.S. Department of Energy (WAPA), and update the plan every five years. As part of this requirement, BPU must also submit annual progress reports and the status of its IRP. The report being made available is the draft BPU's 2019 IRP.

Public comments on BPU's draft 2019 IRP will be accepted for 30 days from notice of this publication. Comments can be forwarded to the Settlement Analyst, Andrew Ferris using any of the contact methods which appear below.

- more -

Paper print copies of the draft 2019 IRP are available to the public by request. To receive a print copy, please contact:

SPP Settlement Analyst
Board of Public Utilities 312 N. 65th Street
Kansas City, KS 66102
Attn: Andrew Ferris

Electronic copies are available by submitting requests to aferris@bpu.com, and are also available on BPU's website at the following http://www.bpu.com/Portals/0/pdf/IntegratedResourcePlan.pdf link.

For additional questions regarding the draft 2019 IRP, please contact Andrew Ferris, (913) 573-6838.

No public comments were received during the open comment period.

RESOLUTION No. 5242

RESOLUTION APPROVING THE 2019 INTEGRATED RESOURCE PLAN OF THE KANSAS CITY BOARD OF PUBLIC UTILITIES AN ADMINISTRATIVE AGENCY OF THE UNIFIED GOVERNMENT OF WYANDOTTE COUNTY/KANSAS CITY KANSAS PERTAINING TO PLANNING FOR NEW ENERGY SOURCES

WHEREAS, the Kansas City Board of Public Utilities (the "BPU") an administrative agency of the Unified Government of Wyandotte County/Kansas City ("Unified Government"), has prepared a 2019 Integrated Resource Plan in accordance with Department of Energy Regulations at 10 CFR Part 905, Subpart B for submittal to the Western Area Power Administration in accordance with the regulations; and

WHEREAS, the BPU reviewed the 2019 Integrated Resource Plan at its work session meeting on July 18, 2019; and

WHEREAS, the BPU has considered all matters it deemed necessary or appropriate to enable it to review, evaluate and reach an informed conclusion as to completeness and approval of the 2019 Integrated Resource Plan as supplemented and has determined that the 2019 Integrated Resource Plan as supplemented is complete to and in the best interests of the BPU.

BE IT RESOLVED BY THE KANSAS CITY BOARD OF PUBLIC UTILITIES AS FOLLOWS:

1. The 2014 Integrated Resource Plan as supplemented is determined complete and is approved for submittal to the Western Area Power Administration pursuant to Department of Energy Regulations at 10 CFR Part 905, Subpart B, and provides for the overall direction of activities related to providing adequate and reliable electric service; and further

2. William Johnson, General Manager of the BPU and Jerry Ohmes as Manager of Electric Supply of the BPU are authorized and directed to execute such planning activities as are necessary to provide reliable electric energy supply consistent with the 2014 Integrated Resource Plan as supplemented.

Passed by the Kansas City Board of Public Utilities this <u>September 4, 2019.</u>

Appendix B (Tab B)

LOAD FORECAST

KANSAS CITY, KANSAS, BOARD OF PUBLIC UTILITIES
LOAD FORECAST

I. BPU SYSTEM LOAD FORECAST

A. Introduction

The Board of Public Utilities updates its electric load forecast on an ongoing basis. Short–term peak demand energy forecasts are developed for use in revenue forecasting and budgeting. Long–term energy and peak demand forecasts are developed for use in longer term system planning such as to assess the long-term energy and demand requirements of the BPU and for use in performing analyses of various capacity and/or energy purchase options.

B. Methodology

BPU's forecasting method is a bottom-up approach developed by aggregating customer class specific forecasts. Developing customer class specific forecasts allows for the ability to get a refined estimate of total system demand. The estimates for the individual customer classes are aggregated to develop the estimate for the entire system as a whole. In using this method, the forecast for the system as a whole is typically more accurate since it allows for careful consideration of the change in demand for each of the customer classes and then combining these carefully considered estimates rather than merely making one large system forecast estimate which may not as thoroughly consider all of the factors causing both the change in number of customers in each class and the use per customer of each individual customer class.

Customer class-specific forecast models of the energy requirements were developed by comparing a linear regression technique with the outputs of the Smart forecasting software. Individual energy sales forecast models were prepared for each of the three largest customer classes, which are industrial, commercial, and residential. The forecast models are based on historical and projected future customer class–specific energy requirements. Below are graphs and output of the industrial, commercial, and residential class data. No future major industrial customers have been added beyond the existing known customers.

C. Forecast Results

The individual historical data and forecasts for industrial, commercial, and residential energy consumption are shown graphically in Figures 1 through 3 below.

Figure 1
Industrial Forecast

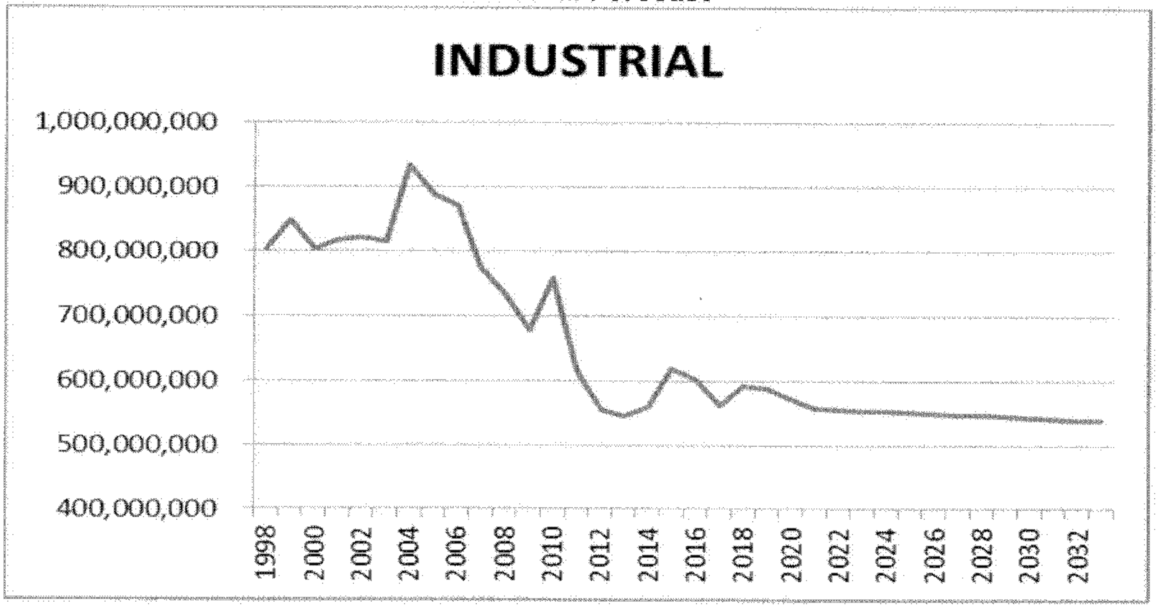


Figure 2
Commercial Forecast

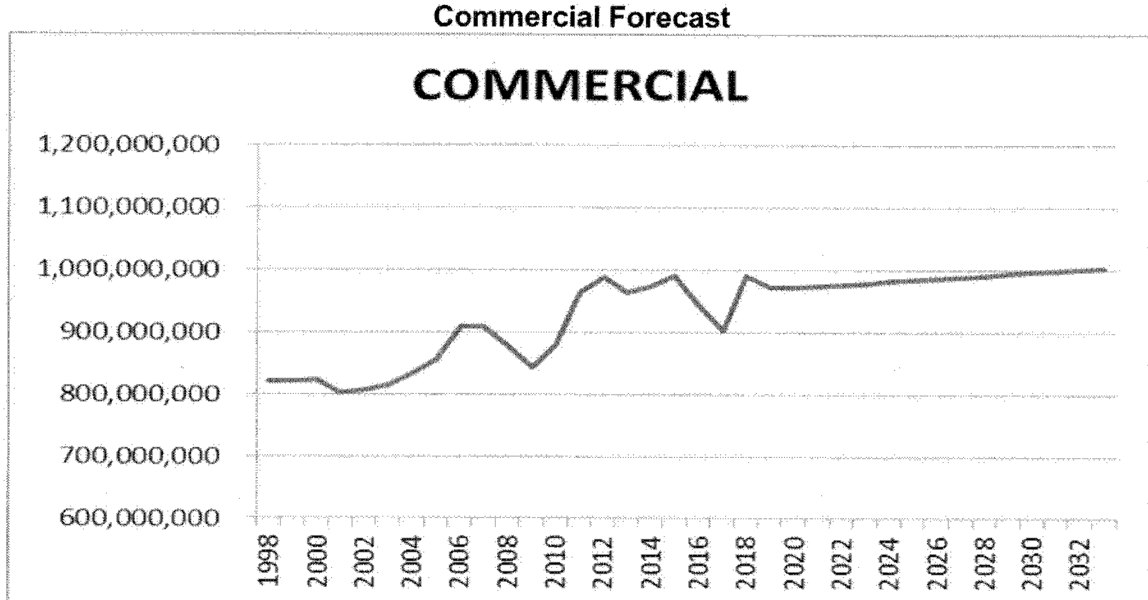
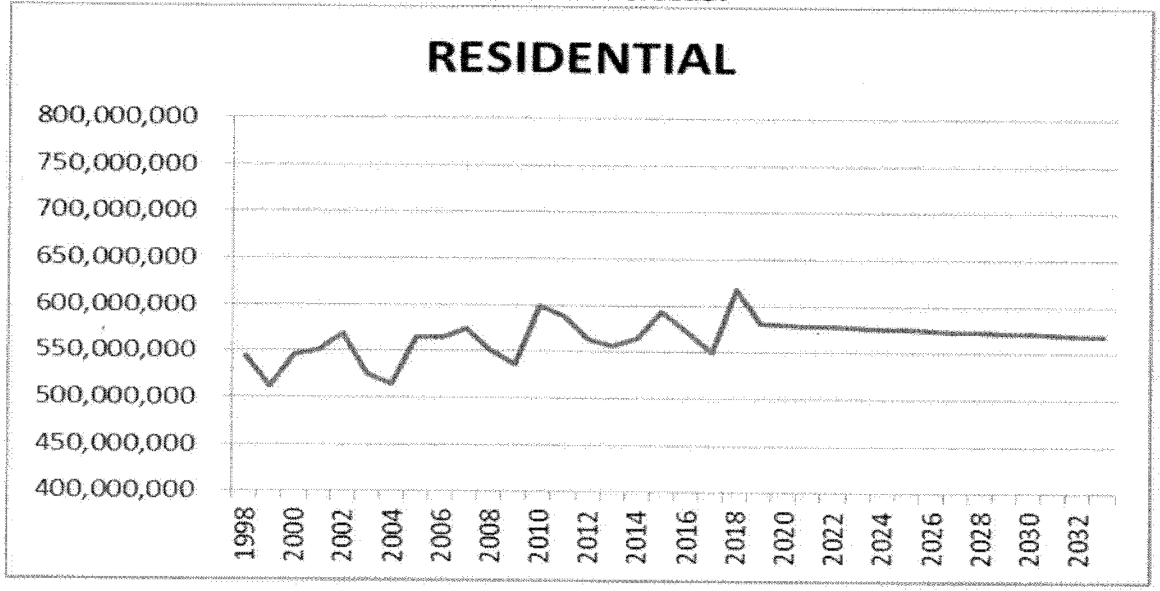


Figure 3
Residential Forecast



D. Major Customer Class Historical and Forecast Demand

The individual historical data and forecasts for industrial, commercial, and residential energy consumption are aggregated in Table 1 below. Aggregated into the Commercial customer class forecast is a forecast of the demand of the developing Village West shopping and entertainment area that was started in 2002. The Village West development includes the International Speedway, the Sporting Kansas City soccer stadium, the Schlitterbahn waterpark, the Cerner complex, the Legends shopping center, dining and entertainment establishments, large retail establishments, and lodging facilities. It is experiencing continued growth in commercial, retail and entertainment venues, as well as a U.S. soccer training and development center. The estimates below are attempting to account for the impact on electric demand through the final phases of the development of the Village West District in western Wyandotte County.

Table 1
Historical and Forecast Annual Major Customer Class Data (MWh)

Year	INDUSTRIAL	Percent Change	COMMERCIAL	Percent Change	RESIDENTIAL	Percent Change	Major Customer Classes Summed	Percent Change
1998	803,331,850	0.58%	820,089,166	2.46%	543,913,298	6.38%	2,167,314,314	2.70%
1999	847,643,070	5.52%	821,146,470.0	0.13%	512,421,552	-5.79%	2,191,211,092	1.10%
2000	803,136,767	-5.25%	822,626,899	0.18%	545,307,672	6.42%	2,171,071,338	-0.92%
2001	817,758,956	1.82%	802,679,313	-2.42%	550,869,096	1.02%	2,171,307,365	0.01%
2002	822,335,834	0.56%	806,031,040	0.42%	568,700,840	3.24%	2,193,557,963	1.02%
2003	814,756,414	-0.92%	814,699,133	1.08%	525,368,930	-7.62%	2,131,266,244	-2.84%
2004	932,858,837	14.50%	833,645,939	2.33%	514,886,934	-2.00%	2,222,835,681	4.30%
2005	889,594,504	-4.64%	856,388,086	2.73%	564,944,642	9.72%	2,252,376,120	1.33%
2006	869,655,917	-2.24%	909,404,930	6.19%	564,353,393	-0.10%	2,278,621,843	1.17%
2007	774,211,822	-10.97%	909,219,828	-0.02%	574,127,016	1.73%	2,167,598,240	-4.87%
2008	733,052,531	-5.32%	877,655,653	-3.47%	550,773,920	-4.07%	2,069,014,083	-4.55%
2009	678,327,267	-7.47%	843,231,586	-3.92%	535,690,414	-2.74%	1,964,810,292	-5.04%
2010	757,355,721	11.65%	879,059,973	4.25%	599,167,144	11.85%	2,135,501,779	8.69%
2011	614,559,741	-18.85%	963,117,955	9.56%	588,240,616	-1.82%	2,050,079,776	-4.00%
2012	555,511,201	-9.61%	988,166,817	2.60%	564,029,077	-4.12%	1,973,157,079	-3.75%
2013	544,416,379	-2.00%	963,696,185	-2.48%	556,786,563	-1.28%	1,944,299,731	-1.46%
2014	559,278,599	2.73%	973,384,174	1.01%	564,782,275	1.44%	2,097,445,048	7.88%
2015	617,838,731	10.47%	991,672,581	1.88%	593,132,956	5.02%	2,202,644,268	5.02%
2016	602,395,303	-2.50%	944,569,395	-4.75%	573,461,087	-3.32%	2,120,425,785	-3.73%
2017	561,731,105	-6.75%	903,387,325	-4.36%	549,713,684	-4.14%	2,014,832,114	-4.98%
2018	593,132,956	5.59%	991,672,581	9.77%	617,838,731	12.39%	2,202,644,268	9.32%
2019	587,201,626	-1.00%	971,839,129	-2.00%	580,768,407	-6.00%	2,139,809,163	-2.85%
2020	572,521,586	-2.50%	971,839,129	0.00%	579,897,255	-0.15%	2,124,257,970	-0.73%
2021	557,063,503	-2.70%	974,268,727	0.25%	579,027,409	-0.15%	2,110,359,639	-0.65%
2022	554,835,249	-0.40%	976,704,399	0.25%	578,158,868	-0.15%	2,109,698,516	-0.03%
2023	554,002,996	-0.15%	979,146,160	0.25%	577,291,629	-0.15%	2,110,440,785	0.04%
2024	553,171,992	-0.15%	981,594,025	0.25%	576,425,692	-0.15%	2,111,191,709	0.04%
2025	551,512,476	-0.30%	984,048,010	0.25%	575,561,053	-0.15%	2,111,121,539	0.00%
2026	549,857,938	-0.30%	986,508,131	0.25%	574,697,712	-0.15%	2,111,063,780	0.00%
2027	548,208,364	-0.30%	988,974,401	0.25%	573,835,665	-0.15%	2,111,018,430	0.00%
2028	546,563,739	-0.30%	991,446,837	0.25%	572,974,912	-0.15%	2,110,985,488	0.00%
2029	544,924,048	-0.30%	993,925,454	0.25%	572,115,449	-0.15%	2,110,964,951	0.00%
2030	543,289,276	-0.30%	996,410,268	0.25%	571,257,276	-0.15%	2,110,956,820	0.00%
2031	541,659,408	-0.30%	998,901,293	0.25%	570,400,390	-0.15%	2,110,961,091	0.00%
2032	540,034,430	-0.30%	1,001,398,546	0.25%	569,544,790	-0.15%	2,110,977,766	0.00%
2033	538,414,327	-0.30%	1,003,902,043	0.25%	568,690,472	-0.15%	2,111,006,842	0.00%

The major customer classes' aggregate number is added to the smaller customer classes' energy forecasts. The smaller customer classes are: schools, local government, highway lighting, and metered and un-metered city government, BPU interdepartmental and borderline customers. Borderline customers' demand is served by BPU through a neighboring utility's distribution system. The customers are billed through the neighboring utility's billing system and BPU is paid by the neighboring utility. The table of historical and forecasted data of the small customer class data appears below:

Table 2
Smaller Customer Class Data

Year	Schools	Highway Lighting	County	Metered City of KCK	Unmetered City of KCK	BPU Inter-department	Borderline	Village West
1998	53,842,157	3,379,918	9,247,141	34,986,176			15,525,400	
1999	51,810,293	2,972,184	8,911,111	35,355,045			13,925,900	
2000	55,483,018	2,961,610	9,379,719	38,028,632	34,932,504	29,600,000	16,874,842	
2001	60,837,512	2,968,798	9,901,089	35,289,968	34,960,667	33,240,000	16,882,433	
2002	63,612,415	2,973,036	7,871,638	34,794,040	35,181,411	41,911,465	18,221,142	3,509,751
2003	68,937,672	3,072,183	8,620,954	35,052,238	35,663,130	31,387,396	17,338,495	23,558,233
2004	68,937,672	2,665,939	8,438,262	34,401,457	36,041,942	42,938,994	17,805,851	58,556,029
2005	68,272,280	2,665,939	8,756,979	31,743,439	45,027,579	47,626,677	18,765,903	58,551,112
2006	70,866,995	2,665,939	8,782,346	34,427,171	36,782,902	44,616,218	18,678,613	64,792,397
2007	75,577,601	2,664,127	8,663,293	30,522,789	38,716,486	44,996,254	19,313,961	89,960,426
2008	75,239,657	2,646,121	7,864,157	36,320,298	37,424,804	45,882,343	18,482,844	92,468,021
2009	77,430,042	2,556,091	7,637,040	33,103,923	37,433,960	36,999,231	18,429,740	92,438,975
2010	73,706,199	2,556,091	7,965,143	40,639,135	37,754,060	38,331,710	18,625,886	100,081,059
2011	70,174,257	2,556,096	5,768,883	38,462,059	37,640,339	38,405,209	17,381,535	115,838,536
2012	66,077,568	2,556,096	11	42,592,110	38,001,433	37,462,727	17,029,530	134,550,016
2013	69,637,035	2,556,096	-	42,694,440	37,364,538	38,369,477	17,972,281	120,599,396
2014	74,760,541	2,552,091	-	44,791,460	37,364,538	29,444,273	18,873,819	-
2015	72,663,778	2,340,156	-	35,502,105	37,364,538	29,248,043	17,780,671	-
2016	73,304,208	2,306,580	-	36,799,229	37,364,538	29,778,091	17,883,518	-
2017	72,111,223	2,306,580	-	39,229,511	38,093,694	27,728,649	16,486,144	-
2018	83,497,634	2,306,580	-	38,121,254	38,093,695	30,559,491	17,565,564	-
2019	77,652,800	2,306,580	-	38,109,818	38,093,695	30,253,896	17,504,085	-
2020	77,381,015	2,303,120	-	38,098,385	37,712,758	29,951,357	17,442,820	-
2021	77,110,181	2,299,665	-	38,086,955	37,335,630	29,651,844	17,381,770	-
2022	76,840,296	2,296,216	-	38,075,529	36,962,274	29,355,325	17,320,934	-
2023	76,571,355	2,292,772	-	38,064,106	36,592,651	29,061,772	17,260,311	-
2024	76,303,355	2,289,332	-	38,052,687	36,226,725	28,771,154	17,199,900	-
2025	76,036,293	2,285,898	-	38,041,271	35,864,458	28,483,443	17,139,700	-
2026	75,770,166	2,282,470	-	38,029,859	35,505,813	28,198,608	17,079,711	-
2027	75,504,971	2,279,046	-	38,018,450	35,150,755	27,916,622	17,019,932	-
2028	75,240,703	2,275,627	-	38,007,045	34,799,247	27,637,456	16,960,362	-
2029	74,977,361	2,272,214	-	37,995,642	34,451,255	27,361,081	16,901,001	-
2030	74,714,940	2,268,806	-	37,984,244	34,106,742	27,087,471	16,841,848	-
2031	74,453,438	2,265,402	-	37,972,848	33,765,675	26,816,596	16,782,901	-
2032	74,192,851	2,262,004	-	37,961,457	33,428,018	26,548,430	16,724,161	-
2033	73,933,176	2,258,611	-	37,950,068	33,093,738	26,282,946	16,665,626	-

E. Losses

Losses are estimated based on component losses for transmission, primary, and secondary loads. These loss estimates are applied by customer class as annotated below.

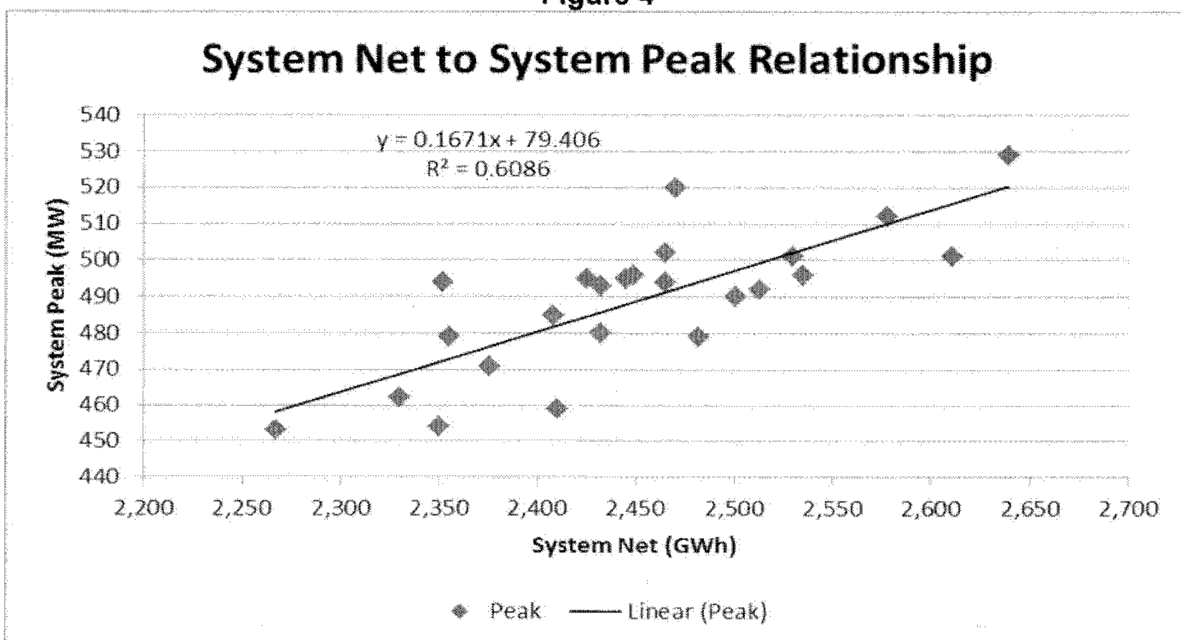
Table 3
LOSSES

Customer Class	Losses		
	Transmission 0.44%	Primary 2.39%	Secondary 4.38%
Industrial	X		
Commercial	X	X	X
Village West	X	X	X
Residential	X	X	X
Schools	X	X	X
Hiway Lighting	X	X	X
County	X	X	X
Metered City of KCK	X	X	X
Unmetered City of KCK	X	X	X
BPU Inter-Departmental	X	X	X
Borderline	X	X	
Nearman Participating	X		
Wholesale	X		

F. Peak System Demand

Peak system demand is calculated based on linear regression trend modeling of the historical peak plotted against the associated system net for the years 1995 through 2018. Figure 4 contains a plot of the system annual net energy and system annual peak demand. The black line in Figure 4 shows the historical trend line relationship between system annual net energy and system annual peak demand.

Figure 4



In addition to its retail load responsibilities, the BPU had wholesale power supply contracts with Columbia, MO and the Kansas Municipal Energy Agency (KMEA) based on their participation in BPU's Nearman Unit No. 1. The contract with Columbia, MO was terminated effective April 2013 and resulted in an additional capacity of 20 MW. The KMEA contract expired as of December 31, 2015 and yielded another 37.5 MW of capacity. The additional capacity was necessary to help offset the expected retirement of the Quindaro steam units as well as CT1. and is expected capacity shortfalls from the retirement of some of the existing CTs. Forecasted Energy sales to KMEA for the remainder of the contract were based on expected unit availability and anticipated SPP pricing. Recent Nearman participating historical data and forecast energy appears in the table below:

Table 4
NEARMAN PARTICIPATING ENERGY

Year	Nearman Participating Energy (kWh)	KMEA	Columbia
2007	434,356,000	275,885,000	158,471,000
2008	398,063,000	247,828,000	150,235,000
2009	296,477,000	149,658,000	146,819,000
2010	296,136,000	145,316,000	150,820,000
2011	277,681,000	131,451,000	146,230,000
2012	101,330,000	50,210,000	51,120,000
2013	93,308,000	86,013,000	7,295,000
2014	111,874,000	111,874,000	-
2015	20,179,000	20,179,000	-

The aggregate peak for Nearman Participants was 58MW, which is the sum of the KMEA and Columbia contract amounts. The historical energy varies from year to year.

G. Forecast Results

The system load forecast developed by the BPU is shown in Table 5. The forecast includes sales to BPU's retail customers, borderline, city, and BPU interdepartmental as well as any system losses that are incurred.

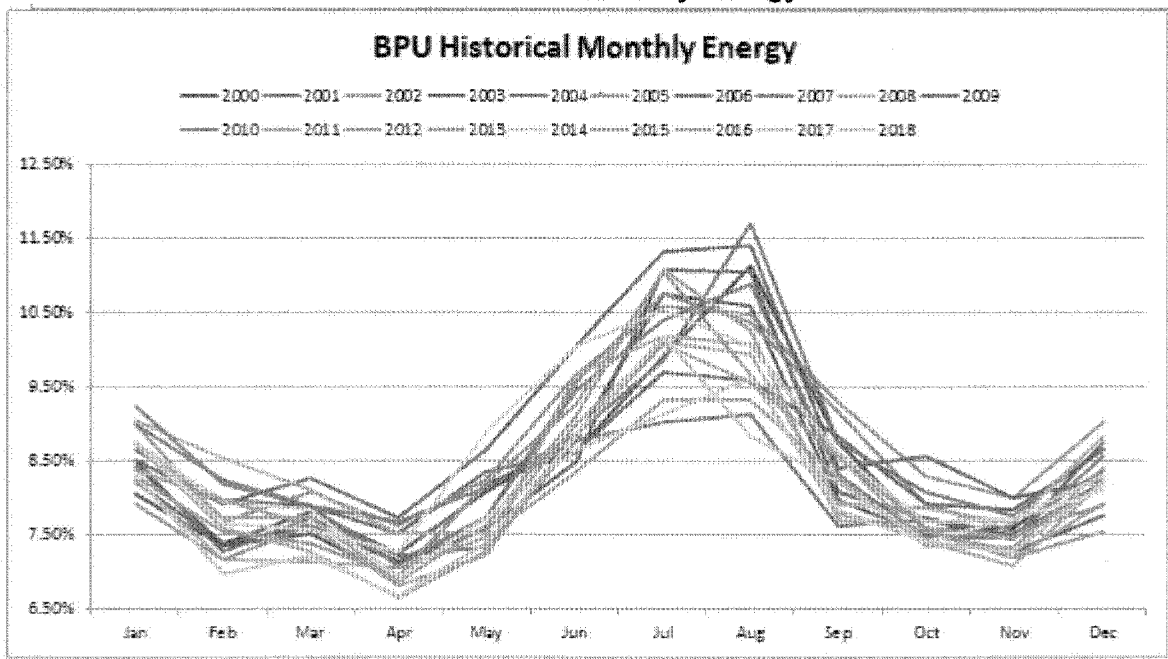
Table 5
Load Forecast

Year	System Peak (MW)	System Energy (GWh)	Load Factor
2000	494	2,465	57%
2001	496	2,449	56%
2002	479	2,482	59%
2003	520	2,470	54%
2004	490	2,501	58%
2005	501	2,611	59%
2006	529	2,639	57%
2007	512	2,578	57%
2008	492	2,513	58%
2009	471	2,376	58%
2010	501	2,530	58%
2011	502	2,465	56%
2012	495	2,425	56%
2013	454	2,350	59%
2014	459	2,410	60%
2015	485	2,408	57%
2016	480	2,432	58%
2017	494	2,352	54%
2018	496	2,535	58%
2019	492	2438	57%
2020	488	2419	57%
2021	485	2403	57%
2022	485	2403	57%
2023	485	2402	57%
2024	485	2402	57%
2025	485	2401	57%
2026	484	2400	57%
2027	483	2400	57%
2028	482	2399	57%
2029	481	2398	57%
2030	480	2398	57%
2031	478	2397	57%
2032	475	2397	58%
2033	474	2396	58%

BPU's base energy requirements are projected to shrink at an average annual rate of about 0.037% per year over the fifteen year forecast.

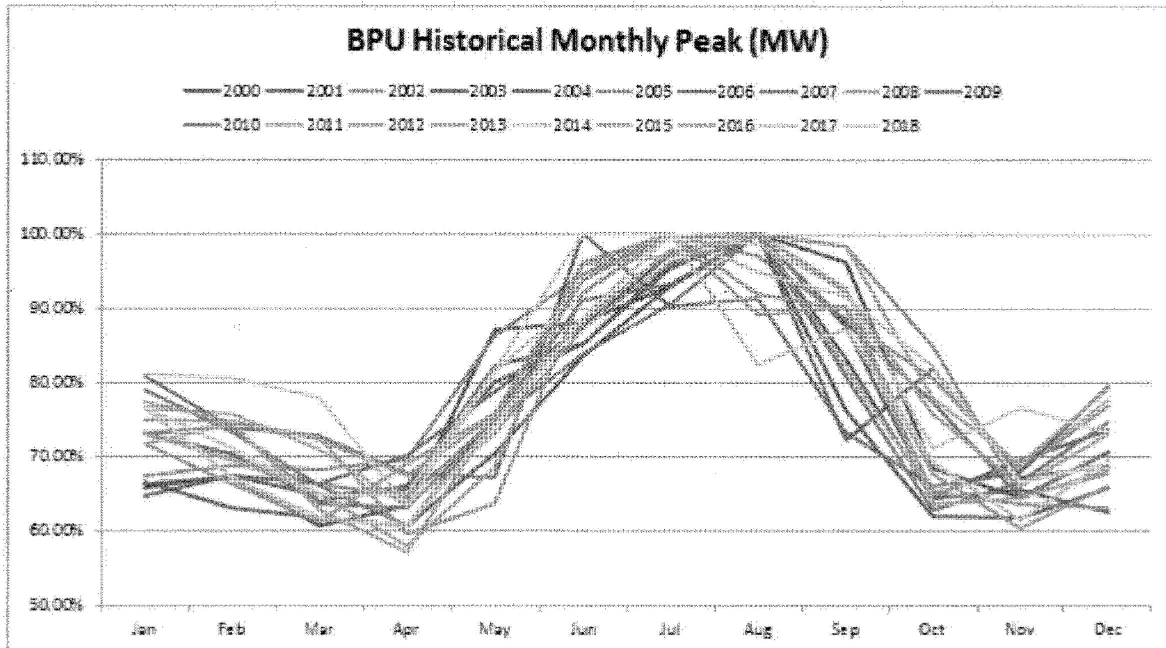
Monthly historical data from 2000 through 2018 was used to allocate energy and peak for each month. A percentage of average monthly system net is used to spread forecasted energy between months in all forecasted years. A percentage of average monthly peak compared to the average annual peak is used to determine monthly peak in all forecasted years. The data tables and graphs appear below:

Figure 5
BPU Historical Monthly Energy



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2000	8.06%	7.36%	7.51%	6.92%	8.18%	8.63%	9.92%	11.12%	8.75%	7.57%	7.59%	8.38%
2001	8.21%	7.38%	7.82%	7.25%	8.09%	8.77%	10.75%	10.60%	7.97%	7.52%	7.26%	7.76%
2002	7.90%	7.16%	7.62%	7.13%	7.74%	9.55%	10.75%	10.37%	9.14%	7.90%	7.54%	7.89%
2003	8.44%	7.38%	7.63%	7.14%	7.55%	8.48%	11.07%	11.04%	8.06%	7.74%	7.48%	8.22%
2004	8.66%	7.97%	7.89%	7.50%	8.34%	8.62%	9.69%	9.60%	8.84%	7.92%	7.83%	8.63%
2005	9.00%	7.66%	8.08%	7.61%	8.23%	9.67%	10.59%	10.49%	9.30%	8.28%	8.00%	9.01%
2006	8.52%	7.91%	8.26%	7.73%	8.65%	10.05%	11.33%	11.40%	8.40%	8.57%	8.00%	8.25%
2007	9.00%	8.23%	7.90%	7.66%	8.13%	8.86%	9.87%	11.70%	8.75%	8.07%	7.75%	8.68%
2008	9.04%	8.54%	8.09%	7.51%	7.52%	8.98%	10.09%	9.94%	7.91%	7.86%	7.64%	8.83%
2009	8.52%	7.26%	7.72%	7.20%	7.31%	8.78%	9.02%	9.12%	7.63%	7.69%	7.42%	8.76%
2010	9.24%	8.17%	7.90%	7.06%	7.73%	9.46%	10.41%	10.90%	8.32%	7.45%	7.46%	8.55%
2011	8.76%	7.72%	7.74%	6.86%	7.62%	9.11%	11.07%	10.27%	7.70%	7.59%	7.45%	8.14%
2012	8.29%	7.55%	7.37%	6.95%	8.19%	9.27%	11.05%	9.68%	7.78%	7.54%	7.19%	7.54%
2013	8.23%	7.16%	7.13%	7.06%	7.45%	8.35%	9.32%	9.32%	8.26%	7.35%	7.32%	8.39%
2014	8.75%	7.93%	7.84%	6.92%	7.74%	8.65%	9.12%	9.60%	7.83%	7.40%	7.73%	8.29%
2015	8.38%	7.96%	7.62%	6.80%	7.22%	8.87%	10.08%	9.57%	8.55%	7.59%	7.17%	7.90%
2016	8.73%	7.59%	7.27%	6.65%	7.25%	9.67%	10.17%	10.08%	8.57%	7.40%	7.08%	8.22%
2017	8.29%	6.96%	7.21%	6.68%	7.37%	8.83%	10.18%	8.83%	8.20%	7.40%	7.27%	8.21%
2018	8.75%	7.66%	7.57%	7.27%	8.88%	10.05%	10.53%	10.05%	8.62%	7.67%	7.70%	8.09%

Figure 6
BPU Historical Monthly Peak (MW)



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2000	66.19%	67.00%	60.53%	63.36%	87.04%	88.06%	92.91%	100.00%	96.15%	68.42%	64.37%	70.65%
2001	65.73%	67.34%	64.72%	65.32%	82.26%	85.28%	95.97%	100.00%	83.27%	64.31%	65.32%	62.50%
2002	67.22%	68.68%	68.27%	69.52%	86.22%	94.78%	99.79%	100.00%	98.33%	84.97%	64.51%	67.64%
2003	66.54%	63.08%	61.54%	60.58%	70.38%	83.46%	93.08%	100.00%	76.35%	61.92%	61.73%	65.77%
2004	73.06%	70.41%	63.88%	66.12%	80.00%	85.10%	95.51%	100.00%	87.55%	64.69%	69.59%	73.47%
2005	73.25%	69.46%	66.27%	64.27%	75.05%	96.41%	100.00%	97.01%	88.82%	80.64%	68.06%	76.85%
2006	64.65%	67.30%	66.16%	69.94%	78.64%	87.71%	97.35%	100.00%	72.21%	81.85%	67.11%	68.62%
2007	73.05%	74.02%	63.67%	63.09%	74.61%	83.79%	90.63%	100.00%	88.09%	77.34%	64.45%	70.51%
2008	76.42%	75.81%	70.73%	63.21%	72.97%	87.40%	96.14%	100.00%	81.91%	65.04%	68.50%	77.64%
2009	80.89%	73.89%	72.82%	67.73%	67.09%	100.00%	90.23%	91.51%	73.25%	66.03%	67.94%	79.41%
2010	79.04%	73.25%	66.07%	60.68%	75.25%	91.22%	93.21%	100.00%	80.84%	62.67%	66.47%	74.65%
2011	71.71%	74.30%	62.75%	57.17%	75.10%	88.45%	97.81%	100.00%	92.63%	63.55%	64.34%	68.13%
2012	71.72%	66.26%	61.01%	69.09%	75.76%	93.94%	100.00%	91.92%	90.10%	65.05%	63.43%	63.03%
2013	77.31%	74.67%	72.25%	67.40%	75.55%	96.04%	97.14%	100.00%	98.46%	77.97%	68.94%	79.30%
2014	81.26%	80.61%	78.00%	63.40%	81.48%	91.94%	100.00%	98.69%	92.59%	71.02%	76.47%	73.20%
2015	75.05%	74.64%	72.37%	59.38%	63.51%	92.16%	100.00%	89.28%	90.31%	67.63%	60.21%	65.98%
2016	73.13%	69.58%	65.00%	57.92%	68.33%	96.04%	99.58%	100.00%	92.29%	75.83%	66.04%	72.92%
2017	76.52%	67.00%	61.54%	60.53%	74.09%	88.66%	100.00%	82.59%	87.25%	69.23%	61.34%	69.43%
2018	76.61%	71.17%	64.52%	64.92%	81.65%	100.00%	100.00%	94.96%	91.73%	82.26%	66.53%	68.95%

Appendix C (Tab C)

Electric Power Research Institute Clean Power Plan Study

- Technical Report Executive Summary
- 2017-01 – Final Report Understanding Clean Power Plan Choices in Kansas

Understanding Clean Power Plan Choices in Kansas

Options and Uncertainties

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THE ELECTRIC POWER RESEARCH INSTITUTE (EPRI) PREPARED THIS REPORT

NOTE

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Acknowledgments

The Electric Power Research Institute (EPRI) prepared this report.

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This publication is a corporate document that should be cited in the literature in the following manner:

Understanding Clean Power Plan Choices in Kansas: Options and Uncertainties.
EPRI, Palo Alto, CA: 2016.
3002009492.

Executive Summary

This report summarizes analysis by the Electric Power Research Institute (EPRI) to evaluate compliance pathway choices for implementing the U.S. Environmental Protection Agency's Clean Power Plan (CPP) in Kansas. This EPRI analysis looked at the implications of Kansas' options in preparing a CPP-required state plan and specifically assessed mass- and rate-based pathways under a range of sensitivities.

EPRI's U.S. Regional Economy, Greenhouse Gas, and Energy (US-REGEN) model was used to compare CPP compliance results to an appropriate reference scenario (i.e., without the CPP) to understand tradeoffs between planning options. In addition to rate and mass paths, the analysis considers alternate trading scenarios to understand how reliance on in-state measures versus participation in multi-state emissions trading markets could influence outcomes.

Model results show that Kansas' business-as-usual generation mix without the CPP would likely be out of compliance with mass and rate targets (Figures 3-4 and 3-5), which means that additional measures (e.g., changes to the fleet, allowance purchases, or emission rate credit purchases) would likely be necessary to close this gap.

The analysis suggests that strong cases can be made for both mass- and rate-based pathways, though neither path dominates under all possible futures. Results are driven principally by the comparative incentives of building new natural gas combined cycle (NGCC) units relative to wind. When gas prices are low, new NGCC units may be built under reference conditions, which would likely make **existing-mass** (implemented as per the proposed Federal Plan in this analysis) a lower cost CPP pathway for Kansas. When gas prices are high and/or wind costs are low, the economics of new wind capacity in Kansas are favorable even without the CPP due to the state's high resource potential. Exports under these conditions increase considerably, and the **subcategory-rate** pathway would align more closely with these investments.

Regardless of gas prices, planned wind capacity installations in Kansas through 2018 help with rate-based compliance and give additional lead time before incremental CPP-related investments have to be made.

Depending on how uncertainties resolve, the primary elements of CPP compliance for Kansas could include:

- Lowering coal-based in-state generation through retirements and/or lower utilization (Figure 5-4 and 5-5)
- Constructing new natural gas combined cycle or wind capacity to comply with the state's chosen mass or rate pathway (Figures 5-3 and 6-3)
- Trading CO_2 allowances or emission rate credits if mass- or rate-based pathways are chosen by the state, respectively (Figures 5-7 and 6-4)

Another robust finding is that promoting multi-state credit trading lowers compliance costs for Kansas compared with "island" scenarios, which implement only in-state mitigation measures (i.e., actions within the state's borders). The magnitude of this cost reduction from access to national markets (Tables 6-3 and 6-4) and impact on in-state capacity investments (Figures 5-3 and 6-3) depend on pathway selections in other states. Despite its potential role in cost containment, inter-state CPP market participation involves tradeoffs with increased uncertainty about the pace of market development, liquidity, volatility, and exposure to forces external to the state of Kansas.

Potential impacts of rate- and mass-based compliance plans vary based on assumed market conditions like natural gas prices, CPP pathway choices in other states, wind costs, transmission, and coal retirements (Figure 6-11). Given uncertainty about these factors, which are largely independent from pathway decisions, the option to amend pathway selection as more information becomes available could help to limit compliance costs.

Although this analysis offers insights for state-level CPP decision-making, model approximations and incomplete system dynamics suggest that the analysis should not be interpreted as a definitive determination of CPP planning for Kansas. The impacts of the CPP vary widely on a state-by-state basis and depend on factors like current and anticipated state-level policies, planned retirements of existing assets, and decisions in neighboring states. These factors can affect insights and least-cost strategies. Each state's preferred portfolio of compliance measures and actual deployment could depend on a broad range of considerations beyond the scope of this economic modeling and analysis, including local incentives, other policy goals, risk tolerance, and other factors (e.g., policy, legal cases, permitting, and uncertainty).

Table of Contents

Section 1: Introduction

This report summarizes analysis by the Electric Power Research Institute (EPRI) of the comparative costs, investment implications, and other impacts of compliance pathway choices for implementing the U.S. Environmental Protection Agency's Clean Power Plan (CPP) in Kansas. The report is intended to provide insight into Kansas' possible options in preparing its CPP state plan. The analysis was conducted with funding from a consortium of Kansas utilities, including Sunflower Electric Power Corporation and Kansas City Board of Public Utilities.

The U.S. Environmental Protection Agency's Clean Power Plan

The U.S. Environmental Protection Agency (EPA) released its *Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units*, also known as the Clean Power Plan, on August 3, 2015.[1]

Promulgated under Section 111(d) of the Clean Air Act (CAA), the CPP would require states to create plans explaining how they would comply with state-specific carbon dioxide (CO_2) emission reduction mandates for existing fossil-fueled electric generating units.

The state plans specify the form and extent of CO_2 emission reduction requirements for affected units. The EPA identifies six compliance pathways for states, three of which are based on emission rates (i.e., emissions per generated electricity) and the others on mass-based emission caps. The CPP provides flexibility for states to develop other compliance approaches, which are subject to EPA approval. In addition to pathway selection, a second decision for states is to determine the degree of participation in multi-state trading programs of CPP allowances or emission rate credits as a complement to in-state mitigation measures.

On February 9, 2016, the Supreme Court issued a stay on CPP implementation while the lower courts review pending legal challenges. The impact of the stay on CPP requirements and timetables was uncertain at the time of this report's preparation.

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[1] The Final Rule was published in the Federal Register on October 23, 2015 (80 FR 64661). EPRI's summary and interpretation of the CPP is provided here as background and is not legal advice.

Motivations for the State-Level Analysis of Clean Power Plan Compliance Options for Kansas

The flexibility of alternate CPP pathways could help states manage compliance costs; however, these options are accompanied by detailed provisions and state-specific considerations requiring careful deliberation and analysis. Some of the factors that can impact a state's compliance strategy are influenced by decisions outside of the state or by circumstances beyond an individual state's ability to control. The challenge for state planners is knowing how these choices could impact implementation decisions, compliance costs, environmental integrity, reliability and other short- and long-term outcomes in an uncertain world.

Since 2012, EPRI's Program 103 (*Analysis of Environmental Policy Design, Implementation, and Company Strategy*) has been creating the tools needed for its members and the public to understand potential CPP impacts on utility assets and operations, and to create cost-effective compliance strategies.

EPRI's in-house electric sector model (**US-REGEN**) captures detailed CPP-related choices and economic tradeoffs.

Program 103 and EPRI's Energy and Environmental Analysis group have supported the continual development and refinement of the U.S. Regional Economy, Greenhouse Gas, and Energy (US-REGEN) model. Among other applications, US-REGEN offers a flexible and customizable platform for assessing impacts of technological developments and policies like the CPP on the electric power sector, providing insights into how alternate pathway choices and multi-state trading markets may influence electricity generation, investments, power system operations, emissions, and costs. Datasets have been created and updated to characterize electricity generation technologies and their costs, renewable energy resources, and specifics of CPP options at the state level.[2]

Research under EPRI's Program 103 has concentrated on national and regional implications of the Clean Power Plan. In 2015, a supplemental project was offered providing US-REGEN analyses on in-depth consideration of CPP implementation at the state level, including the study in Kansas discussed in this report.

[2] See Appendix A for additional information about the US-REGEN model and references to model documentation.

Section 2: Analysis Approach

The analysis strategy in this report is to compare CPP policy and uncertainty scenarios to an appropriate reference case (i.e., without the Clean Power Plan) to provide insight about the implications of different CPP pathways for Kansas. The US-REGEN model offers an analytical testbed for conducting controlled experiments to investigate differences across scenarios.

EPRI's US-REGEN Model Structure, Assumptions, and Data

This analysis uses the electric sector only version of US-REGEN for detailed, state-level analysis of investments and dispatch.

The Electric Power Research Institute developed and maintained the U.S. Regional Economy, Greenhouse Gas, and Energy (**US-REGEN**) model. US-REGEN combines detailed power sector capacity planning and dispatch for the Lower 48 U.S. states with a dynamic computable general equilibrium (CGE) model of the rest of the economy.[3] The two models are solved iteratively to allow policy impacts on the electric sector to account for economic responses (and vice versa), which means US-REGEN can assess a wide range of energy and environmental policies. The analysis in this report uses the electric-sector model only.

The electric-sector model simultaneously determines a cost-minimizing solution for all 48 states subject to technical and policy-related constraints. US-REGEN's spatial and temporal detail provides possible resource adequacy for each state and captures market dynamics not only for electricity markets but also for CPP-related multi-state trading of allowances (for mass-complying states) and emission rate credits (for rate-complying states).

Model outputs are intended to represent critical details of asset investment, power systems operations, and environmental compliance options. However, it is important to interpret these results keeping in mind that they are not meant to be predictions of future states-of-the-world. Primary decision-relevant insights are driven by changes across scenarios in "what-if" analyses under many different sensitivities, not by absolute levels in particular scenarios.

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[3] The CGE model of the U.S. economy includes representations of the residential, commercial, industrial, transportation, and fuels-processing sectors.

Although analysis in this report provides many state-level insights for CPP decision-making, model approximations and incomplete system dynamics suggest that it should not be construed as a definitive determination of planning for Kansas.

- Actual deployment may depend on many additional factors, such as local incentives, regulatory developments, other policy, judicial outcomes, permitting, and other uncertainties.

- The modeling of the "Existing Mass" CPP pathway (discussed in the next section) is based on the proposed Federal Plan, which provides guidelines for managing "leakage" when new units are not covered under a mass-based state plan. These EPA guidelines could change in the final Federal Plan, and such modifications could shift incentives for asset investment, dispatch, and retirement moving forward.

- EPRI's US-REGEN model captures many areas of power-sector planning in detail, but computational constraints place important limitations on the degree of detail in specific states. For instance, the model does not account for unit-commitment-related costs or constraints, intra-state transmission constraints (though inter-state transmission and investment are included), or gas distribution to individual units. These model omissions could impact the representation of potential CPP compliance measures (e.g., the model likely overstates the potential for coal-to-gas re-dispatch relative to a production-cost model due to gas distribution).

Detailed discussions of US-REGEN's data, structure, assumptions, and limitations regarding technological, economic, and policy-related variables are provided in Appendix A of this report.[4]

Analysis Structure

The analysis in this report concentrates on Kansas' state-level decisions to understand the implications of alternate CPP pathways. The four primary paths considered include two rate-based ("Subcategory Rate" and "State Rate") and two mass-based ("Existing Mass" and "Full Mass") pathways, as illustrated in Figure 2-1. Preliminary analysis suggested that the study should focus on the subcategory rate (hereafter referred to as the "rate" path) and mass cap for existing units only (hereafter referred to as the "mass" or "existing mass" path).

The analysis focuses on the "subcategory rate" and "existing mass only" Clean Power Plan compliance pathways for Kansas.

[4] Further detail and examples of model applications can be found in *US-REGEN Model Documentation 2014*, EPRI Technical Update #3002004693 (available online at http://eea.epri.com/models.html).

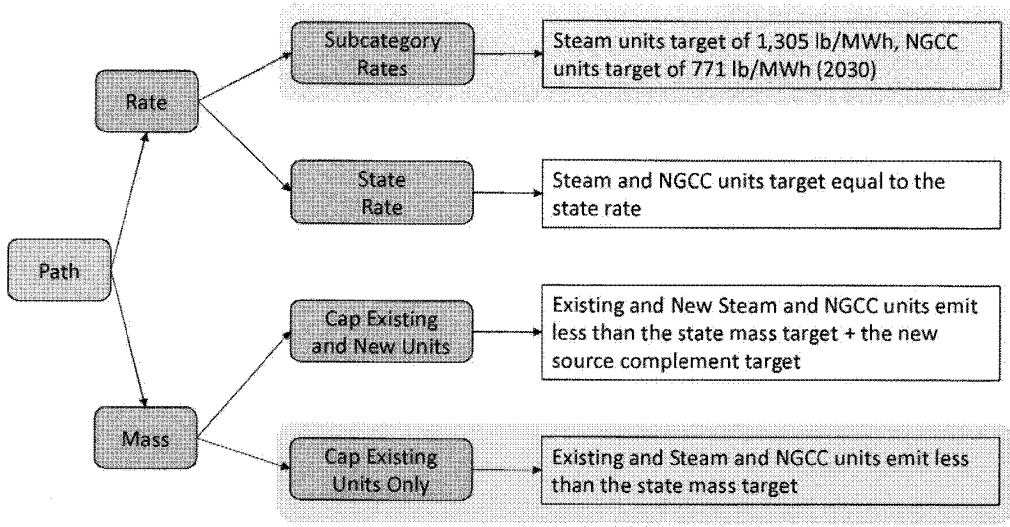

Figure 2-1
Diagram of Clean Power Plan compliance pathways considered in the analysis

The analysis aims to inform decisions about possible pathway selections for Kansas. The foundation for the decision is comparative costs between these pathways, though other identified criteria are also qualitatively discussed in the report. The analysis investigates the relative costs of rate and mass paths under a range of sensitivities due to persistent uncertainties about the future (e.g., fuel prices, asset lifetimes, renewables costs), as discussed in the next subsection.

The flexible compliance options for states under the CPP complicates decision-making and evaluating impacts of alternates, requiring optimization and economic modeling tools to understand these tradeoffs and impacts in a consistent framework. Such evaluations should be conducted on a state-by-state basis given different targets, existing fleets, and compliance options. Regional heterogeneity implies that there may not be a dominant CPP path for all states, and the interdependence of states' actions (which are affected by CPP and power-sector-planning choices elsewhere) means that decisions must be evaluated concurrently. The US-REGEN modeling framework captures interactions between states and their simultaneous optimizing behavior subject to CPP targets. This unique structure allows US-REGEN to represent market interactions for electricity, renewable energy certificates, CO_2 allowances, and emission rate credits to assess economic impacts and trading possibilities of policies like the CPP.

Cost comparisons in the report refer to electric-sector-only cost impacts and, unless otherwise noted, include:

- All capital and operating costs

- Cost of new transmission plus maintenance, which are equally split between states on the line
- Net payments for CPP credits and allowances
- Regulatory costs (e.g., alternative compliance payments for renewable portfolio standards, etc.)
- Cost of imported electricity, priced at the marginal wholesale price of the exporting state (minus the cost of exported electricity)

All costs are expressed in 2010 dollar terms, discounted back to 2010 at a five percent discount rate. Note that cost comparisons on this basis differ from impacts on consumer electricity prices/rates.

CPP compliance costs are incremental electric-sector costs above the reference ("no CPP") scenario. All values are expressed in real 2010 dollar terms.

CPP costs are defined as the incremental electric-sector costs above those incurred in the corresponding reference case, which makes it critical to define the reference scenario carefully and to present results explicitly (as discussed in Section 3).

It is worth reiterating that the goal of this project is not to predict the future by forecasting values of specific variables but to gain insight about the strengths and shortcomings of different pathways based on relative costs. Not only are costs intrinsically uncertain, but the Supreme Court stay creates further cost uncertainty due to potential changes in the regulatory landscape in yet unknown ways.

Many caveats about the uses and limitations of economic models should be kept in mind when interpreting results from this analysis. Models like US-REGEN are by necessity numerical abstractions of the complex economic and energy systems they represent. As such, they may contain approximation errors, incomplete system dynamics, and data quality issues. When viewing results, it is important to keep in mind that insights come from running a variety of scenarios, comparing the results, and asking "what-if" questions.

Scenario Descriptions

Section 3 summarizes reference case assumptions, results, and CPP compliance. Section 4 investigates CPP compliance for Kansas under so-called "island" conditions (i.e., where compliance is achieved using only in-state resources).[5] Section 5 looks at the potential role of trading emissions allowances in mass compliance settings or emission rate credits (ERCs) in rate settings, which are exported or imported from other states to reduce compliance costs. The sensitivity of these results to a number of key assumptions is discussed in Section 6, including:

[5] Model implementation of the CPP in subsequent sensitivities does not assume allowance banking or represent details of the optional Clean Energy Incentive Program.

- Alternate natural gas price paths
- Alternate costs of new wind capacity (both higher and lower costs)
- Transmission additions between Kansas and Indiana (Grain Belt Express)
- Possible post-2030 U.S. CO_2 cap
- Lower coal lifetimes of 70 years
- Negative load growth

Section 3: Reference Scenario

This section focuses on model results for the reference scenario, which assesses how electricity generation in Kansas might evolve between 2015 and 2050 without the Clean Power Plan. The analysis strategy is to compare CPP compliance results in subsequent sections to an appropriate reference to understand the tradeoffs between Kansas' CPP planning options. As discussed in Section 2, the reference scenario is intended to be realistic but is not a forecast of the future. Given this framing, insights are driven by relative changes across scenarios.

Assumptions for the Reference Scenario

Reference scenario results come from running US-REGEN for all of the Lower 48 states in the contiguous United States. The model is calibrated to each state's 2015 generation mix and simultaneously solves the cost-minimizing capacity, dispatch, and transmission expansion problems through 2050.

Key assumptions in the reference scenario include:

- Fuel prices and load growth come from the Energy Information Administration's 2015 Annual Energy Outlook (AEO)
    - Load growth includes existing (i.e., legacy) energy efficiency programs, which assumes that states continue their current programs at average 2010–2014 rates and that this efficiency qualifies for ERC credit when a state selects a rate-based CPP compliance pathway[6]
    - Reference fuel price paths over time come from the EIA's AEO 2015 high estimated ultimate recovery (i.e., low price) case[7]
- The fleet database for all states was most recently updated in December 2015 through the ABB Velocity Suite, which includes all

[6] Legacy EE data come from Form EIA-861. Although these resources may be substantial for some states, these legacy programs do not play a role in Kansas.

[7] See Section 6 for results with higher natural gas prices. Appendix A (Figure A-4) discusses how these assumptions compare with the recently released price trajectories from EIA's AEO 2016.

announced retirements (though more recently announced nuclear retirements were also added)

- Committed (i.e., announced) wind projects in Kansas through 2018 are included per SNL Energy data
- 20% renewable portfolio standard in Kansas
- Energy efficiency (EE) program costs are assumed to be $55/MWh, which reflects the low estimate used by the U.S. EPA in their Clean Power Plan economic analysis
- No forced retirements for existing coal units, though retirements for economic reasons are possible; nuclear has 60–80 year lifetimes
- Technology costs come from the EPRI Generation Options report[8] with recently updated solar and wind costs
- Existing policies include state renewable portfolio standards (RPSs), the Regional Greenhouse Gas Initiative (RGGI), California's AB 32, and recent (2015) federal extensions of the Production Tax Credit (PTC) and Investment Tax Credit (ITC)
- CAA § 111(b) CO_2 performance standards for fossil units are included for new units
- The model captures transmission investments and power flows between states but does not represent transmission or distribution directly within state boundaries

Without the Clean Power Plan or additional policies, new natural gas and wind capacity are on the build margin in many states.

Figure 3-1 shows electricity generation by technology across the U.S. in the reference scenario. In the analysis, the PTC for wind accelerates deployment rather than incenting incremental capacity additions in many states.[9] Retirements of existing capacity and rising demand are met primarily by new natural gas combined cycle (NGCC) units, which are on the margin in many states under the reference case assumptions for gas prices and technological costs.

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[8] Electric Power Research Institute. "Program on Technology Innovation: Integrated Generation Technology Options 2012." Technical Update 1026656.

[9] The reference scenario assumes net metering in California only, which leads to more rooftop solar deployment compared with other states.

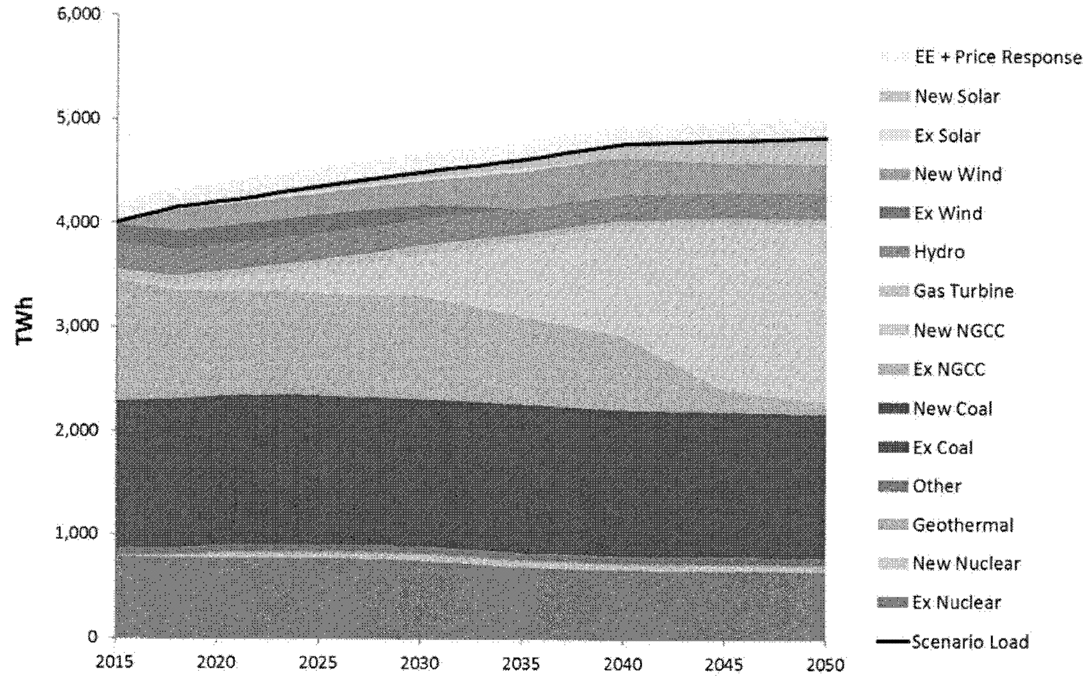


Figure 3-1
Electricity generation (terawatt-hours) for the Lower 48 U.S. states under the reference (i.e., no Clean Power Plan) scenario (2015–2050)

Generation, Capacity, and Emissions Results for Kansas without the Clean Power Plan

Figure 3-2 presents results for Kansas' electricity generation by technology in the reference scenario. Note that 2015 generation is calibrated to historical values using observed natural gas prices (with prices returning to AEO 2015 paths in subsequent projection periods). Existing coal units (dark blue) are Kansas' largest generation resource in 2015, a trend that continues in future years when the CPP is not in place. However, by 2050, fuel diversity increases in Kansas as new NGCC units come online and new solar capacity is added to comply with the 20% renewable mandate. Existing coal units are a low marginal cost resource for dispatch, especially given low coal costs in the state. Wind and NGCC units are the next largest resources by 2050. Low gas prices lead to new NGCC units on the build margin to meet growing demand. Kansas' existing nuclear generates just under 10 TWh annually and remains flat throughout the time horizon.

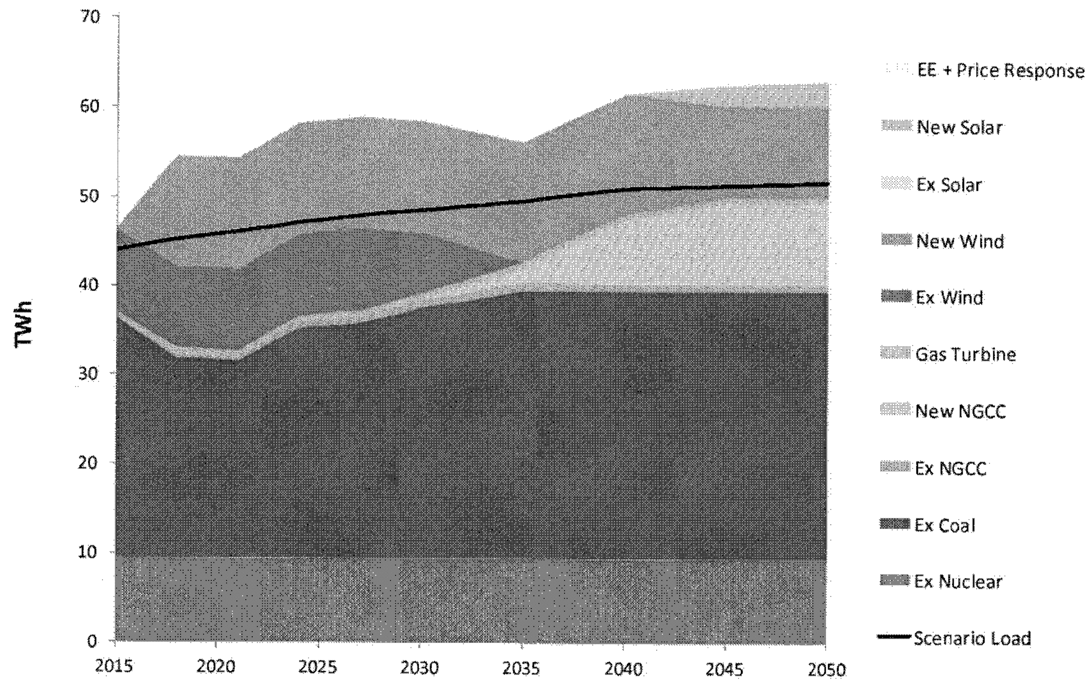


Figure 3-2
Electricity generation (terawatt-hours) in Kansas by technology under the reference (i.e., no Clean Power Plan) scenario (2015–2050)

Without the Clean Power Plan, Kansas' fleet mix is dominated by existing coal, wind, and some new NGCC after 2030.

In years where total generation exceeds the black line (i.e., representing total load for Kansas), power is being exported from Kansas to neighboring states.

Figure 3-3 shows that the reference scenario involves few new capacity investments in Kansas before 2030 apart from early period wind investments. Near-term market conditions are not conducive to deploying capital in new generation in light of the stock of existing capacity with low dispatch costs, slow demand growth, and substantial regulatory uncertainty. New NGCC capacity comes online after 2030, as older wind capacity retires. The lowest-cost capacity additions for Kansas are NGCC units in the reference case.[10] Later sections will illustrate how the CPP will guide choice of replacement capacity and possible early retirements.

[10] Kansas' existing gas turbine capacity is significant in Figure 3-3, but the low capacity factors of these units is indicated by the low generation in Figure 3-2.

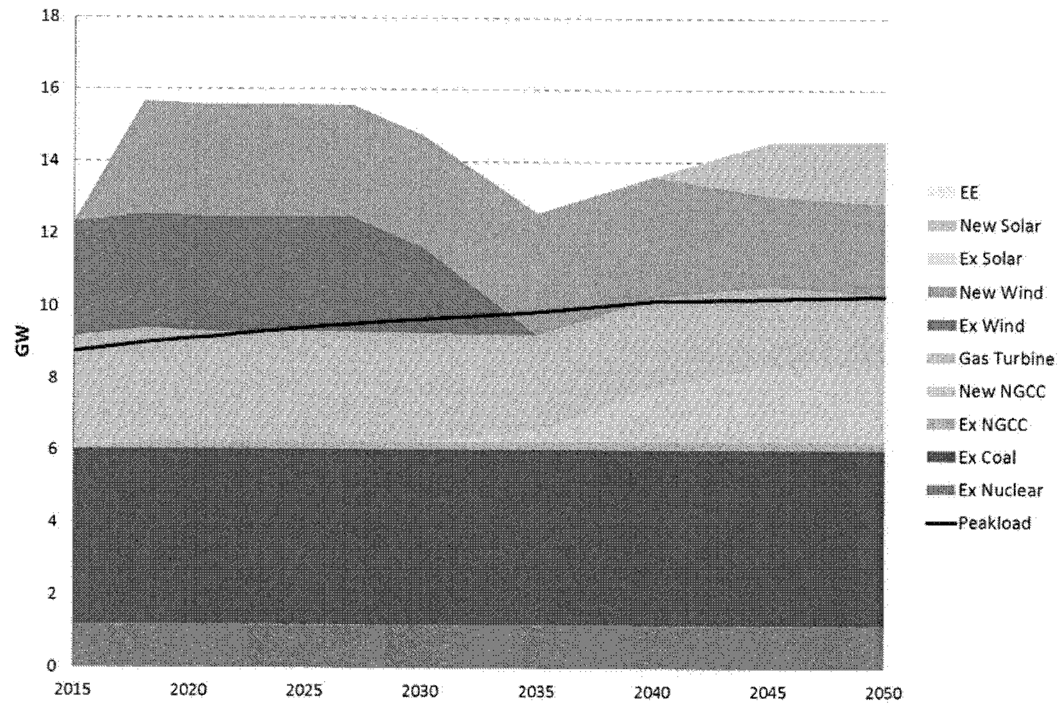


Figure 3-3
Electricity capacity (gigawatts) in Kansas by technology under the reference (i.e., no Clean Power Plan) scenario (2015–2050)

Reference Scenario Compliance with Clean Power Plan Targets

The choice of reference scenario assumptions may impact a state preference for mass or rate CPP pathways based on a range of metrics. Two metrics to compare model reference cases are:

1. The difference between CO_2 emissions (in short tons) from covered units in the reference case and CPP state mass targets

2. The difference between ERCs (in TWh) demanded by covered fossil units and the potential ERC supply from new renewables and EE, nuclear uprates, and gas-shift ERCs

These comparisons indicate how close Kansas comes to meeting CPP mass and rate targets in the reference case. Such metrics indicate the extent and timing of additional efforts required to comply with the CPP.

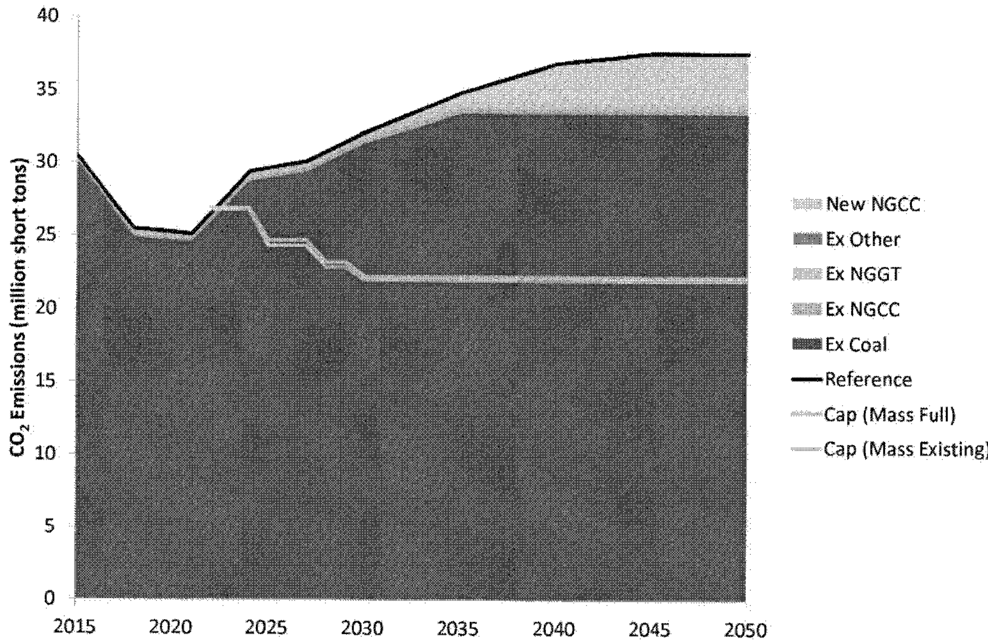


Figure 3-4
Comparison of CO_2 emissions from affected units in Kansas under reference generation and EPA's CPP existing (i.e., existing units only) and full mass targets (i.e., with the new source complement)

The business-as-usual generation mix in Kansas is out of compliance with the Clean Power Plan mass and rate targets.

Figure 3-4 shows CO_2 emissions from Kansas' affected units under the reference scenario. CPP mass caps for Kansas are superimposed to show both the "existing" (i.e., existing units only) and "full" (i.e., existing units with the new source complement) pathways. Even though emissions are close to the initial target, 2030 emissions are approximately 7.2 million short tons above the caps. This mass-based compliance "gap" increases over time with greater coal generation and more new NGCC coming online as the cap becomes more stringent. The existing-mass cap is likely to be binding in later periods, which means that changes to the fleet or allowance purchases are required to come into compliance.

A central question in future sections is whether Kansas can eliminate this shortfall at lower cost (accounting for other considerations) by reducing output from existing units and making other changes to the in-state fleet, or by purchasing allowances on the market and relying more on its existing EGUs.

In terms of subcategory-rate CPP pathway compliance, Figure 3-5 shows the demand and supply of emission rate credits (ERCs). ERC demand represents that (predominantly) coal units would be required to surrender if they were to run at reference levels suggested in Figure 3-2 under a subcategory-rate target. Supply represents ERCs generated if Kansas chose a rate-based pathway with only reference case actions from Figure 3-2. The fraction of wind from installed capacity after 2012 generates ERCs. Given the ratcheting rate target and coal generation, demand for

ERCs grows over time. The rate targets are non-binding in 2024 and 2027 owing to the ERC-eligible wind capacity installations early on. Demand exceeds supply for later compliance periods, and becomes larger in time as rate targets for Kansas become more stringent.

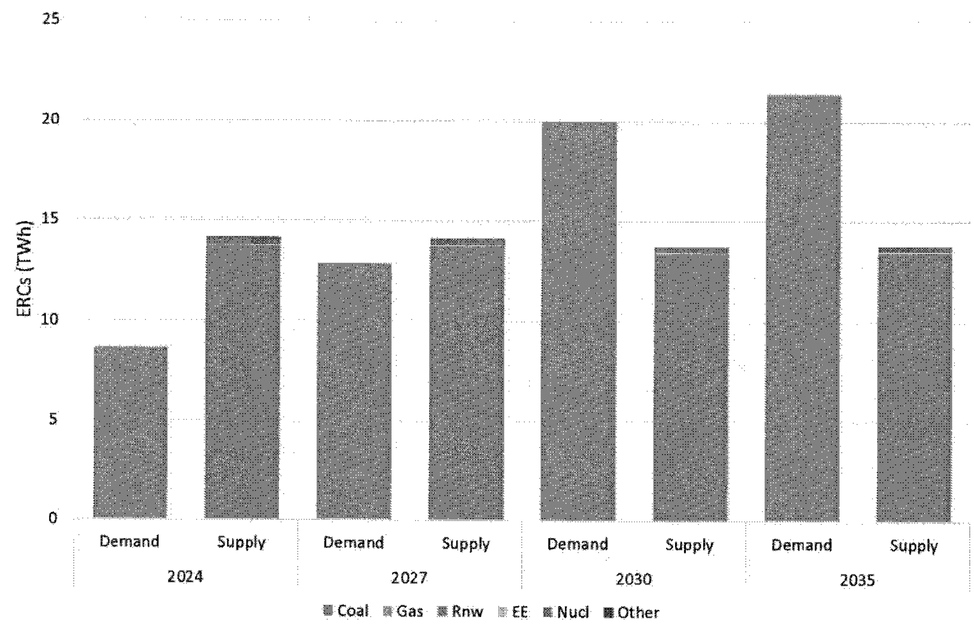


Figure 3-5
Demand and supply of emission rate credits in Kansas under reference case generation under CPP subcategory (unit) rate targets

Overall, from a business-as-usual perspective (i.e., without the CPP), Kansas likely requires additional action to adhere to the CPP guidelines. New wind will help the state to meet goals, but planned additions would not by themselves be sufficient, especially given coal output levels in Kansas under reference conditions.

Figures 3-4 and 3-5 illustrate how expectation for the future of the coal fleet and new ERC sources (e.g., wind, solar, and EE) are key parameters governing how close Kansas is to CPP compliance. These comparisons identify important areas for sensitivity analysis, as discussed in Section 6.

To meet the CPP targets, Kansas must perform a combination of the following alternatives:

- Reduce coal output, by reducing capacity factors or retiring units
- Find additional sources of electricity: New NGCC, new renewables, new EE, or import more power from other states

- Utilize CPP market opportunities like purchasing CO_2 emissions allowances (if Kansas pursues a mass-based pathway) or ERCs (if a rate-based pathway is chosen)

Section 4: Clean Power Plan Compliance without Trading ("Island" Scenarios)

This section discusses CPP "island" compliance for Kansas, where the state uses in-state compliance and mitigation alone with no trading of ERCs (if a rate path is chosen) or CO_2 allowances (if Kansas selects a mass path). Although Kansas still trades electricity with adjacent states, inter-state power flows are locked at their reference levels to more fully isolate compliance mechanisms.

Although this restriction on multi-state market participation is unrealistic for many states, these scenarios can be insightful for decision-makers, modelers, and policy-makers for three reasons. First, this boundary scenario assesses resources and measures Kansas can take individually to comply with the CPP without relying on allowance or credit trading. These "island" scenarios provide a testbed for evaluating least-cost, in-state resources. Second, "island" scenarios elucidate Kansas' possible fallback options should it decide not to engage in trading, which are complements to the trading scenarios in Section 5. Finally, "island" scenarios provide starting points for assessing the value of trade and sensitivities to technological and regulatory uncertainties.

These scenarios restrict Kansas to select the same compliance pathway as all other 47 contiguous states. Section 5 relaxes this assumption by investigating trade with pathway "mixes" where different states select different pathways. This section begins by analyzing the mass-based implementation approach and then explores the rate path.

Results of Existing-Mass and Subcategory-Rate Clean Power Plan Scenarios without Trade

For Kansas and many other states, the mass-based CPP pathway relies more heavily on new NGCC investments and rate-based on wind.

For the existing-mass "island" compliance pathway (Figure 4-1), compliance in Kansas is achieved primarily by lowering coal generation and increasing new NGCC generation. New incremental wind builds come online after 2030 as old turbines age out and the output-based set-aside (OBS) incents more renewable generation; however, low gas prices increase the opportunity costs of developing more wind. By 2030, 1.3 GW of new NGCC is built (compared with no additions in the reference) and 3.1 GW new wind (3.1 in the reference). 840 MW coal capacity retires between 2015 and 2030 in Kansas under the existing-mass island compliance pathway. Annual coal generation decreases in 2030 from 28.2 TWh in the reference case to 19.2 TWh.

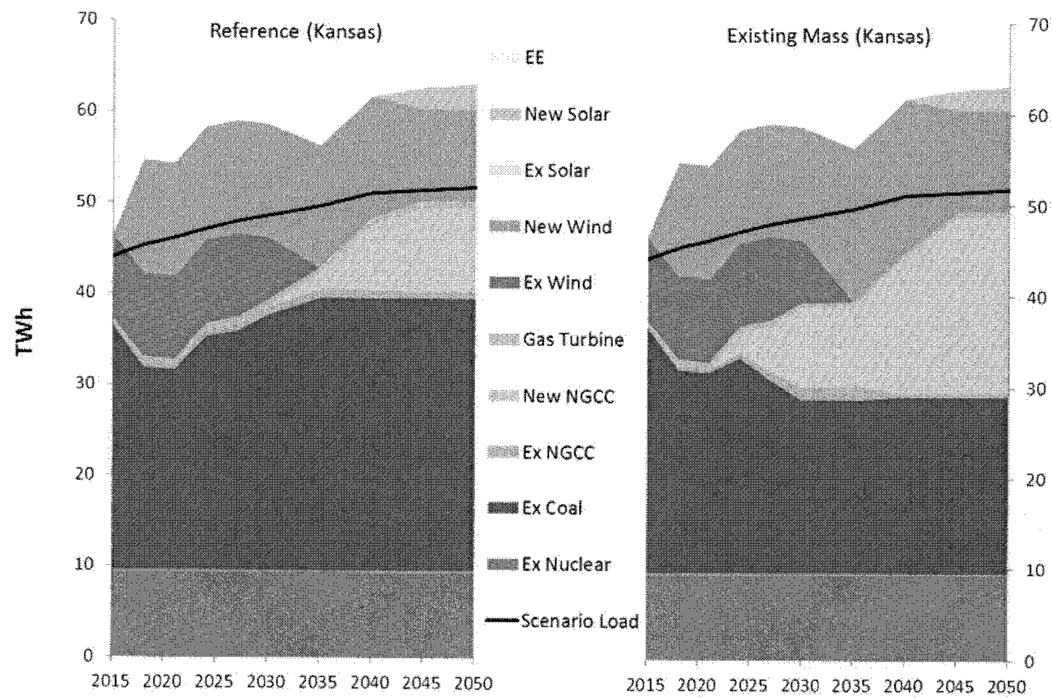


Figure 4-1
Electricity generation by technology in Kansas under reference (i.e., no CPP) and existing-mass island compliance scenarios

Figure 4-2 compares allowance prices under the existing-mass island scenario (top) and ERC prices under the subcategory-rate island scenario (bottom). For both island scenarios, Kansas' marginal compliance costs are far from the highest (some states are high in one metric but small in another) and lowest (the CPP constraints are not binding in some states in 2030). These prices reflect the stringency of the targets and cost of Kansas' compliance options relative to other states.

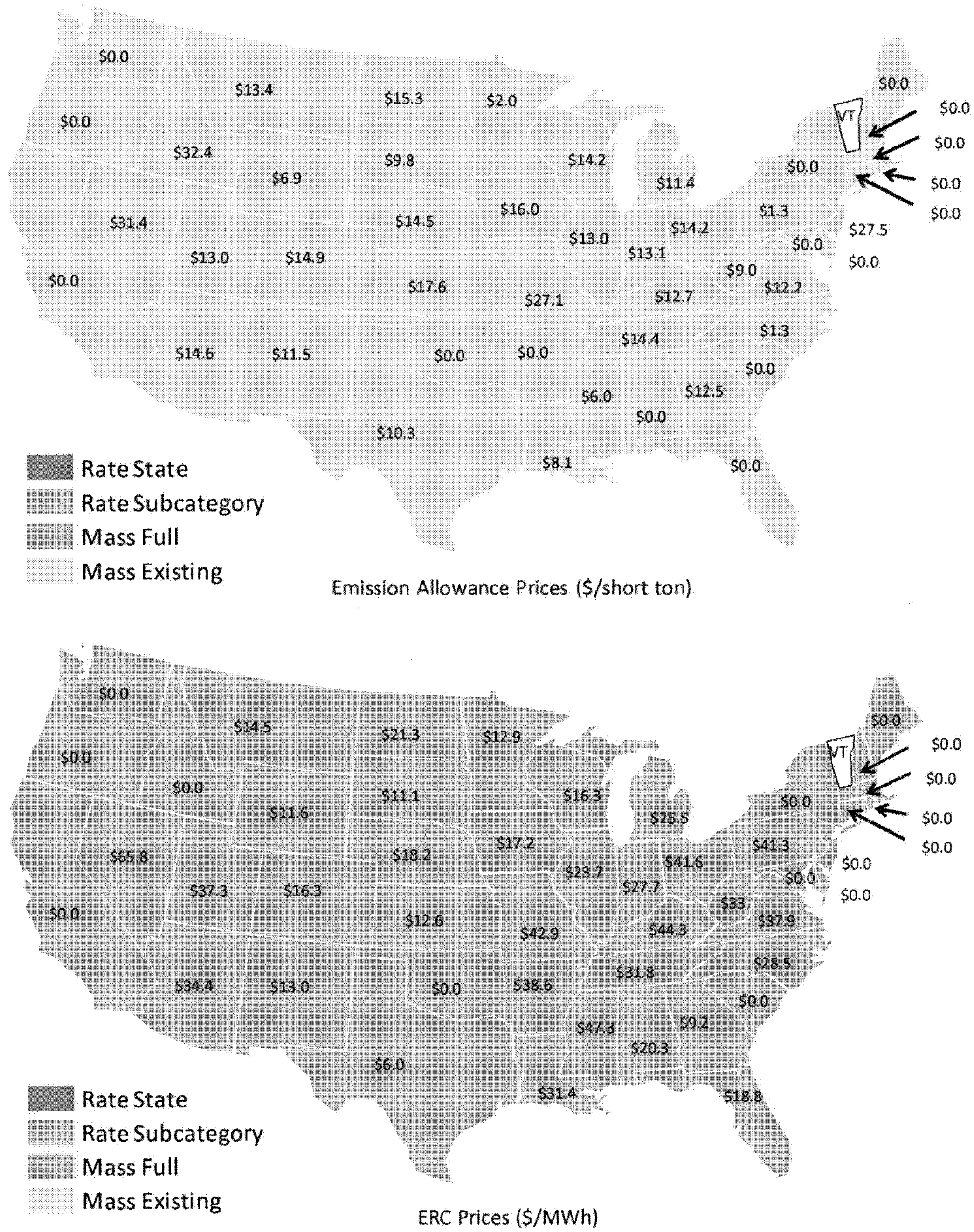


Figure 4-2
Maps of 2030 state allowance and ERC prices under existing-mass island compliance (top) and subcategory-rate island compliance (bottom)

Coal generation in Kansas decreases under mass- and rate-based CPP compliance, especially when trade is restricted.

For the subcategory-rate island compliance pathway (Figure 4-3), Kansas' cost-minimizing compliance strategy would rely heavily on new wind builds. Compared with the mass-based compliance pathway, the rate path entails more new wind capacity and less NGCC. These low-carbon resources keep more coal generation in the portfolio in 2030, as no coal capacity retires in this scenario and generation is only slightly lower than

2015 values (24.3 TWh annually in 2030 compared to 28.2 TWh in the reference). New NGCC capacity and generation are lower for the rate pathway than the reference scenario or the mass-based approach.

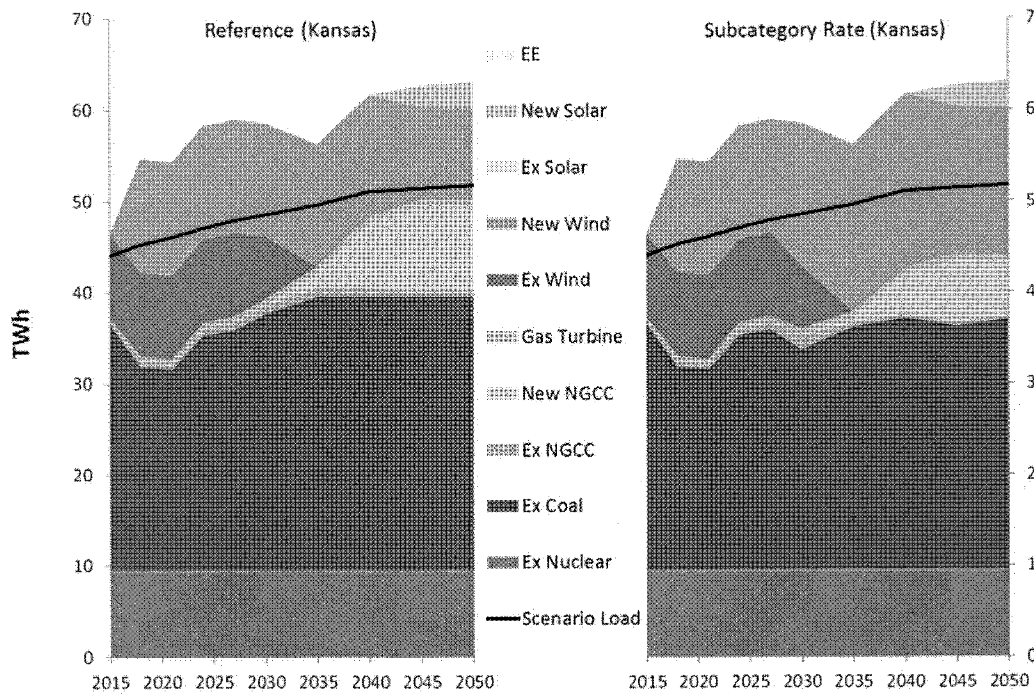


Figure 4-3
Electricity generation by technology in Kansas under reference (i.e., no CPP) and subcategory-rate island compliance scenarios

Table 4-1 shows how ERCs surrendered exactly equal those created in-state under island rate compliance. ERC demand is primarily from steam units, and zero-carbon ERCs come from wind. As shown in Figure 3-5, the 3.1 GW of new wind built in the reference suggest that Kansas likely will not have to undertake additional measures to comply with the CPP rate-based targets. This is reflected in the $0/MWh ERC price in 2024 and 2027 in Table 4-1.

Table 4-1
Emission rate credit (ERC) balance and ERC prices for Kansas under subcategory-rate island compliance

	2024	2027	2030	2035	2040	2045	2050
ERC Demand (TWh)	14.1	14.1	17.1	18.8	19.6	18.9	19.5
ERC Supply (TWh)	14.1	14.1	17.1	18.8	19.6	18.9	19.5
ERC Price ($/MWh)	$0	$0	$12.6	$5.6	$4.8	$5.3	$4.3

Comparing investment decisions under rate and mass pathways also indicates the timing of when commitments have to be made. Based on the pace of investments, it may be useful to understand which plan potentially gives states more time to observe the resolution of uncertainty about policy choices elsewhere and compliance provisions before making irreversible capital allocation decisions.

Given uncertainty about a range of factors (which are explored in the sensitivity analyses in Section 6), the option to amend pathway selection as more information becomes available (i.e., the flexibility for a state to switch compliance pathways from mass to rate or vice versa) would help to limit compliance costs.

Figure 4-4 illustrates how investments under mass compliance must start earlier and requires greater capacity installations than the mass pathway for Kansas. For the existing-mass pathway, incremental additions beyond the reference scenario come online in 2024 and consist largely of NGCC capacity. In contrast, island rate compliance for Kansas mostly consists of new wind additions that begin around 2030.

The rate CPP pathway provides Kansas more time to observe market developments before making capacity deployment decisions.

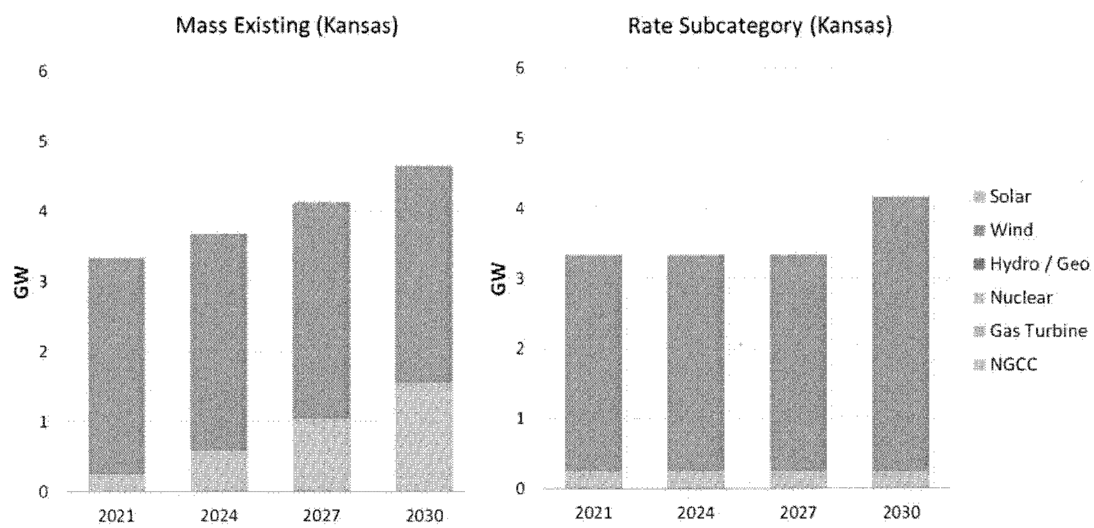


Figure 4-4
Comparison of cumulative capacity additions and retirements (gigawatts) in Kansas over time under existing-mass island compliance (left) and subcategory-rate island compliance (right)

The earlier and more extensive investments under mass compliance under "island" conditions make this pathway slightly costlier for Kansas. The present value of investment through 2030 is $6.18 billion under existing-mass and $6.15 billion under subcategory-rate. Ultimately, the accelerated wind investment helps with rate compliance. Investments that are already being made for planned projected align with rate-based compliance and give additional lead time before incremental CPP-related investments have to be made toward 2030.

Time-series data for emission rate credit and allowance prices over time are presented in Section 5, which compares island results with their values under different trade assumptions.

In summary, an "island" compliance environment where Kansas must rely only on in-state resources without market participation suggests that the subcategory-rate path provides more lead time than its mass-based counterpart to observe market developments before committing to a non-market path to compliance. Investment costs and total compliance costs are higher for the mass pathway, as discussed in Sections 5 and 6.

Section 5: Clean Power Plan Compliance with Inter-State Trading

The "island" compliance results in the previous section assumed Kansas relied on in-state compliance measures alone and did not participate in multi-state emissions trading markets. Emissions trading—through allowances when Kansas selects a mass pathway and ERCs under rate—creates opportunities to lower overall compliance costs.

National or regional markets are potential "backstop" options and strategic cost-containment mechanisms for CPP compliance. However, their size and depth are subject to significant uncertainty, and the use of these options creates tradeoffs between potentially lower costs (or lower price volatility) and reliance on markets. Therefore, increased allowance trading raises questions about recourse options if market are slow to develop, if liquidity problems arise, and if exposure to other regulatory shocks increases.

Trade of CO_2 allowances or emission rate credits may lower compliance costs but come at the expense of increased reliance on uncertain markets.

This section explores these questions and has three specific objectives:

1. To investigate the compliance balance between in-state investments and markets for allowances/ERCs
2. To understand how different "mixes" of compliance pathway selections in other states influence market outcomes for Kansas
3. To demonstrate opportunities to reduce cost through trade

Description of Scenarios and Trading Mixes

This section presents results for state plans that allow inter-state trading of ERCs or allowances in the case of rate-based or mass-based compliance pathways, respectively. Like the island scenarios, in-depth analyses are performed for the subcategory rate (denoted "RU") and the existing mass (denoted "MX") pathways.

Trading scenarios were developed using two "mixes" of alternative market outcomes to represent uncertainty about the selection of compliance pathways by individual states. These mixes are labeled "Mix1" and "Mix 2HP" for this analysis.

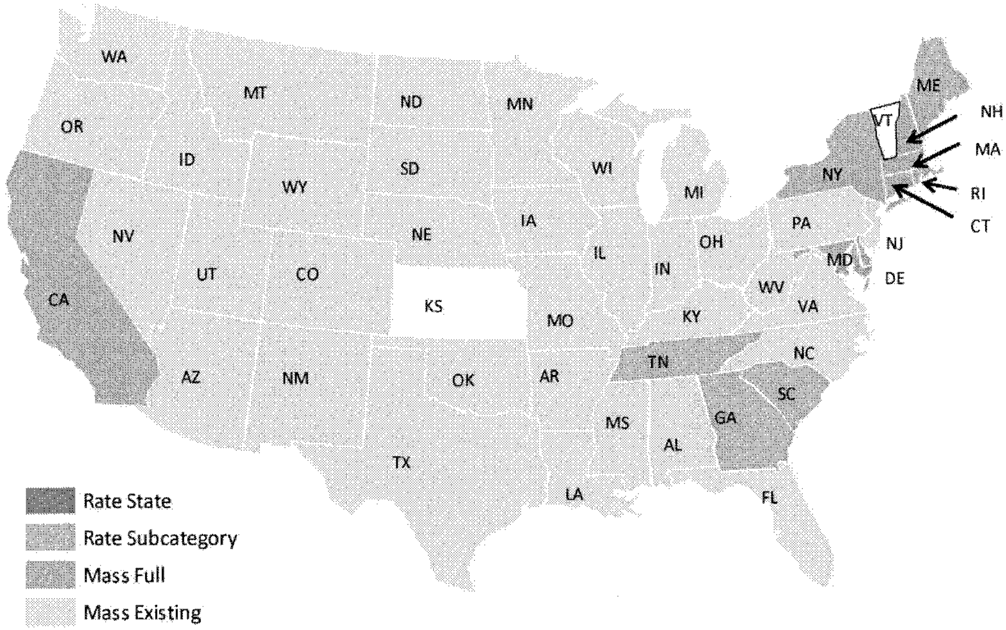
All mixes assume California and the Regional Greenhouse Gas Initiative (RGGI) states choose the full-mass pathway (i.e., with the new source complement), that California does not trade with other states, and that the RGGI states trade only within RGGI. All mixes assume that states with pending new nuclear units (i.e., Georgia, South Carolina, and Tennessee) choose the subcategory-rate pathway.

The mixes differ in how the rest of the states choose between the subcategory-rate and existing-mass pathways. Figure 5-1 shows maps documenting these selections.

Trading "mixes" represent potential developments of emission trading markets with alternate pathway selections for states.

- **Mix 1:** The first mix uses the above assumptions about full-mass states (California and RGGI) and subcategory-rate (states with new nuclear). All other states adopt existing-mass pathways. This scenario represents minimal adoption of rate programs among states and places a lower bound on participation.
- **Mix 2 High Plains (HP):** The second mix takes Mix 1 and adds seven other states to subcategory-rate trading: Colorado, Iowa, Wisconsin, North Dakota, South Dakota, Nebraska, and Oklahoma. These states were selected owing to previous EPRI analysis indicating this pathway could be economically attractive for these states under some states-of-the-world. This result is driven by the comparative attractiveness of new wind in the reference case due to state-specific resources and costs relative to other alternatives.

Note that it is not immediately obvious whether adding additional states to a rate-based trading market will increase or decrease market-clearing ERC prices. The addition of ERC compliance obligations is accompanied by new ERC supply resources, which are brought simultaneously into the trading system. For instance, if states with low ERC demand and high ERC supply join a rate markets, prices will fall (all else equal), whereas prices will rise if states with high ERC demand and low ERC supply join. These dynamics make it important to use modeling frameworks like US-REGEN to understand the implications of alternate pathway selections.



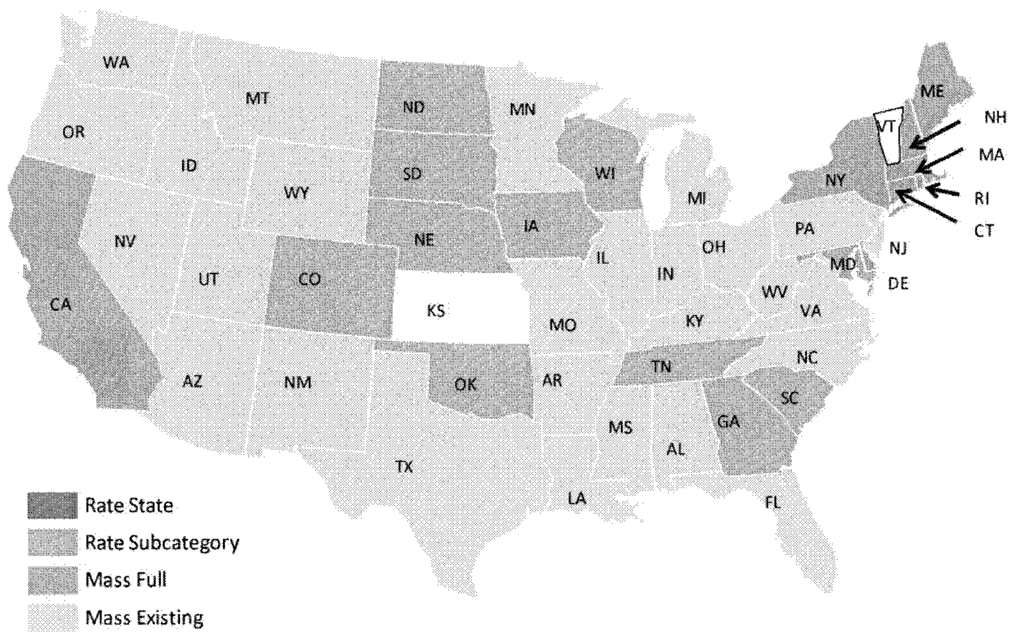


Figure 5-1
Maps of Clean Power Plan state compliance pathway assignments: Mix1 (top) and Mix2HP (bottom)

Generation and Investment Results for Kansas with Trading

Figure 5-2 shows the market-clearing allowance and ERC prices for each state under Mix2HP.[11]

[11] Associated market-clearing prices for each mix are discussed in the next section.

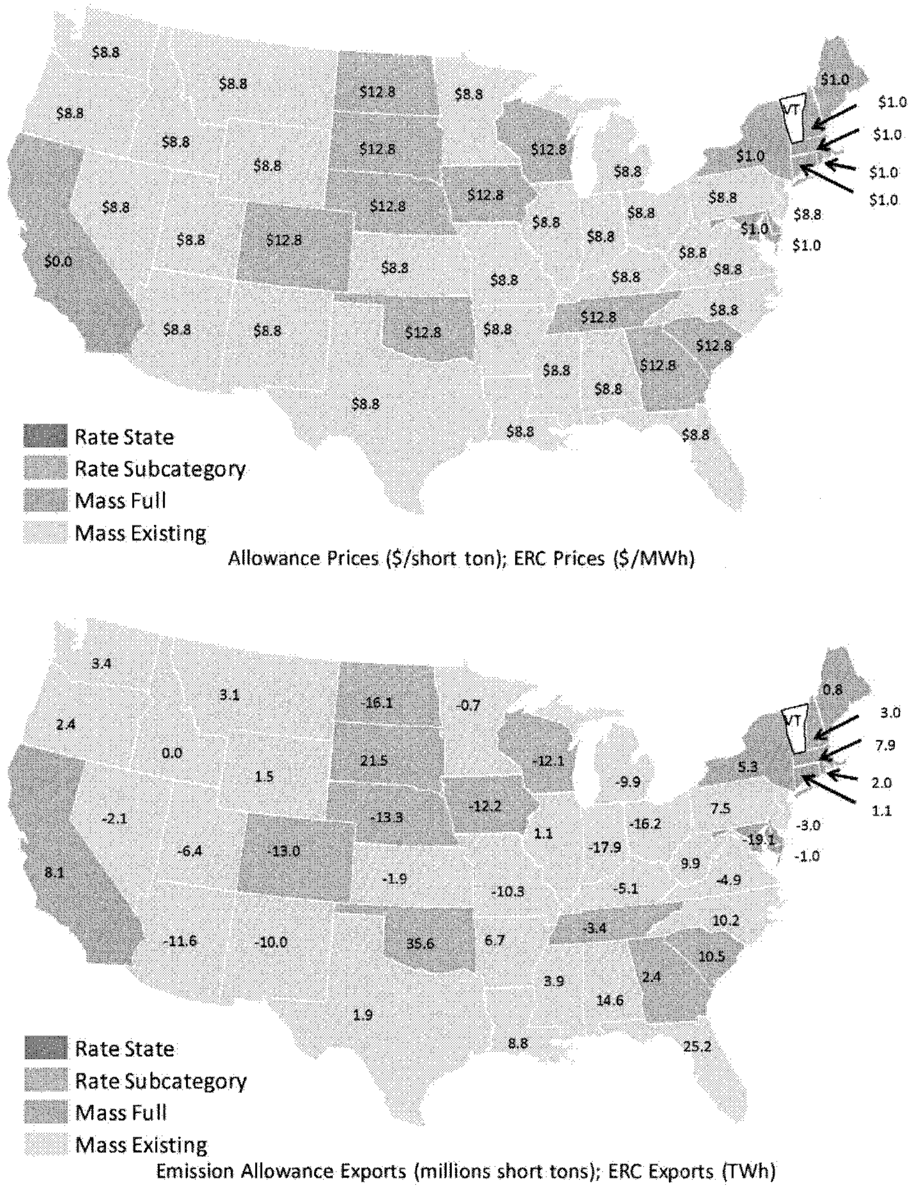


Figure 5-2
Map of "Mix2HP" CPP state compliance pathway assignments and emissions trading prices in 2030 calculated by EPRI's US-REGEN model[12] (top) and net exports in 2030 (bottom)

Comparing investments across the two patchwork trading mixes and "island" compliance scenarios suggests how robust near-term decisions may be under a range of potential futures. According to Figure 5-3, investments through 2030 show variation across the assumed policy

[12] The number superimposed on each state is the emission trading price calculated by US-REGEN. For mass-based states, this is an emission allowance price, denominated in $/short ton CO_2. For rate-based states, this is an ERC price, denominated in $/megawatt-hour of zero-emission generation (or avoided generation in the case of energy efficiency).

compliance selection and trading environment. Island compliance generally entails the most significant in-state capacity investments, but not in all cases. Note how the reference case capacity additions include almost 3 GW new wind, and the NGCC additions come through the Riverton Unit 12 conversion to combined cycle.

The additional investments under island scenarios suggests that potentially strandable investments can result from pursuing an exclusively in-state compliance strategy. Excessive investments under any scenario could later prove unnecessary if market opportunities emerge and could prove costly. These dynamics have important implications for the option value and timing of new investments and may be an incentive to avoid irreversible capital outlays in the presence of uncertainty about the future. The economic implications of these scenarios are discussed later.

Kansas' compliance without trade generally entails greater in-state capacity investments than scenarios with market participation.

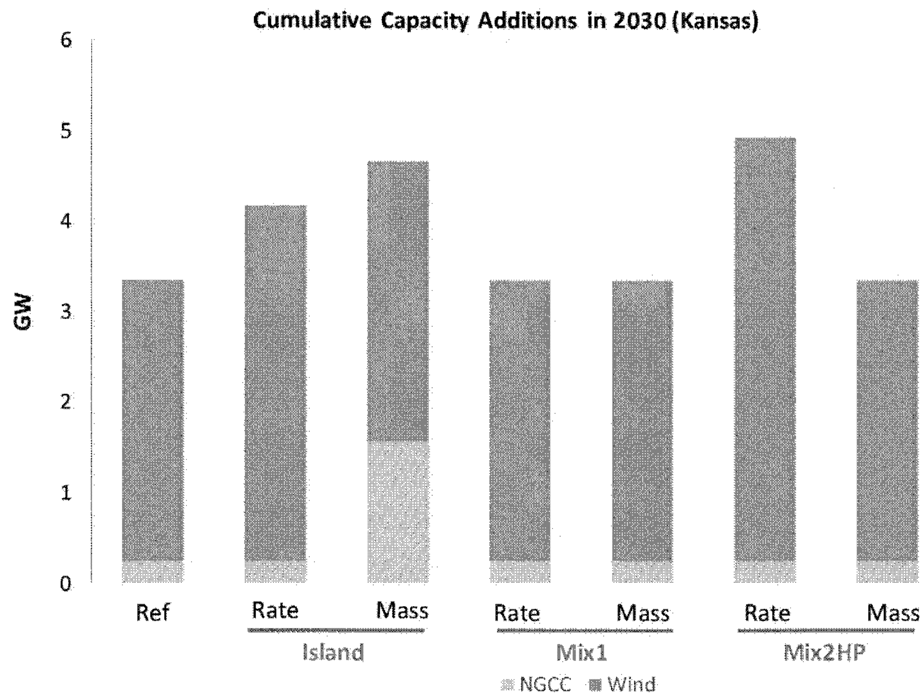


Figure 5-3
Comparison of cumulative capacity investments (gigawatts) in Kansas through 2030 under existing-mass and subcategory-rate compliance under different trading environments (reference shown on left)

Figure 5-4 shows 2030 generation in Kansas across these scenarios and pathways. Many existing units in Kansas remain competitive throughout the model's time horizon.[13] The CPP amplifies pre-existing trends in the

Kansas' compliance with trading involves the combined use of in-state measures and market purchases of credits.

[13] Note that US-REGEN does not include all costs incurred by coal units as they age (e.g., unit commitment constraints are not included in this version of the model). Including such costs could influence retirement and dispatch decisions.

power sector like coal-to-gas fuel switching and wind deployment. However, state decisions about CPP compliance paths and degree of market participation provide opportunities to influence the generation portfolio trajectory moving forward. Scenarios with inter-state allowance trading typically involve greater reliance on importing electricity, especially when Kansas adopts a mass pathway. Coal output is highest when Kansas selects rate-based pathways.

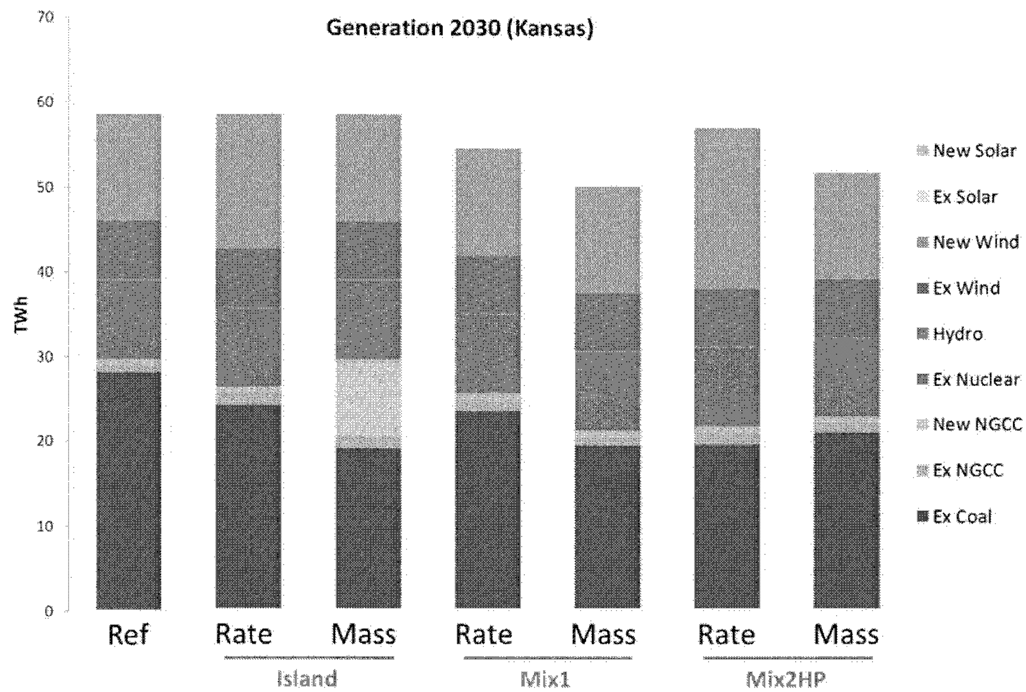


Figure 5-4
2030 electricity generation (terawatt-hours) in Kansas by technology under different trading environments and pathway selections

Figure 5-5 shows the installed capacities of Kansas' coal assets over time. For the reference scenario (black line in Figure 5-5), total coal capacity remains constant over time, as the low operating costs of these units make them economically competitive. The lines for mass- and rate-based CPP compliance for all trading scenarios overlap with the reference values, indicating that coal capacity for these classes does not change when the CPP is in place. This is also true of the scenarios where Kansas selects a rate-based pathway. Retirements only occur in mass-based island compliance scenarios. In these two scenarios, retirements occur primarily for the least efficient units and after 2030.

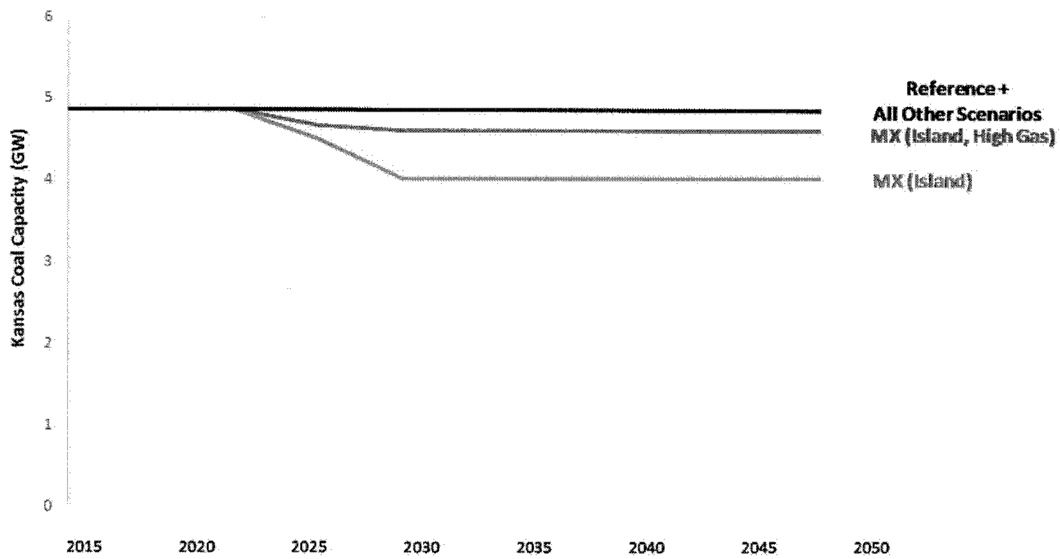
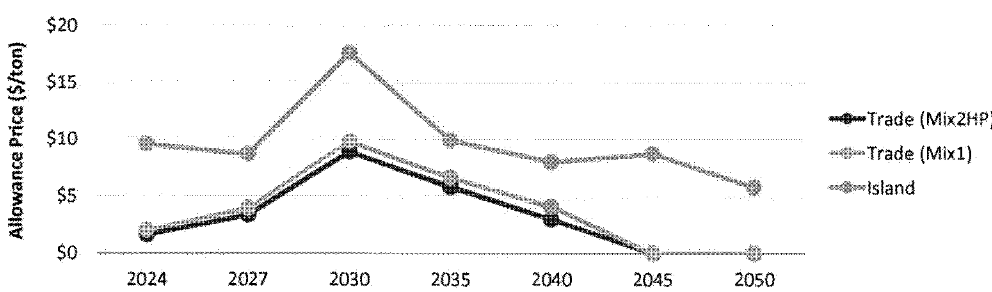


Figure 5-5
Coal capacity (gigawatts) in Kansas by CPP compliance scenarios

Assessing of Economic Outcomes with and without Trading

Comparing market-clearing permit prices over time offers one metric for evaluating CPP-related economic impacts. These marginal values reflect the stringency of the targets and, specifically, the cost of Kansas' compliance options relative to other states.[14] Figure 5-6 shows allowance prices for mass-based paths (top) and ERC prices for rate-based (bottom).



[14] Note that ERC and CO_2 prices are useful metrics for comparisons in individual models, as higher price indicates more expensive mitigation options. However, price comparisons are invalid between models, since prices depend on a host of model-specific assumptions (e.g., reference, trading, capacity, and state resource assumptions).

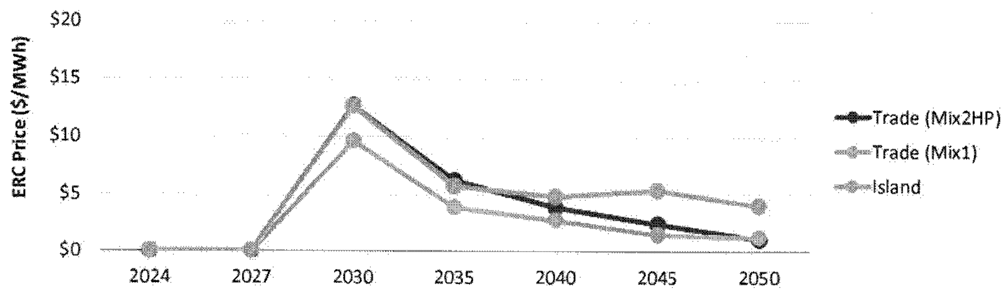


Figure 5-6
Kansas allowance prices ($ per short ton, top) and ERC prices ($ per MWh, bottom) over time for different trade assumptions

Prices under island compliance are typically higher than scenarios where multi-state trade is possible. Market participation lowers costs for Kansas but especially in early years of mass-based compliance owing to the difficulty of meeting early targets.

Market prices for most states tend to differ more under rate compliance than under mass compliance, reflecting less liquidity in the wider market for ERCs. The lower volatility in ERC prices is caused largely by the marginal mitigation option for compliance under rate- versus mass-based pathways. For existing-mass, the marginal compliance option is largely reducing coal generation and increasing generation from new NGCC units. Although the price differential between coal and gas causes some state-specific variation, these costs are largely the same between different regions. For rate, the marginal compliance option varies across mixes, and the cost of developing new wind, quality of existing resources, and total wind deployment exhibit significant regional heterogeneity, which is exacerbated by decreasing returns to scale. These dynamics underscore the importance of modeling interactions between states in national markets to capture trading possibilities using a model like US-REGEN that captures simultaneous optimizing behavior by all states subject to meeting CPP goals.

Note how the ERC prices are highest under Mix2HP trading due to higher ERC demand under this trading mix. These higher values lead to greater investment in wind capacity in Kansas relative to the other trading pathways (Figure 5-3).

Figure 5-7 shows trade volumes for Kansas across these scenarios. Note how the (cost-minimizing) net trade position for Kansas is different for mass and rate compliance. When Kansas adopts a mass-based plan, the state is a net importer of allowances, especially after 2030. However, under a rate-based plan, Kansas is an exporter of ERCs for many periods. The higher ERC prices in Mix2HP trading lead to higher in-state wind investment and higher exports.

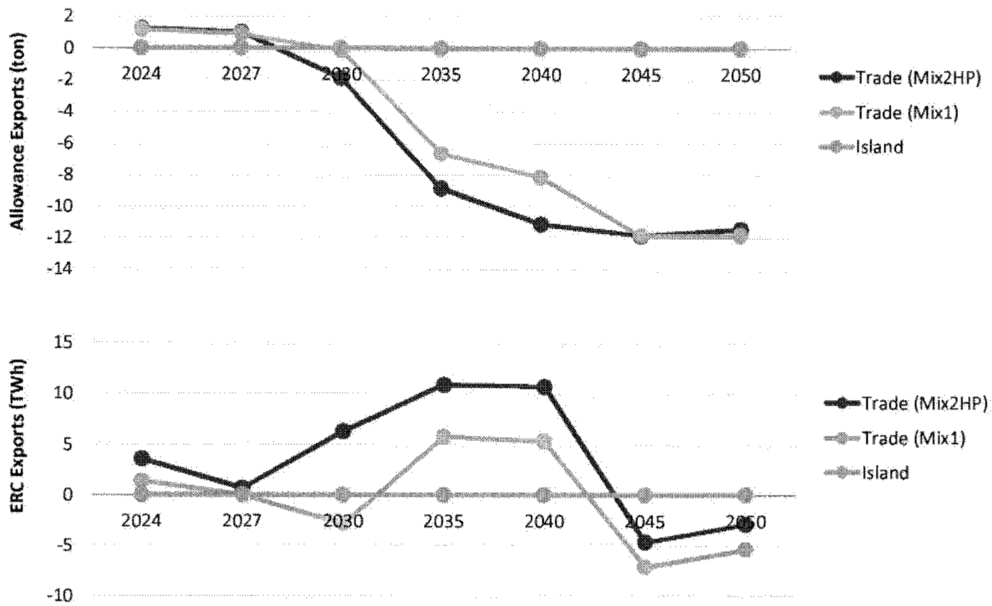


Figure 5-7
Kansas allowance (million short tons, top) and ERC (TWh, bottom) trade volume in net export terms over time for different trade assumptions

On a present value basis,[15] compliance costs for the subcategory-rate pathway are lower than the existing-mass pathway for island compliance but higher for the trading scenarios, as shown in Table 5-1. Recall that the definition of cost includes:

- All capital and operating costs
- Cost of new transmission (evenly apportioned between states on the line) plus maintenance
- Regulatory costs (e.g., alternative compliance payments for RPS, etc.)
- Cost of imported electricity, priced at the marginal wholesale price of the exporting state (minus the cost of exported electricity)
- Net payments for Clean Power Plan credits/allowances

Table 5-1
Comparative incremental CPP policy costs to Kansas ($ billion) in present value terms (2015–2050) and as a percentage of the reference costs

[15] The US-REGEN model works in present value terms, discounted back to 2015 at a discount rate of five percent.

	Policy Cost ($B)		% Reference	
	Rate	Mass	Rate	Mass
Island	0.32	0.79	1.2%	3.0%
Mix1 Trading	0.11	-0.06	0.5%	-0.3%
Mix2HP Trading	0.19	-0.13	0.8%	-0.5%

Examining the net present value of compliance costs is a useful complement to the marginal value comparisons in Figure 5-6. These CPP costs represent the sum of discounted incremental electric-sector costs over time above those incurred in the reference (i.e., no CPP) scenario.

Kansas' participation in inter-state trading lowers Clean Power Plan costs considerably regardless of whether a mass- or rate-based pathway is chosen.

Some mass-based paths entail net negative compliance costs for Kansas. These cases typically involve a greater reliance on electricity imports than the reference scenario and take advantage of opportunities to bring in power from neighboring states during periods with lower marginal wholesale prices. This lowers investment and O&M costs under the mass-based policy scenario, despite higher costs for importing allowances.

Another important takeaway is that encouraging trading lowers costs for Kansas considerably compared with the "island" scenarios where trade is more limited. This result holds for both rate and mass pathways, but the magnitude of the cost reduction from trade depends on pathway selections in other states.

Summary of Trading Scenarios for Kansas

Model results in this section indicate that encouraging trade lowers compliance costs for Kansas compared with "island" scenarios. The magnitude of this cost reduction from access to national markets and impact on in-state capacity investments depend on state pathway selections elsewhere. Despite its potential role in cost containment, market participation involves a tradeoff with increased uncertainty about the pace of market development, liquidity, volatility, and exposure to forces external to the state of Kansas.

Scenarios with trade underscore how pursuing in-state compliance strategies can increase the risk of stranded assets. As illustrated in Figure 5-3, CPP "island" scenarios entail greater capacity investments than the reference case or trade scenarios. If these in-state assets are built in early compliance periods and low-cost trading opportunities later become available, the opportunity cost of the unneeded units could be high.

Although this analysis offers insights for state-level CPP decision-making, model approximations and incomplete system dynamics suggest that it should not be construed as a definitive determination of CPP planning for Kansas. Each state's preferred portfolio of compliance measures (e.g., in-state actions and market participation) will be informed by a range of factors, including in-state compliance costs, risk tolerance, local incentives, and assumptions about market liquidity and participation. Actual deployment may depend on additional factors (e.g., policy, permitting, and uncertainty) that fall outside of the scope of this economic modeling and analysis.

Section 6: Sensitivity Analyses

A series of sensitivity analyses was undertaken to explore how key uncertainties affect the relative costs of Clean Power Plan compliance under the rate versus mass pathways. In addition to the sensitivities of CPP path choices in the previous section, six key uncertainties were examined, including:

- Alternate natural gas price paths
- Alternate costs of new wind capacity (both higher and lower costs)
- Transmission additions between Kansas and Indiana
- Possible post-2030 U.S. CO_2 cap
- Lower coal lifetimes of 70 years
- Negative load growth

Some sensitivities were varied jointly (e.g., natural gas prices and wind costs) to capture possible interactions between these assumptions. Table 6-1 summarizes the scenarios resulting from examining these uncertainties with different combinations of mass and rate CPP compliance (and alternate trading assumptions).

Table 6-1
Master scenario list

Set	Background Assumptions							CPP Pathway		
	ROC Policy	Gas Price	Wind Cost	Transm.	U.S. CO_2 Cap	Coal Life	Load	RU	MX	What we learn
1	Island	Low	Ref	Ref	None	Ref	Ref	1	2	State comparative advantage
2	Mix1	Low	Ref	Ref	None	Ref	Ref	3	4	Rate/mass comparison in alt. realistic setting
	Mix2HP	Low	Ref	Ref	None	Ref	Ref	5	6	
3	Island	High	Ref	Ref	None	Ref	Ref	7	8	How alternate gas price paths affect comparative pathway choices
	Mix1	High	Ref	Ref	None	Ref	Ref	9	10	
	Mix2HP	High	Ref	Ref	None	Ref	Ref	11	12	
	Mix1	High	High	Ref	None	Ref	Ref	13	14	
	Mix2HP	High	High	Ref	None	Ref	Ref	15	16	
	Mix1	High	Low	Ref	None	Ref	Ref	17	18	
	Mix2HP	High	Low	Ref	None	Ref	Ref	19	20	
4	Mix1	Low	Low	Ref	None	Ref	Ref	21	22	Impact of low/high wind costs on pathway
	Mix2HP	Low	Low	Ref	None	Ref	Ref	23	24	
	Mix1	Low	Ref	KS-IN	None	Ref	Ref	25	26	Impact of Kansas-Indiana transmission
	Mix2HP	Low	Ref	KS-IN	None	Ref	Ref	27	28	
	Mix1	High	Ref	KS-IN	None	Ref	Ref	29	30	
	Mix2HP	High	Ref	KS-IN	None	Ref	Ref	31	32	
	Mix1	Low	Ref	Ref	80% by 2050	Ref	Ref	33	34	Impact of a post-2030 U.S. CO_2 emissions cap (80% by 2050) on pathway choices
	Mix2HP	Low	Ref	Ref	80% by 2050	Ref	Ref	35	36	
	Mix1	High	Ref	Ref	80% by 2050	Ref	Ref	37	38	
	Mix2HP	High	Ref	Ref	80% by 2050	Ref	Ref	39	40	
	Mix1	Low	Ref	Ref	None	70	Ref	41	42	Impact of 70-year coal lifetime
	Mix2HP	Low	Ref	Ref	None	70	Ref	43	44	
	Mix1	Low	Ref	Ref	None	Ref	-1%	45	46	Impact of negative load growth
	Mix2HP	Low	Ref	Ref	None	Ref	-1%	47	48	

Notes: ROC = rest of country
Island = all states comply in isolation; no incremental power flows
RU = Subcategory (Unit) Rate
MX = Existing Mass (but with output-based set-asides)
Low/High Wind Cost = -/+ 20% in wind costs

Sensitivity Analysis Descriptions and Results

Natural Gas Prices

Natural gas price uncertainty is represented through the "high price path" shown in Figure 6-1. This path is set to match the U.S. Department of Energy's 2015 Annual Energy Outlook Reference path. Note that the "low price path" shown in Figure 6-1 was used as the reference price in earlier sections of this study. This path matches the AEO 2015 high estimated ultimate recovery (HEUR) path but is still higher than NYMEX Henry Hub prices.[16]

[16] Figure A-4 in Appendix A compares these price trajectories with the updated 2016 Annual Energy Outlook natural gas price scenarios.

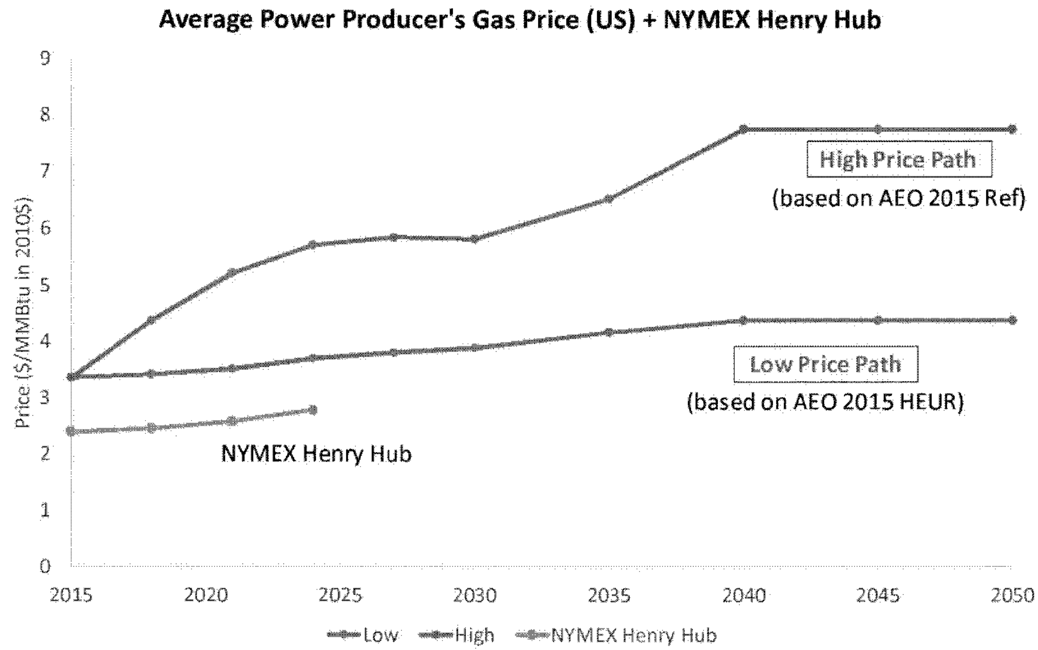


Figure 6-1
Natural gas price paths over time ($ per MMBtu, real terms) for the low and high gas price scenarios

High natural gas prices lead to much higher wind development in Kansas, even in the reference case.

The assumed trajectory of gas prices has important implications on the capacity and generation mix for Kansas. Figure 6-2 compares Kansas' generation under the reference case with low and high gas prices. The high natural gas price path encourages more new wind in Kansas even without the CPP. Exports also increase early in the time horizon as in-state coal units increase output. After 2030, higher gas prices prevent new NGCC deployment, and Kansas' high-capacity-factor and low-cost wind resources lead to significant investments in new wind generation (12.7 GW by 2050). Exports from Kansas to neighboring states with higher wind costs also increase under high gas prices (32.8 TWh in 2050 versus 11.4 with low gas prices).

Note how the high-gas-price scenario is one of many potential drivers of high wind development. Many insights about CPP pathways under these scenarios are also applicable to other environments with significant wind buildouts in Kansas.

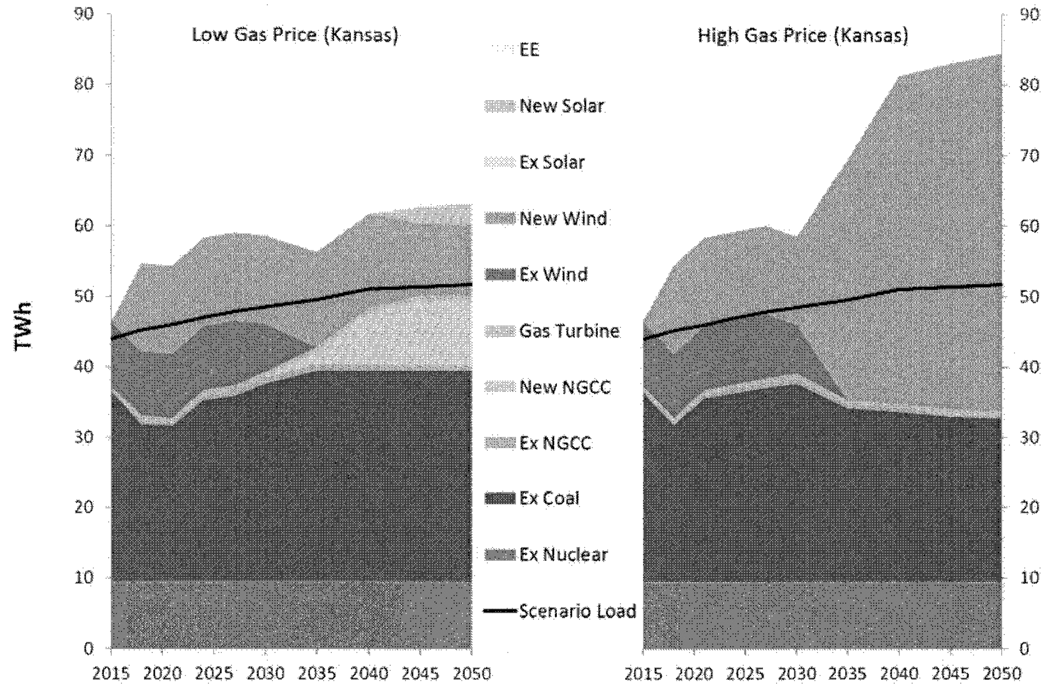


Figure 6-2
Electricity generation (terawatt-hours) by technology in Kansas under reference (i.e., no CPP) scenarios with low gas prices (left) and high gas prices (right)

The new wind in the reference scenario means that Kansas is likely in compliance with CPP rate targets beginning in 2035. However, some fraction of this extensive capacity additions would have to be accelerated to reach rate goals in 2030, which accounts for the additional investments in Figure 6-3. When Kansas participates in ERC and allowance markets, pathway decisions in other states have a larger impact on Kansas capacity additions when gas prices are higher. Due to the state's export potential, some trading scenarios (e.g., those with higher installed wind) entail greater capacity investment than the island compliance scenario.

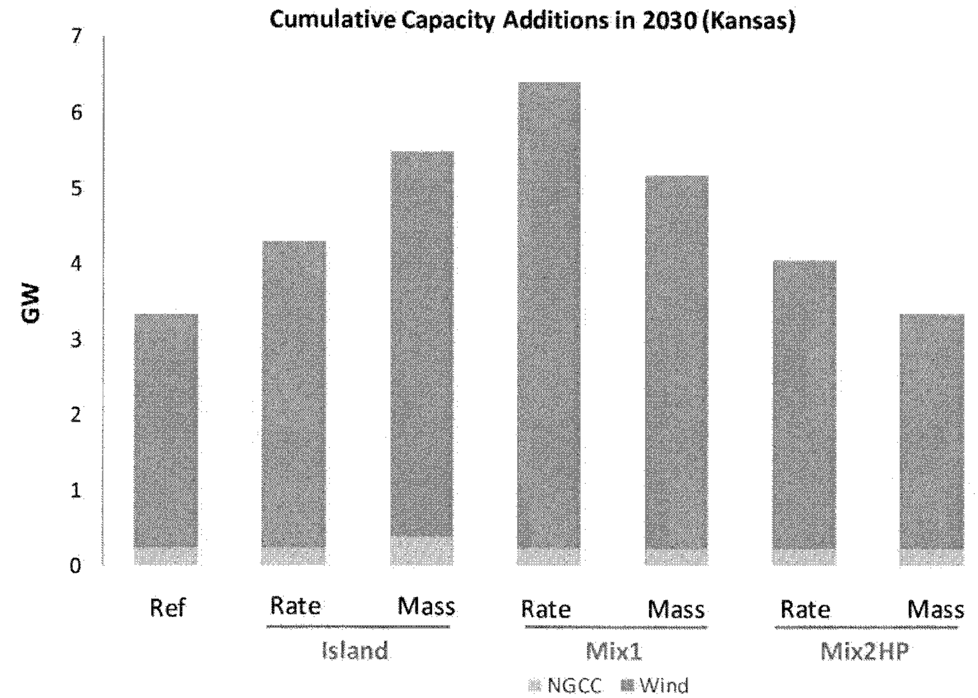
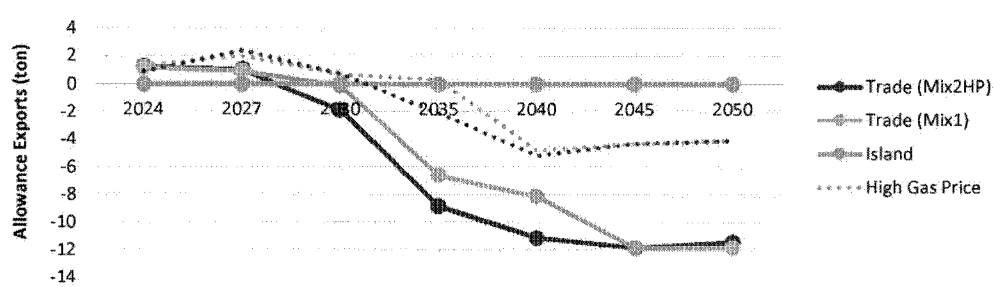


Figure 6-3
Cumulative capacity investments (gigawatts) in Kansas through 2030 under mass and rate compliance under different trading environments (assuming high natural gas prices)

Higher gas prices and wind capacity deployment also impact Kansas' trading incentives in allowance and ERC markets when it chooses a mass or rate path, respectively. When Kansas chooses mass, its net allowance trade position narrows, as shown in Figure 6-4. The wind generation not only leads to greater electricity exports, but it also creates more allowances that Kansas uses in-state instead of relying as much on allowance imports (as it does with lower gas prices in Figure 5-7). When Kansas selects the rate pathway, it becomes a significant ERC exporter after 2030.



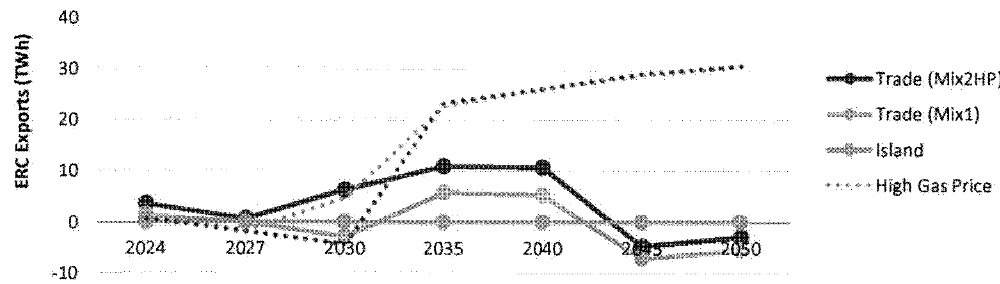


Figure 6-4
Kansas allowance (million short tons, top) and ERC (TWh, bottom) trade volume in net export terms over time for different trade and gas price assumptions

Table 6-2 demonstrates how these alternate gas price scenarios influence CPP compliance costs for Kansas. The economics of wind are more attractive in the reference case, which means that the subcategory-rate pathway minimizes cost for some scenarios with high gas prices.

Table 6-2
Comparative incremental CPP policy costs to Kansas ($ billion) in present value terms (2015–2050) and as a percentage of the reference costs

Set	Background Assumptions							Policy Cost ($B)		% Reference	
	ROC Policy	Gas Price	Wind Cost	Transm.	U.S. CO_2 Cap	Coal Life	Load	RU	MX	RU	MX
1	Island	Low	Ref	Ref	None	Ref	Ref	0.32	0.79	1.2%	3.0%
2	Mix1	Low	Ref	Ref	None	Ref	Ref	0.11	-0.06	0.5%	-0.3%
	Mix2HP	Low	Ref	Ref	None	Ref	Ref	0.19	-0.13	0.8%	-0.5%
3	Island	High	Ref	Ref	None	Ref	Ref	0.09	1.18	0.3%	3.6%
	Mix1	High	Ref	Ref	None	Ref	Ref	0.20	0.44	0.8%	1.7%
	Mix2HP	High	Ref	Ref	None	Ref	Ref	0.17	0.25	0.6%	1.0%
	Mix1	High	High	Ref	None	Ref	Ref	-0.03	0.22	-0.1%	0.8%
	Mix2HP	High	High	Ref	None	Ref	Ref	0.09	0.27	0.4%	1.0%
	Mix1	High	Low	Ref	None	Ref	Ref	0.23	0.61	0.9%	2.3%
	Mix2HP	High	Low	Ref	None	Ref	Ref	0.10	0.62	0.4%	2.4%

Costs of Wind

In this sensitivity, the cost of wind energy is discounted by 20 percent so that the installed cost of new capacity is $1,200/kW.[17]

Figure 6-5 shows how these lower wind costs impact lead to slightly higher wind generation, especially after 2030. Table 6-3 indicates that, although lower wind costs bring some new capacity online, natural gas price assumptions have a larger impact on investments and CPP compliance costs.

[17] Solar cost decreases of 20% did not change the results and were not included.

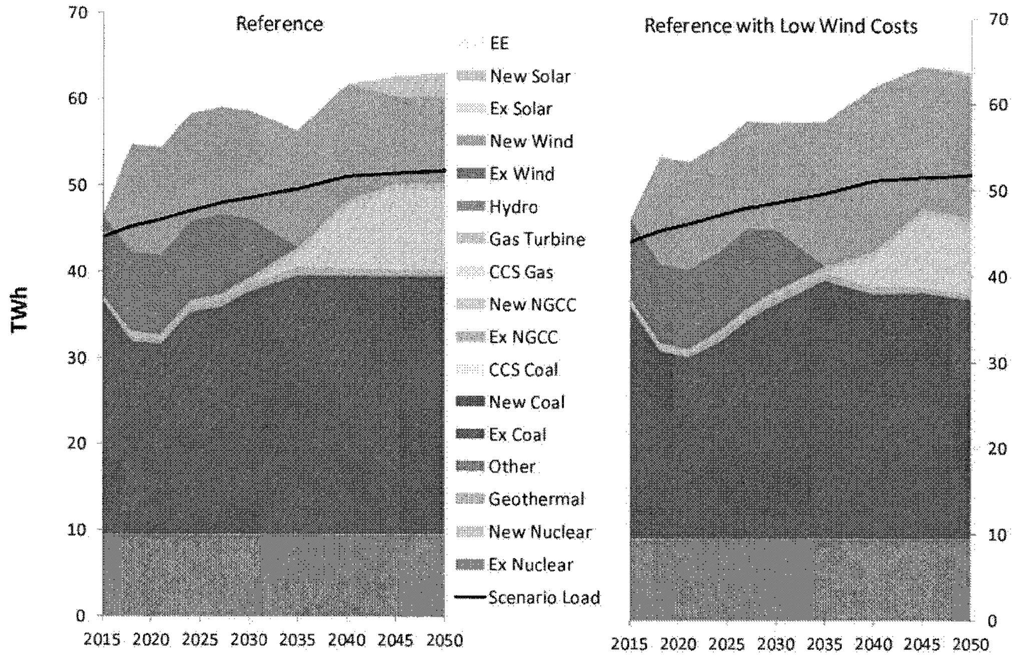


Figure 6-5
Electricity generation (terawatt-hours) by technology in Kansas under reference (i.e., no CPP) scenarios with reference wind costs (left) and low costs (right)

Transmission Additions to Indiana (Grain Belt Express)

This sensitivity explores a scenario where transmission capacity can be added between Kansas and Indiana in addition to its four adjacent neighboring states.

When transmission capacity can be added between these states, additional wind capacity is constructed in Kansas under the CPP compliance scenarios. Figure 6-6 shows how cumulative additions through 2030 are influenced by different gas prices, pathway choices in Kansas, and transmission expansion. Price differentials between regions creates a lucrative electricity export market for Kansas, especially when Kansas chooses a rate pathway (and wind can generate excess ERCs to sell on the market) and natural gas prices are higher (and other states find it cheaper to meet load by importing electricity from Kansas rather than building new in-state capacity).

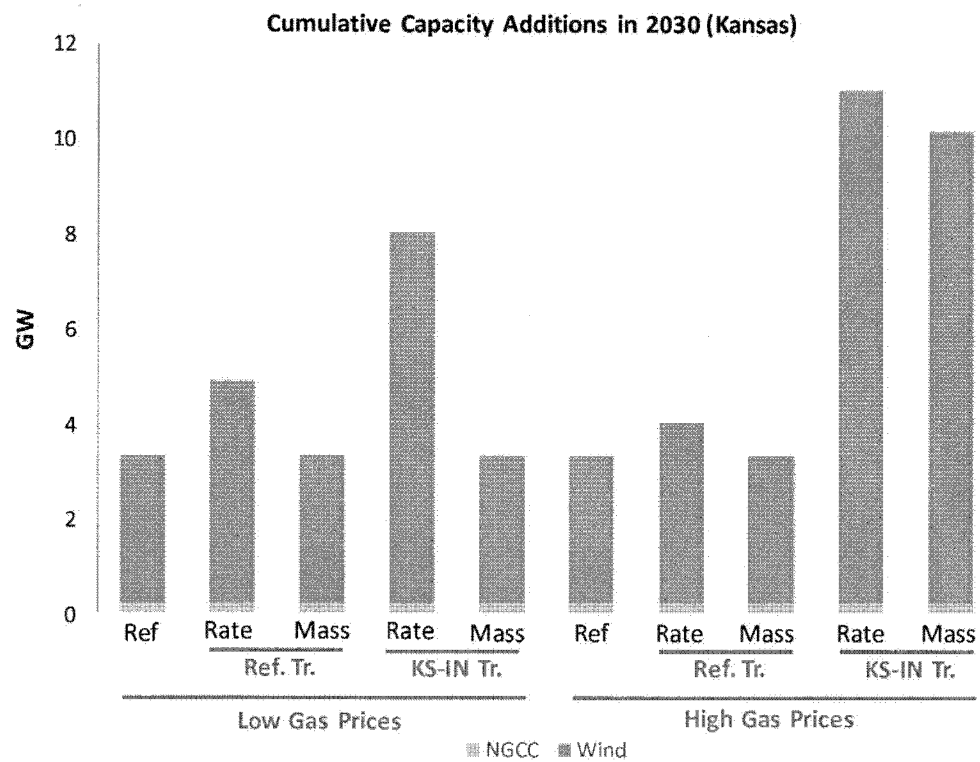


Figure 6-6
Cumulative capacity investments (gigawatts) in Kansas through 2030 under mass and rate CPP compliance with Mix2HP trading under different gas prices and transmission sensitivities (reference transmission assumptions and a sensitivity where Kansas-Indiana transmission can be added)

Post-2030 U.S. CO_2 Cap

This sensitivity considers a case where a post-2030 policy imposes a power sector only CO_2 cap of 80% below 2005 levels by 2050 (beginning with a 50% cap in 2035 and decreasing linearly to the 2050 target).

Figure 6-7 shows that a majority of new capacity additions occur after 2030. The anticipation of a certain and stringent cap after 2030 does not considerably alter investments before 2030. Under low gas prices, fewer than 5 GW new wind capacity is built regardless of whether a stringent post-2030 cap on CO_2 emissions is anticipated. This result suggests that, for Kansas, the CPP does not force appreciable deviations from what would be useful later.

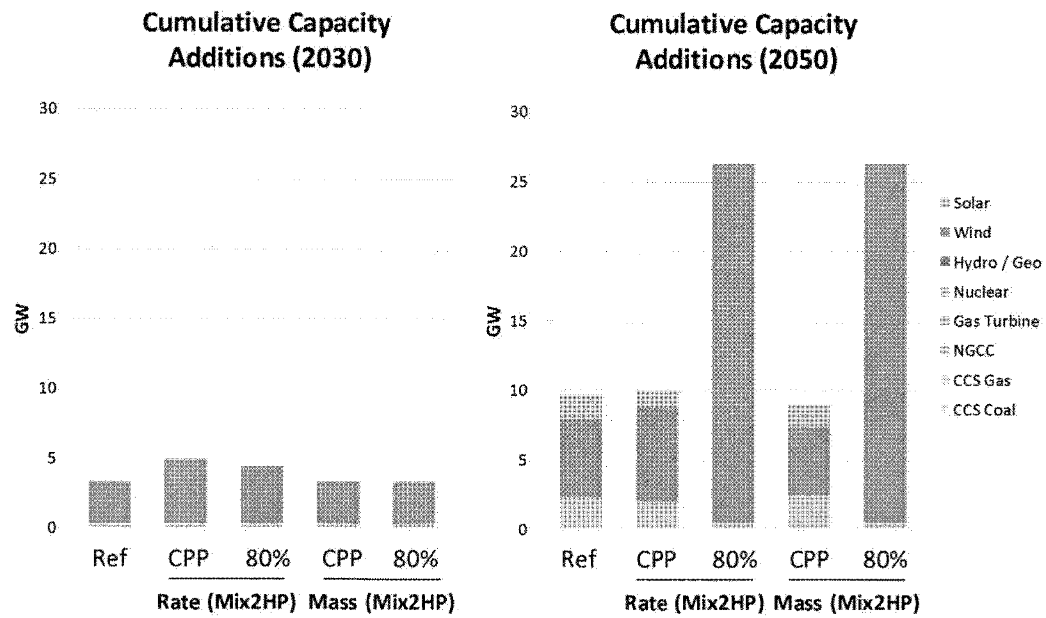


Figure 6-7
Cumulative capacity installations in Kansas through 2030 (left) and 2050 (right) under rate and mass CPP compliance without ("CPP") and with a post-2030 CO_2 cap ("80%"), assuming low natural gas prices

Due to Kansas' high-quality wind resources, stringent national CO_2 targets involve significant wind build-outs in the state by 2050 and electricity exports to neighboring regions. Figure 6-8 demonstrates how Kansas' 2050 generation could be very different under alternate assumptions about post-2030 policies. The reference scenario generation is relatively similar to the CPP scenarios in 2050, as the latter has slightly higher wind and NGCC generation. In contrast, generation in Kansas under a nationwide 80% cap is largely comprised of wind and existing nuclear. Total generation under the 80% with low gas prices is approximately 100 TWh by 2050, which is twice as high as in-state demand. When high gas prices are assumed, wind generation in Kansas is even higher, and total in-state generation is three to four times in-state demand by 2050 (Figure 6-8).

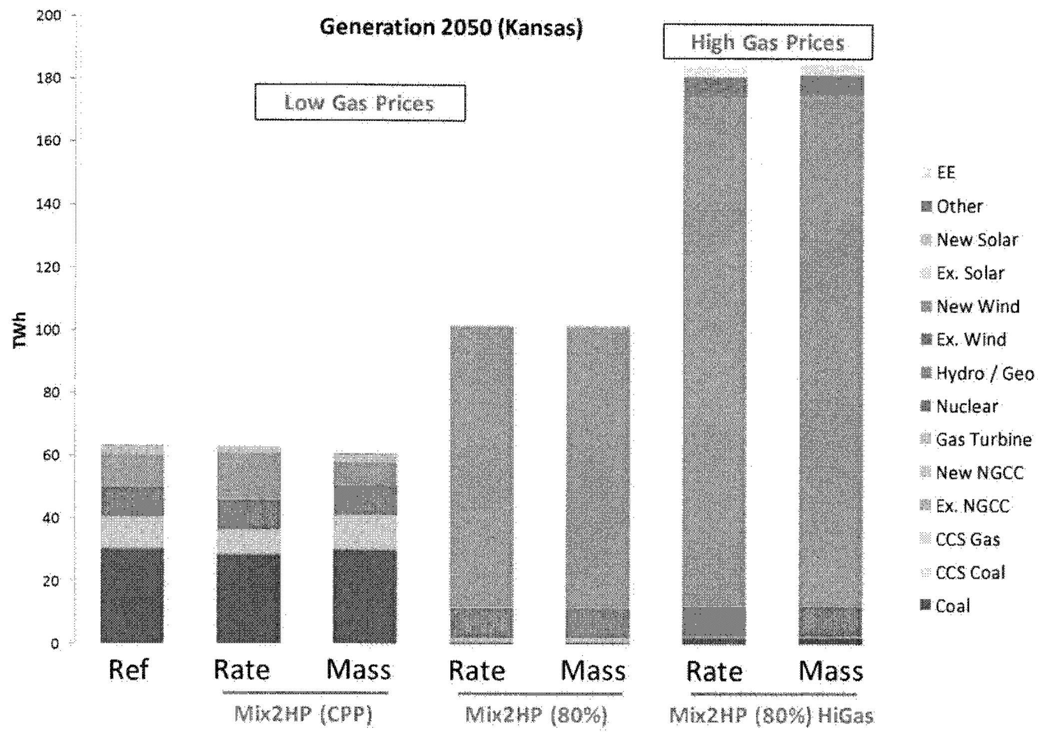


Figure 6-8
2050 electricity generation (terawatt-hours) in Kansas by technology under different pathway selections, gas prices, and post-2030 policies

70-Year Coal Lifetime

This sensitivity assumes that all coal assets in Kansas retire after 70 years instead of endogenously retiring units based on their economic competitiveness. As shown in Figure 6-9, coal retirements lead to lower generation after 2040 and greater deployment of NGCC capacity through 2050. This transition leads to slightly lower incremental CPP compliance costs for both rate and mass pathways in Kansas.

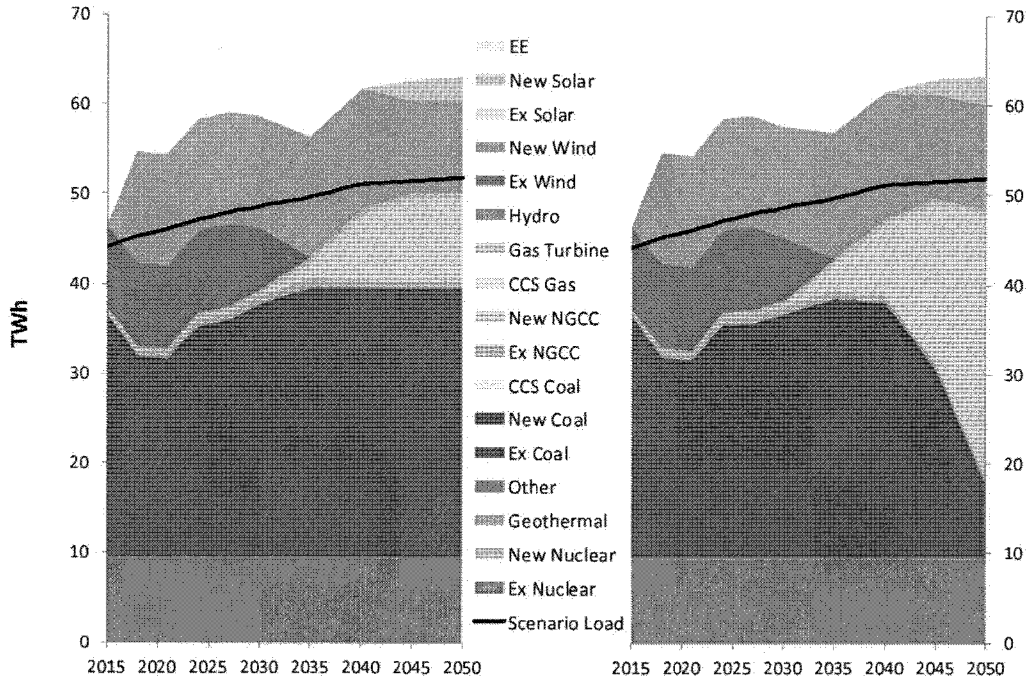


Figure 6-9
Electricity generation (terawatt-hours) by technology in Kansas under reference (i.e., no CPP) scenarios with endogenous coal lifetimes (left) and exogenous 70-year coal lifetimes (right)

Load Growth

Load growth in US-REGEN averages 0.54% through 2050, which is based on 2015 Annual Energy Outlook values. This sensitivity scenario assumes negative growth across the time horizon.

Figure 6-10 shows how reference generation under negative load growth erodes incentives to build new in-state capacity, especially new NGCC after 2030. However, incremental CPP compliance costs are roughly the same for the rate and mass pathways as for the higher load growth reference scenario (see Table 6-3 in the following subsection).

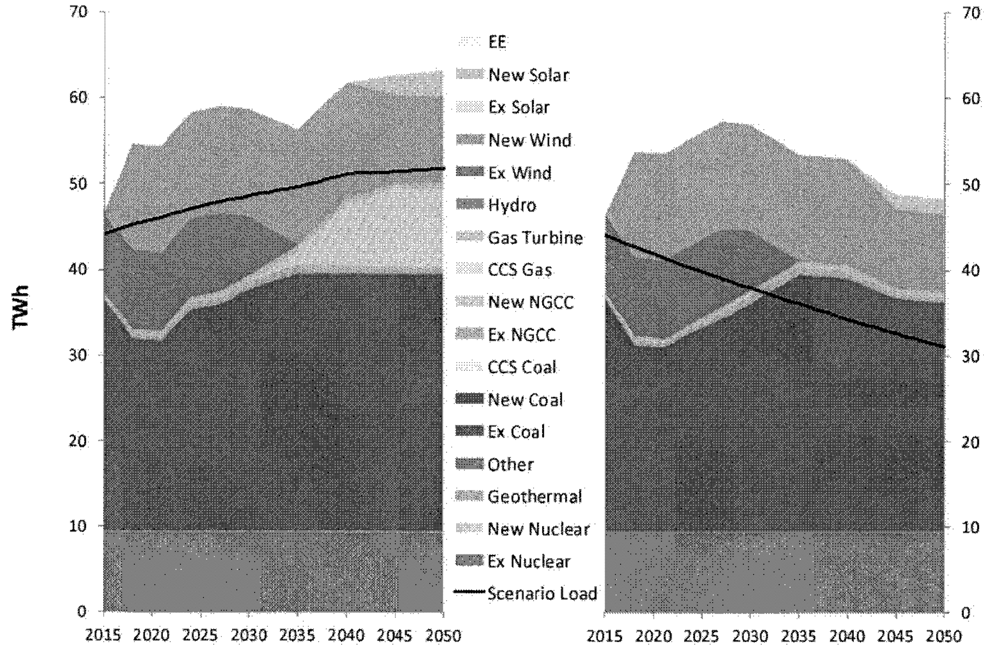


Figure 6-10
Electricity generation (terawatt-hours) by technology in Kansas under reference (i.e., no CPP) scenarios with AEO load growth (left) and negative growth (right)

Incremental Clean Power Plan Cost Comparisons across Scenarios

Given the previous conclusions, these sensitivities evaluate the robustness of a mass- and rate-based plans for Kansas by comparing total CPP compliance costs across all scenarios. Table 6-3 provides an overview of the sensitivity results. The right-hand columns show the incremental policy cost for the two pathways in absolute terms (in billion $, present value through 2050) and as a percentage of the reference (i.e., no CPP) cost. The column on the far right shows the cost-minimizing pathway.

Table 6-3
Comparative incremental CPP policy costs to Kansas ($ billion) in present value

terms (2015–2050) and as a percentage of the reference costs under subcategory-rate (RU) and existing-mass (MX) pathways

Set	Background Assumptions							Policy Cost ($B)		% Reference		
	ROC Policy	Gas Price	Wind Cost	Transm.	U.S. CO_2 Cap	Coal Life	Load	RU	MX	RU	MX	
1	Island	Low	Ref	Ref	None	Ref	Ref	0.32	0.79	1.2%	3.0%	RU
2	Mix1	Low	Ref	Ref	None	Ref	Ref	0.11	-0.06	0.5%	-0.3%	MX
	Mix2HP	Low	Ref	Ref	None	Ref	Ref	0.19	-0.13	0.8%	-0.5%	MX
3	Island	High	Ref	Ref	None	Ref	Ref	0.09	1.18	0.3%	3.6%	RU
	Mix1	High	Ref	Ref	None	Ref	Ref	0.20	0.44	0.8%	1.7%	RU
	Mix2HP	High	Ref	Ref	None	Ref	Ref	0.17	0.25	0.6%	1.0%	RU
	Mix1	High	High	Ref	None	Ref	Ref	-0.03	0.22	-0.1%	0.8%	RU
	Mix2HP	High	High	Ref	None	Ref	Ref	0.09	0.27	0.4%	1.0%	RU
	Mix1	High	Low	Ref	None	Ref	Ref	0.23	0.61	0.9%	2.3%	RU
	Mix2HP	High	Low	Ref	None	Ref	Ref	0.10	0.62	0.4%	2.4%	RU
4	Mix1	Low	Low	Ref	None	Ref	Ref	0.09	-0.01	0.4%	0.0%	MX
	Mix2HP	Low	Low	Ref	None	Ref	Ref	0.06	-0.01	0.3%	-0.1%	MX
	Mix1	Low	Ref	KS-IN	None	Ref	Ref	0.08	0.18	0.3%	0.7%	RU
	Mix2HP	Low	Ref	KS-IN	None	Ref	Ref	0.23	0.00	0.9%	0.0%	MX
	Mix1	High	Ref	KS-IN	None	Ref	Ref	0.74	1.36	2.5%	4.7%	RU
	Mix2HP	High	Ref	KS-IN	None	Ref	Ref	0.89	0.93	3.0%	3.2%	RU
	Mix1	Low	Ref	Ref	80% by 2050	Ref	Ref	-0.08	-0.14	-0.3%	-0.5%	MX
	Mix2HP	Low	Ref	Ref	80% by 2050	Ref	Ref	-0.04	-0.14	-0.1%	-0.5%	MX
	Mix1	High	Ref	Ref	80% by 2050	Ref	Ref	2.68	2.82	9.2%	9.7%	RU
	Mix2HP	High	Ref	Ref	80% by 2050	Ref	Ref	2.63	2.76	9.0%	9.5%	RU
	Mix1	Low	Ref	Ref	None	70	Ref	-0.01	-0.08	0.0%	-0.3%	MX
	Mix2HP	Low	Ref	Ref	None	70	Ref	0.15	-0.15	0.6%	-0.6%	MX
	Mix1	Low	Ref	Ref	None	Ref	-1%	0.17	-0.23	12.9%	-23.0%	MX
	Mix2HP	Low	Ref	Ref	None	Ref	-1%	0.01	-0.01	0.6%	-1.2%	MX

Table 6-3 indicates that existing-mass and subcategory-rate pathways can minimize compliance costs for Kansas depending on the sensitivity.

Many mass-based sensitivities involve net negative compliance costs for Kansas. These cases generally involve a greater reliance on electricity imports than the reference (i.e., no CPP) scenario and take advantage of opportunities to bring in power from neighboring states during hours with lower marginal wholesale prices than the reference case. This lowers investment and O&M costs under the mass-based policy scenario, despite higher costs for importing allowances.

Figure 6-11 plots sensitivity results to illustrate relative costs of the mass- or rate-based pathways. The dashed 45-degree isoquant line shows the domain where the mass and rate pathways are of equal cost. Points falling above this line indicate scenarios where the mass path is costlier, while values falling below the line indicate that the rate path is costlier.

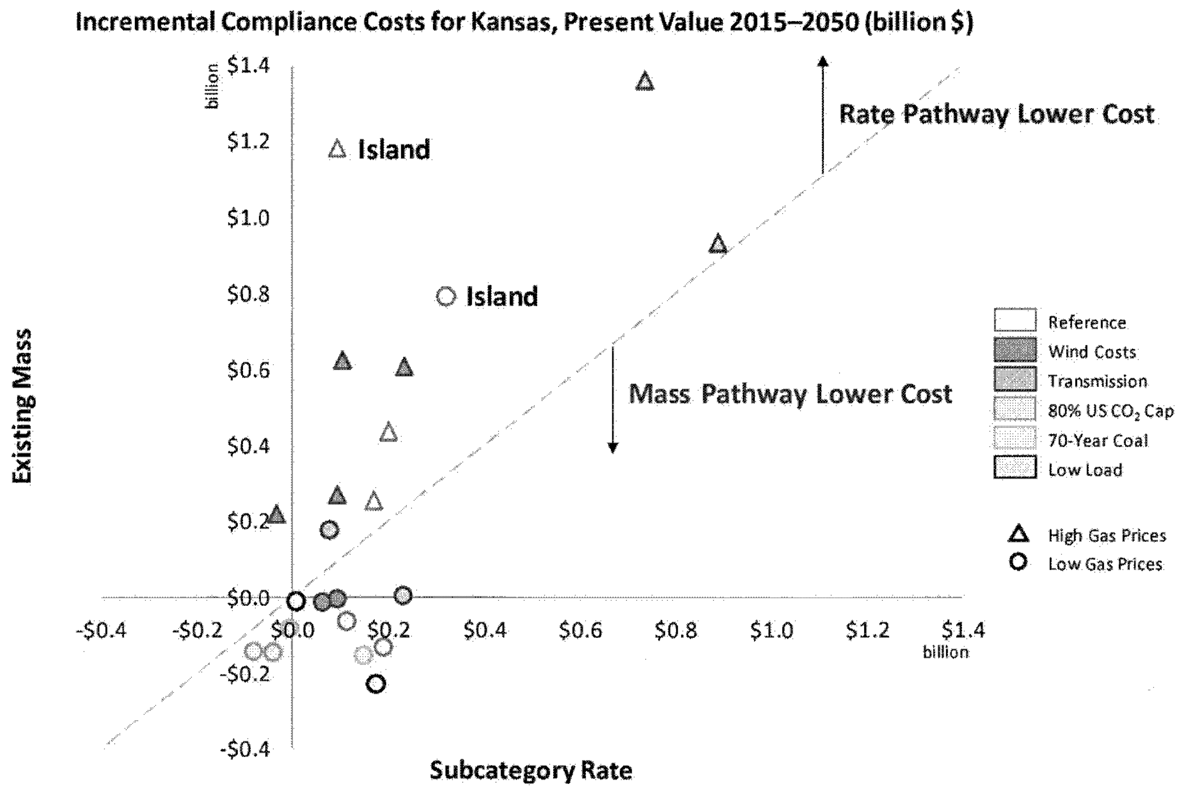


Figure 6-11
Comparison of incremental compliance costs of the Clean Power Plan for Kansas (billion $, present value through 2050) under existing-mass and subcategory-rate compliance pathways under a range of scenarios

This figure demonstrates how scenarios where the mass path entails higher compliance costs for Kansas can be significantly costlier. In the limited scenarios where mass is lower cost, the cost advantage is small. In contrast, the cost advantage of the rate pathway for Kansas is large under many scenarios. Unlike other states, Kansas' costs are influenced more when it picks the mass pathway than the rate, which leads to more total compliance cost variation associated with existing-mass.

When Kansas selects the mass path, costs range from -$0.2 to +$2.8 billion through 2050. Sensitivities that give rise to cheaper mass compliance are ones with lower wind generation and net imports, which leads to negative compliance costs.

Figure 6-11 indicates how trade can considerably lower compliance costs for Kansas regardless of the selected pathway. Participating in permit markets can potentially lower Kansas' compliance costs by millions of dollars (present value terms through 2050), though the magnitude depends on Kansas' selected pathway and compliance mixes elsewhere.

Note that gas prices and wind costs are large drivers of outcomes, as futures that incent high wind development in Kansas will make the rate pathway comparably more attractive. However, if decision-makers are reasonably confident that natural gas prices will not be high, then the mass pathway likely minimizes cost for Kansas.

Table 6-4
Comparative incremental CPP policy costs to Kansas ($ billion) in present value terms (2015–2030) and as a percentage of the reference costs under subcategory-rate (RU) and existing-mass (MX) pathways

Set	Background Assumptions							Policy Cost ($B)	
	ROC Policy	Gas Price	Wind Cost	Transm.	U.S. CO_2 Cap	Coal Life	Load	RU	MX
1	Island	Low	Ref	Ref	None	Ref	Ref	0.59	0.70
2	Mix1	Low	Ref	Ref	None	Ref	Ref	-0.09	-0.20
	Mix2HP	Low	Ref	Ref	None	Ref	Ref	0.89	-0.17
3	Island	High	Ref	Ref	None	Ref	Ref	0.65	1.74
	Mix1	High	Ref	Ref	None	Ref	Ref	1.95	1.23
	Mix2HP	High	Ref	Ref	None	Ref	Ref	0.52	0.05
	Mix1	High	High	Ref	None	Ref	Ref	1.19	0.10
	Mix2HP	High	High	Ref	None	Ref	Ref	1.27	0.03
	Mix1	High	Low	Ref	None	Ref	Ref	1.58	2.43
	Mix2HP	High	Low	Ref	None	Ref	Ref	0.15	1.50
4	Mix1	Low	Low	Ref	None	Ref	Ref	0.11	-0.11
	Mix2HP	Low	Low	Ref	None	Ref	Ref	0.34	-0.05
	Mix1	Low	Ref	KS-IN	None	Ref	Ref	0.48	0.06
	Mix2HP	Low	Ref	KS-IN	None	Ref	Ref	2.72	-0.07
	Mix1	High	Ref	KS-IN	None	Ref	Ref	2.16	4.36
	Mix2HP	High	Ref	KS-IN	None	Ref	Ref	2.86	2.19
	Mix1	Low	Ref	Ref	80% by 2050	Ref	Ref	0.00	-0.15
	Mix2HP	Low	Ref	Ref	80% by 2050	Ref	Ref	0.59	-0.15
	Mix1	High	Ref	Ref	80% by 2050	Ref	Ref	2.61	3.99
	Mix2HP	High	Ref	Ref	80% by 2050	Ref	Ref	1.25	2.74
	Mix1	Low	Ref	Ref	None	70	Ref	-0.05	-0.14
	Mix2HP	Low	Ref	Ref	None	70	Ref	0.62	-0.13
	Mix1	Low	Ref	Ref	None	Ref	-1%	-0.09	-0.26
	Mix2HP	Low	Ref	Ref	None	Ref	-1%	0.04	-0.20

Table 6-4 shows incremental compliance costs through 2030 (instead of through 2050 like Table 6-3). The higher costs through 2030 for many scenarios reflects the cost profile of capital investments over time. The reference scenarios for Kansas often involve large expenditures after 2030, which mean that the incremental compliance costs of the CPP are frequently higher in earlier periods.

Section 7: Summary

The analysis by the Electric Power Research Institute investigates state-level Clean Power Plan choices in Kansas. It focuses on existing-mass and subcategory-rate CPP pathways with and without market participation under a range of sensitivities.

EPRI's US-REGEN model was used to compare CPP results to reference scenarios (i.e., without the CPP) to understand tradeoffs between Kansas' planning options. In addition to rate and mass pathways, the analysis considers alternate trading scenarios to understand how reliance on in-state measures versus participation in multi-state emissions trading markets influence outcomes.

Kansas' business-as-usual generation mix without the CPP would likely be out of compliance with mass and rate targets for many periods and scenarios (Figures 3-4 and 3-5), which means the state would have to take additional measures (either changes to the fleet or purchases of allowances/ERCs) to close this compliance gap. Regardless of gas prices, planned wind capacity installations in Kansas through 2018 help with rate-based compliance and give additional lead time before incremental CPP-related investments have to be made toward 2030. Although these new builds would aid compliance in early periods, additional effort would be needed to reach later goals.

Key Takeaway 1: Neither the mass- nor rate-based Clean Power Plan pathway dominates for Kansas across all scenarios.

The analysis suggests that strong cases can be made for mass- and rate-based pathways, though neither path dominates. Results are driven strongly by the comparative incentives of building new natural gas combined cycle (NGCC) units relative to wind. When gas prices are low, new NGCC units may be built under reference conditions, which would likely make **existing-mass** (implemented with leakage provisions per the proposed federal plan) a lower cost CPP pathway for Kansas. This conclusion is robust to key uncertainties (Figure 6-11), including pathway selections elsewhere, more stringent post-2030 climate policies, existing asset lifetimes, and load projections.

When gas prices are high and/or wind costs are low, the economics of new wind capacity in Kansas are favorable even without the CPP due to the state's high resource potential. Exports under these conditions increase considerably, and the **subcategory-rate** pathway would align more closely with these investments.

Depending on how uncertainties resolve, the primary elements of CPP compliance strategies for Kansas could include:

- Lowering coal in-state generation through retirements and/or lower utilization (Figure 5-4 and 5-5)
- Constructing new natural gas combined cycle or wind capacity to comply with the state's chosen mass or rate pathway (Figures 5-3 and 6-3)
- Trading CO2 allowances or emission rate credits if mass- or rate-based pathways are chosen by the state, respectively (Figures 5-7 and 6-4)

Given uncertainty about pathway selections by other states, rate-based trade involves lower variability in total compliance costs (Table 6-3) and in-state capacity retirements (Figure 5-5). Increases in trade activity beyond 2030 are largely exports from Kansas, which are highest under high wind deployment scenarios and rate-based compliance.

Key Takeaway 2:
Encouraging trading lowers costs in Kansas considerably compared with strategies that rely on in-state measures only.

A second primary takeaway is that encouraging multi-state credit trading lowers compliance costs for Kansas compared with "island" scenarios that implement in-state measures alone. The magnitude of this cost reduction from access to national trading markets (Tables 6-3 and 6-4) and impact on in-state capacity investments (Figures 5-3 and 6-3) depend on state pathway selections elsewhere. Despite these benefits, inter-state trading entails a tradeoff with increased uncertainty about the pace of market development, liquidity, volatility, and exposure to additional forces external to Kansas. Based on gas prices and wind deployment, Kansas could be a net importer or net exporter of credits on secondary markets. Market participation may increase in-state coal generation, though CPP scenarios show increased retirements and lower utilization of coal assets relative to the reference scenario.

Additional factors beyond cost can favor a mass-based pathway selection for Kansas, including:

- **Lower incremental policy costs if low gas prices obtain:** If decision-makers are reasonably confident that natural gas prices will not be high, then the existing-mass pathway likely minimizes cost for Kansas (Figure 6-11).
- **Flexibility to use initial allowance allocations**
- **Administrative simplicity and familiarity** (i.e., relative to the creation and certification process for emissions rate credits under a rate-based plan)

Factors beyond cost that potentially favor a rate-based path include:

- **Timing of investments:** New generation capacity investments under mass compliance must start earlier and requires greater deployment than the rate pathway for Kansas (Figure 4-4). The mass pathway requires new NGCC investments in 2024. Near-term planned wind capacity investments align with rate-based compliance and would likely preclude new CPP-related investments until 2030. This provides extra time to observe market developments before committing to a non-market path to CPP compliance.

- **Disruption of the current generation mix:** 2030 generation under rate-based pathways more closely resemble values from the reference scenario for Kansas (Figure 5-4).

- **Volatility in compliance costs and capacity installations:** Model results suggest lower volatility in compliance costs under rate compliance relative to mass (Figure 6-11) depending on the sensitivity CPP pathway selections in other states.

Small cost differences between mass and rate scenarios under a range of scenarios will increase the importance of these other criteria for CPP pathway selection.

The flexible compliance options under the CPP make decision-making more complex, requiring optimization and economic modeling tools to understand tradeoffs and impacts. Regional heterogeneity means that there is not a dominant approach for all states, and the interdependence of states actions means that decisions must be evaluated simultaneously. The US-REGEN framework captures interactions between states and their simultaneous optimizing behavior subject to CPP targets. This analysis suggests that representing market interactions for electricity, CO_2 allowances, and emission rate credits is important in assessing economic impacts and compliance alternatives of policies like the CPP.

Potential impacts of rate- and mass-based compliance plans vary based on assumed market conditions like natural gas prices, CPP pathway choices in other states, wind costs, transmission, and coal retirements (Figure 6-11). Given uncertainty about these factors, which are largely independent from pathway decisions, the option to amend pathway selection as more information becomes available would help to limit compliance costs. Consideration of this flexibility for a state to switch compliance pathways from mass to rate (or vice versa) over time could allow states to meet CPP goals while reducing cost uncertainty.

Although the analysis offers valuable insights for state-level CPP decision-making, model approximations and incomplete system dynamics suggest that it should not be construed as a definitive determination of CPP planning for Kansas or legal advice on how Kansas can comply with the

CPP.[18] It can be expected that each state's preferred portfolio of compliance measures (e.g., in-state actions and market participation) will be informed by a range of factors, including in-state compliance costs, risk tolerance, local incentives, and assumptions about market liquidity and participation. Likewise, actual deployment may depend on additional factors (e.g., policy, permitting, and uncertainty) that fall outside of the scope of this economic modeling and analysis.

[18] For instance, US-REGEN does not include all costs incurred by coal units as they age (e.g., unit commitment constraints are not included in this version of the model). Including such costs could influence retirements.

Appendix A: US-REGEN Model Description

The U.S. Regional Economy, Greenhouse Gas, and Energy (**US-REGEN**) model was developed by the Electric Power Research Institute.[19] The model links detailed capacity planning and dispatch of the power sector for the Lower 48 U.S. states with a dynamic computable general equilibrium (CGE) model of the national economy.[20] The two models are solved iteratively to allow policy impacts on the electric sector to account for economic responses (and vice versa), which means US-REGEN can assess a broad range of energy and environmental policies.

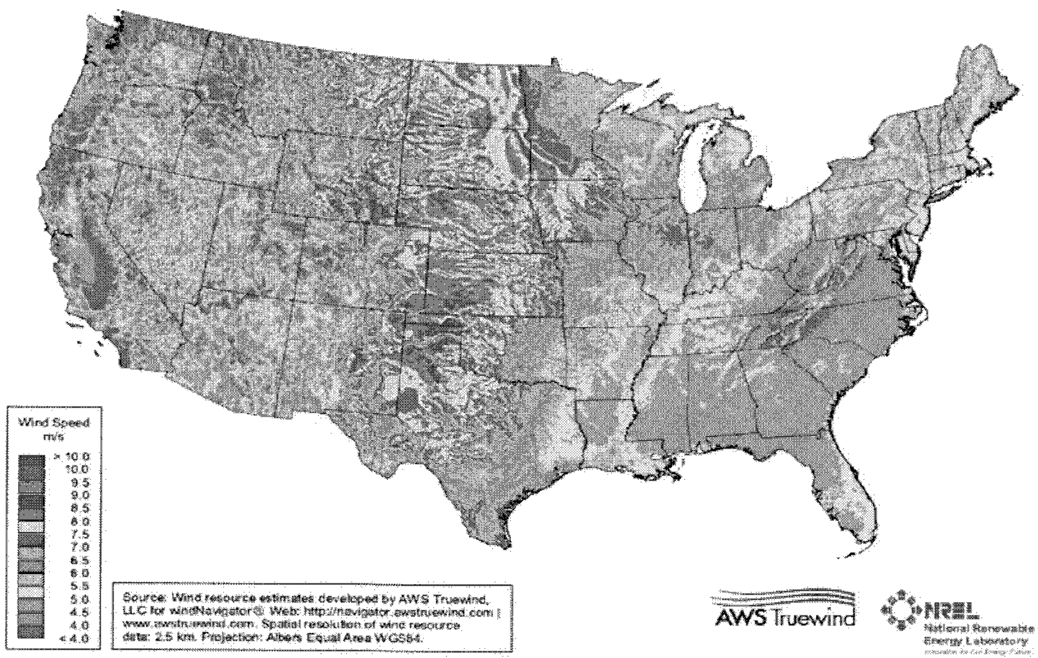


Figure A-1
Location of wind resources by state in US-REGEN

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[19] Additional detail can be found in *US-REGEN Model Documentation 2014*, EPRI Technical Update #3002004693 (available online at http://eea.epri.com/models.html).

[20] The CGE model of the U.S. economy includes representations of the residential, commercial, industrial, transportation, and fuels processing sectors.

The Clean Power Plan analysis in this report uses the electric-sector-only version of US-REGEN. The model contains detail to simultaneously capture capacity investment (including co-optimized transmission) and dispatch decisions for all 48 states in the contiguous United States. The forward-looking, long-term capacity planning model optimizes investments through 2050 to find the least cost way to meet load. Customizable regions and timesteps can be tailored to the needs of specific research questions. For all Clean Power Plan analyses, the model uses three-year timesteps through 2030 and five-year steps between 2030 and 2050.

The model simultaneously determines a cost-minimizing solution for all 48 states subject to technical and policy-related constraints. US-REGEN's spatial and temporal detail ensure resource adequacy for each state and capture market dynamics not only for electricity but also for CPP-related trading of allowances (for mass-complying states) and emission rate credits (for rate-complying states).

Hourly renewable resource data come from AWS Truepower and provide synchronous time-series values with load. Figure A-1 illustrates wind resource data in the Lower 48 U.S. states represented in the model, and Figure A-2 shows the wind resource potential for Kansas, assuming 80/100-meter hub heights. The joint variability of load, wind, and solar in this analysis is based on meteorology from 2010.

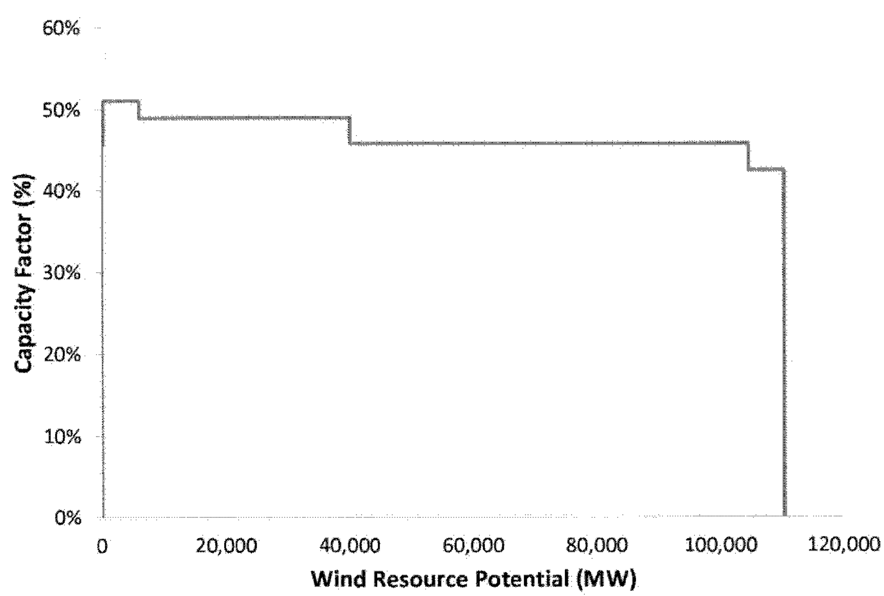

Figure A-2
State-level wind resource potential (MW) in Kansas by capacity factor (%)

US-REGEN employs an innovative algorithm to capture the hourly joint variability of load, wind, and solar profiles in a long time horizon model. This algorithm selects "representative hours" to preserve key distributional requirements for regional time-series data with a two-orders-of-magnitude reduction in dimensionality. This procedure provides between 50 and 100 intra-annual segments for system dispatch and load balancing in each annual timestep. This approach outperforms heuristic selection procedures that focus on representing the load duration curve at the expense of other renewable time-series data. Figure A-3 compares how US-REGEN's "representative hour" approach compares to the "seasonal average" approach.

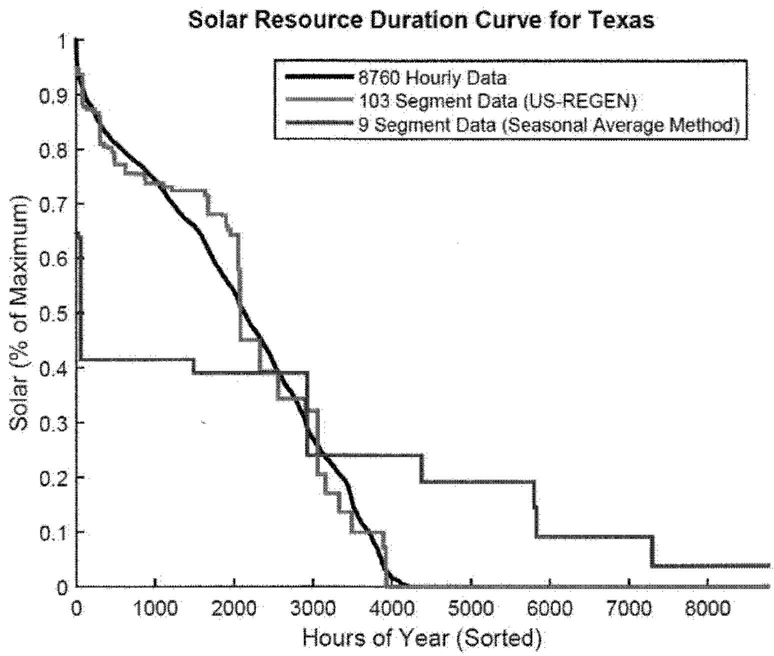

Figure A-3
Comparison of US-REGEN's representative-hour algorithm output (red) for the solar resource duration curve comparison for Texas with the underlying hourly data (black) and the seasonal-average approach (blue)

US-REGEN models a wide range of CPP compliance options in the power sector, including endogenous heat rate improvements, endogenous energy efficiency, detailed renewable resource representations, redispatch, options for existing coal (e.g., co-firing, conversion to gas or biomass, CCS retrofits), and many others.

The reference scenario assumptions are detailed in Section 3. All scenarios use fuel prices from the 2015 Annual Energy Outlook (EIA, 2015). The natural gas price trajectory comes from the 2015 AEO high estimated ultimate recovery (HEUR) case, as shown in Figure A-4. Also shown in Figure A-4 are updated fuel price paths from the AEO 2016. The 2016 reference is closer to the AEO 2015 HEUR case.

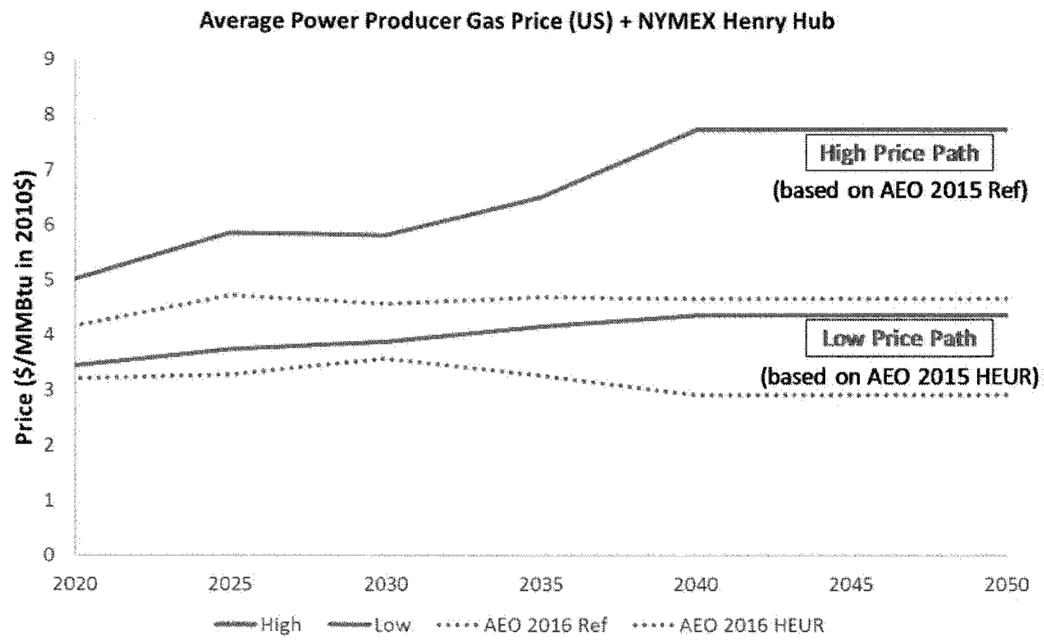

Figure A-4
Natural gas price paths over time ($ per MMBtu, real terms) for the low and high gas prices in the analysis (solid lines) and updated AEO 2016 values (dotted)

EPRI technology costs and limitations (e.g., on the rate and extent of transmission and nuclear deployment) are used. In line with AEO 2015 assumptions, there are no forced retirements for existing coal units in the reference case, though retirements for economic reasons are possible in any period. Endogenous retirement decisions in the model weigh the discounted sum of going-forward costs of maintaining and operating existing capital against anticipated revenues. Without sub-state resolution (e.g., the model does not capture intra-state transmission), US-REGEN retirements are driven primarily by unit-specific heat rates rather than by locational issues.

Technology cost and performance assumptions come from the most recent EPRI Integrated Generation Technology Options report. Solar and wind costs are updated more regularly. Capital costs for onshore wind in Kansas decline from $1,967/kW in 2018 to $1,693/kW in 2030, which includes a one-time $450 per kW charge to reflect incremental intra-regional transmission investment. Utility-scale solar PV capital costs decrease to $1,289/kW by 2030, including the same one-time hookup and network changes. Transmission between regions can be added at a cost of $3.85 million per mile for a notional high-voltage line (e.g., 500 kV AC or 800 kV DC) to transfer 6,400 MW of capacity.

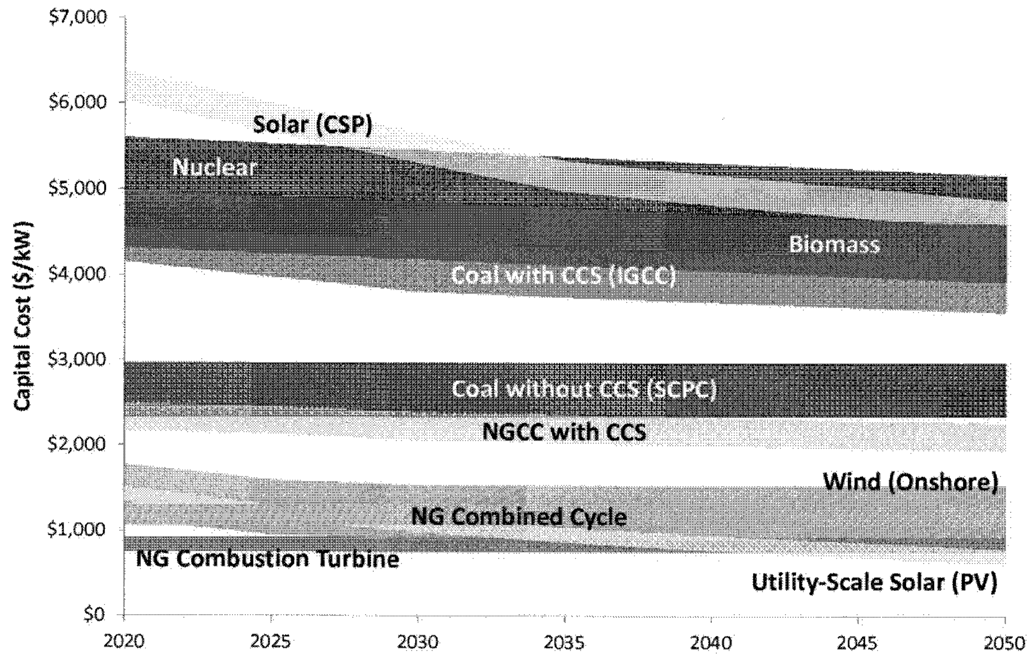

Figure A-5
US-REGEN capital cost trajectories (bands represent regional differences)

All scenarios include most existing and known future state and federal policies and regulations. Updated state renewable portfolio standards are included along with federal policies like MATS and CWA § 316(b). Other state policies include California's AB 32 and the Regional Greenhouse Gas Initiative (RGGI) for eastern states. The Clean Air Act § 111(b) CO_2 performance standards are included in the analysis.

Federal 2015 tax extenders adopted by Congress for wind or solar are included in the analysis. Rooftop solar is modeled as a separate technology "behind the meter" (i.e., rooftop generation receives the retail price for electricity) in California.

Appendix B: Abbreviations

Table B-1
Abbreviations and acronyms used in this report

Abbr.	Definition
AEO	Annual Energy Outlook
CAA	Clean Air Act
CGE	Computable Generation Equilibrium
CO_2	Carbon Dioxide
CPP	Clean Power Plan
EE	Energy Efficiency
EGU	Electric Generating Unit
EPA	Environmental Protection Agency
EPRI	Electric Power Research Institute
ERC	Emission Rate Credit
GW	Gigawatts
ITC/PTC	Investment Tax Credit and Production Tax Credit
MX	Mass Existing (i.e., CPP pathway)
NGCC	Natural Gas Combined Cycle
NGGT	Natural Gas Turbine
NSC	New Source Complement
OBS	Output-Based Set-Aside
ROC	Rest of Country
RE	Renewable Energy
RGGI	Regional Greenhouse Gas Initiative
RPS	Renewable Portfolio Standard
RU	Rate Unit (i.e., CPP pathway, sometimes referred to as "subcategory rate")
TWh	Terrawatt-Hours
US-REGEN	U.S. Regional Economy, Greenhouse Gas, and Energy

Understanding Clean Power Plan Choices in Kansas

Options and Uncertainties

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Abstract

This report summarizes potential implications of ~~alternative pathways~~compliance pathway choices for implementing the U.S. Environmental Protection Agency's Clean Power Plan (CPP) in Kansas. The analysis by the Electric Power Research Institute (EPRI) investigated Kansas' possible options in CPP state plan development. Results using EPRI's U.S. Regional Economy, Greenhouse Gas, and Energy (US-REGEN) model assess potential electricity generation portfolio changes and relative costs of mass- and rate-based CPP compliance pathways across a wide range of scenarios, which represent potential developments of emission trading markets and other key uncertainties.

The analysis suggests that strong cases can be made for mass- and rate-based pathways. Results are driven principally by the comparative incentives of building new natural gas combined cycle units relative to wind. When gas prices are high and/or wind costs are low, the economics of new wind capacity in Kansas are favorable even without the CPP due to the state's high resource potential, and power market exports could increase considerably.

Encouraging trading of CPP allowances or credits lowers potential compliance costs for Kansas relative to scenarios that principally utilize in-state measures (i.e., actions within the state's borders). However, multi-state permit trading entails uncertainty about the pace of market development, liquidity, volatility, and exposure to actions outside of Kansas. The magnitude of cost reductions from access to markets depends on state pathway selections in other states. Based on gas prices and wind deployment, Kansas could be a net importer or net exporter of credits. Market participation may increase in-state coal generation, though CPP scenarios show increased

retirements and lower utilization of coal assets relative to the reference scenario (i.e., without the CPP).

Keywords: Clean Power Plan; Kansas; US-REGEN

Executive Summary

This report summarizes analysis by the Electric Power Research Institute (EPRI) to ~~explore alternative pathways~~evaluate compliance pathway choices for implementing the U.S. Environmental Protection Agency's Clean Power Plan (CPP) in Kansas. This EPRI analysis looked at the implications of Kansas' options in preparing a CPP-required state plan and specifically assessed mass- and rate-based pathways under a range of sensitivities.

EPRI's U.S. Regional Economy, Greenhouse Gas, and Energy (US-REGEN) model was used to compare CPP compliance results to an appropriate reference scenario (i.e., without the CPP) to understand tradeoffs between planning options. In addition to rate and mass paths, the analysis considers alternate trading scenarios to understand how reliance on in-state measures versus participation in multi-state emissions trading markets could influence outcomes.

Model results show that Kansas' business-as-usual generation mix without the CPP would likely be out of compliance with mass and rate targets (Figures 3-4 and 3-5), which means that additional measures (e.g., changes to the fleet, allowance purchases, or emission rate credit purchases) would likely be necessary to close this gap.

The analysis suggests that strong cases can be made for both mass- and rate-based pathways, though neither path dominates under all possible futures. Results are driven principally by the comparative incentives of building new natural gas combined cycle (NGCC) units relative to wind. When gas prices are low, new NGCC units may be built under reference conditions, which would likely make **existing-mass** (implemented as per the proposed Federal Plan in this analysis) a lower cost CPP pathway for Kansas. When gas prices are high and/or wind costs are low, the economics of new wind capacity in Kansas are favorable even without the CPP due to the state's high resource potential. Exports under these conditions increase considerably, and the **subcategory-rate** pathway would align more closely with these investments.

Regardless of gas prices, planned wind capacity installations in Kansas through 2018 help with rate-based compliance and give additional lead time before incremental CPP-related investments have to be made ~~toward 2030~~.

Depending on how uncertainties resolve, the primary elements of CPP compliance for Kansas could include:

- Lowering coal-based in-state generation through retirements and/or lower utilization (Figure 5-4 and 5-5)
- Constructing new natural gas combined cycle or wind capacity to comply with the state's chosen mass or rate pathway (Figures 5-3 and 6-3)
- Trading CO_2 allowances or emission rate credits if mass- or rate-based pathways are chosen by the state, respectively (Figures 5-7 and 6-4)

Another robust finding is that promoting multi-state credit trading lowers compliance costs for Kansas compared with "island" scenarios, which implement only in-state mitigation measures (i.e., actions within the state's borders). The magnitude of this cost reduction from access to national markets (Tables 6-3 and 6-4) and impact on in-state capacity investments (Figures 5-3 and 6-3) depend on pathway selections in other states. Despite its potential role in cost containment, inter-state CPP market participation involves a tradeoffs with increased uncertainty about the pace of market development, liquidity, volatility, and exposure to forces external to the state of Kansas.

Potential impacts of rate- and mass-based compliance plans vary based on assumed market conditions like natural gas prices, CPP pathway choices in other states, wind costs, transmission, and coal retirements (Figure 6-11). Given uncertainty about these factors, which are largely independent from pathway decisions, the option to amend pathway selection as more information becomes available could help to limit compliance costs.

Although this analysis offers insights for state-level CPP decision-making, model approximations and incomplete system dynamics suggest that the analysis should not be interpreted as a definitive determination of CPP planning for Kansas. The impacts of the CPP vary widely on a state-by-state basis and depend on factors like current and anticipated state-level policies, planned retirements of existing assets, and decisions in neighboring states. These factors can affect insights and least-cost strategies. Each state's preferred portfolio of compliance measures and actual deployment could depend on a broad range of considerations beyond the scope of this economic modeling and analysis, including local incentives, other policy goals, risk tolerance, and other factors (e.g., policy, legal cases, permitting, and uncertainty).

Table of Contents

Section 1: Introduction

This report summarizes analysis by the Electric Power Research Institute (EPRI) of the comparative costs, investment implications, and other impacts of ~~alternative pathways~~compliance pathway choices for implementing the U.S. Environmental Protection Agency's Clean Power Plan (CPP) in Kansas. The report is intended to provide insight into Kansas' possible options in preparing its CPP state plan. The analysis was conducted with funding from a consortium of Kansas utilities, including Sunflower Electric Power Corporation and Kansas City Board of Public Utilities.

The U.S. Environmental Protection Agency's Clean Power Plan

The U.S. Environmental Protection Agency (EPA) released its *Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units*, also known as the Clean Power Plan, on August 3, 2015.[1]

Promulgated under Section 111(d) of the Clean Air Act (CAA), the CPP would requires states to create plans explaining how they ~~will~~ would comply with state-specific carbon dioxide (CO_2) emission reduction mandates for existing fossil-fueled electric generating units.

The state plans specify the form and extent of CO_2 emission reduction requirements for affected units. The EPA identifies six compliance pathways for states, three of which are based on emission rates (i.e., emissions per generated electricity) and the others on mass-based emission caps. The CPP provides flexibility for states to develop other compliance approaches, which are subject to EPA approval. In addition to pathway selection, a second ~~fundamental~~ decision for states is to determine the degree of participation in multi-state trading programs of CPP allowances or emission rate credits as a complement to in-state mitigation measures.

On February 9, 2016, the Supreme Court issued a stay on CPP implementation while the lower courts review pending legal challenges.

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[1] The Final Rule was published in the Federal Register on October 23, 2015 (80 FR 64661). EPRI's summary and interpretation of the CPP is provided here as background and is not legal advice.

The impact of the stay on CPP requirements and timetables was uncertain at the time of this report's preparation.

Motivations for the State-Level Analysis of Clean Power Plan Compliance Options for Kansas

The flexibility of alternate CPP pathways could help states manage compliance costs; however, these options ~~come with~~are accompanied by detailed provisions and state-specific considerations ~~that~~ requiringe careful deliberation and analysis. Some of the factors that can impact a state's compliance strategy are influenced by decisions outside of the state or by circumstances beyond an individual state's ability to control. The challenge for state planners is knowing how these choices could impact implementation decisions, compliance costs, environmental integrity, reliability and other short- and long-term ~~resiliency~~ outcomes in an uncertain world.

Since 2012, EPRI's Program 103 (*Analysis of Environmental Policy Design, Implementation, and Company Strategy*) has been creating the tools needed for its members and the public to understand potential CPP impacts on ~~electric~~ utility assets and operations, and to ~~devise~~ create cost-effective compliance strategies.

Program 103 and EPRI's Energy and Environmental Analysis group have ~~prioritized~~ supported the continual development and refinement of the U.S. Regional Economy, Greenhouse Gas, and Energy (US-REGEN) model. Among other applications, US-REGEN offers a flexible and customizable platform for assessing ~~CPP~~ impacts of technological developments and policies like the CPP on the electric ~~utility~~ power sector, providing insights into how alternate pathway choices and multi-state trading markets may influence electricity generation, investments, power system operations, emissions, and costs. Datasets have been created and updated to characterize electricity generation technologies and their costs, renewable energy resources, and specifics of CPP ~~compliance~~ options at the state level.[2]

EPRI's in-house electric sector model (**US-REGEN**) captures detailed CPP-related choices and economic tradeoffs.

Research under EPRI's Program 103 has concentrated on national and regional implications of the Clean Power Plan. In 2015, a supplemental project was offered providing US-REGEN analyses on in-depth consideration of CPP implementation at the state level, including the study in Kansas discussed in this report.

[2] See Appendix A for additional information about the US-REGEN model and references to model documentation.

Section 2: Analysis Approach

The ~~strategy for the analysis~~analysis strategy in this report is to compare CPP policy and uncertainty scenarios to an appropriate reference case (i.e., without the Clean Power Plan) to provide insight about the implications of different CPP pathways for Kansas. The US-REGEN model offers an analytical testbed for conducting controlled experiments to investigate differences across scenarios.

EPRI's US-REGEN Model Structure, Assumptions, and Data

This analysis uses the electric sector only version of US-REGEN for detailed, state-level analysis of investments and dispatch.

The Electric Power Research Institute developed and maintained the U.S. Regional Economy, Greenhouse Gas, and Energy (**US-REGEN**) model. US-REGEN combines detailed power sector capacity planning and dispatch for the Lower 48 U.S. states with a dynamic computable general equilibrium (CGE) model of the rest of the economy.[3] The two models are solved iteratively to allow policy impacts on the electric sector to account for economic responses (and vice versa), which means US-REGEN can assess a wide range of energy and environmental policies. The analysis in this report uses the electric-sector model only.

The electric-sector model simultaneously determines a cost-minimizing solution for all 48 states subject to technical and policy-related constraints. US-REGEN's spatial and temporal detail provides possible resource adequacy for each state and captures market dynamics not only for electricity markets but also for CPP-related multi-state trading of allowances (for mass-complying states) and emission rate credits (for rate-complying states).

Model outputs are intended to represent critical details of asset investment, power systems operations, and environmental compliance options. However, it is important to interpret these results keeping in mind that they are not meant to be predictions of future states-of-the-world. Primary decision-relevant insights are driven by changes across scenarios in "what-if" analyses under many different sensitivities, not by absolute levels in particular scenarios.

[3] The CGE model of the U.S. economy includes representations of the residential, commercial, industrial, transportation, and fuels-processing sectors.

Although analysis in this report provides many state-level insights for CPP decision-making, model approximations and incomplete system dynamics suggest that it should not be construed as a definitive determination of planning for Kansas.

- Actual deployment may depend on many additional factors, such as local incentives, regulatory developments, other policy, judicial outcomes, permitting, and other uncertainties.
- The modeling of the "Existing Mass" CPP pathway (discussed in the next section) is based on the proposed Federal Plan, which provides guidelines for managing "leakage" when new units are not covered under a mass-based state plan. These EPA guidelines could change in the final Federal Plan, and such modifications could shift incentives for asset investment, dispatch, and retirement moving forward.
- EPRI's US-REGEN model captures many areas of power-sector planning in detail, but computational constraints place important limitations on the degree of detail in specific states. For instance, the model does not account for unit-commitment-related costs or constraints, intra-state transmission constraints (though inter-state transmission and investment ~~is~~ are included), or gas distribution to individual units. These model omissions could impact the representation of potential CPP compliance measures (e.g., the model likely overstates the potential for coal-to-gas re-dispatch relative to a production-cost model due to gas distribution).

Detailed discussions of US-REGEN's data, structure, assumptions, and limitations regarding technological, economic, and policy-related variables are provided in Appendix A of this report.[4]

Analysis Structure

The analysis in this report concentrates on Kansas' state-level decisions to understand the implications of alternate CPP pathways. The four primary paths considered include two rate-based ("Subcategory Rate" and "State Rate") and two mass-based ("Existing Mass" and "Full Mass") pathways, as illustrated in Figure 2-1. Preliminary analysis suggested that the study should focus on the subcategory rate (hereafter referred to as the "rate" path) and mass cap for existing units only (hereafter referred to as the "mass" or "existing mass" path).

The analysis focuses on the "subcategory rate" and "existing mass only" Clean Power Plan compliance pathways for Kansas.

[4] Further detail and examples of model applications can be found in *US-REGEN Model Documentation 2014*, EPRI Technical Update #3002004693 (available online at http://eea.epri.com/models.html).

~~Appendix C investigates the "Kansas Plan," which is a mass-based pathway variation.~~

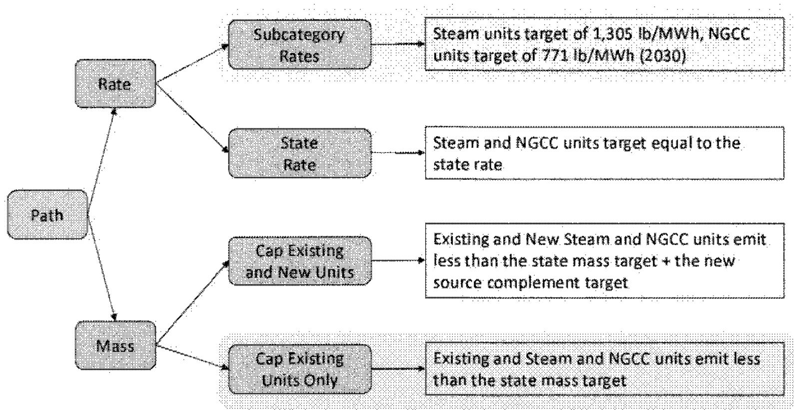


Figure 2-1
Diagram of Clean Power Plan compliance pathways considered in the analysis

The analysis aims to inform decisions about possible pathway selections for Kansas. The foundation for the decision is comparative costs between these pathways, though other identified criteria are also qualitatively discussed in the report. The analysis investigates the relative costs of rate and mass paths under a range of sensitivities due to persistent uncertainties about the future (e.g., fuel prices, asset lifetimes, renewables costs), as discussed in the next subsection.

The flexible compliance options for states under the CPP complicates decision-making and evaluating impacts of alternates, requiring optimization and economic modeling tools to understand these tradeoffs and impacts in a consistent framework. Such evaluations should be conducted on a state-by-state basis given different targets, existing fleets, and compliance options. Regional heterogeneity implies that there may not be a dominant CPP path for all states, and the interdependence of states' actions (which are affected by CPP and power-sector-planning choices elsewhere) means that decisions must be evaluated concurrently. The US-REGEN modeling framework captures interactions between states and their simultaneous optimizing behavior subject to CPP targets. This unique structure allows US-REGEN to represent market interactions for electricity, renewable energy certificates, CO_2 allowances, and emission rate credits to assess economic impacts and trading possibilities of policies like the CPP.

Cost comparisons in the report refer to electric-sector-only cost impacts and, unless otherwise noted, include:

- All capital and operating costs
- Cost of new transmission plus maintenance, which are equally split between states on the line
- Net payments for CPP credits and allowances
- Regulatory costs (e.g., alternative compliance payments for renewable portfolio standards, etc.)
- Cost of imported electricity, priced at the marginal wholesale price of the exporting state (minus the cost of exported electricity)

All costs are expressed in 2010 dollar terms, discounted back to 2010 at a five percent discount rate. Note that cost comparisons on this basis differ from impacts on consumer electricity prices/rates.

CPP compliance costs are incremental electric-sector costs above the reference ("no CPP") scenario. All values are expressed in real 2010 dollar terms.

CPP costs are defined as the incremental electric-sector costs above those incurred in the corresponding reference case, which makes it critical to define the reference scenario carefully and to present results explicitly (as discussed in Section 3).

It is worth reiterating that the goal of this project is not to predict the future by forecasting values of specific variables but to gain insight about the strengths and shortcomings of different pathways based on relative costs. Not only are costs intrinsically uncertain, but the Supreme Court stay creates further cost uncertainty due to potential changes in the regulatory landscape in yet unknown ways.

Many caveats about the uses and limitations of economic models should be kept in mind when interpreting results from this analysis. Models like US-REGEN are by necessity numerical abstractions of the complex economic and energy systems they represent. As such, they may contain approximation errors, incomplete system dynamics, and data quality issues. When viewing results, it is important to keep in mind that insights come from running a variety of scenarios, comparing the results, and asking "what-if" questions.

Scenario Descriptions

Section 3 summarizes reference case assumptions, results, and CPP compliance. Section 4 investigates CPP compliance for Kansas under so-called "island" conditions (i.e., where compliance is achieved using only in-state resources).[5] Section 5 looks at the potential role of trading emissions allowances in mass compliance settings or emission rate credits (ERCs) in rate settings, which are exported or imported from other states

[5] Model implementation of the CPP in subsequent sensitivities does not assume allowance banking or represent details of the optional Clean Energy Incentive Program.

to reduce compliance costs. The sensitivity of these results to a number of key assumptions is discussed in Section 6, including:

- ~~Alternate natural gas price paths~~

- Alternate natural gas price paths

- Alternate costs of new wind capacity (both higher and lower costs)

- Transmission additions between Kansas and Indiana (Grain Belt Express)

- Possible post-2030 U.S. CO_2 cap

- Lower coal lifetimes of 70 years

- Negative load growth

Section 3: Reference Scenario

This section focuses on model results for the reference scenario, which assesses how electricity generation in Kansas might evolve between 2015 and 2050 without the Clean Power Plan. The analysis strategy is to compare CPP compliance results in subsequent sections to an appropriate reference to understand the tradeoffs between Kansas' CPP planning options. As discussed in Section 2, the reference scenario is intended to be realistic but is not a forecast of the future. Given this framing, insights are driven by relative changes across scenarios.

Assumptions for the Reference Scenario

Reference scenario results come from running US-REGEN for all of the Lower 48 states in the contiguous United States. The model is calibrated to each state's 2015 generation mix and simultaneously solves the cost-minimizing capacity, dispatch, and transmission expansion problems through 2050.

Key assumptions in the reference scenario include:

- Fuel prices and load growth come from the Energy Information Administration's 2015 Annual Energy Outlook (AEO)
    - Load growth includes existing (i.e., legacy) energy efficiency programs, which assumes that states continue their current programs at average 2010–2014 rates and that this efficiency qualifies for ERC credit when a state selects a rate-based CPP compliance pathway[6]
    - Reference fuel price paths over time come from the EIA's AEO 2015 high estimated ultimate recovery (i.e., low price) case[7]
- The fleet database for all states was most recently updated in December 2015 through the ABB Velocity Suite, which includes all

[6] Legacy EE data come from Form EIA-861. Although these resources may be substantial for some states, these legacy programs do not play a role in Kansas.

[7] See Section 6 for results with higher natural gas prices. Appendix A (Figure A-4) discusses how these assumptions compare with the recently released price trajectories from EIA's AEO 2016.

announced retirements (though more recently announced nuclear retirements were also added)

- Committed (i.e., announced) wind projects in Kansas through 2018 are included per SNL Energy data
- 20% renewable portfolio standard in Kansas
- Energy efficiency (EE) program costs are assumed to be $55/MWh, which reflects the low estimate used by the U.S. EPA in their Clean Power Plan economic analysis
- No forced retirements for existing coal units, though retirements for economic reasons are possible; nuclear has 60–80 year lifetimes
- Technology costs come from the EPRI Generation Options report[8] with recently updated solar and wind costs
- Existing policies include state renewable portfolio standards (RPSs), the Regional Greenhouse Gas Initiative (RGGI), California's AB 32, and recent (2015) federal extensions of the Production Tax Credit (PTC) and Investment Tax Credit (ITC)
- CAA § 111(b) CO_2 performance standards for fossil units are included for new units
- The model captures transmission investments and power flows between states but does not represent transmission or distribution directly within state boundaries

Without the Clean Power Plan or additional policies, new natural gas and wind capacity are on the build margin in many states.

Figure 3-1 shows electricity generation by technology across the U.S. in the reference scenario. In the analysis, the PTC for wind accelerates deployment rather than incenting incremental capacity additions in many states.[9] Retirements of existing capacity and rising demand are met primarily by new natural gas combined cycle (NGCC) units, which are on the margin in many states under the reference case assumptions for gas prices and technological costs.

[8] Electric Power Research Institute. "Program on Technology Innovation: Integrated Generation Technology Options 2012." Technical Update 1026656.

[9] The reference scenario assumes net metering in California only, which leads to more rooftop solar deployment compared with other states.

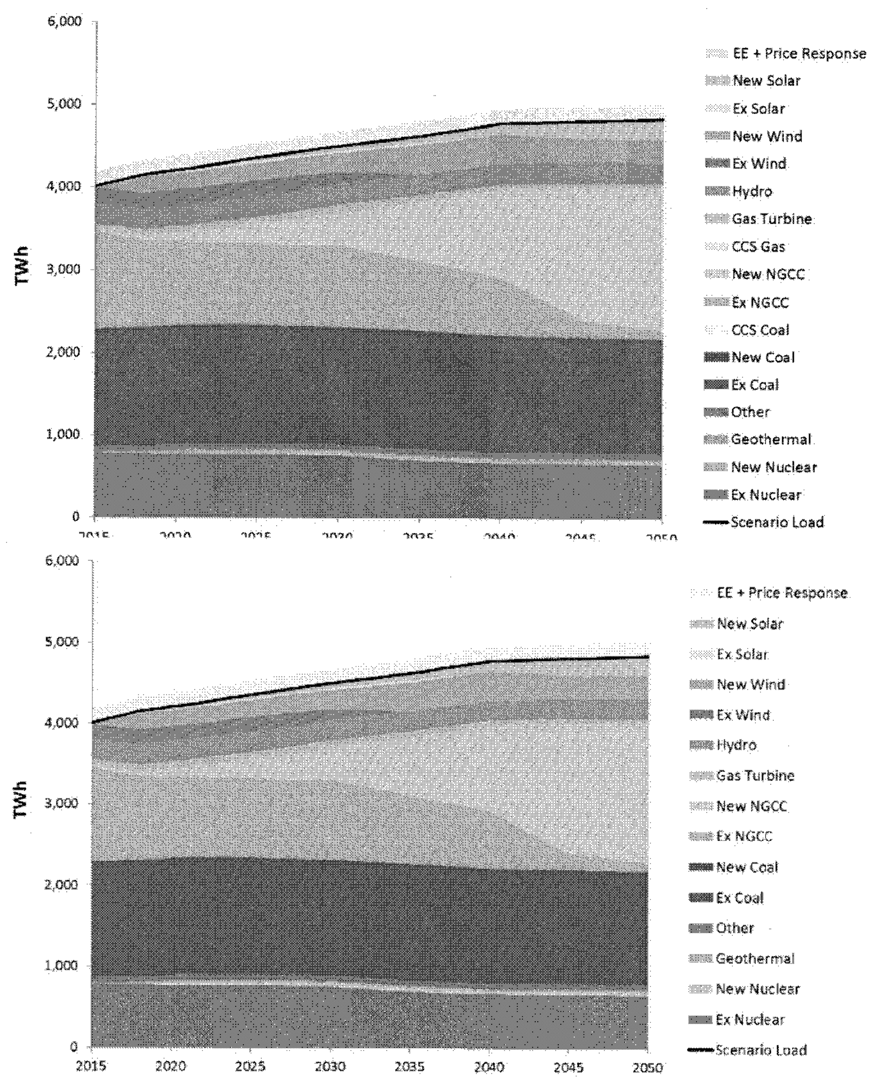


Figure 3-1
Electricity generation (terawatt-hours) for the Lower 48 U.S. states under the reference (i.e., no Clean Power Plan) scenario (2015–2050)

Generation, Capacity, and Emissions Results for Kansas without the Clean Power Plan

Figure 3-2 presents results for Kansas' electricity generation by technology in the reference scenario. Note that 2015 generation is calibrated to historical values using observed natural gas prices (with prices returning to AEO 2015 paths in subsequent projection periods). Existing coal units (dark blue) are Kansas' largest generation resource in 2015, a trend that continues in future years when the CPP is not in place. However, by 2050, fuel diversity increases in Kansas as new NGCC units come online and new solar capacity is added to comply with the 20% renewable mandate. Existing coal units are a low marginal cost resource for dispatch, especially given low coal costs in the state. Wind and NGCC units are the next largest resources by 2050. Low gas prices lead to new NGCC units on the build margin to meet growing demand. Kansas' existing nuclear generates just under 10 TWh annually and remains flat throughout the time horizon.

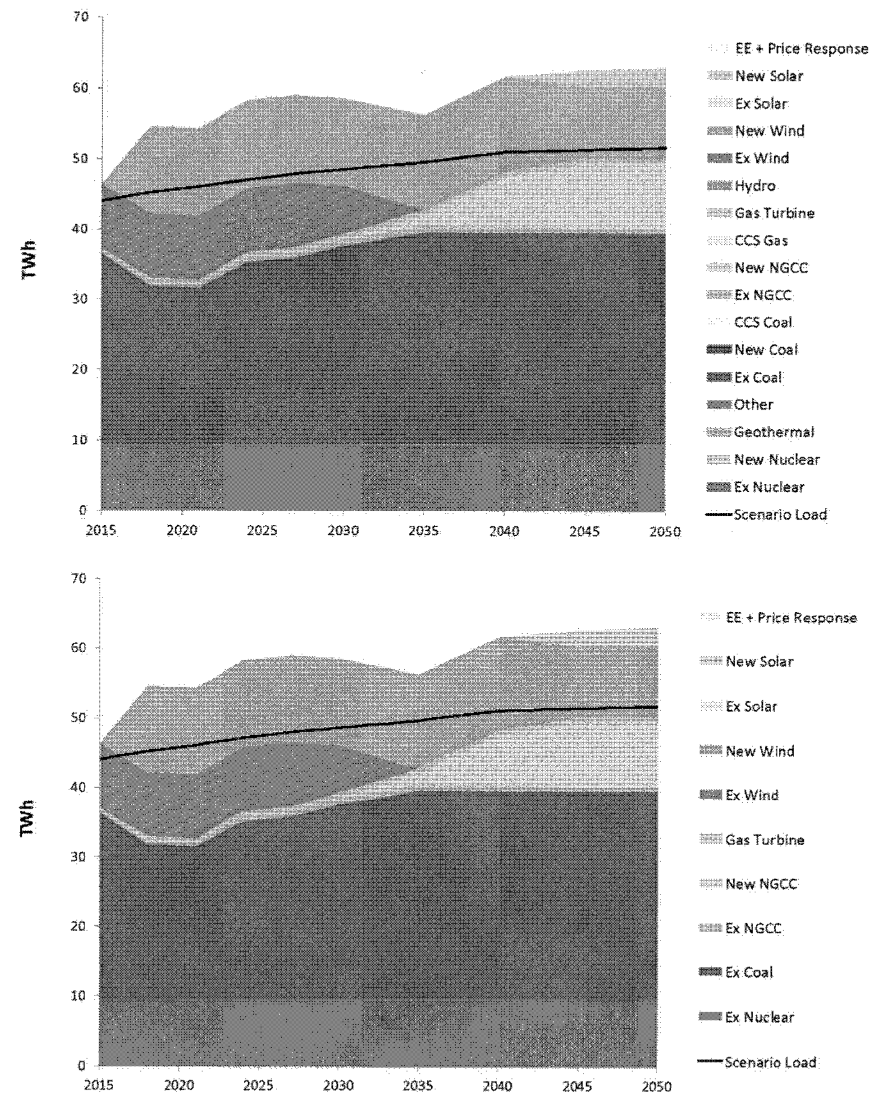


Figure 3-2
Electricity generation (terawatt-hours) in Kansas by technology under the reference (i.e., no Clean Power Plan) scenario (~~2000~~2015–2050)

Without the Clean Power Plan, Kansas' fleet mix is dominated by existing coal, wind, and some new NGCC after 2030.

In years where total generation exceeds the black line (i.e., representing total load for Kansas), power is being exported from Kansas to neighboring states.

Figure 3-3 shows that the reference scenario involves few new capacity investments in Kansas before 2030 apart from early period wind investments. Near-term market conditions are not conducive to deploying capital in new generation in light of the stock of existing capacity with low dispatch costs, slow demand growth, and substantial regulatory uncertainty. New NGCC capacity comes online after 2030, as older wind capacity retires. The lowest-cost capacity additions for Kansas are NGCC units in the reference case.[10] Later sections will illustrate how the CPP will guide choice of replacement capacity and possible early retirements.

[10] Kansas' existing gas turbine capacity is significant in Figure 3-3, but the low capacity factors of these units is indicated by the low generation in Figure 3-2.

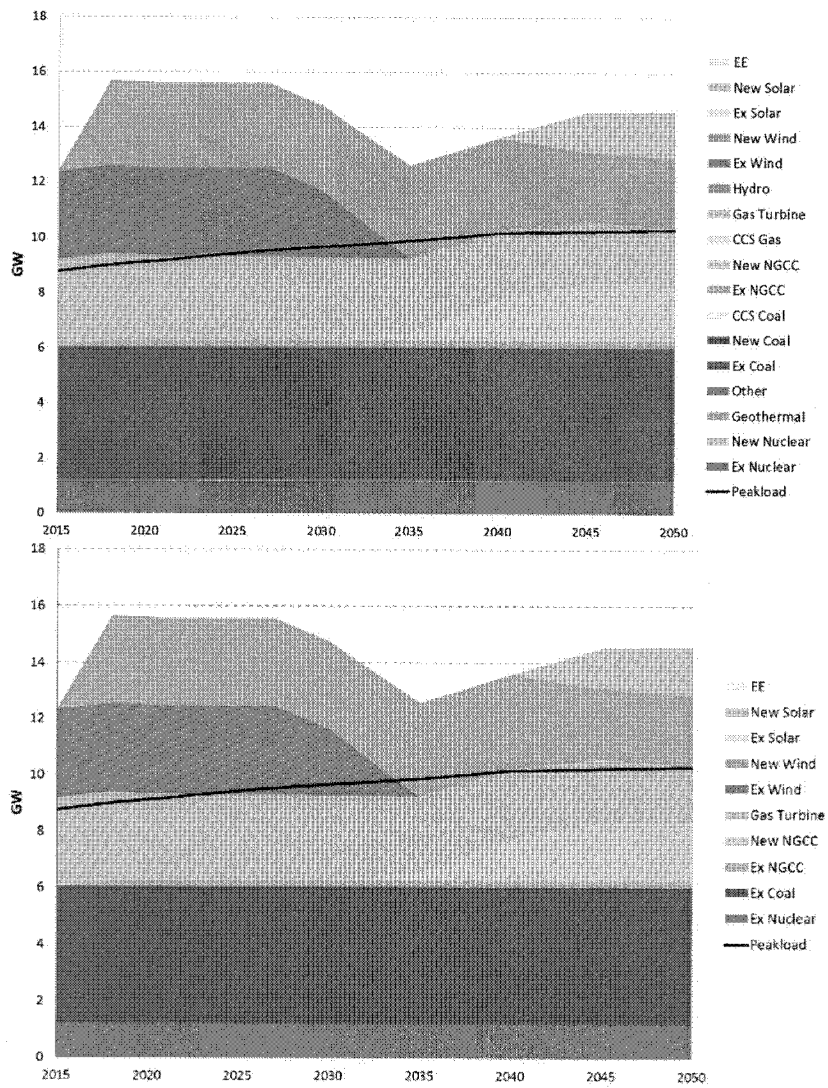


Figure 3-3
Electricity capacity (gigawatts) in Kansas by technology under the reference (i.e., no Clean Power Plan) scenario (2015–2050)

Reference Scenario Compliance with Clean Power Plan Targets

The choice of reference scenario assumptions may impact a state preference for mass or rate CPP pathways based on a ~~variety~~ range of metrics. Two metrics to compare model reference cases are:

1. The difference between CO_2 emissions (in short tons) from covered units in the reference case and CPP state mass targets

2. The difference between ERCs (in TWh) demanded by covered fossil units and the potential ERC supply from new renewables and EE, nuclear uprates, and gas-shift ERCs

These comparisons indicate how close Kansas comes to meeting CPP mass and rate targets in the reference case. Such metrics indicate the extent and timing of additional efforts required to comply with the CPP.

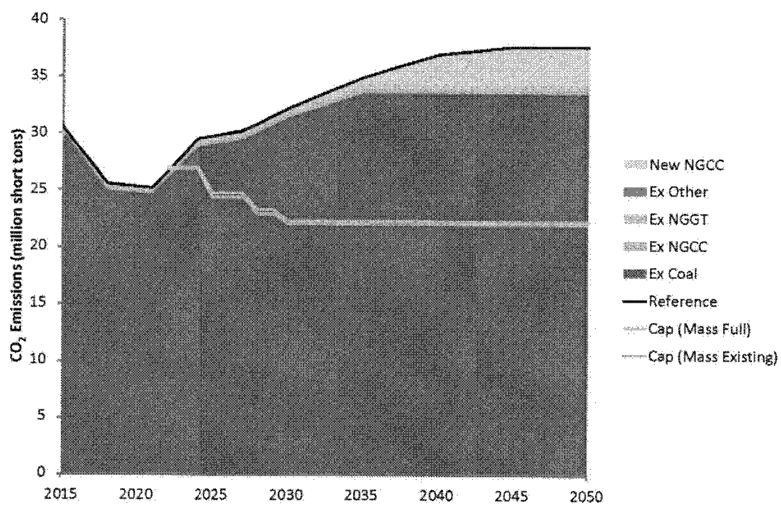


Figure 3-4
Comparison of CO_2 emissions from affected units in Kansas under reference generation and EPA's CPP existing (i.e., existing units only) and full mass targets (i.e., with the new source complement)

Figure 3-4 shows CO_2 emissions from Kansas' affected units under the reference scenario. CPP mass caps for Kansas are superimposed to show both the "existing" (i.e., existing units only) and "full" (i.e., existing units with the new source complement) pathways. Even though emissions are close to the initial target, 2030 emissions are approximately 7.2 million short tons above the caps. This mass-based compliance "gap" increases over time with greater coal generation and more new NGCC coming online as the cap becomes more stringent. The existing-mass cap is likely

The business-as-usual generation mix in Kansas is out of compliance with the Clean Power Plan mass and rate targets.

to be binding in later periods, which means that changes to the fleet or allowance purchases are required to come into compliance.

A central question in future sections is whether Kansas can eliminate this shortfall at lower cost (accounting for other considerations) by reducing output from existing units and making other changes to the in-state fleet, or by purchasing allowances on the market and relying more on its existing EGUs.

In terms of subcategory-rate CPP pathway compliance, Figure 3-5 shows the demand and supply of emission rate credits (ERCs). ERC demand represents that (predominantly) coal units would be required to surrender if they were to run at reference levels suggested in Figure 3-2 under a subcategory-rate target. Supply represents ERCs generated if Kansas chose a rate-based pathway with only reference case actions from Figure 3-2. The fraction of wind from installed capacity after 2012 generates ERCs. Given the ratcheting rate target and coal generation, demand for ERCs grows over time. The rate targets are non-binding in 2024 and 2027 owing to the ERC-eligible wind capacity installations early on. Demand exceeds supply for later compliance periods, and becomes larger in time as rate targets for Kansas become more stringent.

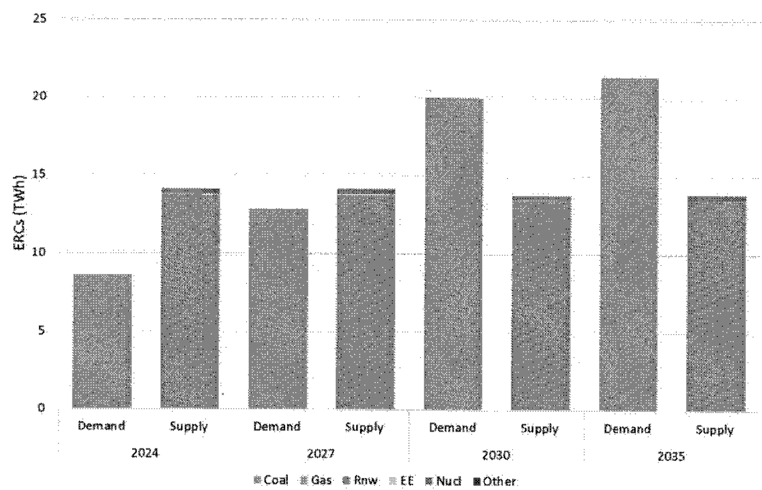


Figure 3-5
Demand and supply of emission rate credits in Kansas under reference case generation under CPP subcategory (unit) rate targets

Overall, from a business-as-usual perspective (i.e., without the CPP), Kansas likely requires additional action to adhere to the CPP guidelines. New wind will help the state to meet goals, but planned additions would not by themselves be sufficient, especially given coal output levels in Kansas under reference conditions.

Figures 3-4 and 3-5 ~~show~~ illustrate how expectation for ~~that~~ the future of the coal fleet and new ERC sources (e.g., wind, solar, and EE) are key parameters ~~in determining~~governing how close Kansas is to CPP compliance. ~~This indicates these are good starting points for~~These comparisons identify important areas for sensitivity analysis, as discussed in Section 6.

To meet the CPP targets, Kansas must perform a combination of the following alternatives:

- Reduce coal output, by reducing capacity factors or retiring units
- Find additional sources of electricity: New NGCC, new renewables, new EE, or import more power from other states
- Utilize CPP market opportunities like purchasing CO_2 emissions allowances (if Kansas pursues a mass-based pathway) or ERCs (if a rate-based pathway is chosen)

Section 4: Clean Power Plan Compliance without Trading ("Island" Scenarios)

This section discusses CPP "island" compliance for Kansas, where the state uses in-state compliance and mitigation alone with no trading of ERCs (if a rate path is chosen) or CO_2 allowances (if Kansas selects a mass path). Although Kansas still trades electricity with adjacent states, inter-state power flows are locked at their reference levels to more fully isolate compliance mechanisms.

Although this restriction on multi-state market participation is unrealistic for many states, these scenarios can be insightful for decision-makers, modelers, and policy-makers for three reasons. First, this boundary scenario assesses resources and measures Kansas can take individually to comply with the CPP without relying on allowance or credit trading. These "island" scenarios provide a testbed for evaluating least-cost, in-state resources. Second, "island" scenarios elucidate Kansas' possible fallback options should it decide not to engage in trading, which are complements to the trading scenarios in Section 5. Finally, "island" scenarios provide starting points for assessing the value of trade and sensitivities to technological and regulatory uncertainties.

These scenarios restrict Kansas to select the same compliance pathway as all other 47 contiguous states. Section 5 relaxes this assumption by investigating trade with pathway "mixes" where different states select different pathways. This section begins by analyzing the mass-based implementation approach and then explores the rate path.

Results of Existing-Mass and Subcategory-Rate Clean Power Plan Scenarios without Trade

For Kansas and many other states, the mass-based CPP pathway relies more heavily on new NGCC investments and rate-based on wind.

For the existing-mass "island" compliance pathway (Figure 4-1), compliance in Kansas is achieved primarily by lowering coal generation and increasing new NGCC generation. New incremental wind builds come online after 2030 as old turbines age out and the output-based set-aside (OBS) incents more renewable generation; however, low gas prices increase the opportunity costs of developing more wind. By 2030, 1.3 GW of new NGCC is built (compared with ~~0 GW~~no additions in the reference) and 3.1 GW new wind (3.1 in the reference). 840 MW coal capacity retires between 2015 and 2030 in Kansas under the existing-mass island compliance pathway. Annual ~~goal~~ coal generation decreases in 2030 from 28.2 TWh in the reference case to 19.2 TWh.

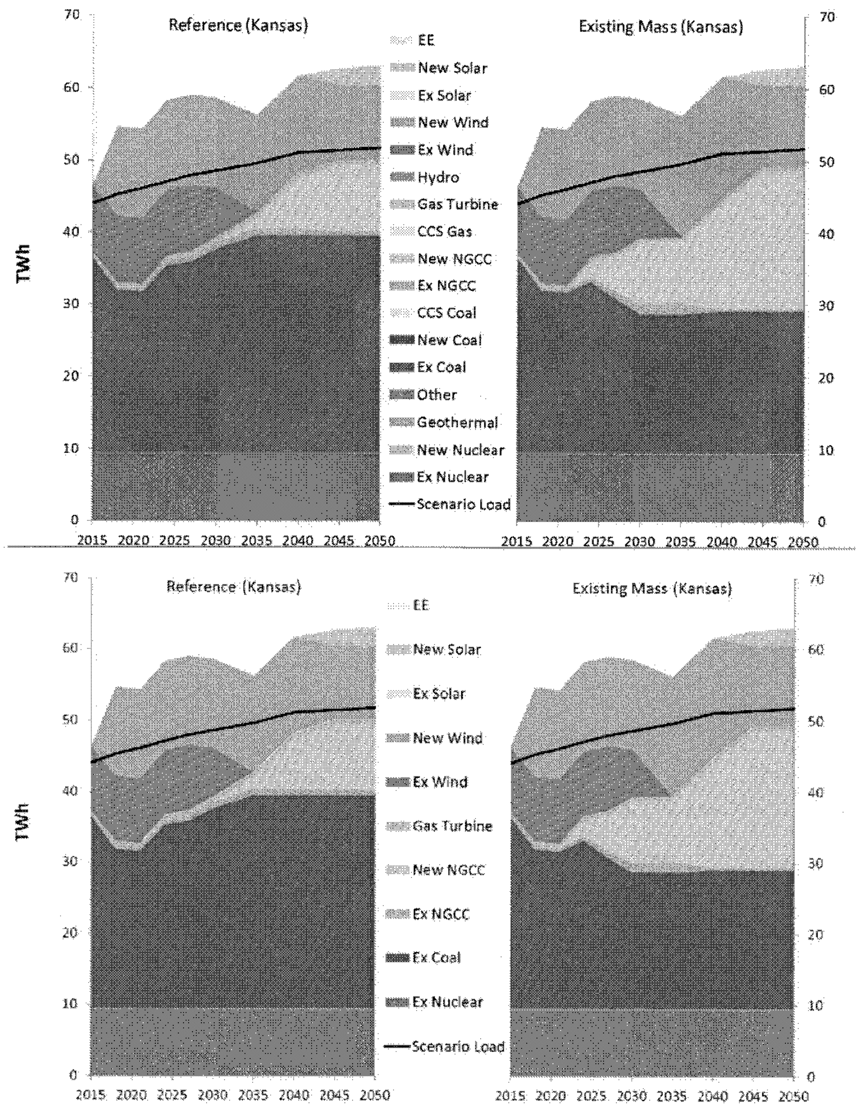
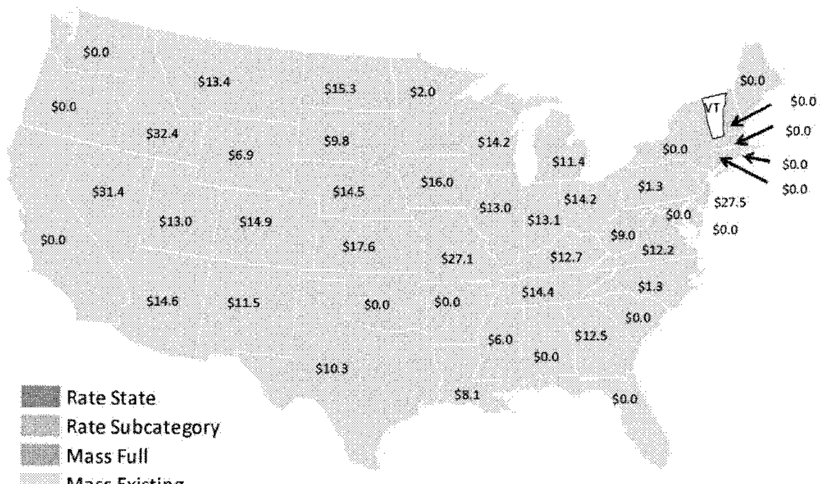
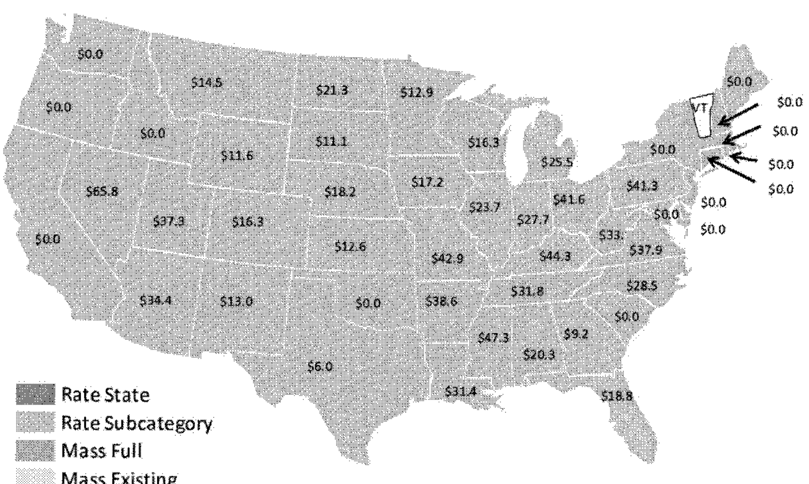


Figure 4-1
Electricity generation by technology in Kansas under reference (i.e., no CPP) and existing-mass island compliance scenarios

Figure 4-2 compares allowance prices under the existing-mass island scenario (top) and ERC prices under the subcategory-rate island scenario (bottom). For both island scenarios, Kansas' marginal compliance costs are far from the highest (some states are high in one metric but small in another) and lowest (the CPP constraints are not binding in some states in 2030). These prices reflect the stringency of the targets and cost of Kansas' compliance options relative to other states.



Emission Allowance Prices ($/short ton)



ERC Prices ($/MWh)

Figure 4-2
Maps of 2030 state allowance and ERC prices under existing-mass island compliance (top) and subcategory-rate island compliance (bottom)

Coal generation in Kansas decreases under mass- and rate-based CPP compliance, especially when trade is restricted.

For the subcategory-rate island compliance pathway (Figure 4-3), Kansas' cost-minimizing compliance strategy would rely heavily on new wind builds. Compared with the mass-based compliance pathway, the rate path entails more new wind capacity and less NGCC. These low-carbon ~~generation~~ resources keep more coal generation in the portfolio in 2030, as no coal capacity retires in this scenario and generation is only slightly lower than 2015 values (24.3 TWh annually in 2030 compared to 28.2 TWh in the reference). New NGCC capacity and generation are lower for the rate pathway than the reference scenario or the mass-based approach.

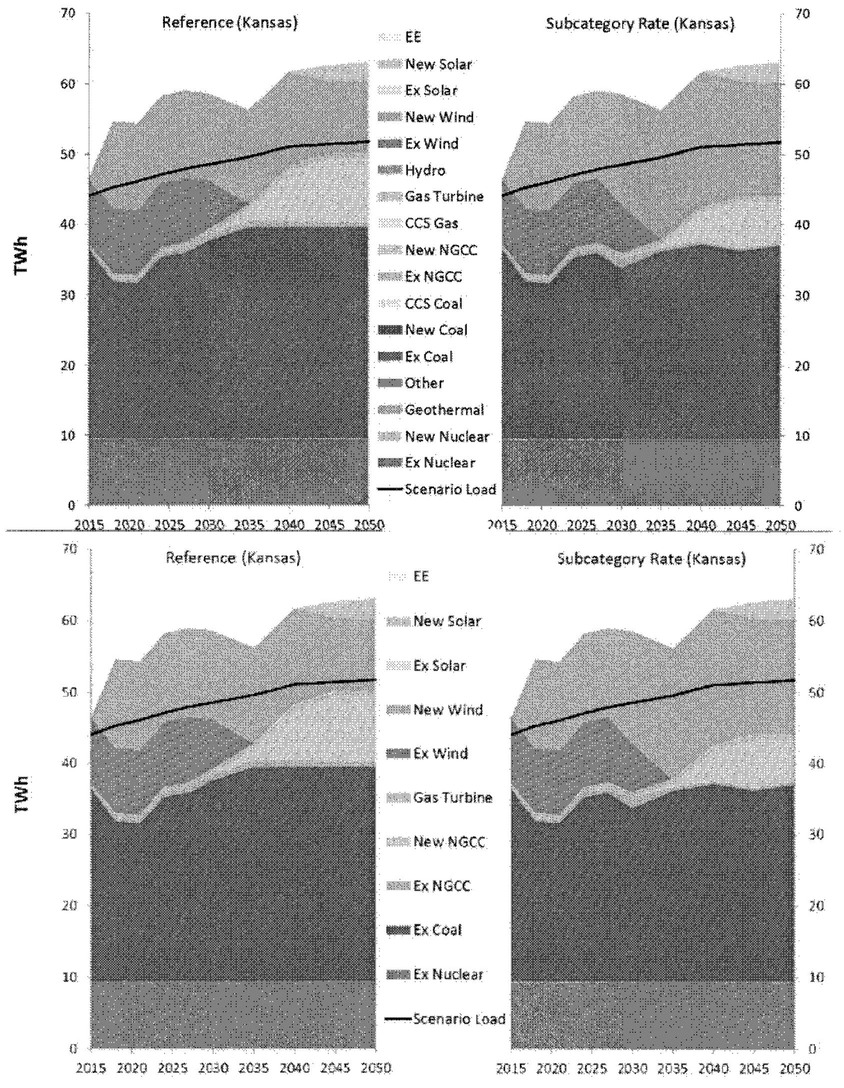


Figure 4-3
Electricity generation by technology in Kansas under reference (i.e., no CPP) and subcategory-rate island compliance scenarios

Table 4-1 shows how ERCs surrendered exactly equal those created in-state under island rate compliance. ERC demand is primarily from steam units, and zero-carbon ERCs come from wind. As shown in Figure 3-5, the

3.1 GW of new wind built in the reference suggest that Kansas likely will not have to undertake additional measures to comply with the CPP rate-based targets. This is reflected in the $0/MWh ERC price in 2024 and 2027 in Table 4-1.

Table 4-1
Emission rate credit (ERC) balance and ERC prices for Kansas under subcategory-rate island compliance

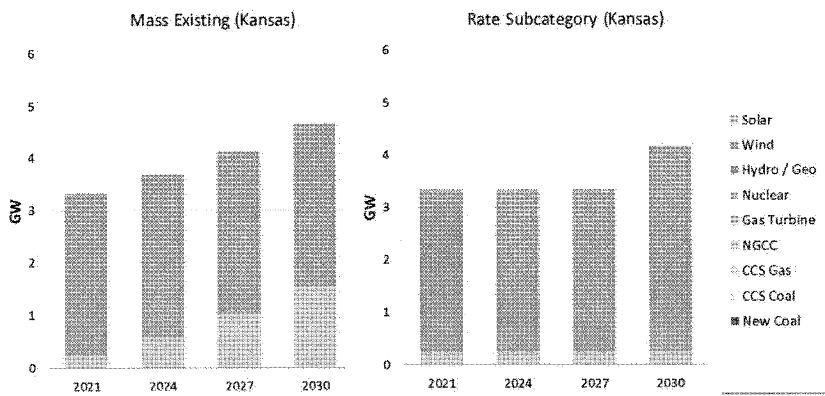
	2024	2027	2030	2035	2040	2045	2050
ERC Demand (TWh)	14.1	14.1	17.1	18.8	19.6	18.9	19.5
ERC Supply (TWh)	14.1	14.1	17.1	18.8	19.6	18.9	19.5
ERC Price ($/MWh)	$0	$0	$12.6	$5.6	$4.8	$5.3	$4.3

Comparing investment decisions under rate and mass pathways also indicates the timing of when commitments have to be made. Based on the pace of investments, it may be useful to understand which plan potentially gives states more time to observe the resolution of uncertainty about policy choices elsewhere and compliance provisions before making irreversible capital allocation decisions.

Given uncertainty about a range of factors (which are explored in the sensitivity analyses in Section 6), the option to amend pathway selection as more information becomes available (i.e., the flexibility for a state to switch compliance pathways from mass to rate or vice versa) would help to limit compliance costs.

Figure 4-4 illustrates how investments under mass compliance must start earlier and requires greater capacity installations than the mass pathway for Kansas. For the existing-mass pathway, incremental additions beyond the reference scenario come online in 2024 and consist largely of NGCC capacity. In contrast, island rate compliance for Kansas mostly consists of new wind additions that begin around 2030.

The rate CPP pathway provides Kansas more time to observe market developments before making capacity deployment decisions.



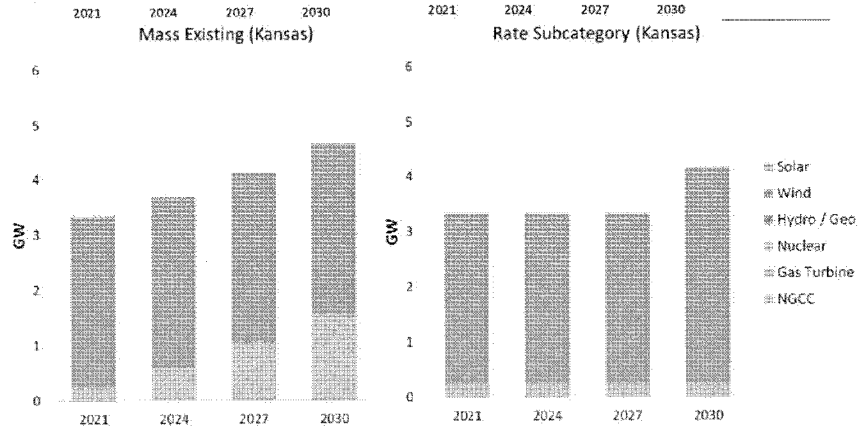


Figure 4-4
Comparison of cumulative capacity additions and retirements (gigawatts) in Kansas over time under existing-mass island compliance (left) and subcategory-rate island compliance (right)

The earlier and more extensive investments under mass compliance under "island" conditions make this pathway slightly costlier for Kansas. The present value of investment through 2030 is $6.18 billion under existing-mass and $6.15 billion under subcategory-rate. Ultimately, the accelerated wind investment helps with rate compliance. Investments that are already being made for planned projected align with rate-based compliance and give additional lead time before incremental CPP-related investments have to be made toward 2030.

Time-series data for emission rate credit and allowance prices over time are presented in Section 5, which compares island results with their values under different trade assumptions.

In summary, an "island" compliance environment where Kansas must rely only on in-state resources without market participation suggests that the subcategory-rate path provides more lead time than its mass-based counterpart to observe market developments before committing to a non-market path to compliance. Investment costs and total compliance costs are higher for the mass pathway, as discussed in Sections 5 and 6.

Section 5: Clean Power Plan Compliance with Inter-State Trading

The "island" compliance results in the previous section assumed Kansas relied on in-state compliance measures alone and did not participate in multi-state emissions trading markets. Emissions trading—through allowances when Kansas selects a mass pathway and ERCs under rate—creates opportunities to lower overall compliance costs.

National or regional markets are potential "backstop" options and strategic cost-containment mechanisms for CPP compliance. However, their size and depth are subject to significant uncertainty, and the use of these options creates tradeoffs between potentially lower costs (or lower price volatility) and reliance on markets. Therefore, increased allowance trading raises questions about recourse options if market are slow to develop, if liquidity problems arise, and if exposure to other regulatory shocks increases.

Trade of CO_2 allowances or emission rate credits may lower compliance costs but come at the expense of increased reliance on uncertain markets.

This section explores these questions and has three specific objectives:

1. To investigate the compliance balance between in-state investments and markets for allowances/ERCs
2. To understand how different "mixes" of compliance pathway selections in other states influence market outcomes for Kansas
3. To demonstrate opportunities to reduce cost through trade

Description of Scenarios and Trading Mixes

This section presents results for state plans that allow inter-state trading of ERCs or allowances in the case of rate-based or mass-based compliance pathways, respectively. Like the island scenarios, in-depth analyses are performed for the subcategory rate (denoted "RU") and the existing mass (denoted "MX") pathways.

Trading scenarios were developed using two "mixes" of alternative market outcomes to represent uncertainty about the selection of compliance pathways by individual states. These mixes are labeled "Mix1" and "Mix 2HP" for this analysis.

All mixes assume California and the Regional Greenhouse Gas Initiative (RGGI) states choose the full-mass pathway (i.e., with the new source complement), that California does not trade with other states, and that the RGGI states trade only within RGGI. All mixes assume that states with pending new nuclear units (i.e., Georgia, South Carolina, and Tennessee) choose the subcategory-rate pathway.

The mixes differ in how the rest of the states choose between the subcategory-rate and existing-mass pathways. Figure 5-1 shows maps documenting these selections.

Trading "mixes" represent potential developments of emission trading markets with alternate pathway selections for states.

- **Mix 1:** The first mix uses the above assumptions about full-mass states (California and RGGI) and subcategory-rate (states with new nuclear). All other states adopt existing-mass pathways. This scenario represents minimal adoption of rate programs among states and places a lower bound on participation.
- **Mix 2 High Plains (HP):** The second mix takes Mix 1 and adds seven other states to subcategory-rate trading: Colorado, Iowa, Wisconsin, North Dakota, South Dakota, Nebraska, and Oklahoma. These states were selected owing to previous EPRI analysis indicating this pathway could be economically attractive for these states under some states-of-the-world. This result is driven by the comparative attractiveness of new wind in the reference case due to state-specific resources and costs relative to other alternatives.

Note that it is not immediately obvious whether adding additional states to a rate-based trading market will increase or decrease market-clearing ERC prices. The addition of ERC compliance obligations is accompanied by new ERC supply resources, which are brought simultaneously into the trading system. For instance, if states with low ERC demand and high ERC supply join a rate markets, prices will fall (all else equal), whereas prices will rise if states with high ERC demand and low ERC supply join. These dynamics make it important to use modeling frameworks like US-REGEN to understand the implications of alternate pathway selections.

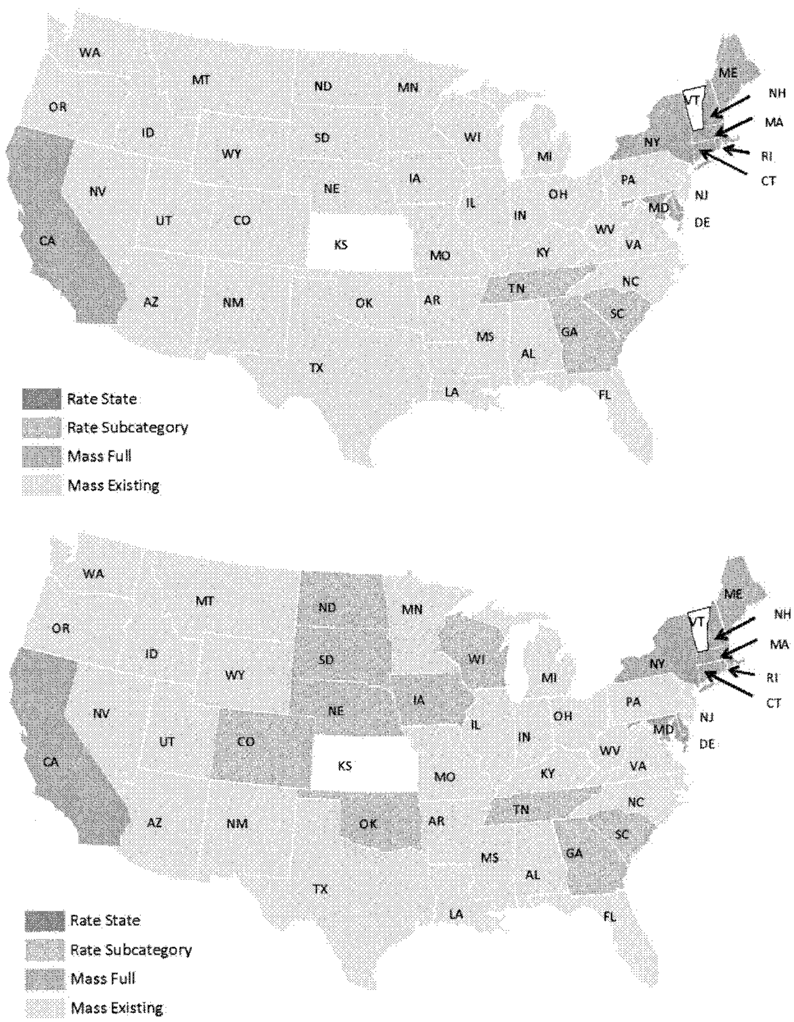
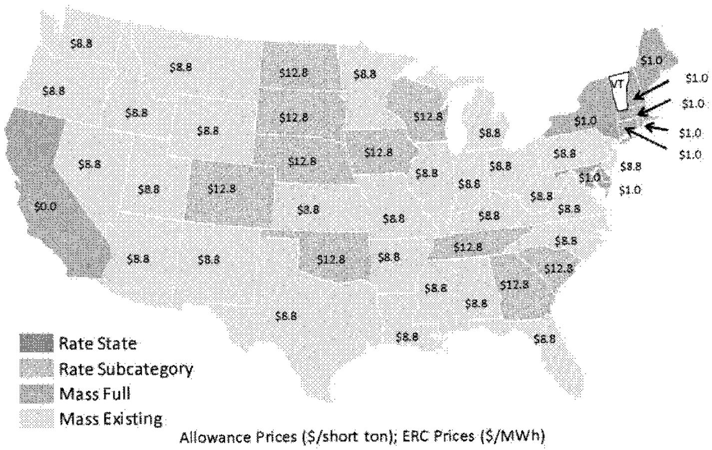


Figure 5-1
Maps of Clean Power Plan state compliance pathway assignments: Mix1 (top) and Mix2HP (bottom)

Generation and Investment Results for Kansas with Trading

Figure 5-2 shows the market-clearing allowance and ERC prices for each state under Mix2HP.[11]

[11] Associated market-clearing prices for each mix are discussed in the next section.



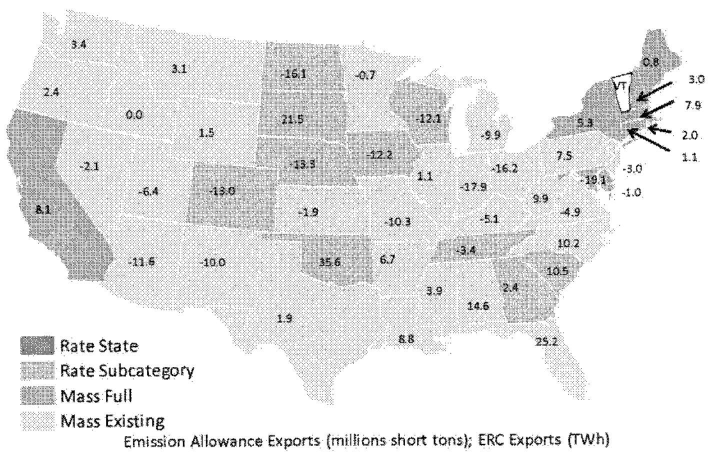


Figure 5-2
Map of "Mix2HP" CPP state compliance pathway assignments and emissions trading prices in 2030 calculated by EPRI's US-REGEN model[12] *(top) and net exports in 2030 (bottom)*

Comparing investments across the two patchwork trading mixes and "island" compliance scenarios suggests how robust near-term decisions may be under a range of potential futures. According to Figure 5-3, investments through 2030 show variation across the assumed policy

[12] The number superimposed on each state is the emission trading price calculated by US-REGEN. For mass-based states, this is an emission allowance price, denominated in $/short ton CO_2. For rate-based states, this is an ERC price, denominated in $/megawatt-hour of zero-emission generation (or avoided generation in the case of energy efficiency).

compliance selection and trading environment. Island compliance generally entails the most significant in-state capacity investments, but not in all cases. Note how the reference case capacity additions include almost 3 GW new wind, and the NGCC additions come through the Riverton Unit 12 conversion to combined cycle.

The additional investments under island scenarios suggests that potentially strandable investments can result from pursuing an exclusively in-state compliance strategy. Excessive investments under any scenario could later prove unnecessary if market opportunities emerge and could prove costly ~~ex post~~. These dynamics have important implications for the option value and timing of new investments and may be an incentive to avoid irreversible capital outlays in the presence of uncertainty about the future. The economic implications of these scenarios are discussed later.

Kansas' compliance without trade generally entails greater in-state capacity investments than scenarios with market participation.

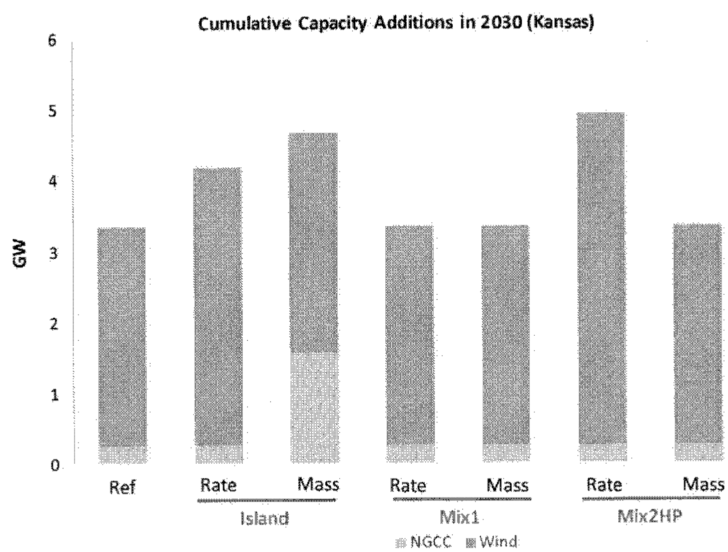


Figure 5-3
Comparison of cumulative capacity investments (gigawatts) in Kansas through 2030 under existing-mass and subcategory-rate compliance under different trading environments (reference shown on left)

Figure 5-4 shows 2030 generation in Kansas across these scenarios and pathways. Many existing units in Kansas remain competitive throughout the model's time horizon.[13] The CPP amplifies pre-existing trends in the

Kansas' compliance with trading involves the combined use of in-state measures and market purchases of credits.

[13] Note that US-REGEN does not include all costs incurred by coal units as they age (e.g., unit commitment constraints are not included in this version of the model). Including such costs could influence retirement and dispatch decisions.

power sector like coal-to-gas fuel switching and wind deployment. However, state decisions about CPP compliance paths and degree of market participation provide opportunities to influence the generation portfolio trajectory moving forward. Scenarios with inter-state allowance trading typically involve greater reliance on importing electricity, especially when Kansas adopts a mass pathway. Coal output is highest when Kansas selects rate-based pathways.

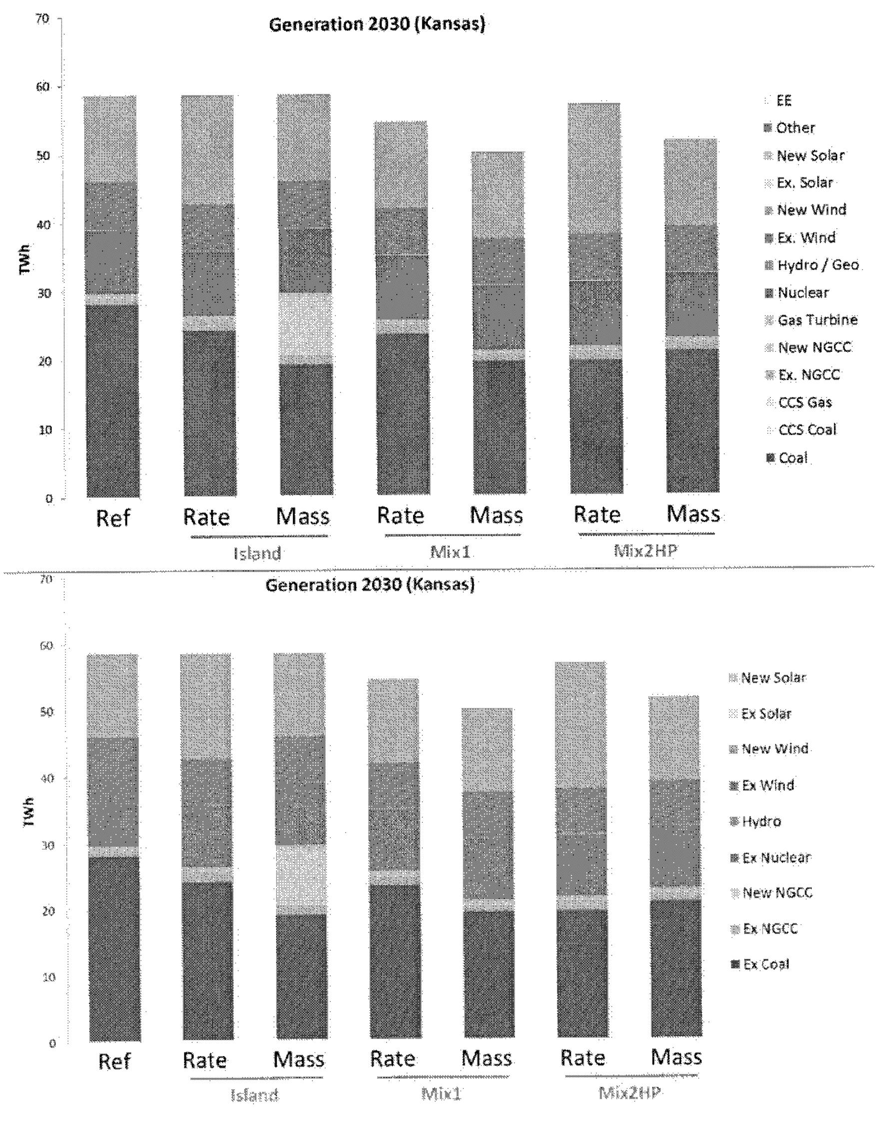


Figure 5-4
2030 electricity generation (terawatt-hours) in Kansas by technology under different trading environments and pathway selections

Figure 5-5 shows the installed capacities of Kansas' coal assets over time. For the reference scenario (black line in Figure 5-5), total coal capacity remains constant over time, as the low operating costs of these units make them economically competitive. The lines for mass- and rate-based CPP compliance for all trading scenarios overlap with the reference values, indicating that coal capacity for these classes does not change when the CPP is in place. This is also true of the scenarios where Kansas selects a rate-based pathway. Retirements only occur in mass-based island compliance scenarios. In these two scenarios, retirements occur primarily for the least efficient units and after 2030.

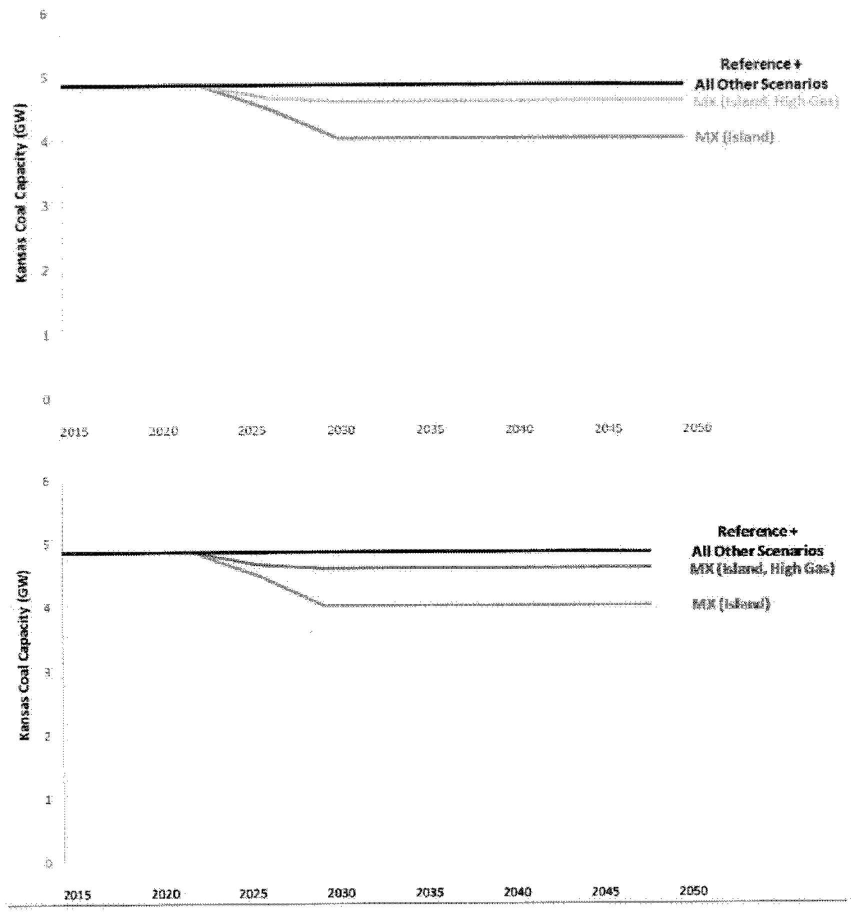


Figure 5-5
Coal capacity (gigawatts) in Kansas by CPP compliance scenarios

Assessing of Economic Outcomes with and without Trading

Comparing market-clearing permit prices over time offers one metric for evaluating CPP-related economic impacts. These marginal values reflect the stringency of the targets and, specifically, the cost of Kansas' compliance options relative to other states.[14] Figure 5-6 shows allowance prices for mass-based paths (top) and ERC prices for rate-based (bottom).

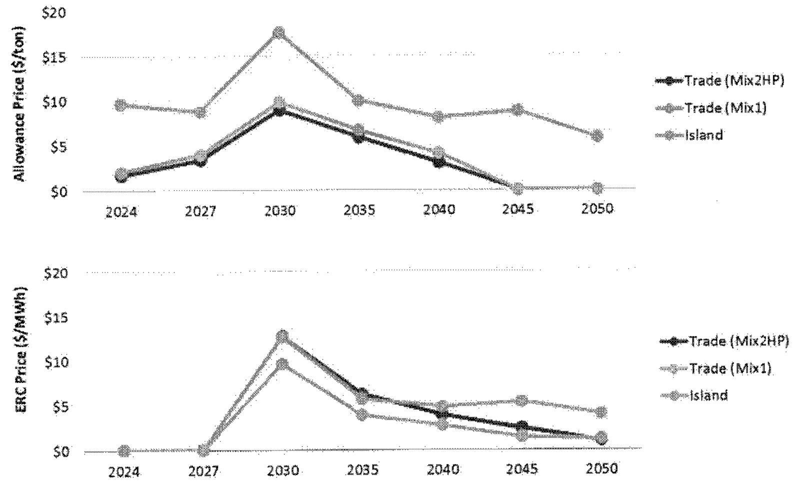


Figure 5-6
Kansas allowance prices ($ per short ton, top) and ERC prices ($ per MWh, bottom) over time for different trade assumptions

Prices under island compliance are typically higher than scenarios where multi-state trade is possible. Market participation lowers costs for Kansas but especially in early years of mass-based compliance owing to the difficulty of meeting early targets.

Market prices for most states tend to differ more under rate compliance than under mass compliance, reflecting less liquidity in the wider market for ERCs. The lower volatility in ERC prices is caused largely by the marginal mitigation option for compliance under rate- versus mass-based pathways. For existing-mass, the marginal compliance option is largely reducing coal generation and increasing generation from new NGCC units. Although the price differential between coal and gas causes some state-specific variation, these costs are largely the same between different regions. For rate, the marginal compliance option varies across mixes, and the cost of developing new wind, quality of existing resources, and total wind deployment exhibit significant regional heterogeneity, which is exacerbated by decreasing returns to scale. These dynamics underscore

[14] Note that ERC and CO_2 prices are useful metrics for comparisons in individual models, as higher price indicates more expensive mitigation options. However, price comparisons are invalid between models, since prices depend on a host of model-specific assumptions (e.g., reference, trading, capacity, and state resource assumptions).

the importance of modeling interactions between states in national markets to capture trading possibilities using a model like US-REGEN that captures simultaneous optimizing behavior by all states subject to meeting CPP goals.

Note how the ERC prices are highest under Mix2HP trading due to higher ERC demand under this trading mix. These higher values lead to greater investment in wind capacity in Kansas relative to the other trading pathways (Figure 5-3).

Figure 5-7 shows trade volumes for Kansas across these scenarios. Note how the (cost-minimizing) net trade position for Kansas is different for mass and rate compliance. When Kansas adopts a mass-based plan, the state is a net importer of allowances, especially after 2030. However, under a rate-based plan, Kansas is an exporter of ERCs for many periods. The higher ERC prices in Mix2HP trading lead to higher in-state wind investment and higher exports.

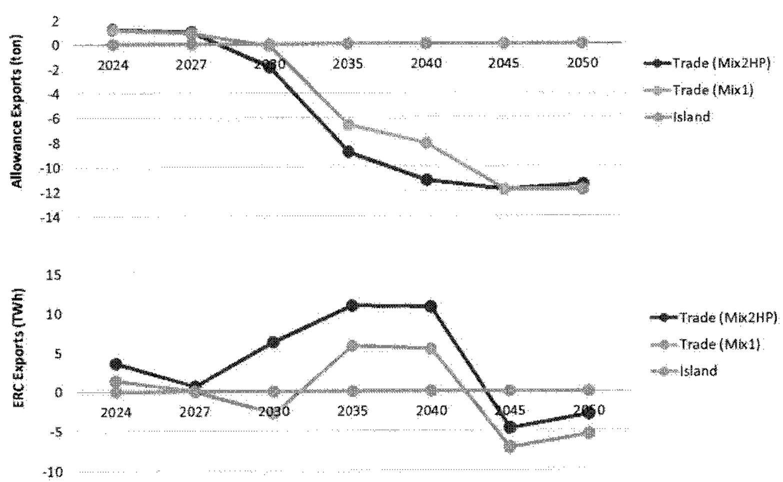


Figure 5-7
Kansas allowance (million short tons, top) and ERC (TWh, bottom) trade volume in net export terms over time for different trade assumptions

On a present value basis,[15] compliance costs for the subcategory-rate pathway are lower than the existing-mass pathway for island compliance but higher for the trading scenarios, as shown in Table 5-1. Recall that the definition of cost includes:

- All capital and operating costs

[15] The US-REGEN model works in present value terms, discounted back to 2015 at a discount rate of five percent.

- Cost of new transmission (evenly apportioned between states on the line) plus maintenance
- Regulatory costs (e.g., alternative compliance payments for RPS, etc.)
- Cost of imported electricity, priced at the marginal wholesale price of the exporting state (minus the cost of exported electricity)
- Net payments for Clean Power Plan credits/allowances

Table 5-1
Comparative incremental CPP policy costs to Kansas ($ billion) in present value terms (2015–2050) and as a percentage of the reference costs

	Policy Cost ($B)		% Reference	
	Rate	Mass	Rate	Mass
Island	0.32	0.79	1.2%	3.0%
Mix1 Trading	0.11	-0.06	0.5%	-0.3%
Mix2HP Trading	0.19	-0.13	0.8%	-0.5%

Examining the net present value of compliance costs is a useful complement to the marginal value comparisons in Figure 5-6. These CPP costs represent the sum of discounted incremental electric-sector costs over time above those incurred in the reference (i.e., no CPP) scenario.

Kansas' participation in inter-state trading lowers Clean Power Plan costs considerably regardless of whether a mass- or rate-based pathway is chosen.

Some mass-based paths entail net negative compliance costs for Kansas. These cases typically involve a greater reliance on electricity imports than the reference scenario and take advantage of opportunities to bring in power from neighboring states during periods with lower marginal wholesale prices. This lowers investment and O&M costs under the mass-based policy scenario, despite higher costs for importing allowances.

Another important takeaway is that encouraging trading lowers costs for Kansas considerably compared with the "island" scenarios where trade is more limited. This result holds for both rate and mass pathways, but the magnitude of the cost reduction from trade depends on pathway selections in other states.

Summary of Trading Scenarios for Kansas

Model results in this section indicate that encouraging trade lowers compliance costs for Kansas compared with "island" scenarios. The magnitude of this cost reduction from access to national markets and impact on in-state capacity investments depend on state pathway selections elsewhere. Despite its potential role in cost containment, market participation involves a tradeoff with increased uncertainty about the pace of market development, liquidity, volatility, and exposure to forces external to the state of Kansas.

Scenarios with trade underscore how pursuing in-state compliance strategies can increase the risk of stranded assets. As illustrated in Figure 5-3, CPP "island" scenarios entail greater capacity investments than the reference case or trade scenarios. If these in-state assets are built in early compliance periods and low-cost trading opportunities later become available, the opportunity cost of the unneeded units could be high.

Although this analysis offers insights for state-level CPP decision-making, model approximations and incomplete system dynamics suggest that it should not be construed as a definitive determination of CPP planning for Kansas. Each state's preferred portfolio of compliance measures (e.g., in-state actions and market participation) will be informed by a range of factors, including in-state compliance costs, risk tolerance, local incentives, and assumptions about market liquidity and participation. Actual deployment may depend on additional factors (e.g., policy, permitting, and uncertainty) that fall outside of the scope of this economic modeling and analysis.

Section 6: Sensitivity Analyses

A series of sensitivity analyses was undertaken to explore how key uncertainties affect the relative costs of Clean Power Plan compliance under the rate versus mass pathways. In addition to the sensitivities of CPP path choices in the previous section, six key uncertainties were examined, including:

- Alternate natural gas price paths
- Alternate costs of new wind capacity (both higher and lower costs)
- Transmission additions between Kansas and Indiana
- Possible post-2030 U.S. CO_2 cap
- Lower coal lifetimes of 70 years
- Negative load growth

Some sensitivities were varied jointly (e.g., natural gas prices and wind costs) to capture possible interactions between these assumptions. Table 6-1 summarizes the scenarios resulting from examining these uncertainties with different combinations of mass and rate CPP compliance (and alternate trading assumptions).

Table 6-1
Master scenario list

Set	Background Assumptions							CPP Pathway			What we learn
	ROC Policy	Gas Price	Wind Cost	Transm.	U.S. CO_2 Cap	Coal Life	Load	RU	MX	KP	
1	Island	Low	Ref	Ref	None	Ref	Ref	1	2	3	State comparative advantage
2	Mix1	Low	Ref	Ref	None	Ref	Ref	4	5	6	Rate/mass comparison in alt. realistic setting
	Mix2HP	Low	Ref	Ref	None	Ref	Ref	7	8	9	
3	Island	High	Ref	Ref	None	Ref	Ref	10	11	12	How alternate gas price paths affect comparative pathway choices
	Mix1	High	Ref	Ref	None	Ref	Ref	13	14	15	
	Mix2HP	High	Ref	Ref	None	Ref	Ref	16	17	18	
	Mix1	High	High	Ref	None	Ref	Ref	19	20	21	
	Mix2HP	High	High	Ref	None	Ref	Ref	22	23	24	
	Mix1	High	Low	Ref	None	Ref	Ref	25	26	27	
	Mix2HP	High	Low	Ref	None	Ref	Ref	28	29	30	
4	Mix1	Low	Low	Ref	None	Ref	Ref	31	32	33	Impact of low/high wind costs on pathway choices
	Mix2HP	Low	Low	Ref	None	Ref	Ref	34	35	36	
	Mix1	Low	Ref	KS-IN	None	Ref	Ref	37	38	39	Impact of Kansas-Indiana transmission
	Mix2HP	Low	Ref	KS-IN	None	Ref	Ref	40	41	42	
	Mix1	High	Ref	KS-IN	None	Ref	Ref	43	44	45	
	Mix2HP	High	Ref	KS-IN	None	Ref	Ref	46	47	48	
	Mix1	Low	Ref	Ref	80% by 2050	Ref	Ref	49	50	51	Impact of a post-2030 U.S. CO_2 emissions cap (80% by 2050) on pathway choices
	Mix2HP	Low	Ref	Ref	80% by 2050	Ref	Ref	52	53	54	
	Mix1	High	Ref	Ref	80% by 2050	Ref	Ref	55	56	57	
	Mix2HP	High	Ref	Ref	80% by 2050	Ref	Ref	58	59	60	
	Mix1	Low	Ref	Ref	None	70	Ref	61	62	63	Impact of 70-year coal lifetime
	Mix2HP	Low	Ref	Ref	None	70	Ref	64	65	66	
	Mix1	Low	Ref	Ref	None	Ref	-1%	67	68	69	Impact of negative load growth
	Mix2HP	Low	Ref	Ref	None	Ref	-1%	70	71	72	

Notes: ROC = rest of country
Island = all states comply in isolation; no incremental power flows
RU = Subcategory (Unit) Rate
MX = Existing Mass (but with output-based set-asides)
KP = Kansas Plan
Low/High Wind Cost = -/+ 20% in wind costs

Set	Background Assumptions							CPP Pathway		What we learn
	ROC Policy	Gas Price	Wind Cost	Transm.	U.S. CO_2 Cap	Coal Life	Load	RU	MX	
1	Island	Low	Ref	Ref	None	Ref	Ref	1	2	State comparative advantage
2	Mix1	Low	Ref	Ref	None	Ref	Ref	3	4	Rate/mass comparison in alt. realistic setting
	Mix2HP	Low	Ref	Ref	None	Ref	Ref	5	6	
3	Island	High	Ref	Ref	None	Ref	Ref	7	8	How alternate gas price paths affect comparative pathway choices
	Mix1	High	Ref	Ref	None	Ref	Ref	9	10	
	Mix2HP	High	Ref	Ref	None	Ref	Ref	11	12	
	Mix1	High	High	Ref	None	Ref	Ref	13	14	
	Mix2HP	High	High	Ref	None	Ref	Ref	15	16	
	Mix1	High	Low	Ref	None	Ref	Ref	17	18	
	Mix2HP	High	Low	Ref	None	Ref	Ref	19	20	
4	Mix1	Low	Low	Ref	None	Ref	Ref	21	22	Impact of low/high wind costs on pathway
	Mix2HP	Low	Low	Ref	None	Ref	Ref	23	24	
	Mix1	Low	Ref	KS-IN	None	Ref	Ref	25	26	Impact of Kansas-Indiana transmission
	Mix2HP	Low	Ref	KS-IN	None	Ref	Ref	27	28	
	Mix1	High	Ref	KS-IN	None	Ref	Ref	29	30	
	Mix2HP	High	Ref	KS-IN	None	Ref	Ref	31	32	
	Mix1	Low	Ref	Ref	80% by 2050	Ref	Ref	33	34	Impact of a post-2030 U.S. CO_2 emissions cap (80% by 2050) on pathway choices
	Mix2HP	Low	Ref	Ref	80% by 2050	Ref	Ref	35	36	
	Mix1	High	Ref	Ref	80% by 2050	Ref	Ref	37	38	
	Mix2HP	High	Ref	Ref	80% by 2050	Ref	Ref	39	40	
	Mix1	Low	Ref	Ref	None	70	Ref	41	42	Impact of 70-year coal lifetime
	Mix2HP	Low	Ref	Ref	None	70	Ref	43	44	
	Mix1	Low	Ref	Ref	None	Ref	-1%	45	46	Impact of negative load growth
	Mix2HP	Low	Ref	Ref	None	Ref	-1%	47	48	

Notes: ROC = rest of country
Island = all states comply in isolation; no incremental power flows
RU = Subcategory (Unit) Rate
MX = Existing Mass (but with output-based set-asides)
Low/High Wind Cost = -/+ 20% in wind costs

Sensitivity Analysis Descriptions and Results

Natural Gas Prices

Natural gas price uncertainty is represented through the "high price path" shown in Figure 6-1. This path is set to match the U.S. Department of Energy's 2015 Annual Energy Outlook Reference path. Note that the "low price path" shown in Figure 6-1 was used as the reference price in earlier sections of this study. This path matches the AEO 2015 high estimated ultimate recovery (HEUR) path but is still higher than NYMEX Henry Hub prices.[16]

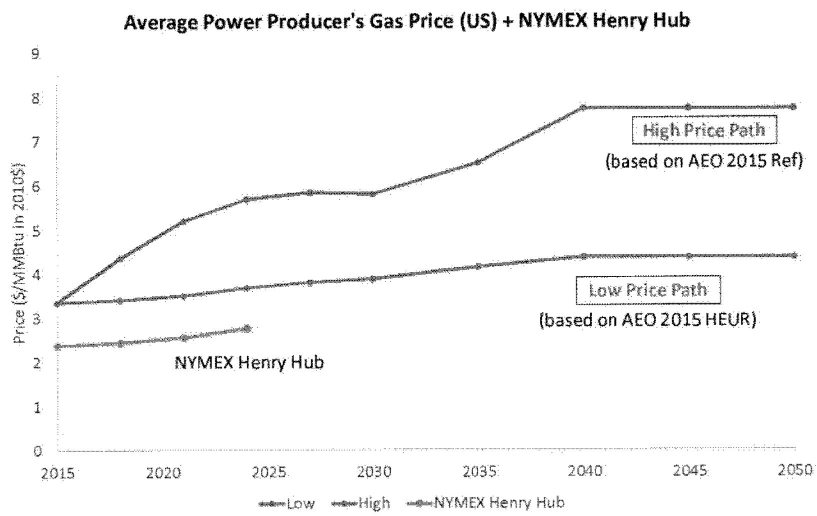


Figure 6-1
Natural gas price paths over time ($ per MMBtu, real terms) for the low and high gas price scenarios

High natural gas prices lead to much higher wind development in Kansas, even in the reference case.

The assumed trajectory of gas prices has important implications on the capacity and generation mix for Kansas. Figure 6-2 compares Kansas' generation under the reference case with low and high gas prices. The high natural gas price path encourages more new wind in Kansas even without the CPP. Exports also increase early in the time horizon as in-state coal units increase output. After 2030, higher gas prices prevent new NGCC deployment, and Kansas' high-capacity-factor and low-cost wind resources lead to significant investments in new wind generation (12.7 GW by 2050). Exports from Kansas to neighboring states with higher

[16] Figure A-4 in Appendix A compares these price trajectories with the updated 2016 Annual Energy Outlook natural gas price scenarios.

wind costs also increase under high gas prices (32.8 TWh in 2050 versus 11.4 with low gas prices).

Note how the high-gas-price scenario is one of many potential drivers of high wind development. Many insights about CPP pathways under these scenarios are also applicable to other environments with significant wind buildouts in Kansas.

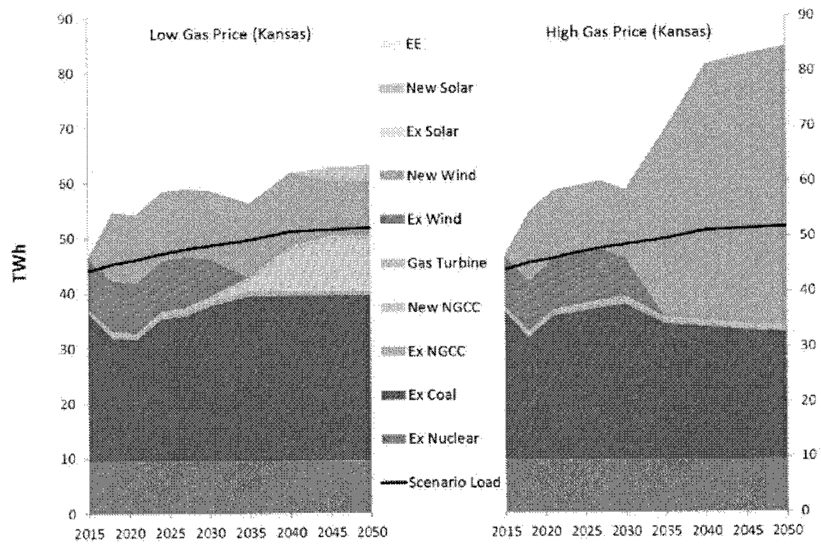


Figure 6-2
Electricity generation (terawatt-hours) by technology in Kansas under reference (i.e., no CPP) scenarios with low gas prices (left) and high gas prices (right)

The new wind in the reference scenario means that Kansas is likely in compliance with CPP rate targets beginning in 2035. However, some fraction of this extensive capacity additions would have to be accelerated to reach rate goals in 2030, which accounts for the additional investments in Figure 6-3. When Kansas participates in ERC and allowance markets, pathway decisions in other states have a larger impact on Kansas capacity additions when gas prices are higher. Due to the state's export potential, some trading scenarios (e.g., those with higher installed wind) entail greater capacity investment than the island compliance scenario.

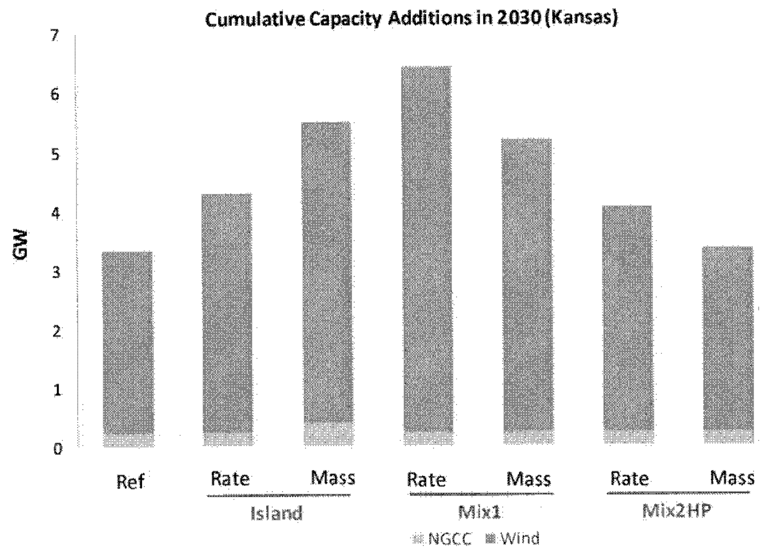
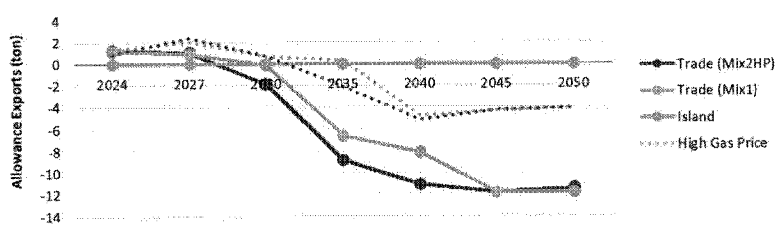


Figure 6-3
Cumulative capacity investments (gigawatts) in Kansas through 2030 under mass and rate compliance under different trading environments (assuming high natural gas prices)

Higher gas prices and wind capacity deployment also impact Kansas' trading incentives in allowance and ERC markets when it chooses a mass or rate path, respectively. When Kansas chooses mass, its net allowance trade position narrows, as shown in Figure 6-4. The wind generation not only leads to greater electricity exports, but it also creates more allowances that Kansas uses in-state instead of relying as much on allowance imports (as it does with lower gas prices in Figure 5-7). When Kansas selects the rate pathway, it becomes a significant ERC exporter after 2030.



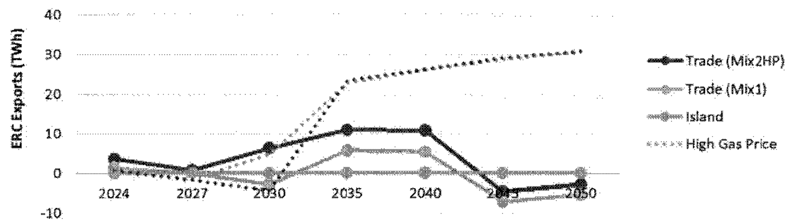


Figure 6-4
Kansas allowance (million short tons, top) and ERC (TWh, bottom) trade volume in net export terms over time for different trade and gas price assumptions

Table 6-2 demonstrates how these alternate gas price scenarios influence CPP compliance costs for Kansas. The economics of wind are more attractive in the reference case, which means that the subcategory-rate pathway minimizes cost for some scenarios with high gas prices.

Table 6-2
Comparative incremental CPP policy costs to Kansas ($ billion) in present value terms (2015–2050) and as a percentage of the reference costs

Set	Background Assumptions							Policy Cost ($B)		% Reference	
	ROC Policy	Gas Price	Wind Cost	Transm.	U.S. CO_2 Cap	Coal Life	Load	RU	MX	RU	MX
1	Island	Low	Ref	Ref	None	Ref	Ref	0.32	0.79	1.2%	3.0%
2	Mix1	Low	Ref	Ref	None	Ref	Ref	0.11	-0.06	0.5%	-0.3%
	Mix2HP	Low	Ref	Ref	None	Ref	Ref	0.19	-0.13	0.8%	-0.5%
3	Island	High	Ref	Ref	None	Ref	Ref	0.09	1.18	0.3%	3.6%
	Mix1	High	Ref	Ref	None	Ref	Ref	0.20	0.44	0.8%	1.7%
	Mix2HP	High	Ref	Ref	None	Ref	Ref	0.17	0.25	0.6%	1.0%
	Mix1	High	High	Ref	None	Ref	Ref	-0.03	0.22	-0.1%	0.8%
	Mix2HP	High	High	Ref	None	Ref	Ref	0.09	0.27	0.4%	1.0%
	Mix1	High	Low	Ref	None	Ref	Ref	0.23	0.61	0.9%	2.3%
	Mix2HP	High	Low	Ref	None	Ref	Ref	0.10	0.62	0.4%	2.4%

Costs of Wind

In this sensitivity, the cost of wind energy is discounted by 20 percent so that the installed cost of new capacity is $1,200/kW.[17]

Figure 6-5 shows how these lower wind costs impact lead to slightly higher wind generation, especially after 2030. Table 6-3 indicates that, although lower wind costs bring some new capacity online, natural gas price assumptions have a larger impact on investments and CPP compliance costs.

[17] Solar cost decreases of 20% did not change the results and were not included.

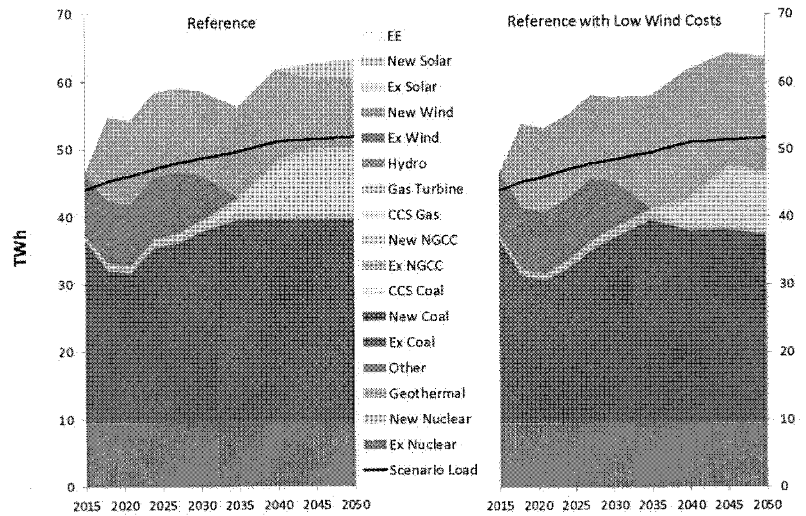


Figure 6-5
Electricity generation (terawatt-hours) by technology in Kansas under reference (i.e., no CPP) scenarios with reference wind costs (left) and low costs (right)

***Transmission Additions to Indiana** (Grain Belt Express)*

This sensitivity explores a scenario where transmission capacity can be added between Kansas and Indiana in addition to its four adjacent neighboring states.

When transmission capacity can be added between these states, additional wind capacity is constructed in Kansas under the CPP compliance scenarios. Figure 6-6 shows how cumulative additions through 2030 are influenced by different gas prices, pathway choices in Kansas, and transmission expansion. Price differentials between regions creates a lucrative electricity export market for Kansas, especially when Kansas chooses a rate pathway (and wind can generate excess ERCs to sell on the market) and natural gas prices are higher (and other states find it cheaper to meet load by importing electricity from Kansas rather than building new in-state capacity).

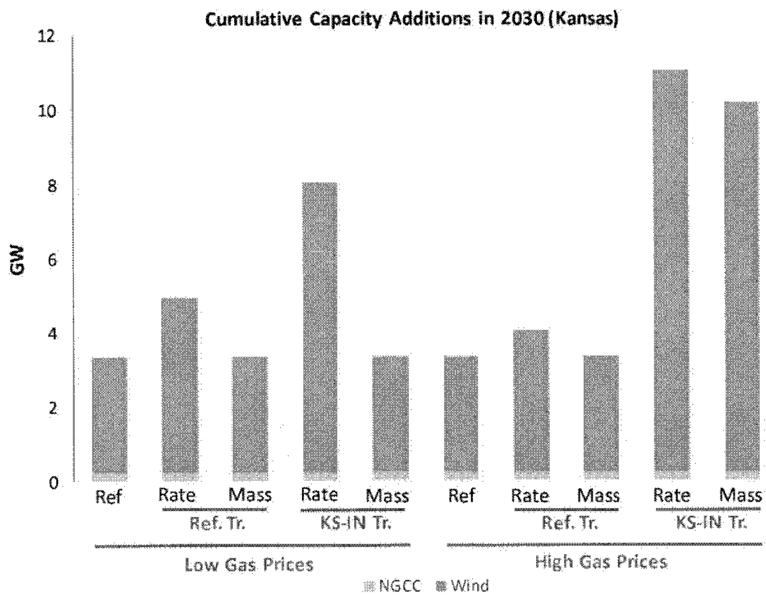


Figure 6-6
Cumulative capacity investments (gigawatts) in Kansas through 2030 under mass and rate CPP compliance with Mix2HP trading under different gas prices and transmission sensitivities (reference transmission assumptions and a sensitivity where Kansas-Indiana transmission can be added)

Post-2030 U.S. CO_2 Cap

This sensitivity considers a case where a post-2030 policy imposes a power sector only CO_2 cap of 80% below 2005 levels by 2050 (beginning with a 50% cap in 2035 and decreasing linearly to the 2050 target).

Figure 6-7 shows that a majority of new capacity additions occur after 2030. The anticipation of a certain and stringent cap after 2030 does not considerably alter investments before 2030. Under low gas prices, fewer than 5 GW new wind capacity is built regardless of whether a stringent post-2030 cap on CO_2 emissions is anticipated. This result suggests that, for Kansas, the CPP does not force appreciable deviations from what would be useful later.

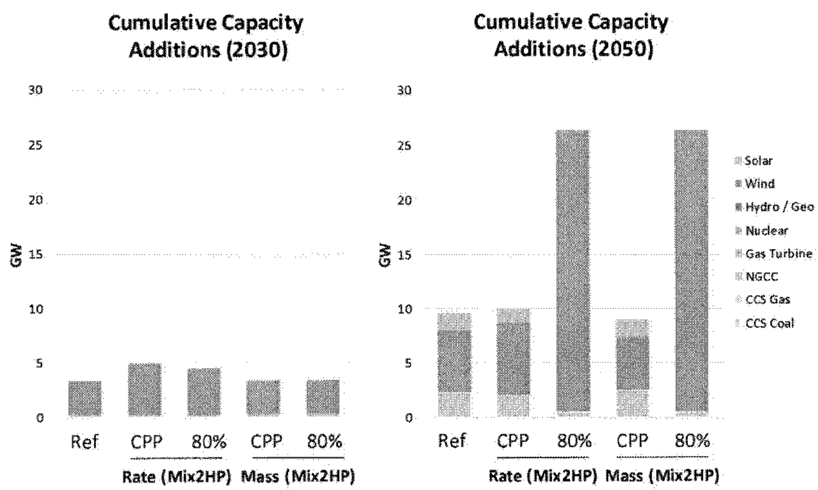


Figure 6-7
Cumulative capacity installations in Kansas through 2030 (left) and 2050 (right) under rate and mass CPP compliance without ("CPP") and with a post-2030 CO_2 cap ("80%"), assuming low natural gas prices

Due to Kansas' high-quality wind resources, stringent national CO_2 targets involve significant wind build-outs in the state by 2050 and electricity exports to neighboring regions. Figure 6-8 demonstrates how Kansas' 2050 generation could be very different under alternate assumptions about post-2030 policies. The reference scenario generation is relatively similar to the CPP scenarios in 2050, as the latter has slightly higher wind and NGCC generation. In contrast, generation in Kansas under a nationwide 80% cap is largely comprised of wind and existing nuclear. Total generation under the 80% with low gas prices is approximately 100 TWh by 2050, which is twice as high as in-state demand. When high gas prices are assumed, wind generation in Kansas is even higher, and total in-state generation is three to four times in-state demand by 2050 (Figure 6-8).

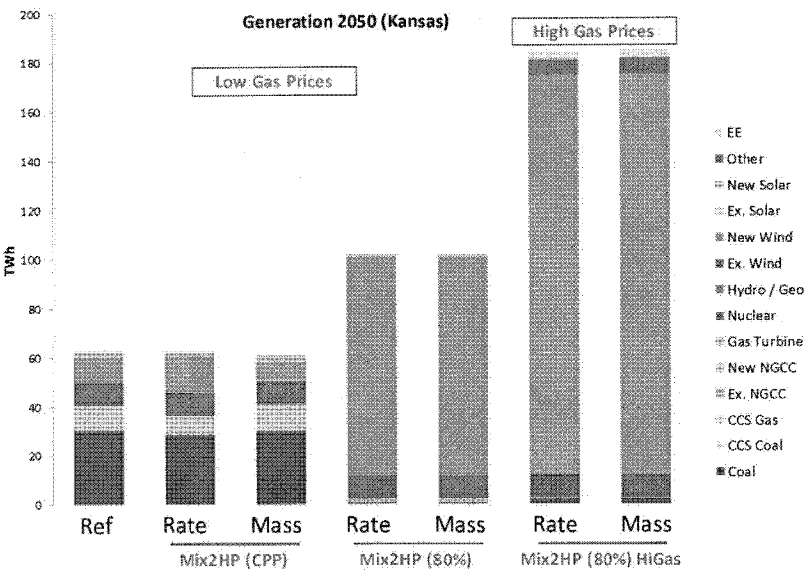


Figure 6-8
2050 electricity generation (terawatt-hours) in Kansas by technology under different pathway selections, gas prices, and post-2030 policies

70-Year Coal Lifetime

This sensitivity assumes that all coal assets in Kansas retire after 70 years instead of endogenously retiring units based on their economic competitiveness. As shown in Figure 6-9, coal retirements lead to lower generation after 2040 and greater deployment of NGCC capacity through 2050. This transition leads to slightly lower incremental CPP compliance costs for both rate and mass pathways in Kansas.

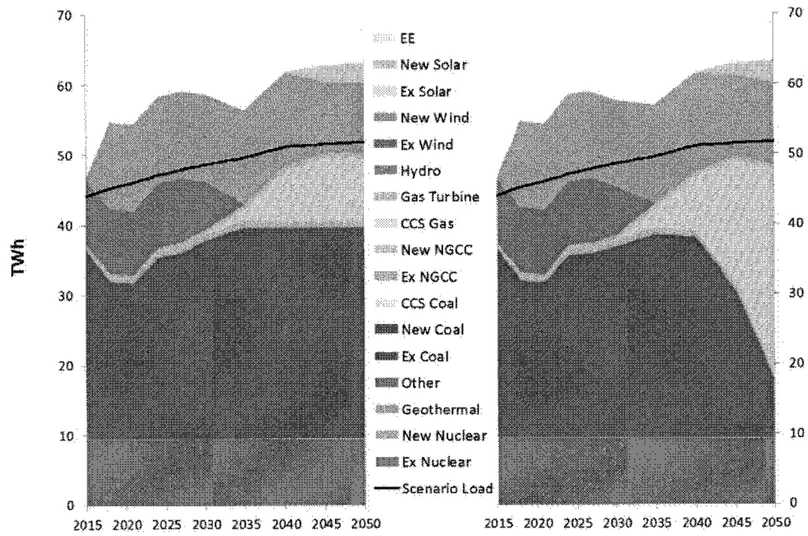


Figure 6-9
Electricity generation (terawatt-hours) by technology in Kansas under reference (i.e., no CPP) scenarios with endogenous coal lifetimes (left) and exogenous 70-year coal lifetimes (right)

Load Growth

Load growth in US-REGEN averages 0.54% through 2050, which is based on 2015 Annual Energy Outlook values. This sensitivity scenario assumes negative growth across the time horizon.

Figure 6-10 shows how reference generation under negative load growth erodes incentives to build new in-state capacity, especially new NGCC after 2030. However, incremental CPP compliance costs are roughly the same for the rate and mass pathways as for the higher load growth reference scenario (see Table 6-3 in the following subsection).

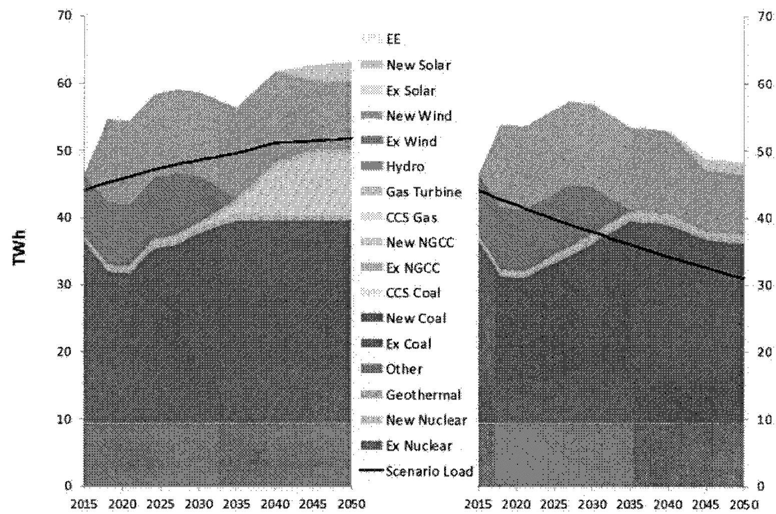


Figure 6-10
Electricity generation (terawatt-hours) by technology in Kansas under reference (i.e., no CPP) scenarios with AEO load growth (left) and negative growth (right)

Incremental Clean Power Plan Cost Comparisons across Scenarios

Given the previous conclusions, these sensitivities evaluate the robustness of a mass- and rate-based plans for Kansas by comparing total CPP compliance costs across all scenarios. Table 6-3 provides an overview of the sensitivity results. The right-hand columns show the incremental policy cost for the two pathways in absolute terms (in billion $, present value through 2050) and as a percentage of the reference (i.e., no CPP) cost. The column on the far right shows the cost-minimizing pathway.

Table 6-3
Comparative incremental CPP policy costs to Kansas ($ billion) in present value

terms (2015–2050) and as a percentage of the reference costs under subcategory-rate (RU) and existing-mass (MX) pathways

Set	Background Assumptions							Policy Cost ($B)		% Reference		
	ROC Policy	Gas Price	Wind Cost	Transm.	U.S. CO_2 Cap	Coal Life	Load	RU	MX	RU	MX	
1	Island	Low	Ref	Ref	None	Ref	Ref	0.32	0.79	1.2%	3.0%	RU
2	Mix1	Low	Ref	Ref	None	Ref	Ref	0.11	-0.06	0.5%	-0.3%	MX
	Mix2HP	Low	Ref	Ref	None	Ref	Ref	0.19	-0.13	0.8%	-0.5%	MX
3	Island	High	Ref	Ref	None	Ref	Ref	0.09	1.18	0.3%	3.6%	RU
	Mix1	High	Ref	Ref	None	Ref	Ref	0.20	0.44	0.8%	1.7%	RU
	Mix2HP	High	Ref	Ref	None	Ref	Ref	0.17	0.25	0.6%	1.0%	RU
	Mix1	High	High	Ref	None	Ref	Ref	-0.03	0.22	-0.1%	0.8%	RU
	Mix2HP	High	High	Ref	None	Ref	Ref	0.09	0.27	0.4%	1.0%	RU
	Mix1	High	Low	Ref	None	Ref	Ref	0.23	0.61	0.9%	2.3%	RU
	Mix2HP	High	Low	Ref	None	Ref	Ref	0.10	0.62	0.4%	2.4%	RU
4	Mix1	Low	Low	Ref	None	Ref	Ref	0.09	-0.01	0.4%	0.0%	MX
	Mix2HP	Low	Low	Ref	None	Ref	Ref	0.06	-0.01	0.3%	-0.1%	MX
	Mix1	Low	Ref	KS-IN	None	Ref	Ref	0.08	0.18	0.3%	0.7%	RU
	Mix2HP	Low	Ref	KS-IN	None	Ref	Ref	0.23	0.00	0.9%	0.0%	MX
	Mix1	High	Ref	KS-IN	None	Ref	Ref	0.74	1.36	2.5%	4.7%	RU
	Mix2HP	High	Ref	KS-IN	None	Ref	Ref	0.89	0.93	3.0%	3.2%	RU
	Mix1	Low	Ref	Ref	80% by 2050	Ref	Ref	-0.08	-0.14	-0.3%	-0.5%	MX
	Mix2HP	Low	Ref	Ref	80% by 2050	Ref	Ref	-0.04	-0.14	-0.1%	-0.5%	MX
	Mix1	High	Ref	Ref	80% by 2050	Ref	Ref	2.68	2.82	9.2%	9.7%	RU
	Mix2HP	High	Ref	Ref	80% by 2050	Ref	Ref	2.63	2.76	9.0%	9.5%	RU
	Mix1	Low	Ref	Ref	None	70	Ref	-0.01	-0.08	0.0%	-0.3%	MX
	Mix2HP	Low	Ref	Ref	None	70	Ref	0.15	-0.15	0.6%	-0.6%	MX
	Mix1	Low	Ref	Ref	None	Ref	-1%	0.17	-0.23	12.9%	-23.0%	MX
	Mix2HP	Low	Ref	Ref	None	Ref	-1%	0.01	-0.01	0.6%	-1.2%	MX

Table 6-3 indicates that existing-mass and subcategory-rate pathways can minimize compliance costs for Kansas depending on the sensitivity.

Many mass-based sensitivities involve net negative compliance costs for Kansas. These cases generally involve a greater reliance on electricity imports than the reference (i.e., no CPP) scenario and take advantage of opportunities to bring in power from neighboring states during hours with lower marginal wholesale prices than the reference case. This lowers investment and O&M costs under the mass-based policy scenario, despite higher costs for importing allowances.

Figure 6-11 plots sensitivity results to illustrate relative costs of the mass- or rate-based pathways. The dashed 45-degree isoquant line shows the domain where the mass and rate pathways are of equal cost. Points falling above this line indicate scenarios where the mass path is costlier, while values falling below the line indicate that the rate path is costlier.

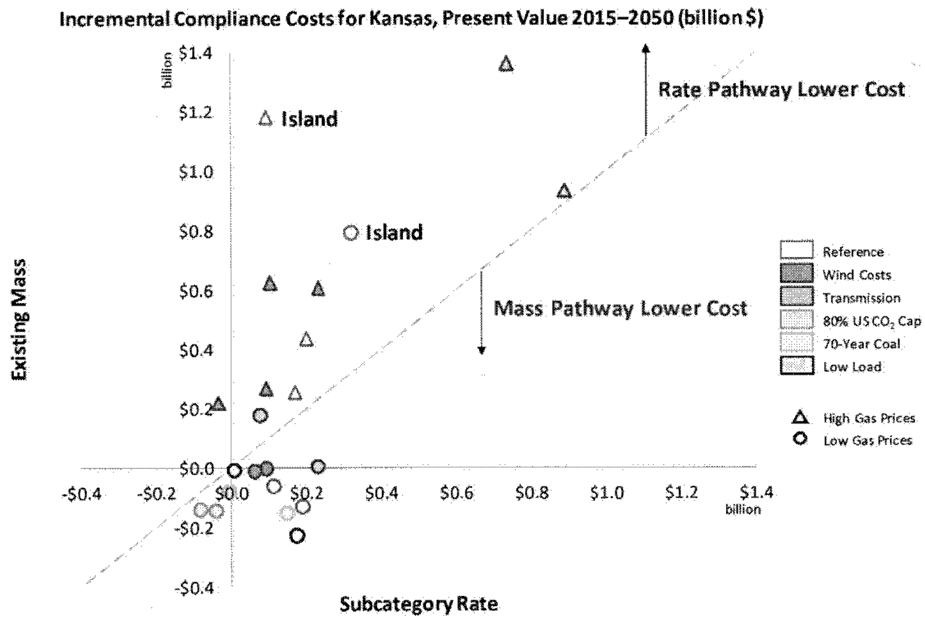


Figure 6-11
Comparison of incremental compliance costs of the Clean Power Plan for Kansas (billion $, present value through 2050) under existing-mass and subcategory-rate compliance pathways under a range of scenarios

This figure demonstrates how scenarios where the mass path entails higher compliance costs for Kansas can be significantly costlier. In the limited scenarios where mass is lower cost, the cost advantage is small. In contrast, the cost advantage of the rate pathway for Kansas is large under many scenarios. Unlike other states, Kansas' costs are influenced more when it picks the mass pathway than the rate, which leads to more total compliance cost variation associated with existing-mass.

When Kansas selects the mass path, costs range from -$0.2 to +$2.8 billion through 2050. Sensitivities that give rise to cheaper mass compliance are ones with lower wind generation and net imports, which leads to negative compliance costs.

Figure 6-11 indicates how trade can considerably lower compliance costs for Kansas regardless of the selected pathway. Participating in permit markets can potentially lower Kansas' compliance costs by millions of dollars (present value terms through 2050), though the magnitude depends on Kansas' selected pathway and compliance mixes elsewhere.

Note that gas prices and wind costs are large drivers of outcomes, as futures that incent high wind development in Kansas will make the rate pathway comparably more attractive. However, if decision-makers are reasonably confident that natural gas prices will not be high, then the mass pathway likely minimizes cost for Kansas.

Table 6-4
Comparative incremental CPP policy costs to Kansas ($ billion) in present value terms (2015–2030) and as a percentage of the reference costs under subcategory-rate (RU) and existing-mass (MX) pathways

Set	Background Assumptions							Policy Cost ($B)	
	ROC Policy	Gas Price	Wind Cost	Transm.	U.S. CO_2 Cap	Coal Life	Load	RU	MX
1	Island	Low	Ref	Ref	None	Ref	Ref	0.59	0.70
2	Mix1	Low	Ref	Ref	None	Ref	Ref	-0.09	-0.20
	Mix2HP	Low	Ref	Ref	None	Ref	Ref	0.89	-0.17
3	Island	High	Ref	Ref	None	Ref	Ref	0.65	1.74
	Mix1	High	Ref	Ref	None	Ref	Ref	1.95	1.23
	Mix2HP	High	Ref	Ref	None	Ref	Ref	0.52	0.05
	Mix1	High	High	Ref	None	Ref	Ref	1.19	0.10
	Mix2HP	High	High	Ref	None	Ref	Ref	1.27	0.03
	Mix1	High	Low	Ref	None	Ref	Ref	1.58	2.43
	Mix2HP	High	Low	Ref	None	Ref	Ref	0.15	1.50
4	Mix1	Low	Low	Ref	None	Ref	Ref	0.11	-0.11
	Mix2HP	Low	Low	Ref	None	Ref	Ref	0.34	-0.05
	Mix1	Low	Ref	KS-IN	None	Ref	Ref	0.48	0.06
	Mix2HP	Low	Ref	KS-IN	None	Ref	Ref	2.72	-0.07
	Mix1	High	Ref	KS-IN	None	Ref	Ref	2.16	4.36
	Mix2HP	High	Ref	KS-IN	None	Ref	Ref	2.86	2.19
	Mix1	Low	Ref	Ref	80% by 2050	Ref	Ref	0.00	-0.15
	Mix2HP	Low	Ref	Ref	80% by 2050	Ref	Ref	0.59	-0.15
	Mix1	High	Ref	Ref	80% by 2050	Ref	Ref	2.61	3.99
	Mix2HP	High	Ref	Ref	80% by 2050	Ref	Ref	1.25	2.74
	Mix1	Low	Ref	Ref	None	70	Ref	-0.05	-0.14
	Mix2HP	Low	Ref	Ref	None	70	Ref	0.62	-0.13
	Mix1	Low	Ref	Ref	None	Ref	-1%	-0.09	-0.26
	Mix2HP	Low	Ref	Ref	None	Ref	-1%	0.04	-0.20

Table 6-4 shows incremental compliance costs through 2030 (instead of through 2050 like Table 6-3). The higher costs through 2030 for many scenarios reflects the cost profile of capital investments over time. The reference scenarios for Kansas often involve large expenditures after 2030, which mean that the incremental compliance costs of the CPP are frequently higher in earlier periods.

Section 7: Summary

The analysis by the Electric Power Research Institute investigates state-level Clean Power Plan choices in Kansas. It focuses on existing-mass and subcategory-rate CPP pathways with and without market participation under a range of sensitivities.

EPRI's US-REGEN model was used to compare CPP results to reference scenarios (i.e., without the CPP) to understand tradeoffs between Kansas' planning options. In addition to rate and mass pathways, the analysis considers alternate trading scenarios to understand how reliance on in-state measures versus participation in multi-state emissions trading markets influence outcomes.

Kansas' business-as-usual generation mix without the CPP would likely be out of compliance with mass and rate targets for many periods and scenarios (Figures 3-4 and 3-5), which means the state would have to take additional measures (either changes to the fleet or purchases of allowances/ERCs) to close this compliance gap. Regardless of gas prices, planned wind capacity installations in Kansas through 2018 help with rate-based compliance and give additional lead time before incremental CPP-related investments have to be made toward 2030. Although these new builds would aid compliance in early periods, additional effort would be needed to reach later goals.

Key Takeaway 1: Neither the mass- nor rate-based Clean Power Plan pathway dominates for Kansas across all scenarios.

The analysis suggests that strong cases can be made for mass- and rate-based pathways, though neither path dominates. Results are driven strongly by the comparative incentives of building new natural gas combined cycle (NGCC) units relative to wind. When gas prices are low, new NGCC units may be built under reference conditions, which would likely make **existing-mass** (implemented with leakage provisions per the proposed federal plan) a lower cost CPP pathway for Kansas. This conclusion is robust to key uncertainties (Figure 6-11), including pathway selections elsewhere, more stringent post-2030 climate policies, existing asset lifetimes, and load projections.

When gas prices are high and/or wind costs are low, the economics of new wind capacity in Kansas are favorable even without the CPP due to the state's high resource potential. Exports under these conditions increase considerably, and the **subcategory-rate** pathway would align more closely with these investments.

Depending on how uncertainties resolve, the primary elements of CPP compliance strategies for Kansas could include:

- Lowering coal in-state generation through retirements and/or lower utilization (Figure 5-4 and 5-5)
- Constructing new natural gas combined cycle or wind capacity to comply with the state's chosen mass or rate pathway (Figures 5-3 and 6-3)
- Trading CO2 allowances or emission rate credits if mass- or rate-based pathways are chosen by the state, respectively (Figures 5-7 and 6-4)

Given uncertainty about pathway selections by other states, rate-based trade involves lower variability in total compliance costs (Table 6-3) and in-state capacity retirements (Figure 5-5). Increases in trade activity beyond 2030 are largely exports from Kansas, which are highest under high wind deployment scenarios and rate-based compliance.

Key Takeaway 2: Encouraging trading lowers costs in Kansas considerably compared with strategies that rely on in-state measures only.

A second primary takeaway is that encouraging multi-state credit trading lowers compliance costs for Kansas compared with "island" scenarios that implement in-state measures alone. The magnitude of this cost reduction from access to national trading markets (Tables 6-3 and 6-4) and impact on in-state capacity investments (Figures 5-3 and 6-3) depend on state pathway selections elsewhere. Despite these benefits, inter-state trading entails a tradeoff with increased uncertainty about the pace of market development, liquidity, volatility, and exposure to additional forces external to Kansas. Based on gas prices and wind deployment, Kansas could be a net importer or net exporter of credits on secondary markets. Market participation may increase in-state coal generation, though CPP scenarios show increased retirements and lower utilization of coal assets relative to the reference scenario.

Additional factors beyond cost can favor a mass-based pathway selection for Kansas, including:

- **Lower incremental policy costs if low gas prices obtain:** If decision-makers are reasonably confident that natural gas prices will not be high, then the existing-mass pathway likely minimizes cost for Kansas (Figure 6-11).
- **Flexibility to use initial allowance allocations**
- **Administrative simplicity and familiarity** (i.e., relative to the creation and certification process for emissions rate credits under a rate-based plan)

Factors beyond cost that potentially favor a rate-based path include:

- **Timing of investments:** New generation capacity investments under mass compliance must start earlier and requires greater deployment than the rate pathway for Kansas (Figure 4-4). The mass pathway requires new NGCC investments in 2024. Near-term planned wind capacity investments align with rate-based compliance and would likely preclude new CPP-related investments until 2030. This provides extra time to observe market developments before committing to a non-market path to CPP compliance.

- **Disruption of the current generation mix:** 2030 generation under rate-based pathways more closely resemble values from the reference scenario for Kansas (Figure 5-4).

- **Volatility in compliance costs and capacity installations:** Model results suggest lower volatility in compliance costs under rate compliance relative to mass (Figure 6-11) depending on the sensitivity CPP pathway selections in other states.

Small cost differences between mass and rate scenarios under a range of scenarios will increase the importance of these other criteria for CPP pathway selection.

The flexible compliance options under the CPP make decision-making more complex, requiring optimization and economic modeling tools to understand tradeoffs and impacts. Regional heterogeneity means that there is not a dominant approach for all states, and the interdependence of states actions means that decisions must be evaluated simultaneously. The US-REGEN framework captures interactions between states and their simultaneous optimizing behavior subject to CPP targets. This analysis suggests that representing market interactions for electricity, CO_2 allowances, and emission rate credits is important in assessing economic impacts and compliance alternatives of policies like the CPP.

Potential impacts of rate- and mass-based compliance plans vary based on assumed market conditions like natural gas prices, CPP pathway choices in other states, wind costs, transmission, and coal retirements (Figure 6-11). Given uncertainty about these factors, which are largely independent from pathway decisions, the option to amend pathway selection as more information becomes available would help to limit compliance costs. Consideration of this flexibility for a state to switch compliance pathways from mass to rate (or vice versa) over time could allow states to meet CPP goals while reducing cost uncertainty.

Although the analysis offers valuable insights for state-level CPP decision-making, model approximations and incomplete system dynamics suggest that it should not be construed as a definitive determination of CPP planning for Kansas or legal advice on how Kansas can ~~company~~ comply with the CPP.[18] It can be expected that each state's preferred portfolio of compliance measures (e.g., in-state actions and market participation) will be informed by a range of factors, including in-state compliance costs, risk tolerance, local incentives, and assumptions about market liquidity and participation. Likewise, actual deployment may depend on additional factors (e.g., policy, permitting, and uncertainty) that fall outside of the scope of this economic modeling and analysis.

[18] For instance, US-REGEN does not include all costs incurred by coal units as they age (e.g., unit commitment constraints are not included in this version of the model). Including such costs could influence retirements.

Appendix A: US-REGEN Model Description

The U.S. Regional Economy, Greenhouse Gas, and Energy **(US-REGEN)** model was developed by the Electric Power Research Institute.[19] The model ~~combines~~ links detailed capacity planning and dispatch of the power sector for the Lower 48 U.S. states with a dynamic computable general equilibrium (CGE) model of the national economy.[20] The two models are solved iteratively to allow policy impacts on the electric sector to account for economic responses (and vice versa), which means US-REGEN can assess a ~~wide~~ broad range of energy and environmental policies.

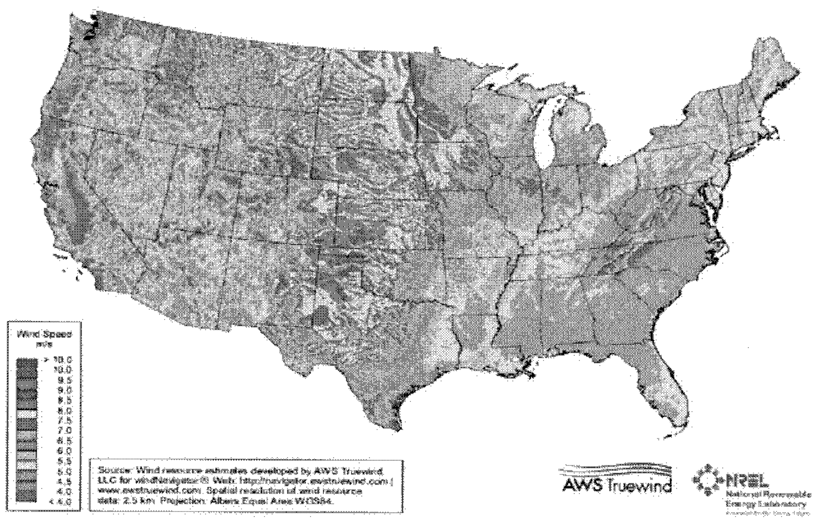


Figure A-1
Location of wind resources by state in US-REGEN

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[19] Additional detail can be found in *US-REGEN Model Documentation 2014*, EPRI Technical Update #3002004693 (available online at http://eea.epri.com/models.html).

[20] The CGE model of the U.S. economy includes representations of the residential, commercial, industrial, transportation, and fuels processing sectors.

The Clean Power Plan analysis in this report uses the electric-sector-only version of US-REGEN. The model contains detail to simultaneously capture capacity investment (including co-optimized transmission) and dispatch decisions for all 48 states in the contiguous United States. The forward-looking, long-term capacity planning model optimizes investments through 2050 to find the least cost way to meet load. Customizable regions and timesteps can be tailored to the needs of specific research questions. For all Clean Power Plan analyses, the model uses three-year timesteps through 2030 and five-year steps between 2030 and 2050.

The model simultaneously determines a cost-minimizing solution for all 48 states subject to technical and policy-related constraints. US-REGEN's spatial and temporal detail ensure resource adequacy for each state and capture market dynamics not only for electricity but also for CPP-related trading of allowances (for mass-complying states) and emission rate credits (for rate-complying states).

Hourly renewable resource data come from AWS Truepower and provide synchronous time-series values with load. Figure A-1 illustrates wind resource data in the Lower 48 U.S. states represented in the model, and Figure A-2 shows the wind resource potential for Kansas, assuming 80/100-meter hub heights. The joint variability of load, wind, and solar in this analysis is based on meteorology from 2010.

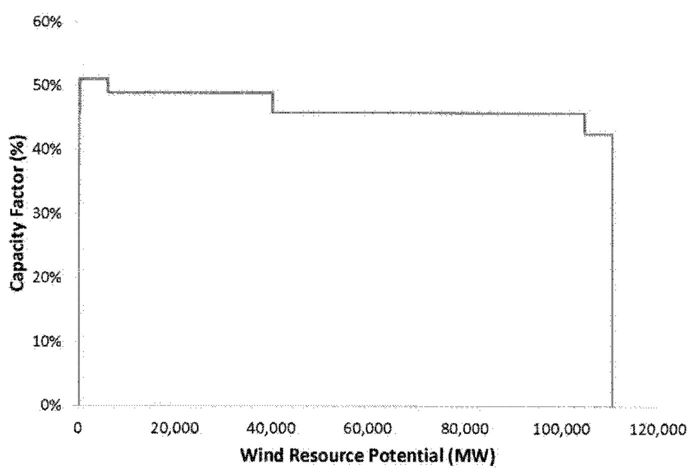

Figure A-2
State-level wind resource potential (MW) in Kansas by capacity factor (%)

US-REGEN employs an innovative algorithm to capture the hourly joint variability of load, wind, and solar profiles in a long time horizon model. This algorithm selects "representative hours" to preserve key distributional requirements for regional time-series data with a two-orders-of-magnitude reduction in dimensionality. This procedure provides between 50 and 100 intra-annual segments for system dispatch and load balancing in each annual timestep. This approach ~~significantly~~ outperforms ~~simple~~ heuristic selection procedures that focus on representing the load duration curve at the expense of other renewable time-series data. Figure A-3 compares how US-REGEN's "representative hour" approach compares to the "seasonal average" approach.

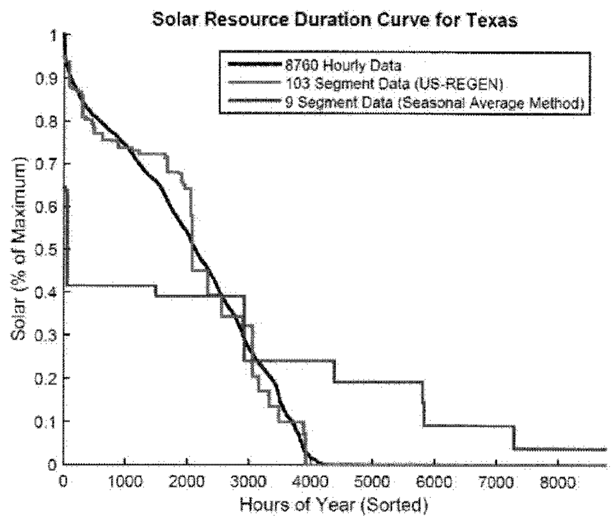

Figure A-3
Comparison of US-REGEN's representative-hour algorithm output (red) for the solar resource duration curve comparison for Texas with the underlying hourly data (black) and the seasonal-average approach (blue)

US-REGEN models a wide range of CPP compliance options in the power sector, including endogenous heat rate improvements, endogenous energy efficiency, detailed renewable resource representations, redispatch, options for existing coal (e.g., co-firing, conversion to gas or biomass, CCS retrofits), and many others.

The reference scenario assumptions are detailed in Section 3. All scenarios use fuel prices from the 2015 Annual Energy Outlook (EIA, 2015). The natural gas price trajectory comes from the 2015 AEO high estimated ultimate recovery (HEUR) case, as shown in Figure A-4. Also shown in Figure A-4 are updated fuel price paths from the AEO 2016. The 2016 reference is closer to the AEO 2015 HEUR case.

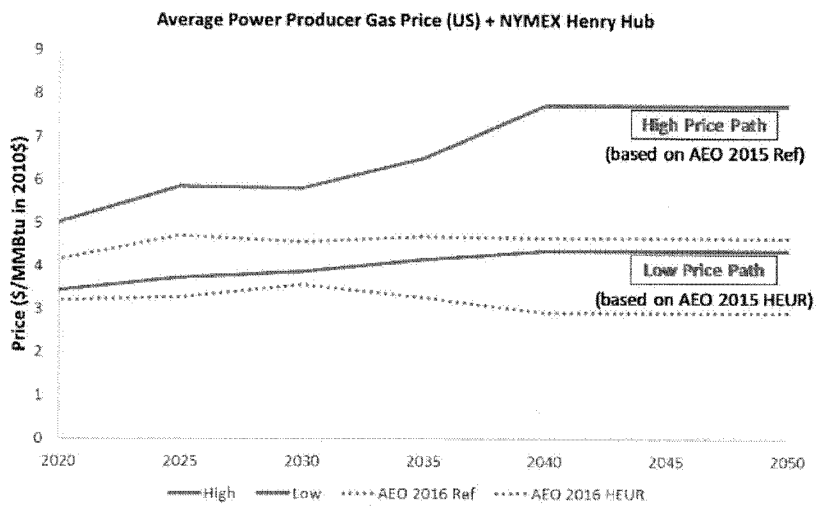

Figure A-4
Natural gas price paths over time ($ per MMBtu, real terms) for the low and high gas prices in the analysis (solid lines) and updated AEO 2016 values (dotted)

EPRI technology costs and limitations (e.g., on the rate and extent of transmission and nuclear deployment) are used. In line with AEO 2015 assumptions, there are no forced retirements for existing coal units in the reference case, though retirements for economic reasons are possible in any period. Endogenous retirement decisions in the model weigh the discounted sum of going-forward costs of maintaining and operating existing capital against anticipated revenues. Without sub-state resolution (e.g., the model does not capture intra-state transmission), US-REGEN retirements are driven primarily by unit-specific heat rates rather than by locational issues.

Technology cost and performance assumptions come from the most recent EPRI Integrated Generation Technology Options report. Solar and wind costs are updated more regularly. Capital costs for onshore wind in Kansas decline from $1,967/kW in 2018 to $1,693/kW in 2030, which includes a one-time $450 per kW charge to reflect incremental intra-regional transmission investment. Utility-scale solar PV capital costs decrease to $1,289/kW by 2030, including the same one-time hookup and network changes. Transmission between regions can be added at a cost of $3.85 million per mile for a notional high-voltage line (e.g., 500 kV AC or 800 kV DC) to transfer 6,400 MW of capacity.

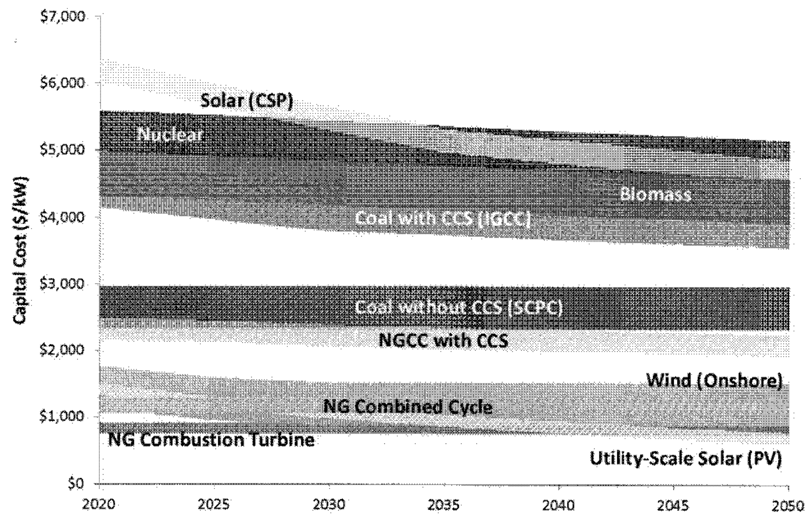

Figure A-5
US-REGEN capital cost trajectories (bands represent regional differences)

All scenarios include most existing and known future state and federal policies and regulations. Updated state renewable portfolio standards are included along with federal policies like MATS and CWA § 316(b). Other state policies include California's AB 32 and the Regional Greenhouse Gas Initiative (RGGI) for eastern states. The Clean Air Act § 111(b) CO_2 performance standards are included in the analysis.

Federal 2015 tax extenders adopted by Congress for wind or solar are included in the analysis. Rooftop solar is modeled as a separate technology "behind the meter" (i.e., rooftop generation receives the retail price for electricity) in California.

Appendix B: Abbreviations

Table B-1
Abbreviations and acronyms used in this report

Abbr.	Definition
AEO	Annual Energy Outlook
CAA	Clean Air Act
CGE	Computable Generation Equilibrium
CO_2	Carbon Dioxide
CPP	Clean Power Plan
EE	Energy Efficiency
EGU	Electric Generating Unit
EPA	Environmental Protection Agency
EPRI	Electric Power Research Institute
ERC	Emission Rate Credit
GW	Gigawatts
ITC/PTC	Investment Tax Credit and Production Tax Credit
MX	Mass Existing (i.e., CPP pathway)
NGCC	Natural Gas Combined Cycle
NGGT	Natural Gas Turbine
NSC	New Source Complement
OBS	Output-Based Set-Aside
ROC	Rest of Country
RE	Renewable Energy
RGGI	Regional Greenhouse Gas Initiative
RPS	Renewable Portfolio Standard
RU	Rate Unit (i.e., CPP pathway, sometimes referred to as "subcategory rate")
TWh	Terrawatt-Hours
US-REGEN	U.S. Regional Economy, Greenhouse Gas, and Energy

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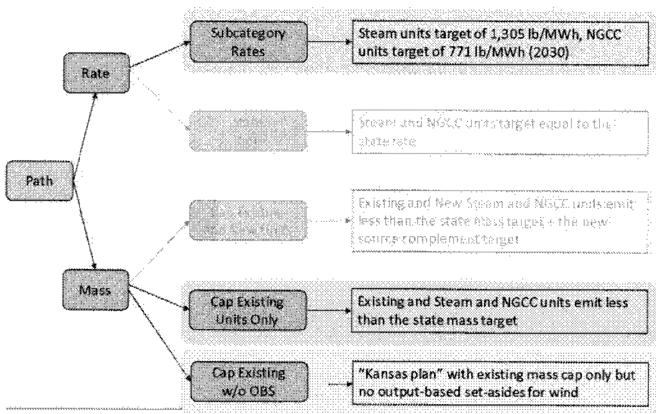
~~Appendix C: Kansas Plan Analysis~~

~~This appendix summarizes analysis of an alternate mass-based CPP pathway called the "Kansas Plan," which is a variation of the existing-mass pathway. Figure C-1 shows the Kansas Plan in relation to the other paths in the analysis.~~



~~*Figure C-1*~~
~~*Diagram of Clean Power Plan compliance pathways considered in the analysis*~~

~~Typically, the existing-mass-only pathway through the model rule allocation method provides two allowance set-asides to address potential leakage concerns:~~

1. ~~Output-based allocation to existing NGCC (with lagged accounting)~~
2. ~~Qualifying renewable energy~~

~~Under the Kansas Plan, the state selects the existing-mass pathway with the corresponding CPP cap values; however, no output-based set-asides are provided to renewables in Kansas.[21] Additionally, the annual capacity factor of Riverton Unit 12 is constrained to be greater than or equal to 75%, assuming a summer capacity of 236 MW.~~

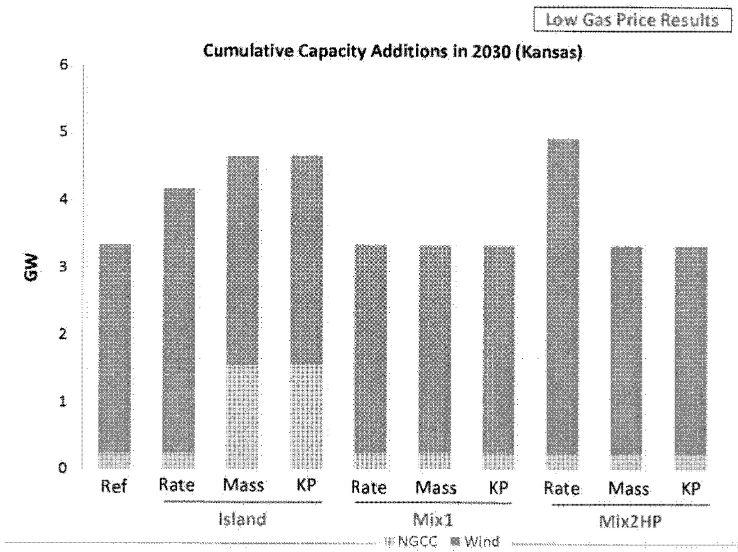
~~[21] Under runs where Kansas selects this pathway, other existing-mass states are assumed to implement output-based set-asides.~~

~~The Kansas Plan (KP) is investigated as a third CPP compliance pathway in addition to the subcategory-rate and existing-mass pathways for each one of the sensitivities in the analysis.~~

~~*Table C-1*~~
~~*Comparative incremental CPP policy costs to Kansas ($ billion) in present value terms (2015–2050) and as a percentage of the reference costs under subcategory-rate (RU), existing-mass (MX), and Kansas Plan (KP) pathways*~~

Set	Background Assumptions							Policy Cost ($B)			% Reference		
	ROC Policy	Gas Price	Wind Cost	Transm.	U.S. CO_2 Cap	Coal Life	Load	RU	MX	KP	RU	MX	KP
1	Island	Low	Ref	Ref	None	Ref	Ref	0.32	0.79	0.87	1.2%	3.0%	3.2%
2	Mix1	Low	Ref	Ref	None	Ref	Ref	0.11	-0.06	0.03	0.5%	-0.3%	0.1%
	Mix2HP	Low	Ref	Ref	None	Ref	Ref	0.19	-0.13	-0.03	0.8%	-0.5%	-0.1%
3	Island	High	Ref	Ref	None	Ref	Ref	0.09	1.18	1.25	0.3%	3.6%	3.8%
	Mix1	High	Ref	Ref	None	Ref	Ref	0.20	0.44	0.54	0.8%	1.7%	2.1%
	Mix2HP	High	Ref	Ref	None	Ref	Ref	0.17	0.25	0.27	0.6%	1.0%	1.0%
	Mix1	High	High	Ref	None	Ref	Ref	-0.03	0.22	0.19	-0.1%	0.8%	0.7%
	Mix2HP	High	High	Ref	None	Ref	Ref	0.09	0.27	0.26	0.4%	1.0%	1.0%
	Mix1	High	Low	Ref	None	Ref	Ref	0.23	0.61	0.91	0.9%	2.3%	3.5%
	Mix2HP	High	Low	Ref	None	Ref	Ref	0.10	0.62	0.89	0.4%	2.4%	3.4%
4	Mix1	Low	Low	Ref	None	Ref	Ref	0.09	-0.01	0.02	0.4%	0.0%	0.1%
	Mix2HP	Low	Low	Ref	None	Ref	Ref	0.06	-0.01	0.01	0.3%	-0.1%	0.1%
	Mix1	Low	Ref	KS-IN	None	Ref	Ref	0.08	0.18	0.05	0.3%	0.7%	0.2%
	Mix2HP	Low	Ref	KS-IN	None	Ref	Ref	0.23	0.00	0.00	0.9%	0.0%	0.0%
	Mix1	High	Ref	KS-IN	None	Ref	Ref	0.74	1.36	1.29	2.5%	4.7%	4.4%
	Mix2HP	High	Ref	KS-IN	None	Ref	Ref	0.89	0.93	1.06	3.0%	3.2%	3.6%
	Mix1	Low	Ref	Ref	80% by 2050	Ref	Ref	-0.08	-0.14	-0.04	-0.3%	-0.5%	-0.1%
	Mix2HP	Low	Ref	Ref	80% by 2050	Ref	Ref	-0.04	-0.14	-0.07	-0.1%	-0.5%	-0.2%
	Mix1	High	Ref	Ref	80% by 2050	Ref	Ref	2.68	2.82	2.92	9.2%	9.7%	10.1%
	Mix2HP	High	Ref	Ref	80% by 2050	Ref	Ref	2.63	2.76	2.75	9.0%	9.5%	9.4%
	Mix1	Low	Ref	Ref	None	70	Ref	-0.01	-0.08	0.02	0.0%	-0.3%	0.1%
	Mix2HP	Low	Ref	Ref	None	70	Ref	0.15	-0.15	-0.05	0.6%	-0.6%	-0.2%
	Mix1	Low	Ref	Ref	None	Ref	-1%	0.17	-0.23	-0.22	12.9%	-23.0%	-21.3%
	Mix2HP	Low	Ref	Ref	None	Ref	-1%	0.01	-0.01	-0.01	0.6%	-1.2%	-1.1%

~~Table C-1 indicates that compliance costs under the Kansas Plan are similar to the existing-mass pathway and depend on the sensitivity. Importantly, the insights about whether the rate or mass pathway is lower cost likely does not depend on whether the mass-based pathway chosen by Kansas is the existing-mass path or the Kansas plan. Scenarios where existing-mass is lower cost than the rate pathway (e.g., low gas prices with trading) also minimize cost if the Kansas Plan is implemented instead. Conversely, investment environments where rate-based paths are lower cost for Kansas (e.g., high gas prices) still hold when compared with the Kansas Plan.~~



~~*Figure C-2*~~
~~*Comparison of cumulative capacity investments (gigawatts) in Kansas through 2030 under subcategory-rate ("Rate"), existing-mass ("Mass"), and Kansas Plan ("KP") compliance under different trading environments (reference shown on left) with low gas prices*~~

~~When gas prices follow the lower price trajectory, Figure C-2 shows how investments under the Kansas Plan compare with the subcategory-rate and existing-mass paths. New capacity installations when Kansas implements the Kansas Plan are the same in 2030 as under the existing-mass pathway, regardless of whether Kansas participates in multi-state trading. When Kansas trades allowances, new investments are similar to the reference case with capacity additions coming primarily from committed wind projects.~~

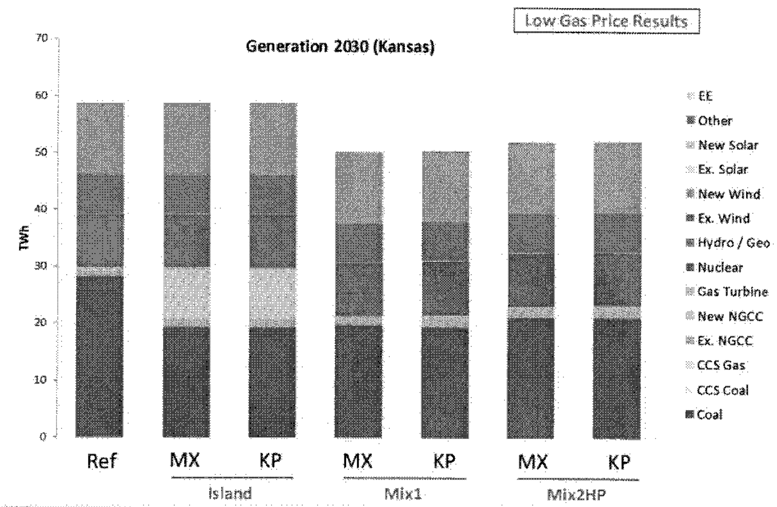
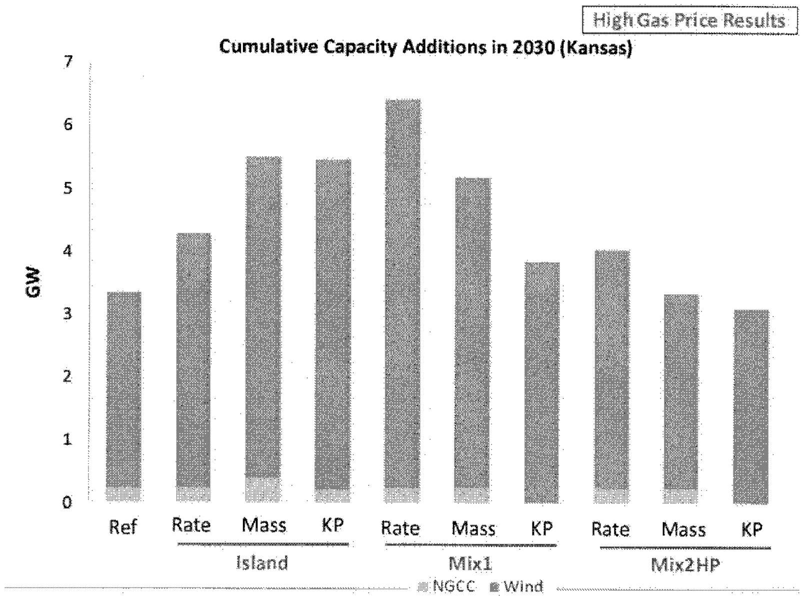


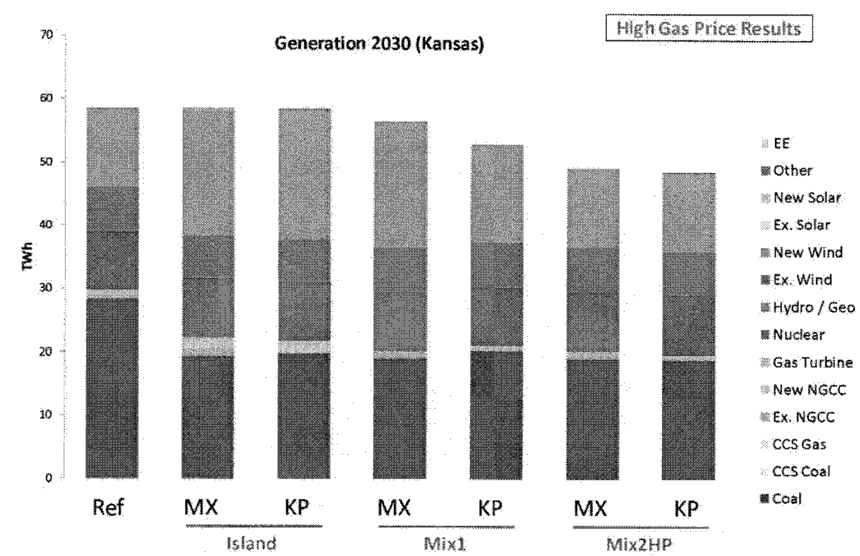
Figure C-3
~~*2030 electricity generation (terawatt-hours) in Kansas by technology under different trading environments and mass-based pathway selections (Existing Mass = "MX" and Kansas Plan = "KP") with low gas prices*~~

~~Figure C-3 shows the corresponding 2030 generation in Kansas under these same CPP sensitivities. Again, Kansas Plan dispatch is very similar to the existing mass pathway. Electricity exports are highest when Kansas relies only on in-state mitigation options to comply with the CPP. Nevertheless, opportunities to export electricity into neighboring regions are more limited when low gas prices depress wholesale prices in nearby regions. Trading emissions allowances lowers investment and generation in new NGCC capacity, and the lower allowance prices under Mix2HP compliance lead to slightly higher coal generation in Kansas, as more permits are purchased.~~

~~When high gas prices are assumed, new wind investments are more attractive in Kansas under the reference and CPP scenarios. These sensitivities also entail exports to neighboring states as well, given Kansas' higher quality wind sites and lower construction costs. Under these scenarios where new wind is often on the build margin, the absence of allowance set-asides for wind can have an impact on capacity builds and generation, as shown in Figures C-4 and C-5. The higher allowance prices under Mix1 trading lead to the most significant differences in investment by 2030, with 5.0 GW of new wind under existing-mass and 3.8 under the Kansas Plan.~~



~~Figure C-4~~
~~Comparison of cumulative capacity investments (gigawatts) in Kansas through 2030 under subcategory-rate ("Rate"), existing mass ("Mass"), and Kansas Plan ("KP") compliance under different trading environments (reference shown on left) with high gas prices~~



~~*Figure C-5*~~
~~*2030 electricity generation (terawatt-hours) in Kansas by technology under different trading environments and mass-based pathway selections (Existing Mass = "MX" and Kansas Plan = "KP") with high gas prices*~~

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