STATE OF NEW YORK

BEFORE THE
PUBLIC SERVICE COMMISSION

Petition Requesting Initiation	**)**	
Of a Proceeding to Examine a Proposal	**)**	**Case 14-E-0270**
For Continued Operation of the	**)**	
R.E. Ginna Nuclear Power Plant	**)**	

COMMENTS OF THE NUCLEAR ENERGY INSTITUTE ON CONTINUED OPERATION OF THE R.E. GINNA NUCLEAR POWER PLANT

May 6, 2015

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CONTINUED OPERATION OF THE R.E. GINNA NUCLEAR POWER PLANT

The Nuclear Energy Institute[1] ("NEI") appreciates the opportunity to provide comments to the New York State Public Service Commission ("NYPSC" or "the Commission") as it considers the future of the R.E. Ginna nuclear power plant in Ontario, N.Y.

NEI commends the Commission for recognizing the significant value provided by the Ginna nuclear plant. Ninety-nine nuclear power plants provide approximately 20 percent of the nation's electricity, and approximately two-thirds of the nation's carbon-free electricity. The six nuclear power plants in New York supply approximately 30 percent of New York's electricity, and approximately 60 percent of the state's carbon-free electricity. NEI believes that these assets provide a uniquely valuable set of attributes:

- Nuclear power plants produce large quantities of electricity around the clock, safely and reliably, when needed. They operate whether or not the wind is blowing and the sun is shining, whether or not fuel arrives by truck, barge, rail or pipeline when needed.
- Nuclear plants provide price stability.
- They provide "reactive power" – essential to controlling voltage and frequency and operating the grid.

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1 NEI is responsible for establishing unified nuclear industry policy on matters affecting the nuclear energy industry, including regulatory, financial, technical and legislative issues. NEI members include all companies licensed to operate commercial nuclear power plants in the United States, nuclear plant designers, major architect/engineering firms, fuel cycle facilities, materials licensees, and other organizations and individuals involved in the nuclear energy industry.

- Nuclear power plants have portfolio value, contributing to the fuel and technology diversity that is one of the bedrock characteristics of a reliable, resilient electric sector.
- Finally, nuclear power plants provide clean air compliance value. In any system that limits emissions – of the so-called "criteria" pollutants or of carbon dioxide – the emissions avoided by nuclear energy reduce the compliance burden that would otherwise fall on emitting generating capacity.

Other sources of electricity have some of these attributes. None of the other sources have them all.

NEI's statement for the record covers two major areas: (1) the economic benefits provided by the Ginna nuclear power plant to the local area and the state, and (2) the negative impact on electricity consumers if the Ginna plant were to close.

I. The Economic Benefits of the Ginna Nuclear Power Plant

The Ginna nuclear power plant is a 581-megawatt facility that produces four percent of New York's electricity – enough power to supply approximately 500,000 people. Ginna produced 4.6 billion kilowatt-hours (kWh) of electricity in 2014, and operated at a capacity factor of 95.04 percent. Over the last 10 years, the facility has operated at more than 95 percent of capacity, which is above the industry average and significantly higher than all other forms of electric generation. This reliable production helps offset the potentially severe price volatility of other energy sources (e.g., natural gas) and the intermittency of renewable electricity sources.

In addition, emission-free electricity from Ginna prevents the release of more than 2 million tons of carbon dioxide annually, the equivalent of taking approximately 400,000 cars off the road. For perspective, New York's electric sector emits more than 30 million tons of carbon dioxide annually. Nuclear energy provides nearly 60 percent of the state's carbon-free electricity, which helps New York meet its carbon-reduction goals under the Regional Greenhouse Gas Initiative. Although a relatively small power plant (by nuclear industry standards, where plants larger than 1,000 megawatts are common), the Ginna plant, by itself, produced as much electricity as approximately three-quarters of New York's renewable energy capacity (excluding hydro).[2]

Earlier this year, NEI published an analysis[3] of the economic impact of the Ginna plant. In order to perform the analysis, the owner of the Ginna plant (Constellation Energy Nuclear Group LLC)

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[2] Ginna produced 4.6 billion kWh of electricity in 2014. In 2013, the last year for which data is available, renewable energy, excluding hydro, supplied 5.9 billion kWh of electricity in New York (see Energy Information Administration, Electric Power Annual, Table 3.14).

[3] *Economic Impacts of the R.E. Ginna Nuclear Power Plant*, Nuclear Energy Institute, February 2015 (included as Attachment I).

provided data on employment, operating expenditures, revenues and tax payments. This data is entered into an input/output economic model. There are several such models, and the Ginna analysis used a model called Policy Insight Plus, developed by a company called Regional Economic Models, Inc., or REMI. This model has been widely used by many different organizations and is universally recognized as best-in-class.

The model allows us to analyze the direct impact of a facility or group of facilities, and the secondary impact – in other words, the "ripple effect," in terms of jobs and economic activity – of having that facility or group of facilities in the state or region. NEI has been conducting these analyses for approximately 20 years, going back to the 1990s and, during that time, has completed 18 analyses of 28 nuclear power stations representing 48 nuclear reactors.

NEI's analysis showed that Ginna employs about 700 people directly (plus another 800 to 1,000 jobs during reactor refueling outages). This direct employment creates more than 800 additional jobs in other industries in New York and the United States. In addition:

- Ginna's operation generates $358 million of annual economic output statewide and $450 million annually across the United States. This analysis showed that, for every dollar of output from Ginna, the state economy produces $1.52 and the U.S. economy produces $1.91.

- The Ginna facility is the largest taxpayer in Wayne County, contributing more than $10 million in state and local property tax and sales tax in 2014. When calculating the total tax impact (direct and secondary), the plant's operations resulted in nearly $80 million in tax revenue to the local, state and federal governments.

In addition to quantifying Ginna's economic impacts, this analysis modeled the adverse effects to the state and national economies if the Ginna plant shuts down prematurely. The results showed that Ginna is integral to the local and state economies. Since nuclear plants often are the largest, or one of the largest, employers in the regions in which they operate, the loss of a nuclear power plant has lasting negative economic ramifications on surrounding communities.

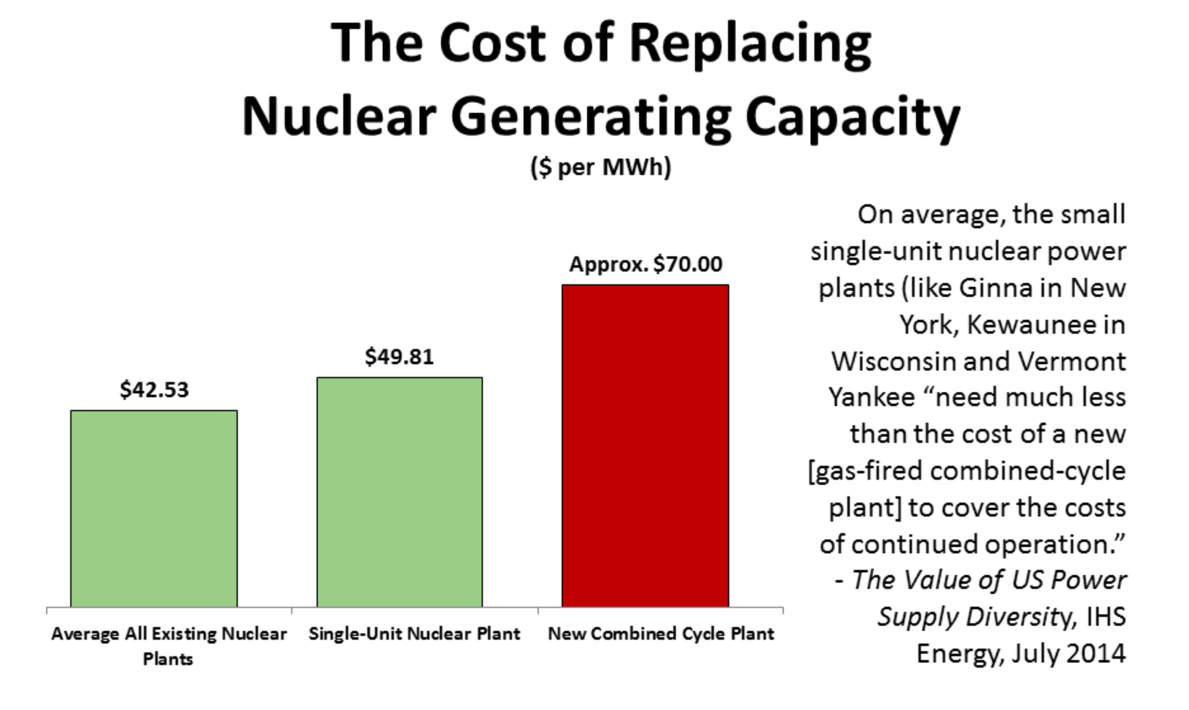
If Ginna closes prematurely, this analysis found that the initial output losses to New York would be $485 million. The losses would increase annually to a peak of $691 million in New York in the seventh year. The number of jobs lost peaks in the sixth year after the plant closes: 3,600 jobs in New York state. Losses would reverberate for decades after the plant is shut down, and host communities may never fully recover. Over that period, the New York economy shrinks because of lost output that cascades across virtually all sectors, taking years to filter completely through the economy.

II. Generating Capacity to Replace Ginna Would Produce More Costly Electricity

If the Ginna nuclear power plant were to shut down prematurely, the 581 megawatts of baseload generating capacity would be replaced, sooner or later, with other generating capacity capable of delivering electricity around the clock. In today's world, that replacement capacity would be a natural gas-fired combined cycle plant. Ironically, that new gas-fired capacity would produce more costly electricity than the Ginna plant, thereby penalizing consumers of electricity.

On average, the 99 U.S. nuclear power plants produce electricity at a total generating cost (operating and maintenance expenses, fuel and capital expenditures) of $42.53 per megawatt-hour (MWh). (This is a three-year average for 2011-2013.) Because they produce less electricity, the smaller nuclear plants in the fleet (like Ginna) are slightly more costly, producing electricity on average at $49.81 per MWh (total generating cost).

Analysis shows, however, that a gas-fired combined cycle plant would produce electricity at much higher prices. According to Lawrence Makovich, Vice President and Senior Advisor for Global Power at IHS Energy, the well-respected consulting firm: "A modern natural gas-fired



Sources: Nuclear plant costs are total generating cost (operations and maintenance, fuel, and capital expenditures) and are 2011-2013 averages from Electric Utility Cost Group. Cost for single-unit nuclear plant is 2011-2013 average for seven small (approx. 600 MW) nuclear plants like Ginna, Kewaunee and Vermont Yankee. Gas-fired combined cycle plant cost from IHS Energy: "The Electric Power Industry's Missing Money Problem," Lawrence Makovich, IHS Energy, in *The Wall Street Journal*, April 22, 2015.

power plant built in North America can produce electricity at a total cost – which includes the up-front investment – of around 14 cents per kilowatt-hour [$140 per MWh] at low utilization rates and around 7 cents per kWh [$70 per MWh] at maximum utilization."[4]

It is, therefore, difficult to see how shutdown of Ginna is in the best interests of electricity consumers.

In terms of size and cost of electricity produced, the Ginna nuclear power plant is similar to two other nuclear power plants that shut down recently due to economic stress caused by competitive markets that failed to value their attributes and the value they provide to the grid. Those two plants were the Kewaunee plant in Wisconsin (shut down in 2013) and the Vermont Yankee plant (shut down at the end of 2014). In an analysis last year of the value of fuel and technology diversity,[5] IHS Energy found that "the Kewaunee plant need[ed] much less than the cost of new plant … to cover the costs of continued operation."

III. Conclusion: Fuel and Technology Diversity Has Value

Americans today enjoy the benefits of a diverse portfolio of electricity sources, based on fuel and technology decisions made decades ago. This diversity is taken for granted, difficult to quantify and, as a result, undervalued. In its analysis on *The Value of Power Supply Diversity*, IHS Energy demonstrated analytically the value of fuel and technology diversity. IHS compared a base case – reflecting the current generation mix in regional U.S. power systems during the 2010-2012 period – with a reduced diversity case involving a generating mix without meaningful contributions from coal and nuclear power, with a smaller contribution from hydroelectric power and an increased share of renewable power. The remaining three-quarters of generation in the scenario would come from natural gas-fired plants. This is clearly the direction in which the United States is heading.

In this analysis, IHS found that:

- the cost of generating electricity in the reduced diversity case was more than $93 billion higher per year, the potential variability of monthly power bills was 50 percent higher compared to the base case, and retail electricity prices 25 percent higher.
- The typical household's annual disposable income was around $2,100 less in the reduced diversity scenario.

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[4] "The Electric Power Industry's Missing Money Problem," Lawrence Makovich, IHS Energy, in *The Wall Street Journal*, April 22, 2015 (included as Attachment II).

[5] *The Value of U.S. Power Supply Diversity*, IHS Energy, July 2014, included as Attachment III.

- There would be around one million fewer jobs compared to the base case and U.S. gross domestic product (GDP) would be nearly $200 billion less.

"These negative economic impacts are similar to an economic downturn," IHS Energy said. "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."

Although the analysis focused on national impacts, the results and the lessons learned apply equally at the state level, and provide additional justification for continued operation of well-managed, safe, reliable, low-cost generating assets like the Ginna nuclear power plant.

Respectfully submitted,

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ATTACHMENT I

Economic Impacts of The R.E. Ginna Nuclear Power Plant

An Analysis by the Nuclear Energy Institute

February 2015

NUCLEAR ENERGY INSTITUTE

www.nei.org

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Executive Summary

The Robert Emmett Ginna Nuclear Power Plant (Ginna), located in Ontario, N.Y., has been a vital part of the region's energy portfolio, providing 100 percent carbon-free electricity since it began operating in 1970. In addition to the reliable, emission-free electricity that the plant generates and the jobs and economic stimulus it provides, the plant's involvement in the local community makes Ginna a significant economic contributor to the region and New York.

To quantify the employment and economic impacts of this facility, the Nuclear Energy Institute (NEI) conducted an independent analysis. Based on data provided by Constellation Energy Nuclear Group on employment, operating expenditures, revenues and tax payments, NEI conducted the analysis using a nationally recognized model to estimate the facility's economic impacts on the state and national economies. Regional Economic Models, Inc. (REMI), developed the Policy Insight Plus (PI+) economic impact modeling system, the methodology employed in this analysis. (See Section 6 of this report for more information on the REMI methodology.)

Ginna employs about 700 people directly and adds another 800 to 1,000 jobs during reactor refueling outages. This direct employment creates more than 800 additional jobs in other industries in New York and the United States.

Key Findings

Ginna's operation supports:

Hundreds of jobs. Ginna employs about 700 people directly and adds another 800 to 1,000 jobs during reactor refueling outages. This direct employment creates more than 800 additional jobs in other industries in New York and the United States.

Clean electricity for New York. Ginna generates about 4 percent of New York's electricity. Emission-free electricity from Ginna prevents the release of more than 2 million tons of carbon dioxide annually, the equivalent of taking approximately 400,000 cars off the road. For perspective, New York's electric sector emits more than 30 million tons of carbon dioxide annually. Nuclear energy provides nearly 60 percent of the state's carbon-free electricity, which helps New York meet its Regional Greenhouse Gas Initiative carbon-reduction goals. Shutdown of Ginna would undo all the renewables investment made by New York in the past decade to comply with RGGI requirements.

Reliability benefits. During full-power operation, Ginna provides 581 megawatts of around-the-clock electricity for New York homes and businesses. Over the last 10 years, the facility has operated at more than 95 percent of capacity, which is above the industry average and significantly higher than all other forms of electric generation. This reliable production helps offset the potentially severe price volatility of other energy sources (e.g., natural gas) and the intermittency of renewable electricity sources. Nuclear energy provides reliable electricity to businesses and consumers and helps prevent power disruptions which could lead to lost economic output, higher business costs, potential loss of jobs, and losses to consumers.

Emission-free electricity from Ginna prevents the release of more than 2 million tons of carbon dioxide annually, the equivalent of taking approximately 400,000 cars off the road.

Balanced portfolio of electricity options. Nuclear energy produces approximately 30 percent of New York's electricity and Ginna plays an important role in maintaining a balanced electric portfolio in the state. New York's other sources of electricity are natural gas, renewables and hydropower. New York policy leaders have expressed concerns about overreliance on any one source of electricity generation.

Economic stimulus. Ginna's operation generates $358 million of annual economic output statewide and $450 million annually across the United States. This study finds that for every dollar of output from Ginna, the state economy produces $1.52 and the U.S. economy produces $1.91.

Tax impacts. The Ginna facility is the largest taxpayer in Wayne County, contributing more than $10 million in state and local property tax and sales tax in 2014. When calculating the total tax impact (direct and secondary), the plant's operations resulted in nearly $80 million in tax revenue to the local, state and federal governments.

Community and environmental leadership. Ginna is a corporate leader in its neighboring communities, supporting education initiatives, environmental and conservation projects, and numerous charitable organizations. Ginna employees are the largest United Way contributor in Wayne County. The plant also is one of the few nuclear energy facilities in America that is ISO 14001-certified, an internationally recognized environmental management standard.

In addition to quantifying Ginna's economic impacts, this analysis modeled the adverse effects to the state and national economies if the Ginna plant shuts down prematurely. The results show that Ginna is integral to the local and state economies. Since nuclear plants often are the largest, or one of the largest, employers in the regions in which they operate, the loss of a nuclear power plant has lasting negative economic ramifications on surrounding communities.

If Ginna closes prematurely, this analysis found that the initial output losses to New York would be $485 million. The output losses to the United States, including New York, would be $808 million in the first year after closure. The losses would increase annually to a peak of $691 million in New York and $1.3 billion nationally in the seventh year. The number of jobs lost peaks in the sixth year after the plant closes: 3,600 jobs in New York and 6,800 throughout the United States. Losses would reverberate for decades after the plant is shut down, and host communities may never fully recover.

Section 1
Background and Generation History

Date of operation:

R.E. Ginna nuclear power plant began generating electricity on June 1, 1970

Location:

Ginna is located on 426 acres along the south shore of Lake Ontario in Ontario, N.Y., about 20 miles northeast of Rochester

NRC License Expiration Year:

2029

Reactor Type:

Pressurized water reactor

Total Electrical Capacity:

581 megawatts, enough to power 400,000 homes year round

Owner:

Constellation Energy Nuclear Group LLC, a joint venture between Exelon Corp. and the EDF Group

Reliable Electricity Generation

Ginna has operated at a capacity factor of more than 95 percent for the last 10 years, above the industry average. Capacity factor, a measure of electricity production efficiency, is the ratio of actual electricity generated to the maximum possible electric generation during the year.

Hundreds of High-Skilled, Well-Paying Local Jobs

Ginna employs about 700 full-time workers and is one of the largest and highest-paying employers in Wayne County. The annual payroll is approximately $100 million. Most jobs at nuclear power plants require technical training and typically are among the highest-paying jobs in the area. Nationwide, nuclear energy jobs pay 36 percent more than average salaries in a facility's local area.

In addition, every 18 months, the plant is refueled and specialized maintenance is conducted. During this time, Ginna supplements its workforce with an additional 800 to 1,000 skilled craft workers, primarily from local unions. Direct payroll for these contractors ranges from $19 million to $25 million depending on outage work scope.

Safe and Clean for the Environment

Nuclear energy facilities generate large amounts of electricity without emitting greenhouse gases. State and federal policymakers recognize nuclear energy as an essential source of safe, reliable electricity that meets both our environmental needs and the state's demand for electricity.

In 2013, Ginna's operation prevented 2.4 million metric tons of carbon dioxide,[1] about the same amount released by more than 400,000 cars each year. Overall, New York's electric sector emits more than 30 million tons of carbon dioxide annually. Ginna also prevents the emission of more than 1,000 tons of nitrogen oxide, equivalent to that released by nearly 60,000 cars, and 1,040 tons of sulfur dioxide. Sulfur dioxide and nitrogen oxide are precursors to acid rain and urban smog.

[1] Emissions prevented are calculated using regional fossil fuel emission rates from the U.S. Environmental Protection Agency and plant generation data from the U.S. Energy Information Administration.

Section 2

Economic Impacts for New York State and National Economies

NEI used the REMI PI+ model to analyze economic and expenditure data provided by Ginna to develop estimates of its economic impacts (more information on REMI can be found in Section 6).

The economic impacts of Ginna consist of direct and secondary impacts. The main variables used to analyze these impacts are:

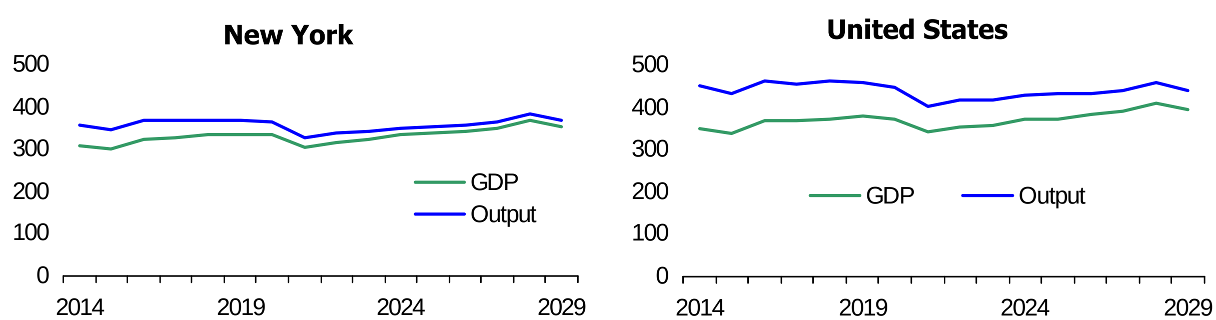
Output
The direct output is the value of power produced by Ginna. The secondary output is the result of how the direct output alters subsequent outputs among industries and how those employed at Ginna influence the demand for goods and services within the community.

Employment
The direct employment is the number of jobs at Ginna. Secondary employment is the number of jobs in the other industries as a result of Ginna's operation.

Gross State Product
Gross state product is the value of goods and services produced by labor and property at Ginna—e.g., sales minus intermediate goods. In the REMI model, electricity is the final good from a nuclear plant. Intermediate goods are the components purchased to make that electricity.

This study evaluated how these factors affect economic activity at the state and national levels.

Figure 2.0
Ginna's Output Impact and Gross Domestic Product Contribution to New York and the U.S.
*(dollars in 2014 millions)**



** Regional electricity price forecasts based on the Energy Information Administration's Annual Energy Outlook 2014*

Substantial Economic Driver

The direct output value of Ginna was $235.3 million in 2014 (the value of the electricity produced), with a total economic impact on the state of $358 million. In other words, for every dollar of output from Ginna, the state economy produced $1.52.

Ginna's total effect on the U.S. economy was more than $450 million. For every dollar of output from the plant, the U.S. economy produced $1.91. The plant contributed more than $300 million to New York's gross state product and nearly $350 million to U.S. GDP.

Figure 2.0 (previous page) shows the value of Ginna's output impact and contributions to GDP to the end of its Nuclear Regulatory Commission license period in 2029, using electricity price forecast data from the Energy Information Administration.

Table 2.0
Ginna's Direct and Secondary Effects on U.S. Economic Sectors
(output in millions of 2014 dollars)

Sector Description	New York	United States
Utilities	$237.52	$238.13
Manufacturing	$8.72	$52.00
State and Local Government	$25.39	$29.50
Professional, Scientific, and Technical Services	$13.92	$22.63
Finance and Insurance	$7.91	$18.00
Health Care and Social Assistance	$11.75	$15.50
Real Estate and Rental and Leasing	$8.88	$14.00
Retail Trade	$8.59	$12.63
Construction	$8.39	$12.13
Information	$4.75	$10.50
Wholesale Trade	$5.86	$10.00
Administrative and Waste Management Services	$5.70	$10.31
Accommodation and Food Services	$4.40	$7.50
Other Services, except Public Administration	$3.09	$5.25
Transportation and Warehousing	$1.15	$4.69
Management of Companies and Enterprises	$0.47	$2.41
Arts, Entertainment, and Recreation	$1.10	$1.97
Educational Services	$0.98	$1.63
Forestry, Fishing, and Related Activities	$0.01	$0.19
Total	**$358.00**	**$450.31**

Ginna's largest impact is on the utilities sector. The next greatest impact in New York is on state and local governments. This is due to Ginna's large tax base from salaries and sales and property taxes generated from the plant's spending.

The third largest sector that benefits from Ginna's operation in New York is professional, scientific and technical services due to the volume of specialized services required to operate and maintain a nuclear power plant. Aside from tax payments, Ginna's largest U.S. impact is on the manufacturing sector, particularly for purchases of pumps, motors and other equipment. A full depiction of the sectors in the United States that benefit from the facility is in Table 2.0.

Ginna's output also stimulates the state's labor income and employment. The plant employs about 700 people in permanent jobs and another 800-1,000 jobs during refueling outages. These jobs stimulate more than 800 additional jobs in other sectors in New York and the United States. Table 2.2 details the numbers and types of jobs that Ginna supported in 2014. Workers at the plant are included in the occupation categories in the table. Because Ginna hires hundreds of workers every 18 months to help with refueling/maintenance outages, Table 2.2 also shows the number of jobs created in outage years and non-outage years.

Economic Stimulus Through Taxes

Ginna's operation results in a total tax impact of $80 million to local, state and federal governments. Constellation Energy Nuclear Group pays more than $10 million in state and local property and sales taxes annually and is Wayne County's largest taxpayer. This is the direct impact. There also are secondary impacts, because plant expenditures increase economic activity, leading to additional income and value creation and, therefore, to higher tax revenue.

Table 2.1
Total Tax Impacts of Ginna's Economic Activity in 2014
*(in 2014 millions of dollars)**

Plant	State and Local	Federal	Total
Ginna	$15.6	$62.3	$77.9

** Calculated based on a percentage of gross domestic product.*

Ginna's impact on the state and national economies is substantial. By producing affordable, reliable electricity, the plant is a hub of economic activity for New York and a boost to the national economy. Table 2.3 provides the multipliers and summarizes the total effects for each region.

Table 2.2
Ginna Supports Direct and Secondary Jobs During Non-Outage and Outage Years

	New York		United States	
Occupation	**Non-Outage**	**Outage***	**Non-Outage**	**Outage***
Sales and related, office and administrative support	399	440	598	602
Installation, maintenance and repair	228	282	259	309
Management, business and financial	177	196	244	246
Production	144	174	202	221
Computer, mathematical, architecture, engineering	124	142	149	156
Building and grounds cleaning and maintenance	86	90	145	139
Health care	86	92	127	122
Transportation and material moving	61	64	127	124
Construction and extraction	91	100	121	122
Other	223	233	341	334
Total	**1,619**	**1,813**	**2,313**	**2,375**

Table 2.3
Ginna's Impact on the State and National Economies in 2014 (dollars in millions)

Description	Direct	Secondary	Total	Multiplier
New York				
Output	$235.3	$136.2	$358.0	1.52
Employment (non-outage)	700	919	1,619	2.31
Employment (outage)	925*	888	1,813	1.96
United States				
Output	$235.3	$243.6	$450.3	1.91
Employment (non-outage)	700	1,613	2,313	3.30
Employment (outage)	925*	1,450	2,375	2.57

** Outage workers are converted to full-time equivalents.*

Section 3

Economic Impacts of Ginna's Retirement

If Ginna shuts down, in the first year, the initial output losses to New York and the United States are $485 million and $808 million, respectively. The losses increase each year until the seventh year after Ginna's retirement, when the lost output peaks at $691 million for New York and $1.3 billion for the United States.

Perhaps the best way to appreciate the value of a nuclear power plant is to examine what happens when it is gone. When the Kewaunee facility in Wisconsin closed prematurely in 2013, Kewaunee County lost 15 percent of its employment and 30 percent of its revenue—not to mention 556 megawatts of reliable, affordable electricity. In California, 1,500 jobs were lost when two reactors at the San Onofre nuclear facility were closed. Recent analysis shows that California's carbon dioxide emissions increased by more than 35 percent, due in large part to the closure of the two reactors. Moreover, when San Onofre was operating, there was virtually no spread in wholesale electricity costs between southern and northern California. When the plant shut down in 2012, the spread between prices in the two regions increased to approximately $7 per megawatt-hour. In 2013, the spread widened further—to about $10/MWh. It is expected to remain at that level for the rest of the decade. This is significant for a state that already has one of the highest retail electricity rates in the country.

California will replace the lost electricity from San Onofre primarily with new natural gas-fired power plants, renewable resources, and imports from out of state. Customers are expected to pay billions of dollars to replace electricity generation at San Onofre.

As discussed in Section 2, the operation of Ginna creates significant economic benefits for New York and beyond. This facility is at significant risk of premature retirement because of a perfect storm of economic challenges—sluggish economy, historically low natural gas prices, and the unintended consequences of current energy policies. The REMI model measures the long-term impact to the New York and U.S. economies if Ginna is shut down prematurely. The economic impacts of a shutdown are analyzed over a 20-year period.

State and National Comprehensive Economic Loss

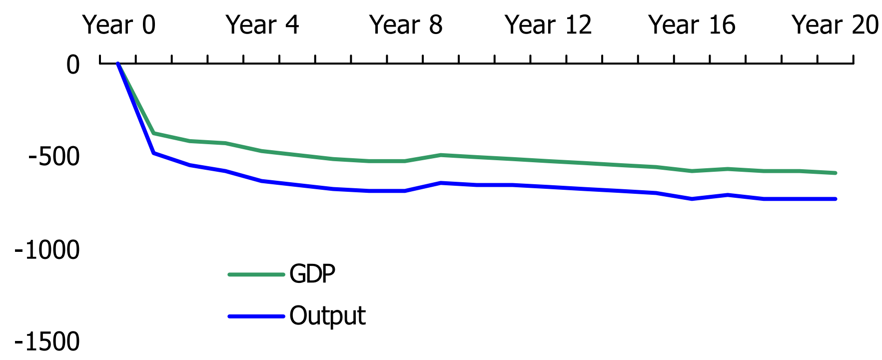
When a productive facility ceases operations, the economic loss affects local, state and national areas for decades. Figure 3.0 shows the value of Ginna's lost output and lost gross state product for the first 20 years the plant is shut down.

In the first year, the lost output in New York and the United States would be $485 million and $808 million, respectively. The losses increase each year until the seventh year after Ginna's retirement, when the lost output peaks at $691 million for New York and $1.3 billion for the United States. Over that period, the New York and U.S. economies shrink because of lost output that cascades across virtually all sectors, taking years to filter completely through the economy.

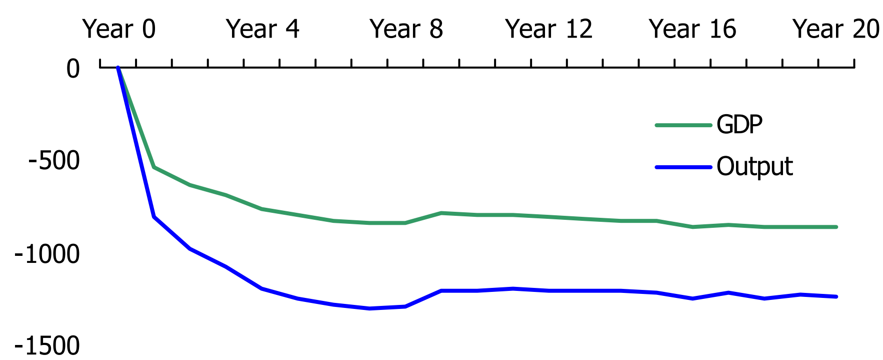
A nuclear power plant shutdown has a greater economic impact than operation. The impacts shown in this section are larger than those in Section 2 primarily

Figure 3.0
Ginna's Lost Output and Gross State Product in New York and the United States
(dollars in 2014 millions)

New York



United States



due to the migration of workers and families moving away from the area in search of new jobs.

In the nation as a whole, the shutdown primarily affects the utilities sector, followed by manufacturing and construction, then by specialized services in the professional, scientific and technical sector.

In New York, the third largest impact, behind construction, is the state and local governments because of a loss in tax revenue estimated at $19 million. Further, nearly 250 jobs would be lost at the state and local government levels.

A full depiction of the sectors affected by Ginna's shutdown is in Table 3.0, which shows the lost output in the seventh year when the losses are at their highest in the United States.

Figure 3.1 shows the number of direct and secondary jobs lost in New York and the United States after Ginna's retirement. While the number of direct jobs lost remains flat, the number of secondary jobs lost increases during the first six

Table 3.0
Peak Lost Output to Affected Sectors in Year 7 After Ginna's Closure *(in 2014 millions of dollars)*

Economic Sector	New York	United States
Utilities	−$288.89	−$292.47
Manufacturing	−$29.08	−$209.50
Construction	−$102.07	−$166.75
Professional, scientific and technical services	−$54.00	−$104.50
State and local government	−$48.50	−$75.75
Finance and insurance	−$10.81	−$54.00
Real estate and rental and leasing	−$23.53	−$62.25
Health care and social assistance	−$21.39	−$37.25
Retail trade	−$29.16	−$49.38
Information	−$26.11	−$57.00
Wholesale trade	−$19.38	−$42.13
Administrative and waste management services	−$11.38	−$29.94
Transportation and warehousing	−$3.27	−$25.63
Accommodation and food services	−$10.10	−$20.00
Other services, except public administration	−$6.41	−$15.88
Mining	−$0.07	−$39.69
Management of companies and enterprises	−$0.23	−$10.44
Arts, entertainment and recreation	−$2.96	−$6.16
Educational services	−$3.43	−$5.16
Forestry, fishing and related activities	$0.00	−$0.78
Total	**−$690.50**	**−$1,308.00**

years. This is because it would take five to seven years before Ginna's lost output filters through the local, state and national economies.

Figure 3.1 displays the population migration out of the state that would occur if the facility were to close. Ten years after closure, about 2,500 would move out of state, increasing to 2,900 in year 20. Since Ginna is one of the largest employers in Wayne County, it can be reasonably assumed that people also would migrate out of the county to other parts of the state.

Table 3.1 shows the number and types of jobs that would be lost when Ginna retires. In Year 1, more than 2,600 jobs would be lost in New York; 4,500 in the United States. In Year 6, job losses in the United States would be 6,828, of which 3,610 would be in New York.

Figure 3.1
Shutdown-Related Job Losses in New York and the United States

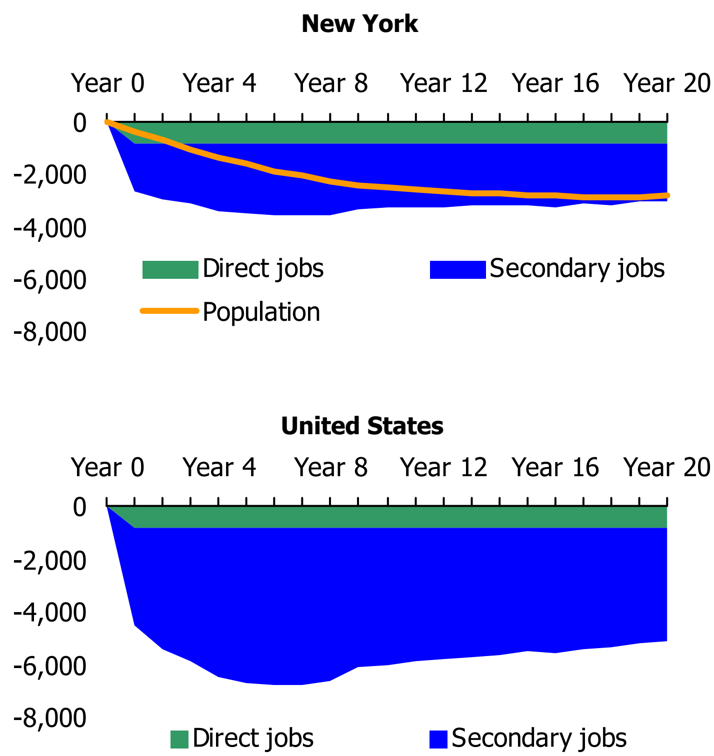


Table 3.1
Peak Direct and Secondary Jobs Lost in Year 6
After Ginna's Closure

Occupation	New York	United States
Sales and related, office and administrative support	−886	−1,711
Construction and extraction	−537	−1,001
Management, business and financial	−380	−715
Installation, maintenance and repair	−378	−548
Production	−234	−486
Transportation and material moving	−154	−433
Building and grounds; personal care and service	−158	−359
Computer, mathematical, architecture & engineering	−235	−396
Health care	−173	−312
Other	−475	−867
Total	**−3,610**	**−6,828**

Section 4

Community Leadership and Environmental Protection

Constellation Energy Nuclear Group is widely recognized as an important corporate citizen in its community. The company and employees at Ginna are dedicated to education, the environment and their community.

Educational Endeavors

Ginna employees believe that quality education and career development opportunities are among the most important tools to help communities prosper. Since 2010, Constellation Energy Nuclear Group has awarded several college scholarships to local high school students. Ginna employees also sponsor after-school programming through Big Brothers and Big Sisters designed to encourage interest in math and science.

Environmental Support

Ginna is dedicated to protecting the environment while meeting New York's clean energy needs. In 2010, Ginna became ISO 14001-certified, an internationally recognized standard that recognizes the plant's excellence in environmental stewardship. Ginna renewed its ISO 14001 certification in August 2013.

Located on Lake Ontario, Ginna plays a key role in protecting the regional environment. In addition to meeting all regulatory requirements and having a formal environmental management system, Ginna also:

- maintains nesting boxes for the Eastern Bluebird
- establishes on-site wildlife habitats
- maintains an active recycling program
- participates in the Ocean Conservancy International Coastal Cleanup and Adopt-a-Highway programs
- maintains an active role in the local community, providing environmental education programs to students and educators
- contributes financially to environmental organizations such as Ducks Unlimited and Seneca White Deer.

Community Leadership

Ginna employees are leading corporate citizens in Wayne County. Members of the facility's team serve their communities as volunteer firefighters, Scout leaders, emergency medical technicians, board members and more. They provide thousands of hours to civic and community organizations and make significant contributions to charities each year.

Here are some examples:

- Constellation Energy Nuclear Group is the largest United Way contributor in Wayne County and its employees participate in the "Day of Caring."
- Ginna sponsors annual fundraising events for local organizations, including a golf tournament, bake sale and silent auctions.
- Over the past decade, the company also has contributed several thousands of dollars annually to various charitable groups and nonprofit organizations in Wayne and Monroe counties.

Section 5
Ginna and the U.S. Nuclear Energy Industry

The Ginna nuclear power plant plays a vital role in helping central New York and the state as a whole meet its demand for affordable, reliable and sustainable energy.

In 2013, electricity production from U.S. nuclear power plants was about 790 billion kilowatt-hours—nearly 20 percent of America's electricity supply. In New York, nuclear energy generates approximately 30 percent of the state's electricity, and Ginna alone generated 5 billion kilowatt-hours of electricity.

Over the past 20 years, America's nuclear power plants have increased output and improved performance significantly. Since 1990, the industry has increased total output equivalent to that of 26 large power plants, when in fact only five new reactors have come on-line.

U.S. nuclear power plants achieved an industry-leading performance capacity factor of 91 percent in 2013, while producing electricity at one of the lowest costs of any fuel source used to generate electricity. Ginna's performance has met or exceeded the industry average for many years.

The Value of Nuclear Energy

Nuclear energy's role in the nation's electricity portfolio was especially valuable during the 2014 winter, when record cold temperatures gripped the United States and other sources of electricity were forced off the grid. Nuclear power plants nationwide operated at an average capacity factor of 96 percent during the period of extreme cold temperatures. During that time, supply volatility drove natural gas prices in many markets to record highs and much of that gas was diverted from use in the electric sector so that it could be used for home heating.

Some of America's electricity markets, however, are structured in ways that place some nuclear energy facilities at risk of premature retirement, despite excellent operations. It is imperative that policymakers and markets appropriately recognize the full strategic value of nuclear energy as part of a diverse energy portfolio.

That value proposition starts with the safe and reliable production of large quantities of electricity around the clock.

Renewable energy, while an emerging part of the energy mix, is intermittent (the sun doesn't always shine and the wind doesn't always blow when generation is needed) and therefore unreliable; natural gas-fired generation depends on fuel being available (both physically and at a reasonable price); and on-site coal piles can freeze. One of nuclear energy's key benefits is the availability of low-cost fuel and the ability to produce electricity under virtually all weather conditions. Nuclear power plants also provide clean-air compliance value. In any cap-and-trade system, nuclear energy reduces the compliance burden that would otherwise fall on carbon-emitting generating capacity.

Nuclear plants provide voltage support to the grid, helping to maintain grid stability. They have portfolio value, contributing to fuel and technology diversity. And they provide tremendous local and regional economic development opportunity, including large numbers of high-paying jobs and significant contributions to the local and state tax base.

Achieving Carbon Goals

New York is a member of the Regional Greenhouse Gas Initiative (RGGI)—the nation's first market-based program to cap and reduce greenhouse gas emissions. Participation in RGGI has yielded positive results for the state through cleaner air, job creation and lower electricity bills.

Retiring Ginna would undo all the renewables investment made by New York in the past decade to comply with RGGI. Since 2005, wind and solar that has come online generate about 3.6 billion kWh annually in New York, compared to 4.6 billion kWh annually from Ginna. If Ginna were to retire, fossil fuels would replace it. As a result, CO_2 emissions would increase by about 2.4 million metric tons each year.

A recent analysis by the investment bank UBS concluded that RGGI could hit its carbon price cap, and the state's greenhouse gas emissions would increase by more than 60 percent, if all of the state's reactors were to shut down. New York's current electricity mix consists of natural gas, hydro, renewables and nuclear. Nuclear energy plays an outsized role in helping the state achieve its clean air objectives by providing nearly 60 percent of the state's clean-air electricity. At the national level, nuclear energy provides 62 percent of the nation's clean electricity.

Affordable Energy for Consumers

In addition to increasing electricity production at existing nuclear energy facilities, power from these facilities is affordable for consumers. Compared to the cost of electricity produced using fossil fuels—which is heavily dependent on fuel prices—nuclear plant fuel prices are relatively stable, making costs to consumers more predictable. Uranium fuel is only about one-third of the production cost of nuclear energy, while fuel costs make up 78 percent to 88 percent of coal-fired and natural gas production costs.

Emphasis on Safety

Safety is the highest priority for the nuclear energy industry. Based on more than 50 years of experience, the industry is one of the safest industrial working environments in the nation. Through rigorous training of plant workers and increased communication and cooperation between nuclear plants and federal, state and local regulating bodies, the industry is keeping the nation's 100 nuclear plants safe for their communities and the environment.

The U.S. Nuclear Regulatory Commission (NRC) provides independent federal oversight of the industry and tracks data on the number of "significant events" at each nuclear plant. (A significant event is any occurrence that challenges a plant's safety system.) The average number of significant events per reactor declined from 0.45 per year in 1990 to 0.06 in 2012, illustrating the emphasis on safety throughout the nuclear industry.

General worker safety also is excellent at nuclear power plants—far safer than in the manufacturing sector. U.S. Bureau of Labor Statistics show that in 2012, nuclear energy facilities achieved an incidence rate of 0.4 per 200,000 work hours, compared to 2.8 for fossil-fuel power plants, 3.1 for electric utilities and 3.9 for the manufacturing industry.

Industry Trends: License Renewal and New Plants

The excellent economic and safety performance of U.S. nuclear power plants has demonstrated the value of nuclear energy to the electric industry, the financial community and policymakers. This is evidenced by the increasing number of facilities seeking license renewals from the NRC.

Originally licensed to operate for 40 years, nuclear energy facilities can operate safely for longer. The NRC granted the first 20-year license renewal to the Calvert Cliffs plant in Maryland in 2000. As of February 2015, 75 reactors have received license renewals, 17 reactors have filed applications for renewal and are under review and the remaining eight reactors have announced their intention to apply. Thirteen reactors have passed the 40-year mark and are operating safely and reliably with renewed licenses in this extended period. License renewal is an attractive alternative to building new electric capacity because of nuclear energy's low production costs and the return on investment provided by extending a plant's operational life.

Besides relicensing nuclear plants, energy companies also are building new, advanced-design reactors. Georgia Power and South Carolina Electric & Gas are building two advanced reactors each, near Augusta, Ga., and Columbia, S.C. These facilities are halfway through the construction program and will employ more than 5,000 workers each during the peak of construction. In addition, Tennessee Valley Authority is completing construction of the Watts Bar 2 reactor in Tennessee.

Section 6

Economic Impact Analysis Methodology

This analysis uses the REMI model to estimate the economic and fiscal impacts of the Ginna plant.

Regional Economic Models, Inc. (REMI)

REMI is a modeling firm specializing in services related to economic impacts and policy analysis, headquartered in Amherst, Mass. It provides software, support services, and issue-based expertise and consulting in almost every state, the District of Columbia, and other countries in North America, Europe, Latin America, the Middle East and Asia.

The REMI model has two main purposes: forecasting and analysis of alternatives. All models have a "baseline" forecast of the future of a regional economy at the county level. Using "policy variables," in REMI terminology, provides scenarios based on different situations. The ability to model policy variables makes it a powerful tool for conveying the economic "story" behind policy. The model translates various considerations into understandable concepts like GDP and jobs.

REMI relies on data from public sources, including the Bureau of Economic Analysis, Bureau of Labor Statistics, Energy Information Administration and the Census Bureau. Forecasts for future macroeconomic conditions in REMI come from a combination of resources, including the Research Seminar in Quantitative Economics at the University of Michigan and the Bureau of Labor Statistics. These sources serve as the main framework for the software model needed to perform simulations.

Policy Insight Plus (PI+)

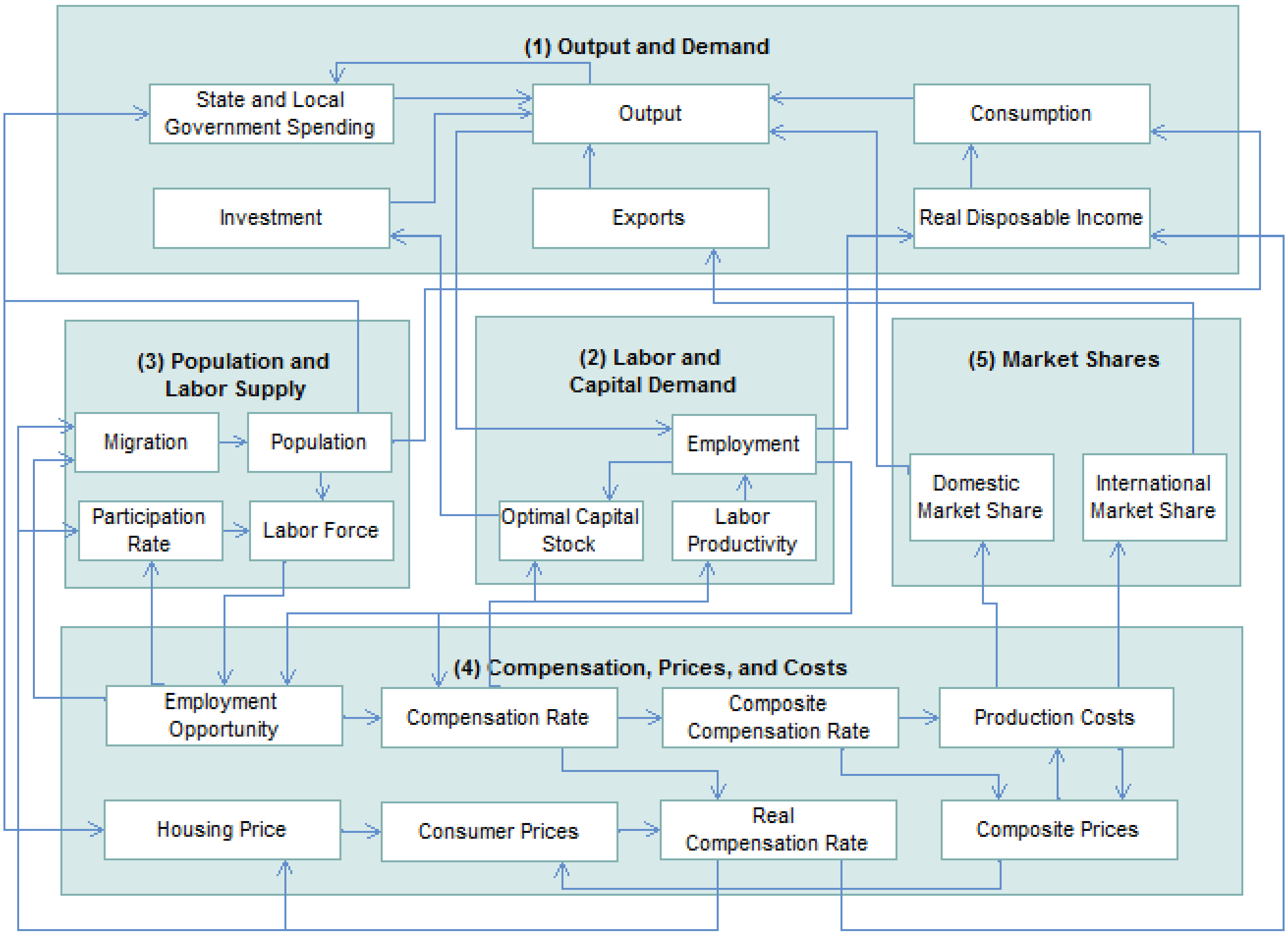
REMI's PI+ is a computerized, multiregional, dynamic model of the states or other sub-national units of the United States economy. PI+ relies on four quantitative methodologies to guide its approach to economic modeling:

1. Input/output tabulation (IO)—IO models, sometimes called "social accounting matrices" (SAM), quantify the interrelation of industries and households in a computational sense. It models the flow of goods between firms in supply-chains, wages paid to households, and final consumption by households, government and the international market. These channels create the "multiplier" effect of $1 going further than when accounting for its echoing.
2. Computable general equilibrium (CGE)—CGE modeling adds market concepts to the IO structure. This includes how those structures evolve over time and how they respond to alternative policies. CGE incorporates concepts on markets for labor, housing, consumer goods, imports and the im-

portance of competitiveness to fostering economic growth over time. Changing one of these will influence the others—for instance, a new knife factory would improve the labor market and then bring it to a head by increasing migration into the area, driving housing and rent prices higher, and inducing the market to create a new subdivision to return to "market clearing" conditions.

3. Econometrics—REMI uses statistical parameters and historical data to populate the numbers inside the IO and CGE portions. The estimation of the different parameters, elasticity terms and figures gives the strength of various responses. It also gives the "time-lags" from the beginning of a policy to the point where markets have had a chance to clear.
4. New economic geography—Economic geography provides REMI a sense of economies of scale and agglomeration. This is the quantification of the strength of clusters in an area and their influence on productivity. One example would include the technology and research industries in Seattle. The labor in the area specializes to serve firms like Amazon and Microsoft and, thus, their long-term productivity grows more quickly than that of smaller regions with no proclivity towards software development (such as Helena, Mont.). The same is true on the manufacturing side with physical inputs, such as with the supply-chain for Boeing and Paccar in Washington in the production of transportation equipment. Final assembly will have a close relationship and a high degree of proximity to its suppliers of parts, repairs, transportation and other professional services, which show up in clusters in the state.

Figure 6.0



This diagram represents the structure and linkages of the regional economy in PI+. Each rectangle is a discrete, quantifiable concept or rate, and each arrow represents an equation linking the two of them. Some are complex econometric relationships, such as the one for migrant, while some are rather simple, such as the one for labor force, which is the population times the participation rate. The change of one relationship causes a change throughout the rest of the structure because different parts move and react to incentives at different points. At the top, Block 1 represents the macroeconomic whole of a region with final demand and final production concepts behind GDP, such as consumption, investments, net exports and government spending. Block 2 forms the "business perspective": An amount of sales orders arrive from Block 1, and firms maximize profits by minimizing costs when making optimal decisions about hiring (labor) and investment (capital). Block 3 is a full demographic model. It has births and deaths, migration within the United States to labor market conditions, and international immigration. It interacts with Block 1 through consumer and government spending levels and Block 4 through labor supply. Block 4 is the CGE portion of the model, where markets for housing, consumer goods, labor and business inputs interact. Block 5 is a quantification of competitiveness. It is literally regional purchase coefficients (RPCs) in modeling and proportional terms, which show the ability of a region to keep imports away while exporting its goods to other places and nations.

Conclusion

Ginna's economic benefits—on taxes and through wages and purchases of supplies and services—are considerable. In addition, plant employees stimulate the local economy by purchasing goods and services from businesses around the area, supporting many small businesses throughout the region. The plant is the largest taxpayer in the county where it is located.

In 2014, total economic impact (direct and secondary) to the country from Ginna's operation was $450 million in output and nearly $350 million in gross domestic product. The operation of the Ginna facility and its secondary effects account for 1,400 to 2,000 jobs in New York and throughout the country.

The facility generated almost 5 billion kilowatt-hours of low-carbon electricity in 2013, enough to serve the yearly needs for 400,000 homes. This low-cost reliable electricity helped keep electricity prices in check in New York.

The Ginna nuclear power plant is a leader economically, fiscally, environmentally and socially within New York and has far-reaching economic impacts across the United States.

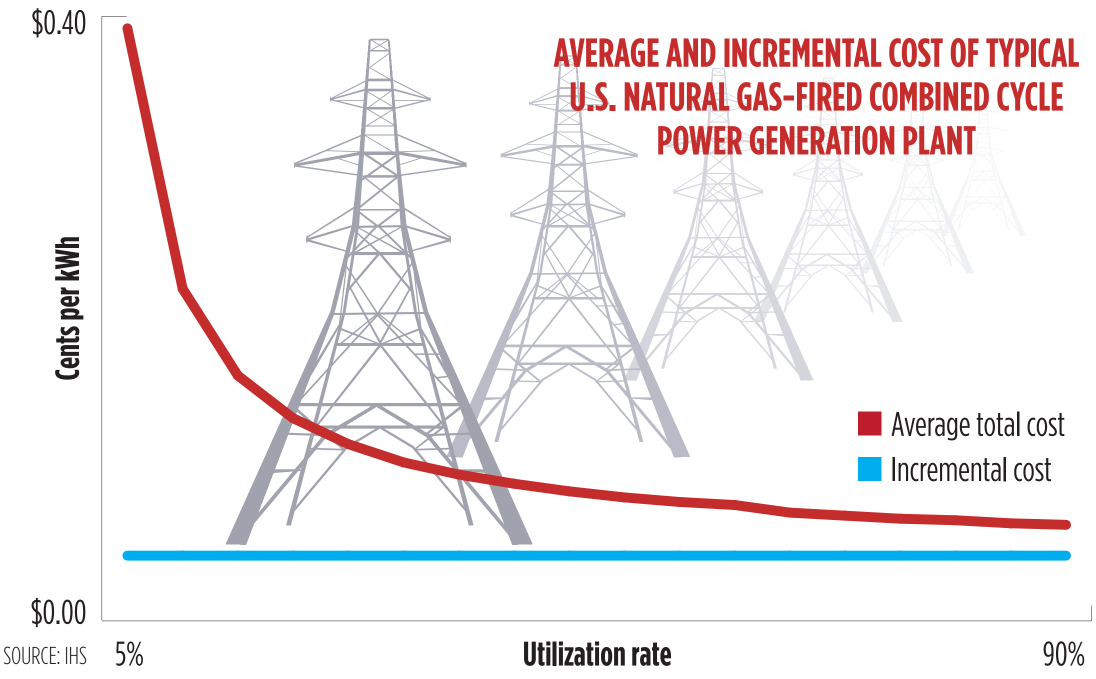
■

ATTACHMENT II

THE ELECTRIC POWER INDUSTRY'S MISSING MONEY PROBLEM

By Lawrence Makovich

A quarter century ago, a large-scale restructuring of the electric power industry got underway in both North America and Europe. The effort was termed "deregulation" on this side of the Atlantic and "liberalization" on the other. But things do not always work out according to plan — and that is what happened here. Restructuring in the United States never reached its intended end state because of what economists call "the missing money problem." This is a market failure arising from the quite distinctive cost structures of the technologies involved in power generation that prevent electricity markets from working the way the marketplace does in economics textbooks. The problem can be summed up this way: Competitive forces drive rival suppliers (who have already built their power plants) to bid to provide electricity in the market at prices high enough to cover variable costs but too low to cover total costs. The resulting gap between market clearing prices and average total costs causes too many power plants to retire before it is economic for them to do so. Similarly, chronically low prices prevent the timely development of new power supply. The combination of too few new power plants being built and too many existing power plants closing down threatens the future adequacy of America's power supply. How well — or poorly — power systems address the missing money problem today and in the years to come will be one of the key factors shaping the future of the electricity sector.



SOURCE: IHS

The missing money problem arises because of the inherent characteristics of electric power production. Building a power generation facility requires a large up-front expenditure, and these fixed costs cannot be altered in the short run. Consequently, for electricity generated by conventional technologies — which still account for more than two-thirds of world supply — fuel is the only significant input that can alter the amount of power generated in the short run.

A modern natural gas-fired power plant built in North America can produce electricity at an average total cost — which includes the up-front investment — of around 14 cents per kilowatt-hour (kWh) at low utilization rates and around 7 cents per kWh at maximum utilization. Variable costs account for a little over half of total costs. When owners of rival facilities with these cost characteristics bid against each other in wholesale markets, they are willing to provide additional electricity for any price above the variable cost because supplying power at that price provides some contribution towards fixed costs. Consequently, competitive forces tend to drive market-clearing prices to short run marginal costs. But here's the catch: As power plant utilization rates increase, the gap between incremental costs and average total costs narrows, but does not fully close (see chart).

As a result, when power demand and supply are in balance — including reserve capacity needed to insure reliability — the market-clearing price remains below average total cost. The average power plant utilization rate in the U.S. is around 45 percent. At this rate, the marginal cost-based price only covers about half of the average total cost. As the example above shows, suppliers that sell their power in wholesale markets face a significant missing money problem.

The missing money problem surfaces in even starker relief with generation technologies such as hydro, wind and solar. These require no fuel, so the short-run marginal cost of production is effectively zero. Suppliers of electricity from these sources therefore face short-run incentives to offer their power at any price greater than zero. As a result, when hydro, wind and solar are competing to meet a change in demand, the market-clearing price tends to be driven toward zero. This problem is most pronounced in the liberalized power markets of Europe.

In the United States, the missing money problem is made worse by policies that subsidize renewable power, which exist in 38 states. When renewable power sources compete in wholesale markets, their owners recognize that losing a bid means losing the opportunity to collect subsidies. Consequently, owners of renewable power sometimes respond by bidding negative prices — effectively offering to pay customers to take their power — as long as the available subsidies can more than cover sums paid to customers.

Besides depressing energy prices, renewables such as wind and solar also typically increase the costs of conventional generation. This is because power systems need conventional generating technologies to back up and fill in for intermittent renewable sources. But doing so makes utilization rates at conventional plants lower and more varied. These so-called added "integration" costs only worsen the missing money problem.

Market-based pricing and well-intentioned subsidies for renewable power have therefore brought about an unexpected result. Prices on wholesale electric power markets chronically settle at levels below those required for producers to recover the full cost of their operations. This has had a very notable effect on merchant power suppliers. These are companies that specialize in producing electricity and selling it to wholesale markets, but do not own the wires that distribute electricity to homeowners and businesses in particular cities or regions. The missing money problem was one of the primary reasons why bankruptcy reorganization was the rule rather than the exception for merchant generators in the era of deregulation. Over the last 15 years, these merchant generators have written down billions of dollars of power plant investments.

The missing money problem has three major consequences. The first is the risk of underinvestment in new power supply. Second, low prices are causing many existing power plants to be retired early, even though their continued operation would be far less costly than replacing the supply they now provide. Several nuclear plants have closed prematurely in the past few years and more than a dozen are vulnerable to closure in the years

Continued on next page

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to come. Left unaddressed, the missing money problem could lead to a reprise in other regions of the power shortages that plagued California in 2000-2001, when consumers experienced dramatic price spikes, brownouts and rolling blackouts. Third, low prices distort market signals and lead to an inefficient mix of fuels and technologies. IHS estimates such inefficiencies are moving the cost of fuel used to generate electricity in the United States to a level 9 percent higher than it should be.

There is no one-size-fits-all solution to the missing money problem. Each regional power system has its own characteristics, and the best mix of solutions in any particular setting will depend on the distinctive characteristics of that system. But IHS, in consultation with key industry stakeholders, has identified 13 different approaches currently being employed, or considered, to address the missing money problem. On the table are a whole range of approaches from adding capacity markets to moving back toward more regulation or public ownership. There is much debate about what to do. No one-size-fits-all solution exists because current regulatory and market conditions vary significantly from one regional power system to the next. Evaluating these approaches against multiple criteria has shown that some approaches, alone or in combination, can meaningfully address the missing money problem. Conversely, some approaches are not likely to provide the building blocks of an effective solution under any conditions — and could make matters worse.

Any measures put forward to address the missing money problem should reflect the interests of all key power sector stakeholders: electricity generators and operators of wholesale markets, as well as consumers, elected representatives and regulators. Implementing effective solutions will first require convincing power-system stakeholders that a problem exists as well as getting them to agree on its nature and causes. Only then will they be able to reach consensus on an effective suite of remedies. And it is better to do all this before a crisis than after.

Lawrence Makovich is Vice President and Senior Advisor for Global Power at IHS and lead author of the IHS Multiclient Special Report, Bridging the Missing Money Problem.

ATTACHMENT III

IHS **Energy**

The Value of US Power Supply Diversity

July 2014

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For clients with access to the IHS Energy website, the following features related to this report may be available online: downloadable data (Excel file format); downloadable, full-color graphics; author biographies; and the Adobe PDF version of the complete report.

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IHS™ **Energy**

The Value of US Power Supply Diversity

Lawrence Makovich, *Vice President and Senior Advisor, IHS Energy*
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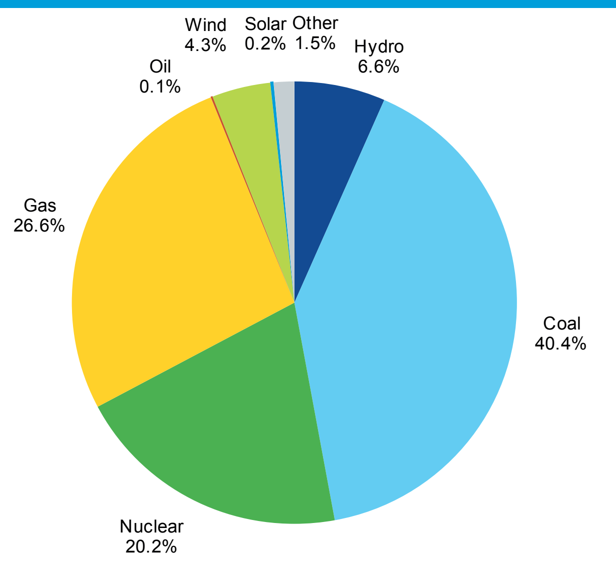
Executive summary

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

US generation mix, 2013



Source: IHS Energy

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.

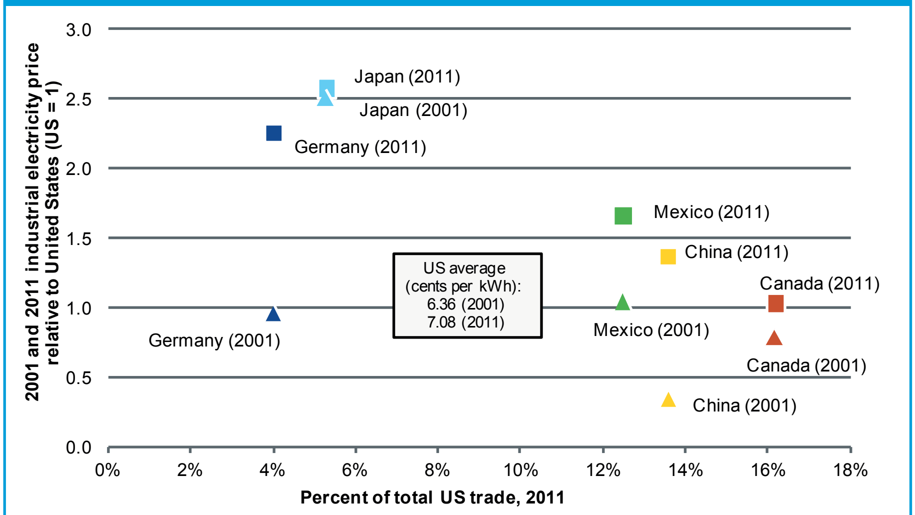
The current diverse US power supply reduces US consumer power bills by over $93 billion per year compared to a reduced diversity case. In addition, the current diversified power generation mix mitigates exposure to the price fluctuations of any single fuel and, by doing so, cuts the potential variability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

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.

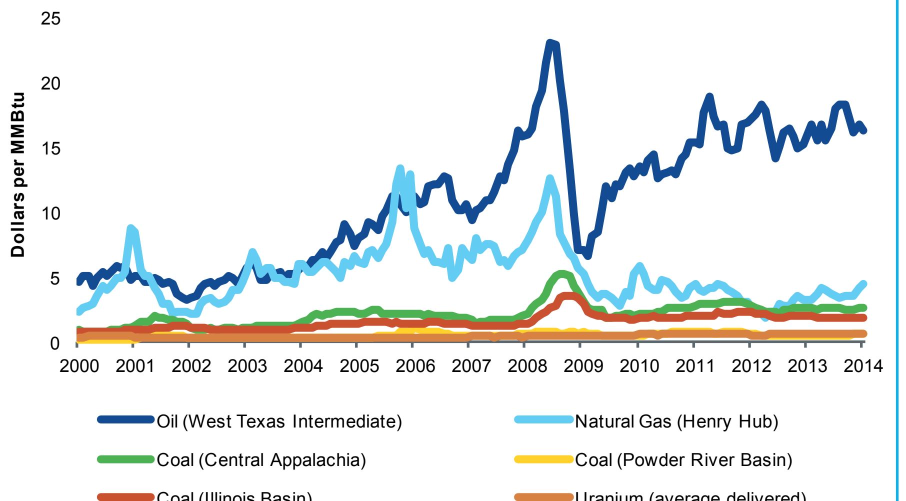
Power production cost fluctuations reflect inherent fuel price uncertainties

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



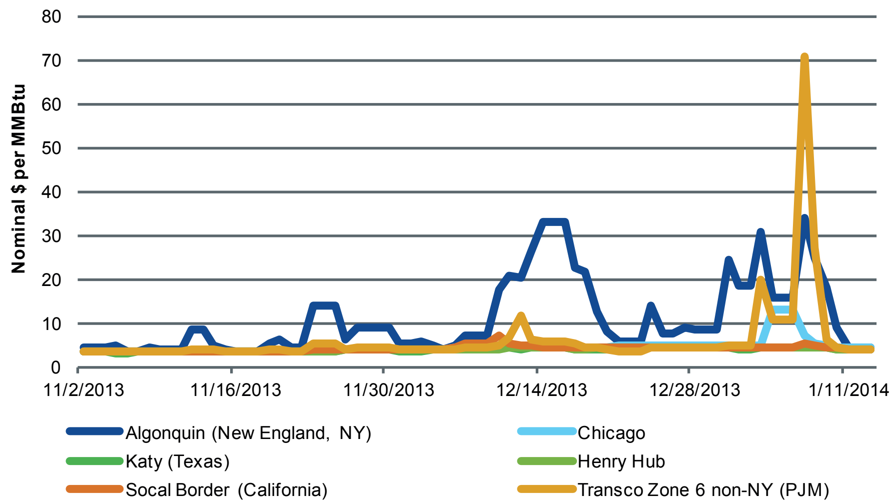
Source: IHS Energy
Data Sources: Energy Information Administration, Platt's and Natural Gas Intelligence, Platts Coal Outlook, SNL Energy Coal

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

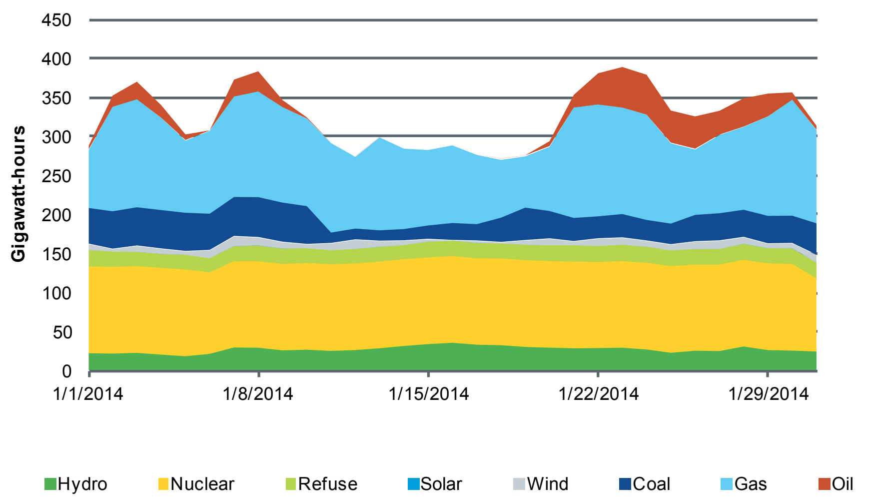
Delivered daily gas prices, November 2013–January 2014



Source: IHS Energy, Ventyx Velocity Suite © 2014 IHS

FIGURE 4

ISO New England generation, January 2014



Source: IHS Energy © 2014 IHS

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).

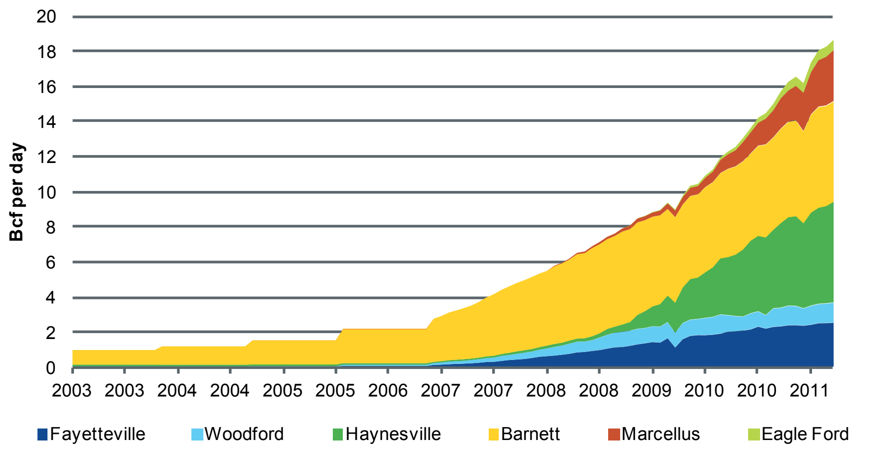
Although shale gas had moved from its innovation phase to its commercialization phase, many in the oil and gas industry did not fully recognize what was happening even as US shale gas output doubled from 2002 to 2007 to reach 8% of US natural gas production. The belief that the United States was running 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)

40609-1Source: IHS Energy

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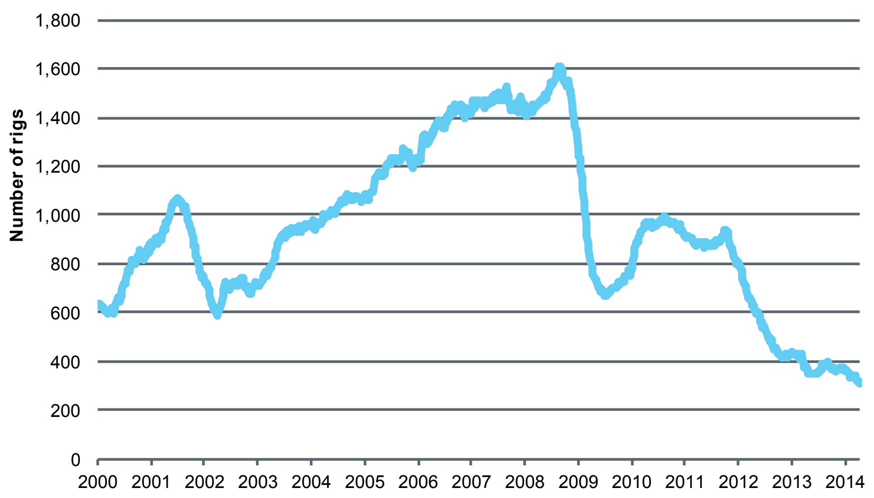
between 2002 and 2008. This level of drilling activity created a supply surplus that caused a precipitous decline of up to 85% in the Henry Hub natural gas price from 2008 to 2012. From the 2008 high count, the number of US natural gas–directed rigs dropped over fivefold to 310 by April 2014 (see Figure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

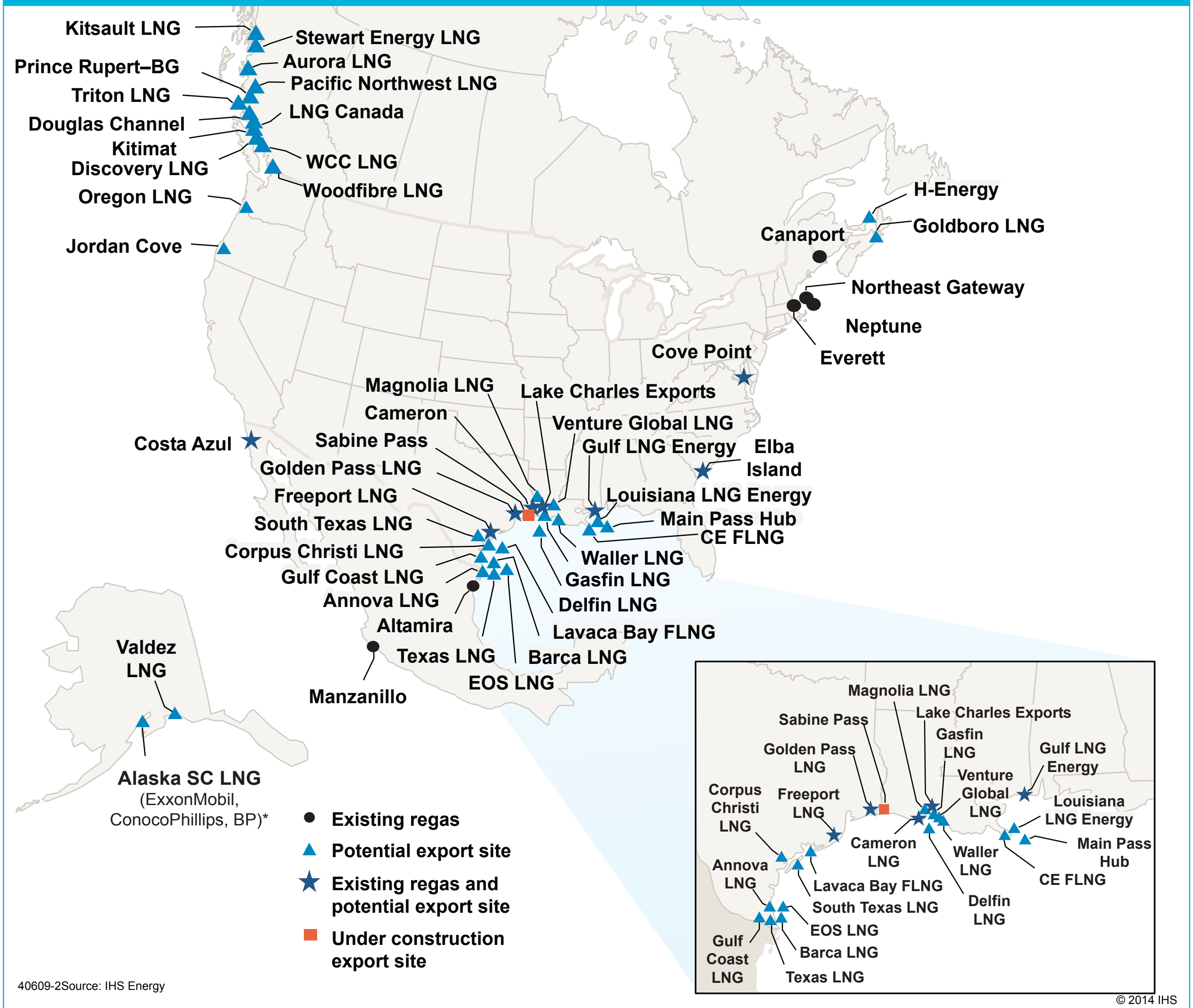
The Northeast delivered natural gas price spikes translated directly into dramatic power production cost run-ups. During the winter of 2013/14, natural gas prices delivered to the New York and PJM power system border hit $140 per MMBtu (at Transco Zone 6, 21 January 2014) and pushed natural gas–fired 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



40609-2Source: IHS Energy

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.

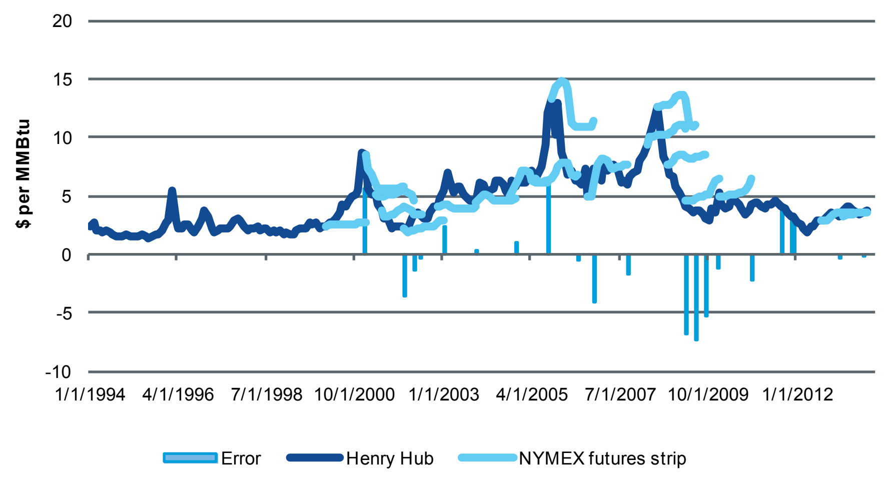
The natural gas–fired generation share is second only to the coal-fired generation share. One of the primary reasons that fuel diversity is so valuable is because natural gas prices and coal prices do not move together.

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

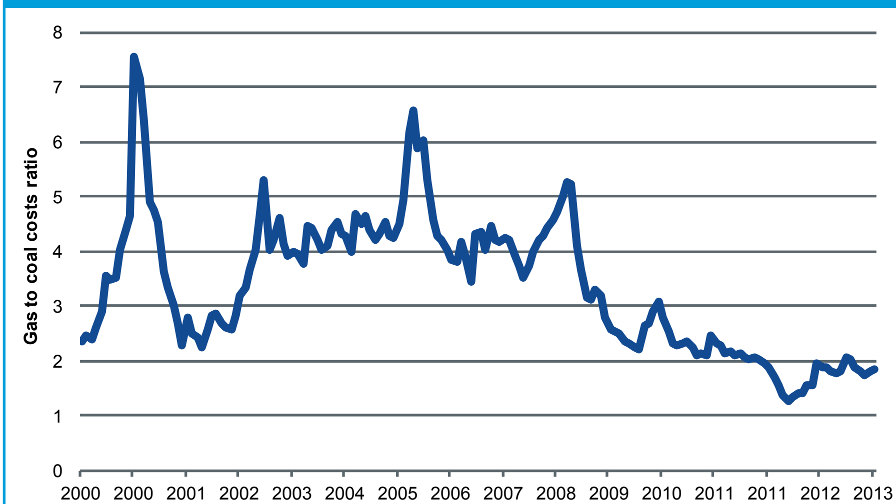
Henry Hub and NYMEX futures, 1994–2013



Source: IHS Energy © 2014 IHS

FIGURE 10

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



Note: ratio of costs per MMBtu.
Source: IHS Energy, Ventyx Velocity Suite © 2014 IHS

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

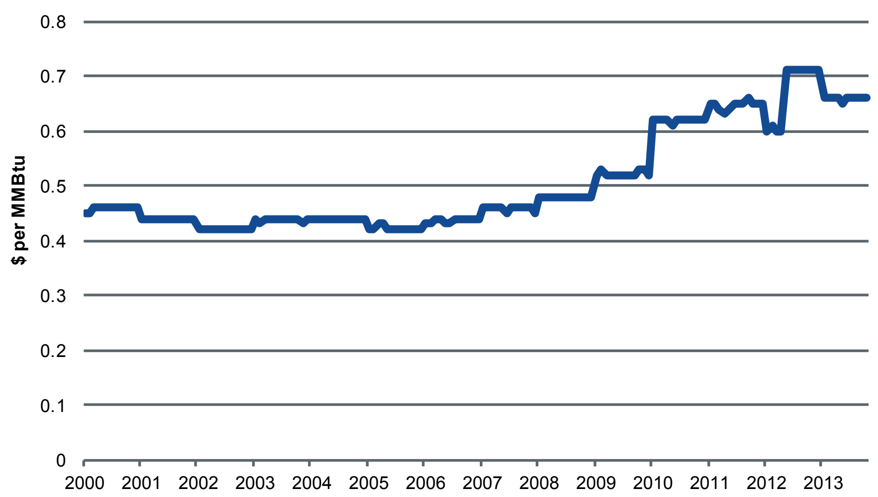
	Typical coal unit	Typical CCGT unit
Size, MW	218	348
Heat rate, Btu/kWh	10,552	7,599
Fuel cost, $/MMBtu	$2.41	$4.46
Fuel cost, $/MWh	$25.43	$33.89
Variable O&M, $/MWh	$4.70	$3.50
Lbs SO_2/MWh (with wet FGD)	1.16	0
SO_2 allowance price, $/ton	70	70
Lbs NO_X/MWh	0.74	0.15
NO_X allowance price, $/ton	252	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

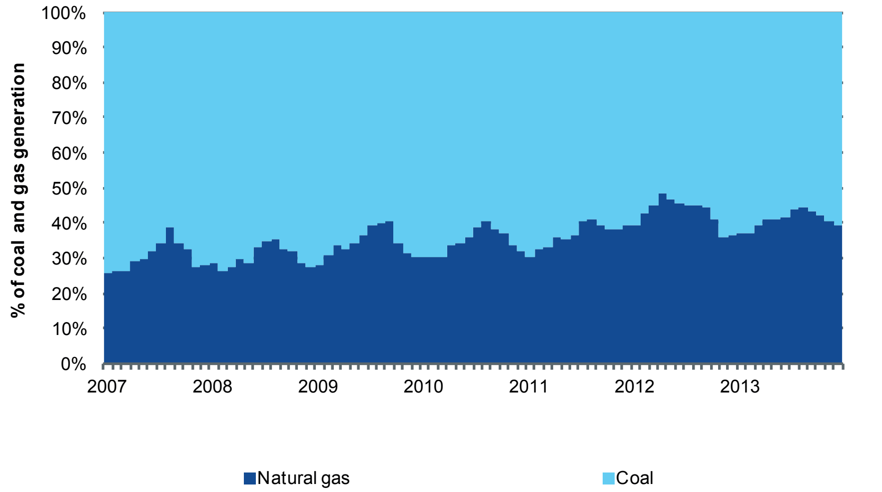
Diversity: The substitution effect

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.

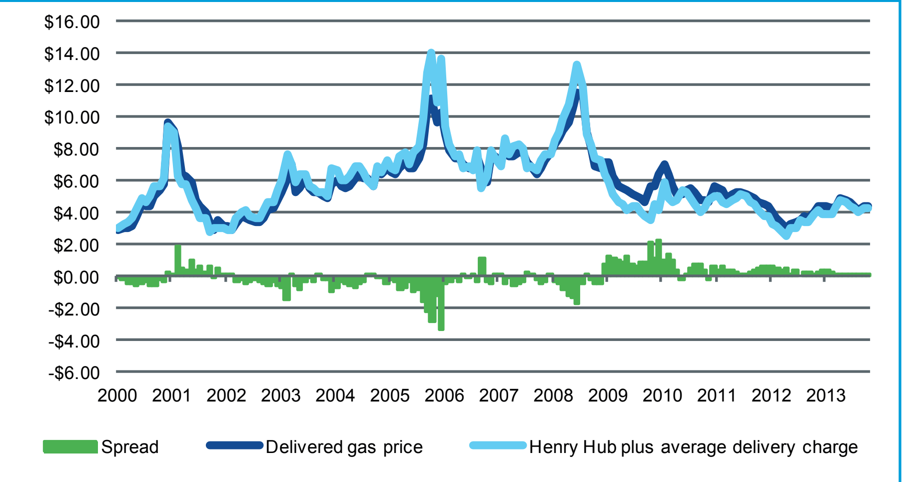
Diversity is the best available power cost risk management tool

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



Source: IHS Energy, Ventyx Velocity Suite

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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.

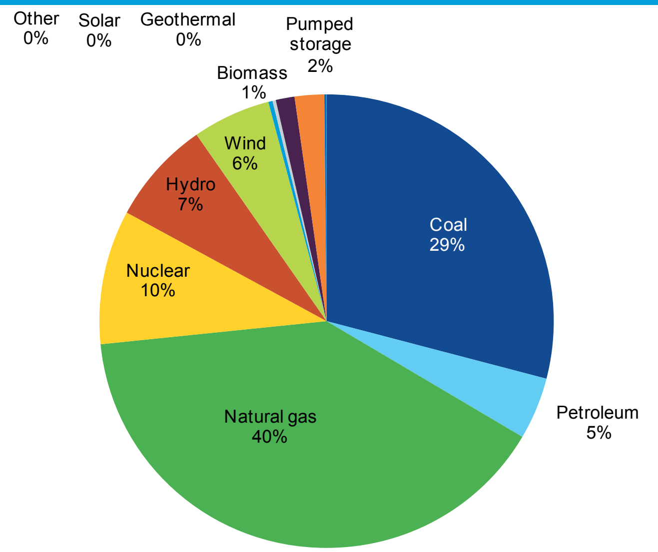
Outside of financial derivatives, fuel deliverability is an important consideration in evaluating power cost risk management. Currently, natural gas pipeline expansion requires long-term contracts to finance projects. Looking ahead, the fastest growing segment of US natural gas demand is the power sector 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.

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

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.

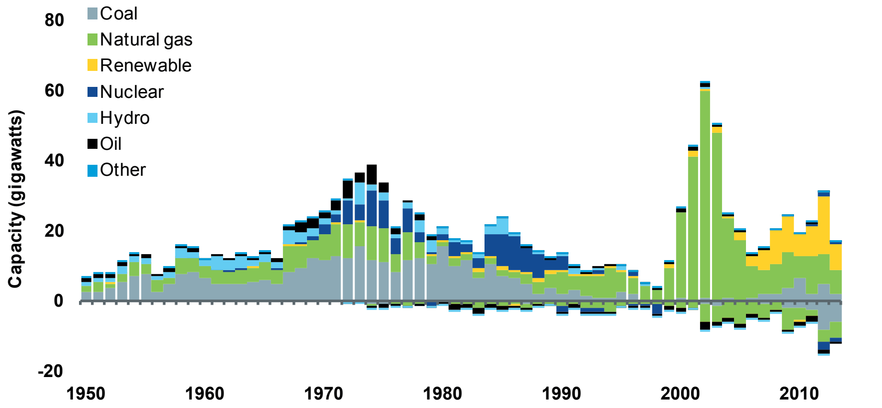
As a result, the United States may move down a path toward a less diverse power supply without consumers realizing the value of power supply diversity until it is gone. For example, if the US power sector had been all natural gas–fired during the shale gas era to date, the average fuel cost for power 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.

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

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.

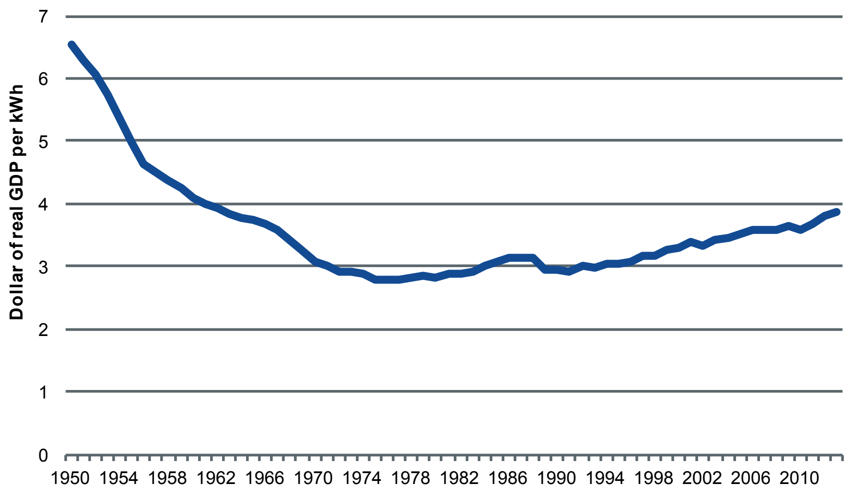
Power plant retirements typically need to be replaced because electricity consumption continues to increase. Although power demand increases are slowing compared to historical trends and compared to the growth rate of GDP, the annual rate of change nevertheless remains positive. US power demand is expected 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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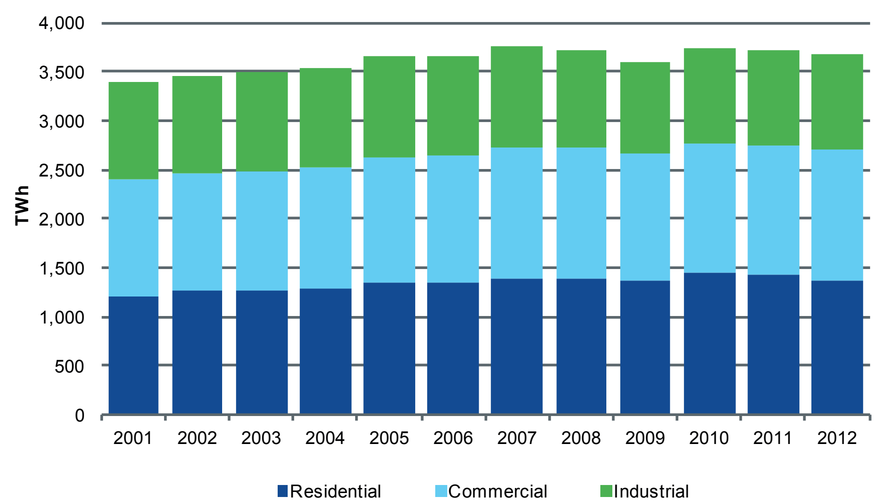
FIGURE 17

US electricity sales by customer class, 2001–12



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

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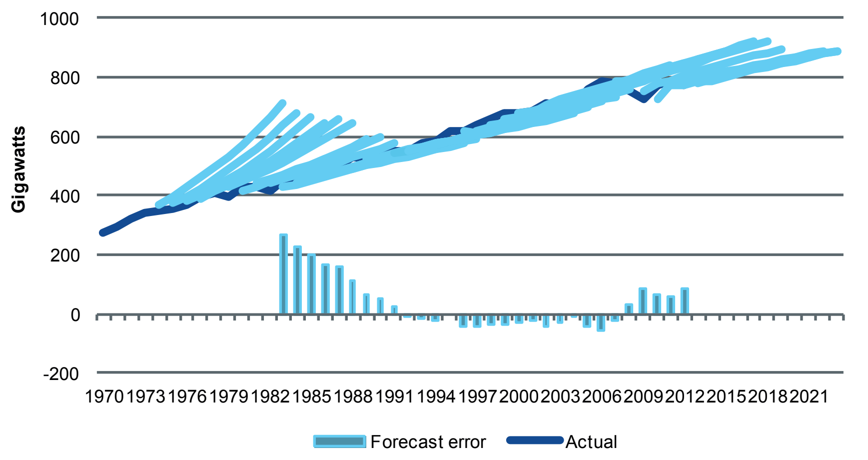
Annual power supply additions do not typically unfold simultaneously with demand increases. Historically, changes in power supply are much more pronounced than the changes in power demand. This uneven pace of change in the capacity mix reflects planning uncertainty regarding future power demand and a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

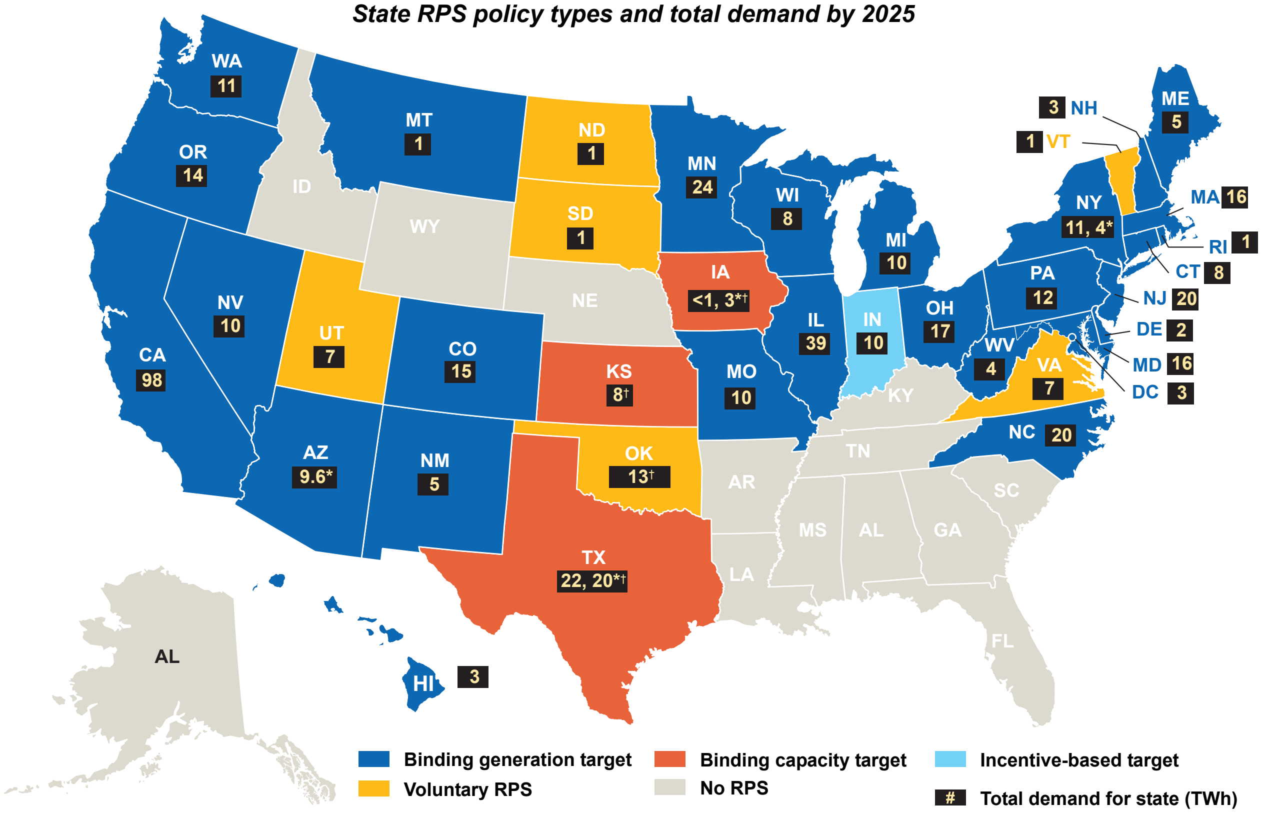
The influence of energy policy on power plant fuel and technology choice is dynamic. For example, as natural gas demand and supply conditions changed following the passage of the Fuel Use Act, the limits on natural gas use for power generation were eventually lifted in 1987. Whereas the Fuel Use Act 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

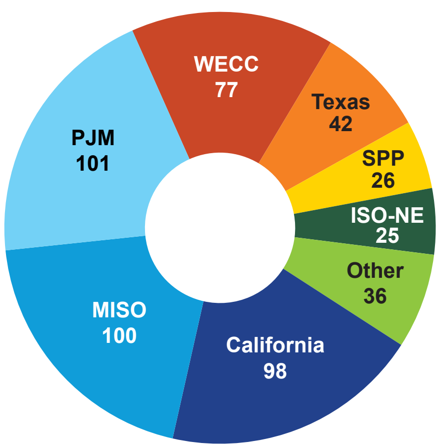
FIGURE 19

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

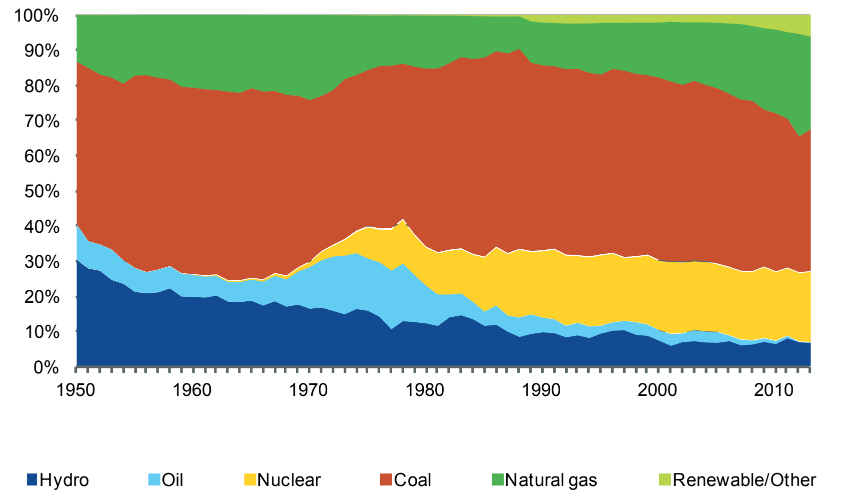
Source: IHS Emerging Energy Research

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,

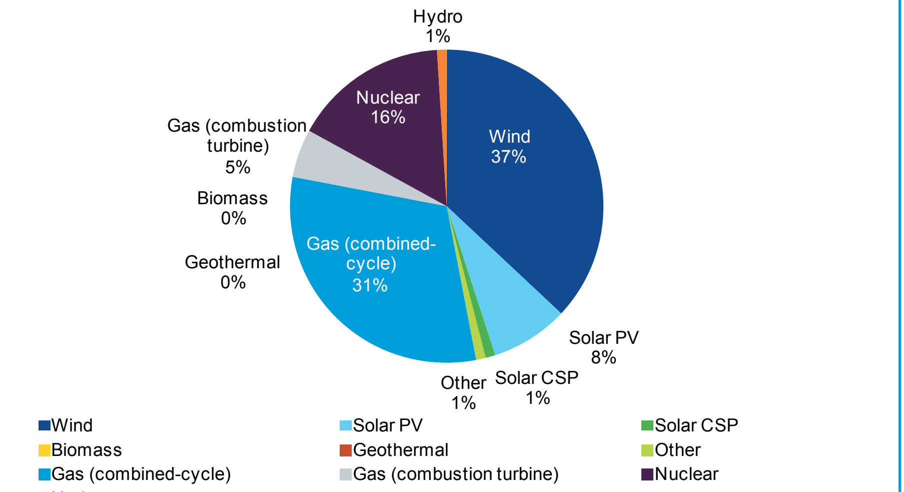
4. *New England Wind Integration Study* produced for ISO New England by GE Energy Applications and Systems Engineering, EnerNex Corporation, and AWS Truepower, 5 December 2010. Accessed 16 April 2014 (http://www.uwig.org/newis_es.pdf).

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

US capacity under construction: 34,620 MW



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

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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.

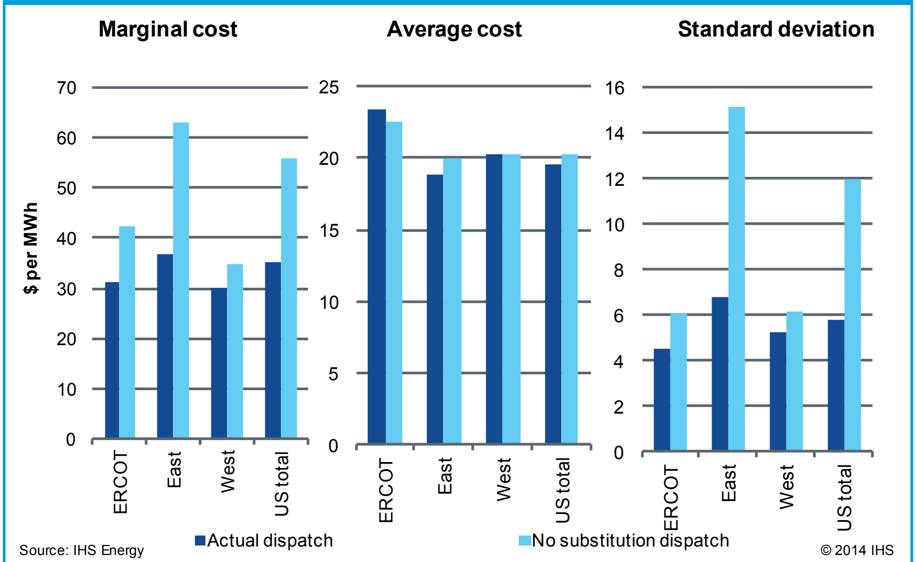
Quantification of the impact of fuel diversity within the US power sector involved a two-step process. The first step quantifies the current value of the substitution effect enabled by a diverse power generating portfolio. The second step quantified the additional value created by the portfolio effect.

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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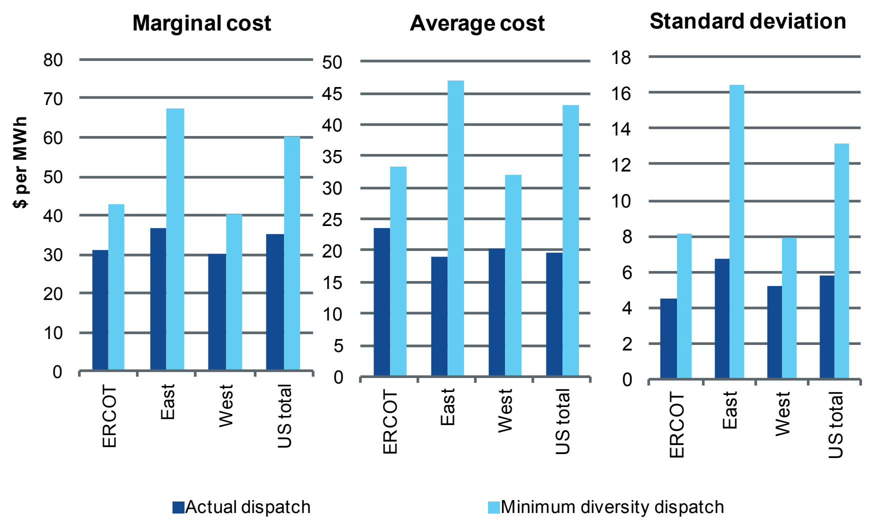
The value of the portfolio effect

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.

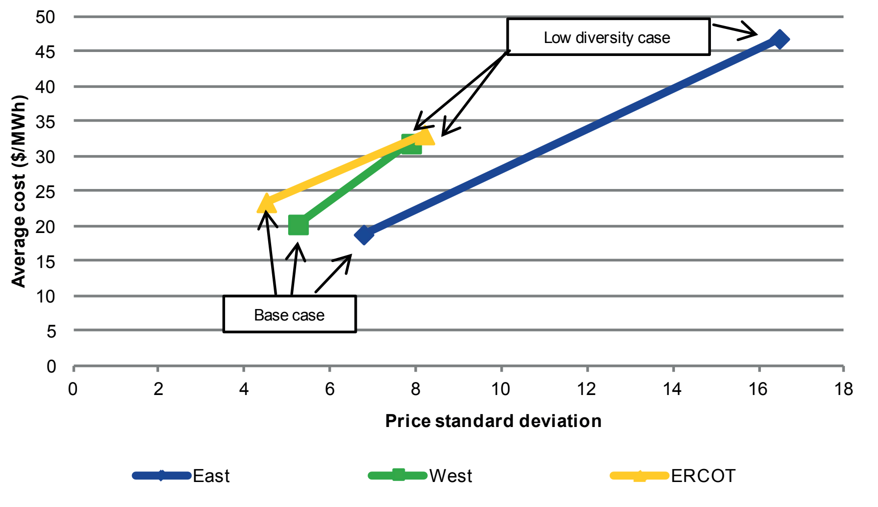
All existing power plants are economic to close and replace at some point in the future. The economic life of a power plant ends when the expected costs of continued operation exceed the cost of replacement. When this happens, the most cost-effective replacement power resource depends on the current 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 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.

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 24

Average cost: Base case versus low diversity case



Source: IHS Energy

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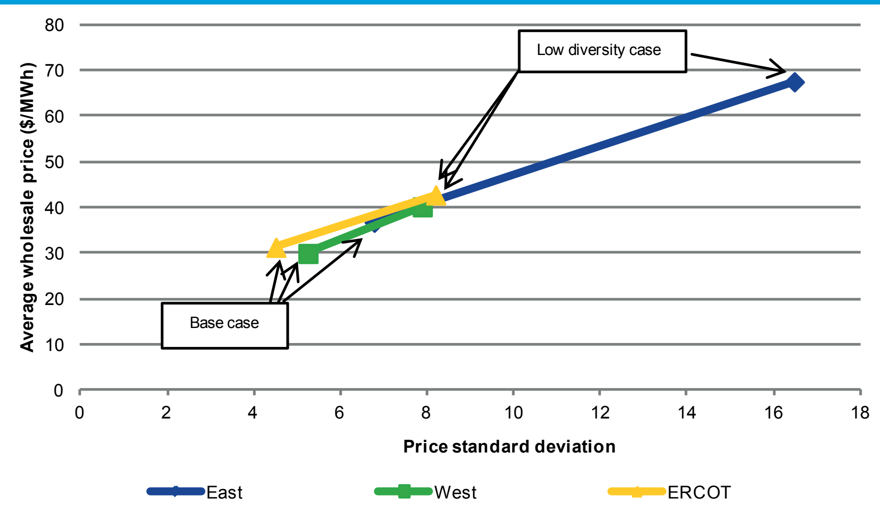
FIGURE 25

Average wholesale price: Base case versus low diversity case



Source: IHS Energy

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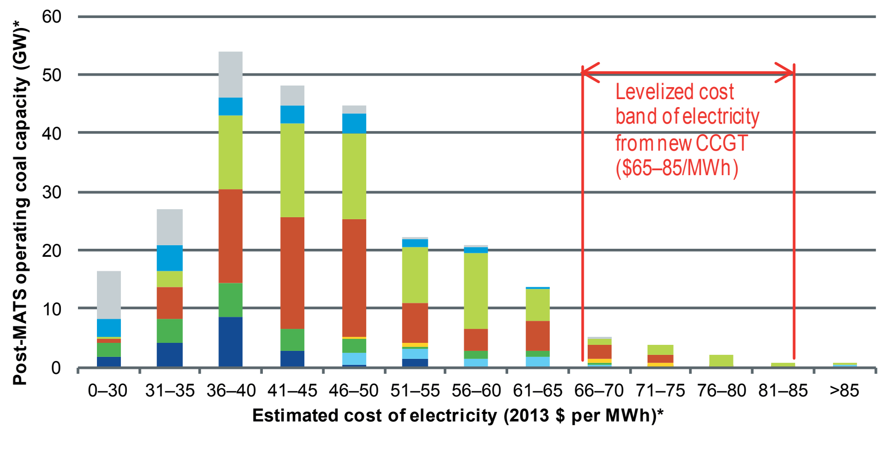
Figure 27 shows the going-forward costs of the existing US nuclear power plant fleet. As with the coal units, there is currently a high cost associated with premature closure. As a point of comparison, closing all existing nuclear power plants and replacing them as quickly as possible with natural gas–fired 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

Going-forward costs of the existing coal fleet



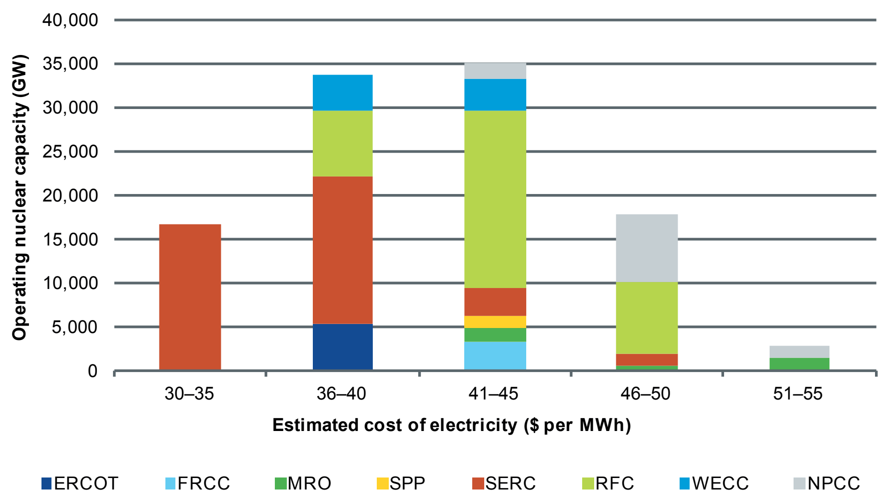
*Only includes those coal units that are forecasted to operate beyond 2020 in our reference case scenario. These coal units are retrofitted with conventional pollution controls.
Source: IHS Energy

Economywide impacts

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

FIGURE 27

Going-forward costs of the existing nuclear fleet



Source: IHS Energy

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

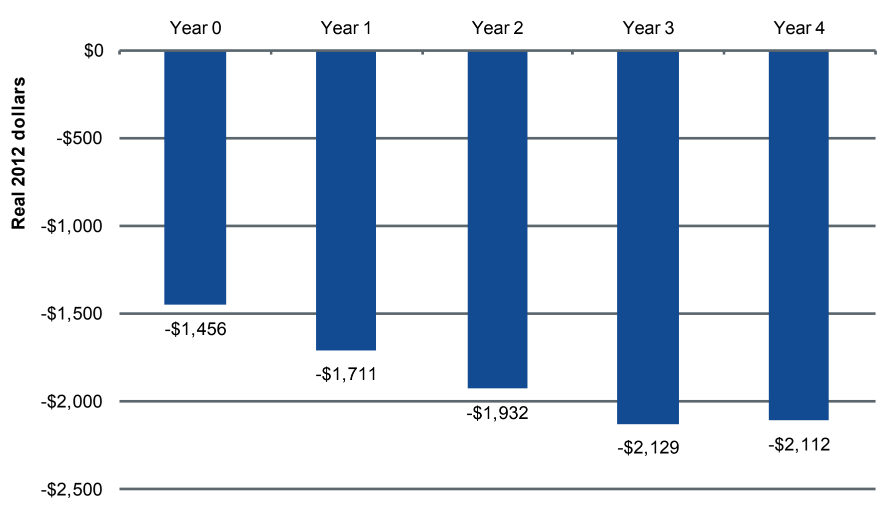
- A drop in real disposable income per household of about $2,100
- A reduction of 1,100,000 jobs
- A decline in real GDP of 1.2%

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

Impact of reduced diversity on real disposable income



Source: IHS Economics

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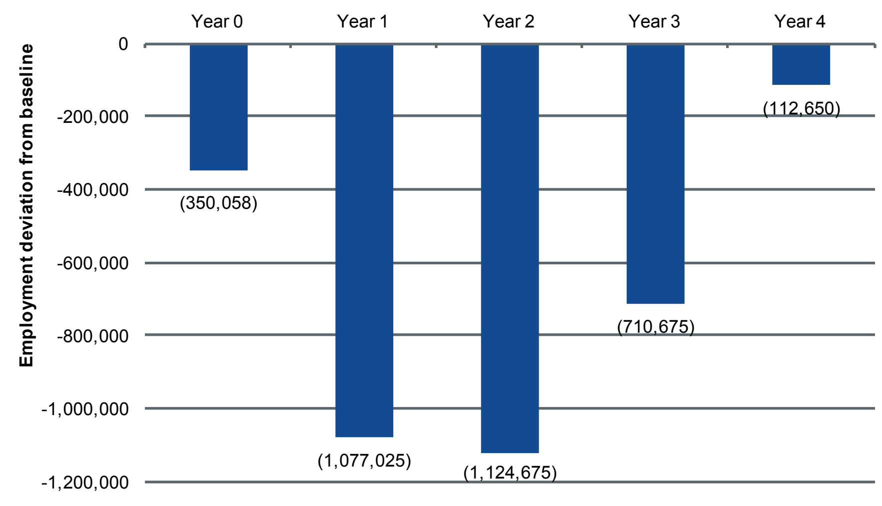
Businesses will face the dual challenge of higher operational costs coupled with decreased demand for their products and services. Industrial production will decline, on average, by about 1% through Year 4. This will lead to fewer jobs (i.e., a combination of current jobs that are eliminated and future 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

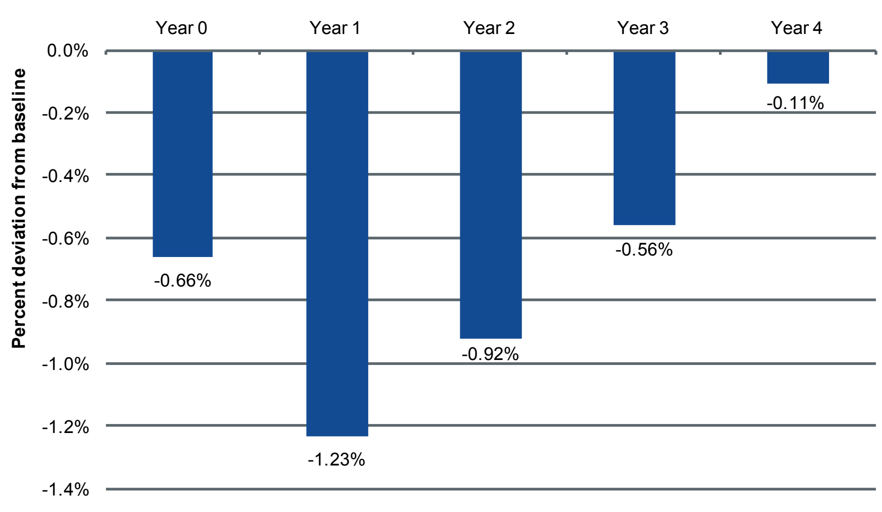
Impact of reduced diversity on employment (deviation from baseline)



Source: IHS Economics

FIGURE 30

Impact of reduced diversity on real GDP



Source: IHS Economics

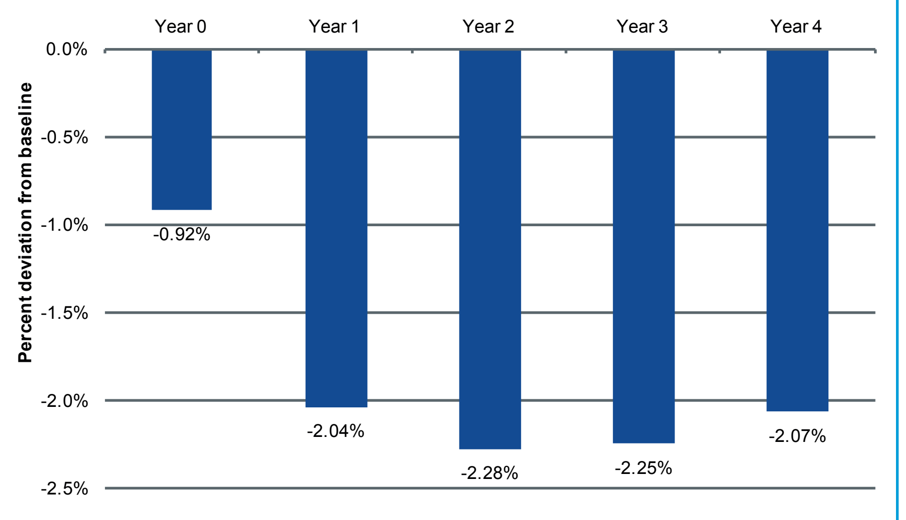
Consumption

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

Impact of reduced diversity on consumption



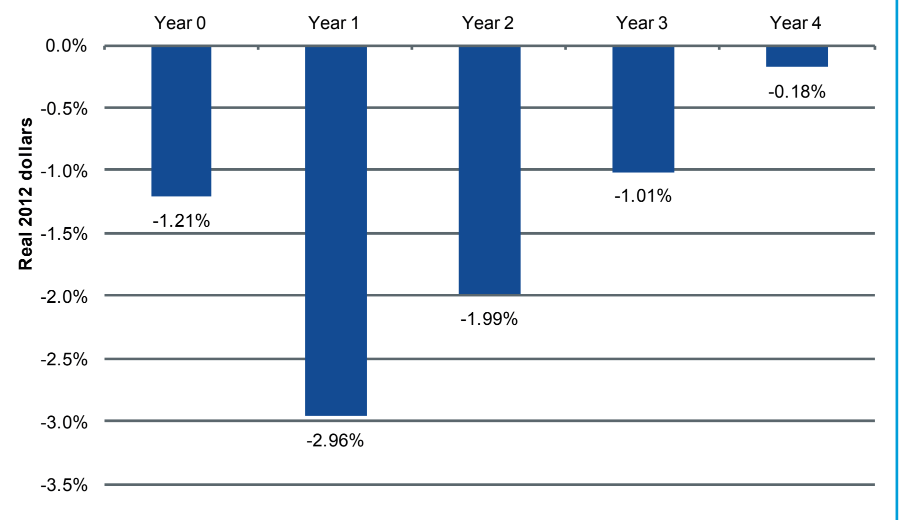
Source: IHS Energy © 2014 IHS

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

Impact of reduced diversity on investment



Source: IHS Energy © 2014 IHS

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.

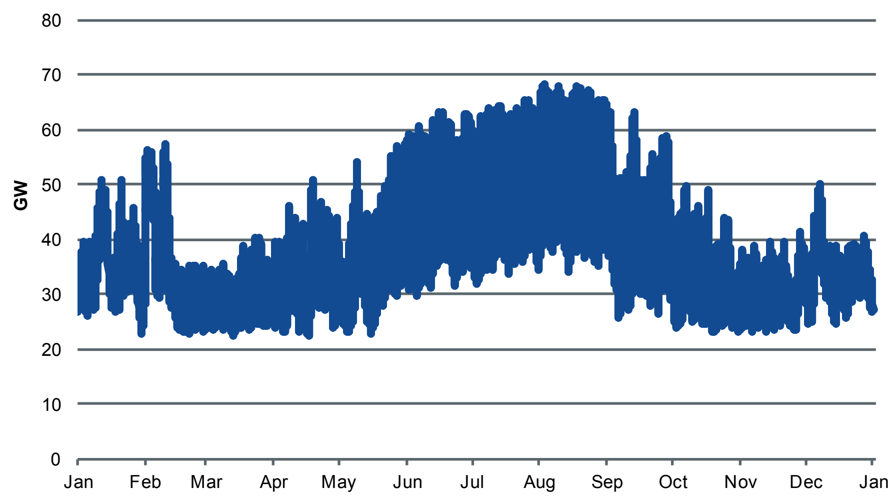
In order to reliably meet aggregate power demands, enough generating capacity needs to be installed and available to meet demand at any point in time. The overall need for installed capacity is determined by the peak demand and a desired reserve margin. A 15% reserve margin is a typical planning target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

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.

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

FIGURE A-1

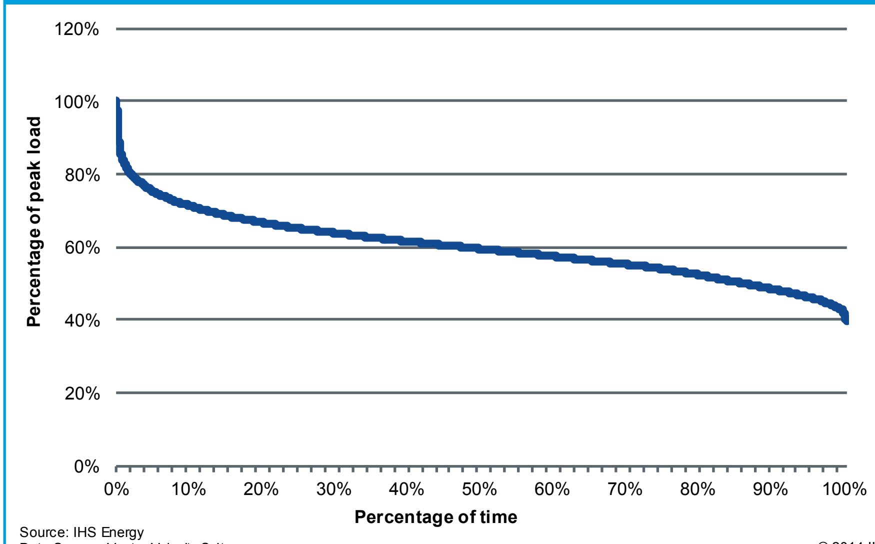
2011 hourly electric loads—ERCOT



Source: IHS Energy © 2014 IHS

FIGURE A-2

Load duration curve



Source: IHS Energy
Data Source: Ventyx Velocity Suite © 2014 IHS

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%.

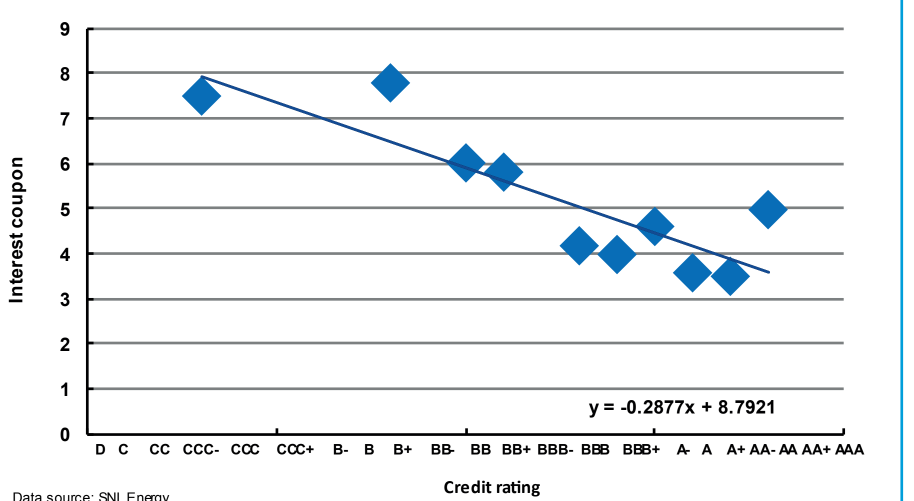
Power generating technologies have different risk profiles. For example, the fluctuations in natural gas prices and demand levels create uncertainty in plant utilization and the level of operating costs and revenues. This makes future net income uncertain. Greater variation in net income makes the risk 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.

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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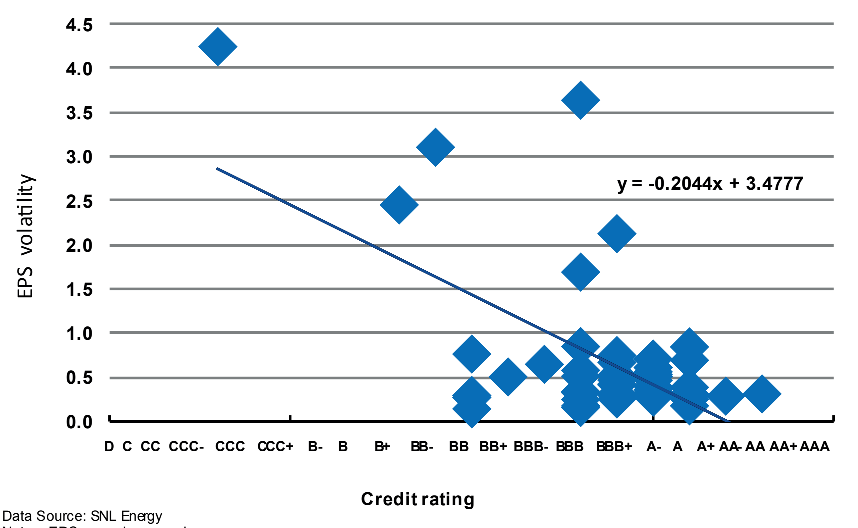
Lower credit ratings result from higher variations in net

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).

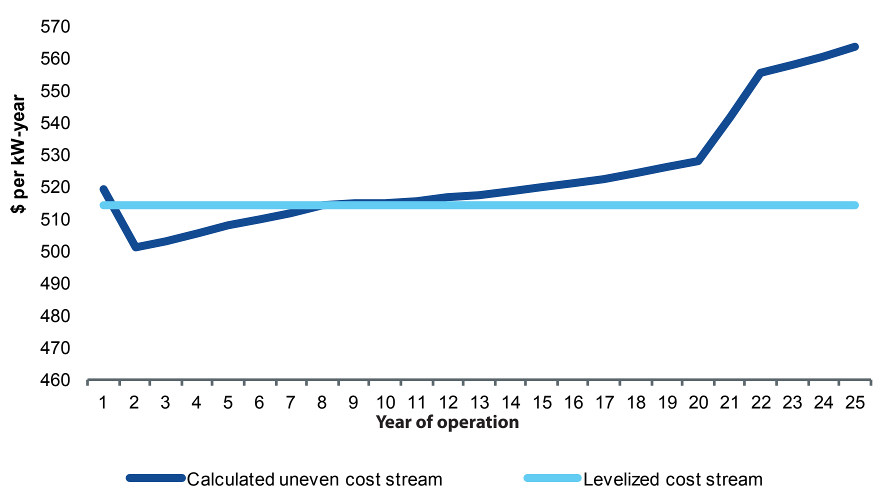
A levelized cost stream makes it possible to compare production costs at different expected utilization rates. A lower utilization rate forces spreading fixed costs over fewer units of output and thus produces higher levelized costs (see Figure A-6).

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

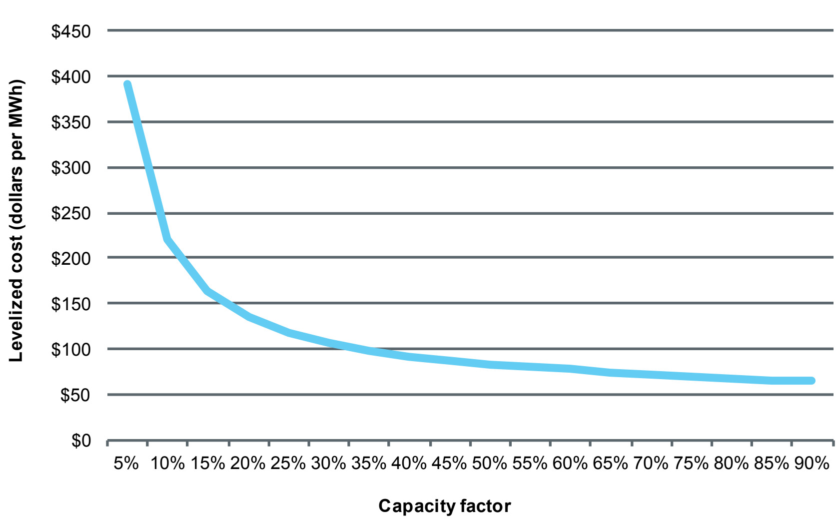
Cost stream comparisons—CCGT, 85% utilization rate



Source: IHS Energy © 2014 IHS

FIGURE A-6

LCOE of CCGT generation



Source: IHS Energy © 2014 IHS

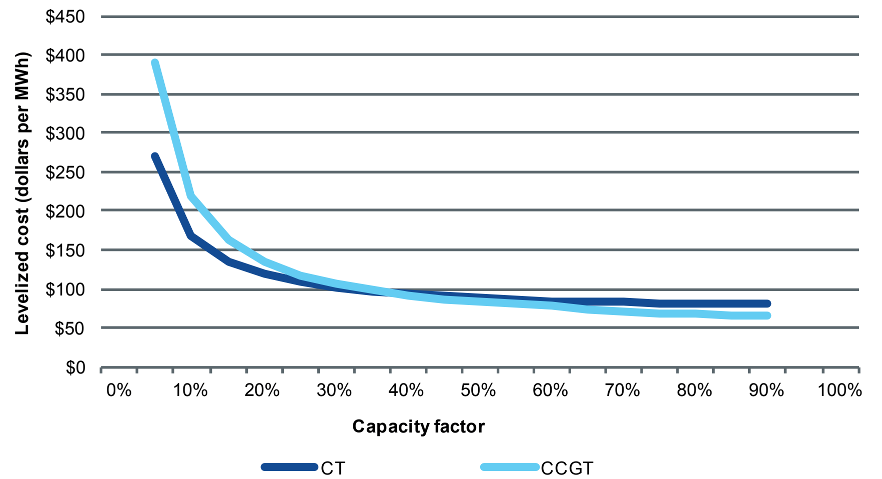
The levelized cost of production for each technology can be determined by finding the average load (and corresponding utilization rate) for the segment of the load duration curve (LDC) that corresponds to each technology (in this example, the two segments that are created by splitting the curve at the 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.

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

FIGURE A-7

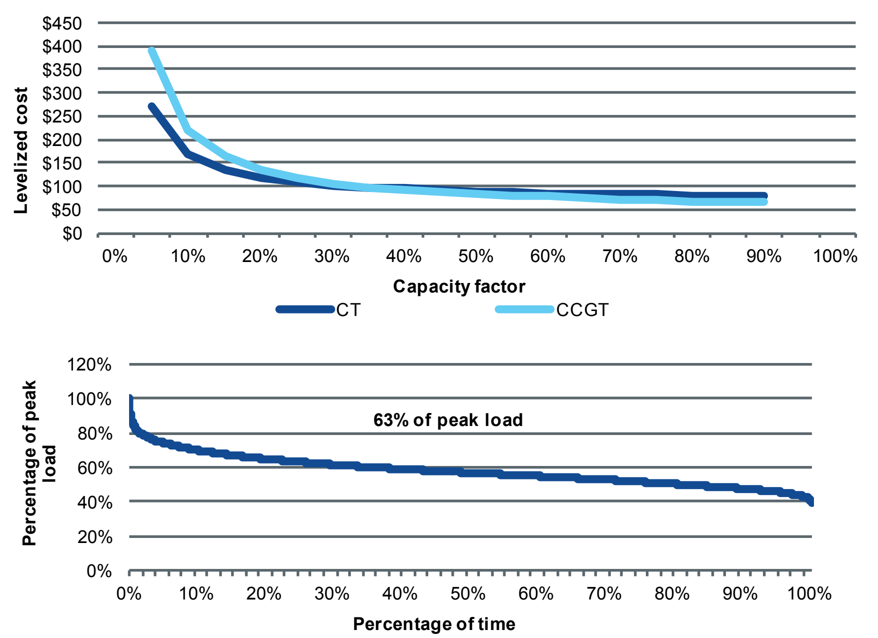
LCOE of CCGT and CT generation



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

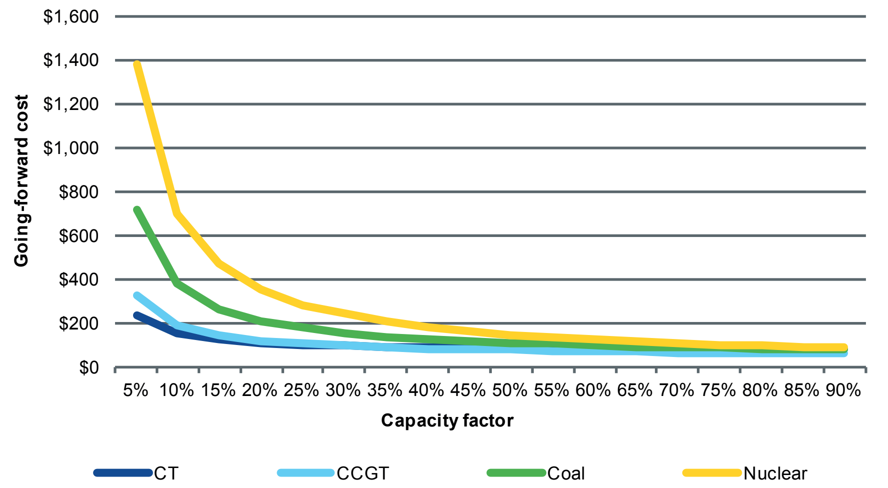
Source:

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

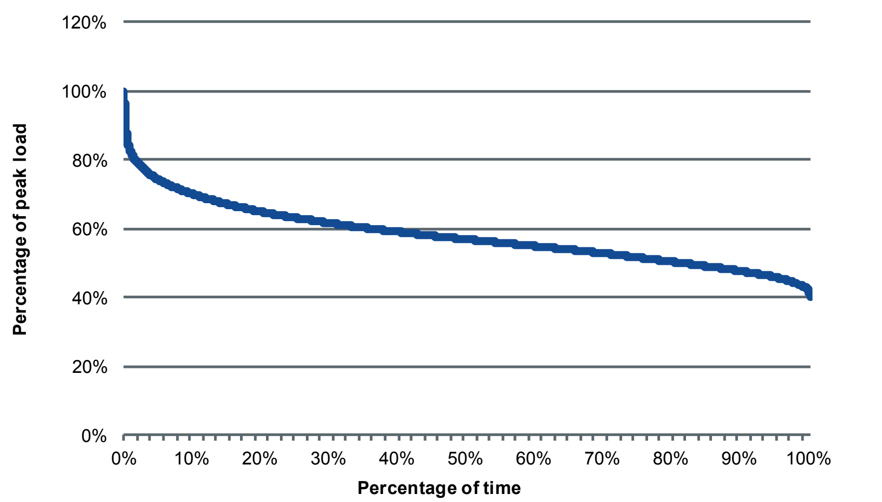
Levelized cost curves of generating resources



Source: IHS Energy

FIGURE A-10

Load duration curve, after solar additions



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

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.

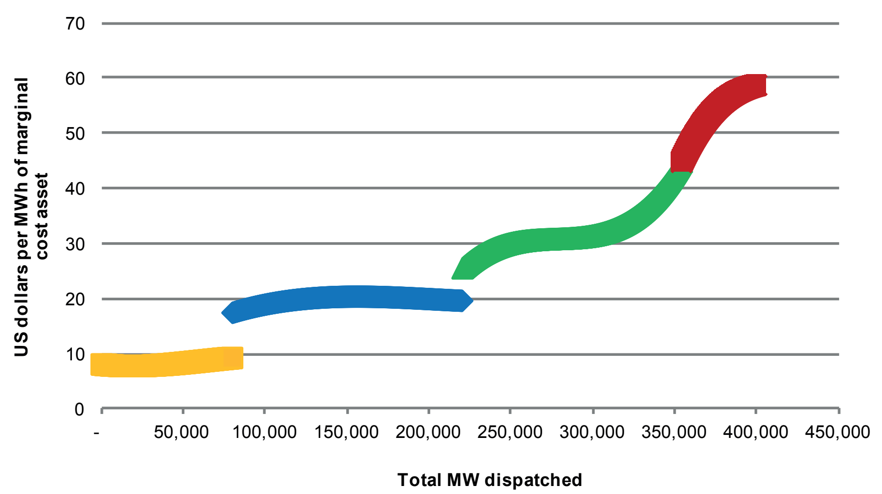
Each cost curve incorporates heat rate as a function of utilization rate.[14] *Heat rate* describes the efficiency of a thermal power plant in its conversion of fuel into electricity. Heat rate is measured by the amount of heat (in Btu) required each hour to produce 1 kWh of electricity, or most frequently 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.

FIGURE B-1

Representative supply curve



Source: IHS Energy
Data Source: Ventyx Velocity Suite

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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.

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:

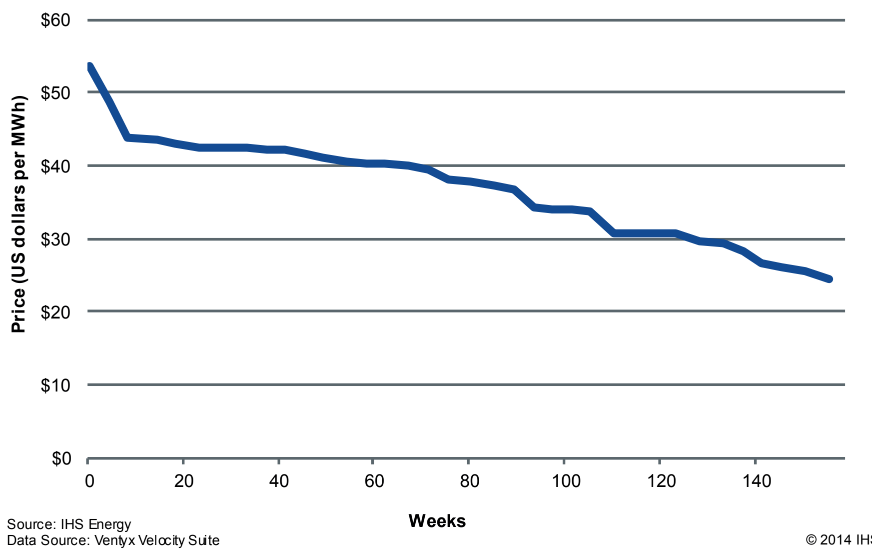
- **Power system SRMC/wholesale price**
- **Generation by fuel and technology type**
- **Average variable cost of production.** The average variable cost is calculated at each dispatch increment by taking the total cost at that generation level divided by the total megawatt dispatch.
- **Price duration 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

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.

FIGURE B-2

Representative price duration curve



Source: IHS Energy
Data Source: Ventyx Velocity Suite

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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