Company Exhibit _____

BEFORE THE
PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Application of Ohio Edison Company, The Cleveland Electric Illuminating Company and The Toledo Edison Company for Authority to Provide for a Standard Service Offer Pursuant to R.C. 4928.143 in the Form of an Electric Security Plan	)))))))	Case No. 14-1297-EL-SSO

SUPPLEMENTAL TESTIMONY OF

DR. LAWRENCE MAKOVICH

ON BEHALF OF

OHIO EDISON COMPANY
THE CLEVELAND ELECTRIC ILLUMINATING COMPANY
THE TOLEDO EDISON COMPANY

MAY 4, 2015

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Lawrence Makovich. My business address is 55 Cambridge Parkway, Cambridge, Massachusetts.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by IHS Energy ("IHS") as Vice President and Senior Advisor for Global Power. IHS is a company that provides data, analyses and strategic insights to businesses around the world with particular focus on the energy, automotive, chemical and defense industries, and I am an energy economist specializing in the analysis of the electric power industry.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND, PROFESSIONAL QUALIFICATIONS, AND EMPLOYMENT EXPERIENCE.

A. I have an undergraduate degree from Boston College where I majored in economics. My graduate degrees are both interdisciplinary and focused on economic policy. I earned a masters degree from the University of Chicago and a doctoral degree from the University of Massachusetts/Boston. I have been engaged in electric power research for over thirty-five years. In the past ten years, I have worked for IHS after it acquired Cambridge Energy Research Associates ("CERA") in September of 2004. Prior to becoming part of IHS, I led the research effort focusing on the power industry at CERA since 1994. Prior to that, I was the senior economist for electric power research at DRI/McGraw Hill for thirteen and one half years. I began my career by spending two years with National Economic Research Associates as a research associate involved in research used to support litigation in cases involving the electric power industry. A copy of my curriculum vitae is attached as Attachment LM-1.

I have testified numerous times before the U.S. Congress on electric power policy, and I have given presentations on the electric power industry to PJM Interconnection LLC ("PJM"), the Midcontinent Independent System Operator, Inc., the Edison Electric Institute, the Energy Initiative Symposium hosted by the Massachusetts Institute of Technology, Harvard Electricity Policy Group and the National Association of Regulatory Utility Commissioners, among others. My current research focuses on electric power market structures, demand and supply fundamentals, wholesale and retail power markets, emerging technologies and asset valuations and strategies. Among other things, I have studied the competitive power landscape in North America and the impact of deregulation on residential power prices. I also have extensively studied the value of U.S. power supply diversity.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony addresses certain benefits that can be produced by implementing the Economic Stability Program proposed by Ohio Edison Company, The Cleveland Electric Illuminating Company and The Toledo Edison Company (collectively, the "Companies"). The program involves a retail stability rider – Rider RRS – that flows through credits or charges to retail customers derived primarily from the costs and revenues associated with the energy, capacity and ancillary services of the Davis-Besse Nuclear Power Station ("Davis-Besse") and the W.H. Sammis Plant ("Sammis") (collectively, the "Plants"). I will discuss the value of power supply diversity and explain why preserving a diverse power supply is important to retail consumers. I also will address how existing base load power plants, such as Davis-Besse and Sammis, are necessary components of supply diversity and why the retirement of such plants can increase electric prices.

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS.

A. The Economic Stability Program will produce benefits for retail consumers because it will prevent the Plants from retiring before it is economic to do so. It makes economic sense for Ohio policy makers and the Public Utilities Commission of Ohio (the "Commission") to protect power supply diversity in Ohio over the long-term by approving the Companies' Economic Stability Program. The probability exists that these base load plants will retire prematurely because the value of fuel diversity is not being properly compensated by power market cash flows and thus properly internalized in current power plant decision making. Currently, PJM focuses on ensuring reliability by generating market cash flows that are intended to be sufficient to cover certain costs of a peaking unit. But cost effectively producing power supply requires more than simply having enough peaking units installed to ensure reliability. Therefore, although the theory behind the market design is that the lowest cost of capacity involves building a peaking unit, the lowest-cost reliable power supply portfolio is not made up entirely by peaking technologies. Efficient power supply requires having the right kind of power supply to provide customers with lower power prices and less variable monthly power bills. This cost-effective power supply portfolio is made up of a diverse mix of generation fuels and technologies. The problem is that inherent market flaws and imposed environmental policies have caused market clearing power prices to chronically fall short of covering the average total cost of efficient power supply – what I refer to as the "missing money" problem. The missing money problem disproportionally affects cycling and base load power plant cash flows and causes uneconomic retirements of these plants. These premature retirements reduce the fuel and technology diversity in the power supply portfolio that produces benefits for consumers.

Q. WHY IS MAINTAINING SUPPLY DIVERSITY IMPORTANT TO CONSUMERS?

A. Consumers have a strong preference for not paying more than they have to for reliable electricity. Consumers also prefer some degree of predictability and stability in their monthly power bills. If supply diversity is reduced – particularly by retiring existing coal and nuclear generating facilities before it is economic and replacing them with a combination of natural gas-fired units and renewable resources – consumers will see electric prices that are both higher and more volatile.

Q. WHEN IS IT ECONOMIC TO RETIRE A POWER PLANT?

A. Without a surplus of generating capacity, it is economic to retire a power plant when the cost of continued operation exceeds the cost of closing the plant and replacing it with the lowest cost source of equivalent power supply. Equivalent power supply involves the production of electric capacity (kilowatts), electric energy (kilowatt-hours) and system benefits (cost risk management, technology performance risk management, production efficiency, environmental impact management, grid locational benefits) created as part of a power supply portfolio. Wind and solar resources are not realistic substitutes because they are not equivalent power supply sources in meeting power customer demands.

Q. HAVE YOU ANALYZED THE VALUE OF DIVERSITY IN A POWER SUPPLY PORTFOLIO?

A. Yes. I directed research and analysis of the value of fuel and technology diversity in the current U.S. power supply portfolio and released a report on this research in 2014. The report explains the engineering and economic principles that lead to the conclusion that an integration of different fuels and technologies produces the least-cost power production mix. The analysis shows that the current diversified portfolio of U.S. power supply lowers the cost of generating electricity by more than $93 billion per year compared to a less diverse portfolio with no meaningful contributions from coal-fired or nuclear power plants, a smaller contribution from hydro-electric resources (4% of generation) and significant increases in wind and solar (22 percent of generation) and natural gas-fired power plants accounting for the remaining power production (74 percent of generation). The less diverse power supply case produced monthly power bills that were 25 percent higher, and twice as variable, as the current power bills reflecting the costs of the current diverse power supply portfolio. This study is attached as Attachment LM-2 and incorporated into my testimony.

Q. WHY DID YOU CONDUCT THE STUDY ON POWER SUPPLY DIVERSITY?

A. The value of fuel and technology diversity in the U.S. power supply portfolio is simply being taken for granted because we inherited a diverse power supply portfolio reflecting fuel and technology choices made decades ago. Current retirements are disproportionately reducing coal and nuclear shares in the capacity mix. I conducted this study because I believed that quantification of supply diversity benefits would help to inform the current policy debates and enable policy makers to take corrective action.

Q. WHAT IS THE "MISSING MONEY" PROBLEM?

A. Competitive markets fail to balance demand and supply at market-clearing prices high enough to support the full cost of supply with the desired level of reliability. It should be cost effective to retire and replace a power plant only when its continued cost of operation becomes greater than the cost of replacement. In PJM, as in other markets, market-based cash flows for energy and capacity are *chronically* and artificially too low to cover the costs of a power supply portfolio that delivers reliable and efficient electric service.

Q. WHAT ARE THE CAUSES OF THE MISSING MONEY PROBLEM?

A. There are two root causes of the missing money problem. First, power generation technologies have inherent characteristics that prevent electric energy markets from delivering prices high enough to balance demand and supply in the long run. Second, environmental regulations imposed on power supply created the unintended consequence of further suppressing electric energy market prices. Both the inherent and the imposed dimensions of this problem cause a persistent gap between energy market prices and average total costs.

Q. IS THE MISSING MONEY PROBLEM NEW OR UNIQUE TO THE POWER INDUSTRY?

A. No. A nineteenth century French engineer and economist, Jules Dupuit, analyzed market failure in the railroad industry resulting from the gap between market prices and average total costs.[1] Dupuit illustrated the root cause of the problem by developing the example

[1] Jules Dupuit. "De l'Influence des Péages sur l'Utilité des Voies de Communication." *Annales des Ponts et Chaussées* no. 207, 1849, p. 170–248.

of a bridge—a technology with a large upfront capital cost and thus a positive average total cost, but also a technology with a zero marginal cost for providing bridge crossings. The incremental cost is zero because it costs the bridge owner nothing extra to let someone cross the bridge.[2] Dupuit understood that in a marketplace, all rival bridge owners would be willing to take any customer payment above zero in order to provide some contribution to their fixed costs. He argued that a market for bridge services would not work because competitive forces would logically drive the market price toward zero. Thus, the market would inherently fail to provide cost recovery and thus fail to attract the investment needed to produce a stable long run market result.

Q. WHY DO YOU SAY THAT POWER TECHNOLOGIES HAVE THE INHERENT CHARACTERISTICS TO PRODUCE THIS TYPE OF MARKET FAILURE?

A. Some power production technologies have cost characteristics similar to Dupuit's bridges with relatively large upfront costs and relatively low (or virtually no) marginal costs. The most striking example is wind and solar technologies, which have significant upfront costs and almost zero incremental generating costs. More generally, the technologies employed to cost-effectively generate electricity do not have the incremental cost characteristics needed to produce a textbook market outcome in which prices keep demand and supply in long-run balance.

Q. DO CONTEMPORARY ECONOMISTS RECOGNIZE THE MISSING MONEY PROBLEM IN POWER MARKETS?

A. Yes. The missing money problem has been identified as a root cause of the California power crisis in 2000 and 2001. The term *missing money* was first used to describe fixed

[2] *Jules Dupuit. "De la mesure de l'utilité des travaux publics." Annales des Ponts et Chaussees, second series, VIII, 1844.*

cost recovery shortfalls in power by Cramton and Stoft in their 2006 paper, "*The Convergence of Market Designs for Adequate Generating Capacity*," written for the California Independent System Operator's Electricity Oversight Board.

Q. HOW DO ENVIRONMENTAL POLICIES CONTRIBUTE TO THE MISSING MONEY PROBLEM?

A. A power market with a well-designed energy and capacity market can produce prices that will ensure enough capacity is built in a portfolio made up of peaking, cycling and base-load power plants. However in most cases, very little of the cost-effective generating portfolio will be made up of wind and solar technologies. This market outcome is at odds with certain environmental policies such as programs intended to address global warming. As a result, policy interventions, including subsidies and the imposition of mandates for renewable power generation shares, have been imposed to override this market outcome. These market interventions increase the amount of technologies with a zero marginal cost in the market supply curve. The impact is that whenever these resources are producing electric energy, the shift in the electric energy market supply curve lowers the market-clearing electric energy price.

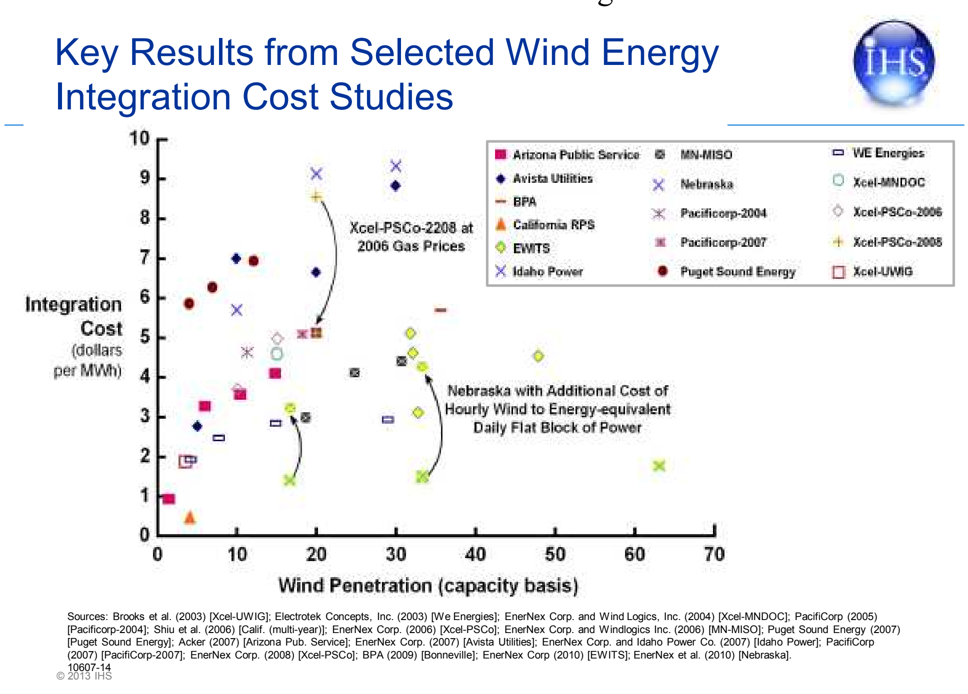
Q. IS THE ENERGY PRICE SUPPRESSION FROM IMPOSING RENEWABLE MANDATES THE REASON FOR MISSING MONEY IN COMPETITIVE GENERATOR CASH FLOWS?

A. The chronic energy price suppression is only part of the problem. Mandates for renewable power and subsidies based on renewable output depress wholesale prices. In addition, on the supply side, mandates for renewable power reduce power plant utilization rates and cause power plants in the supply portfolio to start up, ramp up and down, and shut down more frequently to back up and fill in for the intermittent pattern of renewable power generation. The combined effect is to depress energy market revenues and increase variable operating costs for non-peaking power plants. As a result, the market interventions impose missing money shortfalls in market cash flows and cause an under-recovery of the cycling and base load costs needed in an efficient generation supply portfolio. It is important to note, however, that renewable mandates and renewable supply are only part of the missing money problem. There are other contributors.

Q. IS THERE ANY EVIDENCE OF HIGHER OPERATING COSTS BEING IMPOSED ON NON-PEAKING POWER PLANTS?

A. Yes. Figure 1 shows the results of a number of renewable integration studies that show not only that intermittent renewable power imposes costs but that these integration costs increase as the penetration of intermittent generation increases.

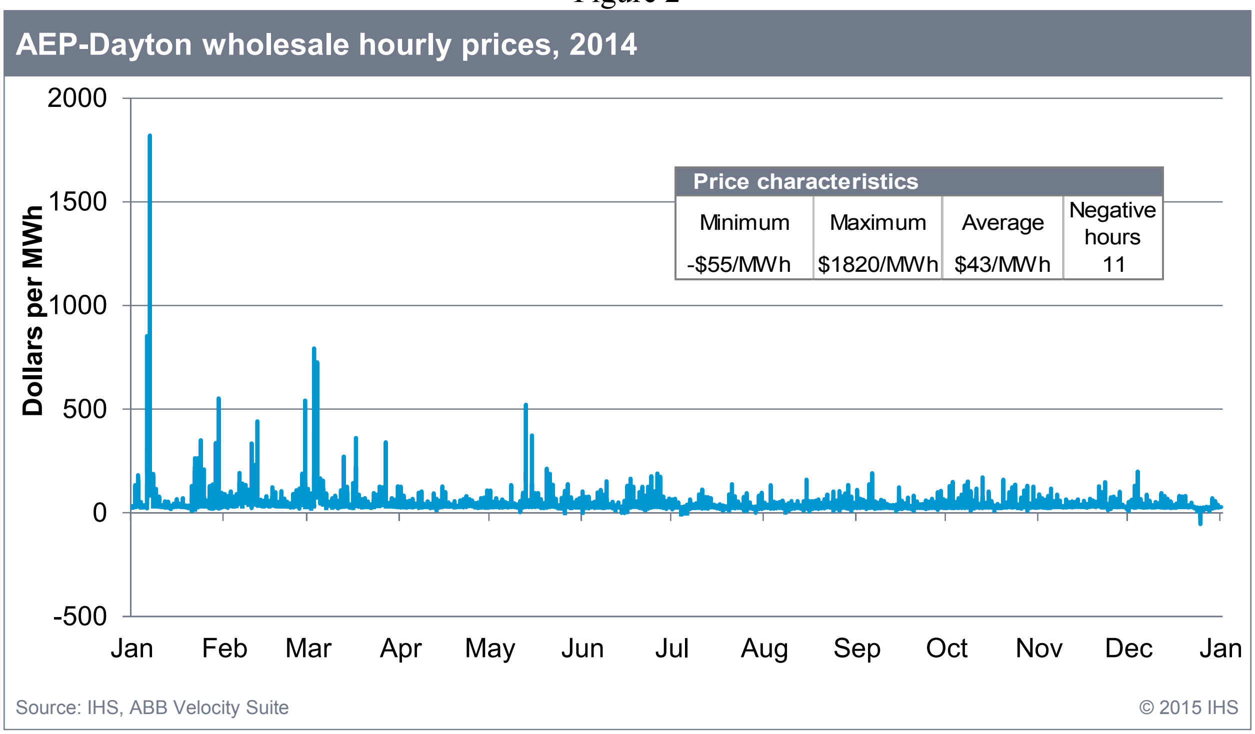
Figure 1



Q. IS THERE ANY EVIDENCE OF THE EXTREME CASE OF ENERGY PRICE SUPPRESSION CAUSING NEGATIVE POWER PRICES IN THE PJM MARKETPLACE?

A. Yes. When demand and supply conditions cause rival wind and solar generators to set the market price, the price suppression from renewable power mandates causes the price to clear at a negative level within the PJM system, as shown in Figure 2.

Figure 2



Q. WHAT HAS PJM DONE TO ADDRESS THE MISSING MONEY PROBLEM?

A. PJM recognized the inherent dimension of the missing money problem would prevent an energy market alone from providing adequate cash flows to keep demand and supply in balance over the long run. As a result, PJM designed its power marketplace to have a capacity market alongside its energy market right from the start when the power market opened in 1997. The goal of the capacity market is to ensure reliability by providing enough cash flows from capacity and energy markets to cover the net cost of entry for the lowest cost source of capacity. This addresses the inherent dimension of the missing money problem, but does not remedy the imposed dimension of the missing money problem resulting from renewable energy mandates. Therefore, a persistent gap is likely in the future between market-based cash flows and the cash flows needed to recover the average total cost of power supply, particularly for cycling and base load units.

Q. HOW GREAT IS THE SHORTFALL IN CASH FLOWS?

A. The cost recovery shortfall for a new base load power plant in PJM is more than ten percent of the annual levelized cost of new entry ("CONE"). A new natural gas-fired combined cycle power plant provides a cost benchmark for the cost of new entry for a power generating technology in a base load mode of operation. Current market conditions illustrate this cost recovery shortfall, with the current market providing approximately $48/MWh to a replacement power plant requiring approximately $55/MWh to cover its annual levelized costs.

Using IHS internal metrics, upfront capital costs would run at around $1,400/kW. With an annual levelized carrying charge rate of 14%, the annual fixed cost would be $196/kW. In a base load mode of operation with an 85% plant factor, this would be equivalent to a $26/MWh cost. On the variable cost side, assuming a heat rate of around 7,000 Btu per KWh and using a delivered price of natural gas of around $3.50 per million Btu, the fuel cost would be around $25/MWh. In addition, other variable costs would include non-fuel operation and maintenance costs of around $4/MWh. Therefore, the variable cost of generation would be roughly $29/MWh. Thus altogether, the replacement power plant would need market prices to cover about $55/MWh.

In 2014, the average price of electric energy at the Dayton/AEP hub was $43/MWh. The capacity price in PJM recently cleared around $40/kW per year. Again, using an 85%

plant factor, this capacity price translates into a \$5/MWh capacity payment. Thus, market payments of approximately \$48/MWh are coming up about 12% short of covering the replacement costs of a base load power plant. This kind of base load cost recovery shortfall has been chronic in PJM for over a decade.

Q. WHY ARE YOU DISCUSSING THE MISSING MONEY PROBLEM IN THIS CASE?

A. The missing money problem is a problem left for PJM and other markets to sort through and attempt to correct. I discuss it here in my testimony to appropriately inform the discussion on how the Plants at issue in this case can be exceptional assets from an operations perspective but nevertheless be financially challenged.

Q. BASED ON YOUR DISCUSSION OF THE MISSING MONEY PROBLEM, HOW DO YOU VIEW THE COMPANIES' ECONOMIC STABILITY PROGRAM?

A. The Economic Stability Program is a reasonable effort to address the missing money problem by compensating the Plants for system benefits that are not explicitly compensated for in the marketplace. One of those benefits is supply diversity, including the system reliability and price stability benefits provided by coal and nuclear base load plants with on-site fuel supply. Ohio may also decide that the Plants have value-of-service attributes that include economic impact (jobs, tax basis) and environmental externalities.

Q. HOW DOES THE ECONOMIC STABILITY PROGRAM ADDRESS THE MISSING MONEY PROBLEM AND PRESERVE SYSTEM DIVERSITY?

A. The Economic Stability Program addresses the missing money problem and prevents uneconomic retirements of cycling and base load power plants that would move the generation portfolio toward a more expensive fuel and technology mix. Power price increases would follow because power production costs would be higher. Cycling and base load power plants are part of a cost-effective mix because of their relative operating efficiency. These power plants have capacity costs in excess of the combustion turbine, but they have a lower overall power supply cost because the expected value of the fuel savings compared to a combustion turbine are more than enough to pay for the higher upfront capacity costs. Thus, some of the additional capacity costs over and above combustion turbine costs in a power supply portfolio are cost-effective investments in production cost efficiency. At a time when current retirements are disproportionately reducing the coal and nuclear shares in the capacity mix, the Economic Stability Program preserves cost-effective coal and nuclear facilities that contribute to production cost efficiency.

Q. WHAT BENEFITS DOES A DIVERSE POWER SUPPLY PORTFOLIO PROVIDE BEYOND GREATER PRODUCTION COST EFFICIENCY?

A. Investments in a diverse portfolio also provide production cost risk management. The cost of generating electricity is inherently uncertain. Oil, natural gas, coal, and uranium prices are difficult to predict and are prone to multiyear price cycles, short term price volatility, and deliverability constraints. Since price movements of various fuels are not highly correlated, a diverse portfolio of fuels and technologies provides the most cost-effective way to manage the cost risk of power production.

Power generation technologies also have different performance risks. For example, hydroelectric power plants are limited by drought and natural gas-fired power plants face fuel deliverability risks from natural gas pipeline constraints (as we saw during the Polar Vortex in 2014). Since performance characteristics of different generation technologies are not highly correlated, a diverse portfolio of technologies provides the most cost-effective way to manage the risk of power technology performance. Quite simply, a diverse fuel and technology mix in a generation portfolio creates benefits because "all your eggs are not in one basket."

Q. WHY IS RISK MANAGEMENT IMPORTANT?

A. Electric consumers reveal a preference for stable and predictable power prices. In addition, risk management reduces the variation in power producer costs, and thus the variation in their market cash flows. The costs of power supply are lowered when more stable cash flows lower the amount of working capital required to manage these variations. In addition, a diverse power supply portfolio produces less volatile earnings for power suppliers and thus lowers the risk of returns for investors. A lower risk profile produces a higher credit rating for a diversified power supplier and a lower cost of capital.

Q. ARE THERE ADDITIONAL BENEFITS PROVIDED BY DIVERSITY IN POWER SUPPLY?

A. Yes. Some investments in power plants manage the environmental impact of power generation. For example, a nuclear power plant reduces the overall carbon footprint of power system operations. Therefore, some of the fixed costs of a nuclear power plant that are over and above those of a peaking technology pay for the production of fewer CO_2 emissions compared to the natural gas-fired combustion turbine technology.

Q. HOW DO THESE ISSUES RELATE TO THE PLANTS?

A. The base load plants involved in the Economic Stability Program are specific examples of power plants that are at risk of retiring before it is economic to do so. The Plants involve fixed costs to fund greater power production efficiency, and provide production cost risk management and technology performance risk management, as well as provide environmental impact management. The Plants participate in the PJM energy market and produce system-wide benefits for consumers. But these benefits are at risk of going away because market interventions result in a missing money problem for the Plants. Therefore, the Economic Stability Program addresses the missing money problem by fully covering the additional costs associated with investments that produce cost-effective fuel diversity and efficiency, fuel cost risk management, technology performance risk management and environmental impact management.

Q. ARE 15-YEAR COMMITMENTS TO PAY FOR THESE BASE LOAD POWER PLANTS IN THE ECONOMIC STABILITY PROGRAM A VIABLE APPROACH FOR THE MISSING MONEY PROBLEM?

A. Yes. Using long-term contracts to cover the total costs of economic cycling and base load power plants is a reasonable approach we have identified as having a high probability of meaningfully addressing the missing money problem and thereby preserving supply diversity benefits for retail customers.

Q. HOW DO YOU RESPOND TO THE COMPLAINT THAT COST-BASED COMPENSATION FOR THE PLANTS IS AN UNECONOMIC SUBSIDY?

A. I reject this characterization as economically unsound. Ohio must face the conundrum that the Plants are both economic (because the cost of continued operation is below the cost of closing the Plants and replacing them with the lowest-cost source of equivalent power supply) and at risk of retirement (because market compensation is chronically below their average total cost). The Plants have not failed an efficient market test, so the compensation the Plants receive for value-of-service attributes is not a subsidy. Indeed, when PJM capacity and energy cash flows increase in future years to cover the costs of a diverse power supply portfolio, then customers will be further benefitted from the Economic Stability Program in place. Because the Plants are not economic to retire, adequate market cash flows would simply flow to retail customers through Rider RRS.

Q. IF THE PERCENTAGE OF COAL-FIRED UNITS DECREASES WHILE THE PERCENTAGE OF WIND, SOLAR AND NATURAL GAS-FIRED RESOURCES INCREASES IN THE POWER SUPPLY PORTFOLIO, WON'T CONSUMERS BENEFIT FROM THIS INCREASED DIVERSITY?

A. A cost-effective mix does not mean equalizing generation shares. Coal and nuclear base load units with on-site fuel supplies have system benefits that cannot be duplicated by wind and solar resources. In addition, a portfolio more reliant on natural gas-fired generation will see higher prices and more price volatility. I would expect that, all else equal, the retirement of Sammis and Davis-Besse in combination with thousands of megawatts of other coal-fired generation in Ohio and elsewhere would result in retail power prices in Ohio that are higher and more volatile than would otherwise occur.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes. I reserve the right to supplement my testimony.

Curriculum Vitae

LAWRENCE J. MAKOVICH

EDUCATION:

University of Massachusetts / Boston
Ph.D., Public Policy, 1997
Dissertation: Fiscal Policy Perversity in State and Local Government Spending

University of Chicago
M.A., Social Science, 1980
Concentration: Economic Policy
Thesis: The Economic Effects of Price Fixing Cases

Boston College
B.A., magna cum laude, 1977
Major: Economics

EXPERIENCE:

Vice President and Chief Power Strategist

2004 to present IHS, Cambridge MA.

Maintain senior client relationships, present IHS/CERA research, conduct multi-clent studies, deliver consulting engagements and advance energy research.

Senior Director

6/94 to 2004 Cambridge Energy Research Associates, Cambridge MA.

Established CERA electric power business and managed the CERA Americas Group. Provided strategic planning support and delivered the research agenda to clients.

Principal

12/80 to 6/94 DRI/McGraw-Hill, Lexington, MA.

Served as the senior economist for electricity market analysis. Developed the DRI Electricity Market Model, prepared periodic forecasts, wrote review articles, conducted economic studies, performed policy analyses, and contributed as a member of the DRI Macroeconomic forecasting council.

Instructor

1989–1994 Northeastern University Graduate Business School, Boston, MA.

Taught both the macroeconomic and microeconomic courses in managerial economics.

Research Associate

1977–1979 National Economic Research Associates, New York, NY

Prepared analyses and testimony for electric utility rate and antitrust cases.

Lawrence Makovich

SELECTED PUBLICATIONS:

1. *Missing Money in Competitive Power Generator Cash Flows: Causes, consequences and solutions,* IHS Energy Special Report, November, 2014
2. *Bridging the Missing Money Gap: Assessing alternative approaches,* IHS Energy Special Report, October, 2014.
3. *The Value of US Power Supply Diversity*, IHS Energy Special Report, July, 2014.
4. *Power Supply Cost Recovery: Bridging the Missing Money Gap*, IHS CERA Private Report, 2013
5. *Too Much, Too Fast: The Pace of Greening the Ontario Power System*, IHS CERA Private Report, 2012
6. *The Volker Rule: Impact Assessment on the US Energy Industry and Economy*, (Chapter 3) IHS CERA Multi-client Study, 2012
7. *Recalibrating Power Supply Cost Assessments: Accounting for Integration*, IHS CERA Private Report, 2012
8. *The Smart Grid: Separating Perception from Reality*, "Issues in Science and Technology, National Academy of Sciences, Spring 2011
9. *The "Smart Grid Narrative" and the "Smarter Grid": Revolution versus Evolution—Which Way Forward*, IHS CERA Multi-client Study, 2010 (with co-authors)
10. *Putting Energy Back to Work, Energy for Economic Growth*: Energy Vision 2012, World Economic Forum, 2012
11. *The US Power Demand Tug-of-War*, IHS CERA Private Report, 2011
12. *Fueling North America's Energy Future: The Unconventional Natural Gas Revolution and the Carbon Agenda*, (Chapter 6), IHS CERA Multi-client Study, 2010
13. *Energy Efficiency—An Investment Perspective, Towards a More Energy Efficient World: Energy Vision 2010*, World Economic Forum, 2010
14. *Grounding the Positive Charge: Finding the Cost of Reducing CO2 Emissions by Increasing US Electric Energy Efficiency*, IHS CERA Special Report, 2009
15. *The Road to Recovery: Keynote Remarks at the November 2009 EEI Financial Conference*, IHS CERA Private Report, 2009
16. *The Cost of Energy Efficiency Investments: The Leading edge of Carbon Abatement*, IHS CERA Special Report, 2008
17. *Renewable Portfolio Standards: Getting Ahead of Themselves*, IHS CERA Private Report, 2008
18. *Gauging the Right Price*, IHS CERA Private Report, 2008
19. *Power Plant Valuation Cycles: Living with the Boom-and-bust Cycle*, IHS CERA Decision Brief, 2007
20. *California Power Crisis Aftershock: The Potential Modification of Western Power Contracts*, IHS CERA Private Report, 2007
21. *Meeting the Power Conservation Investment Challenge*, IHS CERA Private Report, 2007
22. *Does Earnings Quality Matter in the Power Business*, IHS CERA Decision Brief, 2006
23. *Electric Power Watch*, Cambridge Energy Research Associates, 1994 to 2006.
24. *Auctions for Retail Electric Service: Bringing Risk to Light*, CERA Decision Brief, 2004
25. "California in the Dark," with Daniel Yergin, *The Washington Post*, March 16, 2001.

26. *Beyond California's Power Crisis: Impact, Solutions, and Lessons,* with Michael Zenker, Daniel Yergin, Thomas R. Robinson, and Peter F. Moritzburke, Cambridge Energy Research Associates Special Report, March 2001.
27. *Electric Power Trends 2001,* with John P. Villali, David Clement, Paul Parshley, Joseph Sannicandro, Steven Taub, and Jone-Lin Wang, Arthur Andersen and Cambridge Energy Research Associates, September 2000.
28. *High Tension: The Future of Power Transmission in North America,* with Paul Parshley and Mark Smith, Cambridge Energy Research Associates, Autumn 2000.
29. *Knocking More NOx Out of Power Generation: How Much? Who Pays?,* CERA Private Report, 1999
30. *Midwest Wholesale Power Markets: Ready for a Repeat?,* CERA Decision Brief, 1999
31. *Ontario's Nuclear Crisis—The Impact Reaches Far Beyond Its Borders,* CERA Private Report, 1998
32. *Reshaping the North American Electric Power Industry: Scenarios 2010,* with Gary Simon and Bruce Humphrey, Cambridge Energy Research Associates, 1996.
33. *Spot Market Pricing of Electricity: Towards a New Market,* with Joseph Sannicandro, Cambridge Energy Research Associates, August 1996.
34. "Revaluing Generating Assets in the Changing Competitive Market," *Proceedings of the 26th Annual Wichita Workshop on Appraisal for Ad Valorem Taxation of Communications,* Energy and Transportation Properties, August, 1996.
35. *Cost vs. Worth: Revaluing Generating Assets in a Competitive Market,* Cambridge Energy Research Associates, July 1995.
36. "Reality Check: US Electricity Demand at the End of a Rebound," CERA Briefing Note, 1995.
37. "Over the Horizon: New Views of the Electric Power Industry," with Bruce Humphrey and Gary Simon, *Electrical World*, November 1994.
38. 1983 to 1994, regularly authored the DRI/McGraw-Hill electric industry outlook article. Numerous policy and analyses articles appearing in several of the DRI/McGraw-Hill energy publications and *Electrical World* magazine.
39. "Potential for Repowering in the Electric Generation Sector: Impacts on Natural Gas Demand," with Paul Holtberg, *Proceedings of the 15th Annual North American Conference of the International Association for Energy Economics,* October, 1993.
40. "Independent Power," *Institutional Investor*, October, 1991.
41. "Clearing the Air: Acid Rain Emission Reduction," Data Resources' *Review of the U.S. Economy*, July, 1990.
42. "The Sensitivity of Cogeneration Development to Electricity Prices," *Utility Opportunities for New Generation,* Electric Power Research Institute, 1989. (RP2950-4)
43. "The Impact of Global Warming on the Electricity Utility Industry," with Seth Hollander and Joseph Sannicandro of DRI and Dr.Wei-Chyung Wang and David Chang of Atmospheric and Environmental Research Inc., DRI/McGraw-Hill *Electricity Review*, Summer 1989.
44. "Electricity Market Deregulation," *Competition, Profitability and Policy in the Energy Industries,* Guy Caruso (ed.), IAEE, 1988.
45. "Electric Utility Construction at a Turning Point," Data Resources' *U.S. Long Term Review*, Spring 1988.
46. *U.S. National and Regional Impacts of Nuclear Plant Life Extension,* Issued by Sandia National Laboratories, Albuquerque, New Mexico for U.S. Department of Energy, January 1988. NTIS SAND87-7136.
47. "The Impacts of an Electric Generating Capacity Shortage," with J. Coyne, K. Grubb and R. Hilt, *The Changing World Energy Economy,* D. Wood (ed), IAEE, 1988.
48. "The PURPA Problem," Data Resources' *Energy Review*, Autumn 1985.
49. "Electricity Outlook" and "Nuclear Watershed," *The Energy Industries in Transition 1985–2000,* J. Weyant and D. Sheffield (eds.), IAEE, 1984.

Lawrence Makovich

TESTIMONY:

March 18, 2015—Lansing MI, Michigan House Energy Policy Committee regarding retail open access policy.

July 7-9, 2014—Raleigh, NC, North Carolina Public Service Commission regarding the biennial determination of avoided costs in North Carolina.

April 10, 2001 – Sacramento, CA, United States House of Representatives Committee on Government Reform, Committee Chairman: Dan Burton, Representative from Indiana, Subcommittee on Energy Policy, Natural Resources and Regulatory Affairs, Committee Chairman: Doug Ose, Representative from California, "Assessing the California Crisis: How Did We Get to this Point, and Where Do We Go From Here?"

March 22, 2001 – Washington, DC, United States House of Representatives Committee on Energy and Commerce, Subcommittee on Energy and Air Quality, Committee Chairman: Joe Barton, Representative from Texas, "Electricity Makets: California"

January 31, 2001 – Washington, DC, United States Senate Committee on Energy and Natural Resources, Committee Chairman: Frank H. Murkowski, Senator from Alaska, "California's Electricity Crisis and Implications for the West"

Attachment LM-2

IHS **Energy**

The Value of US Power Supply Diversity

July 2014

ihs.com

Contents

About the authors

LAWRENCE J. MAKOVICH, Vice President and Senior Advisor for Global Power, IHS Energy, is a highly respected expert on the electric power industry. He directs IHS CERA research efforts in the power sector as part of IHS Energy's Office of the Chairman. He is an authority on electricity markets, regulation, economics, and strategy. His current research focuses on electric power market structures, demand and supply fundamentals, wholesale and retail power markets, emerging technologies, and asset valuations and strategies. Dr. Makovich is currently advising or has recently advised several large utilities in major strategic engagements. He has testified numerous times before the US Congress on electric power policy. He has advised the government of China on electric power deregulation and transmission in competitive markets, and the Brazilian Congress invited him to testify on power liberalization. He examined the impact of deregulation on residential power prices and the development of resource adequacy mechanisms in the IHS Energy Multiclient Study *Beyond the Crossroads: The Future Direction of Power Industry Restructuring.* He was also a project director for the IHS Energy Multiclient Study *Crossing the Divide: The Future of Clean Energy,* the author of the IHS Energy Multiclient Study *Fueling North America's Energy Future: The Unconventional Natural Gas Revolution and the Carbon Agenda,* and the study director of the IHS Energy Multiclient Study *Smart Grid: Closing the Gap Between Perception and Reality.* Among Dr. Makovich's other significant IHS CERA studies are examinations of the California power crisis in *Crisis by Design: California's Electric Power Crunch* and *Beyond California's Power Crisis: Impact, Solutions, and Lessons.* Dr. Makovich has been a lecturer on managerial economics at Northeastern University's Graduate School of Business. He holds a BA from Boston College, an MA from the University of Chicago, and a PhD from the University of Massachusetts.

AARON MARKS, Associate, IHS Energy, is a member of the Power, Gas, Coal, and Renewables group and specializes in North American Power. He provides analysis on power market fundamentals, regional power markets, power generation technologies, and electricity resource planning. Prior to joining IHS Energy, Mr. Marks worked in growth strategy consulting with Treacy and Company, specializing in manufacturing and insurance. He holds BS and MS degrees from Carnegie Mellon University.

LESLIE MARTIN, Senior Principal Researcher, IHS Energy, is a member of the Power, Gas, Coal, and Renewables group and specializes in North American Power. She provides analysis on power market economics, power market fundamentals, and strategic planning. Prior to this role, Ms. Martin held roles in portfolio strategy; investment banking; and energy market consulting in which she supported energy industry mergers, acquisitions, financings, investments, and restructurings, and analyzed US and international electricity market policy and regulation. She holds a BS degree from the University of Colorado.

We welcome your feedback regarding this IHS Energy report or any aspect of IHS Energy's research, services, studies, and events. Please contact us at customercare@ihs.com, +1 800 IHS CARE (from North American locations), or +44 (0)1344 328 300 (from outside North America).

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.

Project Director

LAWRENCE J. MAKOVICH, Vice President and Senior Advisor for Global Power, IHS Energy

Project Team

JONE-LIN WANG, Vice President, Global Power, IHS Energy—**Project Manager**

BOB FLANAGAN, Director, IHS Economics and Country Risk

RICHARD FULLENBAUM, Vice President, IHS Economics and Country Risk

AARON J. MARKS, Sr. Research Analyst, IHS Energy

LESLIE T. MARTIN, Senior Principal Researcher, IHS Energy

Acknowledgments

We extend our appreciation to IHS Vice Chairman Daniel Yergin, who offered critical insight, guidance, and support in reviewing the methodologies and findings from this study. This report offers an independent assessment of the value of fuel diversity to the US electricity sector. This research was supported by the Edison Electric Institute, the Nuclear Energy Institute, and the Institute for 21st Century Energy at the U.S. Chamber of Commerce. IHS is exclusively responsible for this report and all of the analysis and content contained herein. The analysis and metrics developed during the course of this research represent the independent views of IHS and are intended to contribute to the dialogue on the value of fuel diversity in the discussion and development of electricity sector investment plans, regulation, policy, and education.

IHS™ **Energy**

The Value of US Power Supply Diversity

Lawrence Makovich, *Vice President and Senior Advisor, IHS Energy*
Aaron Marks, *Associate, IHS Energy*
Leslie Martin, *Senior Principal Researcher, IHS Energy*

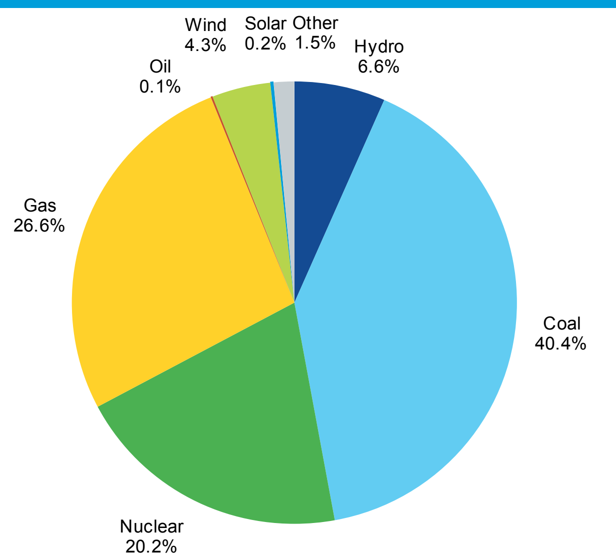
Executive summary

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

© 2014 IHS

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.

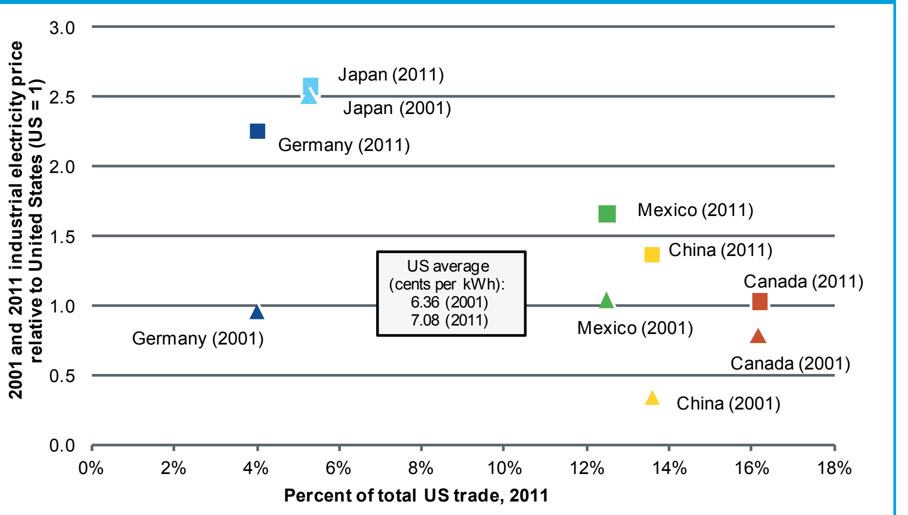
The current diverse US power supply reduces US consumer power bills by over $93 billion per year compared to a reduced diversity case. In addition, the current diversified power generation mix mitigates exposure to the price fluctuations of any single fuel and, by doing so, cuts the potential variability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

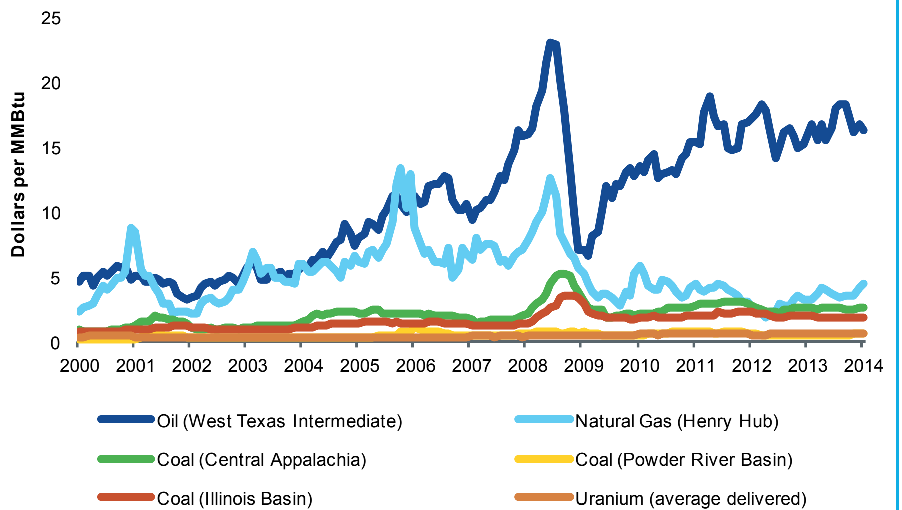
Power production cost fluctuations reflect inherent fuel price uncertainties

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 © 2014 IHS

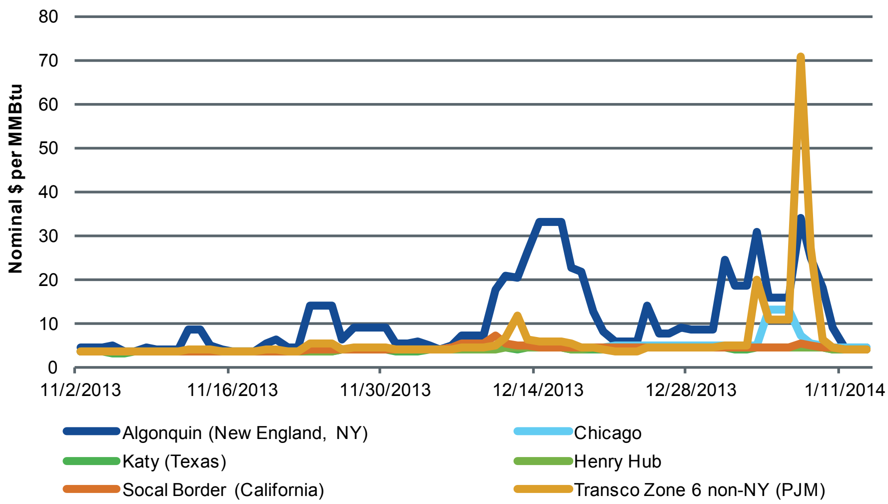
not enough and additional natural gas was not available at any price, even to power plants holding firm supply contracts.

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

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.

FIGURE 3

Delivered daily gas prices, November 2013–January 2014

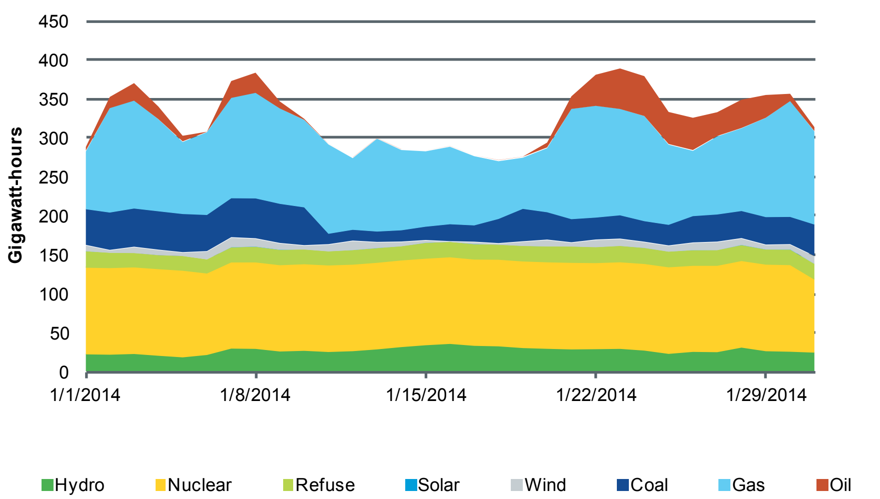


Source: IHS Energy, Ventyx Velocity Suite

© 2014 IHS

FIGURE 4

ISO New England generation, January 2014



Source: IHS Energy

© 2014 IHS

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).

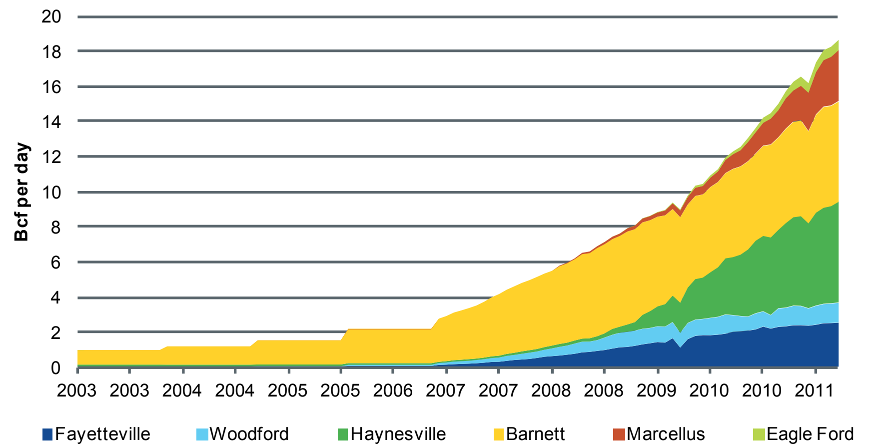
Although shale gas had moved from its innovation phase to its commercialization phase, many in the oil and gas industry did not fully recognize what was happening even as US shale gas output doubled from 2002 to 2007 to reach 8% of US natural gas production. The belief that the United States was running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

FIGURE 6

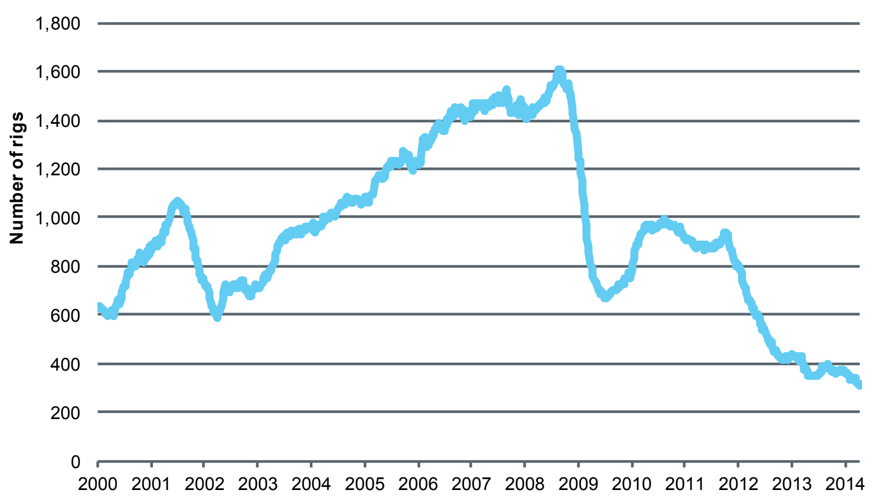
LNG facilities in North America—Existing and proposed (October 2006)

40609-1Source: IHS Energy

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

© 2014 IHS

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.

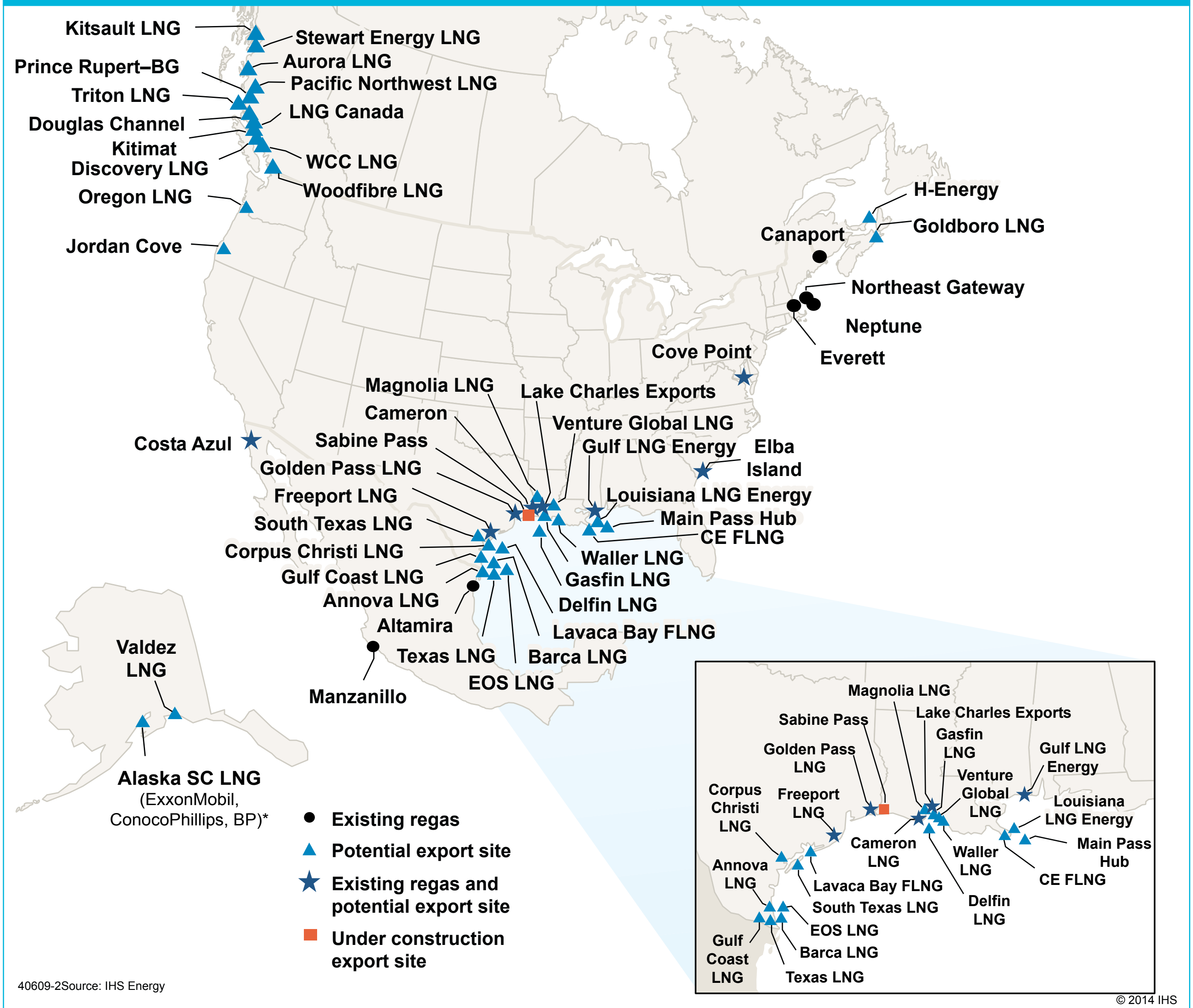
The Northeast delivered natural gas price spikes translated directly into dramatic power production cost run-ups. During the winter of 2013/14, natural gas prices delivered to the New York and PJM power system border hit $140 per MMBtu (at Transco Zone 6, 21 January 2014) and pushed natural gas–fired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

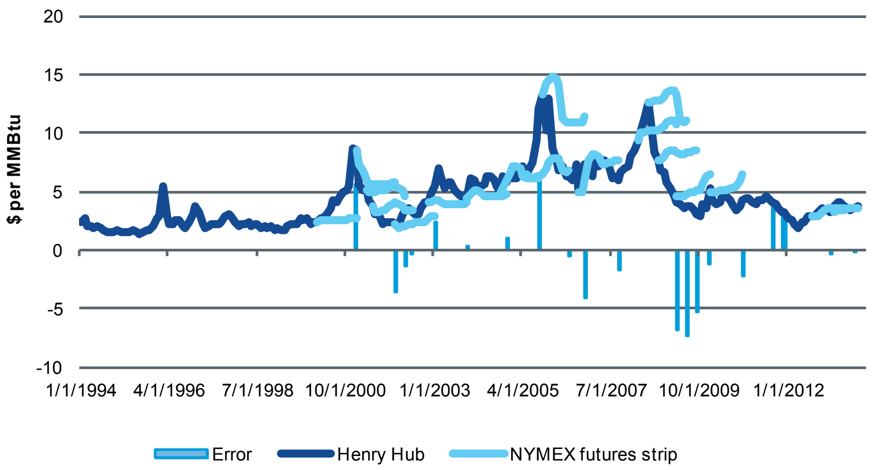
The natural gas–fired generation share is second only to the coal-fired generation share. One of the primary reasons that fuel diversity is so valuable is because natural gas prices and coal prices do not move together.

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

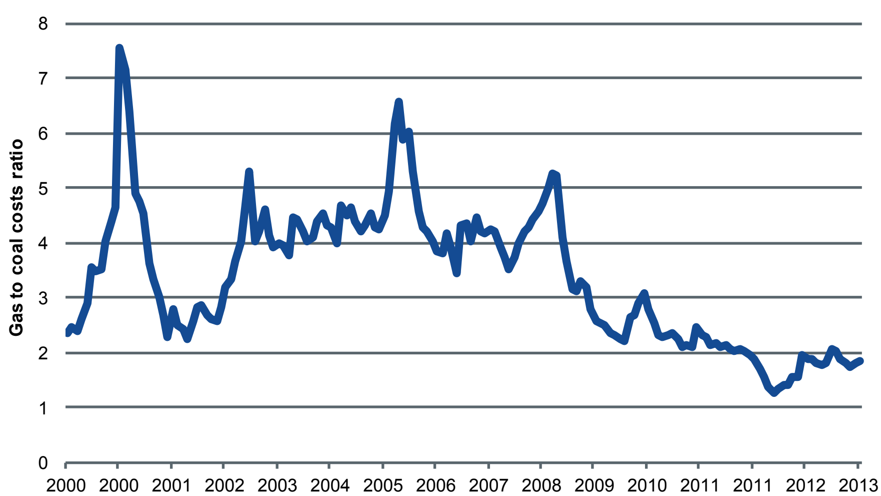
Henry Hub and NYMEX futures, 1994–2013



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.

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.

TABLE 1

Typical generating units

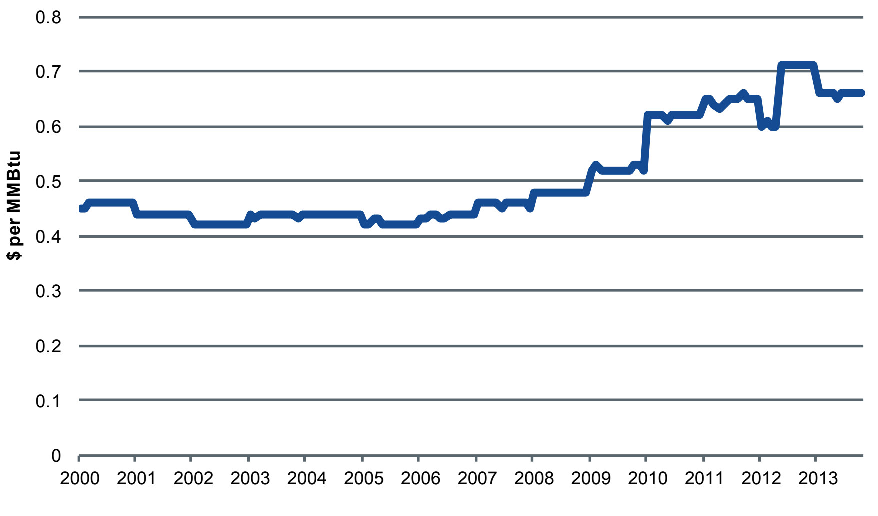
	Typical coal unit	Typical CCGT unit
Btu/kWh	10,552	7,599
Fuel cost, $/MMBtu	$2.41	$4.46
Fuel cost, $/MWh	$25.43	$33.89
Variable O&M, $/MWh	$4.70	$3.50
Lbs SO_2/MWh (with wet FGD)	1.16	0
SO_2 allowance price, $/ton	70	70
Lbs NO_X/MWh	0.74	0.15
NO_X allowance price, $/ton	252	252
SO_2,NO_X emissions cost,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

© 2014 IHS

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

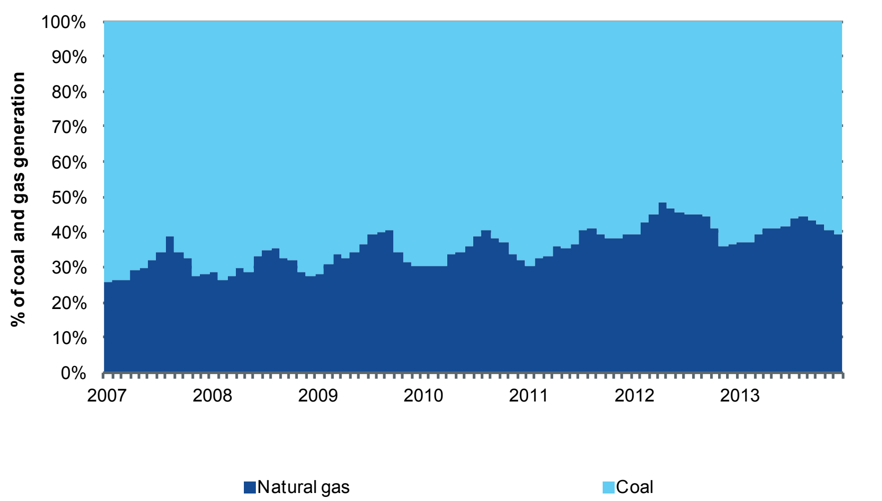
Diversity: The substitution effect

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

© 2014 IHS

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.

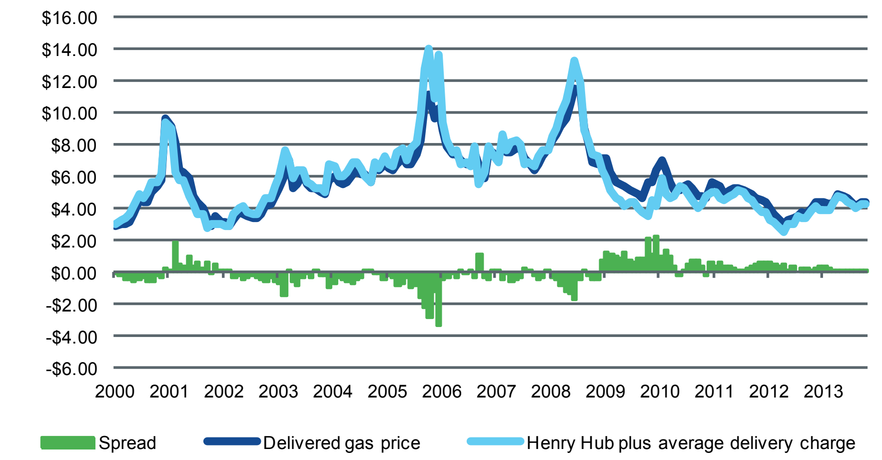
Diversity is the best available power cost risk management tool

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

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

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

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

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

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

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

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

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

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

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

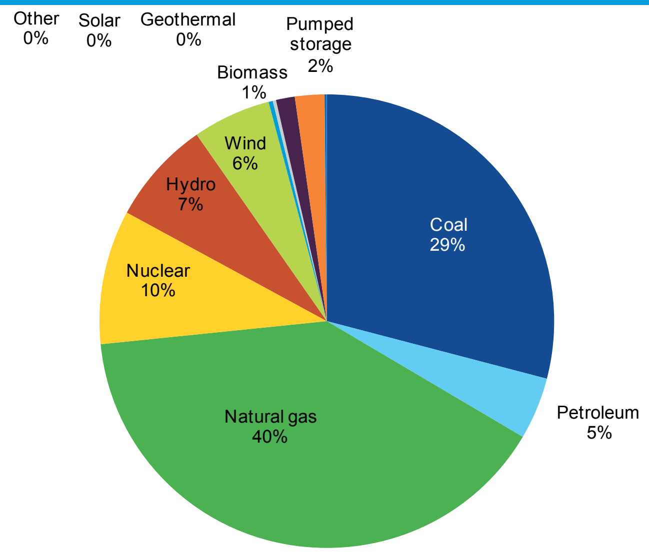
Striking a balance between the costs and benefits of fuel contracting makes this risk management tool an important complement to a diverse generation portfolio but does not indicate that it could provide a cost-effective substitute for power supply diversity.

A starting point taken for granted

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

FIGURE 14

US installed capacity (1,063 GW), 2012



Source: US Energy

© 2014 IHS

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

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

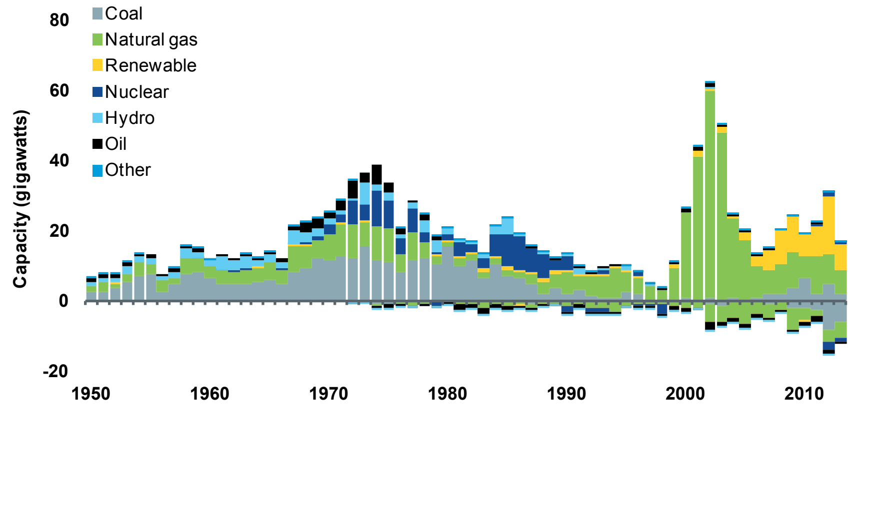
As a result, the United States may move down a path toward a less diverse power supply without consumers realizing the value of power supply diversity until it is gone. For example, if the US power sector had been all natural gas–fired during the shale gas era to date, the average fuel cost for power 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 © 2014 IHS

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.

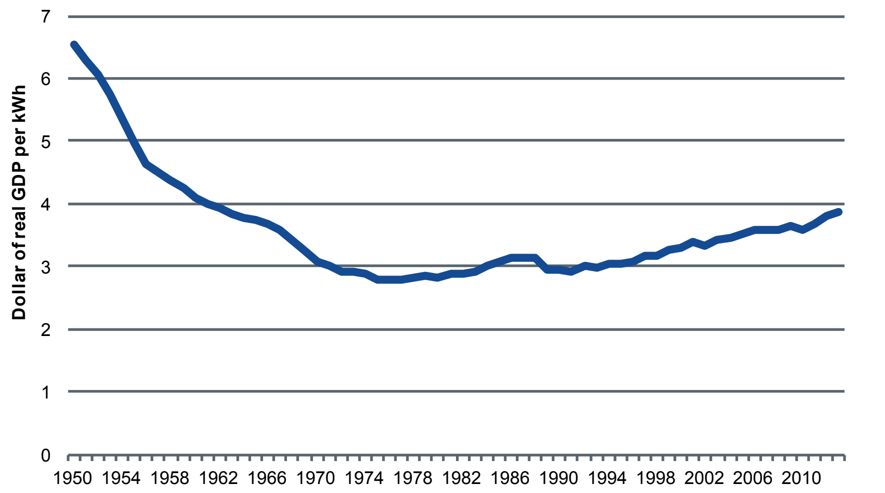
Power plant retirements typically need to be replaced because electricity consumption continues to increase. Although power demand increases are slowing compared to historical trends and compared to the growth rate of GDP, the annual rate of change nevertheless remains positive. US power demand is expected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

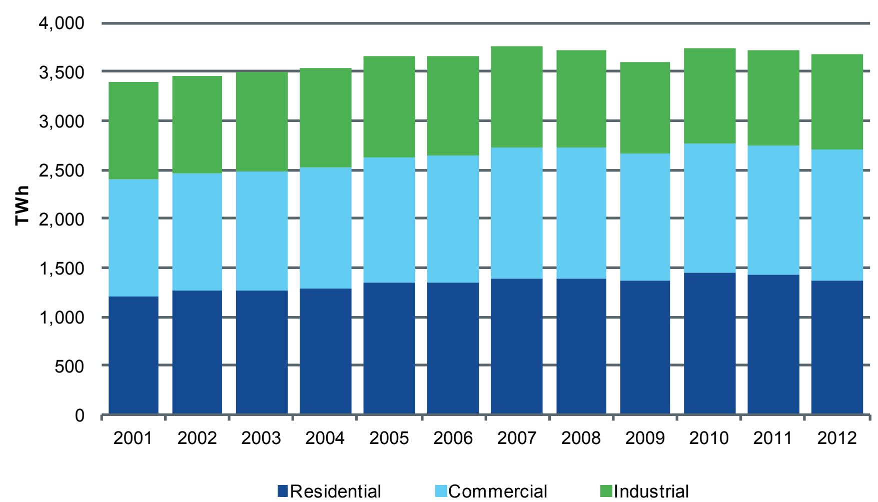


Note: BEA reports Real GDP in 2009 dollars.
Source: IHS Energy, EIA, BEA

© 2014 IHS

FIGURE 17

US electricity sales by customer class, 2001–12



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

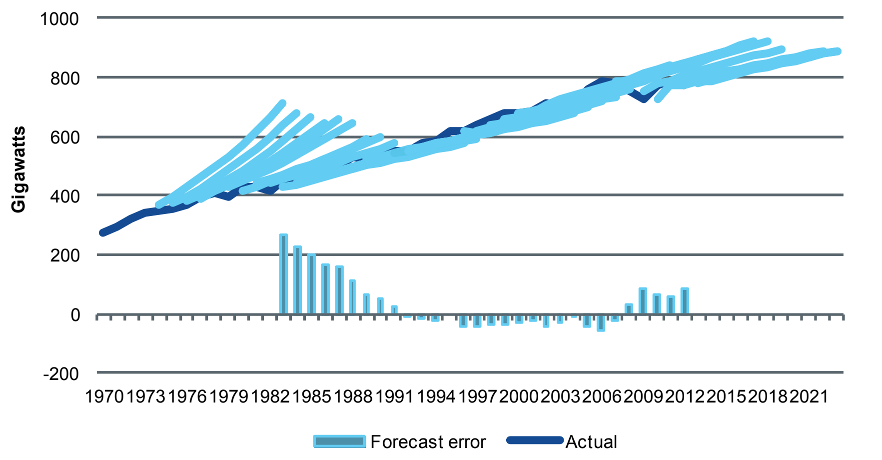
© 2014 IHS

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

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.

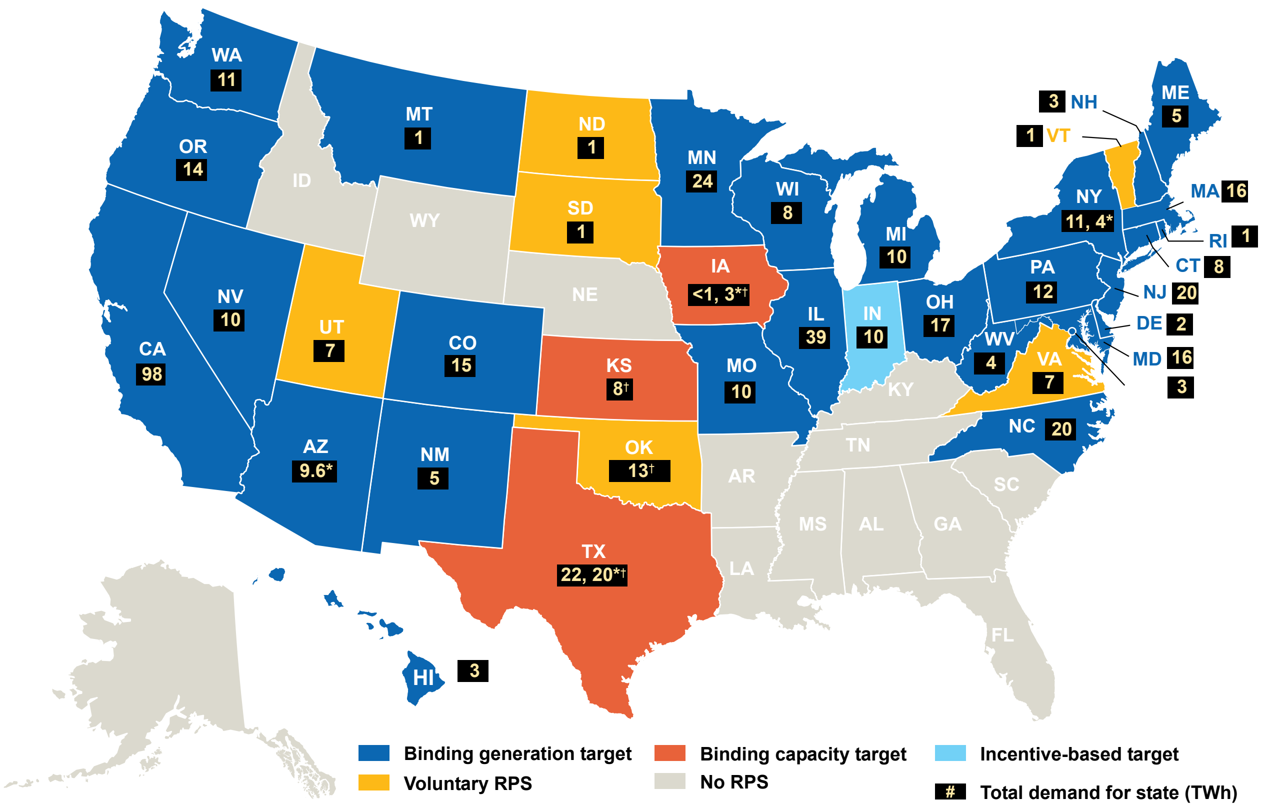
The pace and makeup of power plant additions are influenced by energy policies. The current installed capacity mix reflects impacts from the implementation of a number of past policy initiatives. Most importantly, 35 years ago energy security was a primary concern, and the energy policy response included 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



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.

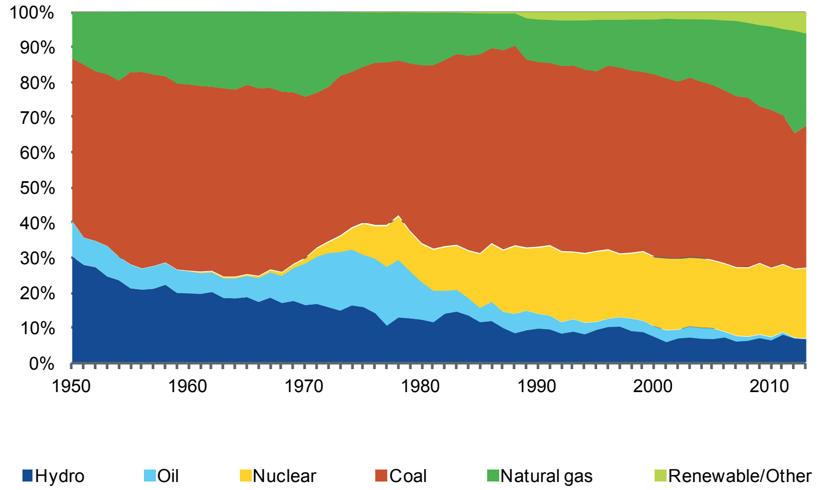
40609-3
Note: *States include both mandatory and voluntary targets; first number reflects mandatory target, second number reflects additional voluntary targets (of state, municipalities, or other political divisions/utilities).
†Capacity targets have been converted to generation for comparison using 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 © 2014 IHS

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,

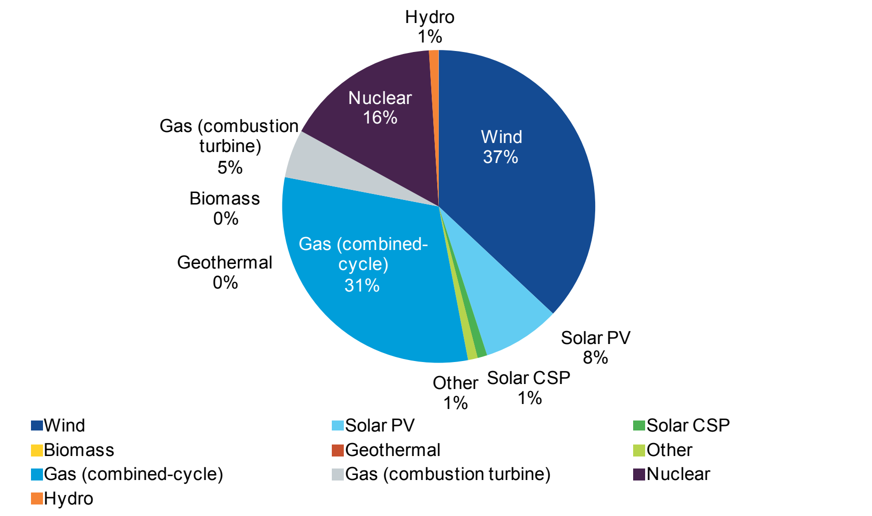
4. *New England Wind Integration Study* produced for ISO New England by GE Energy Applications and Systems Engineering, EnerNex Corporation, and AWS Truepower, 5 December 2010. Accessed 16 April 2014 (http://www.uwig.org/newis_es.pdf).

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

© 2014 IHS

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.

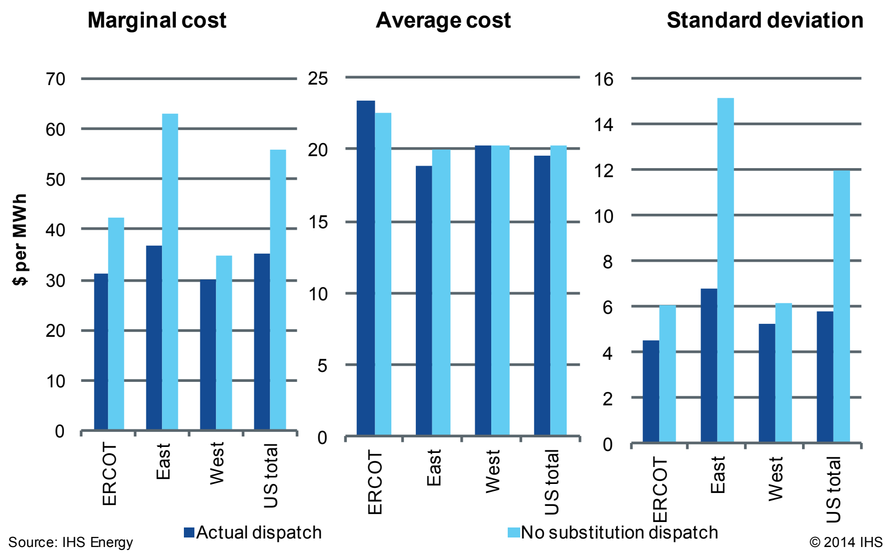
Quantification of the impact of fuel diversity within the US power sector involved a two-step process. The first step quantifies the current value of the substitution effect enabled by a diverse power generating portfolio. The second step quantified the additional value created by the portfolio effect.

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

© 2014 IHS

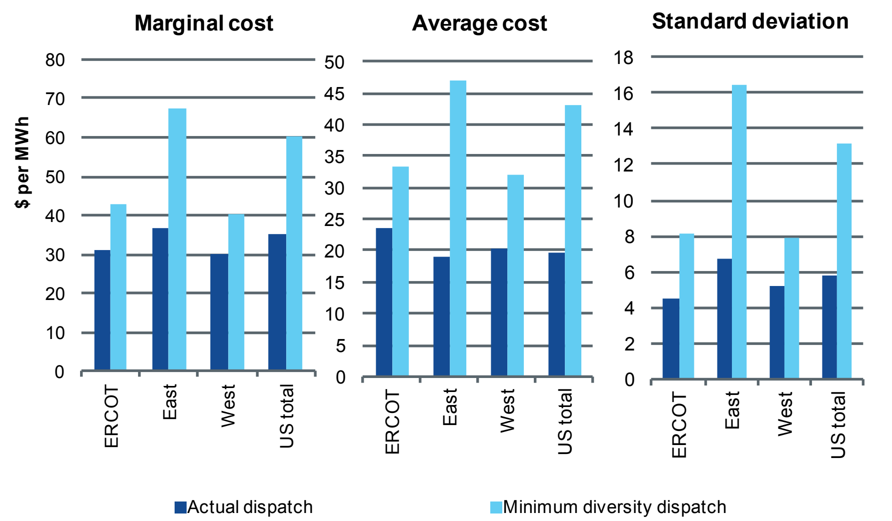
The value of the portfolio effect

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

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

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.

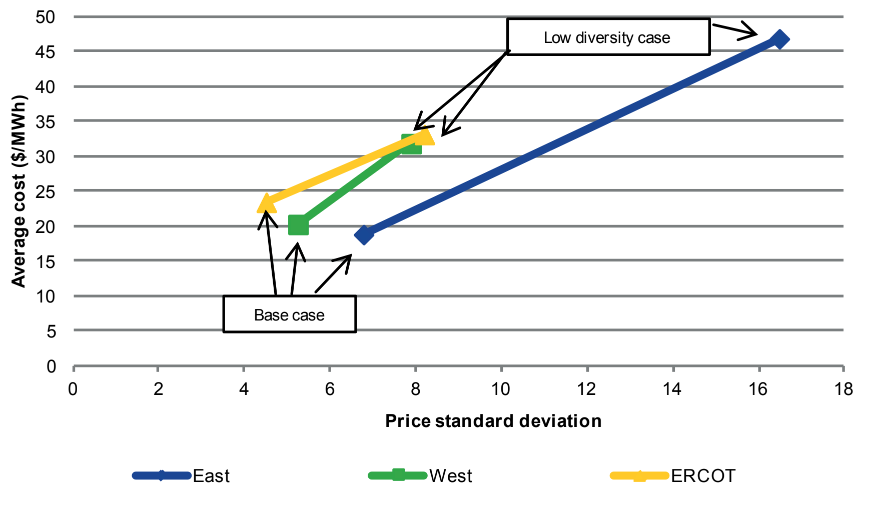
All existing power plants are economic to close and replace at some point in the future. The economic life of a power plant ends when the expected costs of continued operation exceed the cost of replacement. When this happens, the most cost-effective replacement power resource depends on the current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

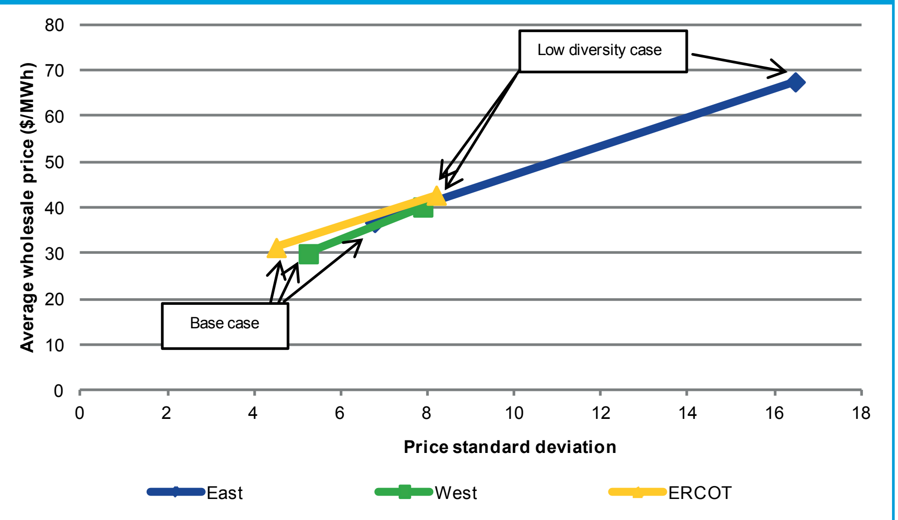
Average cost: Base case versus low diversity case



Source: IHS Energy © 2014 IHS

FIGURE 25

Average wholesale price: Base case versus low diversity case



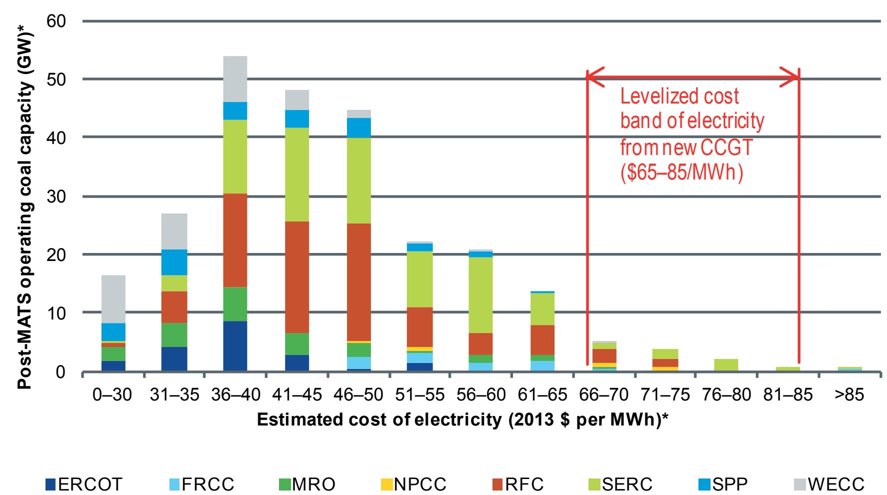
Source: IHS Energy © 2014 IHS

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

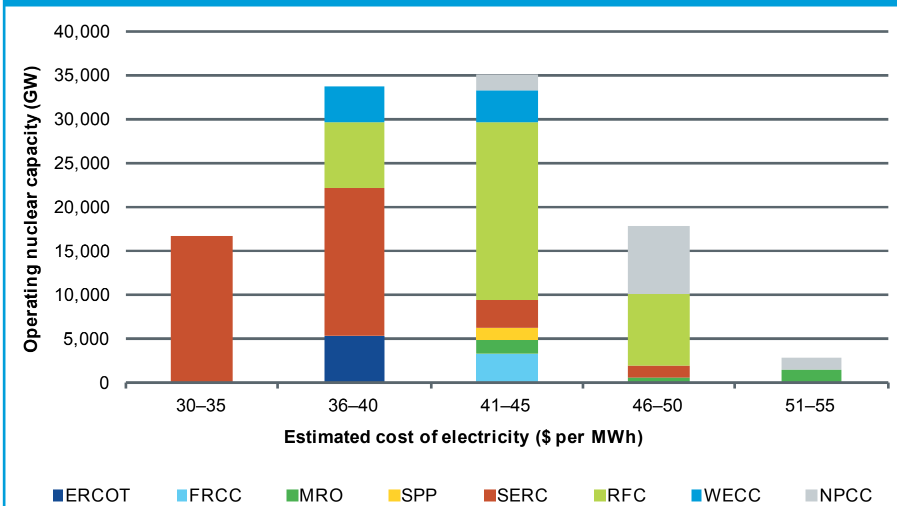


*Only includes those coal units that are forecasted to operate beyond 2020 in our reference case scenario. These coal units are retrofitted with conventional pollution controls.
Source: IHS Energy

Economywide impacts

FIGURE 27

Going-forward costs of the existing nuclear fleet



Source: IHS Energy

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

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

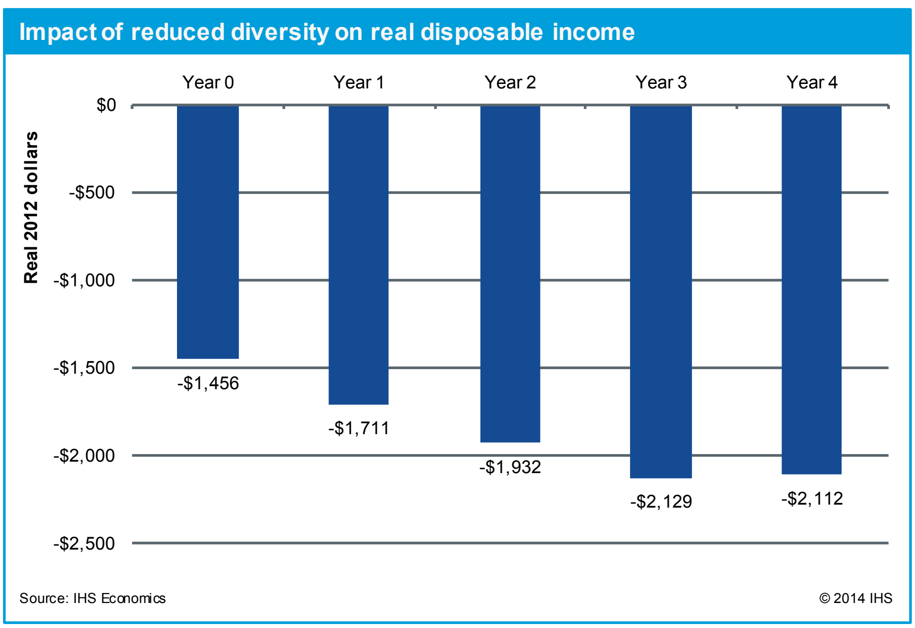
Economic impacts of the power supply reduced diversity case are quantified as deviations from the IHS macroeconomic baseline simulations of the US economy. The major impacts within the three years after the power price change would include

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

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

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

FIGURE 28



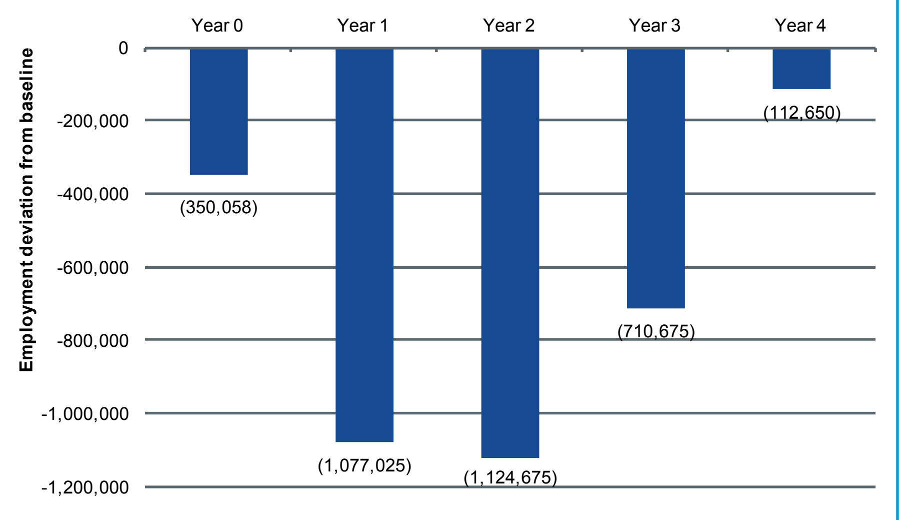
Businesses will face the dual challenge of higher operational costs coupled with decreased demand for their products and services. Industrial production will decline, on average, by about 1% through Year 4. This will lead to fewer jobs (i.e., a combination of current jobs that are eliminated and future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

Impact on GDP

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

FIGURE 29

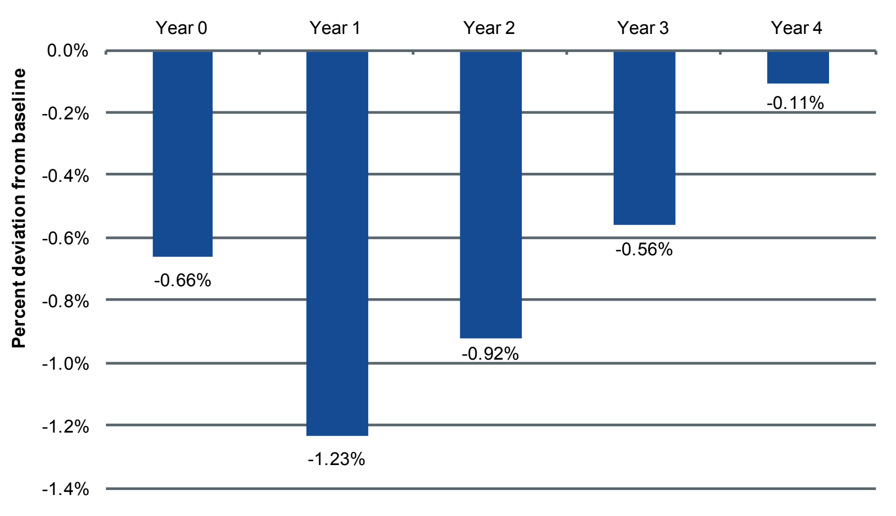
Impact of reduced diversity on employment (deviation from baseline)



Source: IHS Economics © 2014 IHS

FIGURE 30

Impact of reduced diversity on real GDP



Source: IHS Economics © 2014 IHS

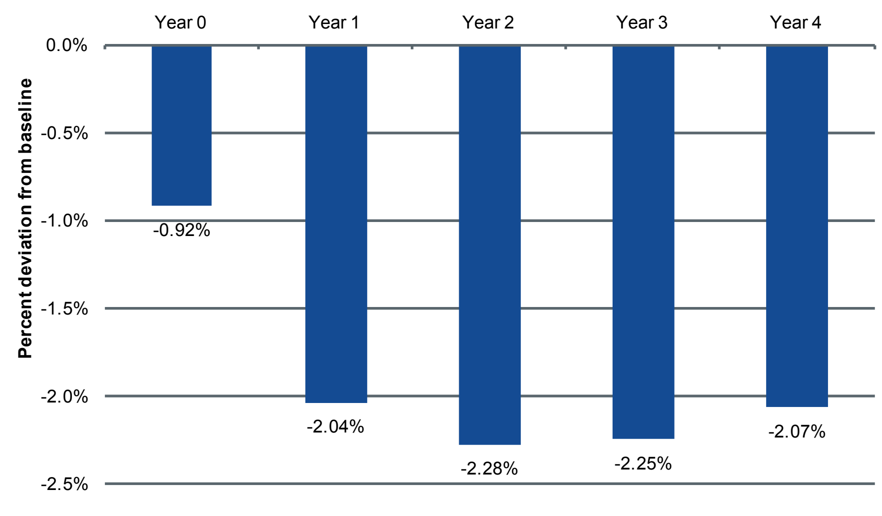
Consumption

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



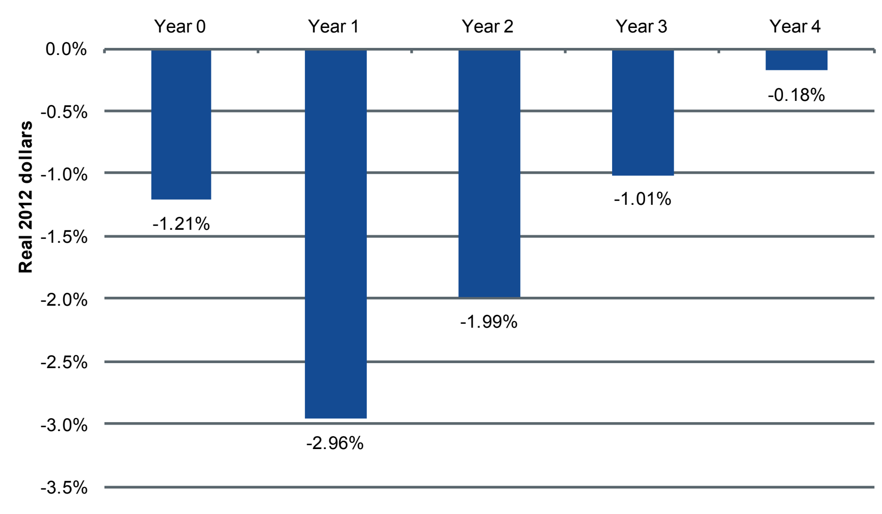
Source: IHS Energy © 2014 IHS

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.

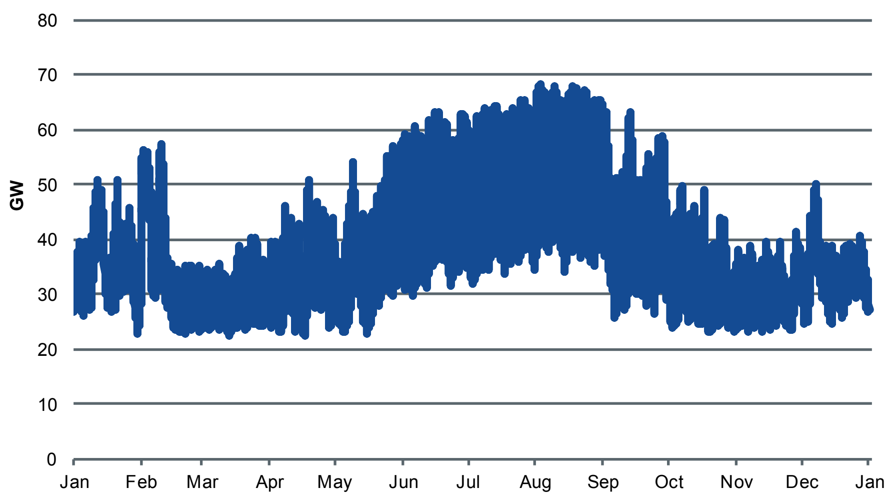
In order to reliably meet aggregate power demands, enough generating capacity needs to be installed and available to meet demand at any point in time. The overall need for installed capacity is determined by the peak demand and a desired reserve margin. A 15% reserve margin is a typical planning target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

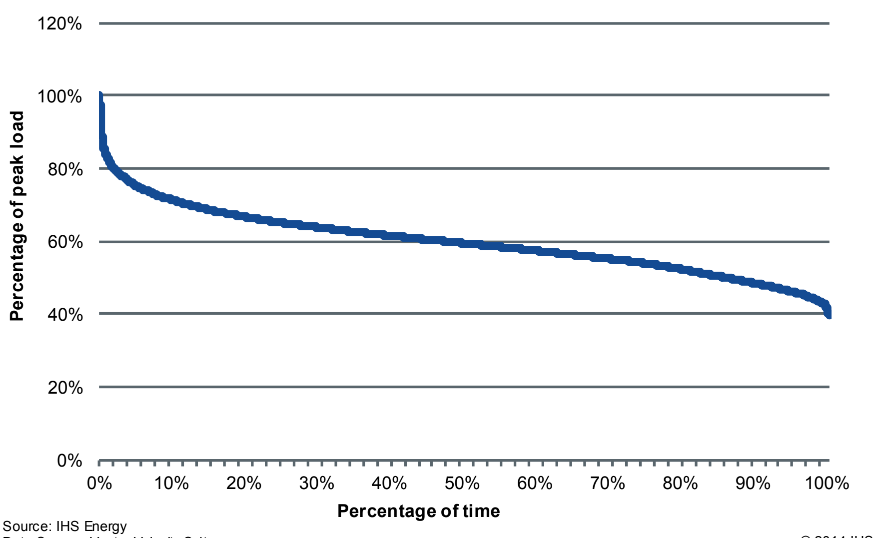


Source: IHS Energy

© 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
Btu)	4.55	2.6	0.7	4.55
Heat rate (Btu per kWh)	6,750	8,300	9,800	10,000
CO_2 emission rate (lbs per kWh)	0.8	1.73	0	1.18

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

Source: IHS Energy

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

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

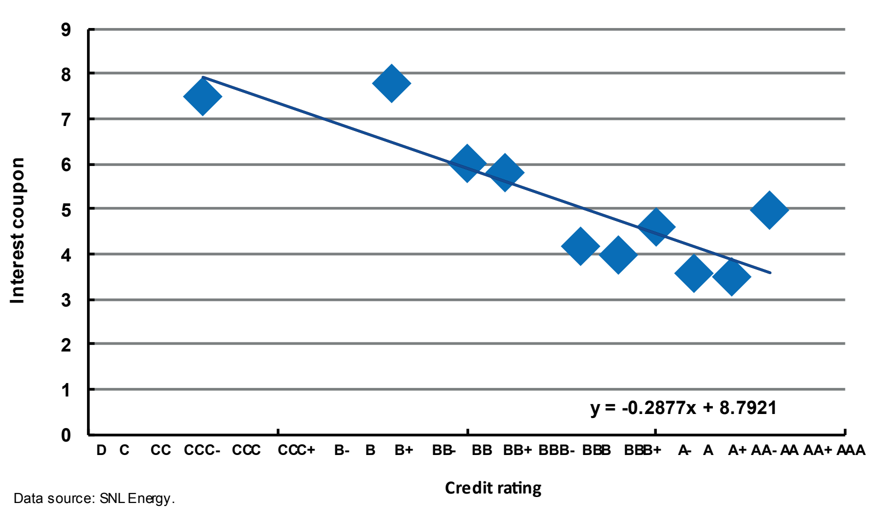
Risk profiles are important because they affect the cost of capital for power generation projects. If a project is seen as more risky, investors demand a higher return for their investment in the project, which can have a significant impact on the overall project cost.

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

Lower credit ratings result from higher variations in net

FIGURE A-3

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



Data source: SNL Energy.

Source: IHS Energy

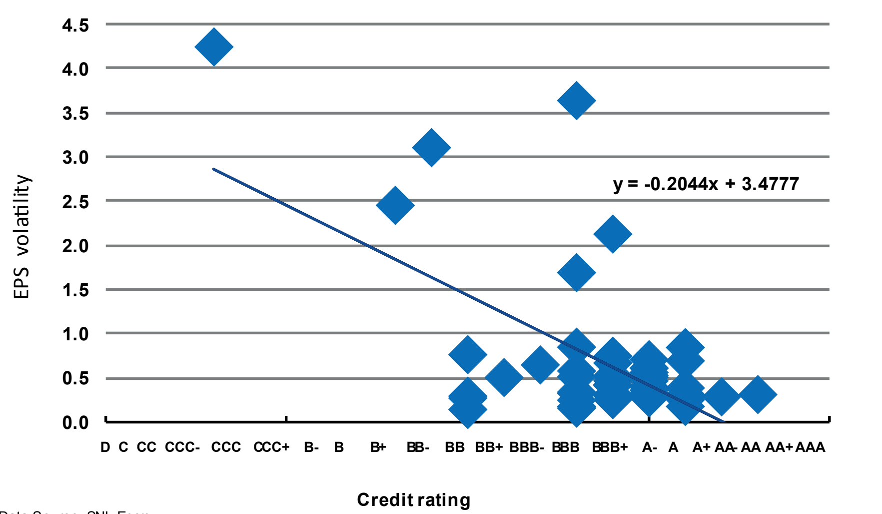
© 2014 IHS

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 © 2014 IHS

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

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

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

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

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

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

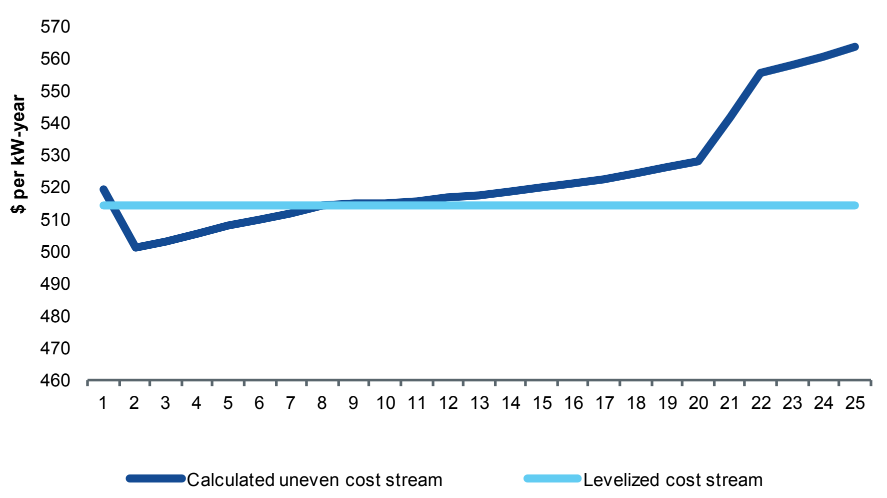
A levelized cost stream makes it possible to compare production costs at different expected utilization rates. A lower utilization rate forces spreading fixed costs over fewer units of output and thus produces higher levelized costs (see Figure A-6).

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

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

FIGURE A-5

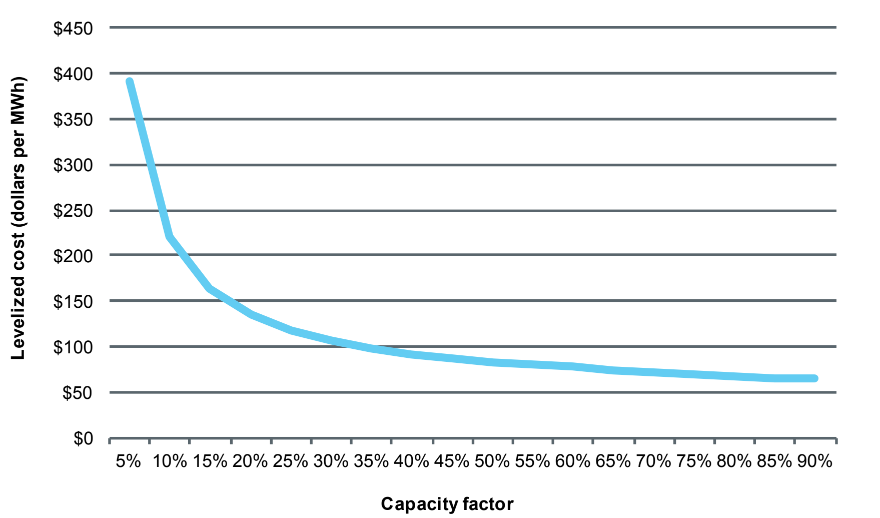
Cost stream comparisons—CCGT, 85% utilization rate



Source: IHS Energy © 2014 IHS

FIGURE A-6

LCOE of CCGT generation

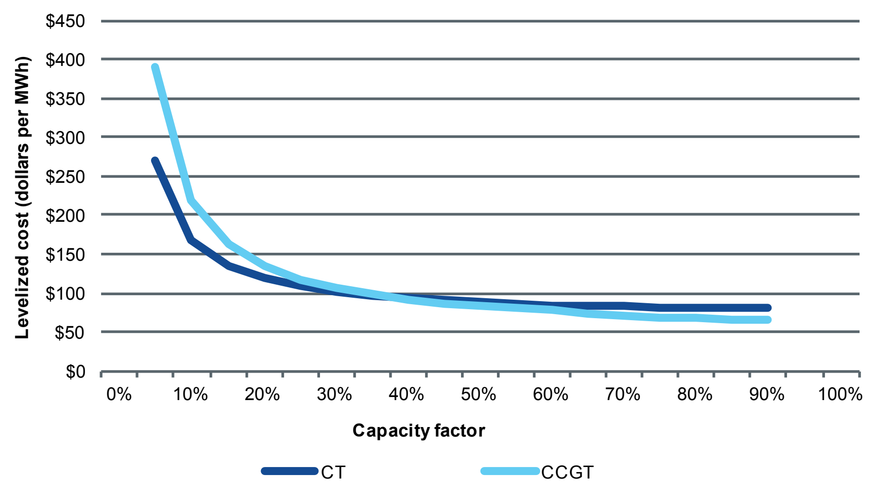


Source: IHS Energy © 2014 IHS

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

FIGURE A-7

LCOE of CCGT and CT generation

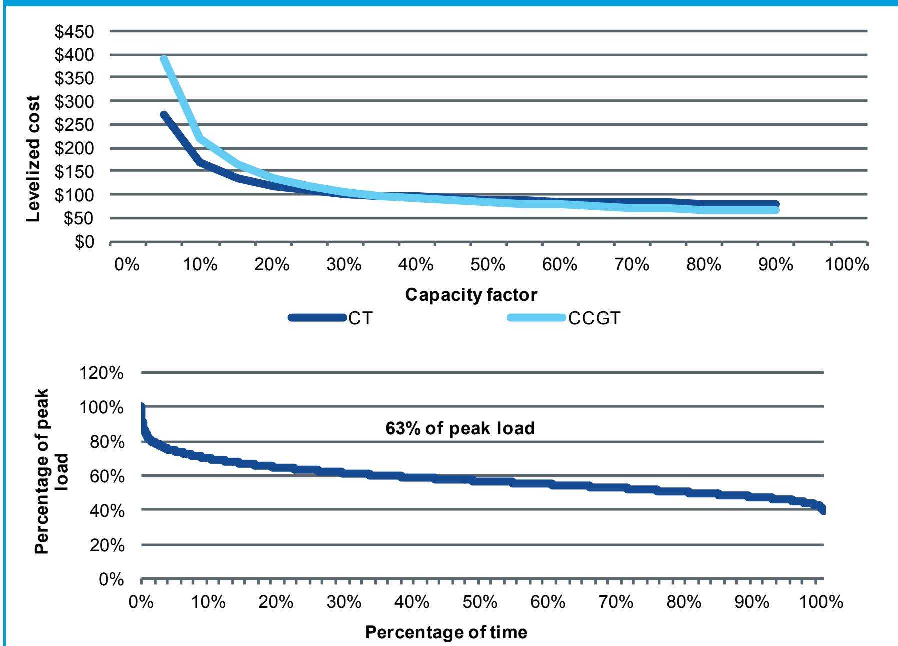


Source: IHS Energy

© 2014 IHS

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:

© 2014 IHS

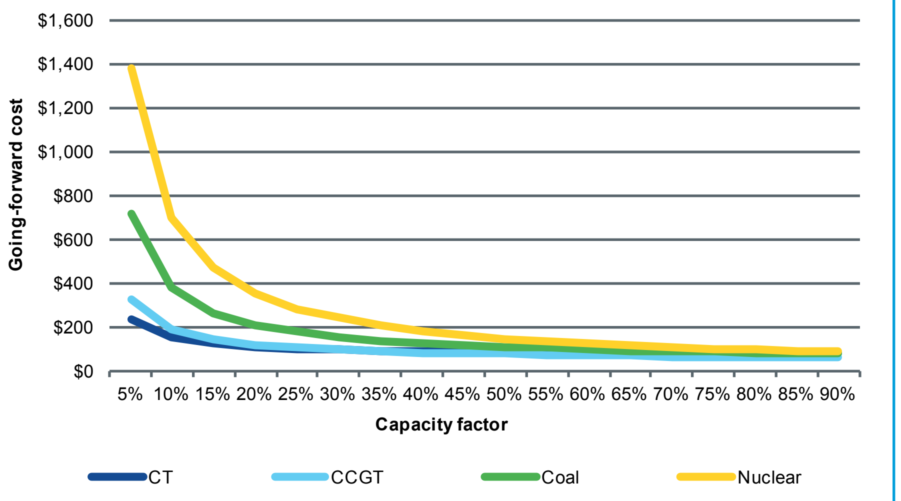
The generating options also can be expanded to include fuels besides natural gas. Stand-alone coal and stand-alone nuclear are not lower cost than stand-alone gas, as shown in Figure A-9, and all have a high-risk premium associated with the lack of diversity. However, when combined as part of a generation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

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

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

FIGURE A-9

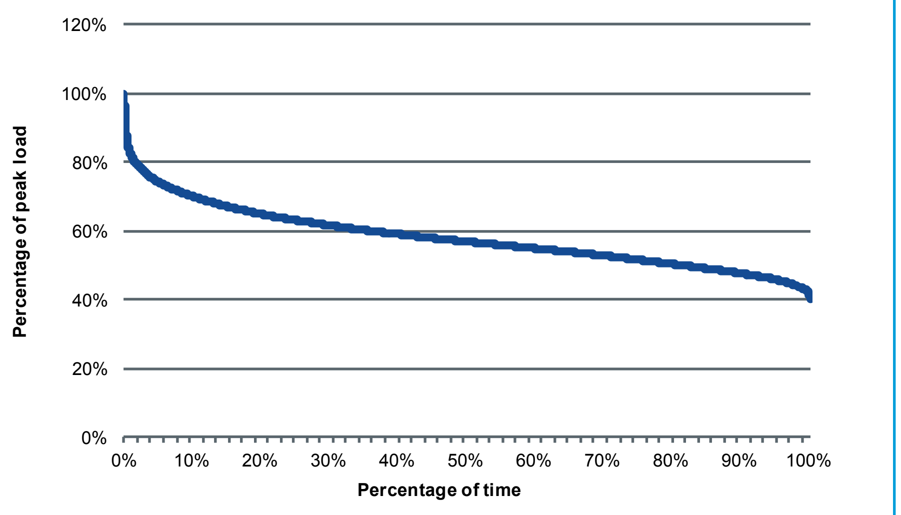
Levelized cost curves of generating resources



Source: IHS Energy © 2014 IHS

FIGURE A-10

Load duration curve, after solar additions



Source: IHS Energy
Data Source: Ventyx Velocity Suite, National Renewable Energy Laboratory © 2014 IHS

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.

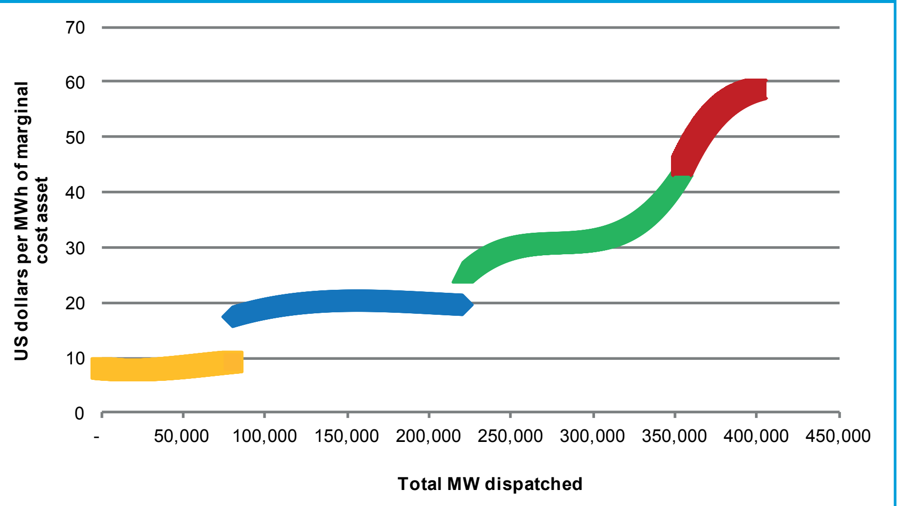
Each cost curve incorporates heat rate as a function of utilization rate.[14] *Heat rate* describes the efficiency of a thermal power plant in its conversion of fuel into electricity. Heat rate is measured by the amount of heat (in Btu) required each hour to produce 1 kWh of electricity, or most frequently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

© 2014 IHS

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.

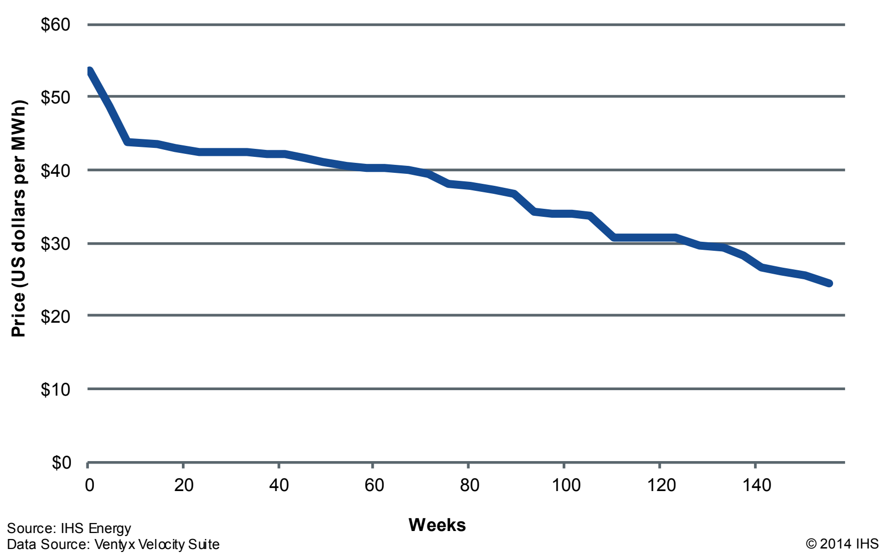
Calibration

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.

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.

FIGURE B-2

Representative price duration curve



Source: IHS Energy
Data Source: Ventyx Velocity Suite

© 2014 IHS

TABLE B-1

IHS power system Razor Model analysis

	East	West	ERCOT

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