Appendix Y:

Moving Ohio Manufacturing Forward: Competitive Electricity Pricing

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Moving Ohio Manufacturing Forward: Competitive Electricity Pricing

Prepared for:
OHIO MANUFACTURERS' ASSOCIATION

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Executive Summary

Today, the price of electricity has a powerful influence on the competitiveness of manufacturing because manufacturing industries are often electricity's largest consumers. Economic regulation of the electric utility business has changed very little over the last decade while regional and national policy makers debate the volatility of energy markets. The electricity industry, because of the large size of the units of its production, wholesale, and distribution, draws major benefits from the economy of scale. At the same time, energy efficiency has become the by-word of energy-intensive manufacturing businesses, which in the Midwest accounted for 60% of industrial fuel and feedstock energy use in 2006.[1] In 2010, Ohio had the highest level of manufacturing activity among Midwestern states resulting in value added mainly from the energy-intensive sectors such as primary metals, petroleum and coal products, chemicals, food, nonmetallic minerals, paper, and wood products.[2]

The goal of this report is to define electricity-intensive manufacturing export industries in Ohio that are sensitive to electricity pricing and to illustrate the impact of electricity pricing on manufacturing productivity through the industrial electricity pricing model. The first section of the report identifies Ohio's manufacturing industries that are electricity- intensive as part of their production (high costs of electricity per unit of production) and Ohio manufacturing industries that consume large quantities of electricity overall due to the large size of this industry in the state (high total expenditures on electricity). Some of these industries have a competitive advantage in the state and demonstrate a high Location Quotient (LQ)[3] of Gross State Product (GSP) and growth in GSP since the last recession. The second section of this report explores the impact of electricity rates, together with states' efforts to deregulate electricity markets, on the competitiveness of manufacturing industries in Ohio and benchmark states expressed through manufacturing productivity.

Twelve Ohio industries are a part of economic base of the state and manufacture a high number of electricity-intensive products. These industries belong to four industrial sectors: *Primary Metal Manufacturing, Chemical Manufacturing, Food Manufacturing,* and *Nonmetallic Mineral Product Manufacturing.* Together, these 12 industries employed over 86,000 people in Ohio in 2010.

According to our empirical modeling of industrial electricity pricing, the growth of manufacturing employment is negatively related to manufacturing productivity. At the same

[1] J. Bradbury et al. "Midwest Manufacturing Snapshot: Energy Use and Efficiency Policies." World Resource Institute, Working Paper, February 2012. P.5

[2] P.4

[3] Location Quotient measures the specialization of an industry in a region by comparing it to data in a larger region. For our analysis: $LQ = \frac{\frac{g_i}{g}}{\frac{G_i}{G}}$ where g_i = The Ohio Gross Product in industry i; g = Total Gross Product in Ohio; G_i= US Gross Product in industry i; G = Total US Gross Product. A location quotient > 1.0 indicates specialization in an industry.

time, the presence of large manufacturing establishments in the state is, as expected, positively associated with manufacturing productivity. This analysis indicates that manufacturing productivity might benefit from both economies of scale and the ability of large electricity consumers to negotiate individual contracts with suppliers at, most likely, lower than average market prices. This finding allows us to consider whether enabling a lower market price across the board for manufacturing users might further benefit the productivity of the manufacturing sector in the state.

An increase in the industrial electricity price by 1 cent per kilowatt-hour (16.3%) is likely, in 99% of cases, to decrease average manufacturing productivity in the five selected states,[4] on average, by $2,527 of annual gross state product per employee (2.2%). The productivity change associated with the industrial electricity price change has low elasticity: 2.2%/16.3%=0.13. The measure of elasticity below 1 is known as inelastic response. This means that for 1% increase of industrial electricity prices, manufacturing productivity drops by 0.13%.

Description of Ohio Electricity-Intensive Industries

In the first section of the report, a number of variables were analyzed to identify Ohio's economic base. These variables include the LQ of GSP, the growth of GSP, and industries' productivity over three time periods, 2000-2010, 2007-2010, and 2009-2010. With a LQ of greater than 1, fifty-two manufacturing industries (Table 7) potentially represented the economic base of Ohio's economy in 2010.[5] Ohio's economic base was heavily represented by manufacturing industries of *Food* (NAICS 311), *Chemical* (NAICS 325), *Nonmetallic mineral product* (NAICS 327), *Primary metal* (NAICS 331), *Fabricated metal product* (NAICS 332), *Machinery* (NAICS 333), *Electrical equipment* (NAICS 335), and *Transportation equipment* (NAICS 336).

Twenty-eight manufacturing industries in Ohio experienced positive GSP growth (at least 1%) between 2007 and 2010[6] . With a 51% increase, the *Petroleum and Coal Products Manufacturing* industry (NAICS 3241) had the greatest GSP growth during the study period followed by *Electrical Equipment and Component Manufacturing* (NAICS 3359) and *Pharmaceutical and Medicine Manufacturing* (NAICS 3254) industries which grew by 31% in the same time period.

The industries that were growing from 2007 to 2010 and were likely to have high productivity in 2010 were *Petroleum and Coal Products Manufacturing* (NAICS 3241); *Pesticide, Fertilizer, and other Agricultural Chemical Manufacturing* (NAICS 3253); *Household Appliance Manufacturing* (NAICS 3352); *Pharmaceutical and Medicine Manufacturing* (NAICS 3254); *and Basic Chemical Manufacturing* (NAICS 3251).

[4] Ohio, Indiana, Kentucky, Michigan, and Pennsylvania
[5] The industries that represent economic base are also called basic industries.
[6] For more information see Table 8.

Basic manufacturing industries that use electricity intensively as a part of production (those with electricity expenditures greater than 1% of total expenditures) were categorized as high, moderate, or low electricity-intensive industries. Ten industries were classified as high electricity-intensive industries, with average electricity expenditures greater than 2% of total expenditures. The *Alumina and Aluminum Production and Processing Industry* (NAICS 3313) ranked highest, with electricity expenditures composing 5.7% of total expenditures (Table 1).

There were seventeen moderately electricity-intensive industries, spending at least 1% of their total expenditures on electricity. The *Sawmills and Wood Preservation* (NAICS 3211) industry ranked highest in this group, with electricity expenditures composing 1.9% of total expenditures.

Twenty manufacturing industries were identified as large consumers of electricity by total expenditures on electricity (Table 2). The top industry, *Basic Chemical Manufacturing* (NAICS 3251), spends over $357 million on electricity per year, followed closely by *Iron and Steel Mills and Ferroalloy Manufacturing* (NAICS 3311) at $305 million. The top eleven industries in this category spend greater than $67 million per year on electricity expenditures per industry.

The other nine industries are considered moderate consumers (based on total expenditures) and spend individually between $41 and $56 million on electricity per year. This group was led by *Other Fabricated Metal Product Manufacturing* (NAICS 3329), at $59 million per year in electricity expenditures.

Fourteen industries were identified as both (1) electricity-intensive in regards to the unit of production and (2) high overall consumption of electricity. These manufacturing industries create electricity-intensive products while purchasing large volumes of electricity relative to their size in Ohio. This group consisted of primary metal, chemical, food, paper, glass, and nonmetallic mineral industries.

Eleven nonmanufacturing industries and broader sectors were identified in Ohio as those that have high per-unit electricity costs and high total expenditures on electricity. These industries cover diverse activities – from farming to large institutions and accommodations – and can occur on such a large scale that electricity needs are magnified, such as in museums, hospitals, universities, and warehouses. Electricity costs as a percentage of total expenditures for non-manufacturing industries exceed 1%. The *Accommodation* industry (NAICS 721) is atop of the list of large non-manufacturing energy consumers, spending 2.9% of its total expenditures for electricity. Total expenditures for electricity in this group of industries vary from over $103 million for *Construction* to over $15 million for *Newspaper, Periodical, Book, and Directory Publishers*.

Empirical Model

The second part of the report explores the impact of electricity pricing on manufacturing productivity through an industrial electricity price regression model. This model was conducted on the data from five comparable states: Ohio, Indiana, Kentucky, Michigan, and Pennsylvania.

The research team chose neighboring states with economic structures and electricity consumers comparable to those of the state of Ohio as the geographic area for statistical modeling. This analysis seeks to answer two research questions: (1) How does industrial electricity pricing influence the productivity of the manufacturing sector? and (2) What are the influences of electricity market deregulation on the industrial electricity market and manufacturing productivity?

The manufacturing productivity and industrial electricity rates in Ohio, Indiana, Kentucky, Michigan, and Pennsylvania were analyzed for the period between 1990 and 2010 - the latest years for which industrial electricity pricing data were available. A statistical model was built to test the effect of policy variables on manufacturing productivity (industrial electricity price and deregulation variables), controlling for the demand on the electricity market (manufacturing employment and presence of large manufacturing companies), the supply on the electricity market (size of power generation industry), and overall economic conditions (using a business cycle variable to estimate the recession).

The results of this analysis indicate that electricity price had a statistically significant negative effect on manufacturing productivity across the five targeted states between 1990 and 2010. The higher the industrial electricity prices were in the five selected states, the lower manufacturing productivity was in these states in 99% of cases. However, productivity change from the movement of industrial electricity price was inelastic—indicating that electricity is only one of the supply price factors influencing manufacturing productivity.

The deregulation of the electricity market was statistically significant (above the 99% critical value) and positively associated with manufacturing productivity. To further assess the impact of electricity market restructuring, an independent sample t-test[7] was used to compare industrial electricity prices and other economic indicators between the states that deregulated their wholesale electricity markets and those that did not. Generally, deregulation had a positive effect on the change of industrial electricity prices and some economic variables characterizing the state of manufacturing industries in the five targeted states. The most profound effect of deregulation was a significant drop in industrial electricity prices. However, the model is based on a small sample of five states and did not control for the level of industrial electricity pricing at the beginning of the study period.

The variables characterizing the demand side of the electricity market shows that the growth of manufacturing employment is negatively related to manufacturing productivity with statistical significance only above the 90% critical value. Also, it should be noted that the presence of a considerable number of large manufacturing establishments in the state was positively associated with manufacturing productivity at the 99% critical value, which might reflect the benefits from the economy of scale where many large companies share the regional supply chain.

[7] The t-test illustrates whether the differences between the states were statistically significant.

The control variable that represents the supply side of the electricity market, capacity of electricity production and distribution, was also positively related to manufacturing productivity and was statistically significant above the 99% critical value. The variable approximating the national recession was negatively associated with manufacturing productivity, indicating that during economic downturns manufacturing productivity was declining.

Based on the results of this analysis, we can conclude that higher industrial electricity rates in Ohio will most likely be associated with lower manufacturing productivity. Moreover, manufacturing productivity is likely to benefit from both economy of scale and the ability of large electricity consumers to negotiate contracts with suppliers at a lower than average market price. Finally, an increase in the state's capacity to generate, transmit, and distribute electricity will most likely support higher productivity in its manufacturing sector.

Introduction

This report is prepared for The Ohio Manufacturers' Association by the Center for Economic Development and the Center for Energy Policy and Applications at the Maxine Goodman Levin College of Urban Affairs at Cleveland State University. The authors of the report would like to acknowledge the research assistance of Ellen Cyran, a senior programmer analyst at the Center for Economic Development for her database support, James Wyles, visiting instructor in GIS and Urban Geography for his mapping, and Joe Andre and Serineh Baboomian, graduate assistants at the Center for Economic Development for their editorial support. We appreciate thoughtful comments by the OMA leaders and staff for their insights and continued support through the duration of this project.

Ohio today faces a considerable challenge in keeping its manufacturing base competitive. Energy-intensive manufacturing, in particular, is threatened by rising electricity costs and the potential need to reduce carbon emissions. One of the responses to mitigate rising electricity prices is developing a model of distributed generation.[8]

In order to examine if electricity rates have a critical influence on Ohio's manufacturing industry, it is imperative to identify Ohio's electricity-intensive manufacturing sector which has comparative advantages across the United States. We present this in the first section of our report, as well as the geographic concentration of electricity-intensive, economic-base manufacturing industries in all Ohio counties. In Ohio's manufacturing base, there are 14 industries that are electricity-intensive industries[9] and industries that are large consumers of electricity.[10] In particular; atop of this list are primary metal manufacturing; chemical manufacturing; food manufacturing; and paper, glass, and nonmetallic mineral product manufacturing.

In the second part of this report, the researchers empirically estimate the impact of electricity rates coupled with the deregulation of electricity markets, and how these impact Ohio's manufacturing competitiveness.

This study is intended to inform manufacturers about the structure of electricity-intense industries of the manufacturing sector, regional distribution of electricity-intense industries, and the largest consumers of electricity in Ohio. Moreover, this study aims to provide insights on major factors influencing electricity pricing. The study empirically illustrates that industrial electricity price is one of the major factors that negatively impacts manufacturing productivity. The authors hope that the study of the state of electricity-intensive manufacturing industries' help craft better electricity pricing public policies in Ohio.

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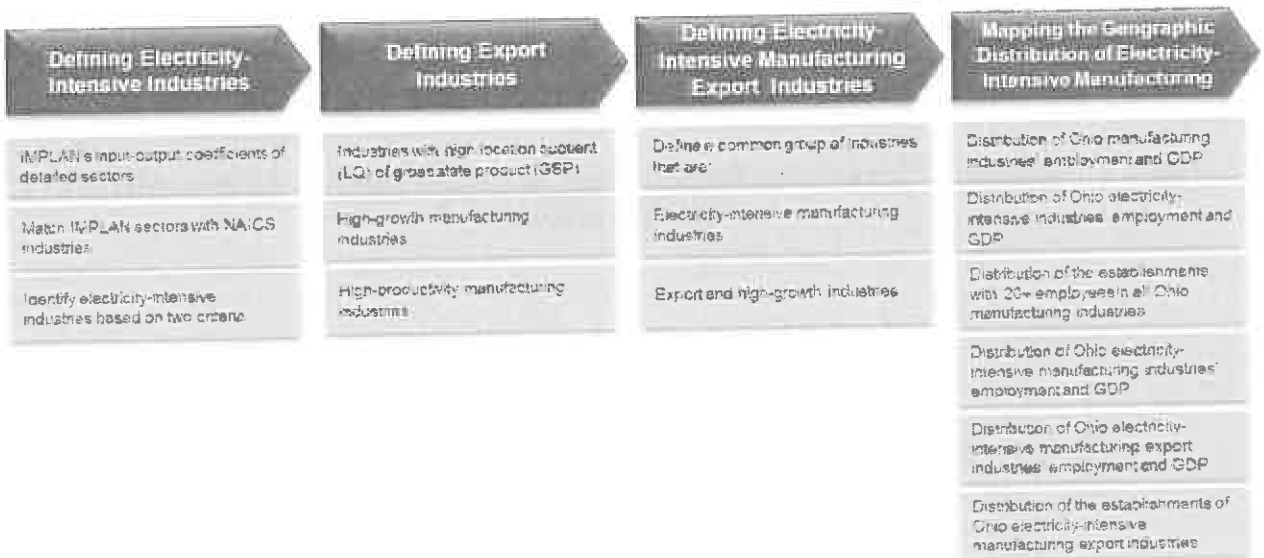
[8] A. Thomas and I. Lendel, "Distributed Generation as a Response to Rising Electricity Costs in Ohio." February 2013.

[9] Electricity-intensive are atop of the list of industries defined by the ratio of an industry's expenditure on electricity to the industry's total expenditures in Ohio, measured as unit expense for electricity.

[10] Large consumers of electricity are industries that pay large shares of their total expenditures for electricity, measured in dollars.

Part 1: Analysis of Ohio Electricity-Intensive Manufacturing Export Industries

The goal of the project is to define a group of electricity-intensive manufacturing export industries that could possibly be eligible for special electricity rates. The Center for Economic Development defines and lists these electricity-intensive industries and then analyzes the distribution and concentration of electricity-intensive industries across the state of Ohio. Steps and methodologies of the analysis are as follows:



Defining Electricity-Intensive Industries

In order to identify electricity-intensive industries, IMPLAN's technical input-output coefficients were used. IMPLAN is a proprietary input-output economic model that provides information on supply relationships (backward linkages) between industries. Two indicators signify electricity-intensive industries:

1. The ratio of an industry's expenditure on electricity to the industry's total expenditures in Ohio, measured as unit expense for electricity
2. Industry's total expenditure on electricity (electricity generation and transmission industry), measured in dollars

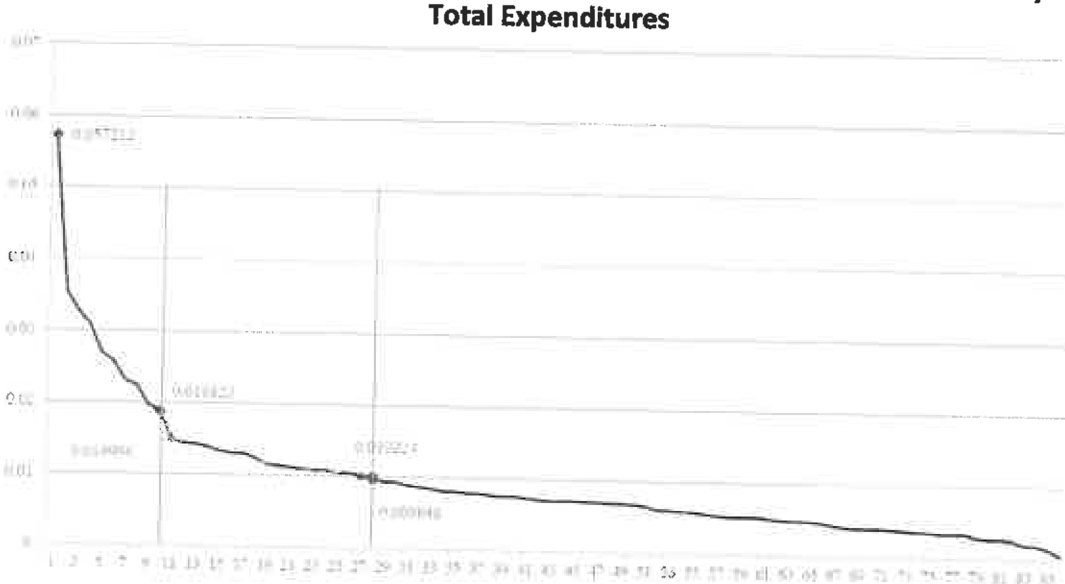
The indicator unit expenses for electricity reflect the share of electricity cost in $1 of output of IMPLAN industry *Electric Power Generation, Transmission, and Distribution* (industry code 31). Ohio's manufacturing industries (at the 4-digit NAICS classification) were ranked separately by each indicator: unit expense for electricity (Table 1) and industry's total expenditure for electricity (Table 2).

✓ Per each $1 of expenses, the Alumina and Aluminum Production and Processing industry spends 5.7cents on electric power generation, transmission, and distribution (Table 1)

✓ The same industry spent $144 million in 2009 buying their supply of electricity from Ohio (Table 2)

Using the "natural break" method,[11] Ohio's manufacturing industries were classified into three groups of electricity users: high, moderate, and low electricity-intensive industries (Figures 1 and 2). Our definition of High and Moderate Electricity-Intensive industries is consistent with the Energy-Intensive and Non-Energy-Intensive Manufacturing groups defined for Industrial Demand Module of the National Energy Modeling System[12] (see Appendix Table 1).

Figure 1. Illustration of Break-Point Method Based on Ratio of Expenses for Electricity in $1 of Total Expenditures



[11] The "natural break" method is based on identifying the significant change of a ranked dependent variable between two observation points. The significant variation in a dependent variable points to the change of a phenomenon, which this variable illustrates.

[12] Office of Energy Analysis, U.S. Energy Information Administration, 2011.

Table 1. Electricity-Intensive Manufacturing Industries by Unit Expenditures for Electricity

	NAICS	Industry Name	Electricity Expenditures Per $1 of Industry Expenses
High Electricity-Intensive Manufacturing	3313	Alumina and Aluminum Production and Processing	0.05721
	3221	Pulp, Paper, and Paperboard Mills	0.03534
	3274	Lime and Gypsum Product Manufacturing	0.03280
	3311	Iron and Steel Mills and Ferroalloy Manufacturing	0.03091
	3251	Basic Chemical Manufacturing	0.02702
	3272	Glass and Glass Product Manufacturing	0.02577
	3315	Foundries	0.02311
	3279	Other Nonmetallic Mineral Product Manufacturing	0.02240
	3253	Pesticide, Fertilizer, and Other Agricultural Chemical Manufacturing	0.01975
	3271	Clay Product and Refractory Manufacturing	0.01882
Moderate electricity-intensive Manufacturing	3211	Sawmills and Wood Preservation	0.01500
	3117	Seafood Product Preparation and Packaging	0.01432
	3328	Coating, Engraving, Heat Treating, and Allied Activities	0.01429
	3112	Grain and Oilseed Milling	0.01395
	3252	Resin, Synthetic Rubber, and Artificial Synthetic Fibers and Filaments	0.01343
	3131	Fiber, Yarn, and Thread Mills	0.01309
	3273	Cement and Concrete Product Manufacturing	0.01307
	3132	Fabric Mills	0.01245
	3212	Veneer, Plywood, and Engineered Wood Product Manufacturing	0.01156
	3312	Steel Product Manufacturing from Purchased Steel	0.01132
	3115	Dairy Product Manufacturing	0.01111
	3113	Sugar and Confectionery Product Manufacturing	0.01094
	3114	Fruit and Vegetable Preserving and Specialty Food Manufacturing	0.01086
	3321	Forging and Stamping	0.01082
	3262	Rubber Product Manufacturing	0.01052
	3359	Other Electrical Equipment and Component Manufacturing	0.01047
	3314	Nonferrous Metal (except Aluminum) Production and Processing	0.01022

High Electricity-Intensive Manufacturing Industries

Table 1 includes industries with relatively high unit expenditures on electric power generation, transmission, and distribution. Ranked by this indicator, all manufacturing industries were divided into three groups: High Electricity-Intensive Manufacturing, Moderate Electricity-Intensive Manufacturing, and Low Electricity-Intensive Manufacturing. The High Electricity-Intensive Manufacturing group includes ten manufacturing industries that annually spend 2% or more of their total expenditures on electricity. The *Alumina and Aluminum Production and Processing* Industry (NAICS 3313) alone spends 5.7% of all expenditures on electricity. This is almost twice the next High Electricity-Intensive Manufacturing Industry, *Pulp, Paper, and Paperboard Mills* (NAICS 3221), which spends 3.5% of all expenses annually on electricity. The top ten electricity-intensive manufacturing industries include three groups of industries: metal-product manufacturing, chemical manufacturing, and paper-producing industries. Two out of three groups historically have had a large presence in Ohio.

Moderate Electricity-Intensive Manufacturing Industries

The 17 industries that belong to the Moderate Electricity-Intensive Manufacturing group spend at least 1% of their total expenditures for electricity. *Sawmills and Wood Preservation* (NAICS 3211) and *Seafood Product Preparation and Packing* (NAICS 3117), the two top industries in this group, are not typical for Ohio. The rest of this cohort represents industries related to metal and equipment manufacturing, food manufacturing, resin and rubber industry, and cement and concrete manufacturing. The 17 industries included in the High and Moderate Electricity-Intensive Manufacturing groups are the subject of further investigation.

Figure 2. Illustration of Break-Point Method Based on Indicator of Total Industry Expenses for Electricity

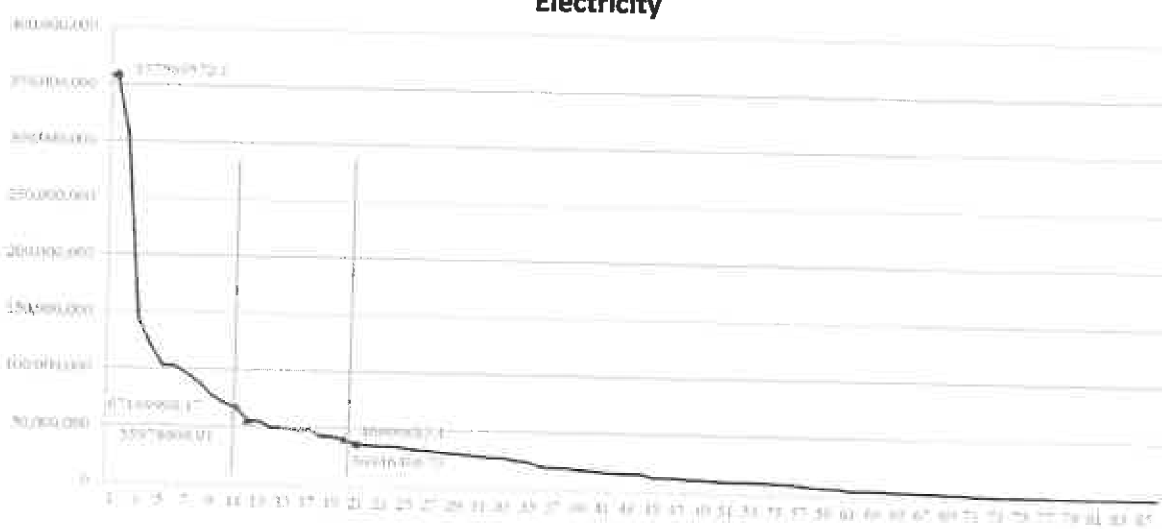


Table 2. Large Consumers of Electricity Identified by Indicator of Total Expenditures for Electricity in Ohio

	NAICS	Industry Name	Total Industry Expenditures for Electricity in OH
High Electricity-Consuming Manufacturing	3251	Basic Chemical Manufacturing	$357,569,572
	3311	Iron and Steel Mills and Ferroalloy Manufacturing	$305,430,664
	3313	Alumina and Aluminum Production and Processing	$144,121,601
	3241	Petroleum and Coal Products Manufacturing	$120,952,662
	3261	Plastics Product Manufacturing	$103,429,390
	3363	Motor Vehicle Parts Manufacturing	$102,961,395
	3221	Pulp, Paper, and Paperboard Mills	$96,450,783
	3252	Resin, Synthetic Rubber, and Artificial Synthetic Fibers and Filaments	$88,811,888
	3253	Pesticide, Fertilizer, and Other Agricultural Chemical Manufacturing	$77,580,568
	3115	Dairy Product Manufacturing	$71,619,224
	3315	Foundries	$67,169,998
Moderate Electricity-Consuming Manufacturing	3329	Other Fabricated Metal Product Manufacturing	$55,978,697
	3114	Fruit and Vegetable Preserving and Specialty Food Manufacturing	$54,834,373
	3312	Steel Product Manufacturing from Purchased Steel	$49,857,376
	3222	Converted Paper Product Manufacturing	$49,737,892
	3272	Glass and Glass Product Manufacturing	$48,513,642
	3279	Other Nonmetallic Mineral Product Manufacturing	$48,513,197
	3112	Grain and Oilseed Milling	$43,094,463
	3314	Nonferrous Metal (except Aluminum) Production and Processing	$42,555,602
	3361	Motor Vehicle Manufacturing	$40,900,683

High Electricity-Consuming Manufacturing

Twenty (20) manufacturing industries were identified as the largest consumers of electricity in Ohio. Each of these manufacturing industries spends at least $40 million per year on electricity supplies. Of those 20 industries, 11 were considered high electricity-consuming manufacturing industries. Each industry in high electricity-consuming manufacturing group spends over $67 million annually on electricity supplies. This group is led by the industry *Basic Chemical Manufacturing* (NAICS 3251), which spends over $358 million annually on electricity supplies, followed by *Iron and Steel Mills and Ferroalloy Manufacturing* (NAICS 3311), which spends over $305 million annually. The other largest consumers of electricity in Ohio belong to industries producing such products as aluminum, petroleum and coal, plastic products, motor vehicle parts, paper, raisin, pesticide and fertilizer, dairy products, and foundries.

Moderate Electricity-Consuming Manufacturing

The Moderate Electricity-Consuming Manufacturing group includes nine industries that spend between $41 and $56 million annually on electricity supply. The largest electricity consumer in this group was *Other Fabricated Metal Product Manufacturing* (NAICS 3329), which pays about $56 million per year for the supply of electricity in Ohio. Other industries in this group include those that manufacture steel products, converted paper products, glass, nonmetallic minerals, motor vehicles, and specialty food. We used both ranked indicators (high unit electricity-intensive and large consumers of electricity) to identify 14 manufacturing industries in Ohio (Table 3).

Table 3. Ohio Manufacturing Industries: Electricity-Intensive and Large Consumers of Electricity

	NAICS	Industry Name
High Electricity-Intensive and Consuming Manufacturing	3313	Alumina and Aluminum Production and Processing
	3221	Pulp, Paper, and Paperboard Mills
	3311	Iron and Steel Mills and Ferroalloy Manufacturing
	3251	Basic Chemical Manufacturing
	3272	Glass and Glass Product Manufacturing
	3315	Foundries
	3279	Other Nonmetallic Mineral Product Manufacturing
	3253	Pesticide, Fertilizer, and Other Agricultural Chemical Manufacturing
Moderate Electricity-Intensive and Consuming Manufacturing	3112	Grain and Oilseed Milling
	3252	Resin, Synthetic Rubber, and Artificial Synthetic Fibers and Filaments
	3312	Steel Product Manufacturing from Purchased Steel
	3115	Dairy Product Manufacturing
	3114	Fruit and Vegetable Preserving and Specialty Food Manufacturing
	3314	Nonferrous Metal (except Aluminum) Production and Processing

Industries that fit both criteria are large, electricity-intensive consumers. This group creates electricity-intensive products and purchases large volumes of electricity due to their industry size in Ohio. Fourteen (14) manufacturing industries are electricity-intensive and large consumers of electricity due to their size in Ohio. These 14 industries include all industries in primary metal manufacturing sector (NAICS 331: NAICS 3311, 3312, 3313, 3314, 3315); three chemical manufacturing industries (NAICS 3251, 3252, 3253); three food manufacturing industries (NAICS 3112, 3114, 3115); and paper, glass, and nonmetallic mineral product manufacturing (NAICS 3221, 3272, 3279).

Table 4. Electricity-Intensive, Non-Manufacturing Industries Identified by Unit Expenses for Electricity

NAICS	Industry Name	Electricity Expenditures Per $1 of Industry Expenses
721	Accommodation	0.029303
2123	Nonmetallic Mineral Mining and Quarrying	0.028517
1119	Other Crop Farming	0.022541
712	Museums, Historical Sites, and Similar Institutions	0.020142
1112	Vegetable and Melon Farming	0.018514
1113	Fruit and Tree Nut Farming	0.017923
611	Educational Services	0.017522
713	Amusement, Gambling, and Recreation Industries	0.016856
2121	Coal Mining	0.016488
722	Food Services and Drinking Places	0.015693
531	Real Estate	0.015551
493	Warehousing and Storage	0.015231
112	Animal Production	0.013455
623	Nursing and Residential Care Facilities	0.012337
8121	Personal Care Services	0.011442
533	Lessors of Nonfinancial Intangible Assets (except Copyrighted Works)	0.010497
622	Hospitals	0.010485

To identify electricity-intensive, non-manufacturing industries in Ohio, we applied the same two criteria used for manufacturing industries: unit expenses for electricity and total industry expenditures for electricity. Seventeen (17) 4-digit NAICS non-manufacturing industries and broader industrial sectors spent at least one cent per each dollar of expenses on electricity supply (1% of their total annual expenditures in Ohio). The largest sectors and industries include farming, accommodations, and industries that utilize large commercial buildings, such as museums, universities, hospitals, and warehouses. To identify the large consumers of electricity among non-manufacturing industries, the total expenditures on the electricity indicator was applied to three groups of industries classified by the level of NAICS: 2-digit sectors, 3-digit sectors, and 4-digit non-manufacturing industries (Table 5).[13]

[13] IMPLAN's industry classification corresponds to a combination of 2-, 3-, and 4-digit NAICS industry classifications for non-manufacturing industries.

Table 5. Non-Manufacturing Industries Identified by Total Industry Expenditures for Electricity

	NAICS	Industry Name	Total Industry Expenditures for Electricity in OH
2-digit NAICS	23	Construction	$103,084,857
	42	Wholesale Trade	$165,244,919
	55	Management of Companies and Enterprises	$91,376,320
3-digit NAICS	531	Real Estate	$385,969,940
	722	Food Services and Drinking Places	$342,473,541
	622	Hospitals	$304,688,721
	611	Educational Services	$124,426,390
	623	Nursing and Residential Care Facilities	$115,215,073
	621	Ambulatory Health Care Services	$90,999,878
	721	Accommodation	$71,800,729
	493	Warehousing and Storage	$50,096,107
	713	Amusement, Gambling, and Recreation Industries	$44,469,557
	813	Religious, Grant making, Civic, Professional, and Similar Organizations	$43,985,471
4-digit NAICS	5415	Computer Systems Design and Related Services	$80,921,712
	1111	Oilseed and Grain Farming	$26,859,565
	8121	Personal Care Services	$26,797,682
	2123	Nonmetallic Mineral Mining and Quarrying	$22,850,089
	8111	Automotive Repair and Maintenance	$18,308,483
	5417	Scientific Research and Development Services	$17,613,731
	2121	Coal Mining	$15,592,757
	5111	Newspaper, Periodical, Book, and Directory Publishers	$15,106,413

Eleven (11) non-manufacturing industries and sectors were identified as large consumers of electricity due both to their significant size in Ohio and the high electricity intensity of their products and services (Table 6). Eight (8) 3-digit NAICS sectors and three 4-digit NAICS industries were the largest electricity consumers and most electricity-intensive non-manufacturing industries in Ohio.

Table 6. Electricity-Intensive, Large Non-Manufacturing Consumers

NAICS	Industry Name
721	Accommodation
2123	Nonmetallic Mineral Mining and Quarrying
611	Educational Services
713	Amusement, Gambling, and Recreation Industries
2121	Coal Mining
722	Food Services and Drinking Places
531	Real Estate
493	Warehousing and Storage
623	Nursing and Residential Care Facilities
8121	Personal Care Services
622	Hospitals

Note: Ranked by unit expenses on electricity

Defining Ohio's Economic Base Industries

To identify Ohio's economic base, we researched the Location Quotient (LQ) of Gross State Product (GSP), the growth of GSP, and industries' productivity over three time periods: 2000-2010, 2007-2010 and 2009-2010. According to GSP LQ, 52 4-digit NAICS manufacturing industries represented the economic base of Ohio's economy in 2010.[14] The manufacturing industries presented in Table 7 are ranked by 2010 GSP LQ.

Table 7. Ohio's Manufacturing Industries

NAICS	Description	GSP LQ, 2010
3352	Household Appliance Manufacturing	4.954
3363	Motor Vehicle Parts Manufacturing	3.722
3321	Forging and Stamping	3.703
3255	Paint, Coating, and Adhesive Manufacturing	3.601
3324	Boiler, Tank, and Shipping Container Manufacturing	3.351
3271	Clay Product and Refractory Manufacturing	3.233
3361	Motor Vehicle Manufacturing	3.200
3312	Steel Product Manufacturing from Purchased Steel	3.198
3322	Cutlery and Handtool Manufacturing	3.186
3328	Coating, Engraving, Heat Treating, and Allied Activities	3.069
3335	Metalworking Machinery Manufacturing	3.017
3262	Rubber Product Manufacturing	2.985
3279	Other Nonmetallic Mineral Product Manufacturing	2.931
3369	Other Transportation Equipment Manufacturing	2.829
3329	Other Fabricated Metal Product Manufacturing	2.802
3256	Soap, Cleaning Compound, and Toilet Preparation Manufacturing	2.617
3272	Glass and Glass Product Manufacturing	2.518
3114	Fruit and Vegetable Preserving and Specialty Food Manufacturing	2.490
3315	Foundries	2.449
3311	Iron and Steel Mills and Ferroalloy Manufacturing	2.441
3327	Machine Shops; Turned Product; and Screw, Nut, and Bolt Manufacturing	2.349
3261	Plastics Product Manufacturing	2.278
3351	Electric Lighting Equipment Manufacturing	2.276
3339	Other General Purpose Machinery Manufacturing	2.112
3115	Dairy Product Manufacturing	2.085
3353	Electrical Equipment Manufacturing	2.001
3332	Industrial Machinery Manufacturing	1.968
3251	Basic Chemical Manufacturing	1.941

[14] Location Quotient measures the specialization of an industry in a region by comparing it to data in a larger region. For our analysis: $LQ = \frac{\frac{g_i}{g}}{\frac{G_i}{G}}$ where g_i = The Ohio Gross Product in industry i; g = Total Gross Product in Ohio; G_i= US Gross Product in industry i; G = Total US Gross Product. A GSP LQ above 1.00 indicates that the share of an industry's gross state product in the total regional gross product exceeds the share of this industry's GDP in the total U.S. GDP. This disproportionally large production of GSP denotes an industry as a potential part of the regional economic base.

NAICS	Description	GSP LQ, 2010
3253	Pesticide, Fertilizer, and Other Agricultural Chemical Manufacturing	1.825
3111	Animal Food Manufacturing	1.815
3326	Spring and Wire Product Manufacturing	1.809
3252	Resin, Synthetic Rubber, and Artificial Synthetic Fibers and Filaments	1.775
3359	Other Electrical Equipment and Component Manufacturing	1.726
3259	Other Chemical Product and Preparation Manufacturing	1.692
3314	Nonferrous Metal (except Aluminum) Production and Processing	1.671
3371	Household and Institutional Furniture and Kitchen Cabinet Manufacturing	1.518
3362	Motor Vehicle Body and Trailer Manufacturing	1.496
3323	Architectural and Structural Metals Manufacturing	1.482
3118	Bakeries and Tortilla Manufacturing	1.480
3231	Printing and Related Support Activities	1.466
3274	Lime and Gypsum Product Manufacturing	1.438
3325	Hardware Manufacturing	1.398
3313	Alumina and Aluminum Production and Processing	1.397
3119	Other Food Manufacturing	1.389
3334	Ventilation, Heating, Air-Conditioning, and Commercial Refrigeration E	1.374
3222	Converted Paper Product Manufacturing	1.343
3219	Other Wood Product Manufacturing	1.309
3169	Other Leather and Allied Product Manufacturing	1.242
3121	Beverage Manufacturing	1.226
3241	Petroleum and Coal Products Manufacturing	1.167
3113	Sugar and Confectionery Product Manufacturing	1.054
3149	Other Textile Product Mills	1.026

Table 7. Ohio's Manufacturing Industries (cont.)

Source: Moody's Economy.com

As shown in Table 7, Ohio's economic base is heavily represented by the following manufacturing industries:

- ✓ Food manufacturing (NAICS 311)
- ✓ Chemical manufacturing (NAICS 325)
- ✓ Nonmetallic mineral product manufacturing (NAICS 327)
- ✓ Primary metal manufacturing (NAICS 331)
- ✓ Fabricated metal product manufacturing (NAICS 332)
- ✓ Machinery manufacturing (NAICS 333)
- ✓ Electrical equipment, appliance, and component manufacturing (NAICS 335)
- ✓ Transportation equipment manufacturing (NAICS 336)

Twenty-eight manufacturing industries in Ohio (26 of these industries are displayed in Table 8) experienced positive GSP growth (at least 1%) between 2007 and 2010.[15] GSP of the *Petroleum and Coal Products Manufacturing* industry (NAICS 3241) increased by 51% over the last 3 years (2007-2010); by 136% from 2000 to 2010. The *Other Electrical Equipment and Component Manufacturing* (NAICS 3359) and *Pharmaceutical and Medicine Manufacturing* (NAICS 3254)

[15] Two very small industries, the Leather and Hide Tanning and Finishing (NAICS 3161) and the Tobacco Manufacturing (NAICS 3122) are removed from the analysis due to data confidentiality.

industries grew by 31% between 2007 and 2010. The *Pesticide and Other Chemical Manufacturing* (NAICS 3253) industry showed a large growth in GSP from 2009 to 2010. However, the size of the industry is too small to influence the overall economy in Ohio.

Table 8. GSP Growth of Ohio's Manufacturing Industries

NAICS	Description	Employment, 2010	2010 GSP (in 2010 dollars)	% GSP change, 2000-2010	% GSP change, 2007-2010	% GSP change, 2009-2010
3241	Petroleum and Coal Products Manufacturing	3,964	$4,963,152	136%	51%	9%
3253	Pesticide, Fertilizer, and Other Agricultural Chemical Manufacturing	966	$585,050	66%	46%	17%
3359	Other Electrical Equipment and Component Manufacturing	6,280	$1,019,356	7%	31%	9%
3254	Pharmaceutical and Medicine Manufacturing	5,793	$1,883,134	131%	31%	11%
3116	Animal Slaughtering and Processing	8,768	$1,061,118	21%	25%	8%
3114	Fruit and Vegetable Preserving and Specialty Food Manufacturing	11,684	$1,834,442	33%	20%	11%
3115	Dairy Product Manufacturing	8,179	$1,409,510	20%	19%	9%
3346	Manufacturing and Reproducing Magnetic and Optical Media	1,180	$27,903	-66%	18%	19%
3352	Household Appliance Manufacturing	4,533	$1,515,133	-7%	18%	9%
3324	Boiler, Tank, and Shipping Container Manufacturing	8,045	$1,102,876	13%	18%	4%
3369	Other Transportation Equipment Manufacturing	1,386	$332,151	30%	18%	0%
3256	Soap, Cleaning Compound, and Toilet Preparation Manufacturing	10,231	$1,761,906	59%	17%	10%
3119	Other Food Manufacturing	6,196	$1,217,421	9%	17%	12%
3353	Electrical Equipment Manufacturing	7,091	$1,423,332	-6%	16%	-2%
3279	Other Nonmetallic Mineral Product Manufacturing	6,171	$708,435	-11%	16%	11%
3111	Animal Food Manufacturing	2,333	$502,929	-5%	12%	8%
3118	Bakeries and Tortilla Manufacturing	9,856	$1,570,680	6%	12%	7%
3255	Paint, Coating, and Adhesive Manufacturing	6,305	$1,363,263	26%	11%	10%
3274	Lime and Gypsum Product Manufacturing	592	$83,441	-30%	10%	10%
3251	Basic Chemical Manufacturing	8,737	$2,832,472	37%	10%	8%
3121	Beverage Manufacturing	6,870	$1,126,952	16%	8%	6%
3113	Sugar and Confectionery Product Manufacturing	1,488	$321,315	66%	4%	7%
3391	Medical Equipment and Supplies Manufacturing	9,034	$1,107,998	21%	4%	6%
3252	Resin, Synthetic Rubber, and Artificial Synthetic Fibers and Filaments	5,307	$1,286,891	54%	3%	6%
3112	Grain and Oilseed Milling	2,029	$335,240	-21%	2%	7%
3272	Glass and Glass Product Manufacturing	7,685	$750,979	-43%	1%	6%

Source: Moody's Economy.com

Industries that were growing from 2007 to 2010 were likely to have high productivity[16] in 2010 (Table 9):

- ✓ Petroleum and coal products manufacturing
- ✓ Pesticide, fertilizer, and other agricultural chemical manufacturing
- ✓ Household appliance manufacturing
- ✓ Pharmaceutical and medicine manufacturing
- ✓ Basic chemical manufacturing

Table 9. Ohio Manufacturing Industries with High Productivity, 2010

NAICS	Description	Employment, 2010	2010 GSP (in 2010 dollars)	Productivity, 2010 ($ per employee)
3241	Petroleum and Coal Products Manufacturing	3,964	$4,963,152	**$1,252,056**
3253	Pesticide, Fertilizer, and Other Agricultural Chemical Manufacturing	966	$585,050	**$605,642**
3352	Household Appliance Manufacturing	4,533	$1,515,133	**$334,245**
3254	Pharmaceutical and Medicine Manufacturing	5,793	$1,883,134	**$325,071**
3251	Basic Chemical Manufacturing	8,737	$2,832,472	**$324,193**
3252	Resin, Synthetic Rubber,& Artificial Synthetic Fibers & Filaments	5,307	$1,286,891	**$242,489**
3369	Other Transportation Equipment Manufacturing	1,386	$332,151	**$239,647**
3255	Paint, Coating, and Adhesive Manufacturing	6,305	$1,363,263	**$216,219**
3113	Sugar and Confectionery Product Manufacturing	1,488	$321,315	**$215,938**
3111	Animal Food Manufacturing	2,333	$502,929	**$215,572**
3353	Electrical Equipment Manufacturing	7,091	$1,423,332	**$200,724**
3119	Other Food Manufacturing	6,196	$1,217,421	**$196,485**
3259	Other Chemical Product and Preparation Manufacturing	5,482	$1,004,093	**$183,162**
3361	Motor Vehicle Manufacturing	16,968	$3,027,235	**$178,408**
3115	Dairy Product Manufacturing	8,179	$1,409,510	**$172,333**
3256	Soap, Cleaning Compound, and Toilet Preparation Manufacturing	10,231	$1,761,906	**$172,213**
3112	Grain and Oilseed Milling	2,029	$335,240	**$165,224**
3351	Electric Lighting Equipment Manufacturing	2,768	$456,119	**$164,783**

[16] Manufacturing industries' productivity is calculated as industry manufacturing GSP divided by industry's employment for the same time period.

Ohio's Electricity-Intensive Base Manufacturing Industries

Twelve (12) of the 14 manufacturing industries that produce electricity-intensive products and are large consumers of electricity in Ohio are part of the state's economic base (Table 10). These industries have a location quotient (LQ) of gross state product (GSP) above 1. Seven (7) of these industries' LQs exceed 2. The largest electricity consumer in this group is NAICS 3329, *Other Fabricated Metal Product Manufacturing* (LQ 1.4), which spends about $56 million per year on the supply of electricity. Other industries in this group include those that manufacture steel products, converted paper products, glass, nonmetallic minerals, motor vehicles, and specialty food.

Table 10. Economic Base Industries: Electricity-intensive and Large Consumers of Electricity in Ohio

NAICS	Definition	Electricity Intensity (per $, total $)	GSP LQ, 2010
3313	Alumina and Aluminum Production and Processing	H, H	1.397
3311	Iron and Steel Mills and Ferroalloy Manufacturing	H, H	2.441
3251	Basic Chemical Manufacturing	H, H	1.941
3272	Glass and Glass Product Manufacturing	H, M	2.518
3315	Foundries	H, H	2.449
3279	Other Nonmetallic Mineral Product Manufacturing	H, M	2.931
3253	Pesticide, Fertilizer, and Other Agricultural Chemical Manuf	H, H	1.825
3252	Resin, Synthetic Rubber,& Artificial Synthetic Fibers & Filaments	M, H	1.775
3312	Steel Product Manufacturing from Purchased Steel	M, M	3.198
3115	Dairy Product Manufacturing	M, H	2.085
3114	Fruit and Vegetable Preserving and Specialty Food Manufacturing	M, M	2.490
3314	Nonferrous Metal (except Aluminum) Production and Processing	M, M	1.671

Note: Ranked by per dollar expense on electricity.
The first letter in the Electricity Intensity column indicates the group of the electricity-intense industries (High (H) or Moderate (M)); the second letter indicates the group of the high (H) or Moderate (M) consumer of electricity in Ohio.

Data Centers

Data Centers are defined as "Industries [...] that provide the infrastructure for hosting and/or data processing services" by U.S. Census Bureau. Those industries are classified under 2007 NAICS 518/5182: *Data Processing, Hosting, and Related Services.*[17] There are seven types of data centers classified by Brown, et al. (2001)[18] as followed:

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[17] Data Centers classified under 1997 NAICS (Darrow & Hedman, 2009):

- ✓ NAICS 514191: *Online Information Services*
- ✓ NAICS 5142: *Data Processing Services*

[18] ACEEE: Overview of Data Centers and Their Implications for Energy Demand, Elizabeth Brown, R. Neal Elliott, and Anna Shipley, American Council for an Energy-Efficient Economy, Washington, DC, Sep. 2001.

- ✓ Telecoms
- ✓ Internet Service Providers (ISP's)
- ✓ Co-located Server Hosting Facilities (CoLos)
- ✓ Server Farms
- ✓ Internet Hotels
- ✓ Corporate Data Centers
- ✓ University, National Laboratory

The site selection of data centers are affected by several factors. Places which have the regional characteristics and economic environment described below are favorable to attract data centers to the location.

- ✓ Less Natural Disasters
- ✓ Favorable Business Climate
  - Workforce – computer science, information technology, and facility management
  - Union rules – a "right to work" state
  - Financial Considerations
    - Tax breaks, incentives, costs of doing business
    - Insurance costs in the area
    - Cost of land
  - Easy access to a fiber network
  - Lower power costs

In Ohio, however, no establishments exist in the *Data Processing, Hosting, and Related Services* industry (NAICS 5182), according to data of the Quarterly Census of Employment and Wages (QCEW). The broader industry where the data centers fit has very low unit electricity intensity in Ohio. Per dollar expenses of electricity for NAICS 518 industry was 0.00044 in 2009 data for the IMPLAN model; the average per dollar expense of electricity for a manufacturing industry was 0.00971. Total expenditure of electricity for the NAICS 518 industry was $473,337. The average total expenditure of electricity for a manufacturing industry was $32,559,567. The data centers industry in Ohio does not belong to the state's economic base. The GSP LQ for NAICS 518 was 0.291 in 2010.
There are three Lexis-Nexis establishments in Ohio. LexisNexis' world headquarters is located in Dayton, Ohio.[19]

- ✓ NAICS 5179 – All Other Telecommunications – Cleveland (Cuyahoga County)
- ✓ NAICS 5411 – Offices of Lawyers – Miamisburg (Montgomery County)
- ✓ Unclassified – Springboro (Warren County)

[19] Source: Reference USA

Summary

Twelve Ohio industries manufacture highly electricity-intensive products and, at the same time, are a significant part of the state's economic base.
These industries belong to four broader sectors:

- ✓ NAICS 311: Two industries in *Food Manufacturing* had a total employment over 20,000 and were growing since 2000.[20] Average GSP growth of these industries in 2009-2010 was 10%.
- ✓ NAICS 325: Three industries in *Chemical Manufacturing* experienced GSP growth since 2000. Two of these three industries (NAICS 3251 & 3252) were also among the industries with high productivity in Ohio. Together, these three industries employed almost 15,000 people in Ohio in 2010.
- ✓ NAICS 327: Two industries in *Nonmetallic Mineral Product Manufacturing* experienced GSP growth since 2007.[21] These two industries employed almost 14,000 people in Ohio in 2010.
- ✓ NAICS 331: Five industries in *Primary Metal Manufacturing* sector were not among those with GSP growth or high productivity. However, this industry sector employed 37,297 people in Ohio in 2010.[22]

[20] This statement implies that the industry was growing from 2000 to 2010, from 2007 to 2010, and from 2009 to 2010.
[21] This statement implies that the industry was growing from 2007 to 2010 and from 2009 to 2010.
[22] See additional industry statistics in Appendix Table1.

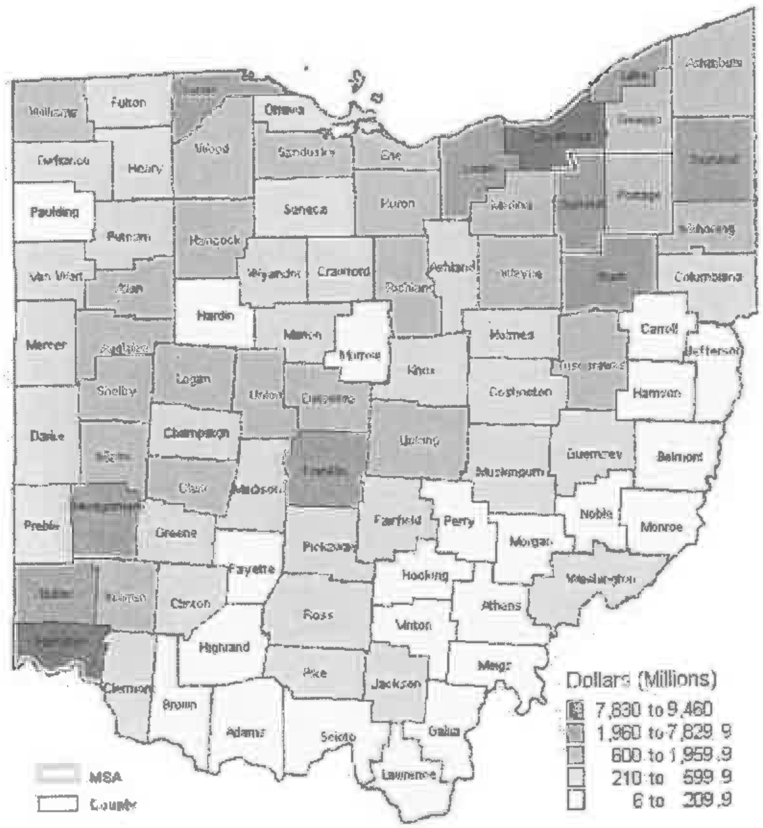
Mapping the Geographic Distribution of Electricity-Intensive Manufacturing Industries in Ohio

Northeast and Southwest Ohio have relatively dense populations of manufacturing employment (Figure 3). In Northeast Ohio, manufacturing employees are concentrated in Cuyahoga, Lake, Summit, and Stark counties. In Southwest Ohio, Montgomery, Butler, and Hamilton counties have a high concentration of manufacturing employment. Manufacturing employees are also concentrated in Lucas County (Northwest Ohio) and Franklin County (Central Ohio). Manufacturing employment tends to locate in urban areas; counties with large cities are more likely to have a greater number of manufacturing employees: Cuyahoga (Cleveland), Hamilton (Cincinnati), Franklin (Columbus), Lucas (Toledo), and Stark (Canton).

Figure 3. Total Manufacturing Employment

Northeast Ohio shows relatively high levels of the gross state product (GSP). Manufacturing GSP is highest in Cuyahoga County (Northeast Ohio). Hamilton County in Southwest Ohio also has a manufacturing GSP between $7,830 and $9,460 million in 2010 (Figure 4).

Figure 4. Total GSP of Manufacturing Industries

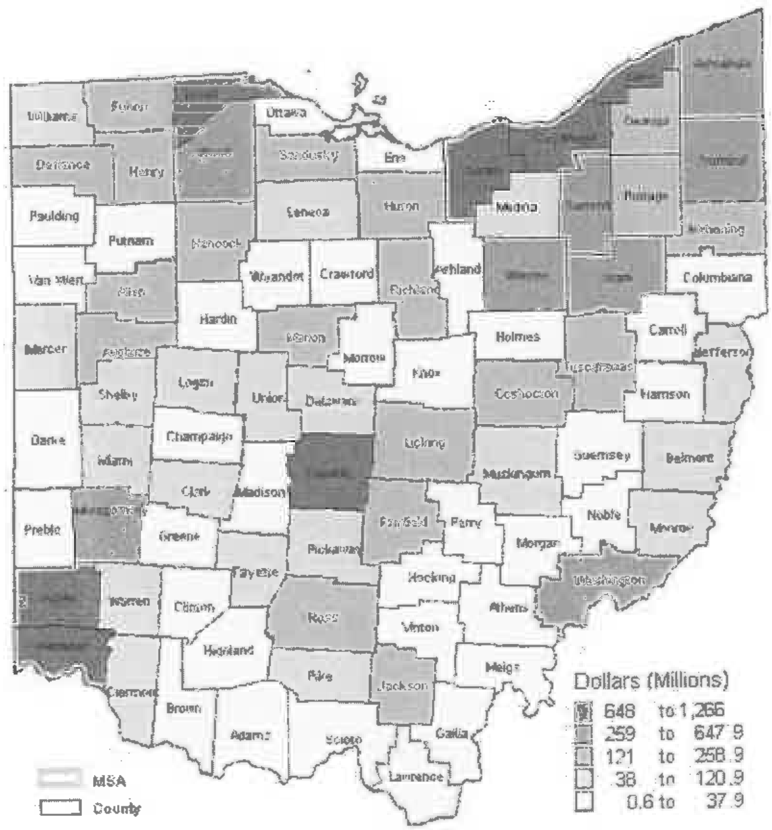


Companies in electricity-intensive manufacturing industries are located primarily in Northeast Ohio (Figure 5). Cuyahoga, Stark, and Trumbull counties each have more than 3,680 employees in electricity-intensive manufacturing. Other counties in the Northeast also have relatively large electricity-intensive manufacturing employment. Other counties with a high concentration of electricity-intensive manufacturing employment include Franklin County in Central Ohio, Hamilton and Butler counties in Southwest Ohio, and Lucas County in Northwest Ohio.

Figure 5. Employment in Electricity-Intensive Manufacturing Industries

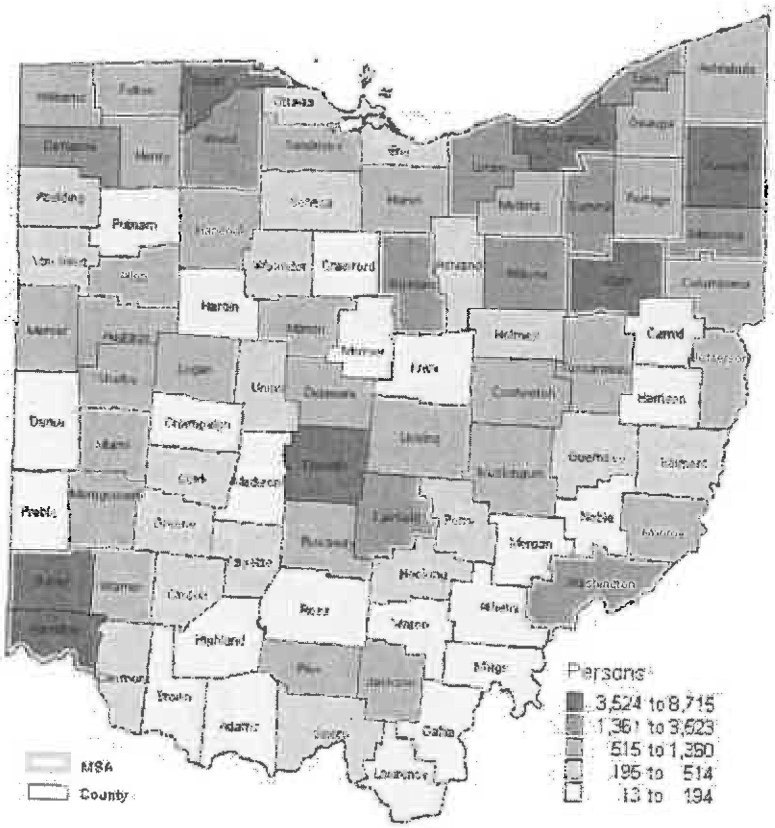
Northeast Ohio counties — Cuyahoga, Lake, and Lorain counties —have higher GSP in electricity-intensive manufacturing industries than other counties in Ohio (Figure 6). Electricity-intensive manufacturing industries also generate high GDP in Franklin County (Central Ohio), Butler and Hamilton counties (Southwest Ohio), and Lucas County (Northwest Ohio).

Figure 6. GSP of Electricity-Intensive Manufacturing Industries



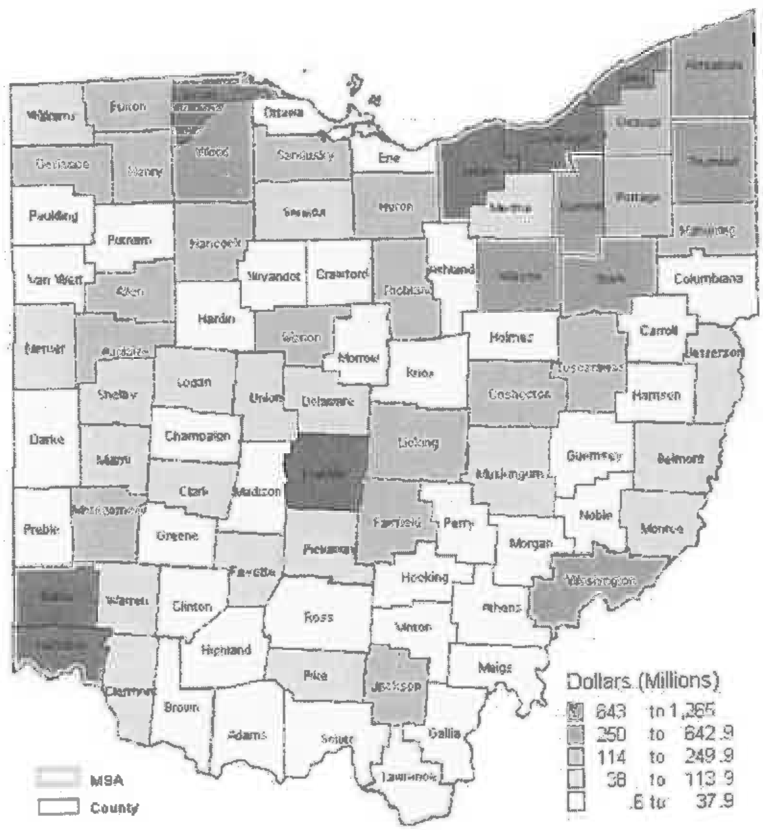
Northeast Ohio has relatively high employment in companies that belong to Ohio's economic base industries (Figure 7). Other regions tend to have companies with high employment in manufacturing economic base industries only within counties with large urban centers: Franklin, Butler, Hamilton, and Lucas counties.

Figure 7. Employment in Manufacturing Base Industries



Counties in Northeast Ohio show high GSP in manufacturing base industries (Figure 8). Cuyahoga, Lake, and Lorain counties produce more than $643 million in manufacturing economic base industries. Other counties in the Northeast also have relatively high GSP in manufacturing economic base industries. GSP in manufacturing base industries is high in Franklin County (Central Ohio), Butler and Hamilton counties (Southwest Ohio), and Lucas County (Northwest Ohio).

Figure 8. GSP in Manufacturing Base Industries



Establishments of all manufacturing industries are concentrated in Northeast and Southwest Ohio (Figure 9). In the Northeast, Cuyahoga and Summit are the most populous counties in terms of number of manufacturing establishments industries. Manufacturing establishments are also highly concentrated in surrounding counties. Hamilton and Montgomery counties in Southwest Ohio have a large number of manufacturing establishments. Franklin County in Central Ohio shows a heavy concentration of manufacturing establishments.

Figure 9. Number of Establishments in All Manufacturing Industries

Electricity-intensive manufacturing base establishments are heavily concentrated in Northeast Ohio (Figure 10), especially among Cuyahoga, Summit, and Stark counties, which are parts of the traditional Cleveland industrial belt. Another county with a large number of electricity-intensive manufacturing establishments is Hamilton County (Southwest Ohio), which has Cincinnati at its core.

Figure 10. Number of Establishments in Electricity-Intensive Manufacturing Base Industries

Part 2: Effects of Electricity Pricing Changes on Manufacturers in Ohio

This part of the study explores the industrial electricity price model through a regression analysis addressing the productivity of the manufacturing sector and industrial electricity pricing. This analysis pursued two research questions: (1) How does industrial electricity pricing influence the productivity of the manufacturing sector; and (2) What are the influences of electricity market deregulation on the industrial electricity market and the productivity of the manufacturing sector? The results of this analysis were applied to a simulation of how Ohio manufacturing productivity responds to changes in industrial electricity pricing and deregulation of Ohio electricity market.

Methodology

The geographic area used for statistical modeling in this study is defined as the state of Ohio and neighboring states Indiana, Kentucky, Michigan, and Pennsylvania. Each of these states is located within the reach of the same industrial electricity market. These states also have similar economic structures and comparable electricity customers, among which are electricity-intensive manufacturing users.

Because the five selected states are located in close geographic proximity and manufacturing represents a significant share of each state's economy, we assume that the data used in the statistical model are homogeneous. Any variation in the data can be explained by different state public policies and other specific factors relevant to industrial electricity pricing and manufacturing productivity.

We analyzed the productivity of the manufacturing industry and industrial electricity rates in Ohio, Indiana, Kentucky, Michigan, and Pennsylvania between 1990 and 2010. The latest year for which industrial electricity pricing data was available was 2010.

This study is based on a total of 105 points of observation, including, for each state, 21 years of history in industrial electricity pricing, manufacturing productivity, electricity market deregulation, and other factors relevant to electricity pricing and manufacturing.

Influence of industrial electricity price on manufacturing productivity

In the model, we hypothesized an inverse relationship between industrial electricity price and performance in the state manufacturing sector over time. To measure the performance of manufacturing, several variables were tested in the model, including manufacturing employment, manufacturing gross state product, and employment and gross state product of electricity-intensive subsectors within the states' manufacturing industries. Due to the short history of statistical data included in the model, none of the proposed variables demonstrated statistical relationships to industrial electricity pricing.

By capturing the peak of economic performance during the last business cycle, including the most recent "Great Recession" that began in 2008, and the slow recovery therefrom, we were able to show the relationship of electricity pricing to a more universal economic variable: productivity. The closest proxy of true labor productivity we were able to derive was an annual amount of gross state product produced per employee. This variable reflects both the shattered employment during the recessionary phase of the business cycle and the enhancement of technology that led to increases in labor productivity. Unfortunately, this variable also reflects the inflationary changes of the products imbedded in the measure of GDP and is ignorant of structural changes in the economy that are likely inflating the value of manufacturing products over time.

We have assumed the states' average industrial electricity prices to explain variation in manufacturing productivity among states and over time. Manufacturing performance, however, was influenced by more than just electricity prices. Some other influences were accounted for in our modeling. We also considered electricity market deregulation as an important policy choice that has influenced manufacturing productivity. In analyzing deregulation, we hypothesized a direct relationship between the variable expressing the year of deregulation in a given state and an increase in lagged manufacturing productivity the subsequent year.

Although industrial electricity prices and energy market deregulation were two policy variables of particular interest, we included a number of additional variables that fit two criteria: (1) they may influence the performance of manufacturing companies, and (2) the data for the variable were available for all five states and over time. This group of control variables included consideration of the following: business cycle phases; the dynamics of manufacturing employment; a presence of large manufacturing companies in the state; and the performance of the "Electric Power Generation, Transmission, and Distribution industry" (NAICS 2211) in the state.

Overall, the statistical model is built to test the effect of policy variables on manufacturing productivity (industrial electricity price and deregulation variables), controlling for the demand on the electricity market (manufacturing employment and significant presence of large manufacturing companies), the supply on the electricity market (size of power generation industry), and overall economic conditions (business cycle variable "*Recession*"). This logic of our statistical model can be expressed in the following equation:

Mnf Productivity = f (Industrial electricity price, Deregulation, Manufacturing employment, Presence of large manufacturing establishments, Size of power generation industry, Recession)

Where:

Mnf Productivity is the approximated productivity of a state's manufacturing sector; and the following variables can be defined as:

Industrial electricity price (IEP) - average state industrial electricity price;

Deregulation – an approximation based upon the change in policy deregulating the electricity market in a given state;

Manufacturing employment (%ch_mnf.emp) – the percentage change of manufacturing employment in a given state;

Presence of large manufacturing establishments (Mnf.1000LQ) – the change in relative number of large manufacturing companies in a state, compared to the number of large manufacturing companies in the United States;

Size of power generation industry (%ch._2211_GSP) – the percent change of gross state product produced by the *Electric Power Generation, Transmission, and Distribution* industry (NAICS 2211) in a state in a given year; and

Recession – approximating the trough of the business cycles between 1990 and 2010.

Variables for the Statistical Model

Dependent variable: Productivity of manufacturing sector in the state

Labor productivity is an indicator of value creation in the economy. Rather than employment or absolute value of gross state product, we believe that the indicator of GSP per employee best reflects the challenges of the manufacturing sector across different phases of the business cycle. Over the last two decades, the Ohio economy has demonstrated prolonged periods between the peaks and troughs of adjoining business cycles. The time period of this study—1990 to 2010—showcases this phenomenon and features several phases of the business cycle: the declining phase from July 1990 to March 1991; the historically long growth of the economy from 1991 to March 2001; the crash between March and November of 1991; the sluggish recovery through December 2007, which represented the shortest expansion phase since the 1990s; a new contraction, which led to a trough in June 2009; and, since then, an uncertain expansion of the economy.

Independent Variables

Industrial Electricity Price

The effect of energy cost on economic performance is a popular topic in academic studies exploring the impact of federal and state policies. In particular, electricity price has been proven to be an important factor in the site selection process of U.S. manufacturing companies. States with relatively low priced industrial electricity are proven to better attract firms looking to reduce their production costs (Carlton, 1983).[23] Deschenes (2010), who employed a state panel data model similar to ours, was unable to disprove the hypothesis that no correlation exists between manufacturing employment and changes in state electricity prices.[24] This study anticipated that low industrial electricity prices may explain in part the economic growth and competitiveness of manufacturing industries in the five targeted states through demonstrated positive relationships with manufacturing productivity.

We used the annual average price of industrial electricity sold within a state as the measure of industrial electricity price (IEP) for the analysis. Industrial electricity prices vary among states and have changed between 1990 and 2010. The state's annual average industrial electricity price data are derived from the Energy Information Administration (EIA) and all price data are inflation-adjusted to 2012.

Electricity market restructuring in a state

Electricity market deregulation and restructuring was operationalized in the statistical model by a dichotomous variable. A state was coded as 1 if it had an active, restructured energy market or an effective legislative act in place allowing for the presence of a competitive electricity market in a given year. A state was coded as 0 if neither of the preceding elements existed. Information to construct this variable is recorded in Table 11.

Table 11. Status and Year of Electricity Market Restructuring and Deregulation in Selected States

State	Status	Enactment Year	Effective Year
IN	Not active	-	-
KA	Not active	-	-
MI	Active	June 3, 2000	January, 2002
OH	Active	July 6, 1999	January, 2001
PA	Active	December, 1996	January, 2000

Data source: U.S. Energy Information Administration
(http://www.eia.gov/cneaf/electricity/page/restructuring/restructure_elect.html)

This variable approximates the changes in state electricity markets, hypothesizing that the increased availability and diversity of sources for generating industrial electricity is likely to increase the supply of electricity and decrease industrial electricity prices. This variable alone would not explain the difference in electricity pricing among the states as it does not account for the flexibility and competitiveness of corresponding state wholesale and transmission markets. It is expected that states with deregulated electricity markets will show positive changes in manufacturing productivity.

23 Carlton, D. (1983). The location and employment choices of new firms: An econometric model with discrete and continuous endogenous variables. *Review of Economics and Statistics*, *65*(3), 440-449.
24 Deschenes, O. (2010). Climate policy and labor markets. *NBER Working Paper* #16111.

Employment in the manufacturing sector of the state (percentage change)

This variable approximates a fluctuation of the change in the whole manufacturing sector at the state level. This variable controls for changes in the demand for electricity in the state from large-scale electricity users such as manufacturers. In regulated electricity markets with low elasticity of demand and high cost of entrance (due to significant capital expenditures), even small changes in demand will influence the market price with restricted access to generation and transmission capacity of neighboring states. This variable will reinforce the disadvantage of regulated market-states in cases of demand fluctuation. We looked at annual percentage changes of manufacturing employment. Employment data estimates were obtained from Moody's Economy.com.

Share of large manufacturing firms (LQ)

The relative share of large manufacturing establishments in the state is calculated as a location quotient (LQ), which is measured as the share of the number of manufacturing establishments with 1,000 or more employees in the state, divided by the same average number in the whole United States. It hypothesizes that states with disproportionally high numbers of large manufacturing establishments might have more individually negotiated contracts (with more customer leverage) between large electricity users and supply companies, which is likely to push down the average industrial electricity price in the state. It also controls for labor productivity advantages within large firms or establishments due to the scale economy found by some academic studies (Miller, 1978).[25] In other word, large firms have a relatively high value added per employee and low unit-cost products, which leads to higher labor productivity when compared to smaller companies and establishments. The number of manufacturing establishments by size classes is available from the U.S. Census Bureau's County Business Pattern (CBP) database.

Size of power industry (% GSP change)

In our study, gross state product of the *Electric Power Generation, Transmission, and Distribution* industry (NAICS 2211) approximates the size and capacity of a state's power generation function. It reflects the supply side of the state's electricity market and, together with the deregulation variable, controls for the state's capacity to supply manufacturing companies with the industrial electricity needed to ensure growth in manufacturing productivity. The source of these data is Moody's Economy.com.

Business cycle (recession)

Variation in the demand for industrial electricity and, consequently, the supply of electricity markets and electricity prices is significantly affected by business cycle fluctuations. Historically,

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[25] Miller, E. M. (1978). The extent of economies of scale: The effects of firm size on labor productivity and wage rates. *Southern Economic Journal*, 470-87.

recessionary years of economic activity and contraction of manufacturing production have yielded low demand for electricity and depressed electricity markets. The influence of the business cycle on state economies is approximated through this variable, which indicates business cycle troughs, or the lowest points of economic recession, between 1990 and 2010. For the years 1991, 2001, 2008, and 2009, when the national economy experienced a trough, the dichotomous variable is equal to 1; it is equal to 0 otherwise. Business cycle reference dates are available from the National Bureau of Economic Research.

Analysis Results

Industrial electricity price showed a statistically significant effect on manufacturing productivity across the five targeted states between 1990 and 2010 (Table 12). The industrial electricity price variable is statistically significant above the 99% critical value and is negatively associated with manufacturing productivity across the selected points of observation. In other words, the higher the industrial electricity prices were in the five selected states, the lower manufacturing productivity was in these states in 99% of cases. Using this history, we can assume with high confidence that higher industrial electricity rates in Ohio will most likely be associated with lower manufacturing productivity.

Moreover, the deregulation of the electricity market is positively associated with manufacturing productivity. This relationship is statistically significant above the 99% critical value.

Table 12. Regression Analysis Results: Determinants of Manufacturing Productivity

Manufacturing Productivity	Unstandardized Coefficients		Standardized Coefficients	t	P-value
	B	Std. Error	Beta		
(Constant)	108174.453	8370.131		12.924	.000
Industrial Electricity Price	-2527.259	795.915	-.274	-3.175	.002
Percentage Change of Manufacturing Employment	-72750.268	38965.873	-.212	-1.867	.065
Output LQ of Large Manufacturing Firms	13350.313	3099.256	.387	4.308	.000
Recession	-6344.511	3617.226	-.179	-1.754	.083
Percentage Change of Output of Power Industry	45218.611	20626.580	.173	2.192	.031
Deregulation	7263.441	2837.308	.236	2.560	.012

Adjusted R square = .404
N = 105

The variables characterizing the demand side of the electricity market show that the growth of manufacturing employment is negatively related to manufacturing productivity with statistical significance only above the 90% critical value. At the same time, the over-presence of large manufacturing establishments in the state is, as expected, positively associated with manufacturing productivity at the 99% critical value. This indicates that manufacturing productivity might benefit from both economy of scale and the ability of large electricity consumers to negotiate individual contracts with suppliers at, most likely, lower than average market prices. This finding allows us to consider that enabling a lower market price across the board for manufacturing users might further benefit the productivity of the manufacturing sector in Ohio.

The control variable that represents the supply side of the electricity market, capacity of electricity production and distribution, is also positively related to manufacturing productivity and is statistically significant above the 99% critical value. Together with the positively associated deregulation variable, an increase in the state's capacity to generate, transmit, and distribute electricity will most likely support higher productivity in its manufacturing sector.

Finally, the variable approximating the national recession was negatively associated with manufacturing productivity. However the statistical association was weak, not quite reaching the 90% critical value.

These statistical results do not allow us to disprove the null hypotheses, i.e., that no statistically significant relationships exist between industrial electricity pricing and manufacturing productivity. On the contrary, an increase in the industrial electricity price by 1 cent per kilowatt-hour (16.3%) is likely, in 99% of cases, to decrease average manufacturing productivity in the five selected states, on average, by $2,527 of annual GSP per employee (2.2%). Although the increase of industrial electricity prices is most likely to inversely affect manufacturing productivity, it is necessary to assess the responsiveness of manufacturing productivity to the changes in industrial electricity. The most appropriate measure of a variable's sensitivity or responsiveness to a change in another variable is elasticity, which is usually expressed in the ratio of percentage changes. The productivity change resulting from industrial electricity price change has low elasticity: 2.2%/16.3%=0.13. The measure of elasticity below 1 is known as inelastic response. This means that for 1% increase of industrial electricity prices manufacturing productivity drops by 0.13%. Inelastic productivity change from the movement of industrial electricity price indicates that electricity is only one of the supply price factors influencing manufacturing productivity.

Impact of Electricity Market Deregulation on Electricity Prices and Economic Indicators

To assess the impact of electricity market restructuring, we ran an independent samples t-test to compare industrial electricity prices and other economic indicators[26] between the states that deregulated their wholesale electricity markets and the states that did not. We also probed deeper into the states that deregulated their electricity markets by comparing industrial

[26] The indicators and their abbreviations as listed in the Table 1 should be listed here. See Section IV for detailed definition and measure of variables.

electricity prices and other economic indicators within the states for the years before and after the restructuring. For Tables 3 and 4, a "1" in the "Deregulation" column represents observations across the years and states where electricity market deregulation occurred; "0" represents observations across the years and states (year-states) where deregulation did not take place.

Table 13 shows the results of an analysis comparing observations from all five target states, including Ohio, Michigan, and Pennsylvania, where deregulation occurred in the early 2000s, and Indiana and Kentucky, where the electricity markets were never deregulated.[27] The group of observations for each state in each year (year-states) with deregulated electricity markets contains 30 observations and the group representing markets that have not been restructured contains 75 observations (column "N" in Tables 13 and 14). The comparison of industrial electricity prices and economic indicators across year-states is a comparison of different values due to the existence of the deregulated energy market.

For all variables included in the t-test, the differences between observations representing deregulated and non-restructured markets were statistically significant above the 99% critical value (according to column "t" in Tables 13 and 14). A statistically significant difference exists in industrial electricity prices between deregulated electricity markets and non-restructured markets; specifically, the average industrial electricity price in deregulated markets was 6.8 cents per kilowatt hour (c/kWh) compared to 6.3 c/kWh for regulated markets (Table 13). At first blush, based upon this simple comparison, it appears that deregulation does not work to reduce electricity prices. However such a comparison would be misleading. Each non-deregulated state enjoyed considerably lower electricity prices than the deregulated states, prior to deregulation. To fully understand the effects of deregulation, it is necessary to examine the history of industrial electricity prices for the three deregulated states (Figure 11) before and after deregulation.

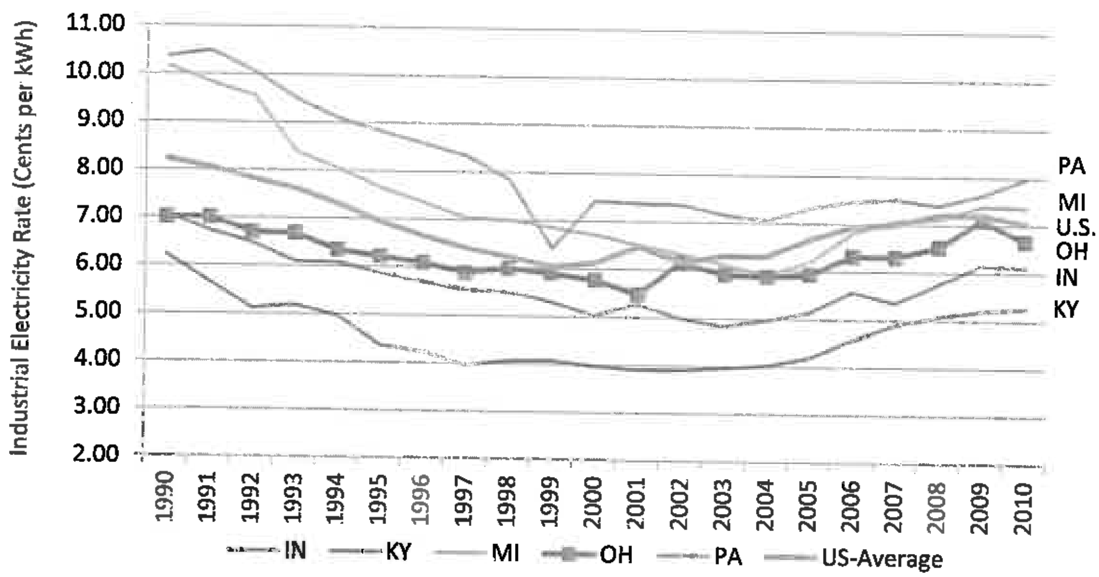
Figure 11 shows that Ohio, Michigan, and Pennsylvania—the three states that deregulated their electricity markets—had higher initial industrial electricity prices than the two states that never deregulated their markets (Indiana and Kentucky). Pennsylvania and Michigan started the study period with industrial electricity prices in 1990 above 10 c/kWh, and Ohio's industrial electricity price in 1990 was 7 c/kWh. In comparison, Indiana and Kentucky started with prices between 6 and 7 c/kWh.

[27] Ohio deregulated wholesale electricity markets in 2001 (Senate Bill 3, passed in 1999); Pennsylvania in 2000; and Michigan in 2002.

Table 13. Comparison of Variables in Regulated vs. Non-regulated Electricity Markets: Five States

Variables	Deregulation	N	Mean	Std. Deviation	t	df	P-value (2-tailed)
Industrial Electricity Price	1	30	6.81269	.665816	2.304	103.944	.023
	0	75	6.27469	1.726396			
Manufacturing Productivity	1	30	119891.59	9151.786	2.710	86.637	.008
	0	75	113335.88	15151.502			
Output LQ of Energy Intensive Manufacturing	1	30	1.62924	.395581	-3.849	93.580	.000
	0	75	2.05604	.728634			
Output LQ of Large Manufacturing Firms	1	30	1.34915	.408251	-2.288	103	.024
	0	75	1.54542	.392583			
Percentage Change of Output of Power Industry	1	30	.0424	.05440	2.378	103	.019
	0	75	.0155	.05166			

Figure 11. Industrial Electricity Price: Five-States and the U.S., 1990-2010



Source: Energy Information Administration

Table 13 and Figure 11 show that if we compare industrial electricity prices for the three states that restructured their markets to prices for those same states after deregulation occurred, the average industrial electricity price dropped from 7.7 c/kWh before deregulation to 6.8 c/kWh post-deregulation.

A similar dynamic related to the averages of indicators was observed on all other tested variables. Manufacturing sector productivity nearly doubled in Indiana and grew by at least $35,000 in the other four states between 1990 and 2010 (Figure 12). The difference in the productivity of state manufacturing sectors (Mgf_Productivity) was statistically significant between deregulated and non-deregulated markets at the 99% critical value. Comparing average manufacturing productivity in all five target states, the difference in this indicator was $6,556 worth of gross state product per employee annually ($119,892 in deregulated markets compared to $113,336 in non-deregulated markets) (Table 13). If we compared state manufacturing productivity before and after deregulation in only Ohio, Michigan, and Pennsylvania, productivity increased by, on average, $14,869 ($105,023 before deregulation compared to $119,892 after deregulation) (Table 13).

The relative presence of electricity-intensive manufacturing establishments (LQ of mnf high intense)[28] also had larger averages in deregulated markets than in non-deregulated markets (Table 13). The difference between these averages is statistically significant. This finding indicates that in the five target states, the relative share of establishments in industries defined in Lendel (2012)[29] as high users of electricity (Table 15) was, on average, 1.6 times higher than in the national economy in non-deregulated markets and 2.1 times higher than in the national economy in deregulated markets. The relative shares of electricity-intensive manufacturing establishments were virtually the same before and after deregulation when considering only the three states that underwent the process.

The relative share of large manufacturing establishments in a state compared to the U.S. average share (mfg1000 LQ) was 1.55 for non-deregulated markets and 1.35 for deregulated markets in the sample including all five target states. In the sample of three states that experienced deregulation, the relative share was 1.33 before deregulation and 1.35 after deregulation, which shows no statistically significant difference.

Finally, the size of the *Electric Power Generation, Transmission, and Distribution* industry (NAICS 2211) (%change_2211GDP) was larger in states with deregulated markets than in states without deregulated markets (Table 13). The industry was also larger in Ohio, Michigan, and Pennsylvania after deregulation occurred, compared to before. These differences were statistically significant. This indicates that the industry producing and delivering electricity grew and delivered more supply after deregulation took place.

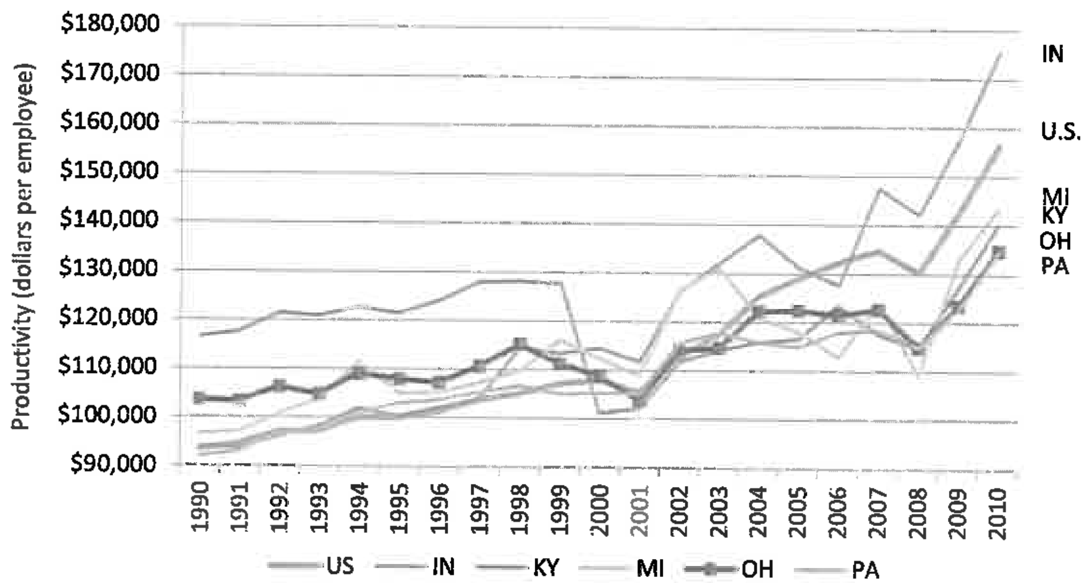
[28] Presence of energy-intense manufacturing establishments (LQ of mnf high intense) is defined as the change in relative number of energy-intense manufacturing companies in a state compared to the number of energy-intense manufacturing companies in the US.

[29] I. Lendel, et al, "Moving Ohio Manufacturing Forward: Competitive Electricity Pricing," the Urban Center, Levin College, Cleveland State University (March 2012).

Table 14. Comparison of Variables in States with Restructured Electricity Markets: MI, OH, PA

Variables	Deregulation	N	Mean	Std. Deviation	t	df	P-value (2-tailed)
Industrial Electricity Price	1	30	6.81269	.665816	-3.108	45.154	.003
	0	33	7.70435	1.492626			
Manufacturing Productivity	1	30	119891.59	9151.786	7.599	48.476	.000
	0	33	105023.28	5848.591			
Output LQ of Energy Intensive Manufacturing	1	30	1.62924	.395581	-.378	56.941	.707
	0	33	1.67591	.575377			
Output LQ of Large Manufacturing Firms	1	30	1.34915	.408251	.216	52.280	.830
	0	33	1.32960	.294151			
Percentage Change of Output of Power Industry	1	30	.0424	.05440	2.752	61	.008
	0	33	.0043	.05547			

Figure 12. Manufacturing Productivity: Five-states and the U.S., 1990-2010



Source: Moody's Economy.com

Table 15. Electricity Intensive Manufacturing Industries

NAICS	Industry Description
3313	Alumina and Aluminum Production and Processing
3221	Pulp, Paper, and Paperboard Mills
3274	Lime and Gypsum Product Manufacturing
3311	Iron and Steel Mills and Ferroalloy Manufacturing
3251	Basic Chemical Manufacturing
3272	Glass and Glass Product Manufacturing
3315	Foundries
3279	Other Nonmetallic Mineral Product Manufacturing
3253	Pesticide, Fertilizer, and Other Agricultural Chemical Manufacturing
3271	Clay Product and Refractory Manufacturing

Overall, deregulation seems to have had a positive effect on the change of industrial electricity prices, and some economic variables characterizing state of manufacturing industries in the five targeted states. The most profound effect deregulation had was on industrial electricity prices, which is evidenced by the significant drops in average price that Ohio, Michigan, and Pennsylvania—the states with the highest average base prices in 1990—experienced after deregulation occurred.

Conclusion

Identifying energy-intensive and large consumers of electricity industries

- ✓ There are 27 unit electricity-intensive industries and 21 industries that are large consumers of electricity in Ohio's manufacturing industries.
- ✓ We found 14 large electricity-intensive consumers (including both high- and medium-) manufacturing industries in Ohio, at the 4-digit NAICS level.
- ✓ All industries in primary metal manufacturing sector (NAICS 331) are defined as large, electricity-intensive consumers of electricity (NAICS 3311, 3312, 3313, 3314, 3315).
- ✓ Three chemical manufacturing industries (NAICS 3251, 3252, 3253); three food manufacturing industries (NAICS 3112, 3114, 3115); and paper, glass, and nonmetallic mineral product manufacturing (NAICS 3221, 3272, 3279) are large electricity-intensive consumer industries.
- ✓ Aluminum manufacturing is the top electricity-intensive consumer, with 5.7% of its expenditures on electricity. The iron and steel, chemical, glass and foundry manufacturing follow, each with a 2.3% or greater portion of its expenses made on the acquisition of electricity. In terms of total dollars spent, chemical manufacturing leads the state, with expenditures of over $352 million per year on electricity. Iron and steel industries, at $305 million, and aluminum at $244 million per year, are next. These industries all employ many thousands in Ohio, and are highly sensitive to increases in electricity costs.

- ✓ Besides manufacturing industries, eight 3-digit NAICS sectors and three 4-digit NAICS industries were identified as the largest electricity consumers and most electricity-intensive non-manufacturing industries in Ohio. They are accommodation (NAICS 721), nonmetallic mineral mining and quarrying (NAICS 2123), educational services (NAICS 611), amusement, gambling, and recreation industries (NAICS 713), coal mining (NAICS 2121), food services and drinking places (NAICS722), real estate (NAICS 531), warehousing and storage (NAICS 493), nursing and residential care facilities (NAICS 623), personal care services (NAICS 8121), and hospitals (NAICS 622).

Defining Ohio's economic base industries

- ✓ According to the location quotient of Ohio manufacturing industries' output or gross product in 2010, 52 4-digit NAICS industries are Ohio's economic base industries. They are represented by food manufacturing (NAICS 311), chemical manufacturing (NAICS 325), nonmetallic mineral product manufacturing (NAICS 327), primary metal manufacturing (NAICS 331), fabricated metal product manufacturing (NAICS 332), machinery manufacturing (NAICS 333), electrical equipment, appliance, and component manufacturing (NAICS 335), transportation equipment manufacturing (NAICS 336).

Ohio's electricity-intensive base manufacturing industries

- ✓ Twelve of 14 large electricity consumer manufacturing industries are part of Ohio's economic base.
- ✓ The Other fabricated metal product manufacturing industry (NAICS 3329) is the largest electricity consumer spending about $56 million per year on electricity consumption.
- ✓ Manufacturing industries that produce steel products, converted paper products, glass, nonmetallic minerals, motor vehicles, and specialty food are also Ohio's base industries that are large consumers of electricity.

Geographic distribution of electricity-intensive manufacturing base establishments

- ✓ The traditional Cleveland industrial belt in Northeast Ohio, especially among Cuyahoga, Summit, and Stark counties are where electricity-Intensive manufacturing base establishments are heavily concentrated (Map 8). Southwest Ohio, Hamilton County, which has Cincinnati at its core which has also a large number of electricity-intensive manufacturing establishments.

In the second part, we analyzed how industrial electricity pricing and electricity market deregulation influences the performance/productivity of the manufacturing industry in the state of Ohio and surrounding states

- ✓ Research area: Ohio and neighboring states of Indiana, Kentucky, Michigan, and Pennsylvania

- ✓ Period of study: 1990 and 2010
- ✓ Among five states, Ohio, Michigan, and Pennsylvania, which have relatively high industrial electricity price, deregulated their electricity market around early 2000 while Indiana and Kentucky did not restructure their electricity market.
- ✓ Analysis results present that the lower the industrial electricity prices were in the five selected states, the higher manufacturing productivity was in these state over the last 20 years. We can assume with a high degree of confidence that higher industrial electricity rates in Ohio will most likely be associated with lower manufacturing productivity.
- ✓ Deregulation of the electricity market explains the increase of manufacturing productivity in Ohio and neighboring states.
- ✓ Increasing the state's capacity to generate, transmit, and distribute electricity measured by % GDP change of power industry will most likely support higher productivity in its manufacturing sector.
- ✓ Manufacturing productivity in those five states is affected by the national economic recession.
- ✓ Manufacturing productivity might benefit from both economy of scale and the ability of large electricity consumers to negotiate individual contracts with suppliers at, most likely, lower than average market prices.
- ✓ Examining only three states that have deregulated their electricity market, Ohio, Michigan, and Pennsylvania
    - The average industrial electricity price dropped since deregulation.
    - Productivity in manufacturing industry increased after deregulation.
    - The size of power industry grew after deregulation occurred.

Appendix Table 1. Employment and Gross State Product of Electricity-Intensive Industries

NAICS	Description	Employment 2010	2010 GSP (in 2010 $)	% Empl of all OH industries	% GSP of all OH industries
3313	Alumina and Aluminum Production and Processing	3,291	$321,942	0.06%	0.07%
3311	Iron and Steel Mills and Ferroalloy Manufacturing	9,890	$1,117,600	0.19%	0.23%
3251	Basic Chemical Manufacturing	8,737	$2,832,472	0.17%	0.59%
3272	Glass and Glass Product Manufacturing	7,685	$750,979	0.15%	0.16%
3315	Foundries	13,341	$968,942	0.26%	0.20%
3279	Other Nonmetallic Mineral Product Manufacturing	6,171	$708,435	0.12%	0.15%
3253	Pesticide, Fertilizer, and Other Agricultural Chemical Manufacturing	966	$585,050	0.02%	0.12%
3252	Resin, Synthetic Rubber, and Artificial Synthetic Fibers and Filaments	5,307	$1,286,891	0.10%	0.27%
3312	Steel Product Manufacturing from Purchased Steel	5,881	$702,124	0.11%	0.15%
3115	Dairy Product Manufacturing	8,179	$1,409,510	0.16%	0.30%
3114	Fruit and Vegetable Preserving and Specialty Food Manufacturing	11,684	$1,834,442	0.23%	0.38%
3314	Nonferrous Metal (except Aluminum) Production and Processing	4,894	$450,210	0.09%	0.09%
311	**Food Manufacturing**	51,610	$8,256,565	1.00%	1.73%
325	**Chemical Manufacturing**	42,821	$10,716,810	0.83%	2.24%
327	**Nonmetallic Mineral Product Manufacturing**	23,987	$2,478,087	0.46%	0.52%
331	**Primary Metal Manufacturing**	37,297	$3,560,818	0.72%	0.75%

Note: Bolded are industries respective 3-digit NAICS sectors of electricity-intensive industries.
Source: Moody's Economy.com, November 2011.

Appendix Table 2. Industries by Energy-Intensive Categories

Industry Categories
Energy-Intensive Manufacturing
Food Products (NAICS 311)
Paper and Allied Products (NAICS 322)
Bulk Chemicals
Inorganic (NAICS 32512 to 32518)
Organic (NAICS 32511, 32519)
Resins (NAICS 3252)
Agricultural (NAICS 3253)
Glass and Glass Products (NAICS 3272)
Cement (NAICS 32731)
Iron And Steel (NAICS 3311)
Aluminum (NAICS 3313)
Non-Energy-Intensive Manufacturing
Metal-Based Durables
Fabricated Metals (NAICS 332)
Machinery (NAICS 333)
Computer and Electronics (NAICS 334)
Electrical Machinery (NAICS 335)
Transportation Equipment (NAICS 336)
Wood Products (NAICS 321)
Plastic Products (NAICS 326)
Balance of Manufacturing (all remaining manufacturing NAICS, excluding Petroleum Refining (32410))
Non-Manufacturing Industries
Agriculture, Crops (NAICS 111)
Agriculture, Other (NAICS 112-115)
Coal Mining (NAICS 2121)
Oil and Gas Mining (NAICS 211)
Other Mining (NAICS 2122-2123)
Construction (NAICS 233-235)

Note: NAICS = North American Industrial Classification System

Source: Office of Management and Budget, North American Industry Classification System, United States, 2007 (Springfield, VA, National Technical Information Service, 2007)

Appendix Z:

The Value of US Power Supply Diversity

IHS Energy

The Value of US Power Supply Diversity

July 2014 ihs.com

Contents

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IHS™ Energy

The Value of US Power Supply Diversity

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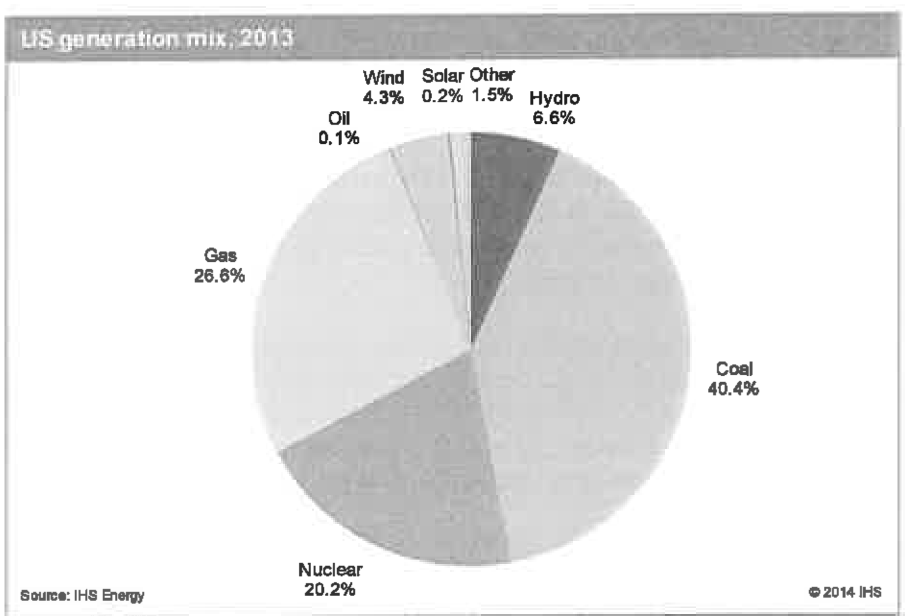
Executive summary

Engineering and economic analyses consistently show that an integration of different fuels and technologies produces the least-cost power production mix. Power production costs change because the input fuel costs—including for natural gas, oil, coal, and uranium—change over time. The inherent uncertainty around the future prices of these fuels translates into uncertainty regarding the cost to produce electricity, known as production cost risk. A diversified portfolio is the most cost-effective tool available to manage the inherent production cost risk involved in transforming primary energy fuels into electricity. In addition, a diverse power generation technology mix is essential to cost-effectively integrate intermittent renewable power resources into the power supply mix.

The current diversified portfolio of US power supply lowers the cost of generating electricity by more than $93 billion per year, and halves the potential variability of monthly power bills compared to a less diverse supply. Employing the diverse mix of fuels and technologies available today produces lower and less volatile power prices compared to a less diverse case with no meaningful contributions from coal and nuclear power and a smaller contribution from hydroelectric power (see Figure ES-1). In this less diverse scenario, called the *reduced diversity case,* wind and solar power make up one-third of installed capacity (up from about 7% in the base case) and 22.5% of generation; hydroelectric power capacity decreases from about 6.6% to 5.3% and represents 3.8% of generation; and natural gas–fired power plants account for the remaining 61.7% of installed capacity and 73.7% of generation.

FIGURE ES-1



Power supply in the reduced diversity case increases average wholesale power prices by about 75% and retail power prices by 25%. Energy production costs are a larger percentage of industrial power prices, and many industrial consumers buy power in the wholesale power market. Thus a loss of power supply diversity will disproportionally affect the industrial sector. These higher electricity prices impact the broader US economy by forcing economic adjustments in production and consumption. If the US power sector moved from its current diverse generation mix to the less diverse generating mix, power price impacts would reduce US GDP by nearly $200 billion, lead to roughly one million fewer jobs, and reduce the typical household's annual disposable income by around $2,100. These negative economic impacts are similar to an economic downturn. Additional potential negative impacts arise from reducing power supply diversity by accelerating the retirement of existing power plants before it is economic to do so. For example, a transition to the reduced diversity case within one decade would divert around $730 billion of capital from more productive applications in the economy. The size of the economic impact from accelerating power plant turnover and reducing supply diversity depends on the deviation from the pace of change dictated by the underlying economics.

Maintaining and preserving a diverse US power supply mix is important to consumers for two reasons:

- Consumers reveal a strong preference for not paying more than they have to for reliable electricity.
- Consumers reveal preferences for some degree of predictability and stability in their monthly power bills.

The economic benefits of diverse power supply illustrate that the conventional wisdom of not putting all your eggs in one basket applies to power production in much the same way as it does to investing. This is the *portfolio effect*. In addition, diversity enables the flexibility to respond to dynamic fuel prices by substituting lower-cost resources for more expensive resources in the short run by adjusting the utilization of different types of generating capacity. This ability to move eggs from one basket to another to generate fuel cost savings is the *substitution effect*. Looking ahead, the portfolio and substitution effects remain critically important to managing fuel price risks because of the relative fuel price dynamics between coal and natural gas.

The shale gas revolution and restrictions on coal are driving an increased reliance on natural gas for power generation and provide strong economic benefits. However, this past winter demonstrated the danger of relying too heavily on any one fuel and that all fuels are subject to seasonal price fluctuations, price spikes, and deliverability and infrastructure constraints. The natural gas price spikes and deliverability challenges during the past winter were a jolt for a number of power systems that rely significantly on natural gas in the generation supply. These recent events demonstrated that natural gas deliverability remains a risk and natural gas prices continue to be hard to predict, prone to multiyear cycles, strongly seasonal, and capable of significant spikes. The root causes of these price dynamics are not going away anytime soon. The best available tool for managing uncertainty associated with any single fuel or technology is to maintain a diverse power supply portfolio.

Maintaining power supply diversity is widely supported—the idea of an all-of-the-above approach to the energy future is supported on both sides of the aisle in Congress and at both ends of Pennsylvania Avenue. Four decades of experience demonstrate the conclusion that government should not pick fuel or technology winners, but rather should create a level playing field to encourage the economic decisions that move the power sector toward the most cost-effective generation mix.

Maintaining a diverse power supply currently is threatened by three emerging trends:

- **Awareness.** The value of fuel diversity is often taken for granted because United States consumers inherited a diverse generation mix based on decisions from decades ago.

- **Energy policy misalignment.** Legislation and regulatory actions increasingly dictate or prohibit fuel and technology choices. The resulting power supply is increasingly at odds with the underlying engineering/economic principles of a cost-effective power supply mix.

- **Power market governance gridlock.** Market flaws produce wholesale power prices that are chronically too low to produce adequate cash flows to support and maintain investments in a cost-effective power generation mix. This "missing money" problem is not being addressed in a timely and effective way through the stakeholder governance processes found in most power markets. As a result, the loss of power supply diversity is accelerating because too many power plants are retiring before it is economic to do so. Consequently, they will be replaced with more costly sources of supply.

US power consumers are fortunate to have inherited a diverse power supply based on fuel and technology decisions made over past decades. Unfortunately, the current benefits of US power supply diversity are often taken for granted. This undervaluation of power supply diversity means there is no counterweight to current pressures moving the United States toward a future generation mix without any meaningful contribution from nuclear, coal, or oil and a diminished contribution from hydroelectric generation.[1]

The United States needs to consider the consequences of a reduced diversity case involving no meaningful contribution from nuclear, coal-fired, or oil-fueled power plants, and significantly less hydroelectric power. A reduced diversity case presents a plausible future scenario in which the power supply mix has intermittent renewable power generation capacity of 5.5% solar, 27.5% wind, and 5.3% hydro and the remaining 61.7% of capacity is natural gas–fired power plants. Comparing the performance of current US power systems to this possible reduced diversity case provides insights into the current nature and value of diversity in the US generation mix.

IHS Energy assessed the current value of fuel diversity by using data on the US power sector for the three most recent years with sufficient available data: 2010 through 2012. IHS Energy employed its proprietary Power System Razor (Razor) Model to create a base case by closely approximating the actual interactions between power demand and supply in US power systems. Following this base case, the Razor Model was employed to simulate the reduced diversity case over the same time period. The differences between the base case and the reduced diversity case provide an estimate of the impact of the current US power supply fuel and technology diversity on the level and variance of power prices in the United States. These power sector outcomes were fed through to the IHS US macroeconomic model to quantify the broader economic impacts of the resulting higher and more varied power prices along with the shifts in capital deployment associated with premature retirements that accelerate the move to the reduced diversity case.

The difference between the base case and the reduced diversity case is a conservative estimate of the value of fuel diversity. The portfolio and substitution values would be greater over a longer analysis time frame because uncertainty and variation in costs typically increase over a longer time horizon. In addition, the estimate is conservative because it excludes indirect feedback effects from a higher risk premium in the reduced diversity power supplier cost of capital. This feedback is not present because the analysis alters only the generation capacity mix and holds all else constant. This indirect cost feedback would increase capital costs in this capital-intensive industry and magnify the economic impact of current trends to replace power plants before it is economic to do so by moving shifting capital away from applications with better risk-adjusted returns.

The United States is at a critical juncture because in the next decade the need for power supply to meet increased customer demands, replace retiring power plants, and satisfy policy targets will require fuel and

1. Oil-fired power plants account for about 4% of US capacity and 0.2% of US generation but can play a critical role in providing additional electricity when the system is under stress.

technology decisions for at least 150 gigawatts (GW)—about 15% of the installed generating capacity in the United States. However, current trends in energy policy could push that power plant turnover percentage to as much as one-third of installed capacity by 2030. The implication is clear: power supply decisions made in the next 10–15 years will significantly shape the US generation mix for decades to come.

The results of this study indicate seven key factors that will shape US power supply diversity in the years to come:

- **Energy policy development.** US policy heavily influences the US power supply mix. Implementing an all-of-the-above energy policy requires properly internalizing the value of fuel diversity.
- **Market structure.** Market flaws distort wholesale power prices downward and result in uneconomic retirement and replacement of existing cost-effective generation resources. This issue and any market structure changes to address it will significantly shape future power plant development.
- **Energy policy discourse.** Preserving the value of fuel diversity depends on public awareness and understanding. The extent and nature of public education regarding the value of power supply diversity may strongly influence public opinion.
- **Planning alignment.** Alignment of fuel and technology choices for power generation with engineering and economic principles is critical to efficient and reliable supply. There is no single fuel or technology of choice for power generation, and all forms of power production have economic, environmental, and reliability impacts.
- **Risk assessment.** To incorporate system considerations into plant-level decisions, prudent fuel price uncertainties must be used with probabilistic approaches to decision making.
- **Flexibility.** Flexibility and exemptions in rule making and implementation allow for the balancing of costs and benefits in power supply systems and may help preserve highly valuable diversity in systemwide decisions as well as on a small but impactful individual plant scale.
- **Scope.** Including fuel price risk and additional storage and transportation infrastructure costs is crucial when evaluating reduced diversity scenarios in comparison to the cost of maintaining and expanding fuel diversity.

The Value of US Power Supply Diversity

Overview

The power business is customer driven: consumers do not want to pay more than necessary for reliable power supply, and they want some stability and predictability in their monthly power bills. Giving consumers what they want requires employing a diverse mix of fuels and technologies in power production. Employing the diverse mix of fuels and technologies available today produces lower and less volatile power prices compared to a less diverse case with no meaningful contributions from coal and nuclear power and a smaller contribution from hydroelectric power. In this less diverse scenario, called the *reduced diversity case*, wind and solar power make up one-third of installed capacity (up from about 7% in the base case) and 22.5% of generation; hydroelectric power capacity decreases from about 6.6% to 5.3% and represents 3.8% of generation; and natural gas–fired power plants account for the remaining 61.7% of installed capacity and 73.7% of generation.

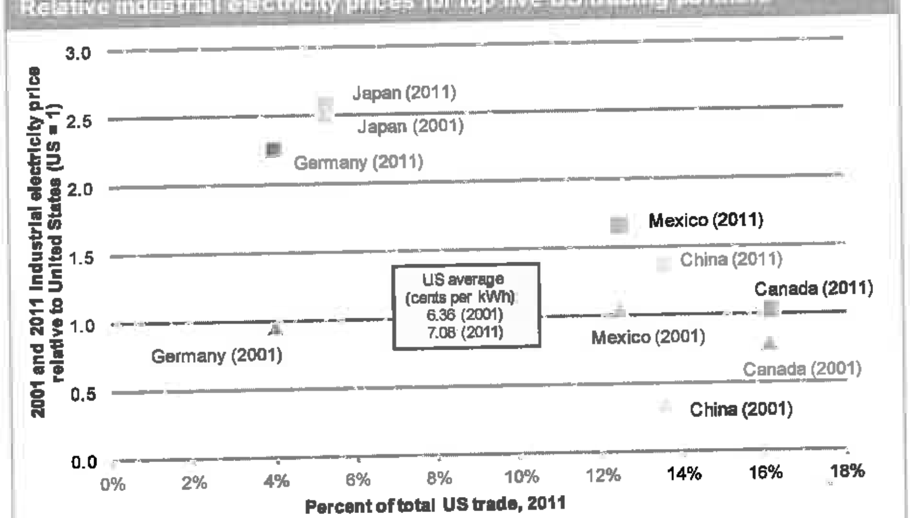
The current diverse US power supply reduces US consumer power bills by over $93 billion per year compared to a reduced diversity case. In addition, the current diversified power generation mix mitigates exposure to the price fluctuations of any single fuel and, by doing so, cuts the potential variability of monthly power bills roughly in half.

Power prices influence overall economic performance. For example, since the recovery of the US economy began in the middle of 2009, manufacturing jobs in the 15 states with the lowest power prices increased by 3.3%, while in the 15 states with the highest power prices these jobs declined by 3.2%. This job impact affected the overall economic recovery. The average annual economic growth in the 15 states with the lowest industrial power prices was 0.6 percentage points higher than in the 15 states with the highest power prices.

Higher and more varied power prices can also impact international trade. In the past decade, the competitive position for US manufacturers improved thanks to lower relative energy costs, including the improving US relative price of electric power (see Figure 1). Although power prices are only one of a number of factors that influence competitive positions in the global economy, there are clear examples, such as Germany, where moving away from a cost-effective power generating mix is resulting in significant economic costs and a looming loss of competitiveness. German power prices increased rapidly over the past decade because Germany closed nuclear power plants before it was economic to do so and added too many wind and solar power resources too quickly into the generation mix. IHS estimates that Germany's net export losses

FIGURE 1

Relative industrial electricity prices for top five US trading partners



Note: Total trade = exports plus imports.
Source: IHS Energy, US Census Bureau, OECD/IEA

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directly attributed to the electricity price differential totaled €52 billion for the six-year period from 2008 to 2013.[2]

A less diverse US power supply would make power prices higher and more varied and force a costly adjustment process for US consumers and businesses. The price increase associated with the reduced diversity case produces a serious setback to US economic activity. The value of goods and services would drop by nearly $200 billion, approximately one million fewer jobs would be supported by the US economy, and the typical household's annual disposable income would go down by over $2,100. These economic impacts take a few years to work through the economy as consumers and producers adjust to higher power prices. The eventual economic impacts are greater if current trends force the closure and replacement of power plants before it is economic to do so. Regardless of the replacement technology, it is uneconomic to close a power plant when the costs of continued operation are less than the cost of a required replacement. Premature power plant turnover imposes an additional cost burden by shifting capital away from more productive applications. A closure and replacement of all nuclear and coal-fired generating capacity in the next 10 years would involve roughly $730 billion of investment. An opportunity cost exists in deploying capital to replace productive capital rather than expanding the productive capital base.

The United States currently faces a key challenge in that many stakeholders take the current benefits of power supply diversity for granted because they inherited diversity based on fuel and technology decisions made decades ago. There is no real opposition to the idea of an all-of-the-above energy policy in power supply. Yet, a combination of factors—tightening environmental regulations, depressed wholesale power prices, and unpopular opinions of coal, oil, nuclear, and hydroelectric power plants—are currently moving the United States down a path toward a significant reduction in power supply diversity. A lack of understanding of power supply diversity means momentum will continue to move the United States toward a future generation mix without any meaningful contribution from nuclear, coal, or oil, and a diminishing contribution from hydroelectric generation.

The United States is at a critical juncture because power plant fuel and technology decisions being made today will affect the US power supply mix for decades to come. These decisions need to be grounded in engineering, economic, and risk management principles that underpin a cost-effective electric power sector. Comparing the performance of the current generation mix to results of the reduced diversity case provides key insights into the current nature and value of diversity. An assessment and quantification of the value of power supply diversity will help achieve a more cost-effective evolution of US power supply in the years ahead.

Generation diversity: A cornerstone of cost-effective power supply

If power consumers are to receive the reliable and cost-effective power supply they want, then cost-effective power production requires an alignment of power supply to power demand. Engineering, economic, and risk management assessments consistently show that an integration of fuels and technologies produces the least-cost power production mix. A cost-effective mix involves integrating nondispatchable power supply with dispatchable base-load, cycling, and peaking technologies. This cost-effective generating mix sets the metrics for cost-effective demand-side management too. Integrating cost-effective power demand management capabilities with supply options requires balancing the costs of reducing or shifting power demand with the incremental cost of increasing power supply. Appendix A reviews the principles of engineering, economics, and risk management that lead to the conclusion that cost-effective power supply requires fuel and technological diversity.

2. See the IHS study *A More Competitive Energiewende: Securing Germany's Global Competitiveness in a New Energy World*, March 2014.

The underlying principles of cost-effective power supply produce five key insights:

- There is no single fuel or technology of choice for power generation. Reliably and efficiently supplying consumers with the amounts of electricity they want when they want it requires a diverse generation mix.
- A cost-effective generation mix involves diversity but does not involve maximizing diversity by equalizing generation shares from all available supply options.
- A cost-effective mix of fuel and technologies for any power system is sensitive to the uncertainties surrounding the level and pattern of consumer power demands as well as the cost and performance of alternative power generating technologies and, in particular, the delivered fuel prices.
- A cost-effective generating mix will differ from one power system to the next because of differences in aggregate consumer demand patterns as well as in the cost and performance of available generating options.
- The best type of capacity to add to any generation portfolio depends on what types of capacity are already in the mix.

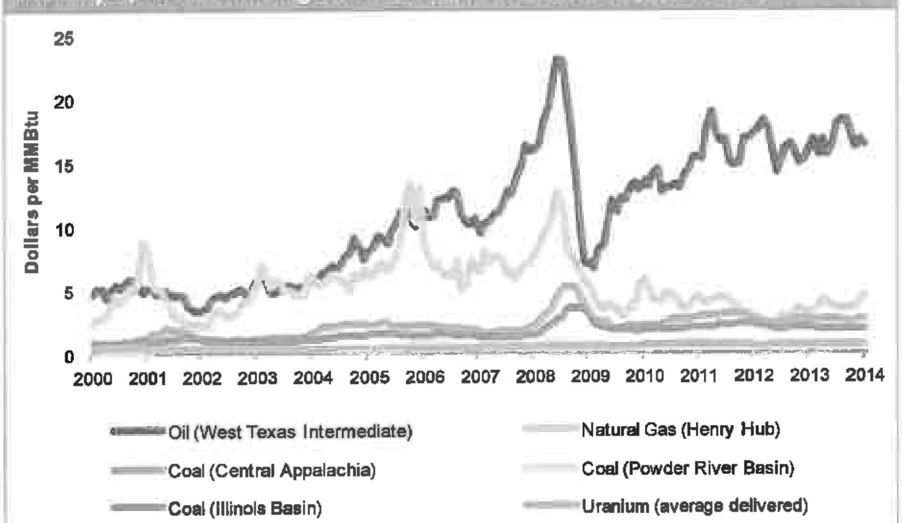
Power production cost fluctuations reflect inherent fuel price uncertainties

Power consumers reveal preferences for some degree of predictability and stability in their monthly power bills. These consumer preferences present a challenge on the power supply side because the costs of transforming primary energy—including natural gas, oil, coal, and uranium—into electric power is inherently risky. Experience shows that the prices of these fuel inputs to the power sector are difficult to anticipate because these prices move in multiyear cycles and fluctuate seasonally (see Figure 2). In addition, this past winter showed that dramatic price spikes occur when natural gas delivery systems are pushed to capacity (see Figure 3).

The recent volatility in the delivered price of natural gas to the US Northeast power systems demonstrates the value of fuel diversity. During this past winter, colder-than-normal weather created greater consumer demand for natural gas and electricity to heat homes and businesses. The combined impact on natural gas demand strained the capability of pipeline systems to deliver natural gas in the desired quantity and pressure. Natural gas prices soared, reflecting the market forces allocating available gas to the highest valued end uses. At some points in time, price allocation was

FIGURE 2

Monthly spot oil, natural gas, and coal prices, 2000–14 year to date



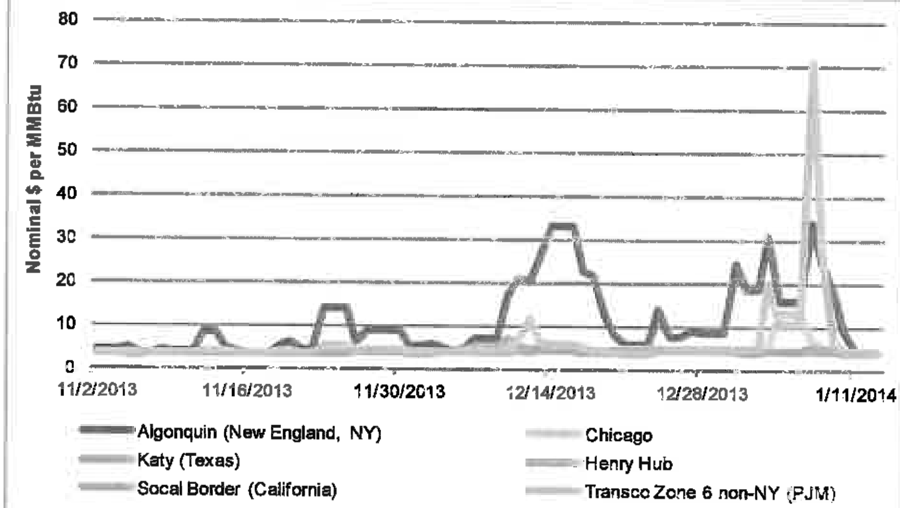
Source: IHS Energy
Data Sources: Energy Information Administration, Platt's and Natural Gas Intelligence, Platts Coal Outlook, SNL Energy Coal © 2014 IHS

not enough and additional natural gas was not available at any price, even to power plants holding firm supply contracts.

As high as the natural gas price spikes reached, and as severe as the natural gas deliverability constraints were, things could have been worse. Although oil-fired power provided only 0.35% of generation in the Northeast in 2012, this slice of power supply diversity provided an important natural gas supply system relief valve. The oil-fired power plants and the dual-fueled oil- and natural gas–fired power plants were able to use liquid fuels to generate 12% of the New England power supply during the seven days starting 22 January 2014 (see Figure 4). This oil-fired generation offset the equivalent of 327,000 megawatt-hours (MWh) of natural gas–fired generation and thus relieved the natural gas delivery system of about 140 million cubic feet per day of natural gas deliveries. This fuel diversity provided the equivalent to a 6% expansion of the daily delivery capability of the existing natural gas pipeline system.

FIGURE 3

Delivered daily gas prices, November 2013–January 2014



Source: IHS Energy, Ventyx Velocity Suite

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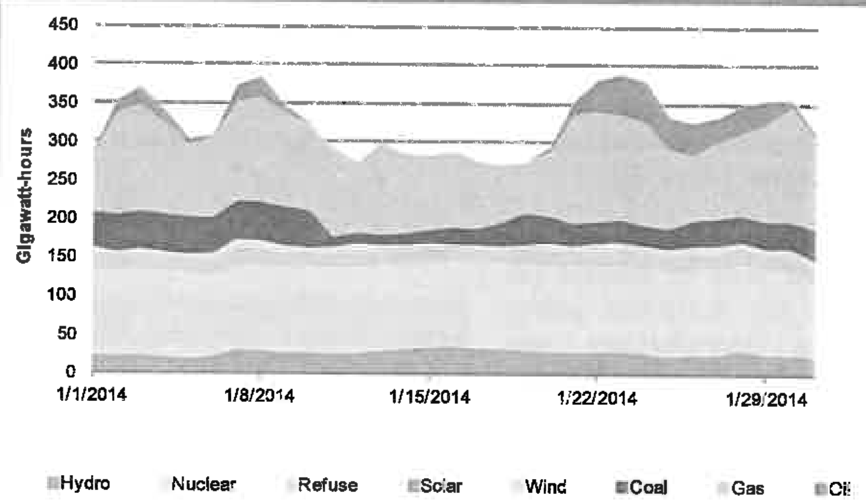
FIGURE 4

ISO New England generation, January 2014



Source: IHS Energy

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The lesson from this past winter was that a small amount of oil-fired generation in the supply mix proved to be highly valuable to the Northeast energy sector despite its production costs and emission rates. Many of these oil-fired power plants are old and relatively inefficient at converting liquid fuel to power. However, this relative inefficiency does not impose a great penalty because these power plants need to run very infrequently to provide a safety valve to natural gas deliverability. Similarly, these units have emissions rates well above those achievable with the best available technology, but the absolute amount of emissions and environmental impacts are small because their utilization rates are so low. Although the going forward costs and the environmental impacts are relatively small, the continued operation of these oil-fired power plants is at risk from tightening environmental regulations.

Oil-fired power plants were not the only alternative to natural gas–fired generation this past winter. Coal played a major role. As the *New York Times* reported on 10 March 2014, 89% of American Electric Power Company, Inc.'s 5,573 megawatts (MW) of coal-fired power plants slated for retirement in 2015 owing to tightening environmental regulations were needed to keep the lights on during the cold snap this past winter in PJM.[3]

The critical role fuel diversity played during the recent polar vortex affected power systems that serve over 40 million US electric consumers and almost one-third of power supply. This widespread exposure to natural gas price and deliverability risks is becoming increasingly important because the share of natural gas in the US power mix continues to expand. The natural gas–fired share of power generation increased from 16% to 27% between 2000 and 2013. Twelve years ago, natural gas–fired generating capacity surpassed coal-fired capacity to represent the largest fuel share in the US installed generating mix. Currently, natural gas–fired power plants account for 40% of the US installed capacity mix.

The increasing dependence on natural gas for power generation is not an accident. The innovation of shale gas that began over a decade ago made this fuel more abundant and lowered both its actual and expected price. But the development of shale gas did not change the factors that make natural gas prices cyclical, volatile, and hard to forecast accurately.

Factors driving natural gas price dynamics include

- Recognition and adjustment lags to market conditions
- Over- and under-reactions to market developments
- Linkages to global markets through possible future liquefied natural gas (LNG) trade
- Misalignments and lags between natural gas demand trends, supply expansions, and pipeline investments
- "Black swan" events—infrequent but high-impact events such as the polar vortex

Natural gas price movements in the shale gas era illustrate the impact of recognition and adjustment lags to changing market conditions. Looking back, natural gas industry observers were slow to recognize the full commercialization potential and magnitude of the impact that shale gas would have on US natural gas supply. Although well stimulation technologies date back to the 1940s, today's shale gas technologies essentially began with the innovative efforts of George Mitchell in the Barnett resource base near Fort Worth, Texas, during the 1980s and 1990s. Mitchell Energy continued to experiment and innovate until eventually proving the economic viability of shale gas development. As a result, shale gas production expanded (see Figure 5).

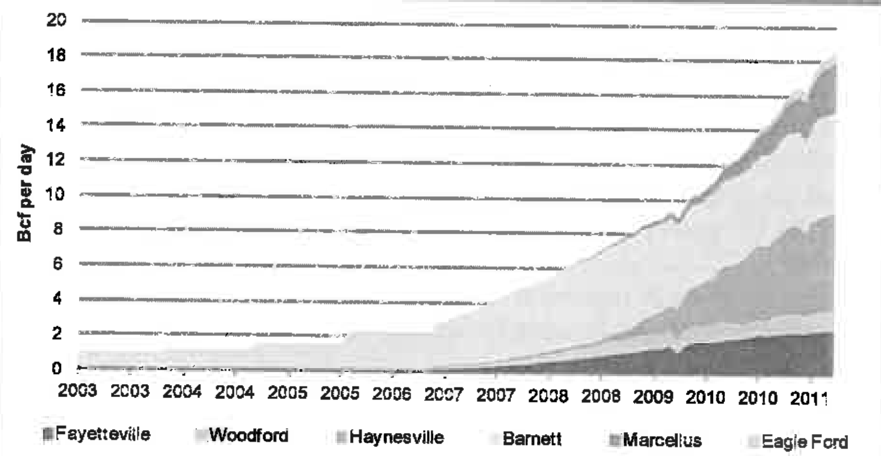
Although shale gas had moved from its innovation phase to its commercialization phase, many in the oil and gas industry did not fully recognize what was happening even as US shale gas output doubled from 2002 to 2007 to reach 8% of US natural gas production. The belief that the United States was running out of natural gas persisted, and this recognition lag supported the continued investment of billions of dollars to expand LNG import facilities (see Figure 6).

3. *New York Times.* "Coal to the Rescue, But Maybe Not Next Winter." Wald, Matthew L. 10 March 2014: http://www.nytimes.com/2014/03/11/business/energy-environment/coal-to-the-rescue-this-time.html?_r=0, retrieved 12 May 2014.

Eventually, evidence of a shale gas revolution became undeniable. However, recognition and adaptation lags continued. Productivity trends in natural gas-directed drilling rigs indicate that only about 400 gas-directed rigs are needed to keep natural gas demand and supply in balance over the long run. Yet operators in the natural gas industry did not fully anticipate this technological trend. Bullish price projections caused the US natural gas-directed rig count to rise from 690 to 1,600 rigs

FIGURE 5

Growth in major US shale plays



Note: Bcf = billion cubic feet.
Source: IHS Energy, Lippmann Consulting

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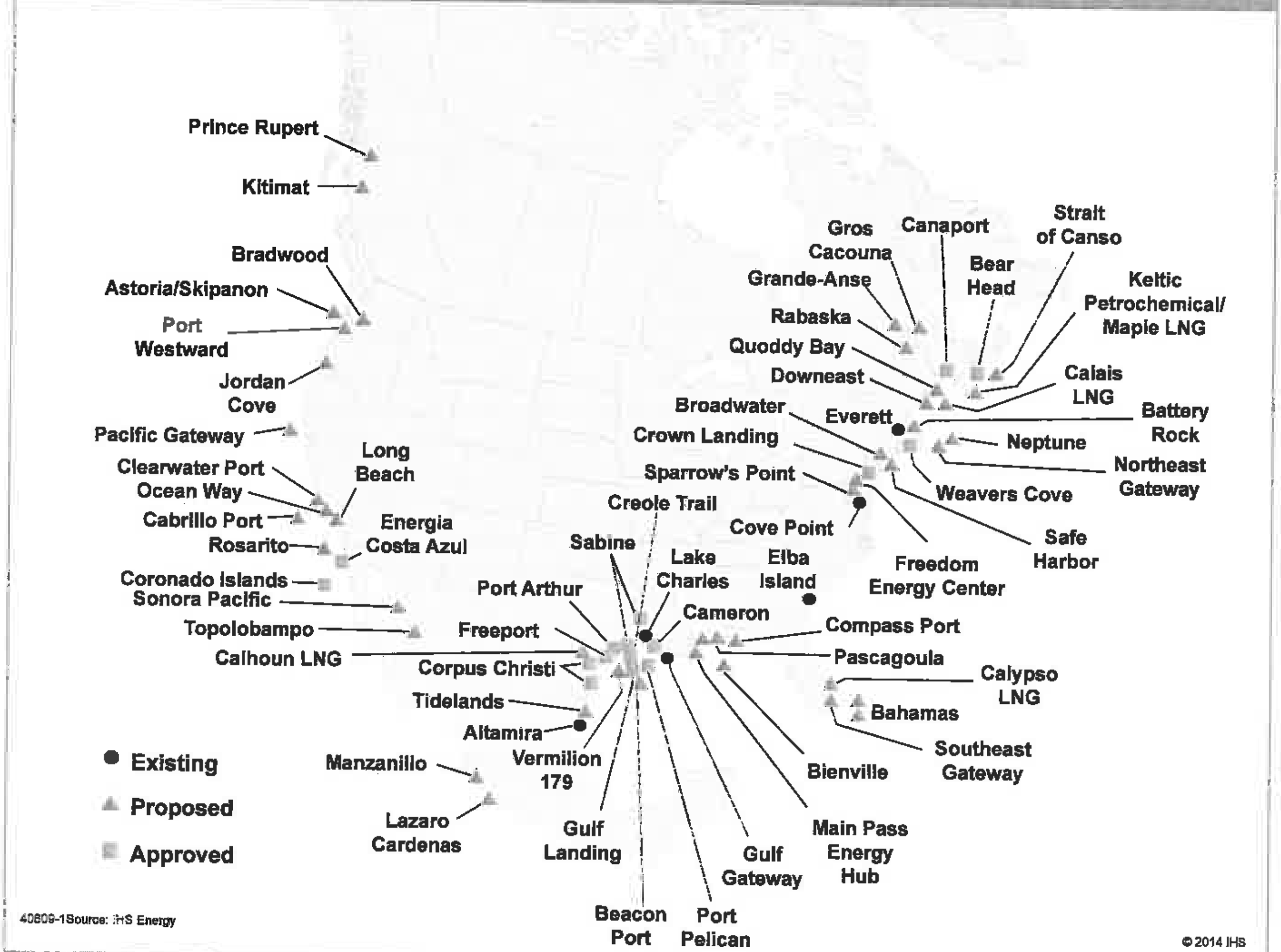
FIGURE 6

LNG facilities in North America—Existing and proposed (October 2006)



40809-1Source: IHS Energy

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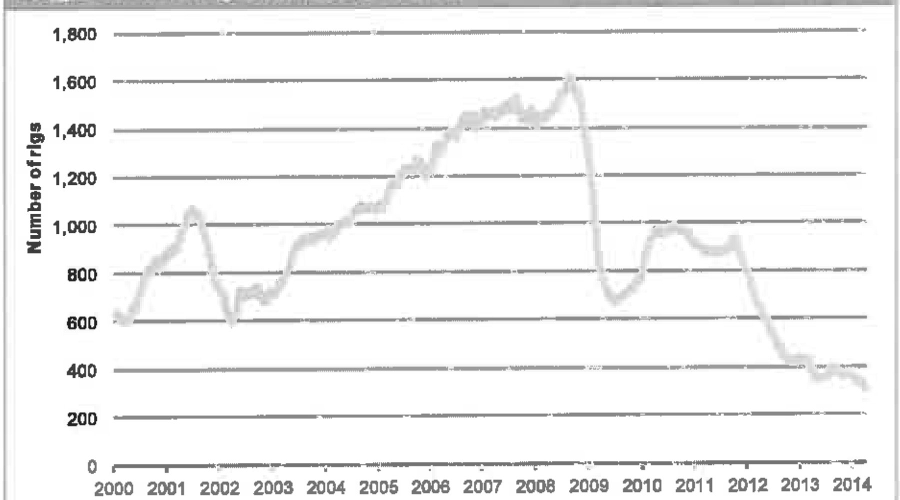
between 2002 and 2008. This level of drilling activity created a supply surplus that caused a precipitous decline of up to 85% in the Henry Hub natural gas price from 2008 to 2012. From the 2008 high count, the number of US natural gas–directed rigs dropped over fivefold to 310 by April 2014 (see Figure 7).

FIGURE 7

US gas-directed rig count, 2000–14 YTD



Source: IHS Energy, Baker Hughes

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Natural gas investment activity also lagged market developments. During this time, the linkage between North American natural gas markets and global markets reversed from an investment hypothesis supporting an expansion of LNG *import* facilities, as shown in Figure 6, to an investment hypothesis involving the expansion of LNG *export* facilities (see Figure 8). At the same time, investment in natural gas pipelines and storage did not keep pace with the shifts in domestic demand, supply, and trade. This asymmetry created vulnerability to low frequency but high impact events, such as colder-than-normal winters that expose gas deliverability constraints and launch record-setting delivered price spikes, as happened in the Northeast in the winters of 2012/13 and 2013/14.

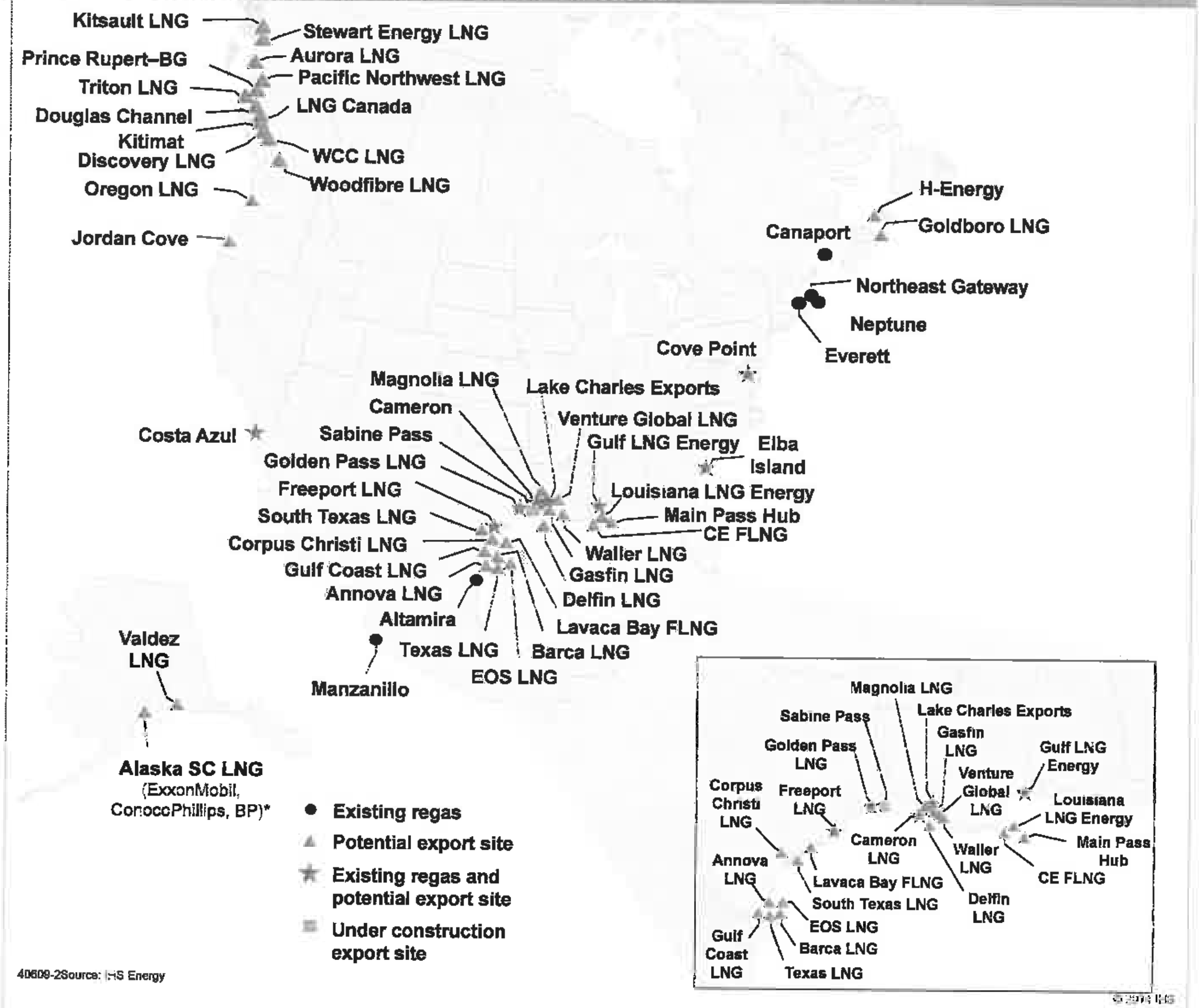
The Northeast delivered natural gas price spikes translated directly into dramatic power production cost run-ups. During the winter of 2013/14, natural gas prices delivered to the New York and PJM power system border hit $140 per MMBtu (at Transco Zone 6, 21 January 2014) and pushed natural gas–fired power production costs up 25-fold from typical levels and well beyond the $1,000 per MWh hourly wholesale power price cap in New York and PJM. This forced the New York Independent System Operator (NYISO) to allow exemptions to market price caps. The Federal Energy Regulatory Commission granted an emergency request to lift wholesale power price caps in PJM and New York. Lifting these price caps kept the lights on but also produced price shocks to 30% of the US power sector receiving monthly power bills in these power systems. The impact moved the 12-month electricity price index (a component of the consumer price index) in the Northeast up 12.7%—the largest 12-month jump in eight years.

The New York Mercantile Exchange (NYMEX) futures contract price strip illustrates how difficult it is to anticipate natural gas price movements. Figure 9 shows the price dynamics over the shale gas era and periodic examples of the NYMEX futures price expectations. The NYMEX future price error pattern indicates a bias toward expecting future natural gas prices to look like those of the recent past. Although these futures prices are often used as an indicator of future natural gas price movements, they have nonetheless proven to be a poor predictor.

The complex drivers of natural gas price dynamics continue to apply in the shale gas era. Prudent planning requires recognition that natural gas price movements remain hard to forecast, affected by multiyear

FIGURE 8

US lower-48 regasification facilities and filed liquefaction projects



investment cycles that lag market developments, subject to seasonality, and capable of severe short-run price volatility.

Natural gas price cycles during the shale gas era and the recent extreme volatility in natural gas prices are clear evidence that the benefits of increased natural gas use for power generation need to be balanced against the costs of natural gas's less predictable and more variable production costs and fuel availability.

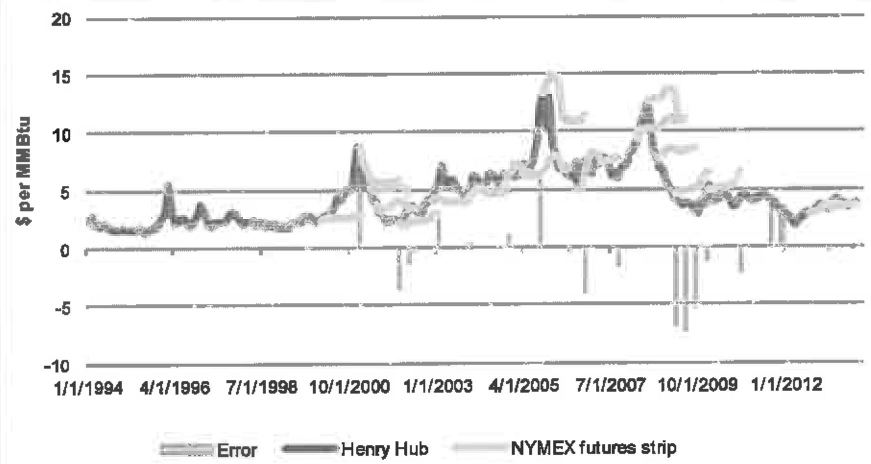
The natural gas–fired generation share is second only to the coal-fired generation share. One of the primary reasons that fuel diversity is so valuable is because natural gas prices and coal prices do not move together.

Significant variation exists in the price of natural gas relative to the price of coal delivered to US power generators (see Figure 10). The dynamics of the relative price of natural gas to coal are important because relative prices routinely change which power plants provide the most cost-effective source of additional power supply at any point in time.

The relative prices of natural gas to coal prior to the shale gas revolution did not trigger as much cost savings from fuel substitution as the current relative prices do. From 2003 to 2007 the price of natural gas was four times higher than the price of coal on a Btu basis. Under these relative price conditions, small changes in fuel prices did not alter the position of coal-fired generation as the lower-cost resource for power generation. The shale gas revolution brought gas prices to a more competitive level and changed the traditional relative relationship between gas and coal generation. As Table 1 shows, the 2013 dispatch cost to produce electricity at the typical US natural gas–fired power plant was equivalent to the dispatch cost at the typical US coal-fired power plant with a delivered natural gas price of $3.35 per MMBtu, about 1.39 times the delivered price of coal. Current price changes move the relative price of natural gas to coal around this average equivalency level and create more generation substitution than has historically occurred.

FIGURE 9

Henry Hub and NYMEX futures, 1994–2013



Source: IHS Energy

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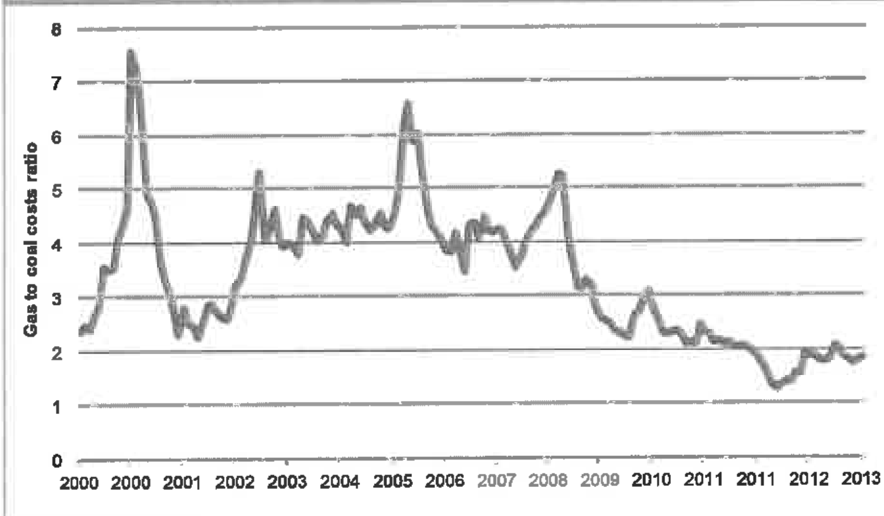
FIGURE 10

Ratio of delivered gas to delivered coal costs, 2000–13



Note: ratio of costs per MMBtu.
Source: IHS Energy, Ventyx Velocity Suite

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The average equivalency level triggers cost savings from substitution within the generation mix. Current relative prices frequently move above and below this critical relative price level. Consequently, slight movements in either coal or natural gas prices can have a big impact on which generation resource provides the most cost-effective source of generation at any given point in time.

Coal price dynamics differ from natural gas price movements. The drivers of coal price dynamics include rail and waterborne price shifts, changes in coal inventory levels, and mine closures and openings. In addition, international coal trade significantly influences some coal prices. For example, when gas prices began to fall in 2008–12, the natural gas displacement of coal in power generation caused Appalachian coal prices also to drop. However, the coal price drop was slower and less severe than the concurrent natural gas price drop because of the offsetting increase in demand for coal exports, particularly for metallurgical coal. Linkages to global coal market prices were significant even though only about one-quarter of Appalachian coal production was involved in international trade. The implication is that as global trade expands, the influence of international trade on domestic fuel prices may strengthen.

TABLE 1

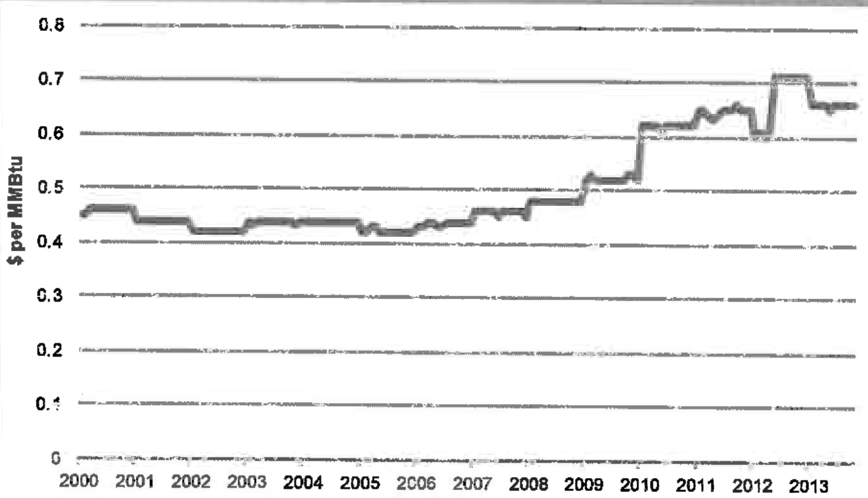
Typical generating units

	Typical coal unit	Typical CCGT unit
Size, MW	218	348
Heat rate, Btu/kWh	10,552	7,599
Fuel cost, $/MMBtu	$2.41	$4.46
Fuel cost, $/MWh	$25.43	$33.89
Variable O&M, $/MWh	$4.70	$3.50
Lbs SO_2/MWh (with wet FGD)	1.16	0
SO_2 allowance price, $/ton	70	70
Lbs NO_x/MWh	0.74	0.15
NO_x allowance price, $/ton	252	252
SO_2, NO_x emissions cost, $/MWh	0.13	0.02
Short-run marginal cost, $/MWh	$30.26	$37.41
Breakeven fuel price, $/MMBtu	$2.41	$3.35

Note: kWh = kilowatt-hour(s); O&M = operation and maintenance (costs); SO_2 = sulfur dioxide; NO_x = nitrogen oxides; CCGT = combined-cycle gas turbine.
Source: IHS Energy

FIGURE 11

Nuclear fuel prices, 2000–13



Source: IHS Energy, Ventyx Velocity Suite

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Nuclear fuel prices are also dynamic, and are different from fossil fuel prices in two ways (see Figure 11). Nuclear fuel cost is a relatively smaller portion of a nuclear plant's overall cost per kilowatt-hour. Also nuclear fuel prices have a different set of drivers. The primary drivers of nuclear fuel price movements include uranium prices, enrichment costs, and geopolitical changes in nuclear trade. These drivers produce price dynamics dissimilar to those of either natural gas or coal. As a result, nuclear fuel price movements are not strongly correlated to fossil fuel price movements.

Diversity: The portfolio effect

A diverse fuel and technology portfolio is a cornerstone for an effective power production risk management strategy. If prices for alternative fuels moved together, there would be little value in diversity. But relative power production costs from alternative fuels or technologies are unrelated and inherently unstable. As a result, the portfolio effect in power generation exists because fuel prices do not move together, and thus changes in one fuel price can offset changes in another. The portfolio effect of power generation fuel diversity is significant because the movements of fuel prices are so out of sync with one another.

The "correlation coefficient" is a statistical measure of the degree to which fuel price changes are related to each other. A correlation coefficient close to zero indicates no similarity in price movements. Correlation coefficients above 0.5 are considered strong correlations, and values above 0.9 are considered very strong correlations. Power production input fuel price changes (natural gas, coal, and nuclear) are not highly correlated and consequently create the basis for a portfolio approach to fuel price risk management (see Table 2).

TABLE 2

Delivered monthly fuel price correlations, 2000–13	
Coal/natural gas	0.01
Natural gas/nuclear	(0.35)
Coal/nuclear	0.85

Source: IHS Energy

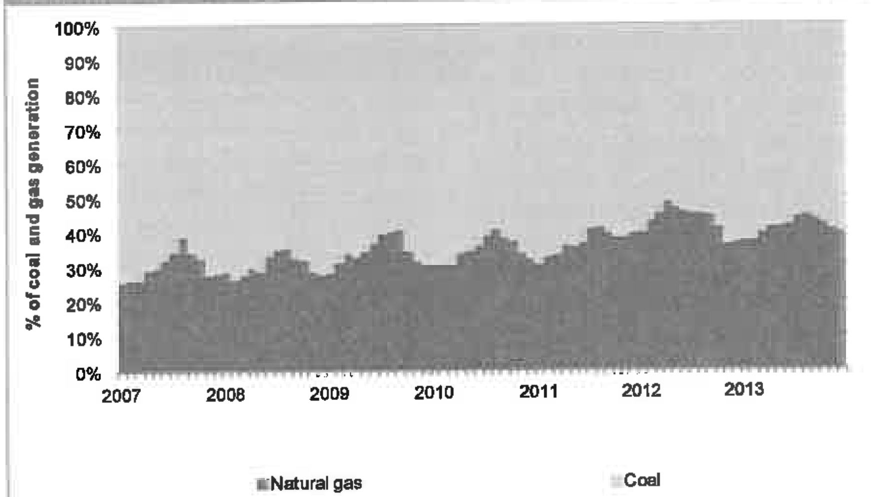
Diversity: The substitution effect

A varied portfolio mitigates power production cost risk because fuel diversity provides the flexibility to substitute one source of power for another in response to relative fuel price changes. Therefore, being able to substitute between alternative generation resources reduces the overall variation in production costs.

Substitution benefits have proven to be substantial. In the past five years, monthly generation shares for natural gas–fired generation were as high as 33% and as low as 19%. Similarly, monthly generation shares for coal-fired generation were as high as 50% and as low as 34%. The swings were driven primarily by a cost-effective alignment of fuels and technologies to consumer demand patterns and alterations of capacity utilization rates in response to changing relative fuel costs. Generation shares shifted toward natural gas–fired generation when relative prices favored natural gas and shifted toward coal-fired generation when relative prices favored coal. Figure 12 shows the recent flexibility in the utilization share tradeoffs between only coal-fired and natural gas–fired generation in the United States.

FIGURE 12

Coal and natural gas generation, 2007–13



Source: IHS Energy

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Diversity benefits differ by technology

All types of generating fuels and technologies can provide the first dimension of risk management—the *portfolio effect*. However, only some types of fuels and technologies can provide the second dimension of risk management—the *substitution effect*. Power plants need to be dispatchable to provide the substitution effect in a diverse portfolio. As a result, the benefits of expanding installed capacity diversity by adding nondispatchable resources such as wind and solar generating technologies are less than the equivalent expansion of power capacity diversity with dispatchable power plants such as biomass, conventional fossil-fueled power plants, reservoir hydro, and nuclear power plants. Therefore, not all diversity in the capacity mix provides equal benefits.

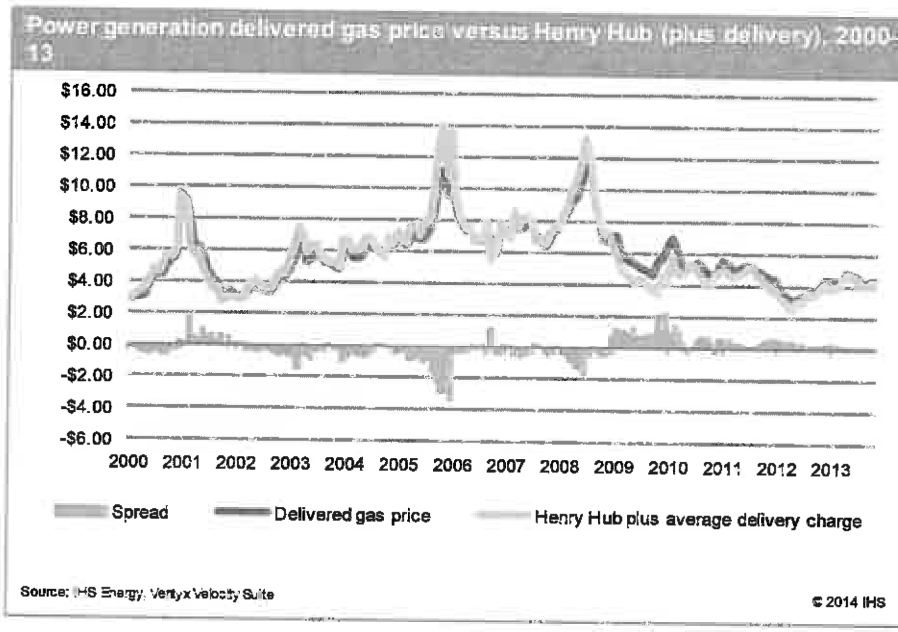
Diversity is the best available power cost risk management tool

A diverse portfolio is the best available tool for power generation cost risk management. Other risk management tools such as fuel contracts and financial derivatives complement fuel and technological diversity in power generation but fall far short of providing a cost-effective substitute for power supply diversity.

Contracts are tools available to manage power production cost risk. These tools include short-run contracts, including NYMEX futures contracts, as well as long-term contracts spanning a decade or more. Power generators have traditionally covered some portion of fuel needs with contracts to reduce the variance of delivered fuel costs. To do this, generators balance the benefits of using contracts or financial derivatives against the costs. With such assessment, only a small percentage of natural gas purchases are under long-term contracts or hedged in the futures markets. Consequently, the natural gas futures market is only liquid (has many buyers and sellers) for a few years out.

FIGURE 13

Power generation delivered gas price versus Henry Hub (plus delivery), 2000-13



The degree of risk management provided by contracts is observed in the difference between the reported delivered price of natural gas to power generators and the spot market price plus a typical delivery change. Contract prices along with spot purchases combine to determine the reported delivered price of natural gas to power generators. Delivered prices are typically about 12% higher than the Henry Hub spot price owing to transport, storage, and distribution costs, so this percentage may be used to approximate a delivery charge. Figure 13 compares the Henry Hub spot price plus this typical delivery charge to the reported delivered price of natural gas to power producers.

A comparison of the realized delivered price to the spot price plus a delivery charge shows the impact of contracting on the delivered price pattern. Natural gas contracts provided some protection from spot price highs and thus reduced some variation of natural gas prices compared to the spot market price plus transportation. Over the past 10 years, contracting reduced the monthly variation (the standard deviation) in the delivered price of natural gas to the power sector by 24% compared to the variation in the spot price plus delivery charges at the Henry Hub. Although fuel contracts are part of a cost-effective risk management strategy, the cost/benefit trade-offs of using contracts limit the application of these tools in a cost-effective risk management strategy.

Using a contract to lock into volumes at fixed or indexed prices involves risks and costs. Contracting for fuel creates volume risk. A buyer of a contract is taking on an obligation to purchase a given amount of fuel, at a given price, and at a future point in time. From a power generator's perspective, the variations in aggregate power consumer demand and relative prices to alternative generating sources make predicting the amount of fuel needed at any future point in time difficult. This difficulty increases the further out in time the contracted fuel delivery date. If a buyer ends up with too much or too little fuel at a future point in time, then the buyer must sell or buy at the spot market price at that time.

Contracting for fuel creates price risk. A buyer of a fuel contract locks into a price at a future point in time. When the contract delivery date arrives, the spot market price for the fuel likely differs from the contract price. If the contract price ends up higher than the spot market price, then the contract provided price certainty but also created a fuel cost that turned out to be more expensive than the alternative of spot market purchases. Conversely, if the spot market price turns out to be above the contract price, then the buyer has realized a fuel cost savings.

Past price relationships also illustrate the potential for gains and losses from contracting for natural gas in an uncertain price environment. When the spot market price at Henry Hub increased faster than expected, volumes contracted at the previously lower expected price produced a gain. For example, in June 2008 the delivered cost of natural gas was below that of the spot market. Conversely, when natural gas prices fell faster than anticipated, volumes contracted at the previously higher expected price produced a loss. For example in June 2012, the delivered cost of natural gas was above that of the spot market purchases.

The combination of volume and price risk in fuel contracting makes buying fuel under contract a speculative activity, capable of generating gains and losses depending on how closely contract prices align with spot market prices. Therefore, cost-effective risk management requires power generators to balance the benefits of gains from contracting for fuel volumes and prices against the risk of losses.

Managing fuel price risk through contracts does not always involve the physical delivery of the fuel. In particular, a futures contract is typically settled before physical delivery takes place, and thus is referred to as a financial rather than a physical hedge to fuel price uncertainty. For example, NYMEX provides a standard contract for buyers and sellers to transact for set amounts of natural gas capable of being delivered at one of many liquid trading hubs at a certain price and a certain date in the future. Since the value of a futures contract depends on the expected future price in the spot market, these futures contracts are derivatives of the physical natural gas spot market.

The potential losses facing a fuel buyer that employs financial derivatives create a risk management cost. Sellers require that buyers set aside funds as collateral to insure that potential losses can be covered. Market regulators want these guarantees in place as well in order to manage the stability of the marketplace. Recently, as part of reforms aimed at improving the stability of the financial derivatives markets, the Dodd-Frank Act increased these collateral requirements and thus the cost of employing financial derivatives.

Outside of financial derivatives, fuel deliverability is an important consideration in evaluating power cost risk management. Currently, natural gas pipeline expansion requires long-term contracts to finance projects. Looking ahead, the fastest growing segment of US natural gas demand is the power sector and, as described earlier, this sector infrequently enters into long-term natural gas supply contracts that would finance new pipelines. Consequently, pipeline expansions are not likely to stay in sync with power generation natural gas demand trends.

The prospect of continued periodic misalignments between natural gas deliverability and natural gas demand makes price spikes a likely feature of the future power business landscape. The nominal volume of long-term fuel contracts and the costs and benefits of entering into such contracts limit the cost-effective substitution of contracts for portfolio diversity. Therefore, maintaining or expanding fuel diversity remains a competitive alternative to natural gas infrastructure expansion.

Striking a balance between the costs and benefits of fuel contracting makes this risk management tool an important complement to a diverse generation portfolio but does not indicate that it could provide a cost-effective substitute for power supply diversity.

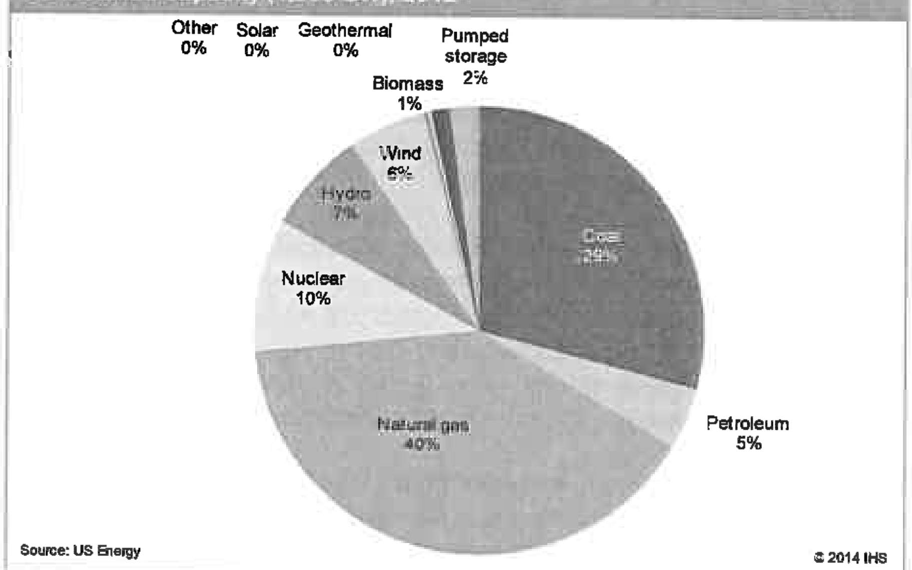
A starting point taken for granted

US power consumers benefit from the diverse power supply mix shown in Figure 14. Simply inheriting this diverse generation mix based on fuel and technology decisions made decades ago makes it easy for current power stakeholders to take the benefits for granted. This underappreciation of power supply diversity creates an energy policy challenge because if the value of fuel and technology diversity continues to be taken for granted, then the current political and regulatory process is not likely to properly take it into account when crafting legislation or setting regulations.

As a result, the United States may move down a path toward a less diverse power supply without consumers realizing the value of power supply diversity until it is gone. For example, if the US power sector had been all natural gas–fired during the shale gas era to date, the average fuel cost for power would have been over twice as high, and month-to-month power bill variation (standard deviation) would have been three times greater (see Table 3). This estimate itself is conservative because the additional demand from power generation would have likely put significant upward pressure on gas prices.

FIGURE 14

US installed capacity (1,063 GW), 2012



Source: US Energy

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TABLE 3

The impact of fuel diversity: Power production fuel costs
(Actual versus all gas generation mix, 2000–13 YTD; cents per kWh)

	Henry Hub	All power sector fuel costs
Average	5.09	2.29
Maximum	11.02	4.20
Minimum	2.46	1.21
Standard deviation	1.63	0.55

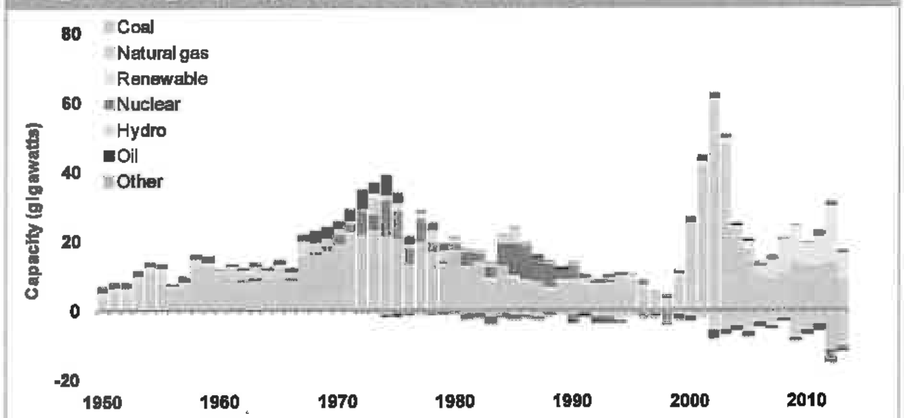
Note: Converted the Henry Hub dollar per MMBtu price to cents per kWh using the average reported heat rate for all operating natural gas plants in the respective month.
Data source: Ventyx Velocity Suite
Source: IHS Energy

Trends in the US generation mix

The current diverse fuel and technology mix in US power supply did not come about by accident. The US generation mix evolved over many decades and reflects the fuel and technology decisions made long ago for power plants that typically operate for 30 to 50 years or more. Consequently, once a fuel and technology choice is made, the power system must live with the consequences—whatever they are—for decades.

FIGURE 15

US generating capacity additions and retirements, 1950–2013



Source: IHS Energy, Ventyx Velocity Suite

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US power supply does not evolve smoothly. The generation mix changes owing to the pace of power plant retirements, the error in forecasting power demand, price trends and other developments in the energy markets, and the impacts of public policy initiatives. All three of these factors unfold unevenly over time. The current diverse generation mix evolved from multiyear cycles of capacity additions that were typically dominated by a particular fuel and technology (see Figure 15). The swings in fuel and technology choice do not indicate a lack of appreciation for diverse power supply. Instead, they show that given the size of the existing supply base, it takes a number of years of homogenous supply additions to move the overall supply mix a small proportion. Therefore, altering the overall mix slightly required a number of years of adjustment.

The uneven historical pattern of capacity additions is important because the future pattern of retirements will tend to reflect the previous pattern of additions as similarly aged assets reach the end of their useful lives. For example, current retirements are disproportionately reducing the coal and nuclear shares in the capacity mix, reflecting the composition of power plants added in the 1960s through 1980s. Current power plant retirements are about 12,000 MW per year and are moving the annual pace of retirements in the next decade to 1.5 times the rate of the past decade.

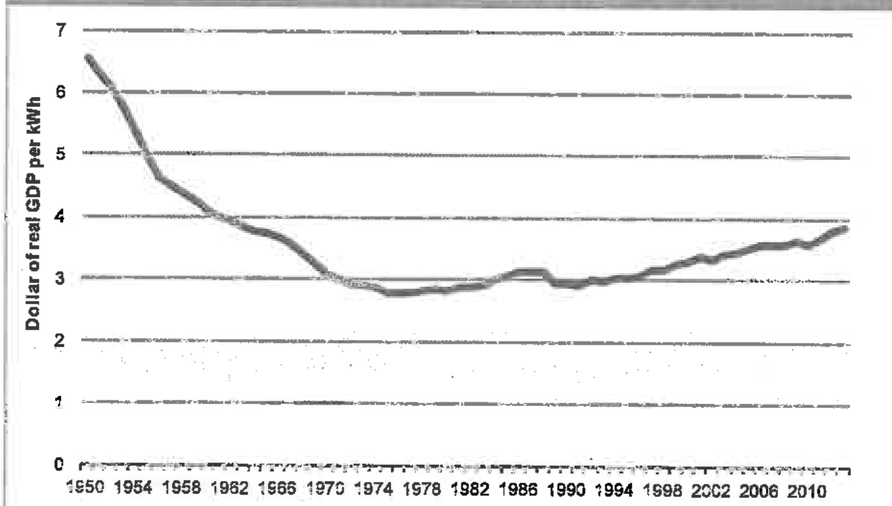
Power plant retirements typically need to be replaced because electricity consumption continues to increase. Although power demand increases are slowing compared to historical trends and compared to the growth rate of GDP, the annual rate of change nevertheless remains positive. US power demand is expected to increase between 1.0% and 2.5% each year in the decade ahead, averaging 1.5%.

The expected pace of US power demand growth reflects a number of trends. First, US electric efficiency has been improving for over two decades. Most appliances and machinery have useful lives of many years. As technology improves, these end uses get more efficient. Therefore, overall efficiency typically increases as appliances and machinery wear out and are replaced. On the other hand, the number of electric end uses keeps expanding and the end-use penetration rates keep increasing owing to advances in digital and communication technologies that both increase capability and lower costs. These trends in existing technology turnover and new technology adoption produce a steady rate of change in electric end-use efficiency (see Figure 16).

Underlying trends in power demand are often masked by the influences of variations in the weather and the business cycle. For example, US electric output in first quarter 2014 was over 4% greater than in the same period one year ago owing in part to the influence of the polar vortex. Therefore, trend rates need to compare power consumption increases either between points in time with similar weather conditions or on a weather-normalized basis. Similarly, power demand trends can be misleading if compared without taking the business cycle into account. Figure 17 shows the trend rate of growth in power use from the previous business cycle peak to peak and tough to trough. Overall, power consumption increased by between 0.5 and 0.6 of the rate of increase in GDP. Looking ahead, GDP is expected to increase on average 2.5% annually through 2025 and thus is likely to produce a trend rate of electric consumption of around 1.5% annually. This US power demand growth rate creates a need for about 9 GW of new power supply per year, for a total of 1,140 GW by 2025.

FIGURE 16

US electric efficiency, 1950–2013



Note: BEA reports Real GDP in 2009 dollars.
Source: IHS Energy, EIA, BEA

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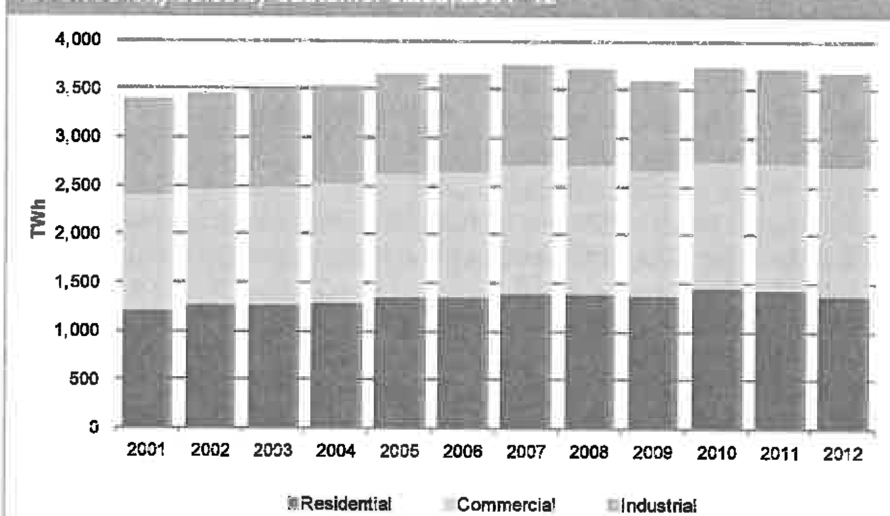
FIGURE 17

US electricity sales by customer class, 2001–12



Note: TWh = terawatt-hour(s).
Source: IHS Energy, EIA

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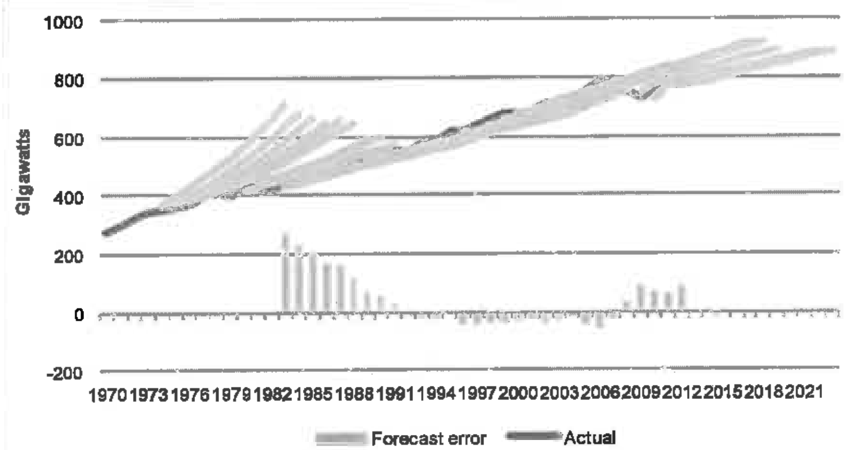
Annual power supply additions do not typically unfold simultaneously with demand increases. Historically, changes in power supply are much more pronounced than the changes in power demand. This uneven pace of change in the capacity mix reflects planning uncertainty regarding future power demand and a slow adjustment process for power supply development to forecast errors.

Future electric demand is uncertain. Figure 18 shows a sequence of power industry forecasts of future demand compared to the actual demand. The pattern of forecast errors indicates that electric demand forecasts are slow to adjust to actual conditions: overforecasts tend to be followed by overforecasts, and underforecasts tend to be followed by underforecasts.

FIGURE 18

US power demand: Projected versus actual, 1983–2012



Source: IHS Energy
Data source: North American Electric Reliability Corporation
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Forecasting uncertainty presents a challenge because fuel and technology decisions must be made years in advance of consumer demand to accommodate the time requirements for siting, permitting, and constructing new sources of power supply. As a result, the regional power systems are subject to momentum in power plant addition activity that results in capacity surpluses and shortages. Adjustment to forecast overestimates is slow because when a surplus becomes evident, the capital intensity of power plants creates an accumulating sunk-cost balance in the construction phase of power supply development. In this case, there is an economic incentive to finish constructing a power plant because the costs to finish are the relevant costs to balance against the benefits of completion. Conversely, if a shortage becomes evident, new peaking power plants take about a year to put into place under the best of circumstances. Consequently, the forecast error and this lagged adjustment process can produce a significant over/underinstallment of new capacity development versus need. These imbalances can require a decade or more to work off in the case of a capacity overbuild and at least a few years to shore up power supply in the case of a capacity shortage.

The pace and makeup of power plant additions are influenced by energy policies. The current installed capacity mix reflects impacts from the implementation of a number of past policy initiatives. Most importantly, 35 years ago energy security was a primary concern, and the energy policy response included the Fuel Use Act (1978) and the Public Utilities Regulatory Policy Act (1978). These policies limited the use of natural gas for power generation and encouraged utility construction of coal and nuclear generating resources as well as nonutility development of cogeneration. Public policy championed coal on energy security grounds—as a safe, reliable, domestic resource.

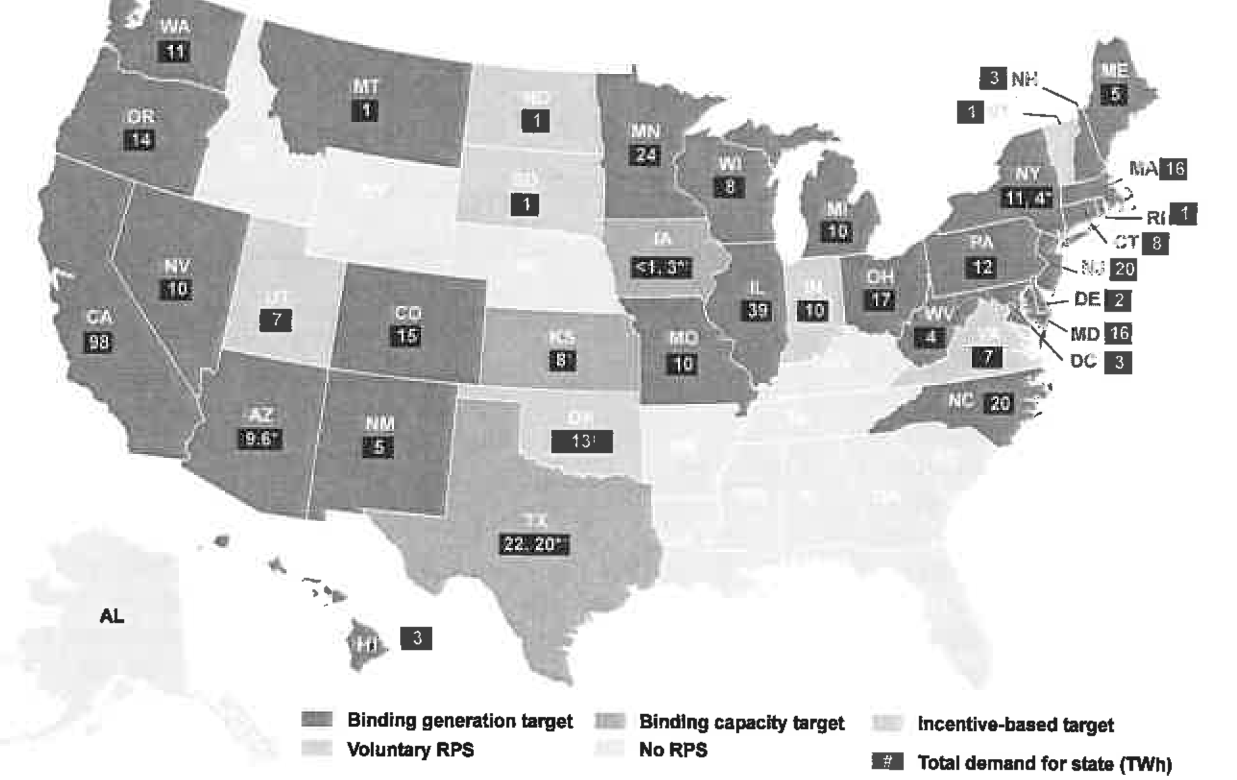
The influence of energy policy on power plant fuel and technology choice is dynamic. For example, as natural gas demand and supply conditions changed following the passage of the Fuel Use Act, the limits on natural gas use for power generation were eventually lifted in 1987. Whereas the Fuel Use Act banned a fuel and technology, other policy initiatives mandate power generation technologies. Energy policies designed to address the climate change challenge created renewable power portfolio requirements in 30 states (see Figure 19).

As states work to implement renewable generation portfolio standards, the complexity of power system operations becomes evident and triggers the need for renewable integration studies. These studies generally find that the costs to integrate intermittent power generation resources increase as the generation share of these resources increases. Some integration studies go so far as to identify the saturation point for wind resources based on their operational characteristics. A wind integration study commissioned by the

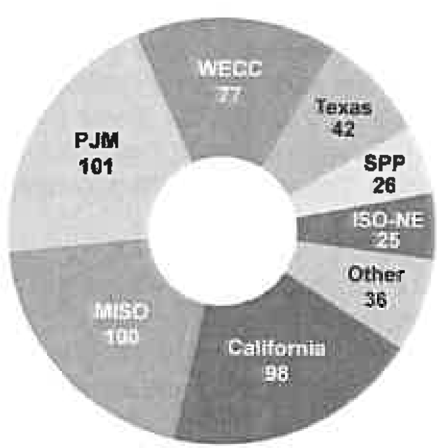
FIGURE 12

The outlook for US State RPS demand to 2025—Total demand: State policy and targets

State RPS policy types and total demand by 2025



Total RPS demand by region (TWh)



30 US states plus the District of Columbia have enacted binding renewable energy targets, and seven others have adopted incentive-based or voluntary targets. These 37 states account for 74% of US retail power sales.

40609-3

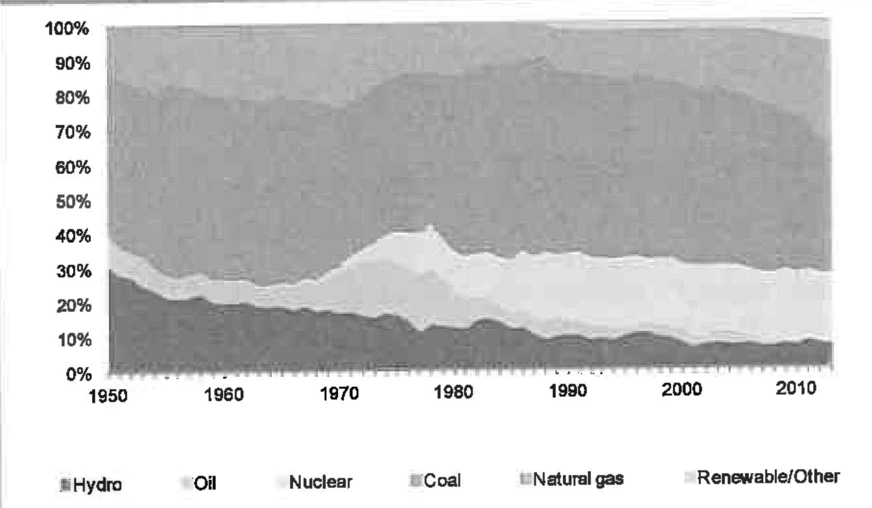
Note: *States include both mandatory and voluntary targets; first number reflects mandatory target, second number reflects additional voluntary targets (of state, municipalities, or other political divisions/utilities).
†Capacity targets have been converted to generation for comparison using estimated regional capacity factors. All quantities reflect primary renewables; see page 2 for additional notes
Source: IHS Emerging Energy Research

power system operator in New England estimated the saturation point for wind in the power system (24% generation share) as well as the additional resources that would be needed to integrate more wind resources.[4] Similarly, a wind integration study by the power system operator in California found that problems were ahead for the California power system because the number of hours when too much wind generation was being put on the grid was increasing. The study noted higher costs were ahead as well because additional resources would be needed to integrate expected additional wind resources planned to meet the renewable portfolio requirements in place.[5] Many of the impacts on the US generation mix from renewable power portfolio requirements are yet to come as higher generation or capacity share mandates become binding in many states in the next few years.

The United States is at a critical juncture because current trends in power plant retirements, demand and supply balances, and public policies are combining to accelerate change in the US generation mix, as shown in Figure 20. In 2013, increases in demand, power plant retirements, and renewable mandates resulted in around 15,800 MW of capacity additions. In the decade ahead, these increasing needs will require power supply decisions amounting to 15% of the installed generating capacity in the United States. In addition, public policies are expected to increase the share of wind and solar generation, and forthcoming regulations from the Environmental Protection Agency (EPA) regarding conventional power plant emissions as well as greenhouse gases (GHG) could significantly increase power plant retirements and accelerate changes further. Altogether, changes in US generating capacity in the next two decades could account for more than one-third of installed capacity.

FIGURE 20

US power generation: shares by fuel, 1950–2013



Source: IHS Energy, EIA

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Threat to power generation diversity: Complacency

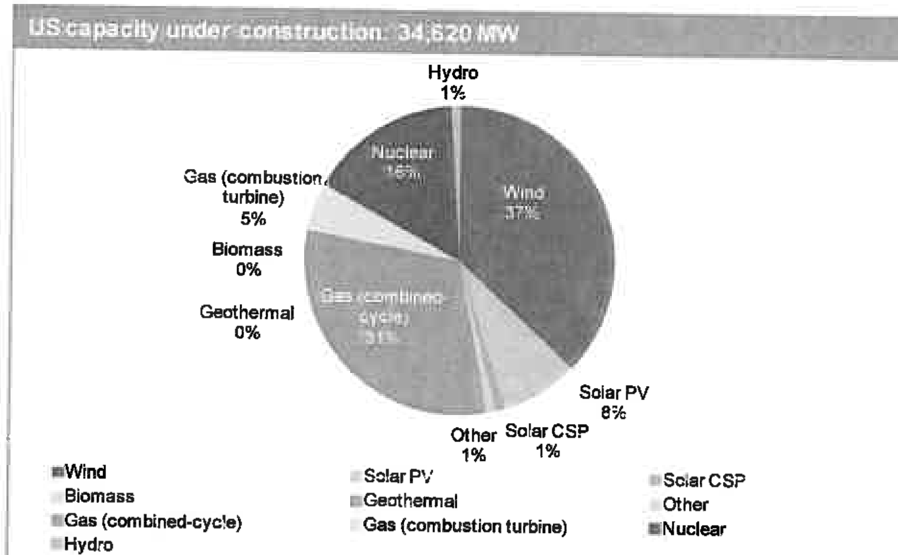
Threats to maintaining diversity in power production do not come from opposition to the idea itself, but rather from the complacency associated with simply taking diversity for granted. The familiar adage of not putting all your eggs in one basket is certainly aligned with the idea of an all-of-the-above energy policy. Four decades of experience demonstrates the conclusion that the government should not be picking fuel or technology winners, but rather should be setting up a level playing field to encourage competitive forces to move the power sector toward the most cost-effective generation mix. Nevertheless, in a striking contrast,

4. *New England Wind Integration Study* produced for ISO New England by GE Energy Applications and Systems Engineering, EnerNex Corporation, and AWS Truepower, 5 December 2010. Accessed 16 April 2014 (http://www.uwig.org/newis_es.pdf).

5. "Integration of Renewable Resources: Operational Requirements and Generation Fleet Capability at 20% RPS." California ISO, 31 August 2010, downloaded from www.caiso.com/2804/2804d036401f0.pdf.

the value of fuel diversity to the end use consumer is not internalized in current power plant decision making. A 2013 review of over eighty integrated resource plans (IRPs) found that many reference fuel diversity but only a few of them refer to it as a risk, and none of them quantify the value of fuel diversity to incorporate it into the decision process.[6] Additionally, environmental policy initiatives do not seem to accommodate diversity issues. Therefore, one power plant decision after another is revealing a de facto energy policy to move away from oil, coal, and nuclear generation and reduce hydroelectric capability, and instead build relatively low utilization wind and solar resources backed up by natural gas–fired generating units (see Figure 21).

FIGURE 21



Notes: Note: CSP = concentrating solar power. PV = photovoltaic. Data as of April 2014.
Source: IHS Energy and Ventyx Velocity Suite

Threat to power generation diversity: The "missing money"

Fuel diversity is threatened as well by the inability of power markets to evolve market rules and institutions to address the "missing money" problem in competitive power generator cash flows. The missing money problem in power markets is the latest manifestation of a long-standing problem in a number of industries, including railroads, airlines, and power, where competitive markets fail to balance demand and supply at market-clearing prices high enough to support the full cost of supply.

Power markets have a missing money problem because they do not have all of the necessary conditions to produce a textbook competitive marketplace. The textbook marketplace has suppliers who maximize their profits by expanding output up to the point where their short-run marginal cost (SRMC) of production equals the market-clearing price. This means that an aggregation of rival suppliers' SRMC curves produces the market supply curve. If this market supply curve intersects the market demand curve at a price too low to support the full cost of new supply (long-run marginal cost [LRMC]), then suppliers will not expand productive capacity. Instead, they will meet increases in demand by adding more variable inputs to the production process with a fixed amount of capacity. However, doing so increases SRMC, and eventually the market-clearing price rises to the point where it covers the cost of expanding productive capacity. This produces the textbook market equilibrium where demand and supply are in balance at the unique point where market-clearing prices are equal to both SRMC and LRMC.

Several characteristics of the technologies that make up a cost-effective power supply create a persistent gap between SRMCs and LRMCs as production varies. As a result, market-clearing wholesale power prices are below the level needed to support the full cost of power supply when demand and supply are in balance with the desired level of reliability.[7] Consequently, the stable textbook market equilibrium does not exist in an electric power marketplace.

6. See the IHS Energy Insight *Reading the Tea Leaves: Trends in the power industry's future plans.*

7. See the IHS Energy Private Report *Power Supply Cost Recovery: Bridging the missing money gap.*

A simple example of a competitive power market made up entirely of rival wind generators illustrates the missing money problem. The cost profile of wind turbine technologies comprises nearly exclusively upfront capital costs (LRMCs). SRMCs for wind technologies equal zero because the variable input to the power production process is wind, and this input is free. In a competitive market, if wind conditions allow for power production, then rival wind generators will be willing to take any price above zero to provide some contribution to recovering the upfront capital costs. If there is adequate supply to balance demand in a competitive marketplace, then rival wind suppliers will drive the market-clearing price to zero. This is not just a theoretical example. When power system conditions create wind-on-wind competition, then zero or negative market-clearing prices (reflecting the cost of losing the production tax credit) are typically observed. Wind generating technologies are a simple and extreme example of a power generating technology with a persistent gap between SRMCs and LRMCs. But this problem exists to some degree with other power generation technologies.

This technology-based market flaw means that periodic shortage-induced price spikes are the only way for market-clearing prices to close the gap between the SRMC and LRMC. This market outcome does not work because of the inherent contradiction—periodic shortages are needed to keep demand and supply in balance.

The missing money problem threatens cost-effective power supply because when market-clearing power prices are chronically too low to support new power plants, then lower expected cash flows at existing plants cause retirements before it is economic to do so, given replacement costs. It is cost effective to retire and replace a power plant only when its cost of continued operation becomes greater than the cost of replacement. Therefore, a market-clearing power price that reflects the full cost of new power supply is the appropriate economic signal for efficient power plant closure and replacement. Consequently, when this price signal is too low, power plant turnover accelerates and moves power supply toward the reduced diversity case.

"Missing money" and premature closing of nuclear power plants

The Kewaunee nuclear plant in Wisconsin is an example of a power plant retirement due to the missing money problem. Wholesale day-ahead power prices average about $30 per MWh in the Midwest power marketplace. This market does not have a supply surplus, and recently the Midwest Independent System Operator (MISO), the institution that manages the wholesale market, announced that it expects to be 7,500 MW short of generating capacity in 2016.[8] The current market-clearing power price must almost double to send an efficient price signal that supports development of a natural gas–fired combined-cycle power plant.

The Kewaunee power plant needs much less than the cost of a new plant, about $54 per MWh, to cover the costs of continued operation. Kewaunee's installed capacity was 574 MW, and the plant demonstrated effective performance since it began operation in 1974. The plant received Nuclear Regulatory Commission approval for life extension through 2033. Nevertheless, the persistent gap between market prices and new supply costs led Dominion Energy, the power plant's owner, to the October 2012 decision to close the plant because of "low gas prices and large volumes of wind without a capacity market."

Kewaunee is not an isolated case. Other nuclear power plants such as Vermont Yankee provide similar examples. Additionally, a significant number of coal-fired power plants are retiring well before it is economic to do so. For example, First Energy retired its Hatfield's Ferry plant in Ohio on 9 October 2013. This is a large (1,700 MW) power plant with a $33 per MWh variable cost of power production.[9] The going-forward

8. Whieldon, Esther. "MISO-OMS survey of LSEs, generators finds resource shortfall remains likely in 2016." SNL Energy, 6 December 2013. Accessed on 14 May 2014 http://www.snl.com/InteractiveX/ArticleAbstract.aspx?id=26168778. Note: LSE = load-serving entity.

9. Source: SNL Financial data for 2012 operations, accessed 5 May 2014. Available at http://www.snl.com/InteractiveX/PlantProductionCostDetail.aspx?ID=3604.

costs involved some additional environmental retrofits, but the plant had already invested $650 million to retrofit a scrubber just four years prior to the announced retirement.

Reducing diversity and increasing risk

Proposed EPA regulations on new power plants accommodate the carbon footprint of new natural gas–fired power plants but do not accommodate the carbon footprint of any new state-of-the-art conventional coal-fired power plants that do not have carbon capture and storage (CSS). Since the cost and performance of CSS technologies remain uneconomic, the United States is now on a path to eliminating coal-fired generation in US power supply expansion. This move toward a greatly reduced role for coal in power generation may accelerate because the EPA is now developing GHG emission standards for existing power plants that could tighten emissions enough to dramatically increase coal-fired power plant retirements.

The impact of a particular fuel or technology on fuel diversity depends on overall power system conditions. As a general rule, the benefits of fuel diversity from any source typically increase as its share in the portfolio decreases. Oil-fired generation illustrated this principle when it proved indispensable in New England in keeping electricity flowing this past winter. Despite only accounting for 0.2% of US generation, it provided a critical safety valve for natural gas deliverability during the polar vortex. Yet, these oil-fired power plants are not likely to survive the tightening environmental regulations across the next decade. The implication is clear: there is a much higher cost from losing this final 0.2% of oil in the generation mix compared to the cost of losing a small percentage of oil-fired generation back in 1978, when oil accounted for 17% of the US generation mix. Losing this final 0.2% of the generation mix will be relatively expensive because the alternative to meet infrequent surges in natural gas demand involves expanding natural gas storage and pipeline capacity in a region where geological constraints make it increasingly difficult to do so.

Public opinion is a powerful factor influencing the power generation mix. The loss of coal- or oil-fired power plants in the generation mix is often ignored or dismissed because of public opinion. Coal- or oil-fired power plants are generally viewed less favorably than wind and solar resources. In particular, labeling some sources of power as “clean energy” necessarily defines other power generating sources as “dirty energy.” This distinction makes many conventional power supply sources increasingly unpopular in the political process. Yet, all sources of power supply employed to meet customer needs have an environmental impact. For example, wind and solar resources require lots of land and must be integrated with conventional grid-based power supply to provide consumers with electricity when the wind is not blowing or the sun is not shining. Therefore, integrating these “clean energy” resources into a power system to meet consumer needs produces an environmental footprint, including a GHG emission rate. The arbitrary distinctions involved in “clean energy” are evident when comparing the emissions profiles of integrated wind and solar power production to that of nuclear power production. A simplistic and misleading distinction between power supply resources is a contributing factor to the loss of fuel diversity.

Edison International provides an example of the impact of public opinion. Antinuclear political pressures in California contributed to the decision in 2013 to prematurely close its San Onofre nuclear power plant. This closure created a need for replacement power supply that is more expensive, more risky, and more carbon intensive.

The going-forward costs of continued operation of the San Onofre nuclear plant were less than the cost of replacement power. Therefore, the closure and replacement of the San Onofre power plant made California power supply more expensive in a state that already has among the highest power costs in the nation. A study released in May 2014 by the Energy Institute at Haas at the University of California Berkeley estimated that closing the San Onofre nuclear power station increased the cost of electricity by $350 million during the first twelve months.[10] This was a large change in power production costs, equivalent to a 13% increase in the total generation costs for the state.

Closing San Onofre makes California power costs more risky. California imports about 30% of its electricity supply. Prior to the closure, nuclear generation provided 18.3% of California generation in 2011, and the San Onofre nuclear units accounted for nearly half of that installed nuclear capacity. The Haas study found that imports increase with system demand but not much, likely owing to transmission constraints, grid limitations, and correlated demand across states. The results imply that the loss of the San Onofre power plant was primarily made up through the use of more expensive generation, as much as 75% of which was out-of-merit generation running to supply energy as well as voltage support. The report's analysis found that up to 25% of the lost San Onofre generation could have come from increased imports of power. The substitute power increases California consumers' exposure to the risks of fossil fuel price movements as well as the risks of low hydroelectric generation due to Western Interconnection drought cycles.

Closing San Onofre makes California power production more carbon intensive. Nuclear power production does not produce carbon dioxide (CO_2) emissions. These nuclear units were a major reason that the CO_2 intensity of California power production was around 0.5 pounds (lb) per kilowatt-hour (kWh). Replacement power coming from in-state natural gas–fired power plants has associated emissions of about 0.9 lb per kWh. Replacement power coming from the rest of the Western Interconnection has associated emissions of 1.5 lb per kWh. Even additional wind and solar power sources in California with natural gas–fired power plants filling in and backing them up have a 0.7 lb per kWh emissions profile. The Haas study found that closing San Onofre caused carbon emissions to increase by an amount worth almost $320 million, in addition to the $350 million in increased electricity prices in the first year. In the big picture, California CO_2 emissions have not declined in the past decade, and the closure of the San Onofre nuclear units will negate the carbon abatement impacts of 20% of the state's current installed wind and solar power supply.

The path toward a less diverse power supply

The relative unpopularity of coal, oil, nuclear, and hydroelectric power plants (compared to renewables), combined with the missing money problem, tightening environmental regulations, and a lack of public awareness of the value of fuel diversity create the potential for the United States to move down a path toward a significant reduction in power supply diversity. Within a couple of decades, the US generation mix could have the following capacity characteristics:

- No meaningful nuclear power supply share
- No meaningful coal-fired power supply share
- No meaningful oil-fired power supply share
- Hydroelectric capacity in the United States reduced by 20%, from 6.6% to 5.3% of installed capacity
- Renewables power supply shares at operational limits in power supply mix: 5.5% solar, 27.5% wind
- Natural gas–fired generation becoming the default option for the remaining US power supply of about 61.7%

10. http://ei.haas.berkeley.edu/pdf/working_papers/WP248.pdf, accessed 30 May 2014.

Comparing the performance of current diverse power supply to this reduced diversity case provides a basis for quantifying the current value of fuel and technology diversity in US power supply.

Quantifying the value of current power supply diversity

A number of metrics exist to compare and contrast the performance of power systems under different scenarios. Three power system performance metrics are relevant in judging the performance of alternative generation portfolios:

- SRMC of electric production (the basis for wholesale power prices)
- Average variable cost of electric production
- Production cost variability

IHS Energy chose a geographic scope for the diversity analyses at the interconnection level of US power systems. The United States has three power interconnections: Electric Reliability Council of Texas (ERCOT), Eastern, and Western. These interconnections define the bounds of the power supply network systems that coordinate the synchronous generation and delivery of alternating current electrical energy to match the profile of aggregate consumer demands in real time.

Analysis at the interconnection level is the minimum level of disaggregation needed to analyze the portfolio and substitution effects of a diverse fuel and technology generation mix. In particular, the substitution effect involves the ability to shift generation from one source of power supply to another. The degree of supply integration within an interconnection makes this possible, whereas the power transfer capability between interconnections does not. The degree of power demand and supply integration within these interconnections creates the incentive and capability to substitute lower-cost generation for higher-cost generation at any point in time. These competitive forces cause the incremental power generation cost-based wholesale power prices at various locations within each interconnection to move together. An average correlation coefficient of monthly average wholesale prices at major trading hubs within each interconnection is roughly 0.8, indicating a high degree of supply linkage within each interconnection.

IHS Energy assessed the current value of fuel diversity by using the most recently available data on the US power sector. Sufficient data were available for 2010 to 2012, given the varied reporting lags of US power system data.

IHS employed its Razor Model to simulate the interactions of demand and supply within each of these US power interconnections from 2010 to 2012. The 2010 to 2012 backcasting analysis created a base case of the current interactions between power demand and supply in US power systems. Appendix B describes the IHS Razor Model and reports the accuracy of this power system simulation tool to replicate the actual performance of these power systems. The high degree of predictive power produced by this model in the backcasting exercise establishes the credibility of using this analytical framework to quantify the impacts of more or less fuel and technology diversity. The macroeconomic impact analysis used the most recently available IHS simulation of the US economy (December 2013) as a base case.

Once this base case was in place, the Razor Model was employed to simulate an alternative case involving a less diverse generation mix. The current generation mix in each of the three interconnections—Eastern, Western, and ERCOT—were altered as follows to produce the reduced diversity case generation:

- The nuclear generating share went to zero.
- The coal-fired electric generating share went to zero.
- The hydroelectric generation share dropped to 3.8%.
- Intermittent wind and solar generation increased its combined base case generation share of about 2% to shares approximating the operational limits—24% in the East, 45% in the West, and 23% in ERCOT—resulting in an overall wind generation share of 21.0% and a solar generation share of 1.5%.
- Natural gas–fired generation provided the remaining generation share in each power system, ranging from about 55% in the West to over 75% in the East and ERCOT, for an overall share of nearly 74%.

Differences between the performance metrics of the current diverse generating portfolio simulation and the reduced diversity case simulation provide an estimate for the current value of fuel diversity. The differences in the level and variance of power prices were fed through to the IHS US macroeconomic model to quantify the broader economic impacts of the higher and more varied power prices and shifts in capital deployment associated with the reduced diversity case.

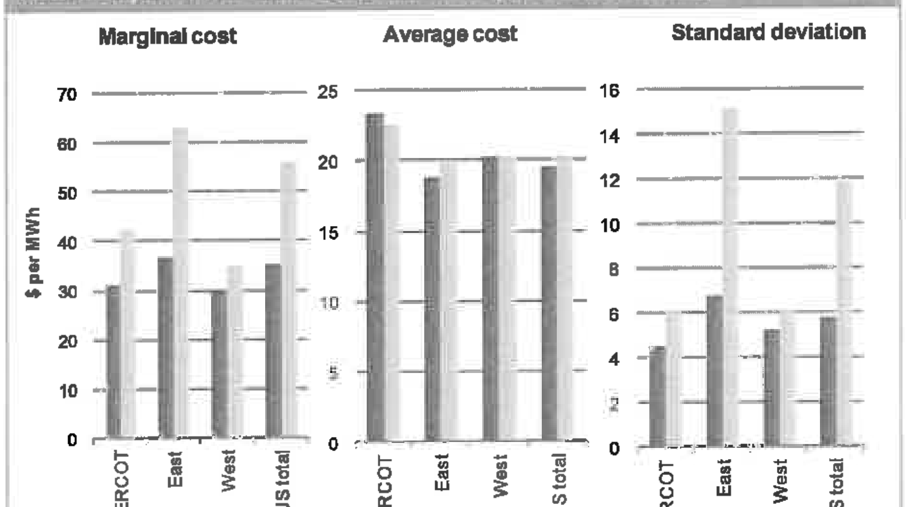
Quantification of the impact of fuel diversity within the US power sector involved a two-step process. The first step quantifies the current value of the substitution effect enabled by a diverse power generating portfolio. The second step quantified the additional value created by the portfolio effect.

The value of the substitution effect

The first step alters the base case by holding relative fuel prices at the average level across 2010 to 2012. Doing this removes the opportunity to substitute back and forth between generation resources based on changes to the marginal cost of generation. This case maintains a portfolio effect but eliminates the substitution effect in power generation. The difference between this constant relative fuel price case and the base case provides an estimate of the current value of the substitution effect provided by the current diverse power generation fuel mix. The results show significantly higher fuel costs from a generation mix deprived of substitution based on fuel price changes. The substitution effects in the current diverse US power generating portfolio reduced the fuel cost for US power production by over $2.8 billion per year. In just the three years of the base case, US power consumers realized nearly $8.5 billion in fuel savings from the substitution effect. Figure 22 shows the results of this first step in the analysis for each interconnection and the United States as a whole.

FIGURE 22

Actual dispatch versus no substitution dispatch: Cost results



Source: IHS Energy

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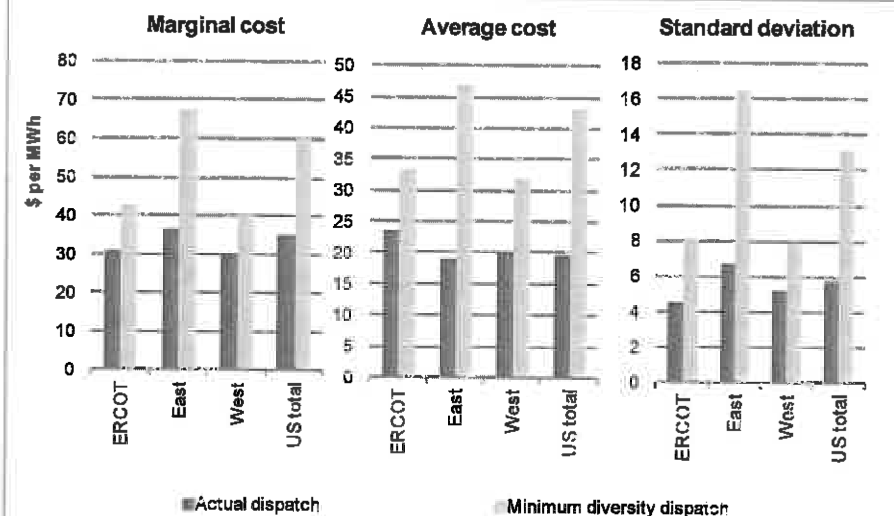
The value of the portfolio effect

The second step quantifies the portfolio value of the current generation mix. To measure this, the base case is altered by replacing the actual current generation mix with the less diverse generation mix. All else is held constant in this reduced diversity case, including the actual monthly fuel prices. Therefore, this reduced diversity simulation reduces the portfolio effect of diverse generation and allows any economic generation substitution to take place utilizing this less diverse capacity mix.

Figure 23 shows the performance metrics for each interconnection and the United States as a whole in the less diverse portfolio case compared to the base case.

FIGURE 23

Actual dispatch versus minimum diversity dispatch: Cost results



Source: IHS Energy

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The portfolio effect reduces not only costs, but also the variation in costs. This translates into a reduction in the typical monthly variation in consumers' power bills of between 25% and 30%.

The differences in average power production costs between the reduced diversity case and the current supply case indicate that fuel and technology diversity in the base case US generation mix provides power consumers with benefits of $93 billion per year. This difference between the reduced diversity case and the base case includes both the substitution and portfolio effects. Using the results of step one allows separation of these two effects, as shown in Table 4.

Figures 24 and 25 show the progression from the base case to the reduced diversity case. The results indicate that the Eastern power interconnection has the most to lose from a less diverse power supply because it faces more significant increases in cost, price, and variability in moving from the base case to the reduced diversity case. The Eastern interconnection ends up with greater variation in part because its delivered fuel costs are more varied than in Texas or the West. In addition, the natural endowments of hydroelectric power in the Western interconnection generation mix continue to mitigate some of the fuel price risk even at a reduced generation share.

In the past three years, generation supply diversity reduced US power supply costs by $93 billion per year, with the majority of the benefit coming from the portfolio effect. These estimates are conservative because they were made only across the recent past, 2010 to 2012. An evaluation over a longer period of history would show increased benefits from managing greater levels of fuel price risk.

The estimates of the current value of power supply diversity are conservative as well because they do not include the feedback effects of higher power cost variation on the cost of capital for power suppliers, as outlined in Appendix A. The analyses indicate that a power supplier with the production cost variation equal to the current US average would have a cost of capital 310 basis points lower than a power supplier

TABLE 4

Diversity cases cost results

		Substitution effect	Portfolio effect	Total
ERCOT	Output (2011, TWh)	334	334	334
	Marginal cost increase ($/MWh)	$11.10	$0.35	$11.45
	Average cost increase ($/MWh)	($0.91)	$10.62	$9.71
	Marginal cost increase split	97%	3%	100%
	Average cost increase split	-9%	109%	100%
	Marginal cost increase percentage	35.40%	1.10%	36.50%
	Average cost increase percentage	-3.90%	45.20%	41.40%
	Marginal cost increase (total)	$3,708,970,847	$116,702,120	$3,825,672,967
	Average cost increase (total)	($302,604,000)	$3,547,080,000	$3,244,476,000
Eastern interconnection	Output (2011, TWh)	2,916	2,916	2,916
	Marginal cost increase ($/MWh)	$26.01	$4.73	$30.74
	Average cost increase ($/MWh)	$1.10	$26.92	$28.02
	Marginal cost increase split	85%	15%	100%
	Average cost increase split	4%	96%	100%
	Marginal cost increase percentage	70.70%	12.80%	83.50%
	Average cost increase percentage	5.80%	142.70%	148.50%
	Marginal cost increase (total)	$75,840,639,098	$13,791,489,884	$89,632,128,981
	Average cost increase (total)	$3,207,600,000	$78,498,720,000	$81,706,320,000
Western interconnection	Output (2011, TWh)	728	728	728
	Marginal cost increase ($/MWh)	$4.94	$5.27	$10.21
	Average cost increase ($/MWh)	($0.10)	$11.67	$11.57
	Marginal cost increase split	48%	52%	100%
	Average cost increase split	-1%	101%	100%
	Marginal cost increase percentage	16.50%	17.60%	34.10%
	Average cost increase percentage	-0.50%	57.50%	57.00%
	Marginal cost increase (total)	$3,593,597,137	$3,837,638,788	$7,431,235,926
	Average cost increase (total)	($72,800,000)	$8,495,760,000	$8,422,960,000
US total	Output (2011, TWh)	3,978	3,978	3,978
	Marginal cost increase ($/MWh)	$20.90	$4.46	$25.36
	Average cost increase ($/MWh)	$0.71	$22.76	$23.47
	Marginal cost increase split	82%	18%	100%
	Average cost increase split	3%	97%	100%
	Marginal cost increase percentage	59.50%	12.70%	72.20%
	Average cost increase percentage	3.60%	116.70%	120.30%
	Marginal cost increase (total)	$83,143,207,082	$17,745,830,792	$100,889,037,874
	Average cost increase (total)	$2,832,196,000	$90,541,560,000	$93,373,756,000

Source: IHS Energy

with the production cost variation associated with the generation mix of the reduced diversity case. Since 14% of total power costs are returned to capital, this difference accounts for 1–3% of the overall cost of electricity. This cost-of-capital effect can have a magnified impact on overall costs if more capital has to be deployed with an acceleration of power plant closures and replacements from the pace that reflects underlying economics.

The cost of accelerating change in the generation mix

Current trends in public policies and flawed power market outcomes can trigger power plant retirements before the end of a power plant's economic life. When this happens, the closure creates cost impacts beyond the level and volatility of power production costs because it requires shifting capital away from a productive alternative use and toward a replacement power plant investment.

All existing power plants are economic to close and replace at some point in the future. The economic life of a power plant ends when the expected costs of continued operation exceed the cost of replacement. When this happens, the most cost-effective replacement power resource depends on the current capacity mix and what type of addition creates the greatest overall benefit—including the impact on the total cost of power and the management of power production cost risk.

FIGURE 24

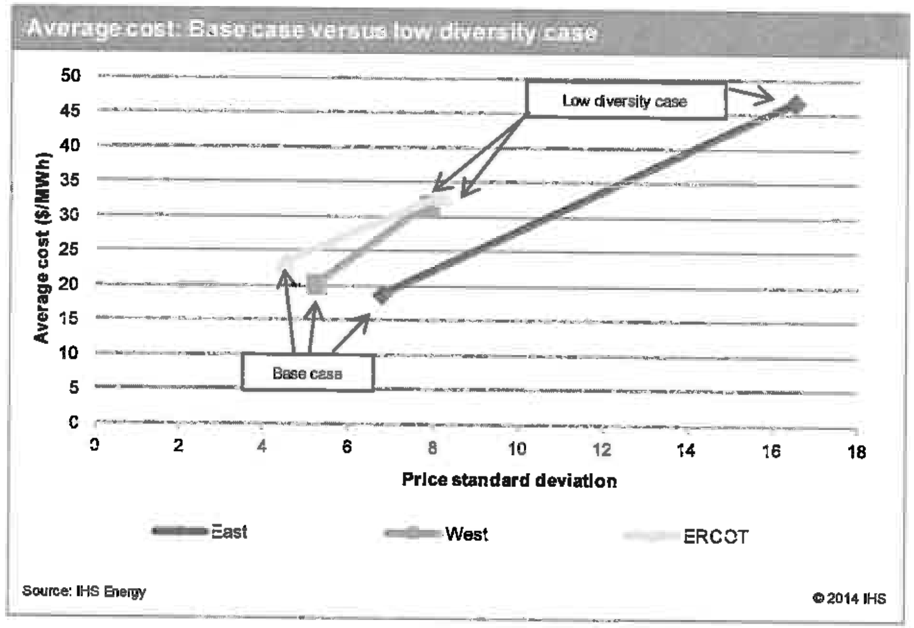
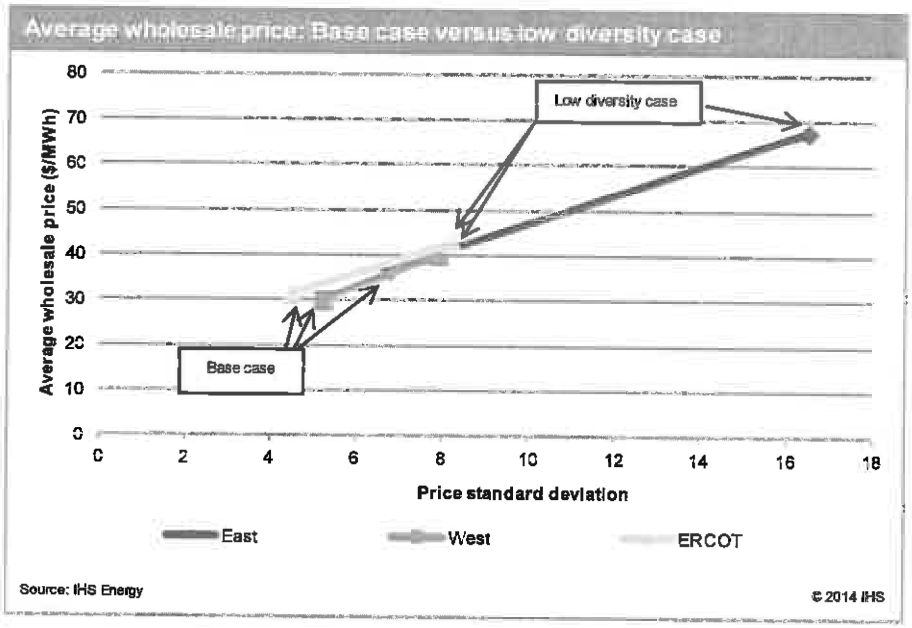


Figure 26 shows the current distribution of the net present value (NPV) of the going-forward costs for the existing US coal-fired generation fleet on a cents per MWh basis in relation to the levelized NPV of replacement power on a per MWh basis.

FIGURE 25

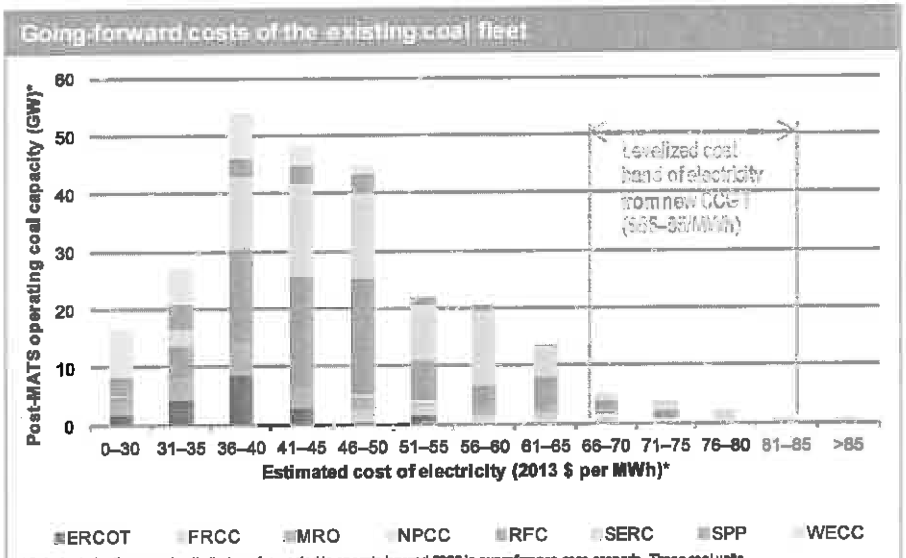


As the distribution of coal-fired power plant going-forward costs indicates, there is a significant difference between the going-forward costs and the replacement costs for the majority of plants. As a result, a substantial cost exists to accelerate the turnover of coal-fired power plants in the capacity mix. For example, closing coal-fired power plants and replacing them as quickly as possible with natural gas–fired power plants would impose a turnover cost of around $500 billion.

Figure 27 shows the going-forward costs of the existing US nuclear power plant fleet. As with the coal units, there is currently a high cost associated with premature closure. As a point of comparison, closing all existing nuclear power plants and replacing them as quickly as possible with natural gas–fired power plants would impose a turnover cost of around $230 billion. Unlike the coal fleet, where a nominal amount of older capacity has a going-forward cost that exceeds the expected levelized cost of replacement, none of the US nuclear capacity is currently more expensive than the lowest of projected replacement costs.

Closing a power plant and replacing it before its time means incurring additional capital costs. The average depreciation rate of capital in the United States is 8.3%. This implies that the average economic life of a capital investment in the United States economy is 12 years. Altering the amount of capital deployed in the US economy by $1 in Year 1 results in an equivalent impact on GDP as deploying a steady stream of about $0.15 of capital for each of the 12 years of economic life. This annual levelized cost approximates the value of the marginal product of capital. Therefore, each dollar of capital deployed to replace a power plant that retires prematurely imposes an opportunity cost equal to the value of the marginal productivity of capital in each year.

FIGURE 26



*Only includes those coal units that are forecasted to operate beyond 2020 in our reference case scenario. These coal units are retrofitted with conventional pollution controls.
Source: IHS Energy

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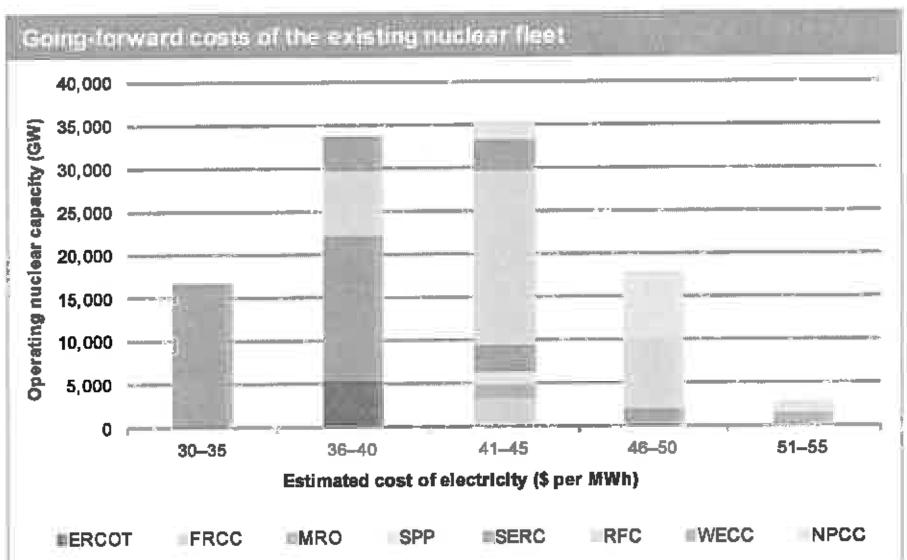
Economywide impacts

FIGURE 27



Source: IHS Energy

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In addition to the $93 billion in lost savings from the portfolio and substitution effects, depending upon the pace of premature closures, there is a cost to the economy of diverting capital from other productive uses. The power price increases associated with the reduced diversity case would profoundly affect the US economy. The reduced diversity case shows a 75% increase in average wholesale power prices compared to the base case. IHS Economics conducted simulations using its US Macroeconomic Model to assess the potential impact of the change in the level and variance of power prices between the base case and the reduced diversity case. The latest IHS base line macroeconomic outlook in December 2013 provides a basis for evaluating the impacts of an electricity price shock due to a reduced diversity case for power supply. Subjecting the current US economy to such a power price increase would trigger economic disruptions, some lasting over a multiyear time frame. As a result, it would take several years for most of these disruptions to dissipate. To capture most of these effects, power price changes were evaluated over the period spanning the past two and the next three years to approximate effects of a power price change to the current state of the economy. Wholesale power price increases were modeled by increasing the

Producer Price Index for electricity by 75% in the macroeconometric model; consumers were affected by the resulting higher prices for retail electricity and other goods and services.

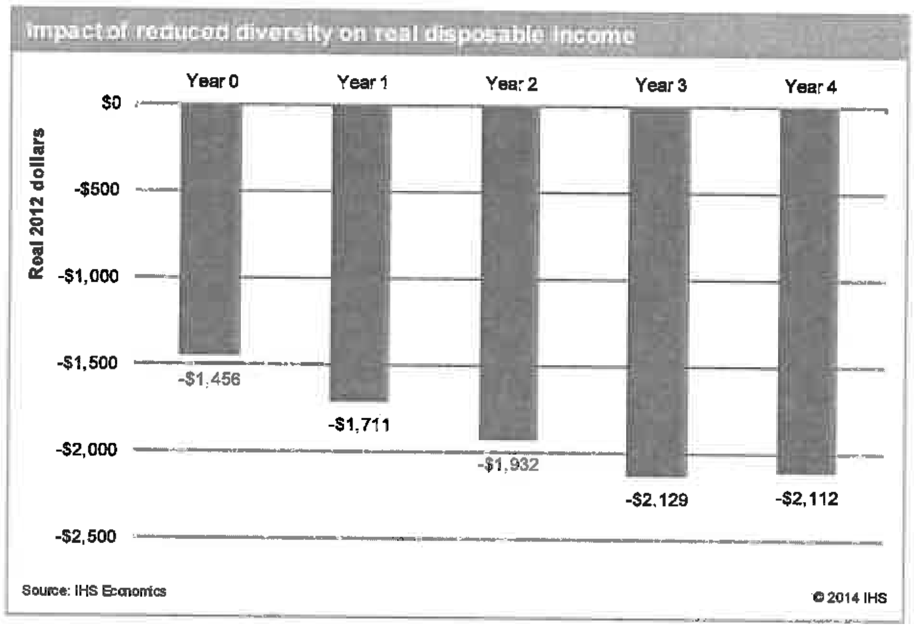
Economic impacts of the power supply reduced diversity case are quantified as deviations from the IHS macroeconomic baseline simulations of the US economy. The major impacts within the three years after the power price change would include

- A drop in real disposable income per household of about $2,100
- A reduction of 1,100,000 jobs
- A decline in real GDP of 1.2%

Consumers will bear the brunt of the impact of higher power prices. The higher price of electricity would trigger a reduction in power use in the longer run (10 or more years out) of around 10%. Yet even with such dramatic reductions in consumption, the typical power bill in the United States would increase from around $65 to $72 per month.

Not only will consumers face higher electric bills, but some portion of increases in manufacturers' costs ultimately will be passed on to consumers through higher prices for goods and services. Faced with lower purchasing power, consumers will scale back on discretionary purchases because expected real disposable income per household is lower by over $2,100 three years after the electric price increase (see Figure 28). Unlike other economic indicators (such as real GDP) that converge toward equilibrium after a few years, real disposable income per household does not recover, even if the simulations are extended out 25 years. This indicates that the price increases will have a longer-term negative effect on disposable income and power consumption levels.

FIGURE 28



Businesses will face the dual challenge of higher operational costs coupled with decreased demand for their products and services. Industrial production will decline, on average, by about 1% through Year 4. This will lead to fewer jobs (i.e., a combination of current jobs that are eliminated and future jobs that are never created) within a couple of years relative to the IHS baseline forecast, as shown in Figure 29, with the largest impact appearing in Year 2, with 1,100,000 fewer jobs than the IHS baseline level.

Impact on GDP

The US economy is a complex adaptive system that seeks to absorb shocks (e.g., increases in prices) and converge toward a long-term state of equilibrium. Although the simulations conducted for this study do not project that the US economy will fall into a recession because of power price increases, it is informative to gauge the underperformance of the US economy under the reduced diversity case. In essence, the higher power prices resulting from the reduced diversity conditions cause negative economic impacts equivalent to a mild recession relative to the forgone potential GDP of the baseline. The economic impacts of the reduced diversity case set back GDP by $198 billion, or 1.2% in Year 1 (see Figure 30). This deviation from the baseline GDP is a drop that is equivalent to about half of the average decline in GDP in US recessions since the Great Depression. However, the impacts on key components of GDP such as personal consumption and business investment will differ.

FIGURE 29

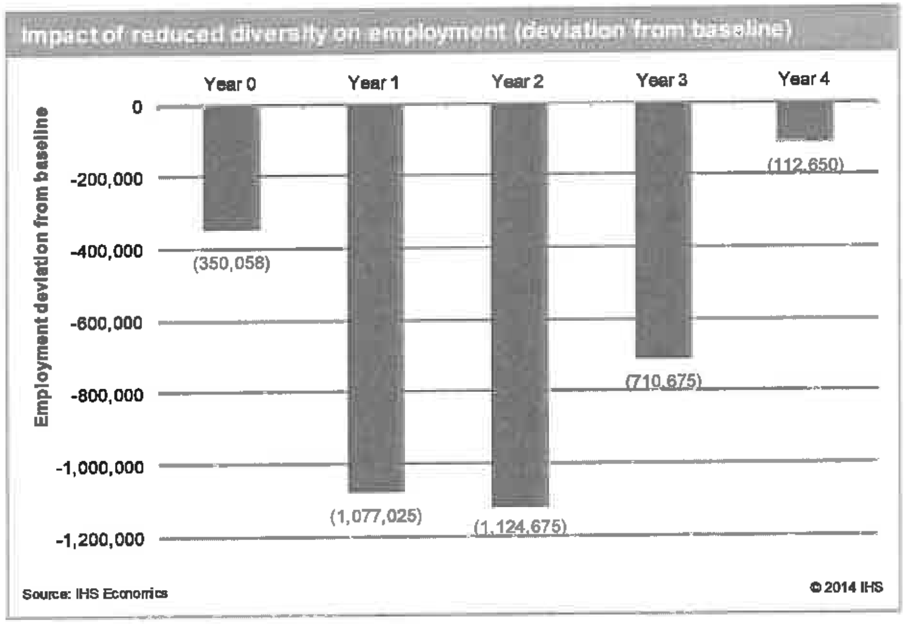
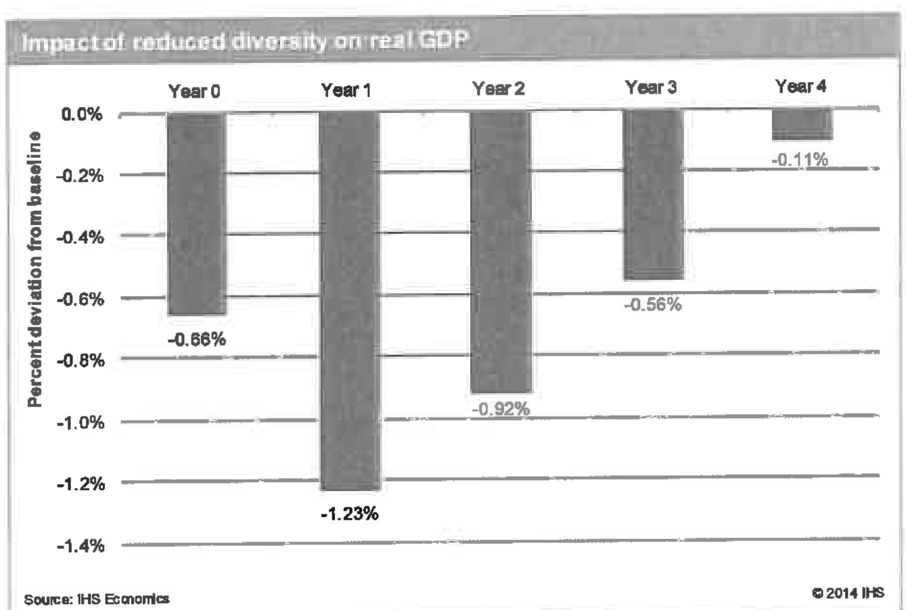


FIGURE 30

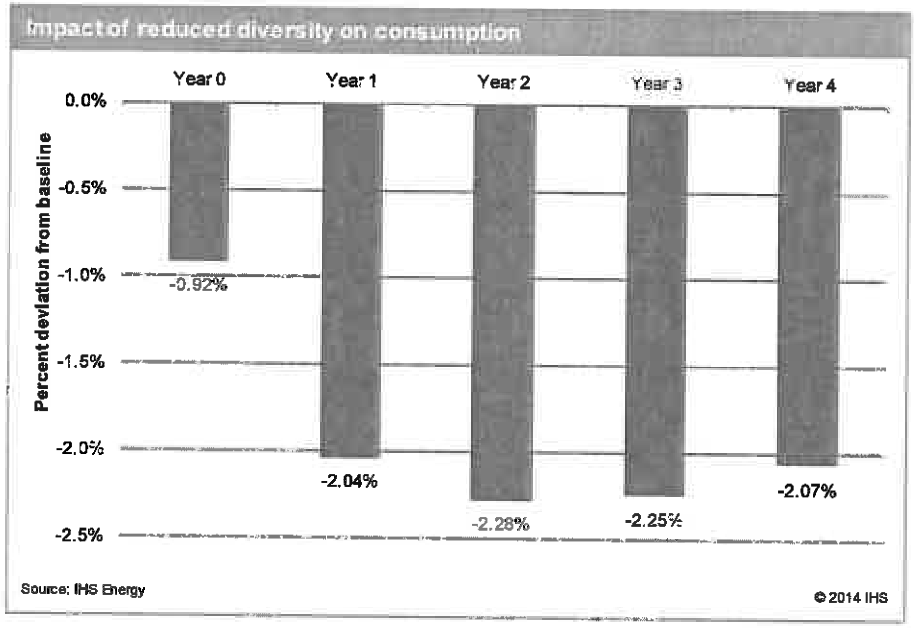


Consumption

Analyzing personal consumption provides insights on the changes to consumer purchasing behavior under the scenario conditions. Consumption, which accounts for approximately two-thirds of US GDP, remains lower over the period with each of its three subcomponents—durable goods, nondurable goods, and services—displaying a different response to the reduced power supply scenario conditions. In contrast with overall GDP, consumer spending shows little recovery by Year 4, as shown in Figure 31. This is due to continued higher prices for goods and services and decreased household disposable income. About 57% of the decline will occur in purchases of services, where household operations including spending on electricity will have a significant impact.

In the early years, lower spending on durable goods (appliances, furniture, consumer electronics, etc.) will account for about 33% of the decline, before moderating to 25% in the longer term. This indicates that consumers, faced with less disposable income, will simply delay purchases in the early years. The US macro simulations also predict moderate delays in housing starts and light vehicle sales, ostensibly due to consumers trying to minimize their spending.

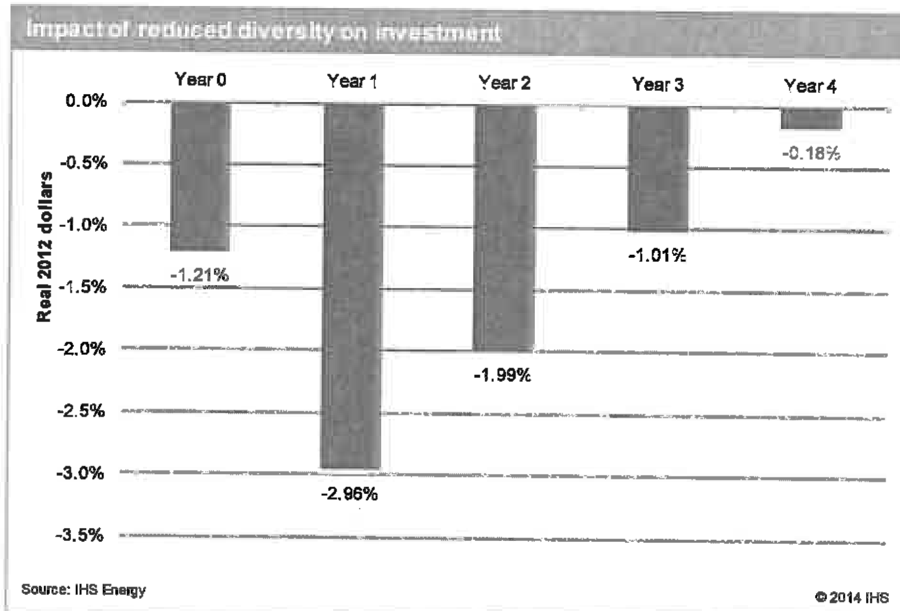
FIGURE 31



Investment

Following an initial setback relative to the baseline, investment will recover by the end of the forecast horizon. Nonresidential investment will initially be characterized by delays in equipment and software purchases, which will moderate a few years after the electric price shock. Spending on residential structures will remain negative relative to the baseline over the four years, as shown in Figure 32. The net effect in overall investment is a recovery as the economy rebounds back to a long-run equilibrium.

FIGURE 32



In the longer term, if current trends cause the reduced diversity case to materialize within the next decade, then the premature closure and replacement of existing power plants would shift billions of dollars of capital from alternative deployments in the US economy.

Conclusions

Consumers want a cost-effective generation mix. Obtaining one on the regulated and public power side of the industry involves employing an integrated resource planning process that properly incorporates cost-effective risk management. Obtaining such a mix on the competitive side of the power business involves employing time-differentiated market-clearing prices for energy and capacity commodities that can provide efficient economic signals. The linkage between risk and cost of capital can internalize cost-effective risk management into competitive power business strategies. Regardless of industry structure, a diverse generation mix is the desired outcome of cost-effective power system planning and operation.

The results of this study indicate seven key factors that will shape US power supply diversity in the years to come:

- **Energy policy development.** US policy heavily influences the US power supply mix. Implementing an all-of-the-above energy policy requires properly internalizing the value of fuel diversity.

- **Market structure.** Market flaws distort wholesale power prices downward and result in uneconomic retirement and replacement of existing cost-effective generation resources. This issue and any market structure changes to address it will significantly shape future power plant development.

- **Energy policy discourse.** Preserving the value of fuel diversity depends on public awareness and understanding. The extent and nature of public education regarding the value of power supply diversity may strongly influence public opinion.

- **Planning alignment.** Alignment of fuel and technology choices for power generation with engineering and economic principles is critical to efficient and reliable supply. There is no single fuel or technology of choice for power generation, and all forms of power production have economic, environmental, and reliability impacts.

- **Risk assessment.** To incorporate system considerations into plant-level decisions, prudent fuel price uncertainties must be used with probabilistic approaches to decision making.

- **Flexibility.** Flexibility and exemptions in rule making and implementation allow for the balancing of costs and benefits in power supply systems and may help preserve highly valuable diversity in systemwide decisions as well as on a small but impactful individual plant scale.

- **Scope.** Including fuel price risk and additional storage and transportation infrastructure costs is crucial when evaluating reduced diversity scenarios in comparison to the cost of maintaining and expanding fuel diversity.

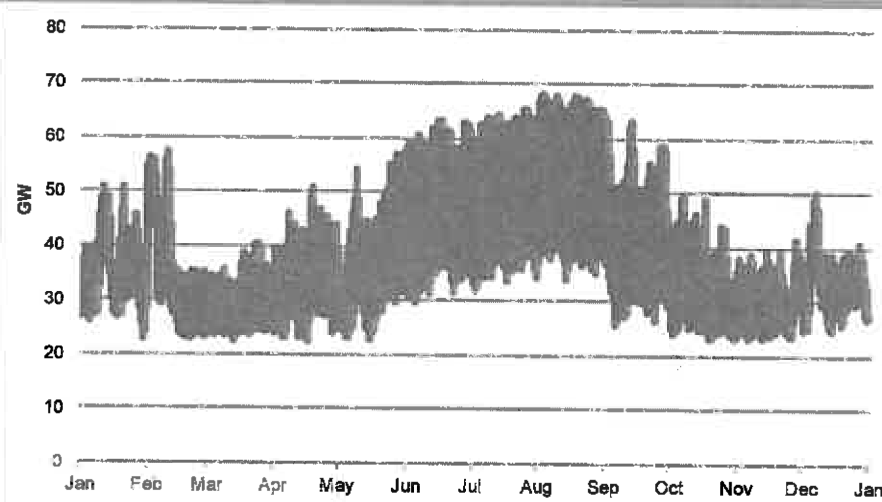
Appendix A: Cost-effective electric generating mix

The objective of power supply is to provide reliable, efficient, and environmentally responsible electric production to meet the aggregate power needs of consumers at various points in time. Consumers determine how much electricity they want at any point in time, and since the power grid physically connects consumers, it aggregates individual consumer demands into a power system demand pattern that varies considerably from hour to hour. For example, Figure A-1 shows the hourly aggregate demand for electricity in ERCOT.

In order to reliably meet aggregate power demands, enough generating capacity needs to be installed and available to meet demand at any point in time. The overall need for installed capacity is determined by the peak demand and a desired reserve margin. A 15% reserve margin is a typical planning target to insure reliable power supply.

FIGURE A-1

2011 hourly electric loads—ERCOT



Source: IHS Energy

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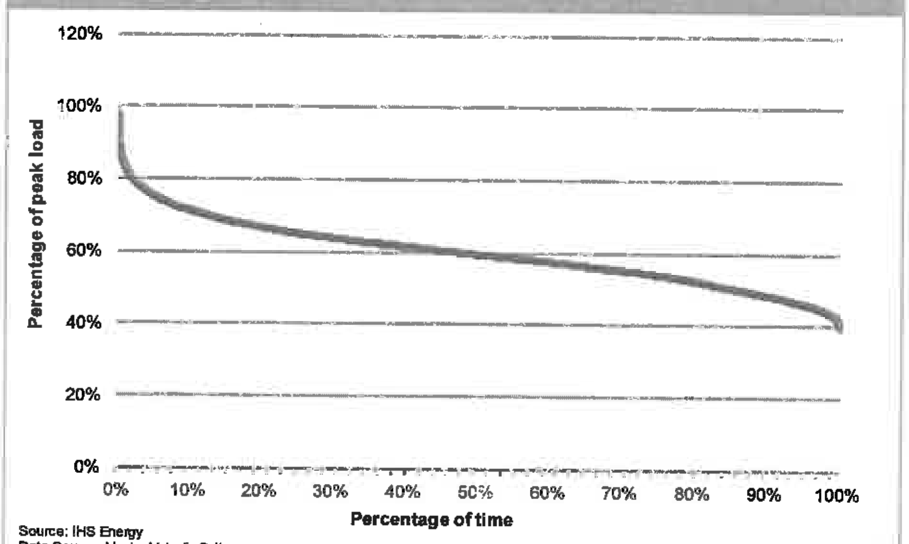
The chronological hourly power demands plus the required reserve margin allow the construction of a unitized load duration curve (see Figure A-2). The unitized load duration curve orders hourly electric demands from highest to lowest and unitizes the hourly loads by expressing the values on the y-axis as a percentage of the maximum (peak) demand plus the desired reserve margin. The x-axis shows the percentage of the year that load is at or above the declining levels of aggregate demand.

FIGURE A-2

Load duration curve



Source: IHS Energy
Data Source: Ventyx Velocity Suite

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This unitized load duration curve has a load factor—the ratio of average load to peak load—of 0.60. Although load duration curve shapes vary from one power system to another, this load factor and unitized load duration curve shape is a reasonable approximation of a typical pattern of electric demand in a US power system. The objective of any power system would be to match its demand pattern with cost-effective power supply.

There are a number of alternative technologies available to produce electricity. These power supply alternatives have different operating characteristics. Most importantly, some power generating technologies can produce electricity on demand that aligns with the pattern of consumer demand through time, while others cannot. For example, solar PV panels can only provide electric output during hours of sunlight and thus cannot meet aggregate demand during the night. In contrast, thermal generation such as coal and natural gas can ramp up and down or turn on and off to match output with customer demand. Technologies such as coal and natural gas are considered dispatchable, while technologies such as solar and wind are considered nondispatchable. A number of combinations of technologies can together provide electric output that matches the pattern of consumer needs.

The lowest-cost generating technologies that can meet the highest increases in demand are peaking technologies such as combustion turbines (CTs). CTs are the most economical technology to meet loads that occur for only a small amount of time. These technologies can start-up quickly and change output flexibly to meet the relatively infrequent hours of highest power demand. They are economic even though they are not the best available technology for efficiently transforming fuel into electricity. CTs have relatively low upfront capital costs and thus present a trade-off with more efficient but higher capital cost generating technology alternatives. Since these resources are expected to be used so infrequently, the additional cost of more efficient power generation is not justified by fuel savings, given their expected low utilization rates.

Cycling technologies are most economical to follow changes in power demand across most hours. Consequently, utilization rates can be high enough to generate enough fuel savings to cover the additional capital cost of these technologies over a peaking technology. These intermediate technologies provide flexible operation along with efficient conversion of fuel into power. A natural gas–fired combined-cycle gas turbine (CCGT) is one technology that is suitable and frequently used for this role.

Base-load technologies are the lowest-cost power supply sources to meet power demand across most hours. These technologies are cost-effective because they allow the trading of some flexibility in varying output for the lower operating costs associated with high utilization rates. These technologies include nuclear power plants, coal-fired power plants, and reservoir hydroelectric power supply resources.

Nondispatchable power resources include technologies such as run-of-the-river hydroelectric, wind, and solar power supplies. These technologies produce power when external conditions allow—river flows, wind speeds, and solar insolation levels. Variations in electric output from these resources reflect changes in these external conditions rather than changes initiated by the generator or system operator to follow shifts in power consumer needs. Some of these resources can be economic in a generation mix if the value of the fuel they displace and their net dependable capacity are enough to cover their total cost. However, since nondispatchable production profiles do not align with changes in consumer demands, there are limits to how much of these resources can be cost-effectively incorporated into a power supply mix.

Alternative power generating technologies also have different operating costs. Typical cost profiles for alternative power technologies are shown in Table A-1. Both nuclear and supercritical pulverized coal (SCPC) technologies are based on steam turbines, whereby superheated steam spins a turbine; in coal's case, supercritical refers to the high-pressure phase of steam where heat transfer and therefore the turbine itself is most efficient. Natural gas CTs are akin to jet engines, where the burning fuel's exhaust spins the turbine. A CCGT combines both of these technologies, first spinning a CT with exhaust and then using that exhaust to create steam which spins a second turbine.

TABLE A-1

Typical cost profiles for alternative power technologies

	CCGT	SCPC	Nuclear	CT
Capital cost (US$ per kW)	1,350	3,480	7,130	790
Variable O&M cost (US$ per MWh)	3.5	4.7	1.6	4.8
First year fixed O&M cost (US$ per kW-yr)	13	39	107	9
Property tax and insurance (US$ per kW-yr)	13	36	78	8
Fuel price (US$ per MMBtu)	4.55	2.6	0.7	4.55
Heat rate (Btu per KWh)	6,750	8,300	9,800	10,000
CO_2 emission rate (lbs per kWh)	0.8	1.73	0	1.18

Total capital cost figures include owner's costs: development/permitting, land acquisition, construction general and administrative, financing, interest during construction, etc.
Source: IHS Energy

Power production technologies tend to be capital intensive; the cost of capital is an important determinant of overall costs. The cost of capital is made up of two components: a risk-free rate of return and a risk premium. Short-term US government bond interest rates are considered an approximation of the risk-free cost of capital. Currently, short-term US government bond interest rates are running at 0.1%. In order to attract capital to more risky investments, the return to capital needs to be greater. For example, the average cost of new debt to the US investor-owned power industry is around 4.5%.[11] This indicates an average risk premium of 4.4%.

Power generating technologies have different risk profiles. For example, the fluctuations in natural gas prices and demand levels create uncertainty in plant utilization and the level of operating costs and revenues. This makes future net income uncertain. Greater variation in net income makes the risk of covering debt obligations greater. In addition, more uncertain operating cost profiles add costs by imposing higher working capital requirements.

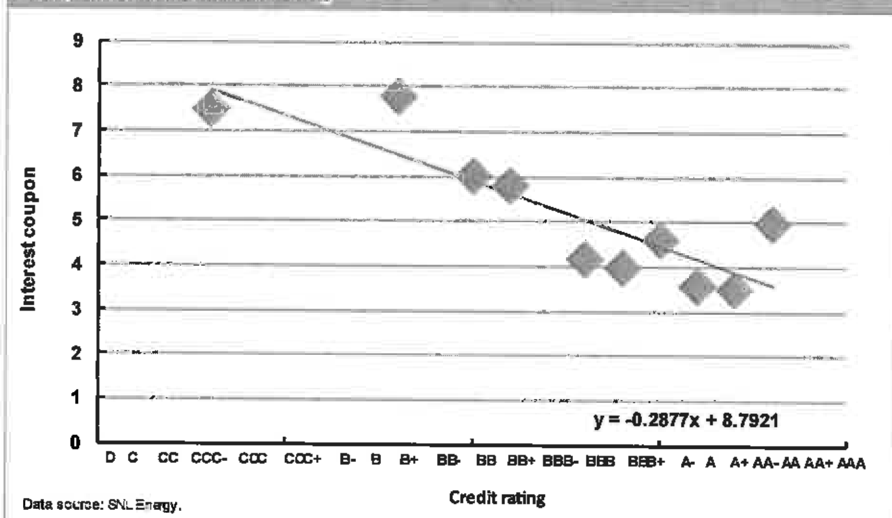
Risk profiles are important because they affect the cost of capital for power generation projects. If a project is seen as more risky, investors demand a higher return for their investment in the project, which can have a significant impact on the overall project cost.

Credit agencies provide risk assessments and credit ratings to reflect these differences. Credit ratings reflect the perceived risk of earning a return on, and a return of, capital deployments. As Figure A-3 shows, the higher credit ratings associated with less risky investments have a lower risk premium, and conversely lower credit ratings associated with more risky investments have a higher risk premium.

Lower credit ratings result from higher variations in net

FIGURE A-3

2010 shareholder-owned utilities senior debt offerings average interest coupon versus credit rating



Data source: SNL Energy.
Source: IHS Energy

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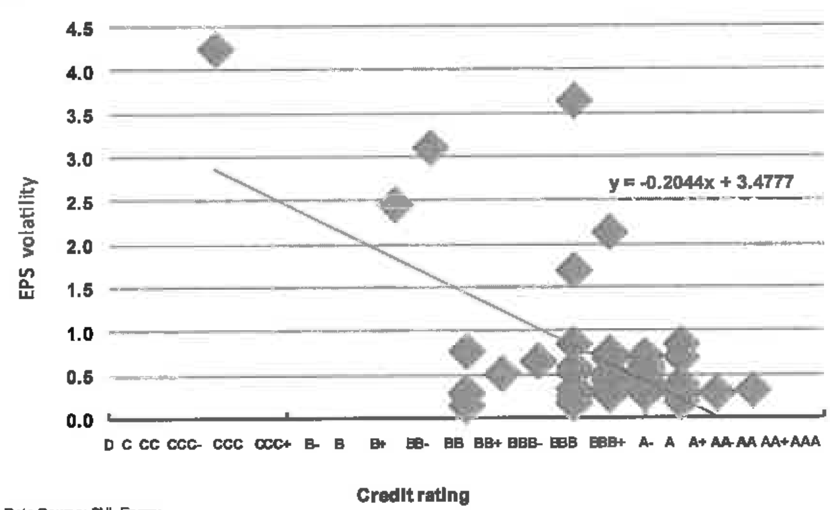
11. Data collected by Stern School of Business, NYU, January 2014. Cost of Capital. Accessed at http://pages.stern.nyu.edu/~adamodar/New_Home_Page/datafile/wacc.htm.

income, as shown in Figure A-4.

FIGURE A-4

Earnings per share volatility versus credit ratings



Data Source: SNL Energy
Notes: EPS = earnings per share.
Volatility is measured by standard deviation.
Source: IHS Energy

Sometimes the cost of capital is directly related to the power plant when project financing is used. In other cases, power companies raise capital at the corporate level with a capital cost that reflects the overall company risk profile rather than just the power plant risk profile. Utilities typically have diverse power supply portfolios, whereas merchant generators tend to be much less diverse—typically almost entirely natural gas-fired. As a result of the different supply mixes and associated risk profiles, utilities and merchant generators have different costs of capital. This difference in the cost of capital provides an approximation of the difference in risk premium.

Overall, the cost of capital for merchant generators is higher than that for utilities broadly. While the power industry has an average cost of debt of roughly 4.5%, merchant generators with significant natural gas holdings tend to have a cost of debt of around 8%. As many of these firms have gone through bankruptcies in the past, this number may be lower than the cost of debt these firms had prior to restructuring.[12] The implied risk premium of a merchant generator to a utility is 3.5%, which is similar to the cost of capital analysis results discussed in the body of the report, where the reduced diversity case generator was calculated to have a cost of capital 310 basis points (3.1%) higher than that of the current US power sector as a whole.

Merchant generators with majority natural gas holdings have higher costs of capital because of the increased earnings volatility and risk of an all natural gas portfolio. In contrast, a generator with a more diverse portfolio needing to secure financing for the same type of plant would have costs of capital more in line with the industry as a whole. This can have a significant impact on the overall cost of the plant. This is not due specifically to the properties of natural gas as a fuel, but rather to the diversity of generating resources available. If a merchant generator were to have an exclusively coal-fired generating fleet or an exclusively nuclear generating fleet, its cost of capital would also increase owing to the higher uncertainty in generation cash flows.

The expected annual power supply costs can be calculated over the expected life of a power plant once the cost of capital is set and combined with the cost and operating profile data. These power costs are uneven through time for a given utilization rate. Therefore, an uneven cost stream can be expressed as a levelized cost by finding a constant cost in each year that has the same present value as the uneven cost stream. The discount rate used to determine this present value is based on the typical cost of capital for the power

12. Based on analysis of the "Competitive" business strategy group, defined by IHS as businesses with generation portfolios that are over 70% nonutility, based on asset value and revenue. Cost of debt based on coupon rates of outstanding debt as of May 2014.

industry as a whole. Dividing the levelized cost by the output of the power plant at a given utilization rate produces a levelized cost of energy (LCOE) for a given technology at a given utilization rate (see Figure A-5).

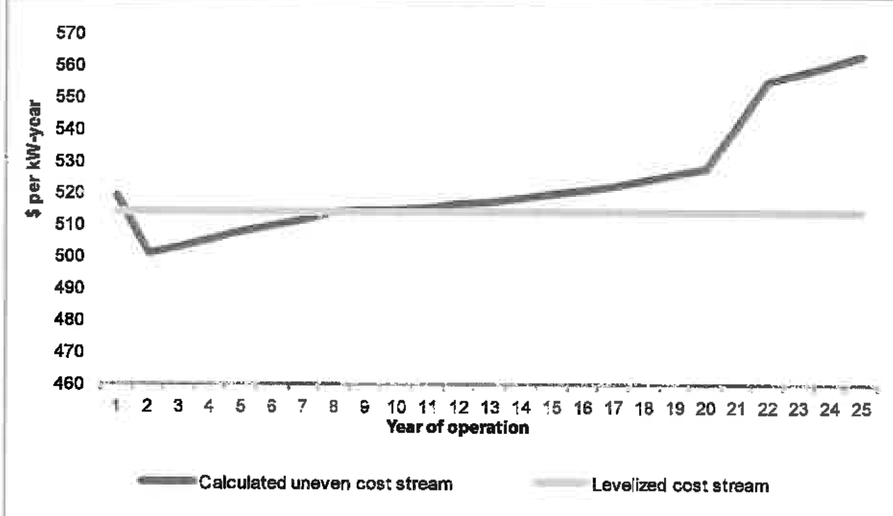
A levelized cost stream makes it possible to compare production costs at different expected utilization rates. A lower utilization rate forces spreading fixed costs over fewer units of output and thus produces higher levelized costs (see Figure A-6).

Figure A-7 adds the LCOE of a CT. Since the LCOE of the CT is lower than that of the CCGT at high utilization rates, adding CTs shows the point at which the savings for a CCGT's greater efficiency in fuel use are enough to offset the lower fixed costs of a CT.

There is a utilization rate at which a CCGT is cheaper to run than a CT. Below a utilization rate of roughly 35%, a CT is more economical. At higher utilization rates, the CCGT is more economical. When referring back to the load duration curve, it can be calculated that a generation mix that is 37% CT and 63% CCGT would produce a least-cost outcome. This can be demonstrated by comparing the LCOE graph with the load duration curve: the intersection point of CT and CCGT LCOEs occurs at the same time percentage on the LCOE graph at which 63% load occurs on the load duration curve (see Figure A-8).

FIGURE A-5

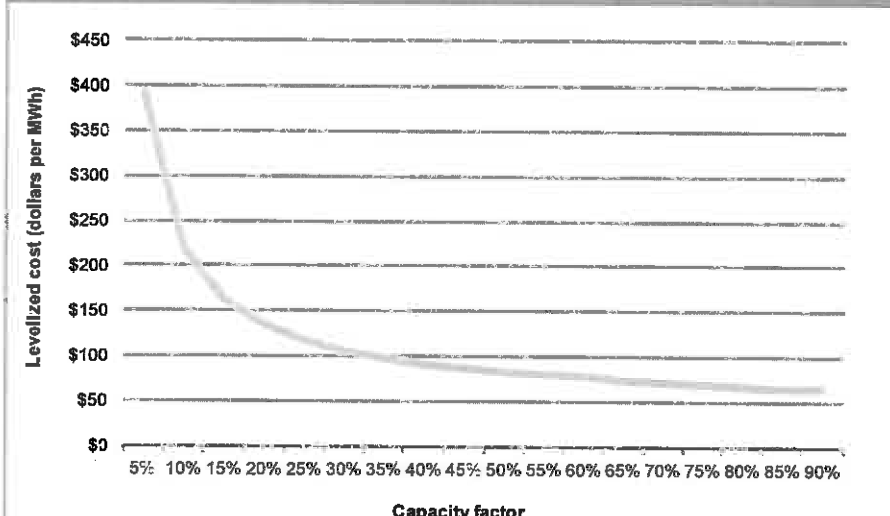
Cost stream comparisons—CCGT, 85% utilization rate



Source: IHS Energy © 2014 IHS

FIGURE A-6

LCOE of CCGT generation

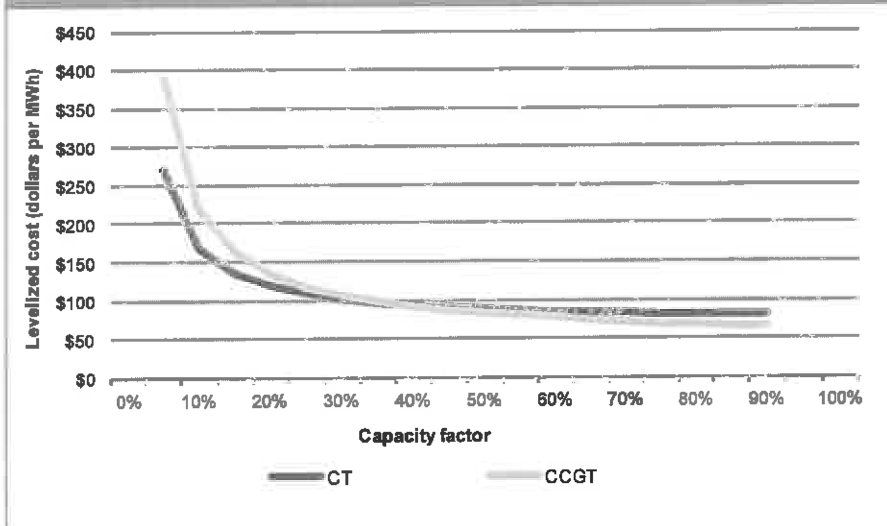


Source: IHS Energy © 2014 IHS

The levelized cost of production for each technology can be determined by finding the average load (and corresponding utilization rate) for the segment of the load duration curve (LDC) that corresponds to each technology (in this example, the two segments that are created by splitting the curve at the 35% mark). Loads that occur less than 35% of the time will be considered peak loads, so the average cost of meeting a peak load will be equivalent to the cost of a CT operating at a 17.5% utilization rate, the average of the peak loads. Cycling loads will be defined as loads occurring between 35% to 80% of the time, with base loads occurring more than 80% of the time. As the CCGT is covering both cycling and base loads in this example, the average cost of meeting theses loads with a CCGT will be equivalent to the levelized cost of a CCGT at a 57.5% utilization rate. A weighted average of the costs of each technology is then equivalent to an average cost of production for the power system. For this generation mix, the levelized cost of production is equal to 9.6 cents per kWh.

FIGURE A-7

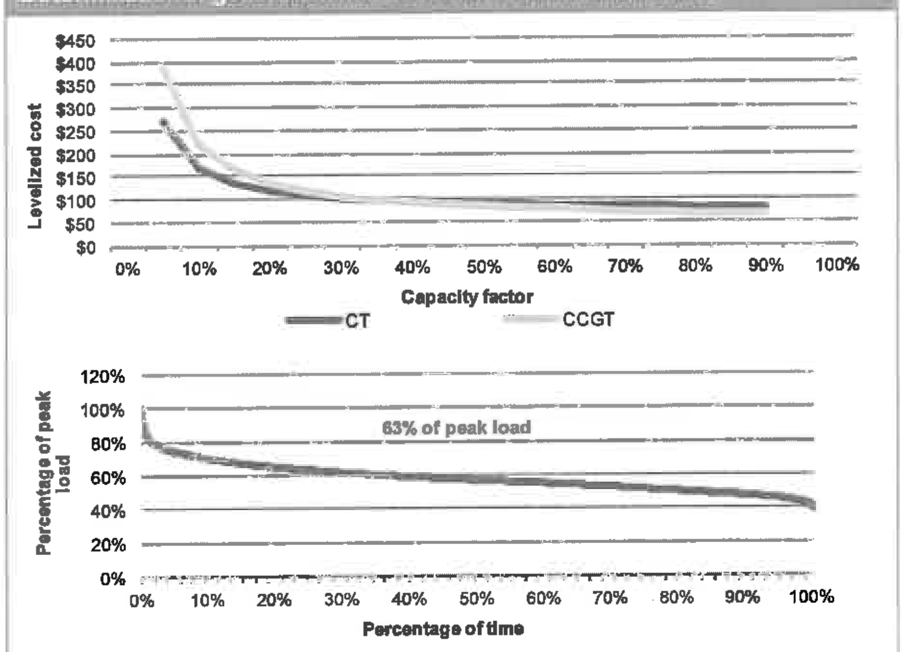
LCOE of CCGT and CT generation



Source: IHS Energy

FIGURE A-8

Determination of generation mix based on load duration curve



Source: IHS Energy
Data Source: Ventyx Velocity Suite, National Renewable Energy Laboratory

Source:

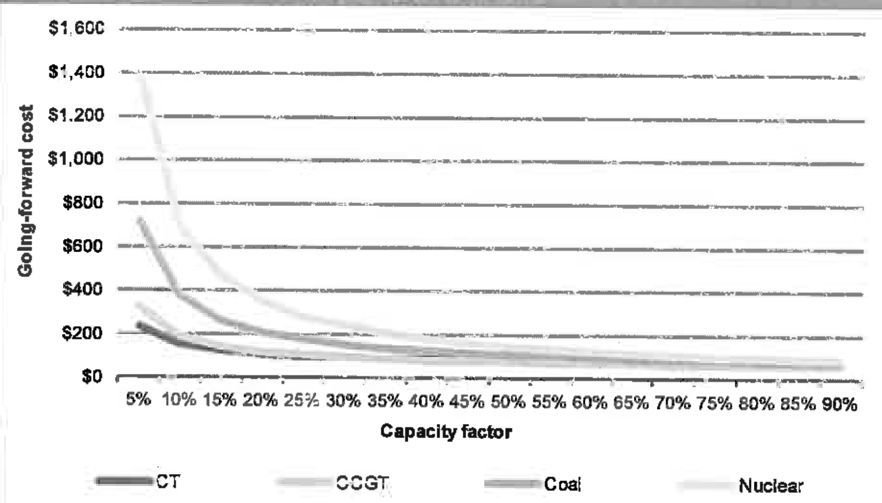
The generating options also can be expanded to include fuels besides natural gas. Stand-alone coal and stand-alone nuclear are not lower cost than stand-alone gas, as shown in Figure A-9, and all have a high-risk premium associated with the lack of diversity. However, when combined as part of a generation mix, the cost of capital will be lower owing to the more diverse (and therefore less risky) expected cash flow.

Based on the LDC, in this example base-load generation was modeled at 52.5% of capacity and was composed of equal parts gas, coal, and nuclear capacity. This combination of fuels and technology produces a diverse portfolio that can reduce risk and measurably lower the risk premium in the cost of capital. The point at which a CCGT becomes cheaper than a CT changes slightly from the previous example owing to the change in cost of capital, but the result is similar, with a 30% utilization rate the critical point and 36% CT capacity the most economical. Cycling loads with utilization rates between 30% and 80% can be covered by CCGTs, equaling 11.5% of capacity. The levelized cost of production for this more diverse portfolio is equal to 9.3 cents per kWh. Even though coal and nuclear have higher levelized costs than gas, all else being equal, the reduced cost of capital is more than enough to offset the increased costs of generation. The implication is that a least-cost mix to meet a pattern of demand is a diverse mix of fuels and technologies.

If the power system has a renewables mandate, this can be incorporated as well. Solar PV has a levelized cost of 14.2 cents per kWh, given a 4.5% cost of capital. If solar made up 10% of generating capacity, the load duration curve for the remaining dispatchable resources would change, as shown in Figure A-10. Using hourly solar irradiation data from a favorable location to determine solar output, the peak load of the power system does not change, as there is less than full solar insulation in the hour when demand peaks.[13] The load factor for this new curve is 0.58, a small decrease from the original curve. A lower load factor typically means that larger loads occur less often, so more peaking capacity is necessary.

FIGURE A-9

Levelized cost curves of generating resources



Source: IHS Energy

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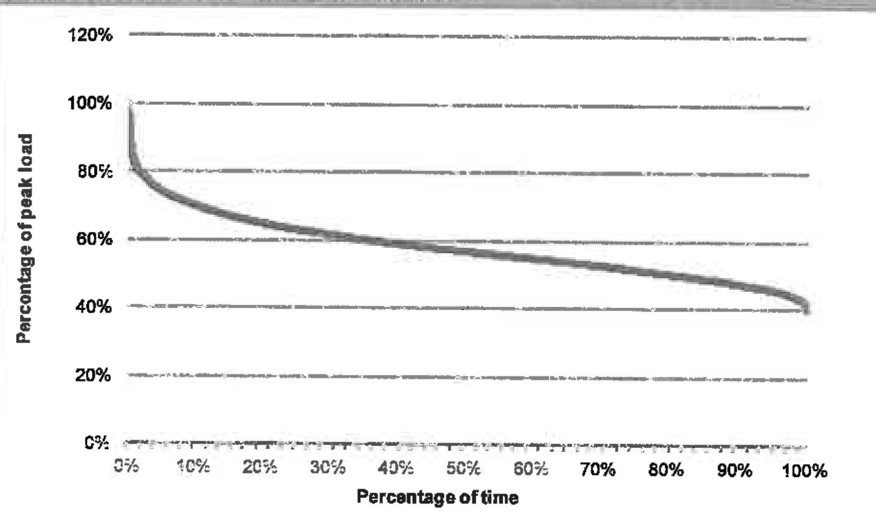
FIGURE A-10

Load duration curve, after solar additions



Source: IHS Energy
Data Source: Ventyx Velocity Suite, National Renewable Energy Laboratory

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The needed dispatchable resources can be recalculated using the new curve, integrating the solar generation. The new curve increases the amount of peaking resources needed, but otherwise changes only very slightly. After solar is added, the total cost is 10.8 cents per kWh. Since the output pattern of solar doesn't match the demand pattern for the power system, adding solar does not significantly decrease the amount of capacity needed.

13. Solar data from National Renewable Energy Laboratory, Austin, TX, site. Data from 1991–2005 update, used for example purposes. http://rredc.nrel.gov/solar/old_data/nsrdb/1991-2005/tmy3/by_state_and_city.html accessed 13 May 2014.

Conclusion

- There is no single fuel or technology of choice for power generation. Reliably and efficiently supplying consumers with the amounts of electricity that they want, when they want it, requires a diverse generation mix.

- A cost-effective generation mix involves diversity but does not involve maximizing diversity by equalizing generation shares from all available supply options.

- The cost-effective mix of fuel and technologies for any power system is sensitive to the uncertainties surrounding the level and pattern of consumer power demands as well as expectations regarding the cost and performance of alternative power generating technologies and, in particular, the expectations for delivered fuel prices.

- The cost-effective generating mix will differ from one power system to the next because of differences in aggregate consumer demand patterns as well as the cost and performance of available generating options.

- The best type of capacity to add to any generation portfolio depends on what types of capacity are already in the mix.

Appendix B: IHS Power System Razor Model overview

Design

The IHS Power System Razor (Razor) Model was developed to simulate the balancing of power system demand and supply. The model design provides flexibility to define analyses' frequency and resolution in line with available data and the analytical requirements of the research investigation.

For this assessment of the value of fuel diversity, the following analytical choices were selected:

- **Analysis time frame**—Backcasting 2010 to 2012
- **Analysis frequency**—Weekly balancing of demand and supply
- **Geographic scope**—US continental power interconnections—Western, Eastern, and ERCOT
- **Demand input data**—Estimates of weekly interconnection aggregate consumer energy demand plus losses
- **Fuel and technology types**—Five separate dispatchable supply alternatives: nuclear, coal steam, natural gas CCGT, gas CT, and oil CT
- **Supply input data by type**—Monthly installed capacity, monthly delivered fuel prices, monthly variable operations and maintenance (O&M), heat rate as a function of utilization
- **Load modifiers**—Wind, solar, hydroelectric, net interchange, peaking generation levels, and weekly patterns

Demand

The Razor Model enables the input of historical demand for backcasting analyses as well as the projection of demand for forward-looking scenarios. In both cases, the Razor Model evaluates demand in a region as a single aggregate power system load.

For backcasting analyses, the model relies upon estimates of actual demand by interconnection. For forward-looking simulations, Razor incorporates a US state-level cross-sectional, regression-based demand model for each of the three customer classes—residential, commercial, and industrial. Power system composite state indexes drive base year demand levels by customer class into the future.

Load modifiers

Utilization of some power supply resources is independent of SRMC-based dispatch dynamics. Some power supply is determined by out-of-merit-order utilization, normal production patterns, or external conditions—such as solar insolation levels, water flows, and wind patterns. These power supply resources are treated as load modifiers.

Net load

Net load is the difference between power system aggregate electric output needs and the aggregate supply from load modifiers. It is the amount of generation that must be supplied by dispatchable power supply resources.

Calibration of the inputs determining net load is possible using data reporting the aggregate output of dispatchable power sources.

Fuel- and technology-specific supply curves

Supply curves are constructed for each fuel and technology type. The supply curve for each dispatchable power supply type reflects the SRMCs of the capacity across the possible range of utilization rates. Applying availability factors to installed capacity produces estimates of net dependable (firm, derated) capacity by fuel and technology type.

Each cost curve incorporates heat rate as a function of utilization rate.[14] *Heat rate* describes the efficiency of a thermal power plant in its conversion of fuel into electricity. Heat rate is measured by the amount of heat (in Btu) required each hour to produce 1 kWh of electricity, or most frequently shown as MMBtu per MWh. The higher the heat rate, the more fuel required to produce a given unit of electricity. This level of efficiency is determined primarily by the fuel type and plant design. Outliers are pruned from data to give a sample of heat rates most representative of the range of operational plants by fuel and technology type.[15]

Dispatch fuel costs are the product of the heat rate and the delivered fuel cost. Total dispatch costs involve adding variable operations and maintenance (VOM, or O&M) costs to the dispatch fuel costs. These O&M costs include environmental allowance costs.

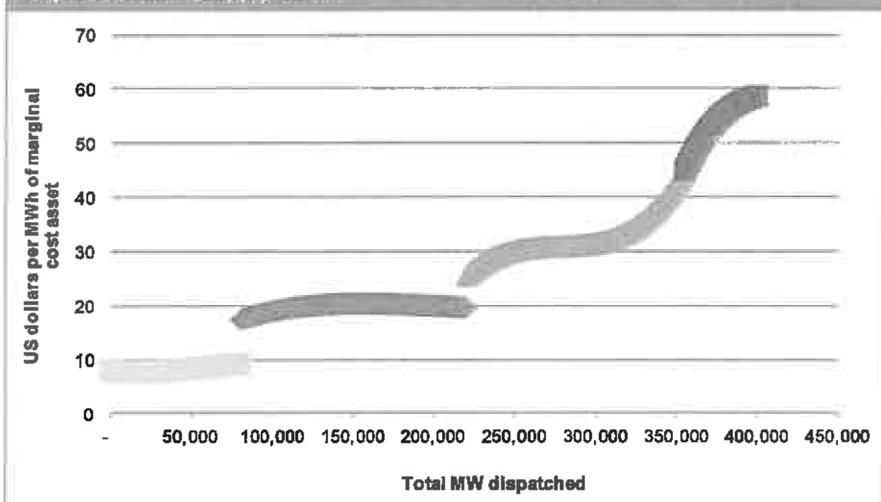
The power system aggregate supply curve is the horizontal summation of the supply curves for all fuel and technology types. Figure B-1 illustrates the construction of the aggregate power system supply curve. The supply curve shows the SRMC at each megawatt dispatch level and the associated marginal resource.

Balancing power system aggregate demand and supply

The Razor Model balances aggregate power system demand and supply by intersecting the demand and supply curves. At the intersection point, power supply equals demand; supply by type involves equilibrating the dispatch costs of available alternative sources of supply.

FIGURE B-1

Representative supply curve



Source: IHS Energy
Data Source: Ventyx Velocity Suite

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14. Power plant data sourced from Ventyx Velocity Suite.

15. Outliers are defined as plants with an average heat rate higher than the maximum observed fully loaded heat rate.

This power system–wide marginal cost of production is the basis for the wholesale power price level that clears an energy market.

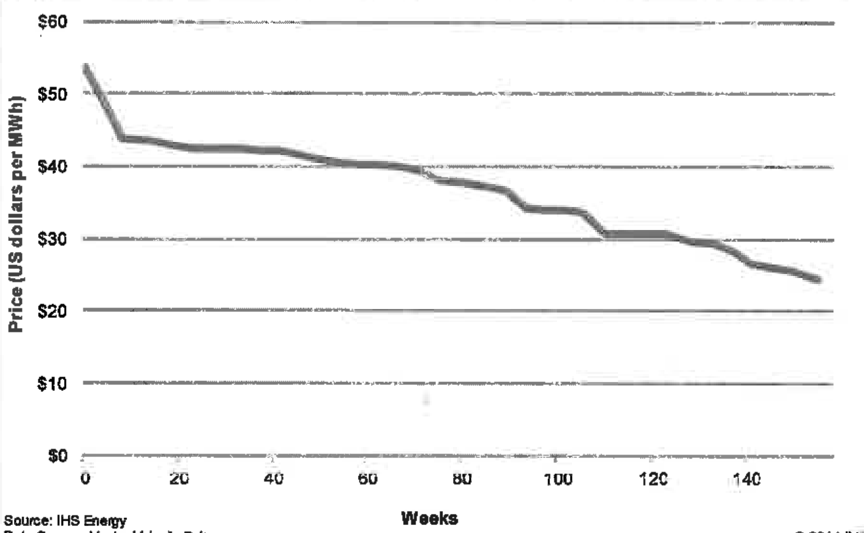
The Razor Model results in the following outputs:

- **Power system SRMC/wholesale price**
- **Generation by fuel and technology type**
- **Average variable cost of production.** The average variable cost is calculated at each dispatch increment by taking the total cost at that generation level divided by the total megawatt dispatch.
- **Price duration curve.** The price duration curve illustrated in Figure B-2 provides an example of wholesale power price distribution across the weeks from 2010 through 2012.

Calibration

FIGURE B-2

Representative price duration curve



Source: IHS Energy
Data Source: Ventyx Velocity Suite
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The predictive power of the Razor Model for portfolio and substitution analysis is revealed by comparing the estimated values of the backcasting simulations to the actual outcomes in 2010–12.

The Razor Model backcasting results provide a comparison of the estimated and actual wholesale power prices. The average difference in the marginal cost varied between (3.8%) and +2.3% by interconnection region. A comparison of the average rather than marginal cost of power production also indicated a close correspondence. The average difference between the estimate and the actual average cost of power production varied between (4.7%) and (0.1%) by interconnection region. Table B-1 shows the assessment of the predictive power of the Razor Model for these two metrics across all three interconnections in the 2010 to 2012 weekly backcasting exercise.

TABLE B-1

IHS power system Razor Model analysis

	East	West	ERCOT
Average wholesale power price difference	2.3	0.3	-3.8
Average production cost difference	-0.2	-4.7	-0.1

Note: Differences reflect deviation averaged over backcasting period. Production cost difference reflects average of five power sources: Coal, gas combined-cycle, gas combustion turbine, nuclear, and oil.
Source: IHS Energy

Appendix AA:

Southwest Power Pool: Clean Power Plan Comment Letter

October 9, 2014

VIA ELECTRONIC FILING

Gina McCarthy, EPA Administrator
Environmental Protection Agency
1200 Pennsylvania Ave NW
Washington, DC 20460

Re: Docket ID No. EPA-HQ-OAR-2013-0602

Dear Administrator McCarthy:

This letter is submitted to the United States Environmental Protection Agency ("EPA") on behalf of Southwest Power Pool, Inc. ("SPP") in its capacity as a Federal Energy Regulatory Commission ("FERC") approved Regional Transmission Organization ("RTO") and a Regional Entity with delegated authorities to ensure the reliability of the bulk electric system within the SPP region[1].

The purpose of this letter is to convey SPP's comments on the "Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units" ("Clean Power Plan" or "CPP") proposed rule that was published in the Federal Register on June 18, 2014.

Specifically, SPP will address three primary areas of concern: 1) the CPP will impact reliability of the bulk electric system; 2) the timing proposed by EPA for compliance is infeasible; and 3) the proposed CPP will have material impacts on the market-based dispatch of electric generating units within the SPP region.

1 SPP is an Arkansas non-profit corporation with its principal place of business in Little Rock, Arkansas. SPP has 78 members that include investor-owned electric utilities, municipals, electric cooperatives, state authorities, independent power producers and independent electric transmission companies. As an RTO, SPP administers open access Transmission Service over approximately 48,930 miles of transmission lines covering portions of Arkansas, Kansas, Louisiana, Missouri, Nebraska, New Mexico, Oklahoma, and Texas, across the facilities of SPP's Transmission Owners. SPP administers its centralized day-ahead and real-time energy and operating reserve markets ("Integrated Marketplace") with locational marginal pricing and market-based congestion management processes to deliver wholesale energy to its customers in the most economic and reliable fashion. As an RTO, SPP also plans for and functionally controls the transmission infrastructure committed to it. For purposes of these comments, SPP has included the Integrated Systems utilities, which are in the process of joining the organization.

To address these areas of concern, SPP is providing four recommendations: 1) a series of technical conferences jointly sponsored by the EPA and FERC; 2) completion of a detailed, comprehensive and independent analysis of the impacts the proposed CPP will have on the reliability of the nation's bulk electric system; 3) extension of the proposed schedule for compliance in order for the necessary electric and gas infrastructure to be identified and constructed; and 4) adoption of a "reliability safety valve". SPP appreciates the opportunity to submit comments and provides the following explanation of its concerns and recommendations.

Pursuant to the Energy Policy Act of 2005, FERC has approved mandatory and enforceable reliability standards promulgated by the North American Electric Reliability Corporation ("NERC") with which the electric industry must comply. Contained in these standards are key requirements necessary to ensure the bulk electric system meets an adequate level of reliability. Failure to comply with these standards affects the ability of the power grid to operate reliably and subjects registered entities such as SPP and its member utilities to civil monetary penalties[2].

These reliability standards require SPP to ensure electric transmission lines are not overloaded and voltage is maintained within certain prescribed limits in the event of the failure of a single element in the monitored system. Additionally, the reliability standards require SPP to maintain the region's bulk electric system within certain reliable operating limits. If the proposed CPP remains as is, the bulk electric system will be at serious risk of violating these limits. The likelihood that this outcome occurs dramatically increases if the timing of the issuance of the final rule effectively prevents the construction of electric system infrastructure necessary to facilitate compliance with the state goals being contemplated under the proposed CPP.

Because maintaining reliability is SPP's most important function, it has completed an assessment of the impacts that the proposed CPP will have on reliability in the SPP region. This assessment includes an evaluation of transmission system impacts and an evaluation of impacts to reserve margin. In both evaluations, SPP modeled EPA's projected Electric Utility Generating Unit ("EGU") retirements within the SPP region and surrounding areas (see Figure 1 below).

[2] Up to $1 million per day, per violation.

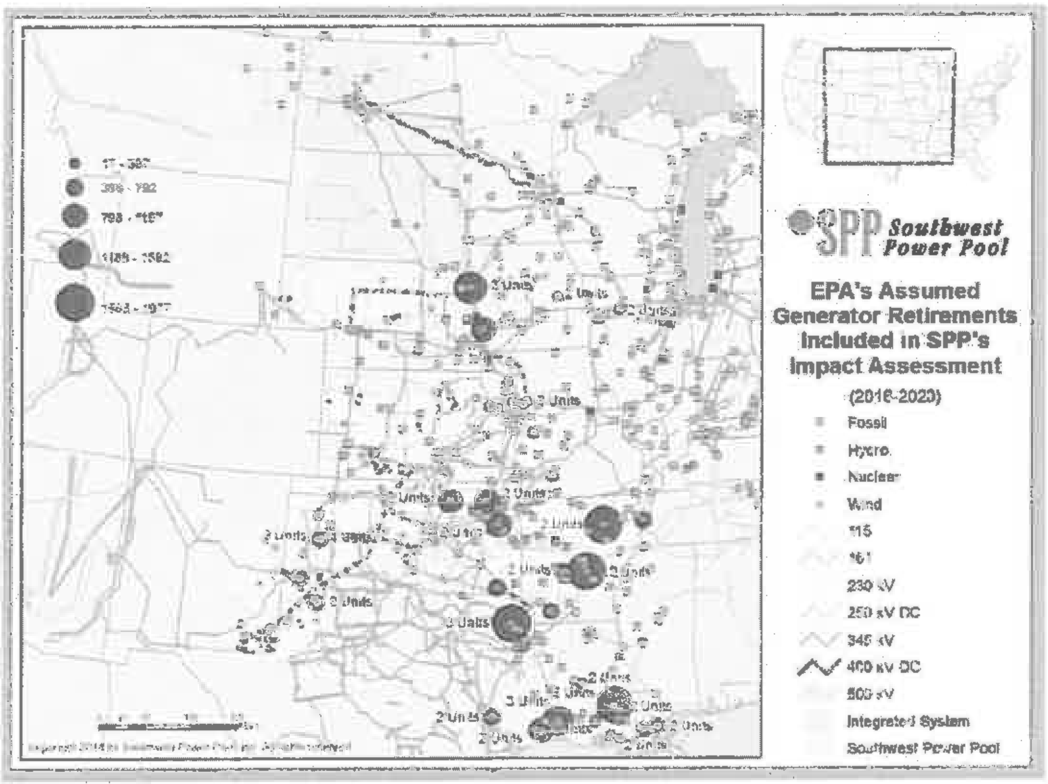

Figure 1: EPA's Projected EGU Retirements by 2020 in the SPP Region and Adjacent Systems

The transmission system impact evaluation was completed in two parts. In the first part, SPP assumed available unused electric generation capacity that currently exists within the SPP region and surrounding areas would be used to replace the projected retired capacity. This scenario is a reflection of what will occur early in the EPA's proposed compliance period where carbon emissions are expected to be drastically reduced but there is insufficient time to make changes to generation and transmission infrastructure or develop other alternatives.

The second part of the transmission system impact evaluation assumed that the projected EGU retirements would be replaced by increased output of existing generation, including wind resources, and new generation capacity modeled according to resource planning information being utilized in SPP's 10-year transmission planning assessment that is currently in progress (see Figure 2 below).

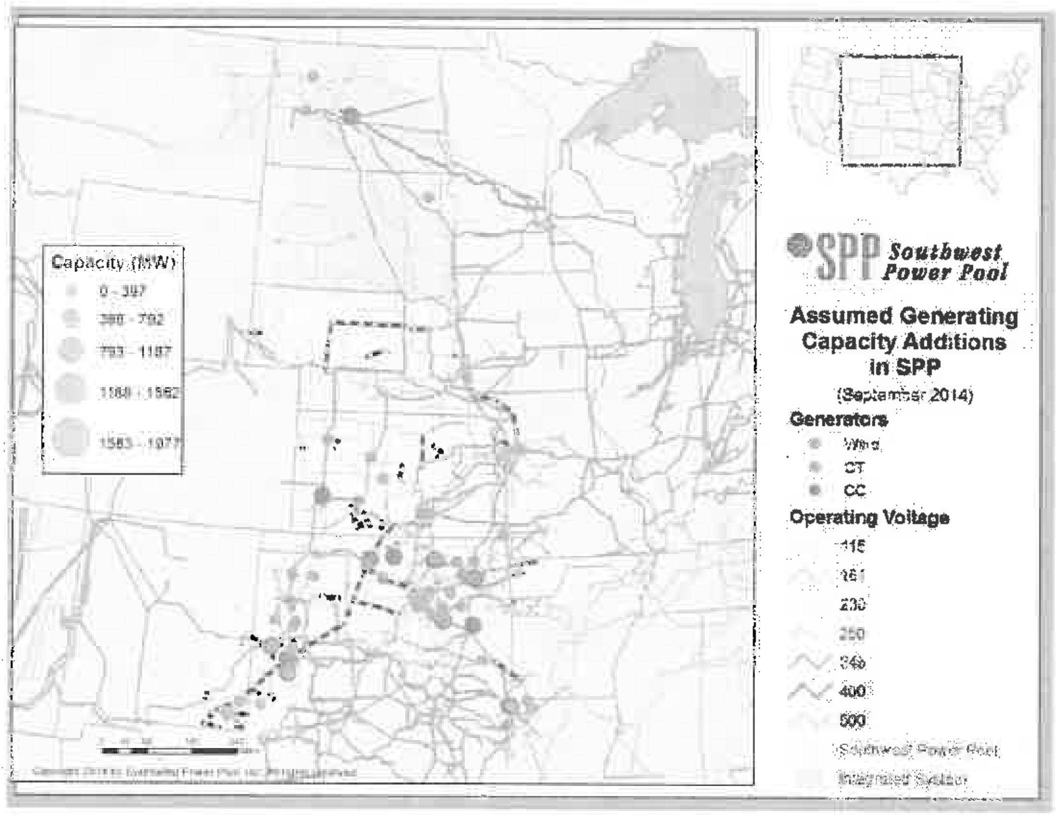

Figure 2: New Generation Capacity Assumed in Part 2 of System Impact Evaluation

This part of the evaluation is not intended to address whether it is possible to install replacement generation capacity in a timely fashion under the proposed CPP compliance timeframe, nor is it intended to suggest locations where replacement generation should be located.

The SPP region will experience numerous thermal overloads and low voltage occurrences under both scenarios studied. Results of the first part of the transmission system impact evaluation indicate that if the assumed EGU retirements were to occur absent requisite transmission and generation infrastructure improvements, the power grid would suffer extreme reactive deficiencies (see Figure 3) that would expose it to widespread reliability risks resulting in significant loss of load and violations of NERC reliability standards.

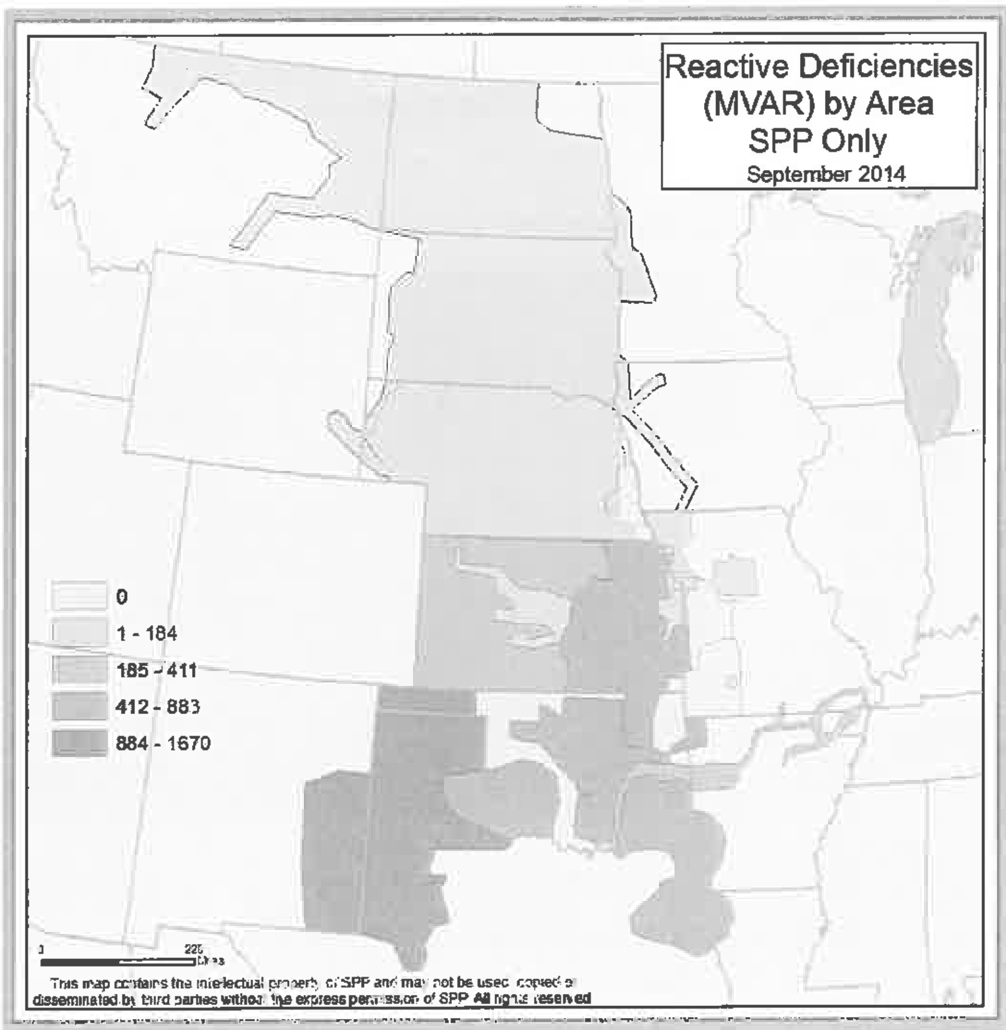

Figure 3: Transmission System Impact Analysis Part 1 - Reactive Deficiencies (MVAR)

Results of the second part of the evaluation indicate that even with generation capacity added to replace the assumed EGU retirements, additional transmission infrastructure will be needed to maintain reliable operation of the grid. This assessment revealed 38 overloaded elements that SPP would be required to mitigate with transmission planning solutions. These overloaded elements were identified in the portions of six states – Arkansas, Kansas, Louisiana, Missouri, Oklahoma, and Texas – that operate within the SPP region. Portions of the system in the Texas panhandle, western Kansas, and northern Arkansas were so severely overloaded that cascading outages and voltage collapse would occur and would result in violations of NERC reliability standards. The following graph shows the number of overloaded elements and significance of loading expected under the conditions studied in this assessment (see Figure 4 below).

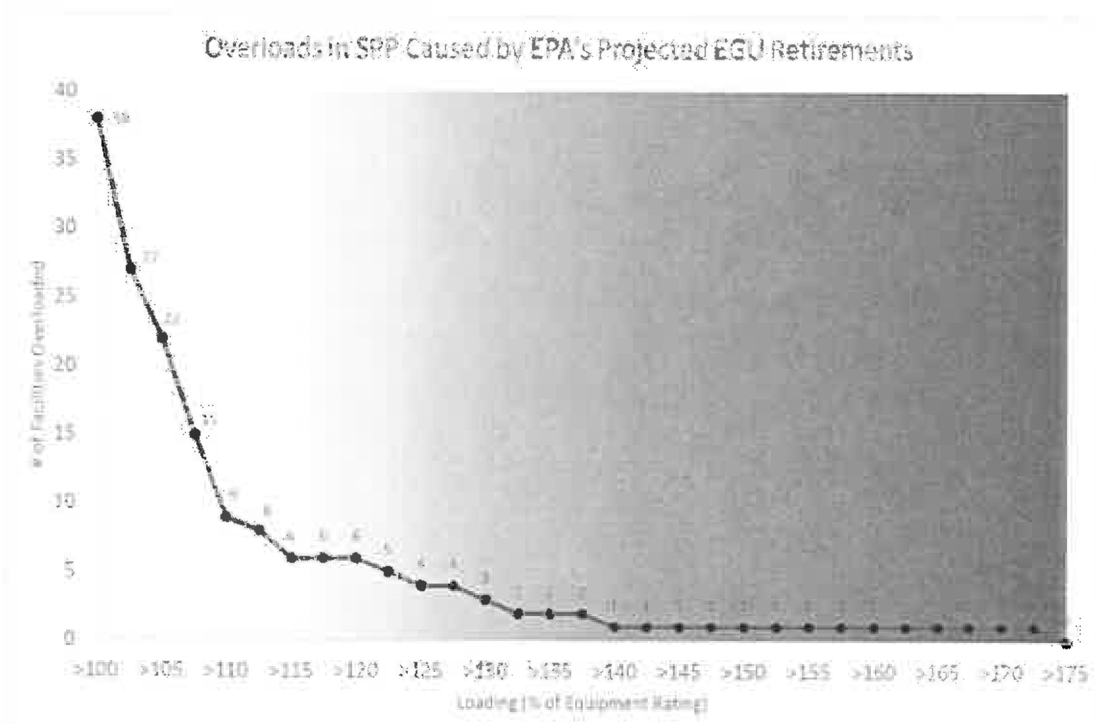

Figure 4: Number of Facilities Overloaded in Part 2 of System Impact Evaluation

Both parts of the assessment assumed that electric transmission expansion currently planned to meet previously identified needs would be available. It is important to note that the transmission expansion currently planned in SPP does not consider EGU retirements expected as a result of the CPP. EPA's projected EGU retirements represent approximately 6,000 MW of additional capacity being retired in the SPP region beyond that currently expected by 2020. This represents approximately a 200% increase in retired generating capacity compared to SPP's current expectations. Unless the proposed CPP is modified significantly, SPP's transmission system impact evaluation indicates serious, detrimental impacts on the reliable operation of the bulk electric system in the SPP region, introducing the very real possibility of rolling blackouts or cascading outages that will have significant impacts on human health, public safety and economic activity within the region.

SPP also performed an evaluation of the impacts of the projected EGU retirements on SPP's reserve margin. Reserve margin is the amount of generation capacity an entity maintains in excess of its peak load-serving obligation. SPP's minimum required reserve margin is 13.6% per load-serving entity. In this evaluation, SPP utilized current load forecasts, firm capacity purchases and sales, currently planned generator retirements and additions, as well as the additional generator retirements projected by the proposed CPP. This evaluation concluded that by 2020, SPP's reserve margin would fall to 4.7%, which is 8.9% below SPP's minimum reserve margin requirement and would result in a violation of SPP's reliability criteria and NERC reliability standards. Out of the fourteen load-serving members impacted by the EPA's projected EGU retirements, nine would be deficient in 2020. Furthermore, SPP found that its anticipated reserve margin would fall to -4.0% by 2024, causing ten of SPP's load-serving members to be deficient (see Figure 5 below).

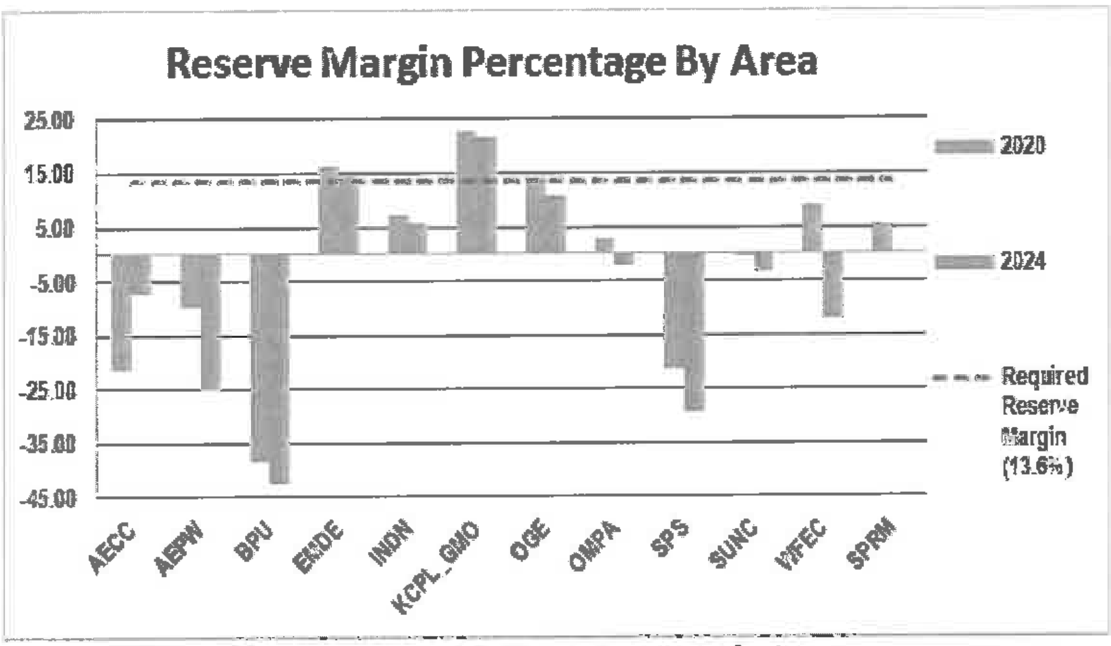

Figure 5: Reserve Margin Percentage by Area

These anticipated reserve margins represent a total generation capacity deficiency in the SPP region of approximately 4,600 MW in 2020 and 10,100 MW in 2024.

Based on SPP's reliability impact assessment, it is clear that the proposed CPP will impede reliable operation of the electric transmission grid in the SPP region, resulting in violations of NERC's mandatory reliability standards and exposing the power grid to significant interruption or loss of load.

SPP has only been able to perform an initial reliability evaluation of steady-state system response during a "normal" future summer peak condition. SPP has not evaluated the impact of the proposed EGU retirements during other potentially critical scenarios, such as drought and polar vortex conditions or times of limited wind resource availability, which have been experienced numerous times within SPP's region in recent history.

Furthermore, there has been inadequate time to perform analysis of the technical feasibility of each of the four building blocks proposed within the CPP. To be clear, if any or all of the four building blocks are not feasible, application of a goal that assumes they are will have untold consequences on the reliability of the bulk electric system. For example, if the projected EGU retirements occur and a 70% capacity factor from natural gas combined cycle generating units, as assumed in CPP building block 2, is not feasible, the reliability implications of this improper assumption will be very significant and serious. Additional time to evaluate the impact of these and other potential concerns on reliability of the bulk electric system is warranted before imposing a final rule that is not properly considerate of potential threats to the reliability of the bulk electric system.

SPP is also concerned with the timing proposed for compliance with the CPP. Within the SPP region, the timing associated with CPP compliance is problematic at best. Based on SPP's review of the proposed CPP, EPA has considered neither the cost nor the time required to plan and construct electric transmission facilities. In the SPP region, as much as eight and a half years to study, plan for and construct new transmission facilities has been required. Compliance with the proposed CPP is impossible due to the transmission expansion that will be required and the time it takes to complete the required transmission expansion. In addition to more time being needed to develop plans for and construction of necessary infrastructure, a "reliability safety valve", as suggested by the ISO/RTO Council prior to release of the proposed CPP, should be incorporated into the final rule. Such an approach would require that state plans include a process to evaluate electric system reliability issues resulting from implementation of the state plan and require mitigation when needed.[3]

Furthermore, while the proposed CPP provides states with significant flexibility for compliance, EPA has not provided state air quality and economic regulators with sufficient time to take advantage of this flexibility. As a consequence, SPP anticipates there will be few, if any, submitted compliance plans that reflect the regional nature of transmission planning, wholesale energy markets or, in the SPP

[3] *EPA CO2 Rule—ISO/RTO Council Reliability Safety Valve and Regional Compliance Measurement and Proposals;* ISO/RTO Council at http://www.isorto.org/Documents/Report/20140128_IRCProposal-ReliabilitySafetyValve-RegionalComplianceMeasurement_EPA-CO2Rule.pdf; January 28, 2014.

region, transmission cost allocation. None of these issues are currently addressed on a state-specific basis within SPP, but rather are addressed regionally in a transparent environment where state boundaries are not acknowledged since the grid crosses city, county and state boundaries.

The proposed CPP will change the market dispatch of generating units by reducing the availability of the most economic generating resources. Such a shift will cause higher market clearing prices in the SPP region resulting in material adverse economic impacts on SPP customers. The proposed CPP will increase reliance on renewables and generators fueled by natural gas, yet there has been no evaluation of additional operating and planning measures needed to support integration of significant additional renewables and of natural gas availability required to fuel the increased number of gas burning units in the SPP region. While SPP's members will likely dramatically increase their reliance on wind generation within the SPP region to meet carbon emission goals under the proposed CPP, a proportional increase in gas burning generators will be necessary during times when wind resources are not available to maintain reliable energy supplies and minimum required planning reserves.

The current electric power grid has evolved incrementally over the last 40-plus years to provide a reliable supply of power in support of the current mix of generation assets. The changes being proposed by the EPA in the proposed timeframe will dramatically change use of the current system and will need to be thoroughly evaluated, modified as necessary, and implemented in a timely and responsible manner to avoid imposition of unnecessarily high costs and reliability risks to customers. The EPA should work closely with the regions, the states and all interested parties to ensure that any final CO_2 rule maintains bulk electric system reliability compatible with a reliable, efficient market dispatch of available generation.

As a result of its concerns, SPP recommends the following:

(1) A series of technical conferences jointly sponsored by FERC and the EPA. The topics that should be discussed at these conferences include impacts of the proposed CPP on power system reliability, impacts on regional markets, and how to move forward in a coordinated fashion that best facilitates accomplishment of both EPA and FERC objectives.

(2) Completion of a detailed, comprehensive and independent analysis of the impacts the proposed CPP will have on the reliability of the nation's bulk electric system. This analysis should take place in an open and transparent manner and should be completed before final rules are adopted by the EPA.

(3) Extension of the proposed schedule for compliance in order for the necessary electric transmission, electric generation, and gas pipeline infrastructure to be identified and constructed within and across the appropriate planning areas. At a minimum, the imposition of the proposed interim goals beginning in 2020 should be extended at least five years. Extending the schedule for compliance will help states develop plans that are achievable and acceptable to the EPA, reduce risks of reliability impacts and violations of reliability standards, and increase the possibility that states will be able to take a regional approach that reflects market realities, and how transmission is planned and paid for.

(4) Adoption of the "reliability safety valve" as proposed by the ISO/RTO Council.

I appreciate your prompt attention to these concerns. Please contact me if you have any questions or would like to discuss this matter further.

Respectfully submitted,

Nicholas A. Brown
President & CEO
Southwest Power Pool, Inc.
(501) 614-3213 · nbrown@spp.org

cc: SPP Board of Directors
SPP Regional State Committee
SPP Strategic Planning Committee
SPP Regional Entity Trustees

Appendix BB:

EPA CO2 Rule – ISO/RTO Council Reliability Safety Valve and Regional Compliance Measurement and Proposals

ISO/RTO Council

EPA CO2 RULE – ISO/RTO COUNCIL RELIABILITY SAFETY VALVE AND REGIONAL COMPLIANCE MEASUREMENT AND PROPOSALS

I. Introduction

ISO/RTO Council (IRC) members play a key role in maintaining electric system reliability and operating wholesale markets for electricity in North America.[1] Accordingly, the IRC has an interest in ensuring that the promulgation of environmental regulations is consistent with bulk electric system reliability and the economic efficiencies reflected in regional dispatches of electric power executed by ISOs/RTOs.

Typically, the IRC does not take positions on substantive policy issues related to the compliance structure of EPA programs. However, the IRC members can serve as a resource to policymakers at the state and federal level to facilitate informed decisions that recognize the relationship between proposed environmental rules, electric system reliability, and economically efficient dispatch. To this end, the IRC is interested in working with EPA, the States and all interested parties to implement a CO2 rule that respects electric system reliability and is compatible with efficient dispatch of the electric grid. The proposals discussed below are intended to support this outcome.

- "Reliability Safety Valve" – a proposal to ensure that any federal CO2 rule or related State Implementation Plan ("SIP") includes a process to assess, and, as relevant, to mitigate, electric system reliability impacts resulting from related environmental compliance actions.
- "Regional Compliance Measurement" – a proposal for EPA to consider allowing states through their SIPs to adopt a regional measurement mechanism for determining compliance with CO2 rule obligations.[2]

A general discussion of the proposals is presented below. These are preliminary concepts intended to promote further dialogue among policymakers, RTOs/ISOs and interested stakeholders; if adopted, the implementation details would have to be further developed.

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[1] The IRC is comprised of the Alberta Electric System Operator ("AESO"), the California Independent System Operator, Inc. ("CAISO"), Electric Reliability Council of Texas, Inc. ("ERCOT"), the Independent Electricity System Operator of Ontario, Inc., ("IESO"), ISO New England, Inc. ("ISO-NE"), Midcontinent Independent System Operator, Inc., ("MISO"), New York Independent System Operator, Inc. ("NYISO"), PJM Interconnection, L.L.C. ("PJM"), and Southwest Power Pool, Inc. ("SPP"). The IESO and AESO are not subject to EPA jurisdiction and are not joining these comments.

[2] This paper focuses on the above proposals, which are intended to mitigate the impact of the CO2 rule and/or state SIPs on electric system reliability and economically efficient dispatch. The proposals call for reliability assessments of compliance impacts, where relevant, and the provision of an option for regional measurement associated with reductions directed by states through their individual SIP plans. The participating ISOs/RTOs take no position on policy or legal matters related to the substantive structure of the CO2 rule / state SIPs beyond the matters discussed herein.

II. Reliability Safety Valve Proposal

A. CO2 RSV Proposal Overview

The potential electric system reliability impacts of the CO2 rule cannot be determined until the compliance parameters of the program are proposed. However, there are preventative measures that could be put in place in the proposed Rule to mitigate potential impacts to electric system reliability regardless of the final CO2 rule compliance policies and rules. Specifically, a "reliability safety valve" (RSV) that provides for reliability assessments and solutions, as well as the requisite compliance and/or enforcement flexibility to implement the reliability solutions, would achieve this goal.

The RSV proposal can help to ensure outcomes that address reliability issues without affecting the policies underlying the CO2 rule compliance design. In 2012, the IRC worked with EPA to establish an enforcement policy related to the MATS rule that reflects the RSV concept. Although the RSV proposal for the CO2 rule differs slightly, the underlying reliability proposition is the same – allow for electric system reliability impact reviews related to compliance requirements and, where relevant, provide for appropriate compliance and/or enforcement flexibility to accommodate solutions to mitigate issues that would otherwise compromise reliability requirements.

The final rule could allow implementation of this proposal by incorporating a reliability review conducted by the relevant system operator,[3] working with the states and relevant reliability regulators, prior to finalization and approval of the SIP.[4] The review would identify the reliability issues and solutions.[5] The RSV process would then provide for appropriate regulatory review and approval of the reliability assessment and solution. Next, the RSV process would accommodate the reliability solution under the CO2 rule and/or SIP by providing for appropriate compliance and/or enforcement flexibility while a long-term reliability solution is developed and implemented.

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[3] The proposals presented herein are IRC proposals and are based on the IRC members' functional ISO/RTO roles in the context of organized electricity markets – i.e., ISO / RTO regions. Although vertically integrated regions may differ in the manner of dispatch, the dispatch is still done on a regional basis. Therefore, the proposed reliability reviews could also be accomplished in non-RTO regions albeit with certain additional safeguards if deemed necessary by the appropriate regulator. The IRC is not representing that these proposals are in any way supported or endorsed by any other entities other than the IRC members.

[4] Reliability issues typically arise when environmental regulations impact the availability of generation capacity to the system operator in executing its security constrained economic dispatch function. RSV reliability reviews would usually only be necessary if the CO2 rule and/or related SIPs affect the availability of generation capacity. Accordingly, different compliance approaches will likely vary with respect to potential electric system reliability impacts.

[5] Proposed reliability solutions would be narrowly tailored to minimize deviations from applicable environmental compliance/enforcement obligations. Although reliability reviews would estimate how long a solution is needed, the process should include periodic reassessments of the need for the solution. Potential reliability solutions include, but are not limited to, short term retention of capacity where such capacity may otherwise be unavailable due to the application of the CO2 rule and prospective transmission solutions.

B. Differences between CO2 RSV Proposal and MATS RSV Process

The MATS reliability safety valve (RSV) proposal allowed non-compliant capacity needed for reliability to operate beyond the scheduled compliance date of the rule. Because the MATS rule was applied on a unit specific basis relative to set compliance dates, the reliability/resource adequacy impacts could be identified and addressed in a timeframe proximate to the initial compliance date without the need for ongoing reliability assessments. Static reliability assessments may not be adequate in all cases for compliance with CO2 regulation. The final rule should allow for the use of a "rolling" RSV process to assess system reliability on a prospective basis at multiple stages both prior to the SIP being finalized and approved and at various steps during its implementation, as necessary.

C. CO2 RSV Process Should Address Conflicts Between SIPs

It is possible that compliance approaches in one SIP can create a regional reliability issue affecting another state. For example, a SIP could restrict the output of a generator within its borders. When that limitation is reflected in the regional dispatch, it could create a transmission security issue in another state(s) within the region, or even in a neighboring region. Similarly, that SIP limitation on the unit could compromise the regional reserve margin obligation. The CO2 rule RSV can be used to address potential conflicts that could arise between state SIPs and RSV reliability assessments/solutions in multi-state regional dispatch areas. To mitigate potential conflicts between state SIPs and system reliability/reserve margin assessments, the CO2 rule should allow for SIP plans that may impact neighboring states (regardless of the region) to be structured so that regional reliability issues and solutions can be identified and developed, respectively, pursuant to the RSV process.

Details for the CO2 rule RSV mechanism(s) would have to be developed, but a reasonable approach would be for the RSV framework, as introduced in the following section, to be generally described and allowed for under the EPA rule, with implementation procedures established via the state SIPs.

D. CO2 Rule RSV Structure / Use Summary

Consistent with the above discussion, the core components of the proposed CO2 rule RSV proposal would include the following:

- The CO2 rule should establish an ongoing RSV process to assess and address electric system reliability/resource adequacy issues that may arise as a result of compliance impacts related to the EPA rule and state SIPs. The basic structure of this process would include the following:
    - A reliability review procedure conducted by the relevant system operator that can be used on a rolling basis, as necessary, within the context of the CO2 rule and/or SIPs;
    - Long-term reliability solutions that accommodate the new carbon rules would need to be sought; but if a long-lead time is necessary to implement such a solution, interim measures, such as keeping units on line until the long-term solution is available, may be necessary;
    - Appropriate regulatory review and approval of the reliability assessments and solutions performed pursuant to the reliability review procedure (proposed reliability solutions would be narrowly tailored to accommodate the interim reliability assessment/solution);

- Compliance and/or enforcement flexibility to accommodate the interim reliability assessment(s)/solution(s);
- Periodic reassessments of the need to continue the interim reliability solution;

- The CO2 rule RSV process should be utilized to support the establishment of compliance dates that are consistent with maintaining electric system reliability while long-term carbon-compliant reliability solutions are implemented;
- The CO2 rule and state SIPs should establish compliance program measures that recognize the need to maintain electric system reliability and resource adequacy requirements on an ongoing basis;[6]
- A process to align state SIPs in multi-state regional dispatch areas with regional reliability issues involving multiple states that are identified in the RSV process. This would include issue identification via the RSV process and a coordination process between EPA, its sister agencies charged by federal or state law with ensuring bulk power reliability, the affected states and the RSV reliability assessment entities (i.e. the relevant system operators). This review would facilitate the identification of cross-state reliability impacts associated with specific SIPs, and would enable the coordination of all requisite authorities to ensure they are managed efficiently and effectively under the CO2 rule.

III. Regional Compliance Measurement Proposal

The involvement of states is central to the regulatory program embodied in Section 111(d) of the Clean Air Act. SIPs are the key vehicles under Section 111(d) for regulating the affected pollutant – in this case greenhouse gases.[7]

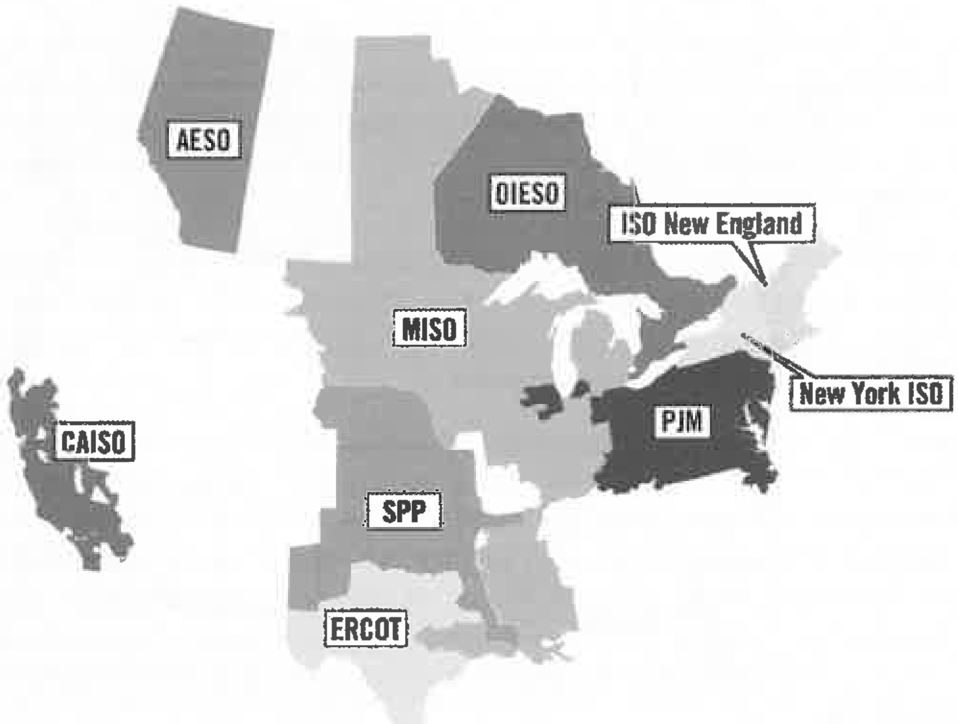
Although this paradigm contemplates individual state controls on GHG emissions, the nature of GHG is such that the location of specific emission sources is not nearly as relevant as the overall nationwide (if not worldwide) reduction in GHG emissions. As a result, coordinated regulatory programs among states can help to ensure that the efficiencies of least cost compliance across a regional, if not national, footprint can be maximized.

Current electric industry market structures provide a platform for capturing the efficiencies of a coordinated regulatory scheme across multiple states. Specifically, regions subject to a single integrated dispatch can provide an effective measurement area for relevant state implementation plans and measuring their impact. States that choose to adopt such an approach already participate in a regional electric system dispatch. Use of a regional measurement of emissions reductions in their SIPs across that same footprint is consistent with their existing participation in regional dispatch to meet the state's load requirements. In the 2/3rds of the nation that have embraced Independent System Operators and Regional Transmission Organizations ("ISOs/RTOs"), the ability to measure and maximize efficiencies can

[6] This flexibility will facilitate effective and efficient reliability solutions regardless of whether the state is a single state regional dispatch area or part of a multi-state regional dispatch area.

[7] EPA has designated greenhouse gases a "pollutant" for purposes of Clean Air Act Section 111(d) regulation.

occur over very large individual RTO/ISO regions. Presently, RTOs/ISOs geographic footprint covers approximately 2/3rds of the nation, encompassing regions that cover all or parts of 38 of the 50 states plus the District of Columbia. ISOs/RTOs serve approximately 75% of national demand.



ISOs/RTOs centrally dispatch power plants within their footprint based on the marginal cost of operation of each individual unit as reflected in bids submitted to the ISO/RTO on a day-ahead basis.[8] By dispatching generation resources across the ISO/RTO footprint based on the marginal cost to produce the next MW of electricity, the economic efficiencies of the generation fleet is maximized for each hour of the operating day across the entire RTO footprint.[9] Supply bids submitted by generators effectively internalize environmental compliance costs while still ensuring least cost compliance with

[8] Each ISO/RTO also addresses real time deviations from the load and generation forecast by accepting bids to balance load and demand each hour in real time.

[9] Moreover, through coordinated dispatch embodied in seams agreements, efficiencies are also captured to manage congestion across ISO/RTO borders.

environmental requirements.[10] The regional centralized dispatch undertaken by ISOs/RTOs is known as Security Constrained Economic Dispatch (SCED).[11]

The footprint over which units are dispatched pursuant to SCED provides a ready measurement area usable by states, *at their option*, for determining a least cost compliance program over a very large multi-state region---one that can optimize the efficiency and effectiveness of a compliance program across a broad fleet of generators and demand response resources.

In short, states in ISO/RTO regions already share in the benefits and costs of the efficient dispatch of the fleet, notwithstanding state boundaries, making the regional measurement option a consideration that is consistent with their participation in a regional SCED. Moreover, the regional dispatch can serve as an efficient regional measurement area that can be utilized by existing regional greenhouse gas initiatives or any such future multi-state agreements.

Furthermore, the SCED model can also be used by states to test the economic impacts of various environmental compliance strategies across state lines. RTOs/ISOs have the modeling tools to assist the states in testing various alternative scenarios which they can use as a resource as they look to devise a least cost multi-state solution using the SCED model.

In summary, by participating in the dispatch of all generation across the large ISO/ RTO footprint, states effectively share the costs and benefits of regional dispatch solutions rather than require that generation dispatch occur solely within their state's boundaries. Since environmental costs are inherent in the cost structure of generation resources, the integrated regional dispatch ensures that all loads in a multi-state region collectively fund, in part, the costs of environmental compliance for a power plant in return for being able to share in the lower cost output of that distant unit. This arrangement facilitates the achievement of the lowest cost of power in a given hour consistent with compliance with existing environmental regulations.

Given that the relevant states effectively share the environmental costs in return for maximizing efficiencies and cost reduction across a very large footprint, the IRC proposes that in its Final Rule EPA should allow states, *at their option*, to utilize reductions achieved across the regional dispatch footprint in measuring compliance pursuant to the individual state's SIP. Even if no agreement can be reached among states on particular compliance strategies, EPA can assure that the efficiencies of a multi-state dispatch are explicitly recognized via a regional measurement *option* in the Final Rule when states develop their SIPs so as to make the cost of compliance more efficient and measurable across a large region.[12] At a minimum, in the Final Rule EPA should recognize that for purposes of measuring compliance, it will be open to SIP plans that look at the region over which power plants are dispatched

[10] The only limitation on economic dispatch across the entire fleet results from the need to dispatch units out of merit order to ensure that transmission security is maintained.

[11] For a discussion of the benefits of SCED see Attachment A to this report.

[12] For states in more than one RTO, recognition will need to be given that the proper measurement may need to be examined with reference to each of the RTOs serving customers in that state.

using SCED. EPA's recognition of a regional measurement option in its final rule as *one* means for defining the area over which emissions reductions will be measured will help to facilitate cost effective and efficient implementation of the GHG rule under Section 111(d) of the Clean Air Act.

IV. Conclusion

The above discussion describes two conceptual frameworks to address potential reliability impacts resulting from the CO2 rule and provide an efficient and effective regional measurement approach for assessing compliance. These proposals can be implemented without compromising or limiting the potential compliance options available to achieve the goals of the CO2 program. Of course, if adopted, the implementation details would have to be further developed. The IRC looks forward to discussing these proposals with the EPA, the states, and all other interested parties.

ATTACHMENT A – SCED BENEFITS SUMMARY DISCUSSION

In the Energy Policy Act of 2005, Congress directed the FERC and states to undertake a study of the economic benefits of SCED. That study, released on July 31, 2006, included analyses from regional joint boards around the nation. As an example, the regional joint board covering the 26-state PJM/MISO region found:

"The broader regional resources available to the RTOs (as contrasted from individual utility dispatch) results in a dispatch stack containing generators from all generating-owning members of the RTOs and some generation resources outside the RTOs. Uncoordinated and separate dispatches by different individual utility companies in response to constraints (under most circumstances) would not be the same as an area-wide dispatch coordinated by each RTO, given the scope of the RTOs. It is also noteworthy that the sum of stand-alone dispatches by individual utility companies is not the same as a regional least cost dispatch where there are transmission constraints that affect and in turn are affected by the dispatch of multiple utility companies throughout the region. That there are economic and operational benefits from pooling generation resources is almost axiomatic. Other factors held constant, separate dispatches would inevitably result in higher total production costs to serve load."

Appendix D, p. 8 to "Security Constrained Economic Dispatch: Definitions, Practices, Issues and Recommendations: A Report to Congress Regarding Recommendations of Regional Joint Boards for the Study of Economic Dispatch Pursuant to Section 223 of the Federal Power Act as Added by Section 1298 of the Energy Policy Act of 2005."[13]

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[13] The entire report can be found at: http://www.ferc.gov/industries/electric/indus-act/joint-boards/final-cong-rpt.pdf

Appendix CC:

North American Energy Reliability Corporation: Potential Reliability Impacts of EPA's Proposed Clean Power Plan, Initial Reliability Review

NERC

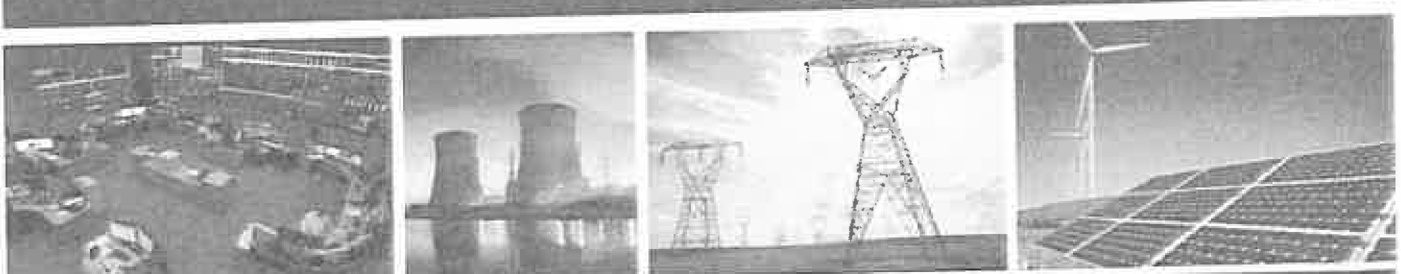
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Potential Reliability Impacts of EPA's Proposed Clean Power Plan

Initial Reliability Review

November 2014

RELIABILITY | ACCOUNTABILITY



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Preface

The North American Electric Reliability Corporation (NERC) has prepared the following assessment in accordance with the Energy Policy Act of 2005, in which the United States Congress directed NERC to conduct periodic assessments of the reliability and adequacy of the bulk power system (BPS) in North America.[1] NERC operates under similar obligations in many Canadian provinces, as well as a portion of Baja California Norte, Mexico.

NERC is an international regulatory authority established to evaluate and improve the reliability of the BPS in North America. NERC develops and enforces Reliability Standards; annually assesses seasonal and long-term (10-year) reliability; monitors the BPS through system awareness; and educates, trains, and certifies industry personnel. NERC is the electric reliability organization (ERO) for North America, subject to oversight by the U.S. Federal Energy Regulatory Commission (FERC) and governmental authorities in Canada.[2]

NERC Regions and Assessment Areas

FRCC	Florida Reliability Coordinating Council
MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RF	ReliabilityFirst
SERC	SERC Reliability Corporation
SPP-RE	Southwest Power Pool Regional Entity
TRE	Texas Reliability Entity
WECC	Western Electricity Coordinating Council

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[1] H.R. 6 as approved by of the One Hundred Ninth Congress of the United States, the Energy Policy Act of 2005. The NERC Rules of Procedure, Section 800, further detail the Objectives, Scope, Data and Information requirements, and Reliability Assessment Process requiring annual seasonal and long-term reliability assessments.

[2] As of June 18, 2007, FERC granted NERC the legal authority to enforce Reliability Standards with all U.S. users, owners, and operators of the BPS and made compliance with those standards mandatory and enforceable. Equivalent relationships have been sought and for the most part realized in Canada and Mexico. Prior to adoption of §215 in the United States, the provinces of Ontario (2002) and New Brunswick (2004) adopted all Reliability Standards that were approved by the NERC Board as mandatory and enforceable within their respective jurisdictions through market rules. Reliability legislation is in place or NERC has memoranda of understanding with provincial authorities in Ontario, New Brunswick, Nova Scotia, Québec, Manitoba, Saskatchewan, British Columbia, and Alberta, and with the National Energy Board of Canada (NEB). NERC standards are mandatory and enforceable in Ontario and New Brunswick as a matter of provincial law. Manitoba has adopted legislation, and standards are mandatory there. In addition, NERC has been designated as the "electric reliability organization" under Alberta's Transportation Regulation, and certain Reliability Standards have been approved in that jurisdiction; others are pending. NERC standards are now mandatory in British Columbia and Nova Scotia. NERC and the Northeast Power Coordinating Council (NPCC) have been recognized as standards-setting bodies by the Régie de l'energie of Québec, and Québec has the framework in place for Reliability Standards to become mandatory. NEB has made Reliability Standards mandatory for international power lines. In Mexico, the Comisión Federal de Electricidad (CFE) has signed WECC's reliability management system agreement, which only applies to Baja California Norte.

Executive Summary

The Environmental Protection Agency (EPA), on June 2, 2014, issued its proposed Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units, commonly referred to as the proposed Clean Power Plan (CPP), under Section 111(d) of the Clean Air Act, which introduces CO_2 emission limits for existing electric generation facilities. On August 14, 2014, the NERC Board of Trustees directed NERC to develop a series of special reliability assessments to examine the proposed CPP. This report is NERC's initial reliability review of the potential risks to reliability, based on the assumptions contained in the proposed CPP.

NERC maintains a reliability-centered focus on the potential implications of environmental regulations and other shifts in policies that can impact the reliability of the bulk power system (BPS). Reliability assessments conducted while the EPA is finalizing the CPP can inform regulators, state officials, public utility commissioners, utilities, and other impacted stakeholders of potential resource adequacy concerns, impacts to system characteristics (such as essential reliability services (ERSs)), and, to some degree, areas that are more likely to require power-flow-related transmission enhancements to comply with NERC Reliability Standards. The goals of this review are listed in more detail below:

- **Provide an evaluation and comparison of the assumptions supporting the CO_2 reduction objectives in the proposed CPP against other reported projections available within NERC assessment reports.**
- Provide insight into planned generation retirements, load growth, renewable resource development, and energy efficiency measures that might impact CO_2 emissions and the EPA's target-driven assumptions.
- Provide insight into the potential reliability consequences of either the target-driven emission assumptions or the NERC projection-based assumptions and, in particular, the potential reliability implications if the EPA assumptions cannot be realized.
- Identify potential reliability impacts resulting from the expected resource mix changes, such as coal resource displacement or retirements, the impacts on regional planning reserve margins, the shifts in resource mix and ERS characteristics, the increase in variable resources, the concentration of resources by fuel source (especially natural gas), transmission and large power transfers, and other reliability characteristics, including regional differences.
- Support the electric power industry and NERC stakeholders by providing an independent assessment of reliability while serving as a platform to inform policy discussions on BPS reliability and emerging issues.

This report and its findings are *not* intended to: (1) advocate a policy position in regard to the environmental objectives of the proposed CPP; (2) promote any specific compliance approach; (3) advocate any policy position for a utility, generation facility owner, or other organization to adopt as part of compliance, reliability, or planning responsibilities; (4) support the policy goals of any particular stakeholder or interests of any particular organization; or (5) represent a final and conclusive reliability assessment.

The objective of this review is to identify the reliability implications and potential consequences from the implementation of the proposed CPP and its underlying assumptions. The preliminary review of the proposed rule, assumptions, and transition identified that detailed and thorough analysis will be required to demonstrate that the proposed rule and assumptions are feasible and can be resolved consistent with the requirements of BPS reliability. This assessment provides the foundation for the range of reliability analyses and evaluations that are required by the ERO, RTOs, utilities, and federal and state policy makers to understand the extent of the potential impact. Together, industry stakeholders and regulators will need to develop an approach that accommodates the time required for infrastructure deployments, market enhancements, and reliability needs if the environmental objectives of the proposed rule are to be achieved.

Herein, NERC examines the assumptions made in the EPA's four Building Blocks:[3]

Building Block 1: Heat rate improvements
Building Block 2: Dispatch changes among affected electric generating units (EGUs)
Building Block 3: Using an expanded amount of less-carbon-intensive generating capacity

[3] Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units.

Building Block 4: Demand-side energy efficiency

NERC identified the following factors as requiring additional reliability consideration:

Implementation of the CPP reduces fossil-fired generation: The proposed CPP aims to cut CO_2 emissions from existing power plants to 30 percent below 2005 levels by 2030. Under the EPA proposal, substantial CO_2 reductions are required under the State Implementation Plans (SIPs) as early as 2020. According to the EPA's *Regulatory Impact Assessment*, generation capacity would be reduced by between 108 and 134 GW by 2020 (depending on state or regional implementations of Option 1 or 2).[4] The number of estimated retirements identified in the EPA's proposed rule may be conservative if the assumptions prove to be unachievable. Developing suitable replacement generation resources to maintain adequate reserve margin levels may represent a significant reliability challenge, given the constrained time period for implementation.

Assumed heat rate improvements for existing generation may be difficult to achieve: NERC is concerned that the assumed improvements may not be realized across the entire generation fleet since many plant efficiencies have already been realized and economic heat rate improvements have been achieved. Multiple incentives are in place to operate units at peak efficiency, and periodic turbine overhauls are already a best practice. Site-specific engineering analyses would be required to determine any remaining opportunities for economic heat rate improvement measures.

Greater reliance on variable resources and gas-fired generation is expected: The CPP will accelerate the ongoing shift toward greater use of natural-gas-fired generation and variable energy resources (VERs) (renewable generation). Increased dependence on renewable energy generation will require additional transmission to access areas that have higher-grade wind and solar resources (generally located in remote areas). Increased natural gas use will require pipeline expansion to maintain a reliable source of fuel, particularly during the peak winter heating season. Pipeline constraints and growing gas and electric interdependency challenges impede the electric industry's ability to obtain needed natural gas services, especially during high-use horizons.

Rapid expansion of energy efficiency displaces electricity demand growth through 2030: In its rate calculation for best practices by state, the EPA assumes up to a 1.5 percent annual retail goal for incremental growth in efficiency savings. The EPA assumes that the states and industry would rapidly expand energy efficiency savings programs from 22 TWh/year in 2012, to 108 TWh/year in 2020, and reach 380 TWh/year by 2029. With such aggressive energy efficiency expansion, the EPA assumes that energy efficiency will grow faster than electricity demand, with total electricity demand shrinking after 2020. The implications of this assumption are complex. If the EPA-assumed energy efficiency growth rates cannot be attained, additional carbon reduction measures would be required, primarily through reduced fossil-fired generation.

Essential Reliability Services may be strained by the proposed CPP: The anticipated changes in the resource mix and new dispatching protocols will require comprehensive reliability assessments to identify changes in power flows and ERSs. ERSs are the key services and characteristics that comprise the following basic reliability services needed to maintain BPS reliability: (1) load and resource balance; (2) voltage support; and (3) frequency support. New reliability challenges may arise with the integration of generation resources that have different ERS characteristics than the units that are projected to retire. The changing resource mix introduces changes to operations and expected behaviors of the system; therefore, more transmission and new operating procedures may be needed to maintain reliability.

More time for CPP implementation may be needed to accommodate reliability enhancements: State and regional plans must be approved by the EPA, which is anticipated to require up to one year, leaving as little as six months to two years to implement the approved plan. Areas that experience a large shift in their resource mix are expected to require transmission enhancements to maintain reliability. Constructing the resource additions, as well as the expected transmission enhancements, may represent a significant reliability challenge given the constrained time period for implementation. While

[4] Regional implementation of Option 2 assumes 108 GW of retirements (includes CC, Coal, CT, Nuclear, O/G, and IGCC) by 2020. State implementation of Option 1 assumes 134 GW of retirements (includes CC, Coal, CT, Nuclear, O/G, and IGCC) by 2020. For additional information, see: Regulatory Impacts Analysis for the Proposed Carbon Pollution Guidelines for Existing Power Plants and Emission Standards for Modified and Reconstructed Power Plants (June 2014) and supporting IPM Model documentation and data.

the EPA provides flexibility for meeting compliance requirements within the proposed time frame, there appears to be less flexibility in providing reliability assurance beyond the compliance period.

A summary of NERC's initial reliability review recommendations is provided below:

General Recommendations

1. **NERC should continue to assess the reliability implications of the proposed CPP** and provide independent evaluations to stakeholders and policy makers.
2. **Coordinated regional and multi-regional industry planning and analysis groups should immediately begin detailed system evaluations to identify areas of concern** and work in partnership with policy makers to ensure there is clear understanding of the complex interdependencies resulting from the rule's implementation.
3. **If the environmental goals are to be achieved, policy makers and the EPA should consider a more timely** approach that addresses BPS reliability concerns and infrastructure deployments.

Recommendations to Address Direct Impacts to Resource Adequacy and Electric Infrastructure

Fossil-Fired Retirements and Accelerated Declines in Reserve Margins
The Regions, ISO/RTOs, and states should perform further analyses to examine potential resource adequacy concerns.

Transmission Planning and Timing Constraints
The EPA and states, along with industry, should consider the time required to integrate potential transmission enhancements and additions necessary to address impacts to reliability from the proposed CPP. The EPA and policy makers should recognize the complexity of the reliability challenges posed by the rule and ensure the rule provides sufficient time for the industry to take the steps needed to significantly change the country's resource mix and operations without negatively affecting BPS reliability.

Regional Reliability Assessment of the Proposed CPP
Other ISO/RTOs, states, and Regions should prepare for the potential impacts to grid reliability, taking into consideration the time required to plan and build transmission infrastructure.

Reliability Assurance
The EPA, FERC, the DOE, and state utility regulators should employ the array of tools and their regulatory authority to develop a reliability assurance mechanism, such as a "reliability back-stop." These mechanisms include timing adjustments and granting extensions where there is a demonstrated reliability need.

Recommendations to Address Impacts Resulting from the Changing Resource Mix

Coal Retirements and the Increased Reliance on Natural Gas for Electric Power
Further coordinated planning between the electric and gas sectors will be needed to ensure a strong and integrated system of fuel delivery and generation adequacy. Coordinated planning processes should include considerations for pipeline expansion to meet the increased reliance on natural gas for electric generation, especially during extreme weather events (e.g., polar vortex).

The Changing Resource Mix and Maintaining Essential Reliability Services
ISO/RTOs, utilities, and Regions (with NERC oversight) should analyze the impacts to ERSs in order to maintain reliability. Additionally, system operators and ISO/RTOs need to develop appropriate processes, tools, and operating practices to adequately address operational changes on the system.

NERC should perform grid-level performance expectations developed from a technology-neutral perspective to ensure ERS targets are met.

The development of technologies (such as electricity storage) help support the reliability objectives of the BPS, and these technologies should be expedited to support the additional variability and uncertainty on the BPS.

Increased Penetration of Distributed Energy Resources (DERs)
ISO/RTOs and system planners and operators should consider the increasing penetration of DERs and potential reliability impacts due to the limited visibility and controllability of these resources.

Plan for NERC Reliability Assessments

After the proposed CPP is finalized, specific transmission and resource adequacy assessments—including resulting reliability impacts—will be essential for supporting the development of SIPs that are aligned with system reliability needs. NERC's plan for reviewing and assessing the reliability impacts of the EPA proposal is included in Figure 1. This review includes a preliminary review of the assumptions and potential reliability impacts resulting from the implementation of the EPA's proposed CPP. As the EPA is scheduled to finalize its rule by June 2015, NERC will develop a specific reliability assessment in early 2015 that will focus on evaluating generation and transmission adequacy and reliability impacts. After the EPA rule is finalized, the states, either individually or in multi-state groups, are required to develop their SIPs by 2016 and 2018, respectively. NERC plans to provide a more specific and comprehensive reliability assessment before SIPs are submitted to the EPA. Additionally, a Phase III approach is tentatively planned for December 2016, which will examine finalized SIPs.

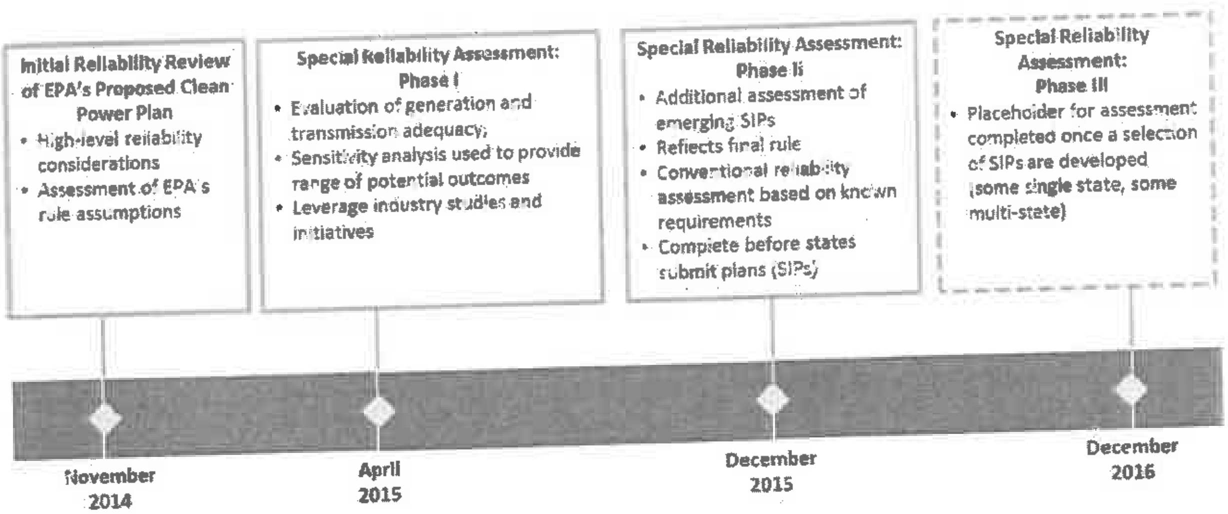

Figure 1. NERC's Assessment Actions and Schedule Timeline

Summary of the Proposed Clean Power Plan

The proposed CPP aims to cut CO_2 emission from existing power plants to 30 percent below 2005 levels by 2030. Substantial CO_2 reductions are required under State implementation Plans. Under the EPA proposal, CO_2 reductions are required as early as 2020. According to the EPA's reliability assessment included in the proposed rule, these existing generation rules would result in between 108 and 134 GW of generation retirements by 2020 (depending on state or regional implementations of Option 1 or 2).[5]

The CPP proposal would apply to fossil-fired generating units that meet four combined qualification criteria: (1) units that commenced construction prior to January 8, 2014;[6] (2) units with design heat input of more than 250 MMBtu/hour (approximately a 25 MW unit); (3) units that supply over one-third of their potential output to the power grid; and (4) units that supply more than 219,000 MWh/year on a three-year rolling average to the power grid.[7] Given these criteria, the EPA estimates that approximately 3,000 U.S. fossil-fired electric generation units representing over 700,000 MW of existing nameplate generating capacity will be subject to the rule limitations.[8] NERC estimates that this magnitude represents approximately 65 percent of the total existing nameplate capacity in the United States.

The EPA-proposed draft regulations would, for the first time, limit CO_2 from existing power plants, thus addressing risks to health and the economy posed by climate change. These proposed regulations are intended to provide implementation flexibility and maintain an affordable, reliable energy system while cutting CO_2 and protecting public health and the environment.[9]

The EPA regulations propose implementation through a state-federal partnership under which states identify plans to meet the emission reduction goals. The EPA provides guidelines for states to develop implementation plans to meet state-specific CO_2 reduction goals and provides states the flexibility to design requirements suited to their unique situations. These plans may include generation mix changes using diverse fuels, energy efficiency, and demand-side management, and they allow states to work individually or to develop multi-state plans. The primary driver for realizing the EPA's 111(d) objectives is that SIPs need to produce significant CO_2 reductions starting as early as 2020.

As currently proposed, states have a flexible timeline for submitting plans to the EPA. Within one year of finalizing the rule—expected in June 2015—state environmental agencies must submit implementation plans to the EPA for approval. Submitted state-specific plans, due in June 2016, must outline requirements and enforceable limitations for affected generating units to meet the rule's average CO_2 emission rate goal for each state within two compliance periods: (1) an initial 10-year average interim emission rate limit for the period 2020–2029, and (2) a final annual emission rate limit starting in 2030.

The EPA provides states with an option to convert CO_2 emission rate limitation into an annual mass-based limitation. It is likely that most states will pursue this option due to the challenges state permitting agencies have in developing unit-specific emission rate limitations. The simpler mass-based CO_2 emission cap program also negates the need for state legislative action to authorize agencies to limit plant output and enact an enforceable program for compliance with average emission rates. The EPA's proposed Clean Power Plan timeline is outlined in Figure 2.

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[5] State implementation of Option 1 assumes 134 GW of retirements (includes CC, Coal, CT, Nuclear, O/G, and IGCC) by 2020. For additional information, see: Regulatory Impacts Analysis for the Proposed Carbon Pollution Guidelines for Existing Power Plants and Emission Standards for Modified and Reconstructed Power Plants (June 2014) and supporting IPM Model documentation and data. Regional implementation of Option 2 assumes 108 GW of retirements (includes CC, Coal, CT, Nuclear, O/G, and IGCC) by 2020.

[6] All sources starting construction after January 8, 2014, would be subject to new source performance standards and exempt from the EPA Clean Power Plan requirements.

[7] 79 FR 34854 [illegible]

[8] EPA CPP TSD – 2012 Unit-Level Data Using EGrid – Methodology, June 2014. Generation, Emissions, Capacity data used in EPA's State Goal Computation TSD.

[9] EPA Fact Sheet: Clean Power Plan – Why we Need A Cleaner, More Efficient Power Sector "*The proposed Clean Power Plan will cut hundreds of millions of tons of carbon pollution and hundreds of thousands of tons of harmful particle pollution, sulfur dioxide and nitrogen oxides. Together these reductions will provide important health protections to the most vulnerable, such as children and older Americans.*" [illegible]

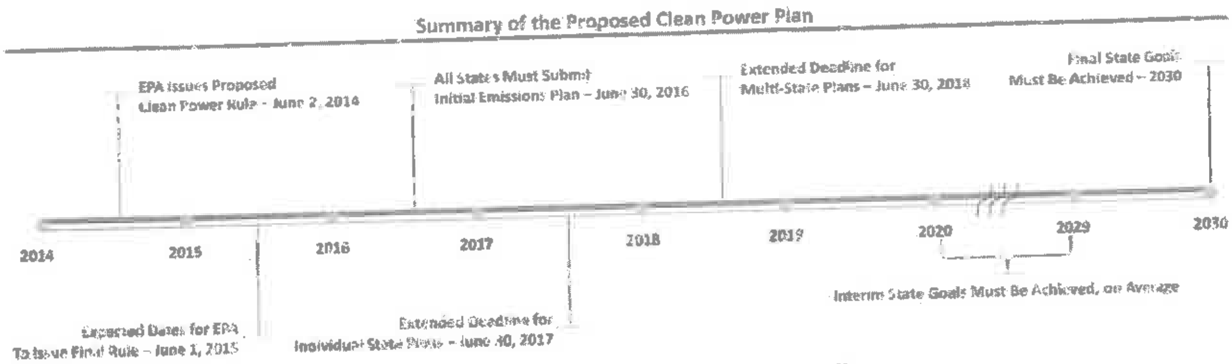

Figure 2. EPA Proposed Clean Power Plan Timeline

The EPA would have one year to review and approve implementation plans for each state by June 2017. Under this schedule, impacted generating units would have two and a half years to develop respective compliance strategies and potentially permit, finance, and build needed replacement capacity and transmission. In its current form, this implementation schedule would be a challenge for states to implement and for affected sources to comply with, especially given the expected legal challenges to both the EPA and state rules. In recognition of these challenges, the EPA would provide states with a one-year extension to June 2017 to submit a SIP if justification is provided, and a two-year extension (June 2018) for states that elect to develop multi-state (regional) programs (e.g., Regional Greenhouse Gas Initiative (RGGI)). While the EPA extensions apply to state plan submissions, the January 1, 2020, program start date for affected sources would not be extended under the proposed CPP. Therefore, the impacted fossil-fired units may be left with as little as six months to develop and implement compliance plans. Considering the number and variety of outcomes for each of the proposed scenarios, the states and industry should initiate planning immediately upon finalization of the CPP.

EPA's Proposed Clean Power Plan Options

The EPA is proposing a Best System of Emission Reduction (BSER) goal, referred to as Option 1, and is taking comment on a second approach, referred to as Option 2.

Option 1: Involves higher deployment of emission reduction but allows a longer time frame (2030).

Option 2. Has a lower deployment of emission reductions over a shorter time frame (2025) by each state. Proposed guidelines allow states to collaborate and demonstrate emission performance on a multi-state basis, in recognition that electricity is transmitted across state lines.

The proposed Clean Power Plan, which is based on EPA analysis of historical data about emissions and the power sector, is intended to create a consistent national formula for reductions that reflects their Building Block assumptions. The formula applies the four Building Blocks to each state's specific information, yielding a carbon intensity rate for each state.[10] There is a wide range of potential proposals, including individual state and multi-state groupings, each with different implementation schedules. The range of potential submitted SIPs and changes to the proposed timeline create significant uncertainties for industry and resource planners.

Clean Power Plan Building Blocks

According to the proposed plan, this can be achieved through the development of state-specific emission rates to limit CO_2 by applying four different BSER Building Blocks.[11] Each Building Block represents a different approach for achieving the proposed targets. According to the EPA, the proposed plan considers impacts to system reliability and electricity prices. The BSER is not intended to impact resource planning and does not dictate retirements, additions, or operating practices for individual units. Instead, it would provide state emission rate limits that would shape the future resource mix through state and market processes in subsequent years as SIPs and multi-state plans are developed and implemented.

[10] EPA Fact Sheet: Clean Power Plan – National Framework for States.

[11] EPA Clean Air Act: Section 111(d) authorizes EPA to apply "best system of emission reduction" to this section's affected sources.

The EPA's Proposed Clean Power Plan: Four Building Blocks

Plant Efficiency

Make fossil fuel power plants more efficient by implementing a 6 percent (on average) unit heat rate improvement for all affected coal-fired units. The EPA suggests that some plants could further improve process efficiency by 4 percent through the adoption of best operational practices, and an additional 2 percent through capital upgrade investments.

Natural Gas

Use low-emitting power sources more by redispatching existing natural gas combined-cycle (NGCC) units before the coal and older oil-gas steam units. EPA draft rate limitations include CO_2 reduction assumptions from the ongoing increases in the use of NGCC capacity (with up to a 70 percent capacity factor). This additional NGCC capacity (440 TWh/year) displaces coal (376 TWh/year) and oil-gas steam generation (64 TWh/year) by 2020, compared to 2012 levels.

Use more zero- and low-emitting power sources through building capacity by adding both non-hydro renewable generation and five planned nuclear units. EPA calculations assume qualifying non-hydro renewable generation can grow rapidly from 218 TWh/year in 2012, to 281 TWh/year by 2020, to reach 523 TWh/year by 2030.

Energy Efficiency

Use electricity more efficiently by significantly expanding state-driven energy efficiency programs to improve annual electricity savings by up to 1.5 percent of retail sales per year. The calculation assumes the states and industry can rapidly expand energy efficiency programs to increase savings from 22 TWh/year in 2012, to 108 TWh/year in 2020, and to 380 TWh/year by 2029. Ultimately, EPA energy efficiency assumptions suggest that electric power savings will outpace electricity demand growth, resulting in negative electricity usage from 2020 through 2030.

Clean Power Plan – Assumption Review

This section provides a critical review of the EPA's assumptions for state-specific CO_2 emission rates and presents possible reliability challenges that need to be considered.

Building Block 1 – Coal Unit Heat Rate Improvement

Plant Efficiency

The EPA's heat rate assessment analyzed gross data for 884 coal-fired electric generating units (EGUs) during a 10-year period.[12] The regression analysis examined the effects of the capacity factor and the ambient temperature on the gross heat rate efficiencies of coal-fired EGUs. The EPA's assessment concluded that in-state coal units can achieve up to a 4 percent rate of improvement through the use of best operational practices. An additional 2 percent of efficiency improvements would be achieved through capital upgrade investments.

Review of EPA Assumptions and Potential Reliability Impacts

The EPA calculated unit-specific heat rates using gross generation data from the Continuous Emission Monitoring Systems (CEMSs). With this approach, the EPA excluded generation-reducing effects from post-combustion environmental controls, such as selective catalytic reduction and flue-gas desulfurization controls. The EPA then used net generation data, without consideration for these retrofits, for coal-fired EGUs when calculating the state CO_2 emission rate goals. These retrofits will reduce the net output of these units, as well as their associated net heat rate efficiency. Not considering these reductions creates an inconsistent approach, especially considering that most coal-fired EGUs will require control retrofits to comply with environmental regulations, such as the Mercury Air Toxic Standards (MATS) and Section 316(b) of the Clean Water Act.

The EPA's regression analysis does not adjust for the following factors that have profound effects on the process efficiency of a coal-fired EGU:[13] (1) subcritical versus supercritical boiler designs; (2) fluidized bed combustion, integrated gasification combined-cycle (IGCC), and pulverized coal; (3) unit size and age; and (4) coal quality variations in moisture and ash (i.e., every 5 percent change in coal moisture results in a 1 percent change in boiler heat rate efficiency).

Impacts on Coal-Fired Unit Efficiency Rates

Lower capacity factors will cause an increase in heat rates, particularly if the lower-capacity factors are due to the cycling of the coal units. As a result of Building Block 2, coal units will cycle more often; therefore, assumed heat rate improvements across the entire coal fleet are unlikely. While recognizing capacity effects in the regression analysis, the EPA did not evaluate the effects of lower-capacity factors resulting from the dispatching of natural gas generation before coal generation.

Periodic Turbine Overhauls

Turbine overhauls are referenced as a major heat rate improvement method in an EPA Clean Power Plan technical support document.[14] Regular turbine overhauls are generally not practical or economical, because these procedures require the unit to be out of service for an extended period of time. As well, the power industry already has multiple incentives to operate units at peak efficiency (i.e., profit maximization and competitive advantage).

Overall, improving the existing U.S. coal fleet's average heat rate by 6 percent may be difficult to achieve. Possible options and considerations for attaining a portion of this target may include the following:

- Site-specific engineering analyses are required to determine if there are remaining opportunities for heat rate improvement measures through implementation of operational best practices or capital investments.
- If the U.S. coal fleet does not achieve target heat rates, more CO_2 reductions would be required from other CPP Building Block measures.
- This can result in some coal-fired power plants retiring earlier than anticipated, which creates additional uncertainty in future generation resources.

[12] *GHG Abatement Measures* (EPA June 2014) (EPA-HQ-OAR-2013-0602) pg. 2-18.
[13] These differences are illustrated in Figure 2-2 of *GHG Abatement Measures* (EPA June 2014).
[14] Coal-Fired Power Plant Heat Rate Reductions (January 2009).

Building Block 2 – Gas Unit Re-Dispatching

The EPA assumes that reductions in CO_2 emissions from existing power plants can be achieved by dispatching existing NGCC units ahead of coal units. In particular, the EPA assumes existing NGCC units can achieve a 70 percent utilization rate with avoided incremental costs of less than \$33/metric ton CO_2.[15] In its state-specific goal computation, the EPA calculated that 440 TWh/year of additional NGCC generation could potentially displace 376 TWh/year of coal and 64 TWh/year of oil-gas steam units of 2012 generation.[16]

Review of EPA Assumptions and Potential Reliability Impacts

Upon reviewing the EPA's Building Block 2 assumptions, NERC found a number of reliability concerns regarding increased reliance on natural-gas-fired generation that should be evaluated.

Historically, the primary function of the NGCC unit is to follow the load of energy throughout the day (i.e., the intermediate, or midrange, part of the load duration curve). While some NGCC units are capable of operating at a high capacity factor, the vast majority of this type of generation is used for load following. Due to lower gas prices, NGCC units are currently being dispatched as a baseload resource, displacing baseload coal-fired EGUs. Unlike baseload coal-fired generation, NGCC units are better suited to follow load. As mentioned earlier, cycling coal-fired EGUs reduces heat rate efficiencies, causing their CO_2 emission rates (lbs/MWh) to deteriorate, and further offsetting the Building Block 1 assumptions.

Generally, the power industry relies upon diversification of fuel sources as a mechanism to offset unforeseen events (e.g., abnormal weather, regional transfers, labor strikes, unplanned outages); ensure reliability; and minimize cost impacts. Fuel diversification is also a component of an "all-hazards" approach to system planning, which inherently provides resilience to the BPS. The EPA estimates that an additional 49 GW of nameplate coal capacity will retire by 2020 due to the impacts of the proposed CPP.[17] When including the 54 GW of nameplate coal capacity already announced to retire by 2020[18] (mostly due to MATS), the power industry will need to replace a total of 103 GW of retired coal resources by 2020, largely anticipated to be natural-gas-fired NGCC and CTs. Considering the current and ongoing shift in the resource mix, the EPA proposes to further accelerate the shift, lessening the industry's diversification of fuel sources.

As observed during the 2014 polar vortex,[19] the relationship between gas-fired generation availability and low temperatures challenges the industry's ability to manage extreme weather conditions—particularly when conditions affect a wide area and less support is available from the interconnection. The polar vortex served as an example of how extended periods of cold temperatures had direct impacts on fuel availability, especially for natural-gas-fired capacity. Higher-than-expected forced outages were observed during the polar vortex, particularly for natural-gas-fired generators, as a result of fuel delivery issues and low temperatures. Overall, extreme weather conditions have the potential to strain BPS reliability and expose risks related to natural-gas-fired generation availability (Figure 3). With greater reliance on natural-gas-fired generation, the resiliency and fuel diversification that is currently built into the system may be degraded, which NERC has highlighted in recent gas-electric interdependency assessments.

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[15] *GHG Abatement Measures* (EPA June 2014) (EPA-HQ-OAR-2013-0602) pg. 3-26.

[16] Clean Power Plan Proposed Rule: Goal Computation – Technical Support Document [illegible]

[17] *Regulatory Impact Analysis for the Proposed Carbon Pollution Guidelines for Existing Power Plants and Emission Standards for Modified and Reconstructed Power Plants* (EPA June 2014 pg. 3-32).

[18] Energy Ventures Analysis maintains a complete list of announced power plant retirements in the contiguous United States, retirements as of 10/02/2014.

[19] NERC 2014 Polar Vortex Review: [illegible]

Fuel Supply and Delivery

- Natural gas interruptions
  - supply injection
  - compressor outages
  - one pipeline explosion
- Oil delivery problems
- Inability to procure gas
- Fuel oil gelling

Extended Low Temperatures

- Low temperature limits for wind turbines
- Icing on hydro units
- Failed auxiliary equipment
- Stress of extended run times
- Frozen instrumentation (drum level sensors, control valves, and flow and pressure sensors)

Figure 3. Causes for Generator Outages Observed during the 2014 Polar Vortex

Pipeline Capacity Constraints

During its assessment of Building Block 2, the EPA concludes that the power industry in aggregate can support higher gas consumption without the need for any major investments in pipeline infrastructure. However, there are a few critical areas that likely will need additional capital investments. As an example, current and planned pipeline infrastructures in Arizona and Nevada are inadequate for handling increased natural gas demand due to the CPP. Pipeline capacity in New England is currently constrained, and more pipeline capacity additions will be needed as more baseload coal units retire—this is generally occurring as projected and independent of the CPP. Timing of these investments is also critical as it take three to five years to plan, permit, sign contract capacity, finance, and build additional pipeline capacity, in addition to placing replacement capacity (e.g., NGCC/CT units) in service. The proposed CPP timelines would provide little time to add required pipeline or related resource capacity by 2020.

Due to abundant availability of natural gas, the power industry is generally able to accommodate increased demand from NGCC plants that operate as baseload capacity. This higher dependence on natural gas can expose additional reliability risks, including pipeline transportation constraints that could result as more gas-fired generation is built. Overall, the increase in natural gas use and capacity expansion increases gas-electric interdependency issues and raises the following concerns:

- NGCC units could displace coal-fired generating units as baseload units, forcing less-efficient coal units out of service, further increasing demand for natural gas.
- Adequate timing is required to add new pipeline and generation resource capacity where it is needed to offset coal plant retirements and supply natural gas to new generation.
- As gas-electric dependency significantly increases, unforeseen events like the 2014 polar vortex could disrupt natural gas supply and delivery for the power sector in high-congestion regions, increasing the risk for potential blackouts.

Building Block 3 – Clean Energy

Building Block 3 describes the EPA's method to reduce CO_2 emissions by investing in zero-CO_2-emitting energy sources (i.e., nuclear and non-hydro renewable generation).

Review of EPA Assumptions and Potential Reliability Impacts

Building Block 3 includes the assumption about the preservation of nuclear generating units that are currently at risk of being retired within the next two decades due to (1) age, (2) an increase in fixed operation and maintenance costs, (3) relatively low wholesale electricity prices, and (4) additional capital investment associated with ensuring plant security and emergency preparedness. The EPA assumes that 5.7 percent of each state's nuclear generating capacity is at risk of retirement. However, the EPA included this generation as well as the five new nuclear units currently under construction (Watts Bar Unit 2 (TN), Summer Units 2-3 (SC), and Vogtle Units 3-4 (GA)) in its state-by-state CO_2 emission rate goal calculations.[20] The nuclear retirement assumptions add pressure to states that will need to retire nuclear units. For these states, more CO_2 reductions from other measures than originally estimated by the EPA may be required.

Under its draft CPP, the EPA also proposes significant expansion of non-hydro renewable generation as part of its BSER determination. The EPA adopted a methodology to estimate non-hydro renewable generation by state and year and applied these estimates in their calculation of individual state emission rate limitations. The greater the EPA's assumed non-hydro renewable generation in a given state, the lower the state's calculated CO_2 emission rate limit.

The EPA assumes that qualifying non-hydro renewable generation will grow from 213 TWh/year in 2012, to 281 TWh/year by 2020, reaching 523 TWh/year by 2030. These projections exceed the Energy Information Administration (EIA) non-hydro renewable generation forecast in their Annual Energy Outlook 2013 (AEO 2013) that grows from 202 TWh/year in 2012, to 275 TWh/year by 2020, to reach 317 TWh/year by 2030 for all sectors.[21] The EPA-assumed rapid growth in non-hydro renewable generation exceeds its own forecast in the EPA's *Regulatory Impacts Assessment* (356 TWh/year by 2030).[22]

To calculate the state target levels of renewable energy performance, the EPA examined mandatory state Renewable Portfolio Standard (RPS) requirements from the Database for State Incentives for Renewables and Efficiency (DSIRE).[23] RPS requirements vary widely by state; many states include resource-specific percentage requirements (i.e., set-asides) that promote development of certain resources in addition to their general requirements. The database distinguishes the complex web of state policies by applying them to a standardized tier system which, according to DSIRE, helps "to compare RPS policies on equal footing."[24] To determine the state effective levels in 2020, the EPA added each state's tiers together and excluded secondary and tertiary tiers that include energy efficiency or qualified fossil fuels (waste coal, carbon capture sequestration, etc.). The only RPS "type" considered was the primary type, referring to requirements for investor-owned utilities (IOUs).

Significant regional differences exist in the availability of renewable resources and their power production costs across the United States. In order to quantify these regional differences, the EPA divided the lower 48 states into six regions, based on designations by NERC Regions and ISO/RTOs. After the regions were assigned, the EPA averaged the 2020 effective levels for states that have mandatory RPS percentage standards. By applying the average regional renewable energy (RE) percentages to each region's aggregate 2012 generation, the EPA derived a new RE target generation level for 2030. The EPA notes that Alaska and Hawaii were assigned RE generation target percentages equal to the lowest value of the six regions, equivalent to the Southeast's target. The EPA assumes that RE generation will begin increasing in 2017 and continue through 2029. Moreover, they assume no growth occurs in between 2012 and 2016. The EPA derived the annual growth factor by determining "the amount of additional renewable generation (in megawatt-hours) that would be required beyond each

[19] *GHG Abatement Measures* (EPA June 2014) (EPA-HQ-OAR-2013-0602) pg. 4-33.
[20] *Annual Energy Outlook 2013* (EIA April 2013) reference case data.
[21] *Regulatory Impact Analysis for the Proposed Carbon Pollution Guidelines for Existing Power Plants and Emission Standards for Modified and Reconstructed Power Plants* (EPA June 2014) Table 3-11 pg. 3-27.
[22] http://www.dsireusa.org/.
[23] DSIRE. DSIRE RPS Field Definitions. April 2011. [illegible] p.1.

region's historic (2012) generation to reach that region's RE target"[25] by 2030. This constant growth rate is then applied to each state to obtain annual state RE target levels.

The EPA's reliance on state RPS standards to compute the regional performance targets poses a variety of issues. States' main-tier RPS qualifications vary significantly and, in addition to in-state non-hydro renewable generation, also often include hydroelectric generation, municipal solid waste (MSW), combined heat and power (CHP), clean coal, carbon capture and sequestration, and energy efficiency measures. As an example, New York has an RPS percentage of 30 percent.[26] According to the *New York Renewable Portfolio Standard Cost Study Report* produced by the New York State Department of Public Service, hydroelectricity contributes 18.25 percent of total generation and is included under baseline renewables.[27] New York's RPS percentages, therefore, include the state's hydroelectric generation as qualifying renewable resources, which is different from what the EPA assumed in its methodology.

In addition to hydroelectric power, energy efficiency plays an important role in various states' RPSs. North Carolina's RPS includes a provision that allows up to 25 percent of its target to be met by energy efficiency gains. This provision, if it were properly excluded by the EPA, would reduce North Carolina's RPS target to 7.5 percent from 10 percent, thereby lowering targets for the entire Southeast region, Alaska, and Hawaii. When establishing 2012 non-hydro renewable generation performance levels, the EPA excluded all hydroelectric generation and energy efficiency programs used in the state CO_2 emission rate calculations. The adjusted state RPS targets, as well as 2012 non-hydro RE performance levels, are used to determine the regional RE targets and regional annual growth rates.

NERC notes several other concerns with the CPP's assumption for Building Block 3, such as:

- Multipliers given to select resources' options (e.g., in-state, wind, solar, etc.). Six states (CO, DE, MI, NV, OR, and WA) give extra credit (up to 3.5 renewable energy credits per 1 MWh of energy produced) for using these resources.[28] Excluding the multiplier suggests a target that is ultimately higher than what may actually be attainable.
- The use of qualifying out-of-state renewable generation resources in effective RPS target calculations. Most RPS programs allow out-of-state qualifying renewable resources toward RPS compliance. For example, several Indiana wind projects account for nearly 50 percent of the Ohio RPS requirement. This issue is important since states realize that much of the lower-cost renewable resources may come from outside the state in locations more suitable for VERs. The underlying assumption—that the state RPS reflects in-state renewable capability that can be matched by the other states in their census region—appears incorrect and could only be dealt with via a regional state approach similar to a regional greenhouse gas initiative. In order to properly account for regional renewable resource potential, the EPA should consider including only in-state renewable resource portions of the state RPSs.
- The EPA method of assigning renewable regions is questionable. Of the six renewable regions created in the lower 48 states, targets for two regions (South Central and Southeast) were set based upon a single-state RPS. For example, the South Central state region (AR, KS, LA, NE, OK and TX) was set based upon only the Kansas RPS. Kansas accounts for only 6 percent of this region's retail power sales and has the third-best wind resources in the country. Given the combination of a low population, large land area, and very high wind resource availability, Kansas has relatively low costs to meet its RPS. However, Louisiana (ranked #48 in wind resources and double the retail sales) is assigned the same non-hydro renewable target. To put these two states in the same region sets unattainable targets for Louisiana.
- The EPA's determination of state goals for renewable generation does not fully reflect the economic aspects of renewable resources. Resource limitations exist due to permitting, market saturation, transmission access, and project financing issues. Many prime wind locations have difficulty obtaining the necessary permits and are often objected to at the local level. Many high-grade wind sites are also located in remote areas. Energy generated from

[25] *GHG Abatement Measures* (EPA June 2014) (EPA-HQ-OAR-2013-0602) pg. 4-18.
[26] http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=NY03R&re=0&ee=0.
[27] http://www.dps.ny.gov/rps/Appendix-B-2-19-04.pdf.
[28] DSIRE http://www.dsireusa.org/.

these locations requires large capital investments to build transmission infrastructure to interconnect to the BPS. Location matters, and sites with high capacity factors are limited.

- The expiration of the production tax credits (PTCs) and potential reduction of the investment tax credits (ITCs) for RE resources in the coming years will impact investment decisions and the economics of new resources. As a result, the marginal cost of new RE generation increases, which could impact the long-term development of RE resources. There is also the implicit need to increase ancillary services as a result of the increased variable resource output. Moreover, there are higher production costs associated with more non-hydro renewable generation due to a combination of increased capital costs and low-capacity operating factors. Overall, significant cost uncertainties will directly impact the electric industry's plan to quickly adapt to the CPP requirements.

Finally, grid reliability issues associated with increased variable resources are not directly addressed in the EPA's proposed Building Blocks. Conventional generation (e.g., steam and hydro), with large rotating mass, has inherent operating characteristics, or ERSs,[29] needed to reliably operate the BPS. These services include providing frequency and voltage support, operating reserves, ramping capability, and disturbance performance. Conventional generators are able to respond automatically to frequency changes and historically have provided most of the power system's essential support services. As variable resources increase, system planners must ensure the future generation and transmission system can maintain essential services that are needed for reliability.

A large penetration of VERs will also require maintaining a sufficient amount of reactive support and ramping capability. More frequent ramping needed to provide this capability could increase cycling on conventional generation. This could contribute to increased maintenance hours or higher forced outage rates, potentially increasing operating reserve requirements. While storage technologies may help support ramping needs, successful large-scale storage solutions have not yet been commercialized. Nevertheless, storage technologies support the reliability challenges that may be experienced when there is a large penetration of VERs, and their development should be expedited.

Based on industry studies and prior NERC assessments,[30] as the penetration of variable generation increases, maintaining system reliability can become more challenging. Additional assessments, including interconnection-wide studies, will be needed as the resource plans unfold to better understand the impacts.

If the states fall short of meeting the renewable energy targets established by the EPA, more CO_2 reductions from other measures may be required than were estimated by the EPA. These measures include more coal unit retirements, expanded natural gas-fired generation plants, or energy efficiency deployment.

The CPP proposes reductions in CO_2 emissions by investing in zero-CO_2-emitting energy sources (i.e., nuclear and non-hydro renewable generation). However, increased reliance on VERs creates reliability challenges that take considerable time to implement and require substantial changes in BPS planning and operations. Most notably, the challenges with this Building Block are:

- The CPP analysis relies on resource projections that may overestimate reasonably achievable expansion levels and exceed NERC and industry plans and do not fully reflect the reliability consequences of renewable resources.
- Increased reliance on VERs can significantly impact reliability operations and requires more transmission and adequate ERSs to maintain reliability.
- With a greater reliance on VERs, transmission and related infrastructure expansion lead times may not align with the CPP implementation timeline.

[29] See NERC's Essential Reliability Services Task Force website for more information: http://www.nerc.com/comm/Other/Pages/Essential-Reliability-Services-Task-Force-(ERSTF).aspx

[30] NERC-CAISO Joint Report, Maintaining Bulk Power System Reliability While Integrating Variable Energy Resources – CAISO Approach; other industry reports include those developed by the Integration of Variable Generation Task Force (IVGTF); Integrating Variable Renewable Energy in Electric Power Markets: Best Practices from International Experience (Appendix D).

Building Block 4 – Energy Efficiency

Electricity savings from enhanced energy efficiency measures are assumed as a major reduction in U.S. power generation requirements and thereby lower U.S. power industry CO_2 emissions. In calculating individual state CO_2 emission rate limits, the EPA assumes that existing state energy efficiency programs can be significantly expanded to achieve 108 TWh in cumulative savings in 2020, continue to grow to 283 TWh by 2025, and reach 380 TWh by 2030.[31] The EPA's estimated future energy efficiency program performance will have significant effects on state compliance measures and costs.

Review of EPA Assumptions and Potential Reliability Impacts

In its *Regulatory Impact Assessment*, the EPA assumes that energy efficiency will grow faster than electricity demand, with total electricity demand shrinking beyond 2020. The implications of this assumption are complex. If such energy efficiency growth cannot be attained, more carbon reduction measures would be required, primarily from reduced coal generation in most states. More low-emitting or new NGCC/CT generating capacity (not regulated under the CPP) would need to be built. Construction of new replacement capacity, as well as related infrastructure, would take time to plan, permit, finance, and build. If these needs are not identified at an early enough stage, either grid reliability or state CO_2 emission goals could be compromised.

The EPA relied on 12 state studies to set its expanded annual program target savings improvement rate at 1.5 percent per year. However, the EPA appears to overestimate most states' energy efficiency savings potential versus prior energy efficiency projections, resulting in setting performance targets too high for individual states.[32] Savings potentials are highly state specific in their consumer mix, credit for measures already taken, and levels of subsidies provided. The EPA applies one national energy efficiency growth factor to all state situations and does not consider energy efficiency program performance or cost. The discrepancies are subsequently compounded by extrapolating these annual energy efficiency performance targets as incremental improvements that can be sustained through 2030—beyond the 12 studies evaluated.

Out of 12 studies, 11 contain multiple scenarios with different sets of assumptions to demonstrate wide ranges of what is achievable under alternative financial, technological, and behavioral environments. There is no documentation on how each study's respective average annual improvement rate was calculated, which was used as the foundation to calculate the incremental performance improvement target of 1.5 percent per year.

The assumed base year is of critical importance when comparing multiple studies' achievable potential for energy efficiency. When drawing comparisons between percentages, the baseline level of electricity demand must be the same; otherwise, the total amount of energy avoided due to energy efficiency measures would be different. Under the CPP, all energy efficiency savings are applied to Business As Usual (BAU) sales forecasts generated from EIA-861 data.[33] Base years used in the 12 studies range from as early as 2007 to as recently as 2013 and are not consistent throughout the sample.[34] Comparing achievable energy efficiency potential percentages is therefore difficult, since BAU electricity demand levels are inconsistent between the studies.

Study length is another important assumption regarding the sustainability of achievable savings. It is uncertain whether the level of annual energy efficiency savings could be sustained after the expiration of the program, as the most cost-effective and impactful measures would have been utilized already—leaving only increasingly expensive incremental energy efficiency measures. The cited studies vary significantly in length: from as few as four years, to as many as 21 years.

The CPP assumes that dividing cumulative potential by the study length provides an adequate estimation for an average annual achievable potential that is sustainable over a much longer (13-year) period (2017–2030). However, there is a discrepancy in the longitudinal application of cross-sectional studies.

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[31] EE savings estimates calculated using EPA's methodology, EE savings %, BAU sales estimates. Source: *GHG Abatement Measures* (EPA June 2014) (EPA-HQ-OAR-2013-0602) Chapter 5.
[32] Electric Power Research Institute (EPRI) and EIA.
[33] *Annual Electric Power Industry Report* (EIA 2012) (EIA 861 Data).
[34] *GHG Abatement Measures* (EPA June 2014) (EPA-HQ-OAR-2013-0602) pg. 5-65.

The CPP assumes an average life of 10 years for energy efficiency measures. This average does not fully capture the unique distribution of the length of measures when analyzing regionally available energy efficiency measures. Key assumptions when determining energy efficiency potential are "breadth of sectors and end uses considered, study period, discount rate, pattern of technology penetration, whether economically justified early replacement of technologies is allowed for, whether continued improvement in efficiency technology is provided for,"[35] yet the EPA applies a broad average rather than determining individual measure life curves. Most of the source studies perform bottom-up approaches and evaluate thousands of permutations of measures, building types, climate zones, market penetration factors, and measure lives to determine which energy efficiency technologies to include and exclude. By approximating thousands of measure lives using one average, the CPP does not capture measure life disparities and possibly underestimates the amount of energy efficiency savings that expire throughout the compliance period.

While the studies on energy efficiency consider different potentials for the three main sectors (residential, commercial, and industrial), the CPP uses one number across all sectors in its emission rate calculation. Industrial processes are designed to use as little energy as possible in order to maximize profits of daily operations and may have already invested in energy efficiency programs, leaving minimal and costly opportunities remaining for incremental improvement. Applying the same energy efficiency potential percentage for all three sectors indirectly provides incentives for industrial utility customers to reduce their energy load proportional to residential customers, but by a much greater magnitude per capita.

The underlying state and regional studies used as the base for calculating the 1.5 percent potential include the full range of financial incentives from 25 to 100 percent, when considering base, low, and high cases. Since the EPA uses an averaging method in translating from the observed studies' sector and scenario findings to the final average annual projected potential, it is difficult to evaluate the financial incentives that are assumed in both the Building Block calculations and study results.

The EPA used the EIA's AEO 2013 baseline forecast to estimate its BAU electricity sales forecast. Growth rates calculated by the National Energy Modeling System (NEMS) region were applied to state-level 2012 retail sales from the EIA-861 survey to arrive at an annual BAU sales forecast. These growth figures include the net effect of implicit forms of energy efficiency, as that information is not explicitly presented in AEO 2013 reference case. Because the EIA does not explicitly model energy efficiency as a forecast line item, the retail sales growth is skewed for the purposes of calculating the energy efficiency Building Block.

The EIA presents some metrics to gauge energy efficiency in the AEO 2013 model results. Energy intensity, defined as energy use per dollar of GDP, represents the aggregate effects of energy consumption trends and a rising national output. Electricity energy intensity, in particular, has been on a steady decline in both consumption per dollar of GDP and consumption per capita. This is due in large part to energy efficiency, but its contribution is difficult to isolate. The EIA's AEO 2013 energy load growth projections include implicit forms of energy efficiency measures, and the proposed CPP does not appear to account for these savings. This effectively double counts the savings of some energy efficiency measures and results in state-specific energy efficiency targets that are too high to be considered reasonably achievable.

With potentially overstated expectations for energy efficiency savings, the EPA's demand forecast results in a decline in electricity use between 2020 and 2030. While other major power market forecasters' electricity sales compounded annual growth rates (CAGRs) for the period between 2020 and 2030 are strictly positive (AEO 2013: 0.7 percent, EPRI: (achievable potential) 0.4 percent, NERC average of assessment studies: 1.5 percent), the EPA assumes a CAGR of -0.2 percent for the same time period. Between 2020 and 2030, the EPA assumes incremental year-over-year reductions from energy efficiency to be almost 41 TWh nationally on average, outpacing year-over-year national electricity sales growth of 31.6 TWh, on average.

The main reason for this result is the EPA's assumption of states being able to sustain an annual incremental growth rate in energy efficiency savings of 1.5 percent once achieved. As mentioned above, this sustainability is not supported by any peer-reviewed or technical studies of energy efficiency potential.

[35] *GHG Abatement Measures* (EPA June 2014) (EPA-HQ-OAR-2013-0602) pg. 5-22.

By overestimating efficiency savings resulting in declining electricity retail sales, the results of the EPA's entire *Regulatory Impact Assessment* are concerning from a reliability perspective and have implications to electric transmission and generation infrastructure. Underlying electricity demand forecasts directly influence the required level of generation—and hence, CO_2 emissions—from existing and affected generating units under the CPP. They also affect the required new construction of generating units that are needed to meet expected electricity demand, which is projected to increase during the next 10 years.[36]

The EPA projection for energy efficiency growth at a 1.5 percent annual increase is substantially greater compared to what NERC examined in its current and prior long-term reliability assessments (LTRAs). NERC collects energy efficiency program data that is embedded in the load forecast for each LTRA assessment area. Projected annual energy efficiency growth as a portion of Total Internal Demand since 2011 has ranged from only 0.12 to 0.15 percent, as shown in the table below.

Table 1. 2011–2014 LTRA Energy Efficiency Growth

LTRA	10-Year Growth of EE (%)	Portion of Total Internal Demand (%)		Annual Growth in Relation to Total Internal Demand (%)
		Year 1	Year 10	
2011	10.7	0.59	1.63	0.12
2012	12.2	0.72	1.88	0.13
2013	11.6	0.92	2.02	0.12
2014	15.4	0.87	2.25	0.15

In summary, the CPP assumes energy efficiency gains outpace electricity demand growth through the compliance period. However, this assumption does not reasonably reflect energy efficiency achievability and is a departure from normalized forecasts. If states are unable to achieve the EPA target savings, additional CO_2 reduction measures beyond BSER measures would be needed to meet the proposed rate limits—primarily through further reductions in existing generation or expansion of natural gas and VERs. The energy efficiency assumptions underpin the CPP proposal and present the following reliability issues:

- The EPA appears to overestimate the amount of energy efficiency expected to reduce electricity demand over the compliance time frame. The results of overestimation have implications to electric transmission and generation infrastructure needs.
- Substantial increases in energy efficiency programs exceed recent trends and projections. Several sources, including but not limited to NERC, EIA, EPRI, and various utilities, have published reports, analysis, and forecasts for energy efficiency that do not align with the CPP's assumed declining demand trend.
- The CPP assumption appears to underestimate costs and may underestimate the capital investments that would be required by utilities to sustain energy efficiency performance through 2030.
- The offsetting requirements in more coal retirements, along with expansions in natural gas and VERs, in a constrained time period could potentially result in reliability or ERS constraints.

[36] *NERC 2014 Long-Term Reliability Assessment.*

Reliability Impacts Potentially Resulting from the CPP

To meet the proposed CPP emission reduction levels, the states are expected to select the mass based limitation approach over the emission rate approach due to its greater flexibility, as well as ease to enforce and implement. The power industry has been successful in complying with prior mass-based emission cap and trade programs (e.g., Acid Rain program, Clean Air Interstate Rule, and RGGI) without creating reliability impacts. The CPP introduces potential reliability concerns that are more impactful than prior environmental compliance programs due to the extensive impact to fossil-fired generation. Additionally, there is potential for an accelerated decision-making period for the implementation of the CPP's Building Blocks. It is also important to consider the ongoing transformation to the resource mix and corresponding impacts on ERSs required to maintain a reliable BPS. State-specific carbon intensity targets create potential reliability concerns in two major areas: (1) direct impacts to resource adequacy and electric infrastructure, and (2) impacts resulting from the changing resource mix that occur as a result of replacing retiring generation, accommodating operating characteristics of new generation, integrating new technologies, and imposing greater uncertainty in demand forecasts.

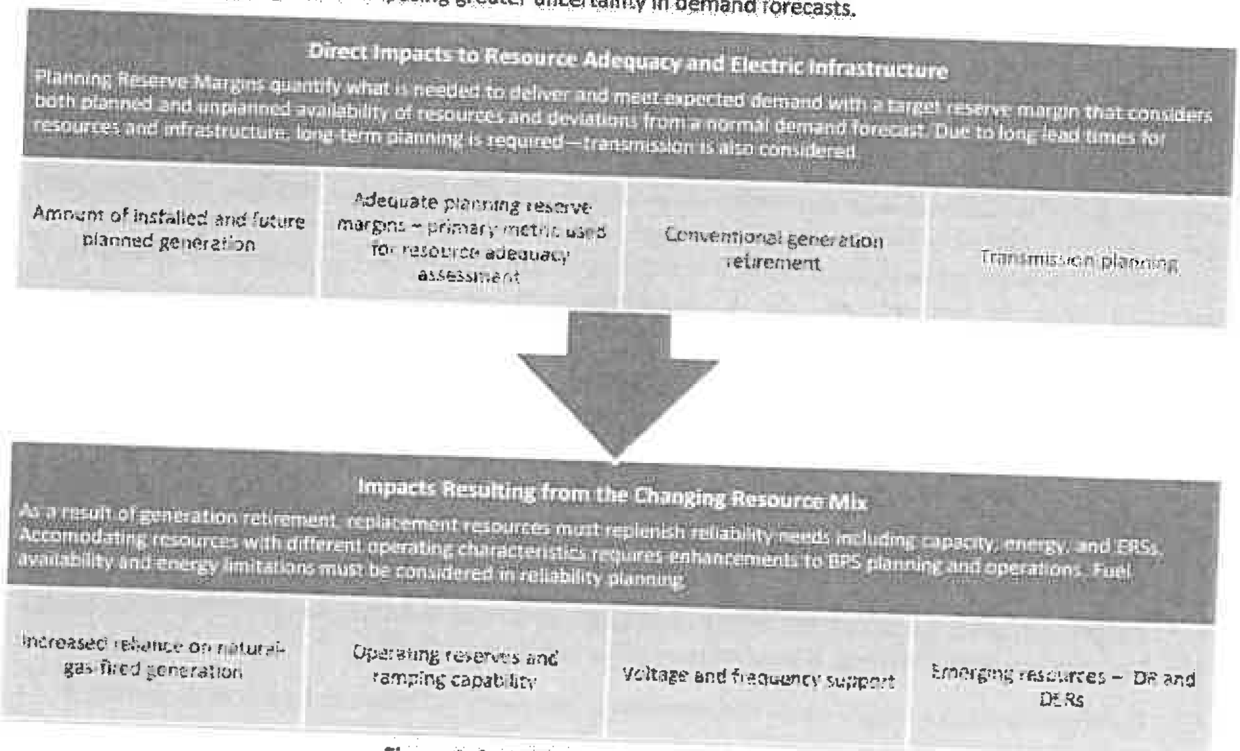


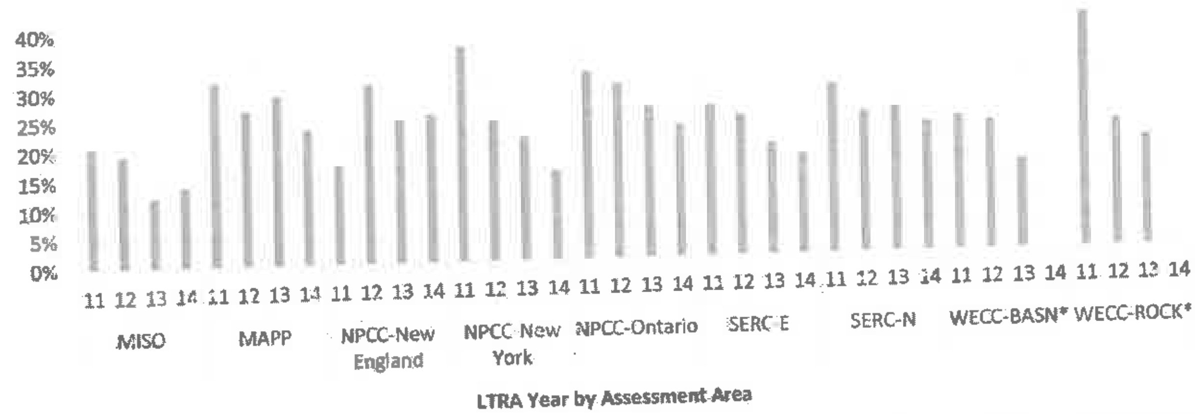
Figure 4. Summarized Reliability Challenges

Most importantly, generation (along with other system resources) and transmission must provide specific capabilities to ensure the BPS can operate securely under a myriad of potential operating conditions and contingencies, in compliance with a wide range of NERC planning and operating Reliability Standards. The above challenges warrant further consideration by policy makers. The following sections discuss these key reliability challenges in detail.

Direct Impacts to Resource Adequacy and Electric Infrastructure

Fossil-Fired Retirements Result in Accelerated Declines of Reserve Margins

In recent long-term assessments, NERC has highlighted resource adequacy concerns, particularly in ERCOT, NPCC-New York, and MISO, as projections continue to reflect declining reserve margins that fall below each area's Reference Margin Level over the next five years, despite low demand growth rate (Figure 5). As most LTRA assessment areas attribute stagnant demand growth to the ongoing projected economic indicators (typically based on either employment levels or GDP) in the residential, commercial, and industrial sectors, total capacity additions have paralleled the ongoing declines in load growth. The trend of declining margins in a number of NERC assessment areas is rooted primarily from a general reduction in 10-year capacity additions observed over the past several years. Total capacity additions continue to fall behind the ongoing declines in load growth rates (Figure 6).[37]



*Due to changes to the WECC subregional boundaries, resulting in four subregions instead of nine, the 2014 Anticipated Reserve Margins are not shown for WECC-BASN and WECC-ROCK for this comparison.

Figure 5. Short-Term (Year 2 Forecast) Anticipated Reserve Margins Show Declining Trends for Some Assessment Areas

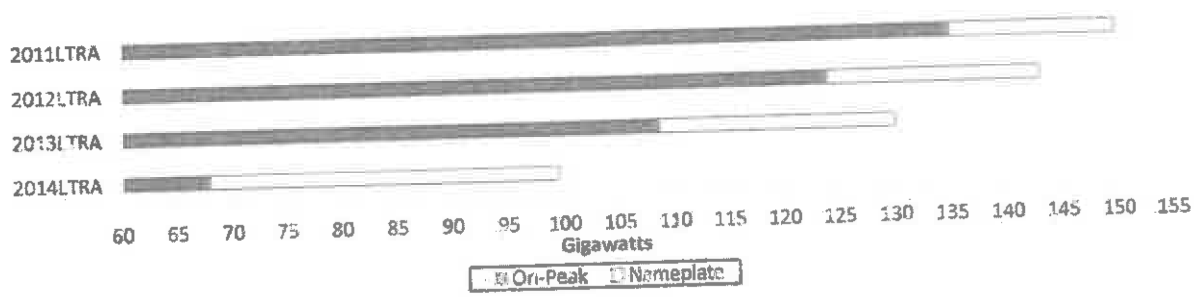


Figure 6. NERC-Wide 10-Year Projected Capacity Additions Declining Since 2011

The EPA's supporting documents estimate that up to 19 percent of the nation's coal plants will become "uneconomical" as a result of the proposed CPP. Although the CPP may not become enforceable until 2020, its effect may overshadow and change large retrofit capital decisions needed to comply with earlier EPA regulations—primarily MATS.

According to the EPA, the state implementation would result in a reduction in coal to 193 GW by 2025. The EPA finalized MATS, which is factored into *2014 LTRA* and identifies capacity retirements through 2016. In its *Technical Support Document – Resource Adequacy and Reliability Analysis*, the EPA used the Integrated Planning Model (IPM) to project likely future electricity market conditions with and without the proposed CPP. The IPM assumed that adequate transmission capacity exists to deliver any resources located in, or transferred to, the individual regions. Additionally, since most regions currently have capacity above their target reserve margins, the EPA assumed most of the retirements are absorbed by a reduction in excess reserves over time. However, uncertainty remains for a large amount of existing conventional generation that may be vulnerable to retirement resulting from additional pending EPA regulations. These retirements reduce reserve margins over the course of the CPP implementation.[38]

[37] 2011, 2012, and 2013LTRA data includes Future-Planned capacity additions [illegible]
[38] EPA Technical Support Document –Resource Adequacy and Reliability Analysis [illegible]

The EPA's analysis assumes the electric system will maintain resource adequacy, even with the ongoing retirements from existing regulations, including MATS. In addition, because the proposed CPP will require the development of significant amounts of new generation in a short period, additional time for infrastructure development will be needed to support these new resources. The EPA's modeling of a potential implementation scenario predicts an additional 40–48 GW of fossil-fired EGU retirements, and the addition of 21 GW of new NGCC resources.

With existing environmental regulations, the EPA's base case projections indicate that total coal-fired capacity will decline rapidly from 309.6 GW in 2013 to just 245 GW by 2016, and 243 GW by 2025. The EPA's base case—without implementation of the proposed CPP—assumes a significant reduction in coal-fired capacity by 2016: 27.2 GW beyond what is currently projected in the *2014LTRA* reference case. According to the *2014LTRA* reference case, an additional 44.2 GW of fossil-fired and nuclear capacity is projected to retire between 2014 and 2024.[39] These projections are based on the assumption that current environmental regulations will remain and do not account for potential impacts from the proposed CPP (**Figure 7**).

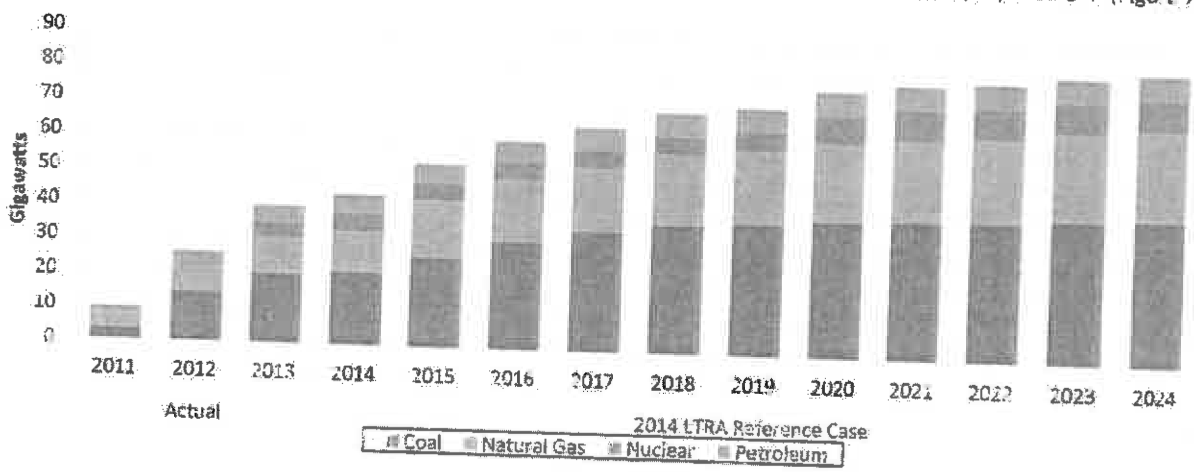


Figure 7. Cumulative Fossil-Fuel and Nuclear Retirements between 2011 and 2024 Total 83 GW

According to the EPA, the state implementation of Option 1 would result in a reduction in coal to 193 GW by 2025. Option 1 and the *2014LTRA* reference case are shown in **Figure 8** and **Table 2**.[40]

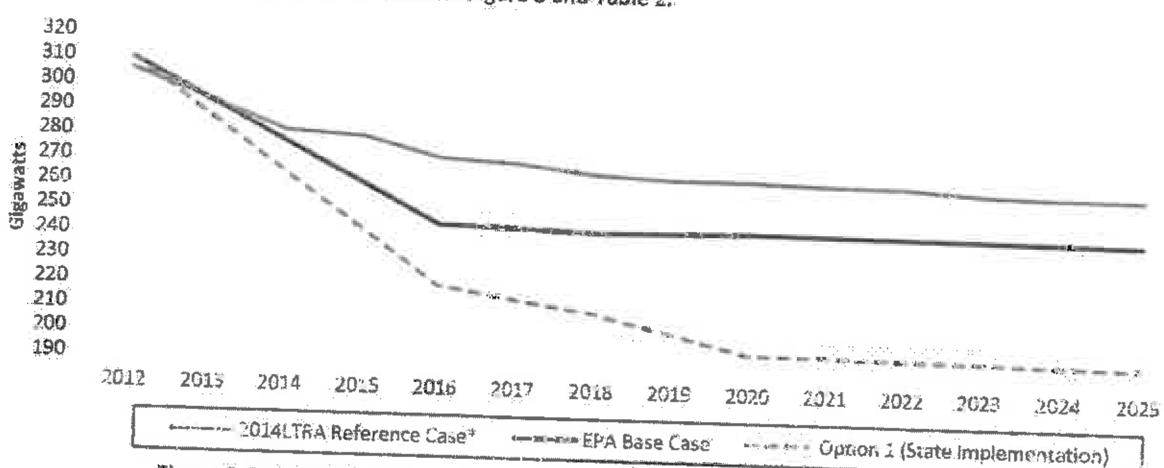


Figure 8. 2014LTRA Reference Case & EPA Power Plan Assumptions: Coal-Fired Capacity

[39] While the assessment period for the *2014LTRA* is 2015–2024, projected retirements for 2014 are included in NERC's *2014LTRA* analysis.

[40] *Regulatory Impacts Analysis for the Proposed Carbon Pollution Guidelines for Existing Power Plants and Emission Standards for Modified and Reconstructed Power Plants* (June 2014) and supporting IPM Model documentation and data.

Table 2. 2014LTRA Reference Case & EPA Power Plan Assumptions

NERC 2014LTRA Reference Case - Total On-Peak Capacity (GW)	2016	2018	2020	2025*
Total Coal (Existing-Certain and Tier 1 Capacity Additions)	271.8	266.4	264.9	261.3
EPA Analysis of the Proposed Clean Power Plan - Total Coal Generating Capacity (GW)	2016	2018	2020	2025
Base Case	244.6	243.3	243.6	243.3
Option 1 (State Implementation)	219.7	210.4	195.1	193.1
EPA Assumed Coal Reduction Beyond NERC 2014LTRA Reference Case (GW)	2016	2018	2020	2025
Base Case	27.2	23.1	21.3	18.0
Option 1 (State Implementation)	52.1	56.0	69.8	68.2

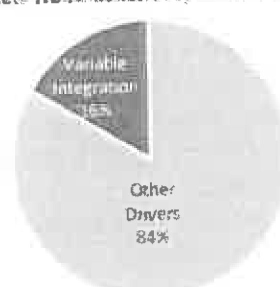
Transmission Planning and Timing Constraints

Long lead times for transmission development and construction require long-term system planning—typically a 10–15-year outlook. In addition to designing, engineering, and contracting transmission lines, siting, permitting, and various federal, state, provincial, and municipal approvals often take much longer than five years to complete. The CPP analysis assumes that adequate transmission capacity is available to deliver any resources located in, or transferred to, the region.[41] Given the significant changes and locations anticipated to occur in the resource mix, it is likely that additional new transmission, or transmission enhancements, will be necessary in some areas. New transmission lines will be required to transport the amount of renewable generation coming online, particularly in remote areas, and that creates additional timing considerations. Further, as replacement generation is constructed, new transmission may be needed to interconnect new generation. Mitigating transmission constraints identified from the proposed EPA regulations in a timely way, consistent with CPP targets, presents a potential reliability concern. Construction of new interstate high-voltage lines would require transmission owners to confer to state and federal laws with respect to environment impacts, siting, and permitting. A construction timeline for a new high-voltage line can range from 5 to 15 years depending on the voltage class, location, and availability of highly skilled construction crews. The construction of transmission assets is a very lengthy process starting from planning to the actual physical construction. It is recommended that any policies that could potentially impact the reliable operation of the transmission system also consider the associated timeline for implementing plans.

Transmission Considerations with Additional VERs

The projected 30.8 GW of additional wind and solar resources will require additional transmission to reliably integrate these resources. VERs are often built in parts of North America that are distant from the point of interconnection to the transmission system. In many cases, the location of these variable resources only meets the minimum voltage support requirements. According to the 2014LTRA Reference Case, 16 percent of new transmission projects (under construction, planned, or conceptual) identify variable resource integration as a primary driver.

New Transmission Project Drivers



The location of additional transmission resources will be informed by the outcome of the transmission planning studies. The transmission planning process will not be able to fully incorporate the impacts of potential retirements until those resource addition requirements are made known to the system operator. For ISO/RTOs, this will likely not happen until the final state plans are developed.

To support variable generating capacity increases, the power industry would need to invest heavily to expand transmission capacity to access more remote areas with high-quality wind resources. Developing a resource mix that has sufficient ERSs to support integration and reliable BPS operation is also a consideration. Given the natural wind variability in these locations, incremental wind project resources would have relatively low capacity factors (20–35 percent) that would require complex financial decisions to support transmission capacity.

[41] *Regulatory Impacts Analysis for the Proposed Carbon Pollution Guidelines for Existing Power Plants and Emission Standards for Modified and Reconstructed Power Plants* (June 2014) and supporting [illegible] documentation and data.

NERC anticipates that after the CPP guidelines are finalized in 2015, and SIPs are developed and approved by the EPA in 2016/2017, entities will work with their state utility commissions or other appropriate governing entities to assess resource and system options. Extensive transmission reliability screening assessments will be performed to support these decisions and will include comprehensive local and regional reliability analyses, which must be coordinated with states and neighboring entities. As resource decisions are made, reliability screening will transition into the established NERC reliability assessment processes. Consistent with the NERC Reliability Standards, transmission enhancements to address reliability constraints will be identified, incorporated into transmission expansion plans, and coordinated with other projects locally and regionally. Because committed transmission projects typically require three to five years to be completed, and often longer for major projects with significant right-of-way needs, NERC is concerned that reliability-related enhancements may not be able to be completed for a 2020 implementation.

Initial Regional Reliability Assessment of the Proposed CPP

Some regions started an initial reliability assessment of the proposed CPP focused on their respective footprints to better understand the plan's potential impacts. The initial analyses are slightly different in focus and are in varying stages of development. The key findings from recent MISO and SPP studies are provided below.

MISO

MISO focused primarily on generation capacity impacts. MISO, which is based on a 14.8 percent reserve margin requirement determined by the 1-day-in-10-year loss-of-load event, projects that in in 2016 it will operate at the reliability level of approximately 3-days-in-10-year loss-of-load event, increasing the likelihood that resources will not be sufficient to serve peak demand. The number of expected days per year of a loss-of-load event is projected to increase throughout the assessment period. The proposed CPP could further exacerbate resource adequacy concerns in the MISO footprint unless additional replacement capacity is built in a timely fashion.[42] Additionally, the analysis showed that the EPA's carbon proposal could put an additional 14,000 MW of coal capacity at risk of retirement. This amount is beyond the 12,600 MW within MISO's footprint that is slated to retire by the end of 2016 to comply with MATS.[43] The contributing factors driving the projected deficit include:

- Increased retirements and suspensions (temporary mothballing) due to EPA regulations and market forces and low natural gas prices
- Exclusion of low-certainty resources that were identified in the resource adequacy survey
- Exclusion of surplus of capacity in MISO South above the 1,000 MW transfer from the Planning Reserve Margin requirement (PRMR)[44]
- Increased exports to PJM and the removal of non-Firm imports[45]
- Inadequate Tier 1 capacity additions[46]

[42] Anticipated Reserve Margin includes operable capacity expected to be available to serve load during the peak hours with firm transmission. Prospective Reserve Margin operable capacity that could be available to serve load during the peak hour, but lacks Firm transmission and could be unavailable for a number of reasons

[43] MISO EPA Regulation Impact Analysis – Initial Study Results

[44] For this assessment, 1,000 MW of capacity is transferred from the MISO South to the MISO North/Central Region pending the outcome of regulatory issues currently under FERC review.

[45] Capacity sales (imports and exports) in MISO depend on decisions of the respective resource owners, assuming that the tariff requirements are met (including planning of necessary transmission of both the buying and selling areas). Regarding the removal of non-Firm imports, the MISO market monitor double-counted non-firm imports in the 2013LTRA reference case. These imports are accounted for in the Reference Margin Level (PRMR).

[46] In the MISO footprint, 91 percent of the load is served by utilities with an obligation to serve customers reliably and at a reasonable cost. Resource planning and investment in resources are part of state and locally jurisdictional integrated resource plans that only become certain upon the receipt of a Certificate of Public Convenience and Necessity (CPCN).

SPP

SPP looked at both generation capacity and transmission reliability impacts of the proposed CPP.[47] The initial study indicated that compliance with the carbon regulations, if implemented as modeled by the EPA, will not be possible without significant investment in new generation and associated major improvements to both the electric transmission and natural gas infrastructure to accommodate new generation. The results indicate that by 2020, SPP's anticipated reserve margin would be 5 percent, representing a capacity margin deficit of approximately 4,500 MW. By 2024, 10,000 MW beyond current plans would be needed to maintain their reserve margin. Given the 8- to 10-year timeline needed to plan for and construct these additional resources, SPP has concluded that there is not sufficient time to achieve compliance with the EPA's interim goals, and that widespread reliability impacts are likely.

The reliability issues identified in the initial studies will require significant upgrades to the transmission infrastructure to maintain system reliability, accommodate new generation or, when new generation is not warranted, to support the dispatch of the system in a manner significantly different from historical operations. Other ISO/RTOs, states, and Regions should prepare for the potential impacts to grid reliability, especially related to the time required to plan and build transmission infrastructure.

Reliability Assurance

NERC Reliability Standards and Regional Entity criteria must be met at all times to ensure reliable operation and planning of the BPS. Therefore, NERC supports policies developed by the EPA, FERC, the DOE, and state utility regulators that include a "reliability assurance mechanism," such as a reliability back-stop, to preserve BPS reliability and manage emerging and impending risks to the BPS.

Many utilities and ISO/RTOs have discussed a possible reliability safety valve similar to the one-year compliance extension that has been used to avoid retirement-related reliability impacts from the MATS compliance deadline. A reliability safety valve will be of limited utility if the EPA's proposal is implemented as currently designed, and it appears the EPA has far more flexibility under Section 111(d) than was available under the Section 112 program. Accordingly, a set of reliability assurance provisions that may include a reliability backstop, as well as other measures, would be recommended to maintain BPS reliability.

Stakeholders expressed to NERC staff their concerns regarding the need for additional time to mitigate the impacts of the carbon regulation. The proposed timeline does not provide enough time to develop sufficient resources to ensure continued reliable operation of the electric grid by 2020. To attempt to do so would increase the use of controlled load shedding and potential for wide-scale, uncontrolled outages. Additionally, policy changes may be required to ensure the Planning Coordinators and Transmission Planners perform the necessary studies and exercise the authority to implement transmission and related infrastructure solutions and assure that ERSs are provided in a timely manner.

[47] SPP Reliability Assessment of EPA 111(d) Clean Power Plan Rule http://www.spp.org/publications/[illegible]

Direct Impacts to Resource Adequacy and Electric Infrastructure
Summary and Recommendations

Fossil-Fired Retirements and Accelerated Declines in Reserve Margins: Despite low demand growth, NERC has highlighted resource adequacy concerns as projections continue to reflect declining reserve margins that fall below the Reference Margin Level in three assessment areas within the next five years.

- *The Regions, ISO/RTOs, and states should perform further analysis to examine the potential resource adequacy concerns.*

Transmission Planning and Timing Constraints: The proposed CPP implementation is currently scheduled to begin in mid-2016. Some reliability impacts could be mitigated by the construction of new (or enhancement of existing) transmission facilities; however, long lead times (e.g., 10 years) are required for transmission planning and construction.

- *The EPA and states, along with industry, should consider the time required to integrate potential transmission enhancements and additions necessary to address impacts of the proposed CPP.*

Regional Reliability Assessment of the Proposed CPP: To better understand its potential impacts, some Regions have started an initial reliability assessment of the proposed CPP focused on their respective footprints. The initial analyses are slightly different in focus and are in varying stages of development.

- *Other ISO/RTOs, states, and Regions should prepare for the potential impacts to grid reliability, especially related to the time required to plan and build transmission infrastructure.*

Reliability Assurance: NERC Reliability Standards and Regional Entity criteria must be met at all times to ensure reliable operation and planning of the BPS.

- *The EPA, FERC, the DOE, and state utility regulators should employ the array of tools at their disposal and their regulatory authority to develop reliability assurance mechanisms such as a reliability back-stop. These mechanisms include timing adjustments and granting extensions where there is a demonstrated reliability need.*

Impacts Resulting from the Changing Resource Mix

Coal Retirements Increase Reliance on Natural Gas for Electric Power

The electricity sector's growing reliance on natural gas raises concerns regarding the electricity infrastructure's ability to maintain system reliability when facing a constrained natural gas capacity for delivering natural gas to electric power generators. These concerns are already being articulated in light of gas-electric dependency studies and analyses, and include ISO/RTOs, electricity market participants, industrial consumers, national and regional regulatory bodies, and other government officials.[48] The extent of these concerns varies from region to region; however, concerns are most acute in areas where power generators rely on interruptible pipeline transportation as the natural gas use for generation rapidly grows.

Under the CPP, an accelerated shift in the power generation mix from coal to natural gas is expected to ensue. The EPA's state limitation calculations assume a 440 TWh/year shift to existing NGCC generation from coal (376 TWh/year) and older oil-gas steam (64 TWh/year) generators due to redispatched NGCC units up to a 70 percent capacity factor. In its *Regulatory Impact Assessment*, the EPA projects that the natural gas market portion of total U.S. power generation will grow from 29 percent energy in 2013 to 33–34 percent from 2020 to 2030. In an analysis of the CPP prepared by Energy Ventures Analysis (EVA), natural gas generation is found to increase by an additional 400–450 TWh/year and increase the gas generation energy market share to reach 35 percent in 2020, 39 percent in 2030, and 49 percent in 2040.[49]

As reliance increases more on natural gas for both baseload and on-peak capacity, it is important to also examine potential risks associated with reduced diversity and increased dependence on a single fuel type. Currently, natural-gas-fired resources account for large portions of both the total and on-peak resource mix in several assessment areas when considering both existing capacity and planned additions (Table 3).

Table 3. Assessment Areas with Natural-Gas-Fired Capacity Accounting for Over One-Third of Existing Nameplate Capacity[50]

	Nameplate Capacity (GW)		On-Peak Capacity (GW)		10-Year Nameplate Capacity Additions (GW)		
Assessment Area	Gas-Fired	Portion of Total	Gas-Fired	Portion of Total	Tier 1	Tier 2	Tier 3
FRCC	40.2	64%	33.9	63%	10.1	0.0	0.0
MISO	69.0	39%	58.7	41%	2.8	0.0	10.0
NPCC-New England	18.6	54%	13.3	43%	1.1	3.3	0.0
NPCC-New York	21.0	55%	14.2	40%	0.0	3.5	0.0
PJM	80.0	43%	56.5	32%	10.0	47.5	0.0
SERC-SE	31.2	47%	28.4	46%	0.0	0.0	2.6
SPP	32.3	40%	30.2	47%	1.1	0.7	5.7
TRE-ERCOT	48.4	54%	45.2	63%	4.9	21.5	0.0
WECC-CA/MX	47.7	61%	43.9	70%	5.5	6.2	0.9
WECC-RMRG	7.2	36%	6.2	41%	1.2	0.0	0.0
WECC-SRSG	19.5	47%	16.3	50%	0.6	1.0	3.0

With this shift toward more natural gas consumption in the power sector, the power industry will become increasingly vulnerable to natural gas supply and transportation risks. Extreme conditions, although rare, must be studied and integrated in planning to ensure a suitable generating fleet is available to support BPS reliability. While there are several plants with dual-fuel capability, the capability to switch to a secondary fuel can be limited during certain operating conditions.

Overdependence on a single fuel type increases the risk of common-mode or area-wide conditions and disruptions, especially during extreme weather events. Disruptions in natural gas transportation to power generators have prompted the gas and electric industries to seek an understanding of the reliability implications associated with increasing gas-fired generation. For example, adverse winter weather, such as that experienced during January 2014, provided signs of natural gas supply and deliverability risks.[51] This can be a local issue in areas where there is already a heavy concentration of natural gas generation.

[48] See NERC's Special Reliability Assessments on electric and gas interdependencies for more information and recommendations: [illegible] and [illegible].

[49] Energy Ventures Analysis: FUELCAST – The Long-Term Outlook 2014, October 2014.

[50] Tier 1, 2, and 3 Capacity Category Definitions are provided in the *2014 Long-Term Reliability Assessment*.

[51] NERC Polar Vortex Review Report [illegible]

While several gas pipeline construction projects are underway to increase gas deliverability, the CPP proposal accelerates the shift toward more natural gas generation and could create additional pipeline needs. The increased demand can be addressed with sufficient lead time (i.e., more than three years), which is needed to plan, collect contracts, permit, procure, and build new pipeline. To the extent that the CPP assumptions regarding natural-gas-fired capacity expansion and existing coal-fired generation retirements are achieved, the gas and electric sectors will lean more heavily on each other.

The Availability of Essential Reliability Services Is Strained by a Changing Resource Mix

The proposed CPP provides states and developers additional incentives to rapidly expand their non-hydro renewable capacity to displace existing coal generation. The state calculations assume that non-hydro renewable capacity could grow rapidly by 5 percent per year, from 218 TWh/year in 2012 to reach 523 TWh/year by 2030. This incremental renewable generation represents well over twice the energy currently supplied by VERs and would be dominated mostly by new wind, and to a lesser extent, new solar capacity.

In addition, wind projects will significantly increase the demand for reactive power and ramping flexibility. Ramping flexibility will increase cycling on conventional generation and often results in either increased maintenance hours or higher forced outage rates—in both cases, increased reserve requirements may result. While storage technologies may help support ramping needs, successful large-scale storage solutions have not yet been commercialized.[52] Storage technologies support the reliability challenges that may be experienced when there is a large penetration of VERs, and their development should be expedited.

Based on industry studies and prior NERC assessments,[53] as the penetration of variable generation increases, maintaining voltage stability can be more challenging. Additional studies will be needed to further understand potential challenges that may indirectly result from the proposed CPP. In its role of assessing reliability, NERC commissioned the Essential Reliability Services Task Force (ERSTF) with members from NERC's Planning Committee and Operating Committee to study, identify, and analyze the planning and operational changes that may impact BPS reliability. NERC, under the ERSTF work plan and activities, has issued an initial assessment of ERSs that identifies ERS reliability building blocks as a foundational approach for further assessment and studies.[54]

Increased Penetration of Distributed Energy Resources

The EPA projects that retail electricity prices will increase by \$1/MWh to \$18/MWh under the CPP[55] as a result of a combination of higher natural gas prices and the implementation of new carbon penalties on impacted fossil-fired generators.[56] As retail power prices increase, some existing customers may install DERs, when economically advantageous. Depending on the price advantage, the market penetration of DERs could be substantial, creating potential reliability impacts for grid operators that lack visibility and control of these resources. Given that DERs displace grid retail sales, DERs could become a larger grid capacity planning challenge since the grid will remain responsible for being the DER site's back-up power supplier. Reliability issues with large onsets of non-dispatchable resources have already created operational challenges in California, Hawaii, and Germany. Such experienced reliability challenges are:

- The loss of inertia and the loss of generating units used to control transient instability driven by the significant non-controllable generation and lack of sufficient attention to ERSs—Hawaii.

[52] Pumped storage offers fast and large ramping capabilities to the BPS; however, increases in this technology is not likely due to land restrictions, permitting limitations, and environmental opposition. Less than 1 GW of pumped storage capacity is projected over the next 10 years.

[53] NERC-CAISO Joint Report: Maintaining Bulk Power System Reliability While Integrating Variable Energy Resources – CAISO Approach; other industry reports include those developed by the Integration of Variable Generation Task Force (IVGTF): Integrating Variable Renewable Energy in Electric Power Markets: Best Practices from International Experience (Appendix D)

[54] NERC Essential Reliability Services Task Force - A Concept Paper on Essential Reliability Services that Characterize Bulk Power System Reliability http://www.nerc.com/comm/Other/essntlrlbltysrvcstskfrcDL/ERSTF_Draft_Concept_Paper_Sep_2014_Final.pdf

[55] *Regulatory Impact Analysis for the Proposed Carbon Pollution Guidelines for Existing Power Plants and Emission Standards for Modified and Reconstructed Power Plants* (June 2014) and supporting IPM Model documentation and data.

[56] According to EIA, closing coal plants will drive up natural gas prices by 150 percent over 2012 levels by 2040; this cost rise will cause electricity prices to jump seven percent by 2025 and 22 percent by 2040. Because natural gas prices are a key determinant of wholesale electricity prices, which in turn are a significant component of retail electricity prices. Accordingly, the cases with the highest delivered natural gas prices also show the highest retail electricity prices. 2014 Annual Energy Outlook.

- DERs only operate within frequency ranges that are in many cases close to nominal frequency and, therefore, frequency and voltage ride-through capabilities are needed—Germany.
- Increased wind and solar levels that mandate increased ramping, load-following, and regulation capability—this applies to both expected and unexpected net load changes. This flexibility will need to be accounted for in system planning studies to ensure system reliability—California.

Studies and Assessments Needed to Support Reliability

The following assessments are needed to form a complete reliability evaluation. Table 4 provides a list of the types of studies and analysis that must be done to demonstrate reliability, recognizing that the industry does not operate the grid without a thorough and complete analysis.

Table 4. Study and Assessment Types Needed for a Complete Reliability Evaluation

Local Reliability Assessments	Area/Regional Reliability Assessments
• Specific generator retirement studies • Specific generator interconnection studies • Specific generator operating parameters • Power flow (thermal, voltage) • Stability and voltage security • Offsite power for nuclear facilities	• Resource adequacy • Power flow (regional) • Stability and voltage security (regional) • Gas interdependencies; pipeline constraints • Operating reserves and ramping • System restoration/blackstart

Impacts Resulting from the Changing Resource Mix
Summary and Recommendations

Coal Retirements and the Increased Reliance on Natural Gas for Electric Power: As the industry relies more on natural-gas-fired capacity to meet electricity needs, close examination will be necessary to ensure risks have been fully identified and evaluated. Potential issues are most acute in areas where power generators rely on interruptible natural gas pipeline transportation.

- *Further coordinated planning processes between the electric and gas sectors will be needed to ensure a strong and integrated partnership. Coordinated planning processes should include considerations for pipeline expansion to meet the increased reliance on natural gas for electric generation—especially during the extreme weather events (e.g., polar vortex).*

The Changing Resource Mix and Maintaining Essential Reliability Services: The proposed CPP provides states and developers additional incentives to rapidly expand their non-hydro renewable capacity to displace existing coal generation. Resource adequacy assessments do not fully capture the ERSs needed to reliably operate the BPS and are generally limited to identifying supply and delivery risks.

- *ISO/RTOs, utilities, and Regions, with NERC oversight, should analyze the impacts to ERSs in order to maintain reliability. Additionally, system operators and ISO/RTOs need to develop appropriate processes, tools, and operating practices to adequately address operational changes on the system.*
- *NERC should perform grid-level performance expectations developed from a technology-neutral perspective to ensure ERS targets are met.*
- *The development of technologies (such as electricity storage) help support the reliability objectives of the BPS, and these technologies should be expedited to support variability and uncertainty on the BPS.*

Increased Penetration of Distributed Energy Resources: A potential risk in additional DERs is the temporary displacement of utility-provided service, which could create additional planning challenges, considering utilities must act as a secondary supplier of electricity.

- *ISO/RTOs and system planners and operators should consider the market penetration of DERs and potential reliability impacts due to the limited visibility and controllability of these resources.*

Conclusions

This report represents NERC's initial review of reliability concerns regarding the EPA's proposed Clean Power Plan (CPP) under Section 111(d) of the Clean Air Act. As the CPP is finalized and implemented, NERC will develop special reliability assessments in phases. This initial evaluation highlights the underlying CPP assumptions and identifies a range of potential reliability impacts of the CPP on the BPS. It is NERC's intention that this document be used as a platform by industry stakeholders and policy makers to discuss technically sound information about the potential reliability impacts of the proposed CPP.

The Building Block assumptions in the EPA's proposed CPP are critical to NERC's evaluation of the reliability impacts. NERC will provide independent assessments of the BPS under a wide range of conditions that reflect the implications of the proposed policy, varied resource mixes, and impacts to transmission and will share the results with the industry and states as they develop their implementation plans.

Recommendations

1. **NERC should continue to assess the reliability implications of the proposed CPP and provide independent evaluations to stakeholders and policy makers.**
   The NERC Board of Trustees endorsed a plan for the review and assessment of the reliability impacts of the EPA proposal at its August 2014 Board meeting. The NERC Planning Committee should lead NERC and industry efforts in conducting the reliability assessments and scenario analyses as identified in this report. NERC will work through its stakeholder process to solicit industry input on assessment approaches and assumptions as further special assessments and evaluations are developed.

2. **Coordinated regional and multi-regional industry planning and analysis groups should immediately begin detailed system evaluations to identify areas of concern and work in partnership with policy makers to ensure there is clear understanding of the complex interdependencies resulting from the rule's implementation.**
   Given the potential reliability concerns of the EPA's 2020 proposed implementation date, NERC encourages the states to begin operational and planning scenario studies, including resource adequacy, transmission adequacy, and dynamic stability, to assess economic and reliability impacts. A number of studies and analyses must be performed to demonstrate reliability, and industry must closely coordinate with the states to ensure the SIPs are aligned with what is technically achievable within the known time constraints. Additionally, industry should review system flexibility and reliability needs while achieving the EPA's emission reduction goals. As a result, states that largely rely on fossil-fuel resources might need to make significant changes to their power systems to meet the EPA's target for carbon reductions while maintaining system reliability.

3. **If the environmental goals are to be achieved, policy makers and the EPA should consider a more timely approach that addresses BPS reliability concerns and infrastructure deployments.**
   NERC Reliability Standards and Regional Entity criteria must be met at all times to ensure reliable operation and planning of the BPS. Based on NERC's initial review, more time would be needed in certain areas to ensure resource adequacy, reliability requirements, and infrastructure needs are maintained. The EPA, FERC, the DOE, and state utility regulators should consider their regulatory authority to make timing adjustments and to grant extensions to preserve BPS reliability. NERC supports policies that include a reliability assurance mechanism to manage emerging and impending risks to the BPS, and urges policy makers and the EPA to ensure that a flexible and effective reliability assurance mechanism is included in the rule's implementation.

Appendix DD:

AEP: Transmission Challenges with the EPA Clean Power Plan

AEP AMERICAN ELECTRIC POWER

Transmission Challenges with the EPA Clean Power Plan

American Electric Power

November 2014

Transmission Reliability Concerns

AEP AMERICAN ELECTRIC POWER

❑ Keeping the lights on is job #1

- Grid operation in violation of thermal, voltage, and stability limits places the system at risk for collapsing voltages, cascading outages and ultimately blackouts

❑ Retirement of base-load coal units at key locations can cause:

- Significant changes in power flow magnitude and direction compared with historical operation, leading to thermal overloads
- Reactive power deficiencies that lead to voltage collapse
- Loss of spinning reserves, dynamic voltage regulation and frequency control
- Loss of black start capabilities

AEP Reliability Analysis of PJM

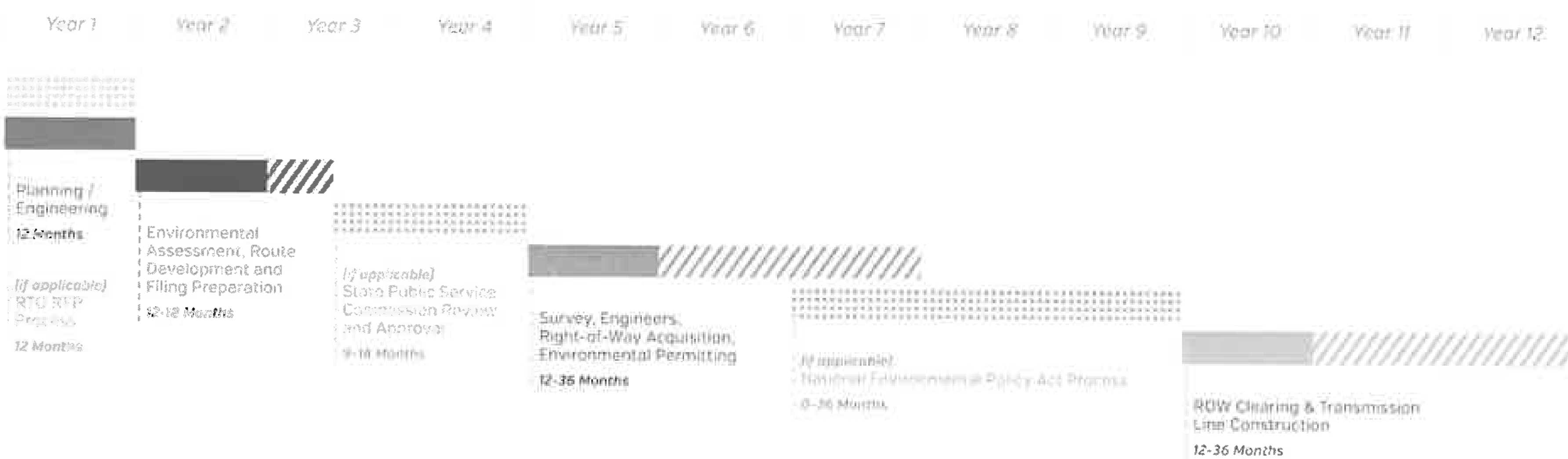
AEP AMERICAN ELECTRIC POWER

- **PJM is a regional transmission organization (RTO) operating in all or parts of 13 states and the District of Columbia**
  - Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and the District of Columbia
- **AEP's preliminary analysis identified severe, widespread reliability concerns across the region for each scenario studied**
  - In several instances, the software models could not solve suggesting voltage collapse leading to cascading outages
- **Study results are likely to be conservative**
  - Assumes all PJM queued generation would be constructed, with nearly all gas generation located in the east
  - Does not consider the significant renewable generation that may be necessary for compliance
  - Broad, interregional impacts not yet assessed (MISO, TVA, Duke Carolinas and NYISO will impact PJM region)
- **Constraints on the AEP system alone would require between \$1B and \$2B to resolve**

	Projected Retirements Modeled	
	PJM RTO Only	PJM States (incl. MISO)
Scheduled Unit Retirements	14,036	21,372
111(d) - Projected Retirements	8,600	16,300
Total Capacity Retired	22,636	37,672
	Replacement Capacity Modeled	
Capacity Additions (Gas, Wind)	8,300	15,700

Incompatible Timelines

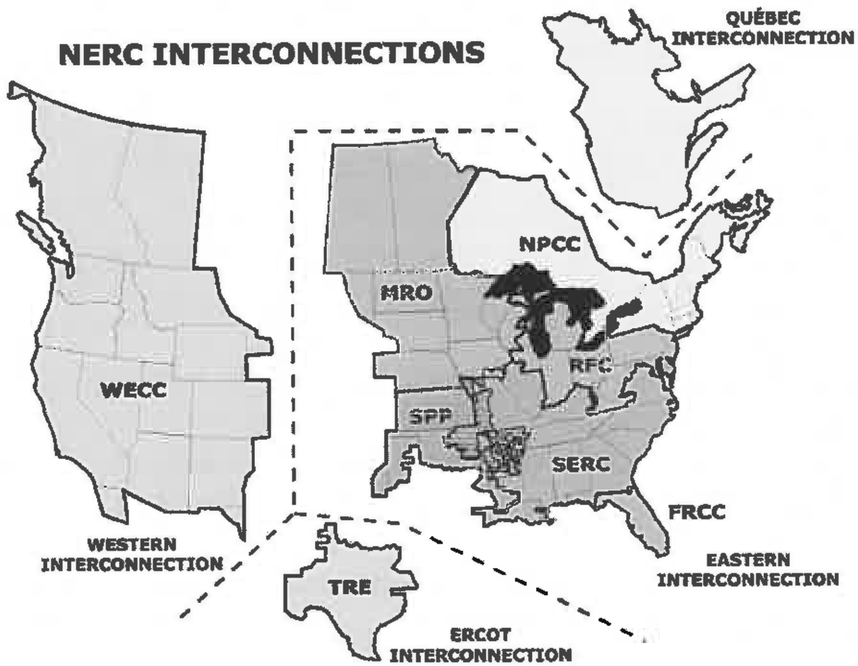
SAMPLE EXTRA HIGH VOLTAGE **TRANSMISSION LINE PROJECT SCHEDULE**



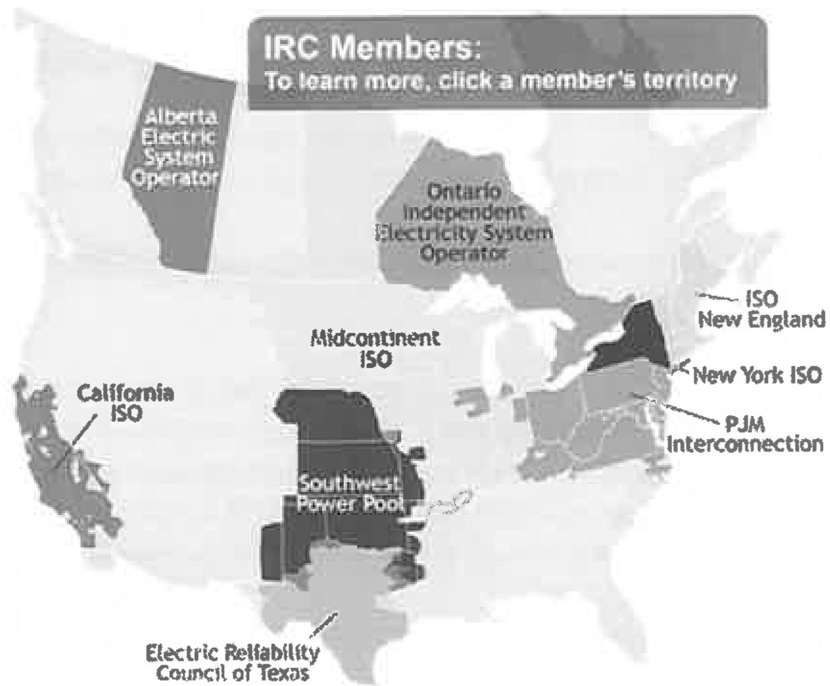
- **CPP compliance time lines do not consider transmission mitigation requirements**
  - Transmission project lifecycle can vary significantly depending upon the type of project and geographic location
  - Nature of the project (for example, its voltage and length), trigger different regulatory processes in different areas
  - Environmental issues, necessary permits and crossing public lands widely affect the process

The Interconnected Grid

Synchronous Interconnections



RTOs / ISOs



Due to the highly interconnected nature of the Transmission system, it must be planned on a regional / interregional basis.

Industry Agreement

AEP AMERICAN ELECTRIC POWER

North American Electric Reliability Corporation (NERC)

- "The anticipated changes in the resource mix and new dispatching protocols will require comprehensive reliability assessments to identify changes in power flows and ERSs. ERSs are the key services and characteristics that comprise the following basic reliability services needed to maintain BPS reliability: (1) load and resource balance; (2) voltage support; and (3) frequency support."
- "Coordinated regional and multi-regional industry planning and analysis groups should immediately begin detailed system evaluations to identify areas of concern and work in partnership with policy makers to ensure there is clear understanding of the complex interdependencies resulting from the rule's implementation."
- "If the environmental goals are to be achieved, policy makers and the EPA should consider a more timely approach that addresses BPS reliability concerns and infrastructure deployments."

Southwest Power Pool (SPP)

- "The EPA's interim goals are very close to its final goals, which means significant measures have to be taken very early in the compliance period."
- "If the CPP compliance period begins before generation and adequate infrastructure can be added, the SPP region will face a significant loss of load and violations of regulatory reliability standards."

Midcontinent Independent System Operator (MISO)

- Subject to the study assumptions, significant reliability violations anticipated that are widely distributed with high levels of overload / under-voltage - indicative of substantial transmission solution needs
- The rule's implementation must allow for continued reliability and resource adequacy
- The EPA should remove the interim goals from the final rule to allow sufficient time for reliable and efficient implementation of compliance strategies
- The final rule should provide structured flexibility to support a variety of compliance strategies to preserve reliability of bulk electric system

Industry Agreement

AMERICAN ELECTRIC POWER

❑ Electric Reliability Council of Texas (ERCOT)

- Implementation of the proposed Clean Power Plan will have a significant impact on the planning and operation of the ERCOT grid
- Retirement of generation in and around major load centers could result in transmission reliability issues
- Loss of generation will strain ERCOT's ability to integrate new intermittent renewable generation resources
- The CPP will also result in increased energy costs for consumers in the ERCOT region by up to 20% in 2020, without accounting for the costs of transmission upgrades, procurement of additional ancillary services, energy efficiency investments, capital costs of new capacity, and other costs associated with the retirement or decreased operation of coal-fired capacity

❑ Electric Power Research Institute (EPRI)

- "The changes in the utilization of various generating plants driven by this proposal could have a significant impact on transmission reliability due to potential large changes in power flows across the system and retirement of generation that contributes to transmission system voltage and frequency performance."
- "The change in generation will almost certainly require development of new transmission to ensure operational reliability, but scheduling outages of existing facilities will be difficult if simultaneous upgrades across many systems are needed such that time lines for commissioning of new transmission facilities may be delayed."

Dealing with Disruption

AEP AMERICAN ELECTRIC POWER

- **Disruptive changes in supply mix will have a dramatic impact on the reliability of the transmission system**
- **Detailed technical analysis required to evaluate and address the impacts**
  - Preliminary analysis suggests widespread reliability challenges
- **The interconnected nature of the grid requires regional and interregional assessments**
  - Unprecedented coordination and cooperation beyond current regional planning efforts will be necessary, including natural gas pipeline and storage requirements
- **Reliable operation of the grid will be threatened without adequate time**
  - Implementation of approved state plans will take time, as will potential mitigation measures to address unacceptable system conditions to accommodate retirements
  - 5-10 years required to implement transmission upgrades after generation scenarios are determined

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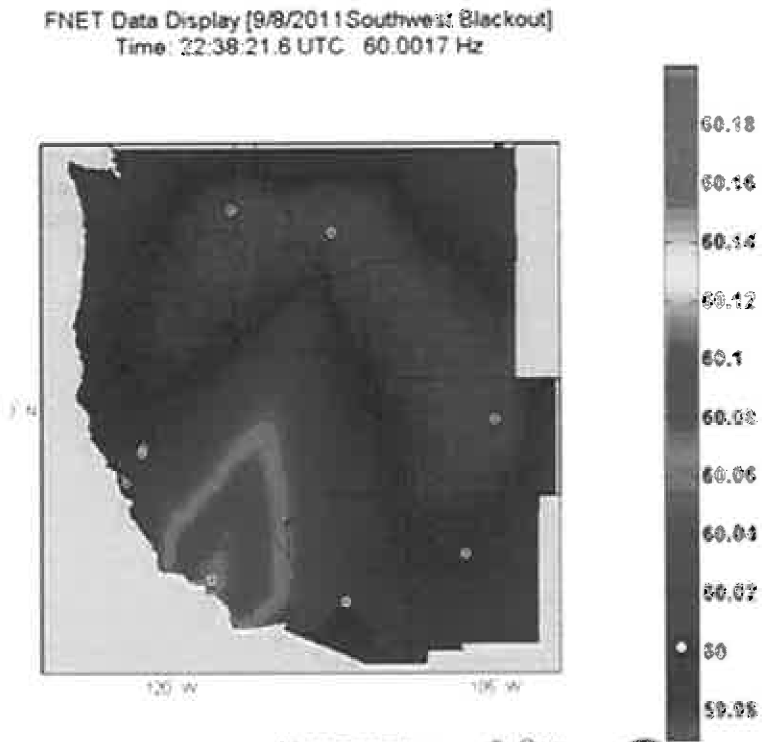
ADDITIONAL MATERIAL

The Interconnected Grid

- The Inter-Connected Grid is a Dynamic Machine
  - Local events and changes can have national impacts
- Sample Events
  - Measured and simulated by the Power IT Lab at the University of Tennessee (Knoxville) using PMUs and PSS/e
  - Southwest Blackout – 2011
    - http://www.youtube.com/watch?v=YsksUyeLu2Y
  - Florida Outage - 2008
    - http://www.youtube.com/watch?v=bdBB4byiZ8U
  - Northeast Blackout – 2003
    - http://www.youtube.com/watch?v=eBucq1IX2Q4



Appendix EE:

Attorneys General Omission of Data Section 307 Letter

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August 25, 2014

Via Certified Mail and Regulations.gov
The Honorable Gina McCarthy
Administrator
U.S. Environment Protection Agency
William Jefferson Clinton Building
1200 Pennsylvania Ave., N.W.
Washington, DC 20460

Re: Request for Withdrawal (EPA-HQ-OAR-2013-0602 and EPA-HQ-OAR-2013-0603)

Dear Administrator McCarthy:

This letter concerns the failure of the Environmental Protection Agency ("EPA") to include required and critical information in the regulatory dockets of two recent proposed rules: the *Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units* ("Existing Source Rule")[1] and the *Carbon Pollution Standards for Modified and Reconstructed Stationary Sources: Electric Utility Generating Units* ("Modified Sources Rule")[2] (together, "Proposed Rules"). By failing to include in the dockets key materials on which the agency relies as support for the Proposed Rules, EPA has violated Section 307(d) of the Clean Air Act ("CAA") (codified at 42 U.S.C. § 7607(d)). Both the Existing Source Rule and the Modified Sources Rule must thus be withdrawn.

Section 307(d) of the CAA imposes certain mandatory requirements for all proposed rules, which reflect Congress's judgment that information on which a proposed rule is based must be made available to the public at the time of proposal to ensure meaningful comment and sound rulemaking. Upon publication, a proposal must include a "statement of basis and purpose . . . [which] shall include a summary of . . . the factual data on which the proposed rule is based[,] . . . the methodology used in obtaining the data and in analyzing the data[,] and . . . the major legal interpretations and policy considerations underlying the proposed rule." 42 U.S.C. § 7607(d). Section 307(d) further requires that "*[a]ll data, information, and documents* . . . on

[1] 79 Fed. Reg. 34,830 (June 18, 2014).
[2] 79 Fed. Reg. 34,960 (June 18, 2014).

which the proposed rule relies shall be included in the docket *on the date of publication* of the proposed rule." *Id.* (emphases added). These docketing requirements are nondiscretionary. *See Union Oil Co. v. EPA*, 821 F.2d 678, 681-82 (D.C. Cir. 1987). Finalizing a rule without providing parties with the technical information necessary for meaningful comment renders the final rule unlawful. *See Conn. Light & Power Co. v. Nuclear Regulatory Comm'n*, 673 F.2d 525, 530-31 (D.C. Cir. 1982). Nor can the problem be cured by late docketing of the required data, as such late docketing does not permit the public with sufficient time for meaningful review and comment. *See Small Refiner Lead Phase-Down Task Force v. U.S.E.P.A.*, 705 F.2d 506, 540 (D.C. Cir. 1983); *Sierra Club v. Costle*, 657 F.2d 298, 398 (D.C. Cir. 1981).

In the Existing Source Rule and the Modified Sources Rule, EPA has repeatedly violated Section 307's unambiguous requirements:

In the Existing Source Rule, EPA omitted from the docket 84% of the modeling runs on which it relied in crafting the proposed Rule, without which the States and the public cannot comment meaningfully on the proposal. Specifically, the docket does not include 21 out of 25 of the Integrated Planning Model modeling runs that the agency used to justify the standards imposed by the Rule. The missing modeling runs cover projections for 2016, 2018, 2020, 2025 and 2030. This information is critical to assessing EPA's claims that States and industry will be able to comply with the four "building blocks" in the proposed Existing Source Rule. The States need the modeling run data for sufficient analysis of what that data shows on a unit by unit and state by state basis.

Similarly, EPA failed to include in the Existing Source Rule's docket vital net heat rate and emissions data, which are central to EPA's assertion that existing power plants are able to achieve a four to six percent heat rate improvement under EPA's first "building block." For example, EPA claims in the proposed Existing Source Rule to have reviewed its database of existing coal-fired units and found 16 facilities that have achieved heat rate improvements of three to eight percent "year-to-year,"[3] but it does not include any supporting data. Without the "year-to-year" data showing that facilities can comply with the four to six percent heat rate improvement, the States and the public cannot meaningfully comment on the achievability of EPA's heat rate projections.

In the Modified Sources Rule, EPA has completely failed to include *any technical information to support its proposed standard* for modified Subpart Da units or for the proposed standards for either modified or reconstructed Subpart KKKK units. For instance, the preamble to the Modified Source Rule references a technical support document, "Standard of Performance of Natural Gas-Fired Combustion Turbines," which it says is available in the docket. *See* 79 Fed. Reg. at 34,990 n.94. But that document is not available on the docket. Without such missing data and related materials, States and the public cannot properly determine the basis on which EPA claims that these emission standards are achievable and reasonable.

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[3] EPA, GHG Abatement Measures, Technical Support Document ("TSD") for *Carbon Pollution Guidelines for Existing Power Plants: Emission Guidelines for Greenhouse Gas Emissions from Existing Stationary Sources: Electric Generating Units*, at 2-32 (EPA-HQ-2013-0602) (June 10, 2014).

All told, the missing information unquestionably constitutes "data, information and documents," and likely contains "policy considerations underlying the proposed rule" that should have been in the rulemaking dockets from the beginning, according to Section 307(d). Deprived of this missing information, the notices of proposed rulemaking published on June 18 "fail[ed] to provide an accurate picture of the reasoning that has led [EPA] to the proposed rule." *Conn. Light*, 673 F.2d at 530. This is particularly problematic where, as here, the proposals seek to overhaul the existing electric generating sector on an unprecedented scale. *See Maryland v. E.P.A.*, 530 F.2d 215, 222 (4th Cir. 1975) (vacating rule due to EPA's failure to comply with notice and comment requirements, emphasizing the "drastic impact" that compliance with rule would have), *vacated on other grounds*, 431 U.S. 99 (1977).

In light of these clear violations of Section 307, EPA should withdraw the Existing Source Rule and the Modified Sources Rule immediately. With regard to the proposed Existing Source Rule, that Rule is wholly unlawful on other grounds and therefore may not be re-proposed at all, even if EPA were to compile the data and documents required by Section 307. *See* Letter from Patrick Morrisey, Attorney General of West Virginia, to Gina McCarthy, Administrator, EPA (June 6, 2014); *State of West Virginia, et al. v. EPA*, No. 14-1146 (D.C. Cir.); *In re Murray Energy Corporation*, No. 14-1112 (D.C. Cir.). As to the proposed Modified Sources Rule, the comment deadline on that rule is October 16, 2014 and is thus fast approaching. The undersigned States therefore request that if EPA wishes to press forward with the Modified Sources Rule, EPA should withdraw that Rule and re-propose it with all the supporting documents and data required by Section 307. EPA should then provide 120 days from the re-proposal date to provide sufficient time for States and the public to review and comment. Alternatively, EPA should—at a minimum—publish the missing data immediately and then extend the comment period 120 days from the date of such publication.

Sincerely,

Patrick Morrisey
West Virginia Attorney General

Jon Bruning
Nebraska Attorney General

E. Scott Pruitt
Oklahoma Attorney General

Luther Strange
Alabama Attorney General

Gregory F. Zoeller
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Peter K. Michael
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