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# STATE OF THE MARKETS REPORT



**Federal**

**Energy**

**Regulatory**

**Commission**

888

First Street, N.E.

Washington, D.C.



**FEDERAL ENERGY REGULATORY COMMISSION**  
888 First Street, N.E. Washington, D.C.

## **2012 State of the Markets Report**

**OFFICE OF ENFORCEMENT**  
Division of Energy Market Oversight

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## Executive Summary and Overview

### WHOLESALE NATURAL GAS AND ELECTRICITY PRICES CONTINUED TO EXHIBIT LOW LEVELS

Natural gas production grew to a new record in 2012 which contributed to the lowest nominal natural gas prices since 2002. Prices for natural gas were at or near 10-year lows in virtually every region of the United States, with the spot price at Louisiana's Henry Hub averaging \$2.74/MMBtu for the year, down 31 percent from 2011 (Figure 2-3). Low natural gas prices resulted in much greater reliance on natural gas as the fuel of choice for power generation while coal-fired power generation fell to its lowest level in 30 years.

Since natural gas is often the marginal fuel in electric generation, lower natural gas prices generally resulted in lower electricity prices nationwide. On average, wholesale electricity prices decreased compared to 2011 in all regions of the United States. A warm winter in 2012, a slow economic recovery, and increasing energy efficiency contributed to a second year of declining electricity demand.



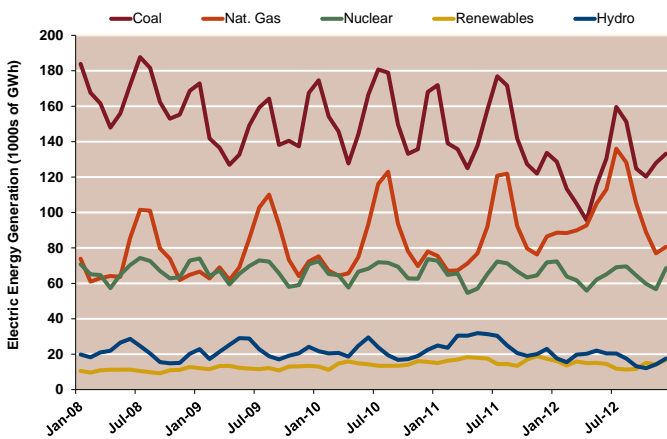
## HIGHLIGHTS OF THE NATURAL GAS AND ELECTRICITY MARKETS IN 2012

### Power Generators Ramped Up Their Use of Natural Gas

Natural gas-fired generation displaced substantial amounts of electricity output from coal-fired generation in 2012, particularly from generators in the PJM Interconnection and the Southeast (Figure ES-1). Due to low natural gas prices, the nation's fleet of natural gas-fired combined-cycle plants was more heavily used than at any time in the past decade. Natural gas-fired generation reached 1,193 TWh, 31 percent of total net generation in 2012, up from 25 percent in 2011. Coal-fired generation fell to 1,506 TWh, 39 percent of total net generation, down from 43 percent in 2011.

Figure ES-1

#### Monthly Net Generation by Energy Source



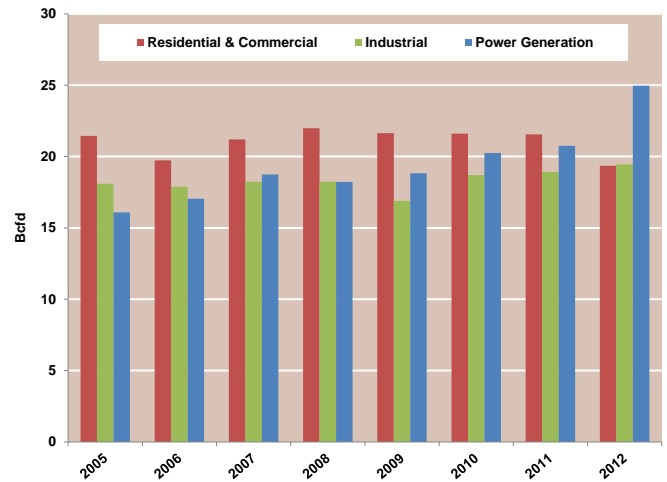
Source: EIA 923 Monthly Utility Power Plant Database, U.S. EPA CEMS

Total average daily U.S. natural gas demand grew 4 percent to 70 Bcfd in 2012, the highest level on record. This occurred despite a 10 percent decline in residential and commercial natural gas demand

(Figure ES-2). For the first time, natural gas used for power generation was greater than the combined residential and commercial gas demand.

Figure ES-2

#### Growth in U.S. Natural Gas Power Burn in 2012



Source: Derived from Bentek Energy

Greater reliance on natural gas as a fuel for power generation led to increased awareness about the importance of greater coordination between the natural gas and electric industries. New England was identified as a market particularly at risk for service disruption due to limited pipeline capacity into the region. Most natural gas-fired generators in New England have little or no firm transportation capacity in their natural gas supply portfolios and depend on interruptible capacity on pipelines for their supplies. Moreover, availability of interruptible capacity in the region is decreasing. Natural gas-fired generators also rely on the capacity release market, but this option may not be available on high-demand days, such as during a cold snap when local distribution companies (LDC) need pipeline capacity to meet increased customer demand.

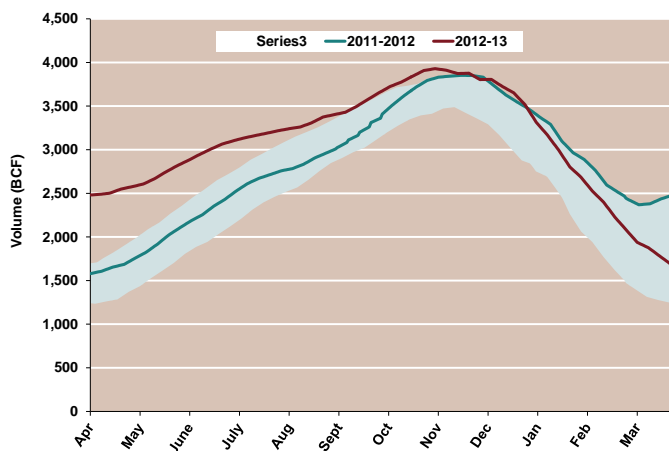
While the substitution of natural gas-fired generation for coal-fired generation (also referred to as “coal-to-gas switching”) was notable in 2012, the trend is less likely to be as pronounced in 2013 due to higher natural gas prices. However, the level of natural gas use in power plants will still be higher than it was prior to 2011 as long as natural gas price increases are moderate. With the expectation that natural gas will retain much of its price gains relative to coal for electric generation, investment decisions for new electric generating plants will reflect that new balance.

### Record U.S. Natural Gas Supply in 2012

Contributing to natural gas’ lower price was a 5 percent growth in its production, a 10 percent drop in residential and commercial natural gas demand due to one of the warmest winters on record in the first quarter of 2012, and high storage levels. By spring 2012, working gas in storage stood at a record 934 Bcf surplus to the five-year average and robust injections in the spring and fall brought storage to near-record levels by November 2012 (Figure ES-3).

**Figure ES-3**

#### Natural Gas Storage



Source: Derived from EIA data

Growth in natural gas production was driven by gains in drilling rig efficiency and was centered mostly in Pennsylvania’s Marcellus Shale, Texas’ Eagle Ford, and Arkansas’ Fayetteville Shale. In other major shale plays, production stalled or declined as producers focused on liquids-rich natural gas fields. By the end of 2012, production from the six major U.S. shale formations accounted for 38 percent of total U.S. natural gas production, up from 22 percent at the beginning of 2011.

During the year, spot natural gas prices at Henry Hub fell to a low of \$1.82/MMBtu, before gradually rising to a high of \$3.77/MMBtu in late November. The rise was largely a result of high natural gas demand from power burn and the onset of the 2012 to 2013 winter heating season.

### Regional Natural Gas Prices Fall

In 2012, natural gas prices fell 22 to 36 percent across the nation. The price difference between major trading hubs and the Henry Hub, also known as basis, in many cases was only pennies.

- Capacity expansions on Florida Gas Transmission Co. eliminated price spikes at the FGT-Z3 hub, and natural gas prices there averaged \$2.92/MMBtu.
- In New England, the Algonquin Citygate hub near Boston had the highest spot prices in the nation, averaging \$3.91/MMBtu due to pipeline constraints and a drop in liquefied natural gas (LNG) imports (Figure 2-2).
- Except for very cold days, there were few natural gas transportation constraints into New York City and spot prices at Transco Zone 6 NY averaged \$3.19/MMBtu.
- Natural gas prices in the Rocky Mountains were among the lowest in the nation. They averaged \$2.59/MMBtu at the Colorado Interstate Gas hub. Regional natural gas producers lost market share to growing production closer to the markets in the Northeast and Midcontinent.



- In California, increased demand for natural gas-fired power generation due to the outage at the San Onofre Nuclear Generating Station put upward pressure on natural gas prices through spring and summer.

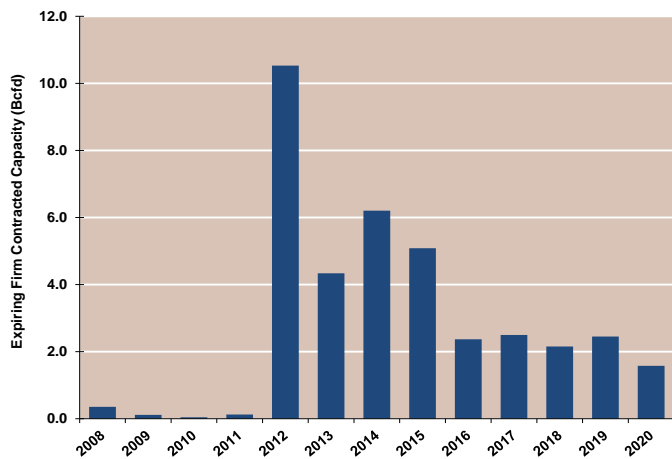
### Changes in Regional Natural Gas Supply Pose Financial Challenges to Pipelines

Declines in pipeline utilization and changing customer needs pose financial risks to long-haul pipelines. More than 10 Bcfd of long-term capacity contracts on U.S. natural gas pipelines expired during 2012 (Figure ES-4). In cases where customers re-contracted, it was generally for shorter durations and smaller volumes.

The erosion of regional price differences over the past few years has reduced the value of many long-haul pipeline routes. Pipelines that move natural gas into the Northeast from the Gulf Coast and the Rocky Mountains experienced the greatest declines in utilization in 2012. The new natural gas flow patterns raised the possibility that some pipelines may be unable to find buyers for long-term capacity once their contracts expire.

#### Figure ES-4

Quantity of Natural Gas Pipeline Firm Transportation Contracted Capacity Expiring by Year



Source: Derived from Velocity Suite data based on FERC Form No. 549 B - Index of Customers data

As a result of declining utilization, some pipeline companies are converting or considering converting natural gas pipelines to transport crude oil or natural gas liquids. Cumulatively, almost 26 Bcfd of long-term capacity contracts are due to expire by 2015, 37 Bcfd by 2020.

### Electricity Prices Decline

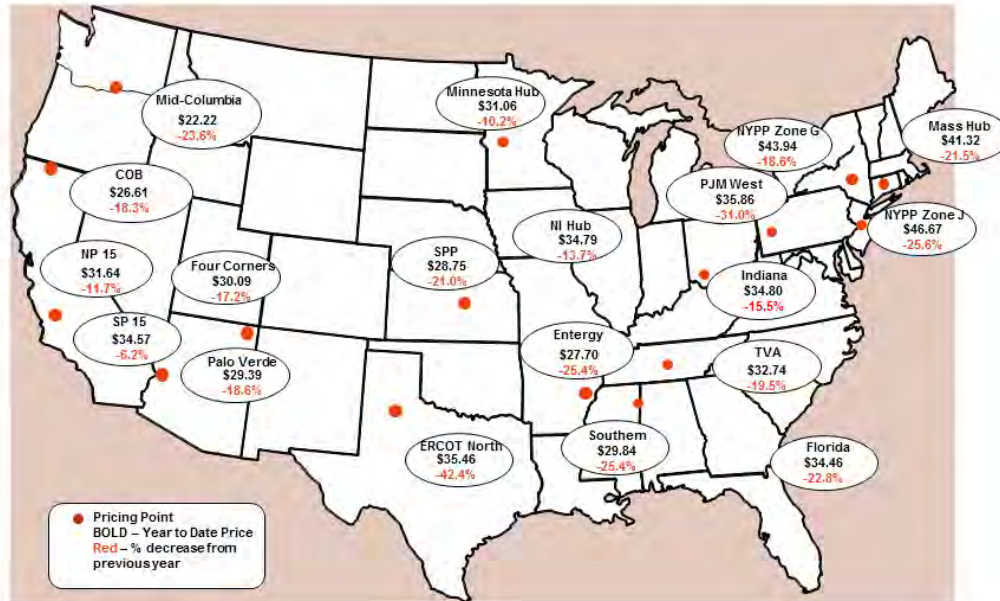
Nationwide, average on-peak prices for electricity were lower in 2012 than in 2011. The lower prices followed natural gas prices, a major determinant of electricity prices. Low natural gas prices have largely been responsible for relatively low electricity prices since the beginning of 2009, but lower electricity demand from continued weak economic activity and energy efficiency were also contributors. Low prices in 2012 were seen in all regions of the nation, but varied due to region-specific conditions. Eastern prices were between 10 percent and 31 percent lower than in 2011 while Western prices fell between 6 percent and 23 percent (Figure ES-5 on the next page).

### Electricity Demand Falls for Second Year

Compared to 2011, sales of electricity dropped by 1.7 percent or 62.9 TWh in 2012. Annual consumption of electricity across the three principal sectors (residential, commercial, and industrial) is shown in Figure ES-6 (next page). Demand was down across the nation due to three primary factors: a decrease in residential demand, lack of demand growth in the commercial and industrial sectors, and increased energy efficiency. Residential demand decreased because of a drop in heating load due to a warm winter. The first quarter of 2012 broke the January to March average temperature record for the continental United States by a significant 1.4 F. In 2012, industrial sales fell by 1.1 percent, commercial sales by 0.2 percent.

Figure ES-5

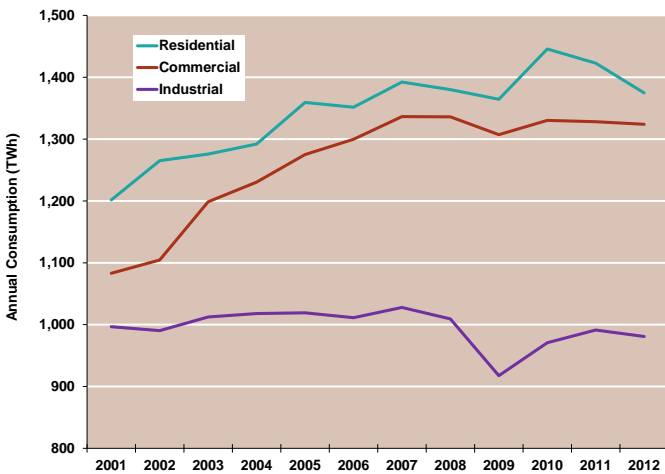
2012 Average Electricity Prices



Source: Derived from Platts data

Figure ES-6

Annual Electricity Consumption by Sector



Source: Derived from EIA data

Reduced industrial demand generally reflects a slowly recovering economy with commercial consumption staying flat as a result of the economy and weather.

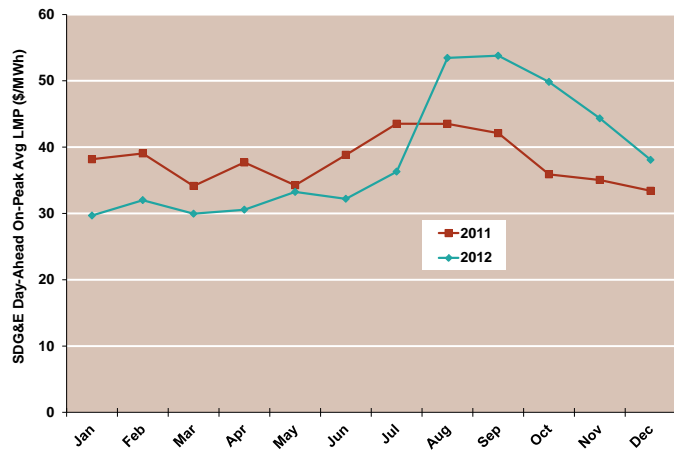
Energy efficiency is responsible for a portion of the reduction in load. Several states with active energy efficiency programs were able to achieve savings that amounted to about one percent of total sales. Even with just part of the nation represented by active state programs, documented results are sufficient to influence the overall trend in consumption.

### Import-Constrained Southern California Experienced a Tightened Energy Market

An extended outage of the San Onofre Nuclear Generating Station led to a tightening of the supply-demand balance in already-constrained Southern California, particularly in peak load hours. The need for local voltage support exacerbated the area’s challenges with imports as the loss of San Onofre stressed the power market during 2012, particularly during August and September. The stress elevated prices (Figure ES-7). With San Onofre offline, replacement power came primarily from increased use of natural gas-fired generation, including units brought back out of retirement. Among other actions, California accelerated the in-service date for its new 500 kV transmission project, the Sunrise Powerlink. Southern California utilities also made other transmission upgrades to improve flows in the region.

Figure ES-7

2012 Monthly Electricity Prices for San Diego Load Zone



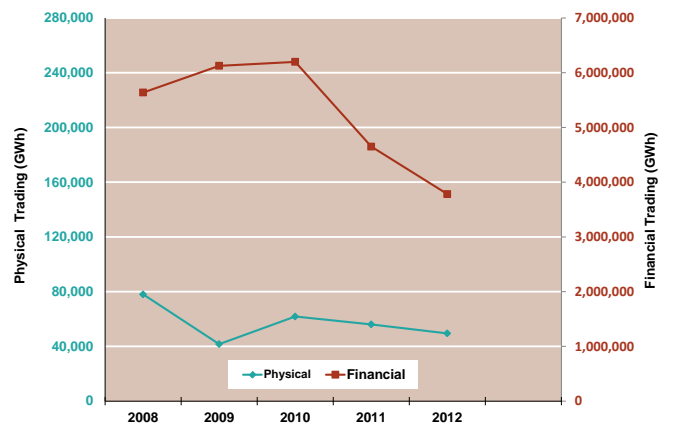
Source: Derived from CAISO data

### Physical and Financial Markets for Natural Gas and Electricity

Trading in financial products continued to fill an important role in energy markets. The volume of financial trading significantly exceeds physical trading. In 2012, financial trading for both natural gas and electricity remained substantial overall, and the markets remained liquid. There were two key trends in financial trading of energy products. First, trading on IntercontinentalExchange, Inc. for electricity products decreased 19 percent compared to 2011 (Figure ES-8). One possible explanation for the decline is that there was lower volatility in power prices. Lower volatility implies less potential for profit and a decline in potential profits might steer investors away from energy products, and into other assets. Second, toward the end of the year, market participants desiring to trade in financial products for natural gas, electricity, or both, were offered new trading products after the Dodd-Frank Wall Street Reform and Consumer Protection Act required regulatory changes. In particular, markets transitioned by converting some traditional swaps products into futures.

Figure ES-8

Historical ICE Electricity Trading Volumes



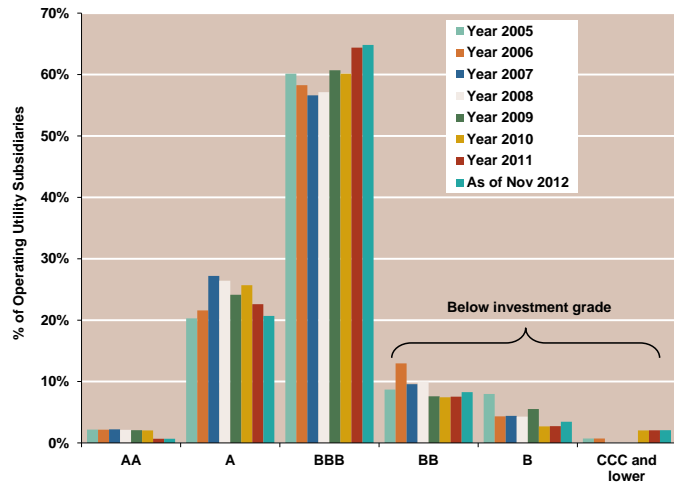
Source: Derived from ICE data

Participation by banking institutions in physical natural gas and power markets continued to wane. Declining activity in asset ownership and physical energy transactions is part of a multi-year trend with banking institutions participating in the natural gas and electricity markets peaking in the 2007 and 2008 period and declining since then.

Public utilities maintained access to investment capital through stable credit ratings. A relatively favorable credit environment existed for utilities that maintained higher credit ratings. With low interest rates available for investment grade utilities, debt issuance by the lowest investment grade-rated (BBB) utilities stayed flat while A-rated utilities increased their issuance by 25 percent in 2012 (Figure ES-9).

**Figure ES-9**

**Investment-Grade Ratings for Natural Gas and Electricity Sectors**



Source: Derived from Standard & Poor's data

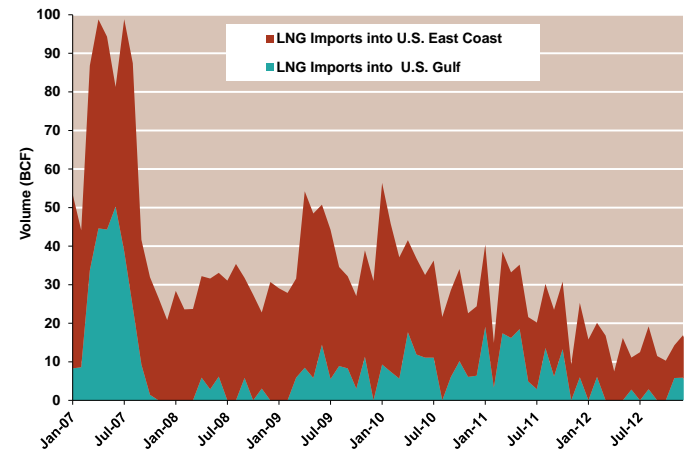
Note: Major rating categories are grouped by base rating and include all ratings with (+) to (-) modifiers

**LNG Imports Drop as U.S. Gears Up for Exports**

United States LNG imports continued to decline in 2012 (Figure ES-10). Low domestic natural gas prices made it difficult to attract LNG cargo to the United States, and imports fell 47 percent. Of 12 active U.S. terminals, only Everett LNG in Massachusetts and Elba Island in Georgia received regular LNG cargo throughout the year, albeit with lower frequency than in past years. Both have long-term contracts.

**Figure ES-10**

**Volume of LNG Imports in 2012**



Source: Derived from U.S. Department of Energy data

LNG sold in Asia for about \$15/MMBtu, four to six times higher than in the United States, \$10-\$11/MMBtu in Europe, and around \$12-\$13/MMBtu in South America (Figure ES-11 on next page). The price spread between the United States and world natural gas prices created interest in liquefying and exporting U.S. natural gas. However, it is unlikely that the United States will export any LNG before 2016 due to the time required to build and permit export facilities.

Figure ES-11

## Estimated World-Wide LNG Landed Prices



Source: Derived from Waterborne Energy data

Even as companies contemplated LNG exports, U.S. natural gas exports to Mexico increased 25 percent in 2012. Exports of Marcellus Shale gas to Canada also began in the latter half of 2012. Natural gas imported

from Canada fell 9 percent in 2012 due largely to the fact that U.S.-produced natural gas generally had a transportation advantage over Canadian natural gas, particularly in the Northeast and upper Midwest.





## Chapter 1: Market Developments

### SUMMARY

Low natural gas prices and their effects on power markets spurred key market developments in 2012 and increased the interrelationship between the natural gas and electricity markets. Overall, natural gas increased its presence and role in the electricity markets as a primary and growing resource for power generation. Other key market developments stemmed from the implementation of technologies, including the use of phase-angle regulators to aid in addressing loop flow, and the integration of renewable resources.

Sharply higher output from natural gas-fired generation resulted from natural gas's increased abundance and lower price. Throughout much of the Eastern Interconnection, particularly in PJM and the Southeast, natural gas-fired power plants realized significant gains in output, frequently at the expense of coal-fired generators. This shift was manageable, but not seamless.

Robust local natural gas production growth from the Marcellus Shale continued to experience pipeline bottlenecks in the Northeast. While planning for the possibility of extreme weather, and facing reduced supplies from liquefied natural gas (LNG), stakeholders in the



region focused their attention on fuel supply reliability. In New England, in particular, the growth in natural gas use for power generation, together with the increased use of natural gas for home heating, led stakeholders to seek ways to alleviate stresses on the natural gas pipeline delivery system under high load conditions.

Further, long-haul natural gas pipelines saw some increases in financial risk as customers with firm contracts considered whether to renew expiring transportation contracts. Customers who did not renew their contracts faced opportunities for accessing shale gas from cheaper local supplies, as opposed to gas supplies previously delivered from the Gulf Coast and South Central United States.

California increased its dependence on natural gas as a result of the lengthy outage at the San Onofre Nuclear Generating Station. The plant's output was replaced in part by increased production from natural gas-fired generating units both in Southern California and in surrounding areas of the West. Natural gas and electricity prices saw some increases in the region, particularly during the summer and early fall.

Changing technology implementation occurred with the placement into service of phase angle regulators at the MISO-Ontario border which helped reduce loop flows at this well-used transmission path. Additionally, wind integration continued to increase, providing benefits to consumers when prices drop and challenged balancing authorities when congestion occurs. For example, MISO experienced a sudden drop in wind generation, which led the grid operator to commit and use ancillary services to balance supply on the grid. As use of wind generation and other

variable resources increase use of ancillary service to compensate for fluctuations in their output will take on heightened priority.

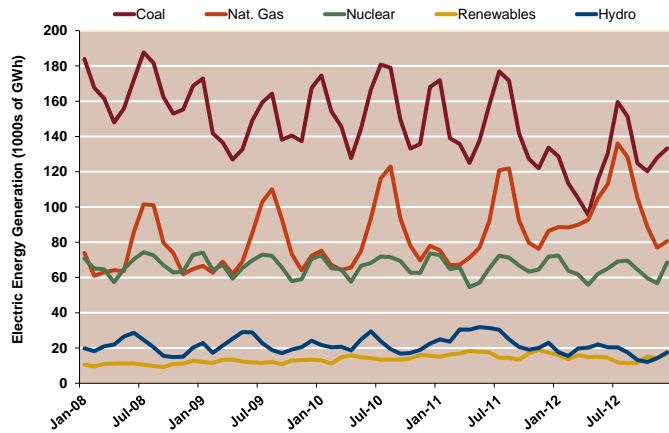
### *Natural Gas Increasingly Displaced Coal for Electricity Generation*

Competitive fuel pressures between natural gas and coal led to a marked shift in electricity generation resource utilization. The United States saw a displacement of substantial amounts of electricity output from coal-fired generation by increased output from natural gas-fired generation. Broader market declines in the price of natural gas as compared to a more modest decline in coal prices drove the trends in 2012. These trends may drive investment decisions with respect to the fuel type of new electric generating plants which may lead to further demand for construction of natural gas-fired facilities in the coming year.

The share of electricity generation fueled by natural gas increased substantially in 2012. Natural gas-fired generation reached 31 percent of total generation in 2012, up from 25 percent in 2011. The increase resulted in displacement of coal-fired generation, particularly generation burning Appalachian coal. Coal's share of net generation declined to 39 percent from 43 percent in 2011. While on an annual basis coal-fired generation was still the largest source of electricity supply, by May 2012 the spread in electricity production between monthly amounts from coal and from natural gas had narrowed sharply. The 2012 changes relative to other fuel sources and the prior four years are illustrated in Figure 1-1 on the next page.

Figure 1-1

Monthly Net Generation by Energy Source



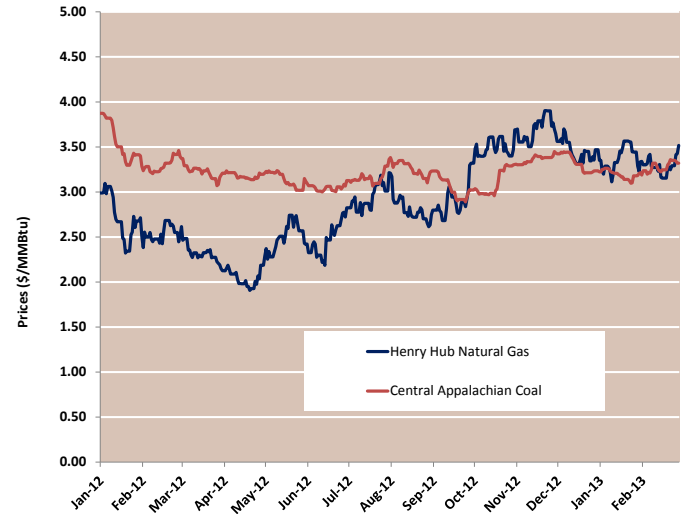
Source: EIA 923 Monthly Utility Power Plant Database, U.S. EPA CEMS

Lower natural gas prices have driven the shift in generation resources because of increases in natural gas supply from shale gas production in the United States. For the first time in over ten years, natural gas began to trade at a discount to coal in the third quarter of 2011. Through the first half of 2012, the price of natural gas averaged \$2.38/MMBtu, 45 percent lower than for the same period in 2011. By April 2012, natural gas at Henry Hub traded near \$2/MMBtu, over \$1/MMBtu cheaper than Appalachian coal when adjusted for the heat rate difference between the two technologies (Figure 1-2).<sup>1</sup> This decline in the price of natural gas was the catalyst for the substantial shift from coal to natural gas-fired electric generation. Further discussion of shale natural gas production trends is provided in Chapter 2.

1 In order to show comparable prices in terms of their electricity production value, coal prices are adjusted to reflect the lower average heat rate of coal-fired power plants compared to that of combined-cycle power plants. Heat rate is a measure of how efficiently a generator converts fuel into electrical energy. It is determined by dividing the heat content of the fuel input consumed in the generator by the electrical energy output, usually expressed as BTU/kWh. The lower the heat rate, the higher the efficiency of the generating unit.

Figure 1-2

Natural Gas Prices Dip Below Coal Prices for Most of 2011-2012



Source: Derived from Bloomberg data

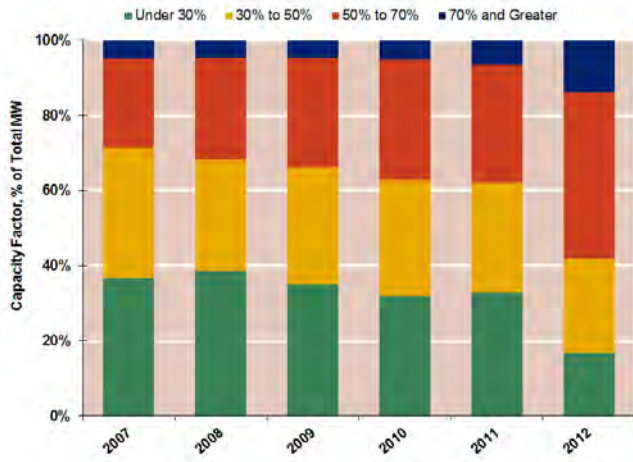
The national shift from coal-fired to natural gas-fired generation was reflected in a significant increase in the use of combined-cycle power plants. With lower fuel prices, natural gas-fired combined-cycle units are less expensive to run due to their high efficiency fuel prices. As a result, they increasingly operated in a baseload mode generation (greater than 50 percent capacity utilization, or capacity factors).<sup>2</sup> Figure 1-3 on the next page shows the relative distribution of capacity factors across selected production ranges for the last six years. Sixty-three percent of the nation's combined-cycle plants operated above 50 percent capacity factors during 2012, compared to 29 percent in

2 A baseload supply is a generator that is used throughout the day or throughout the year. In contrast, non-baseload supply is typically used during certain parts of the day (e.g., high load hours in the afternoon) or part of the year. For this analysis, baseload generation was chosen as generators having greater than 50 percent utilization, where utilization is measured in terms of capacity factors. A capacity factor is a measure of the average output of an electric generator over a specific period of time compared to how much the generator could produce if running at its maximum rated production, i.e., at continuous full power operation during the same period.

2007. Nationwide, the share of combined-cycle plants running at 70 percent-plus capacity factors reached 18 percent compared to just 7 percent in 2011.

**Figure 1-3**

**Major Shifts in Combined-Cycle Plant Capacity Factors in 2012**



Source: Derived from SNL data

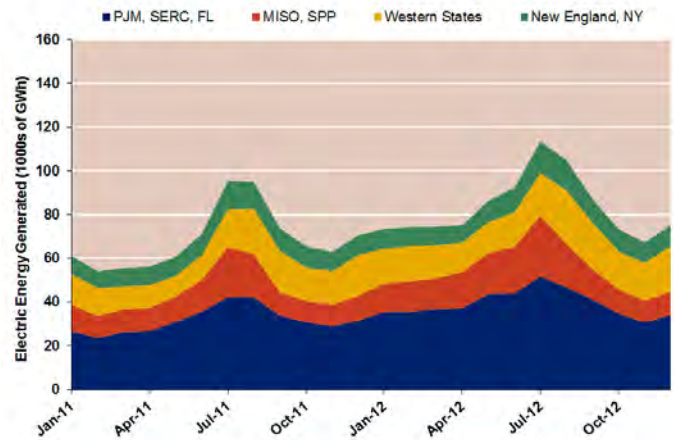
The most notable shifts from coal-fired to natural gas-fired generation occurred in areas of the Eastern Interconnection relying on Appalachian coal. This was particularly the case in PJM and the Southeast where there is significant use of Appalachian coal, but much under-utilized combined-cycle generation capacity. For PJM and the Southeast, coal's share of net generation declined to 40 percent of total generation from 47 percent in 2011. Electricity produced by natural gas-fired generation was 31 percent of the production in 2012, an increase from 24 percent in 2011.<sup>3</sup> MISO and SPP, utilizing more of the lower cost Powder River Basin (PRB) coal, experienced less displacement of coal by natural gas. Appalachian coal

costs averaged about \$63 per ton in 2012 compared to \$11 per ton for PRB coal. Even allowing for the higher heat content of Appalachian coal, and higher transportation costs for PRB coal, PRB coal enjoyed a delivered price advantage over Appalachian coal.

Figures 1-4 and 1-5 (on the next page) illustrate natural gas and coal utilization for electricity generation by region. These figures show where the two fuel sources are in greatest use and how the displacement played out over the past two years. Seasonal peaks in electricity output are still greatest in the summer, however, the shift in electricity generation between the two fuel sources took place in all months of 2012 compared to the prior year.

**Figure 1-4**

**Monthly Electricity Output by Natural Gas-fired Generation**

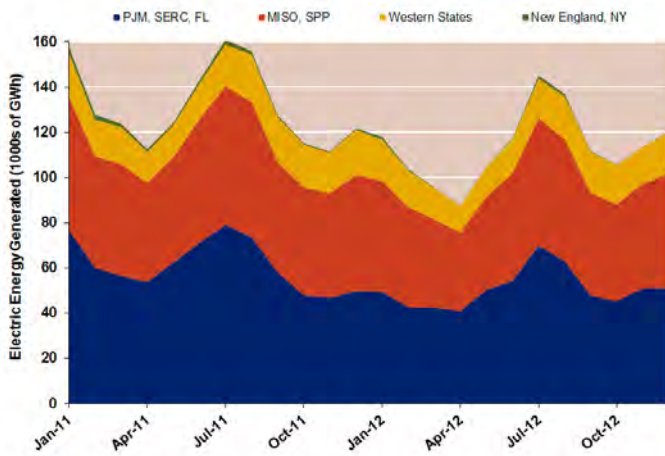


Source: EIA 923 Monthly Utility Power Plant Database, U.S. EPA CEMS

<sup>3</sup> Of note, the Southeast is the nation's largest consumer of natural gas for power generation, accounting for 30 percent of U.S. power burn in 2012.

Figure 1-5

## Monthly Electricity Output by Coal-fired Generation



Source: EIA 923 Monthly Utility Power Plant Database, U.S. EPA CEMS

As the price of natural gas and coal decreased relative to 2011, electricity prices declined.<sup>4</sup> In the eastern regions burning Appalachian coal, natural gas increasingly became the marginal generation source. In PJM, for example, among all marginal resources affecting the real-time price in the first 9 months of 2012, 58 percent were coal-fired generators, down from 69 percent of the marginal resources in 2011. At the same time natural gas units were marginal 31 percent of the time up from 26 percent in 2011.<sup>5</sup> However, since the prices of the fuels were close on a \$/MMBtu basis, the range of electricity prices produced were driven by overall lower costs of the fuels. Throughout the rest of nation, natural gas-fired generation remained the marginal resource.

Lower utilization of coal-fired generation, along with an expected need to invest in emissions-related capital equipment, led to announcements by owners to schedule retirements of coal-fired power plants.<sup>6</sup> Some analysts anticipated an upturn in new natural gas-fired generation to be constructed in the coming years, especially in areas close to shale gas formations.<sup>7</sup> These retirement or build decisions will be a key determinant in coming years' electricity resource fundamentals.

As a result of the shift in fuel utilization for electricity production, natural gas consumption by power generators (referred to as power burn) grew 20.3 percent to 25 Bcfd in 2012, up from 20.8 Bcfd the year prior. As explained in Chapter 2, power burn is the fastest growing use for natural gas and surpassed residential and commercial sector natural gas consumption.

### New England Faces Seasonal Supply and Pipeline Constraints

New England continued to face power and natural gas market challenges in 2012 due to growing competition for limited natural gas supply between heating and electric load during the coldest winter days. Low domestic natural gas prices led to low imports of LNG and Canadian natural gas, important sources for meeting peak demand days in New England. Lack of LNG and natural gas from Canada exacerbated pipeline constraints into New England from the southern supply corridor, including Marcellus Shale natural gas

<sup>4</sup> Discussion of the overall lower prices for natural gas and electricity, and factors that contributed to regional price differences, are provided in Chapter 2, for natural gas, and Chapter 3, for electricity.

<sup>5</sup> Monitoring Analytics, LLC, "2011 State of the Market Report for PJM," Vol. 2, March 15, 2012, p. 31. See also Monitoring Analytics, LLC, "2012 Quarterly State of the Market Report for PJM: January through September," November 15, 2012, p. 29.

<sup>6</sup> SNL Energy reported that U.S. power companies have announced plans to retire nearly 30 GW of coal-fired capacity between 2012 and 2021. SNL Energy: "Upcoming, recent coal-fired unit retirements," August 15, 2012. The Energy Information Administration estimated 49 GW of retirements from 2011 through 2035. U.S. Energy Information Administration (EIA), "Annual Energy Outlook 2012," DOE/EIA-0383, June 2012, p. 4.

<sup>7</sup> Northeast Power Markets Energy Watch, ESAI Power, LLC, December, 2012.

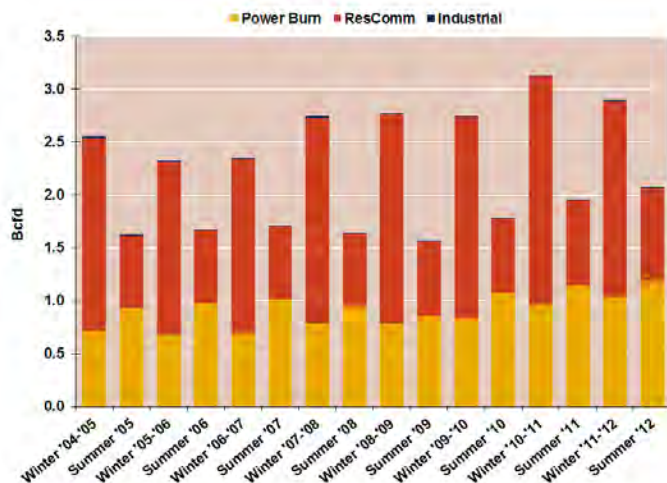


production, as New England relied more heavily on these pipelines for supply. This led to concerns that extreme cold weather could result in some service interruptions, particularly to power generators that generally rely on interruptible pipeline capacity to meet their fuel needs.

New England is a winter-peaking natural gas market driven by heating demand from the residential and commercial sectors. In the last two years, power burn has increased its share of total natural gas demand in New England and grew 4 percent during the summer of 2012 (compared to 2011). Figure 1-6 illustrates growth in New England power burn, which has led to constraints on pipelines serving the region. These are particularly acute during cold snaps when demand from power plants coincides with peak residential and commercial natural gas demand. While the higher power burn pushed regional pipeline capacity to operating limits at times, New England avoided any major supply issues due to an unusually warm winter that suppressed residential and commercial load during the first quarter of 2012.

Figure 1-6

Gas-Fired Generation Increased Share of New England Natural Gas Demand



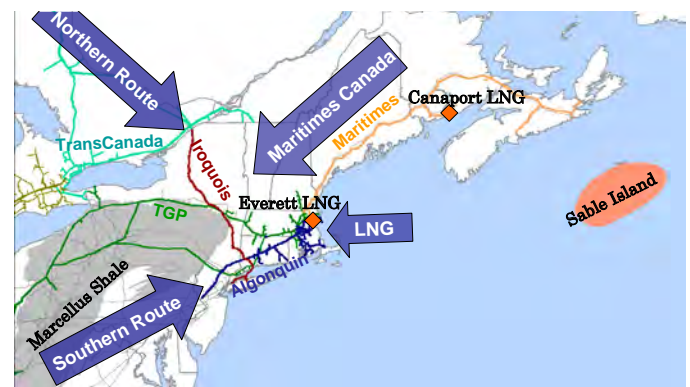
Source: Derived from Bentek Energy data

Figure 1-7 shows major natural gas supply routes into the New England natural gas market, including natural gas pipelines and LNG terminals. Main routes into New England include:

- Maritimes Canada - This includes Canaport LNG supplies (New Brunswick) and Sable Island (Nova Scotia) offshore production via the Maritimes & Northeast Pipeline (Maritimes);
- LNG - This includes LNG imports through the onshore Everett LNG terminal and offshore Northeast Gateway and Neptune LNG terminals near Boston. Most of Everett's LNG is used to fuel the Mystic power plant in Boston or trucked to local distribution companies' LNG storage tanks and used to meet peak demand. Northeast Gateway and Neptune LNG have not imported any LNG since 2010;
- Northern Route - This includes Canadian natural gas supplies from the TransCanada Mainline via the Iroquois Pipeline and Portland Natural Gas Transmission (PNGTS); and,
- Southern Route - This includes Gulf Coast, Rocky Mountains, and Marcellus Shale natural gas supplies via Tennessee Gas Pipeline (TGP) and Algonquin Gas Transmission (Algonquin).

Figure 1-7

New England Natural Gas Infrastructure

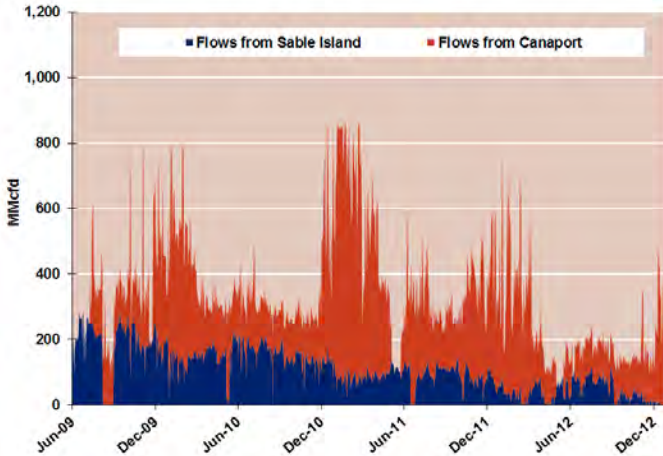


Source: Derived from Ventyx data

LNG imports from Everett LNG and Canaport LNG, plus natural gas production from Sable Island have historically supplemented natural gas supplies into New England on Algonquin and TGP. However, LNG imports were at their lowest in 10 years during 2012, with Canaport LNG sendout down sharply as cargoes were redirected to higher-priced buyers in Asia and Europe. As shown in Figure 1-8, natural gas sendout from Canaport LNG along the Maritimes pipeline into New England was down 44 percent in 2012 while natural gas flows from Sable Island fell dramatically due to depletion of the offshore field. Not shown in the figure, natural gas exports from Everett LNG to the Boston market was down 68 percent from 2011.

**Figure 1-8**

**Natural Gas Flows on the Maritimes and Northeast Pipeline**



Source: Derived from Bentek Energy data

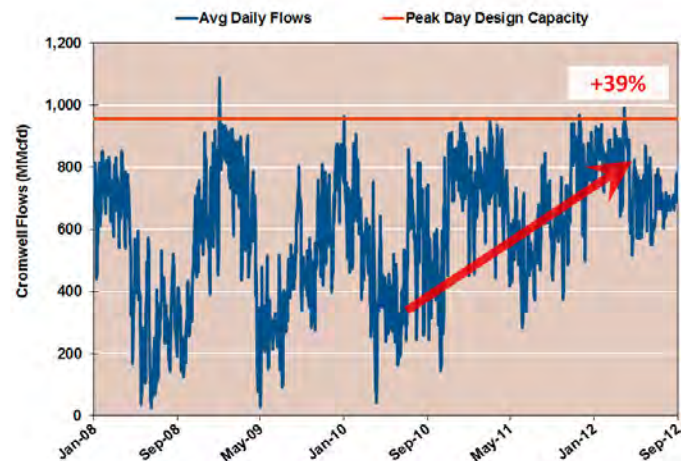
Natural gas imports from Canada on Iroquois Pipeline at Waddington declined 11 percent in 2012 due to high transportation costs on the TransCanada pipeline and its lack of competitiveness with new Marcellus natural gas production. New England has historically imported Canadian natural gas via Iroquois to Algonquin. However, natural gas flows were sometimes restricted by bottlenecks on Algonquin.

The Algonquin pipeline, a 2.4-Bcfd pipeline that runs from Lambertville, N.J. to Boston, Mass., experienced transportation capacity constraints at a number of compressor stations during 2012. Algonquin transports natural gas from the Gulf Coast, the Marcellus Shale, and Canada into New England. Algonquin receives Marcellus natural gas supplies from TGP at the Stony Point Compressor Station. During periods when this point became constrained, natural gas flows were restricted downstream to serve the Boston market.

Average natural gas flows through the Cromwell Compressor Station in Connecticut have increased 39 percent since 2010 (Figure 1-9) to serve numerous non-power and power customers in Connecticut and Rhode Island. Since the winter of 2008-2009, scheduled natural gas flows at Cromwell reached 97 percent of peak design capacity a total of 24 days (22 days during winter). Almost half of these days occurred last winter despite mild temperatures. Pipeline utilization reached 100 percent of capacity on six of those days.

**Figure 1-9**

**Flows at Algonquin’s Cromwell Compressor Station Up 39 Percent**



Source: Derived from Bentek Energy data

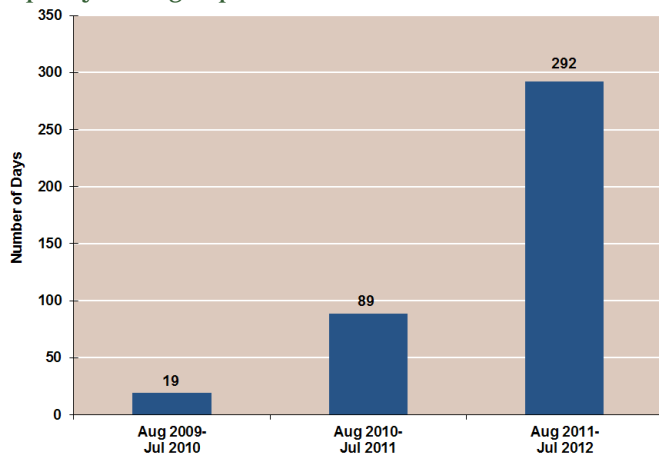


Algonquin's interconnection with TGP near Mendon, Massachusetts provides an alternate supply point for the Algonquin pipeline. TGP has expanded its take-away capacity from the Marcellus Shale and now delivers Marcellus Shale natural gas into New York. TGP's 200 line cuts across New York and into Massachusetts. However, constraints into New England have not yet been addressed. Consequently, New England natural gas often traded at a premium to New York during the winter of 2012. In January and February 2012, flows on the TGP 200 line into New England averaged 80 percent of pipeline capacity, and peaked at 94 percent of capacity in March 2012.

High utilization on pipelines supplying New England with natural gas from the Gulf Coast and Marcellus Shale resulted in diminished availability of interruptible transportation capacity to power generators in 2012. Figure 1-10 shows that since 2009, the availability of interruptible capacity on Algonquin fell substantially. For the 12-month period ending July 2010, there were only 19 days with no interruptible capacity. That number jumped to 292 for the 12-months ending July 2012.

**Figure 1-10**

Days with no Availability of Interruptible Pipeline Capacity on Algonquin



Source: Derived from Spectra Energy data

Lack of interruptible pipeline capacity is a concern for New England with its increased reliance on natural gas-fired power plants. Most of these plants have little or no firm transportation capacity in their supply portfolios and depend on interruptible capacity on the pipeline for their supplies. This option may not be available on high-demand days such as during a cold snap when LDCs need to meet increased customer demand, and power generators may not have sufficient fuel to operate during peak-demand days.

Greater reliance on natural gas as a fuel for power generation led FERC to hold a series of regional technical conferences during July and August 2012 on natural gas-electric industry coordination.<sup>8</sup> New England was identified as a market particularly at risk of disruption. Based on some of the issues highlighted at the New England conference, the New England ISO and natural gas pipelines took steps to increase coordination by implementing monthly New England Gas-Electric Focus Group discussions. The discussions explored common market issues and possible resolutions, including changes to natural gas scheduling practices, improved communication and information sharing, and availability of non-firm pipeline capacity.

Participants at the New England conference also discussed the cost of pipeline expansions. These costs are usually borne by long-term firm customers, such as local distribution companies and industrial customers. New England power generators generally have not contracted for firm capacity because they only need it intermittently during peak periods. Most participants agreed that the answer to New England's

<sup>8</sup> *Coordination between Natural Gas and Electricity Markets*, Notice of Technical Conferences, Docket No. AD12-12-000 (July 5, 2012).

pipeline constraints is to build more pipeline capacity, but the allocation of costs between customers was not resolved.

### LNG Imports into Boston Fall

LNG imports into the Everett LNG facility outside Boston fell 37 percent in 2012, from 137 Bcf to 87 Bcf and the terminal declared force majeure during April and May. The terminal has firm long-term LNG supply agreements with Trinidad and Tobago and Yemen, but repeated terrorist attacks on the natural gas pipeline that supplies the Yemen LNG facility sharply curtailed deliveries from that country in 2012. This led Distrigas of Massachusetts (DOMA), the owner of Everett LNG, to declare force majeure in April and May. They curtailed deliveries to firm customers by 20 percent, and halted deliveries to interruptible customers. DOMA requested accelerated deliveries of LNG from Trinidad, but by the fall of 2012, LNG cargoes into Everett had dropped from four to five vessels per month to two to three per month. As a result, Everett sent out only a small amount of re-gasified LNG into the regional grid. Most of its send-outs were dedicated to serving the adjacent Mystic power plant, and firm customers who truck LNG to storage tanks throughout the region.

The supply disruption led to concerns for adequate sendout of re-gasified natural gas to the adjacent Mystic power plant. Mystic units 8 and 9 can provide up to 1,600 MW of electricity supplies into the Boston area. The Mystic units, connected to Everett through a dedicated pipeline, are directly dependent on Everett for its fuel supply. Subsequent to the supply challenges that emerged in the spring, DOMA and ISO-NE worked closely together to ensure that the Mystic power plant had enough fuel to run during peak electricity demand periods.

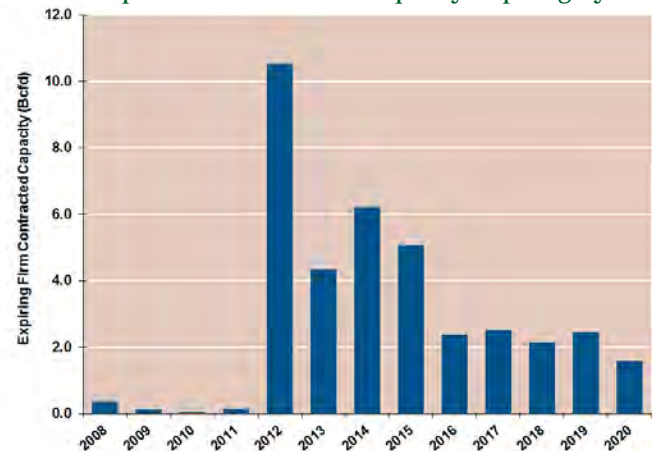
### Record Amounts of Long-Term Pipeline Capacity Contracts Expire in 2012

Regional changes in natural gas production, particularly the growth of shale natural gas in the Northeast, resulted in a decline in utilization on some segments of long-haul natural gas pipelines. At the same time, record amounts of long term pipeline capacity contracts expired in 2012. Declines in pipeline utilization and changing customer needs raised concerns about how much expiring capacity would be re-subscribed. In cases where customers re-subscribed, it was generally for shorter contract terms and smaller contracted volumes. Pipelines with available firm capacity faced financial pressure either on segments of their lines or, in some cases, along the entire pipeline. Some underutilized pipelines proposed conversion to alternative fuels such as crude oil or natural gas liquids.

As shown in Figure 1-11, over 10 Bcfd of long-term capacity contracts on U.S. natural gas pipelines expired during 2012. Cumulatively, almost 26 Bcfd of capacity is due to expire by 2015 and 37 Bcfd by 2020.

Figure 1-11

#### Firm Transportation Contracted Capacity Expiring by Year



Source: Derived from Velocity Suite data based on FERC Form No. 549 B - Index of Customers data

Note - Pipelines included in analysis: TGP, El Paso, Northern Natural, TETCO, ANR Great Lakes, Columbia Gulf, Transwestern, and Trunkline

Natural gas from new shale plays in the vicinity of consuming markets shifted contracted pipeline volumes to closer supply sources. In particular, growing Marcellus Shale natural gas production, increased available natural gas supply in the proximity of Northeast markets, reduced the Northeast's dependence on natural gas supply from the Gulf Coast, the Rocky Mountains, and the Mid-Continent. Similarly, natural gas imports from Canada and LNG imports into the Northeast also declined. Growing Mid-Continent shale natural gas has reduced the Upper Midwest's reliance on supplies from the Gulf Coast and Rocky Mountains, as well as natural gas imports from Canada.

Growing regional sources of natural gas, coupled with plentiful long-haul pipeline capacity resulted in erosion of regional price differences in 2012. This reduced the value of many long-haul pipeline routes and reduced pipeline profitability. A number of long-haul pipelines, including Tennessee Gas Pipeline, Trunkline, Transwestern, and El Paso reported falling rates of return in 2012.

By region, key natural gas pipelines with significant capacity contract expirations (above 500 MMcfd) between 2012 and 2015 include:

#### Midwest Market

- ANR pipeline experienced a shift in natural gas supply from the offshore Gulf of Mexico to the Marcellus Shale in the Northeast. Some segments on ANR's southeast mainline began to transport natural gas from north to south, reversing the traditional flow direction from Louisiana to Michigan. Utilization on the southeast portion of ANR's mainline was down 20 percent in 2012 from 2011, and down almost 50 percent from 2009. Compensating for the decline, utilization of ANR's southwest mainline, using natural gas sourced from the Anadarko Basin, increased to 84 percent in 2012 from 54 percent in 2009.

- Trunkline traditionally sourced its natural gas supplies from East Texas, but during 2012 shifted its source to northern Louisiana. Natural gas receipts from northern Louisiana have increased 15 percent since 2010. Overall utilization on Trunkline in the South Texas zone declined to zero in 2012, while flows in the North Texas portion of the pipeline are 5 percent lower than in 2011.

#### Northeast Market

- TGP experienced a decline in natural gas receipts from the Gulf Coast and a significant increase in natural gas receipts from the Marcellus Shale. Flows on TGP south of the Kentucky/Ohio border declined 49 percent in 2012 compared to 2011, while flows from Marcellus-producing areas in Pennsylvania grew 25 percent.
- Texas Eastern Transmission Co. (TETCO) experienced a decline of 60 percent of natural gas receipts from South Texas and west Louisiana supply zones on its southern leg and 52 percent on the northern leg.

#### Southwest Market

- Transwestern Pipeline delivers natural gas supplies from the San Juan Basin in New Mexico and the Permian Basin in West Texas to markets in the Southwest and Southern California. The southern line on El Paso is now also sourcing some supplies from the growing Eagle Ford production in Texas. Flows out of West Texas grew 38 percent in 2012 from 2011. Overall flows on the north mainline, which transports supplies from the Permian Basin as well as San Juan production to the Southwest and Southern California markets, declined 3 percent in 2012 from 2011. This has prompted talk of converting one of the lines to carry oil and oil products.

Table 1-1 (next page) demonstrates the trend towards lower utilization on the highlighted pipelines. Firm transportation contract expirations on these pipelines amounts to 34 percent of their contracted capacity over the next three years.

Table 1-1

Pipeline Flow Utilization at Key Locations

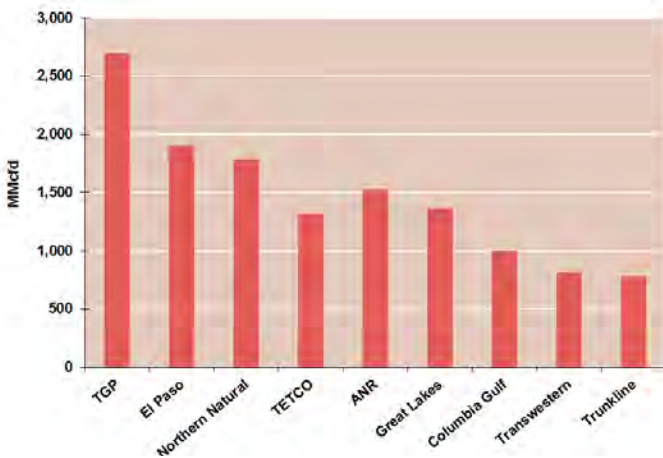
Point Location	ANR		Trunkline		NNG	TGP		TETCO		El Paso		
	SE Mainline	SW Mainline	N. TX to LA	N. LA	Nebraska	Station 200	Station 325	Northern Gulf Leg	Southern Gulf Leg	North Mainline	San Juan	Eunice Station*
2009	72%	54%	93%	72%	87%	NA	NA	72%	83%	95%	81%	76%
2010	70%	67%	87%	79%	77%	NA	NA	77%	86%	80%	79%	73%
2011	50%	80%	75%	96%	62%	37%	89%	59%	75%	66%	73%	66%
2012	39%	84%	79%	83%	58%	34%	82%	24%	38%	62%	69%	89%

Source: Derived from Velocity Suite data \* Texas Flows

Figure 1-12 demonstrates that TGP, El Paso, and Northern Natural had the largest amounts of long-term firm capacity contracts expire in 2012.

Figure 1-12

Firm Transportation Contracted Capacity Expired in 2012



Source: Derived from Velocity Suite data based on FERC Form No. 549 B - Index of Customers data

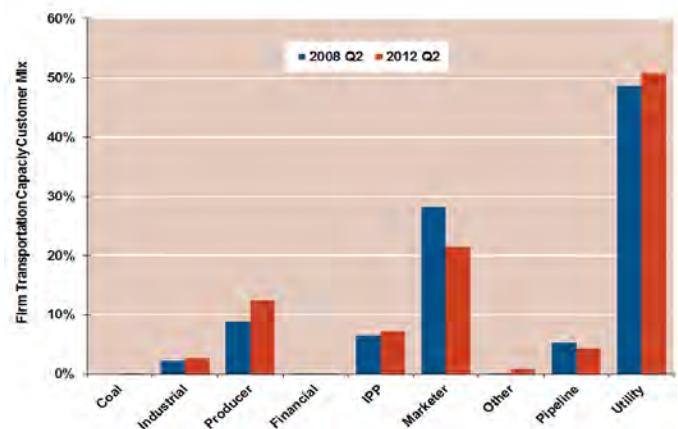
During 2012, natural gas marketers reduced their share of firm transportation commitments on long-haul pipelines, while natural gas and electric utilities retained or grew theirs. Marketers were the largest share of customers whose contracted firm transportation capacity expired in 2012, with 46 percent of their total firm transportation capacity expiring.

Marketers comprised about half of the customers holding firm transportation capacity on pipelines serving the Northeast. Electric and natural gas utilities made up the majority of firm transportation customers on pipelines serving the Midwest markets, since the majority of the capacity is held by local distribution companies (LDCs). Nearly 30 percent of their firm contracted capacity expired in 2012.

Figure 1-13 illustrates the decline in contracted capacity subscribed by marketers and the relative increase in capacity contracted by producers between the second quarter of 2008 and the second quarter of 2012.

Figure 1-13

Customer Mix Shifts from Marketers to Producers



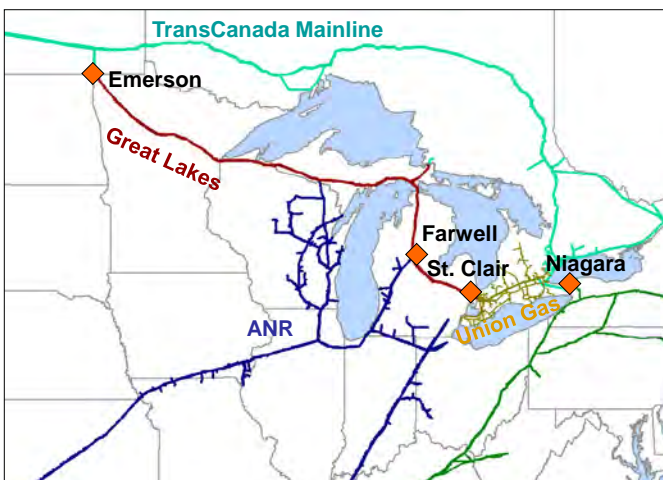
Source: Derived from Velocity Suite data based on FERC Form No. 549 B - Index of Customers data

As contracts shifted from long haul to shorter haul, the term of contracts were reduced. Contracts with terms longer than 10 years declined on ANR pipeline, while three to four-year and shorter than one-year term contracts increased in 2012. In some cases producers stepped up their presence and were more willing to enter into long-term capacity commitments.

Shippers on pipelines declined to renew some long-term contracts that sourced natural gas supplies from Canada. On October 31, 2012, 1.3 Bcfd, or 60 percent, of firm transportation capacity on the Great Lakes Gas Transmission Pipeline (Great Lakes shown on Figure 1-14) expired. TransCanada PipeLines, which owns Great Lakes, held more than half of this capacity, while marketers held most of the remaining expiring contracts, most of which were also not renewed. An additional 370 MMcfd of contracted firm transportation capacity is set to expire in 2013, while TransCanada's remaining contracts on Great Lakes, equaling 313 MMcfd, are set to expire in 2014.

### Figure 1-14

Great Lakes Gas Transmission Pipeline Receipt/Delivery Points



Source: Derived from Ventyx data

Due to declining utilization, some pipeline owners proposed to convert segments or entire natural gas lines to transport crude oil and products. TransCanada filed plans with its regulator, the Canadian National Energy Board, to convert sections of its intercontinental Mainline to carry up to 900,000 barrels/day of crude oil from the oil sands in Alberta to refineries in eastern Canada. In July 2012, Trunkline Gas Co. proposed to convert 770 miles of its loop line to oil.

Pipelines with access to new local production, such as the Marcellus, are focused on building capacity to relieve local supply bottlenecks. They expect to replace expired and expiring long-haul firm contracts with short-haul contracts. Anticipation of long-haul natural gas pipeline contract expirations in the near term have increased the financial risk faced by long-haul natural gas pipelines. A number of pipelines are reporting rates of return lower than their allowed rate of return, which increases the likelihood they will ask the Commission for rate increases in the coming years.



## Superstorm Sandy

Superstorm Sandy, which landed on Monday, October 29, significantly hobbled the Northeast power sector. Northeastern utilities declared that it was the most crippling event in their history. Distribution outages were extensive and resulted in more than six million customers without power by the morning of Wednesday, October 31. Several power plants were forced out of service, including three nuclear plants. At least one plant, Dynegy's 500 MW Danskammer plant, was rendered inoperable and its owner announced it would retire the plant. The most notable impacts from the storm were the significant loss of load and, generally, lower prices that resulted from the lost load. Despite the interruption to financial markets on Wall Street, power trading on the Atlanta-based IntercontinentalExchange, Inc. (ICE) and on CME Group (CME) continued throughout the storm.

Due to the storm, utilities lost revenue and incurred substantial capital costs. Long Island Power Authority (LIPA) was one utility hardest hit by Sandy and the subsequent November 11 Nor'easter. LIPA's load dropped approximately 2,100 MW on the first day of the storm, costing LIPA and its suppliers lost revenues. Upon completing early estimates, utilities expected to see capital costs in excess of \$1 billion. LIPA estimated capital requirements at between \$800 and \$850 million. Consolidated Edison Company of New York, Inc. (ConEd) expected response and restoration costs to be between \$350 million to \$450 million. Public Service Electric and Gas Company (PSEG) estimated restoration costs to be as much as \$300 million.

On the natural gas side, lower demand for natural gas-fired generation helped mitigate the impact of Superstorm Sandy on the Northeast natural gas market. Demand, which was already low during this shoulder season, dipped lower as outages reduced fuel consumption by natural gas-fired generators. Decreased demand was temporary, as natural gas-fired generation ramped up to substitute for lost nuclear generation. Jurisdictional pipelines did not experience major damage or disruptions. The hurricane had no discernible impact on wholesale prices or production.

## Import Constrained Southern California Experiences Tightened Energy Market

An extended outage of the two-unit San Onofre Nuclear Generating Station (SONGS) in Southern California led to a tightening of the supply-demand balance in the southern part of the CAISO market, particularly in peak load hours. The outage increased reliance on natural gas-fired generation, which in turn increased demand for natural gas, affecting both natural gas and power prices in the region. Higher-than-average hydroelectric generation and increases in wind production in the Northwest helped ease the tight supply conditions into the early summer. However, transmission limitations in the Southern California Edison Company (SCE) and San Diego Gas and Electric Company (SDG&E) load areas affected the amount of power that could flow into the region.

The two SONGS units (2,200 MW) were unable to operate for most of 2012. Unit 3 went off line in January due to a steam generator tube leak.<sup>9</sup> Unit 2 was already out of service for scheduled maintenance and remained offline when investigation of the cause of Unit 3's leakage found similar design problems in Unit 2's steam generators.

The loss of the SONGS units removed a large source of power generation, tightening the supply located within the greater Southern California and San Diego load pockets. Further, the SONGS units had provided voltage support for transmission flows into the region, so the loss of the two units reduced the amount of imports the system could maintain. CAISO, SCE and

9 The steam generator tube leak in SONGS Unit 3 was caused by tube-to-tube wear from excessive vibration. A small amount of radioactive steam was released during the tube leak event. The steam generators for both units had been replaced in the past two years. Nuclear Regulatory Commission, "Special NRC Oversight at San Onofre Nuclear Generating Station: Steam Generator Tube Degradation," Nuclear Regulatory Commission website, <http://www.nrc.gov/info-finder/reactor/songs/tube-degradation.html>, accessed January 4, 2013.



SDG&E developed contingency plans to address power needs for the summer of 2012. Huntington Beach power plant Units 2 and 3 were brought out of retirement to provide generation and local voltage support. SDG&E accelerated construction of its new 500 kV transmission project, the Sunrise Powerlink, bringing it online in June. Sunrise Powerlink supported power imports into San Diego and helped achieve import levels similar to those occurring before the SONGS outage. SDG&E and SCE upgraded other transmission facilities to improve flows in the region.<sup>10</sup>

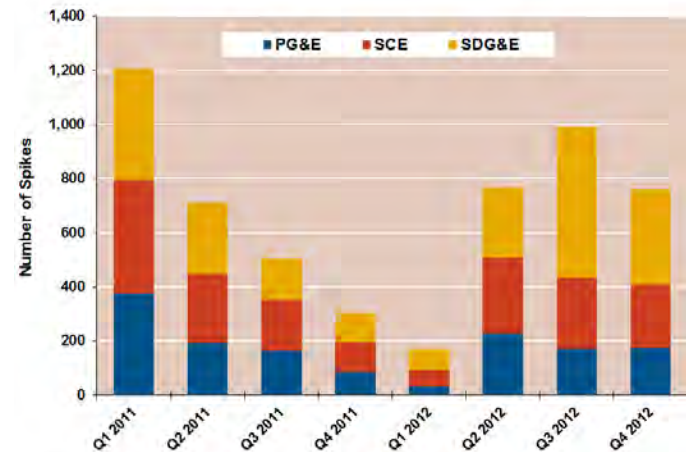
With the nuclear units offline, replacement power came primarily from increased generation at natural gas-fired power plants. California's natural gas-fired generation output reached about 37 percent of average hourly generation in the second quarter of 2012, compared to about 22 percent of generation in the second quarter of 2011. Natural gas-fired generation provided about 45 percent of average hourly generation in the third quarter of 2012, up from 33 percent in the third quarter the prior year. This contributed to a 13 percent increase in natural gas demand in California overall compared to 2011 levels. With nearly 0.7 Bcfd of additional natural gas demand, the price of natural gas at the Southern California Citygate price rose. See Chapter 2 for discussion of natural gas prices.

While customers did not lose power as a result of the tightened supply of electric generation, the reduction in supply led to increased price levels and price spikes. CAISO dispatched less efficient units, increasing the cost of power. Further, CAISO experienced price spikes due to insufficient amounts of generation available for ramping up or down to meet changes in

demand (ramp capacity), especially in the San Diego area. This lack of local ramp capacity increased the incidence of price spikes experienced in the area, as shown in Figure 1-15.<sup>11</sup> Other power system issues, including updated transmission limits for voltage stability and unscheduled power flows (also known as loop flow), contributed to the price spikes.

**Figure 1-15**

**California Price Spikes Increase in 2012**



Source: Derived from CAISO data via Ventyx

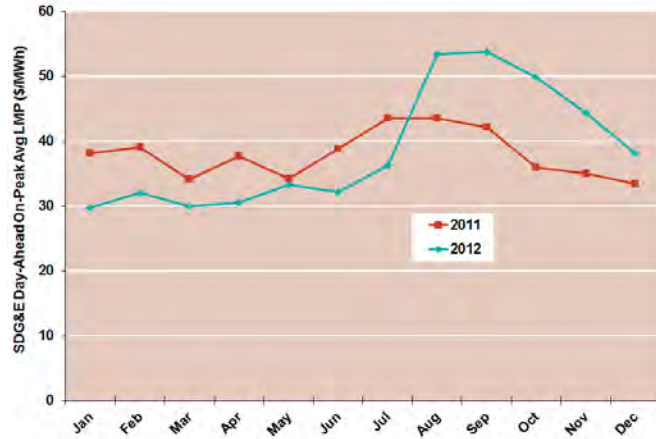
Price spikes in the real-time market led to higher overall prices particularly in August and September. Eventually, these higher prices carried into the day-ahead market, in part due to convergence bidding and modeling changes. Figure 1-16 illustrates the on-peak, day-ahead prices in the San Diego load zone, which were noticeably elevated in August and September, but below 2011 levels on average.

11 CAISO experienced price spikes in prior years as well, also due to a large extent to insufficient ramp capability. The ISO has taken steps to address the situation and spikes in 2011 declined from 2010 levels. In December 2011, CAISO implemented a market software feature, or "constraint," to procure ramp capability in the 15-minute and five-minute model runs of the real-time market. However, the constraint procured ramp capability across the entire CAISO transmission system, not by specific locations where it might be needed. Without sufficient ramp capability in the ISO's southern region, real-time market price spikes increased. See "California ISO Q4 2012 Report on Market Issues and Performance", Feb. 12, 2013, CAISO web site, [http://www.caiso.com/Documents/2012FourthQuarterReport-MarketIssues-Performance-Feb\\_2013.pdf](http://www.caiso.com/Documents/2012FourthQuarterReport-MarketIssues-Performance-Feb_2013.pdf), accessed March 27, 2013.

10 California Independent System Operator (CAISO), "Briefing on Summer 2012 Operations Preparedness," March 22-23, 2012, CAISO web site, <http://www.caiso.com/Documents/BriefingSummer2012OperationsPreparedness-Presentation-Mar2012.pdf>, accessed March 8, 2013.

Figure 1-16

CAISO Electricity Prices at San Diego Increase with Summer Stresses and SONGS Outage



Source: Derived from CAISO data

The 2013 summer may again be challenging for Southern California. SCE, the plant's operator and part owner, filed with the Nuclear Regulatory Commission to operate Unit 2 at partial capacity for five months. However, CAISO is planning its summer operations assuming the units will not be available. Further, the Huntington Beach generation from Units 3 and 4 will no longer be available due to a lack of air emission permits. The ISO, SCE and SDG&E are again pursuing contingency plans for the summer, which primarily focus on improving the ability of the southern system to move power.

The loss of SONGS also increased the need for carbon allowances in the power sector, as natural gas generation replaced lower emitting nuclear generation. This additional demand may put upward pressure on carbon allowance prices in the Greenhouse Gas Cap-and-Trade Program that California implemented in 2013.

### CAISO Ramp Constraint Fails to Support San Diego Operations without SONGS

From time to time, CAISO lacks generating capacity that can flexibly increase or decrease output to quickly keep up with supply and demand changes. Such fast-moving generation is referred to as ramp capacity. At times when CAISO lacks ramp capacity, certain market software constraints are violated, i.e., constraints associated with requiring supply and demand to be equal (in the CAISO market, this is called the power balance constraint). When this happens, penalty prices are triggered (at \$1,000/MWh for energy shortages), and real-time prices spike.

In December 2011, CAISO implemented a constraint in its market software to procure sufficient ramp capacity in the real-time market. This flexible ramp constraint was imposed in the 15-minute pre-dispatch and the five-minute real-time model runs to ensure that ramping capacity is procured to meet system needs. However, CAISO implemented the constraint for the ISO as a whole, rather than for specified locations. This failed to prevent insufficient ramp capability to meet load ramping needs around San Diego in summer 2012.<sup>12</sup> Figure 1-15 on page 22 illustrates the rise in price spikes with the SONGS outage.

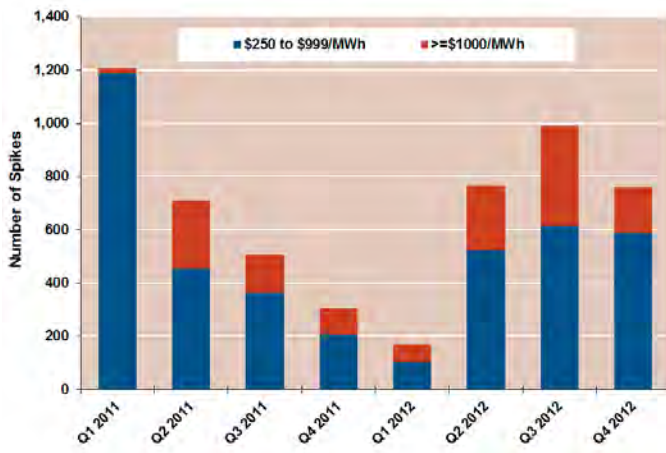
Price spikes increased for CAISO as a whole as well, as shown in Figure 1-17 on the next page. The graph shows the number of five-minute intervals when prices rose above \$250/MWh as well as the instances when prices rose above \$1,000/MWh. Implementation of the ramping constraint led to decreased price spikes in the first quarter of 2012, which was seven

<sup>12</sup> CAISO Department of Market Monitoring, "California ISO Q4 2012 Report on Market Issues and Performance," March 22-23, 2012, CAISO web site: [http://www.caiso.com/Documents/2012FourthQuarterReport-MarketIssues-Performance-Feb\\_2013.pdf](http://www.caiso.com/Documents/2012FourthQuarterReport-MarketIssues-Performance-Feb_2013.pdf), accessed March 8, 2013.

times fewer than the same quarter in 2011. However, the number of spikes increased by a factor of four in the second quarter of 2012 due in large part to insufficient ramp during adverse conditions around San Diego. In the third quarter of 2012, the number of spikes increased further, driven mainly by San Diego price spikes.

**Figure 1-17**

**Real-Time Price Spikes in California Q1 2011 to Q3 2012**



Source: Derived from CAISO data via Ventyx

Because ramp is procured system wide, and transmission constraints limit the ability of power to move into Southern California and San Diego, not all ramp was available to address the ramping needs in that part of the state. According to CAISO's market monitor, the average amount of ramp procured in San Diego in the second half of 2012 was 62 MW. Almost two-thirds of the procured ramp lies in Pacific Gas & Electric's load area, which falls on the opposite side of constrained pathways and therefore cannot help in San Diego and may, instead, tend to increase congestion on the constrained path.

CAISO implemented a stakeholder process to develop a short-term ramp product and is working with the California Public Utilities Commission (CPUC) and

others in California to develop products that take into account locational ramp needs in the CPUC's resource adequacy procurement process.

### *New Phase Angle Regulating Transformers between Michigan and Ontario Entered Service*

ITC, the transmission owner in Michigan at the border with Ontario, Canada, installed new phase angle regulator (PAR) equipment in April of 2012. The equipment was installed on one of four lines that cross the Michigan-Ontario border. Existing PAR equipment was in place on the other three lines. After repairs and adjustments to other related equipment, MISO and the Independent Electric System Operator (IESO), Ontario's grid operator, placed the interface between Michigan and Ontario under full PAR control on June 29, 2012.

Phase angle regulators are electrical devices that help control electricity flows, typically across key transmission elements or paths.<sup>13</sup> When actual electricity flows diverge substantially from scheduled contract paths, resulting loop flows can adversely affect power markets.<sup>14</sup> By controlling the flow of electricity, PAR equipment helps align electricity flows with scheduled transactions. Loop flows can cause congestion on systems that are not part of a particular transmission transaction. Participants in affected transmission systems have no direct way to be compensated for

<sup>13</sup> Phase angle regulators are special purpose transformers that change the phase angle at their location, allowing power flows to be regulated. Power flows may not match contract paths in that power flows follow Ohm's Law in which electricity takes its own path in inverse proportion to the impedance of the lines in a parallel circuit. So, power transfers use every available electrical path between source and sink, regardless of contract schedules.

<sup>14</sup> On an interconnected grid of transmission, the movement of electricity from generator to load typically spreads and flows along one or more parallel paths. Loop flow refers to electricity's flow along a path or paths that departs from the scheduled or contract path.

the congestion or to control flows for reliability. For reliability, balancing authorities must rely on cumbersome Transmission Loading Relief (TLR) procedures to prevent potentially harmful flows from other parties' transactions.

From July through December, loop flow across the MISO-Ontario interface averaged 79 MW, and has steadily declined with increased operational experience. This was much narrower than 157 MW for the same period in 2011. MISO has studied the success of the installation thus far and reports that congestion costs in Michigan are lower with fewer binding constraints.<sup>15</sup> According to MISO, the control of loop flow has also reduced the need for TLR procedures and has boosted the interchange capacity across the Michigan-Ontario interface.

The time over which the Michigan-Ontario PAR equipment was in full service in 2012 was a relatively short period. For years, loop flow around Lake Erie has caused difficult-to-manage congestion and reliability costs in the four surrounding regions, NYISO, IESO, MISO, and PJM. PAR control on the interface was the culmination of more than 20 years of projects.

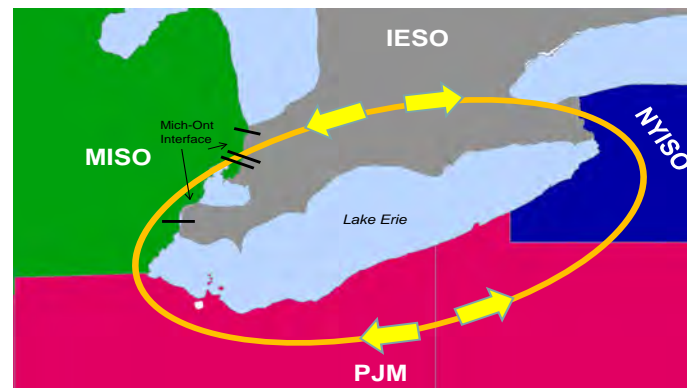
Completion of the final parts of the project became a topic of interest in the discussions that stemmed from an increased incidence of costly loop flow experienced by the NYISO in 2007 and 2008. The flows increased uplift costs in NYISO by approximately \$95 million because of uncompensated congestion in

western New York. NYISO prohibited select transactions to control loop flows. This issue prompted a general study of Lake Erie loop flow and a multi-region program to find solutions. One of the solutions discussed in the program was the use of PAR equipment.<sup>16</sup>

As MISO and IESO gain experience in the operation and effects of the PAR equipment, they may identify further needed adjustments to the operation procedure to better control loop flow. Since the use of PAR equipment on the Michigan-Ontario interface affects the pricing, congestion costs, and reliability of various market regions, Commission staff will continue to examine the operational protocols used, behavior of market participants, and pricing implications.

**Figure 1-18**

**Lake Erie Loop Flow and Surrounding RTOs**



Source: Derived from Ventyx data

15 MISO, "Market Impact of Michigan-Ontario Phase Angle Regulators," Report to the Market Subcommittee, February 5, 2013, MISO web site, <https://www.midwestiso.org/Library/Repository/Meeting%20Material/Stakeholder/MSC/2013/20130205/20130205%20MSC%20Item%2006a%20PARS%20Market%20Impact.pdf>, accessed March 12, 2013.

16 The Commission explicitly directed NYISO to include a discussion of the use of PAR equipment in the report on solutions to loop flow. See *New York Independent System Operator, Inc.*, 128 FERC ¶ 61,239 at P 8 (2009).

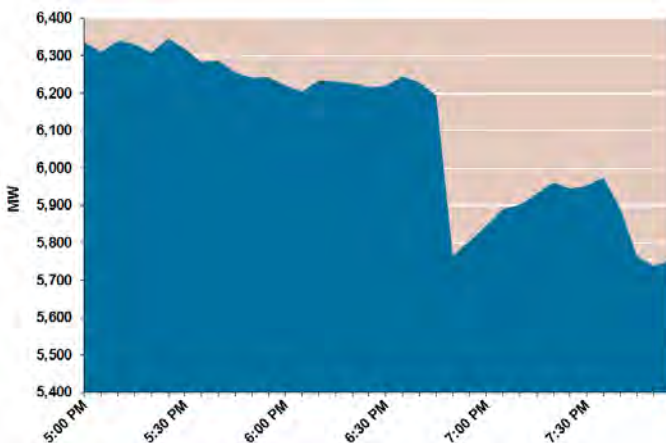


## MISO Successfully Counters Wind Loss with Spinning Reserves

Nationally, variable energy resources make up an increasing percentage of new generating capacity.<sup>17</sup> Wind generation, in particular, has reached a point where it has become a substantial component of the nation's energy supply. Total wind generating capacity surpassed 50 GW in August of this year, twice the 25 GW the U.S. had by year-end 2008 and 10 times the 5 GW mark reached in 2003. While events such as the following have been rare, the successful commitment and use of ancillary services to balance supply at a time of supply variability was an important example of the manner in which such resources can be managed in the electricity markets.

**Figure 1-19**

Wind Powered Generation Falls During Evening Ramp  
(February 20, 2012)



Source: Derived from MISO data

In one of the largest wind-generating regions, MISO reported total wind capacity of 10,600 MW or almost 10 percent of its installed capacity. On February 20, 2012, on one of the market's higher wind production days where wind output had been averaging about 6,000 MW since the night before, MISO suddenly lost 500 MW of wind-powered generation. Occurring during the evening ramp (Figure 1-19), MISO called on 500 MW of spinning reserves to successfully stay within reliability limits during the 10-minute loss. Prices spiked by almost \$100/MWh from the previous \$18-\$24 range for two five-minute periods, though MISO did not analyze the dispatch to separate the effects of the sudden wind loss from the increasing load.

The historic peak at year-end 2012 was 9,885 MW set on November 23. Except for this event, MISO had previously managed the large amount of wind in its system without reliability-based reserves.

<sup>17</sup> A Variable Energy Resource is a device for the production of electricity that is characterized by an energy source that: (1) is renewable; (2) cannot be stored by a facility owner or operator; and (3) has variability beyond the control of the facility owner or operator. This includes, for example, wind, solar thermal and photovoltaic, and hydrokinetic generating facilities. See *Integration of Variable Energy Resources Notice of Proposed Rulemaking*, FERC Stats. & Regs. ¶ 32,664, at P 64 (2010).





## Chapter 2: Natural Gas Markets in 2012

### SUMMARY

2012 was a year for breaking records in the U.S. natural gas industry, with plentiful natural gas supply satisfying a growing market. Natural gas prices were at or near 10-year lows across the nation for most of 2012. Driven by shale natural gas, average daily natural gas production grew 5 percent to a record 65.7 Bcfd, a level unseen since the 1970s (Figure 2-1). Low prices and strong domestic production contributed to the lowest natural gas imports via pipeline from Canada or LNG from overseas since 1998. Overall, U.S. natural gas supply grew 3.2 percent to 71.5 Bcfd.

Spurred by low natural gas prices, average daily U.S. natural gas demand grew 4.4 percent to 70 Bcfd, the highest level on record. Growth was led by the power sector, which saw a 4 Bcfd<sup>18</sup> or 21 percent year-over-year increase in natural gas demand, as natural gas-fired generators were increasingly utilized in preference to coal generation, particularly in PJM and the Southeast states. However, high natural gas demand for power generation was offset by a 2.3 Bcfd or 10 percent decline in residential and commercial demand following one of the warmest winters on record.

The warm winter and plentiful natural gas supply resulted in relatively low winter withdraw-

<sup>18</sup> Includes pipeline loss and exports to Mexico.

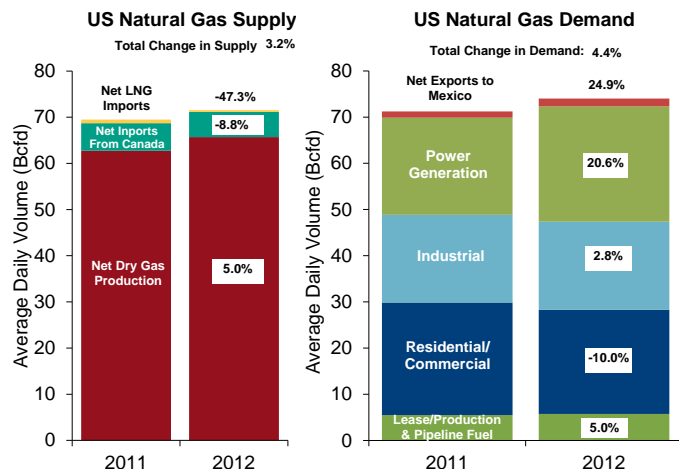
als from natural gas storage during the first quarter of 2012 and the highest storage level ever at the beginning of the traditional refill season in April. This, coupled with strong spring and fall injections, contributed to record levels of natural gas in storage by the beginning of the 2012-13 winter.

North American LNG import facilities were not able to attract many cargoes in 2012 because U.S. natural gas prices were four to five times lower than the rest of the world, and net imports fell 131 Bcf for the year. As a result LNG sendout into the U.S. pipeline system fell 53 percent and averaged 342 MMcfd. Furthermore, abundant U.S. natural gas supplies led to proposals to build liquefaction facilities to export cheaper domestic natural gas to the higher priced markets in Asia and Europe.

Even as companies contemplated LNG exports, U.S. natural gas exports to Mexico increased 25 percent in 2012, to 1.7 Bcf. Exports of Marcellus Shale natural gas to Canada also commenced in the latter half of 2012. Figure 2-1 shows the major components of U.S. natural gas supply and demand in 2012 compared to 2011.

**Figure 2-1**

**U.S. Natural Gas Supply and Demand – 2011 vs. 2012**



Source: Derived from EIA data

**U.S. Natural Gas Prices Fall to 10-Year Lows**

Strong production growth from shale natural gas helped push U.S. natural gas prices to a 10-year low in 2012. The spot price at Henry Hub averaged \$2.74/MMBtu for the year, down 31 percent from 2011. Natural gas prices at all trading points in the U.S. experienced price drops in the 22 to 36 percent range. Regional differences in prices (basis) also fell. This was driven by rising shale natural gas production closer to consuming markets and additional pipeline infrastructure that eliminated transportation constraints from most regions. Growing Marcellus Shale natural gas production in the Northeast caused the basis between most Northeast price points and the Henry Hub to flatten. In the Southeast, energy efficiency savings and capacity expansions on Florida Gas Pipeline reduced price spikes at the FGT-Z3 hub.

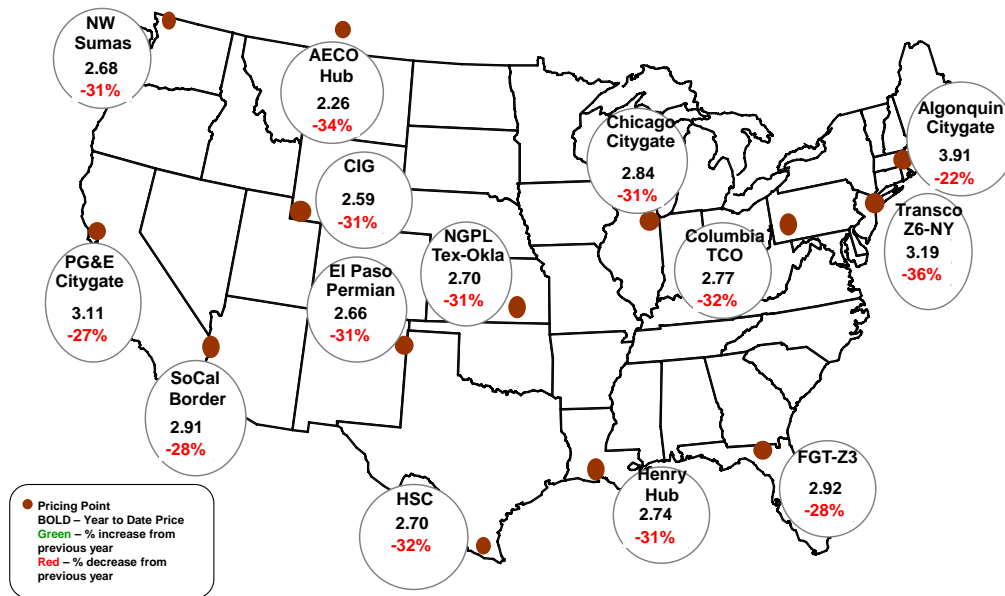
Although the convergence of regional natural gas prices was good for consumers, it put financial pressure on some long-haul pipelines, which experienced flows falling either on segments of the pipelines or sometimes the entire route. Pipelines which move natural gas from the Gulf Coast and the Rocky Mountains into the Northeast experienced the greatest declines in utilization. Marcellus natural gas displaced Gulf natural gas to the Northeast, which led to underutilization on the southern portion of pipelines such as Tennessee Gas Pipeline and Texas Eastern Pipeline. Similarly, the Rockies Express Pipeline, which moves natural gas from the Rocky Mountains to Ohio, experienced a sharp drop in volumes in 2012. The new natural gas flow patterns raised the possibility that some pipelines may not be able to find buyers for long-term capacity once their current contracts expire. Further discussion of natural gas pipeline contract expiration and re-contracting is provided in Chapter 1.

The only region to experience sustained pipeline constraints in 2012 was New England. There were no significant pipeline capacity additions into this region in 2012 and New England was not able to fully benefit from nearby Marcellus natural gas production. As a result, the Algonquin Citygate, near Boston, experienced the highest spot prices in the nation, averaging \$3.91/MMBtu for the year. With the exception of very cold days, there were few natural gas transporta-

tion constraints into New York City and spot prices at Transco Zone 6 NY averaged \$3.19/MMBtu for the year. In California, increased demand for natural gas-fired power generation due to the outage of the SONGS nuclear plant put upward pressure on natural gas prices through spring and summer. In contrast, prices in the Rocky Mountains were among the lowest, averaging \$2.59/MMBtu at the Colorado Interstate Gas (CIG) hub (Figure 2-2).

**Figure 2-2**

Average Spot Natural Gas Prices, 2012 (\$/MMBtu)

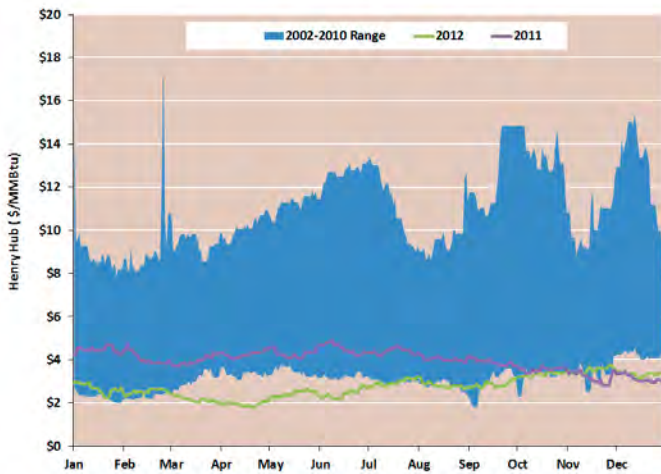


Source: Derived from Platts data

Natural gas prices began to strengthen in late October and November, largely as a result of high natural gas demand from power generators and the onset of the winter heating season (Figure 2-3). Forward contracts showed continued strength into the 2013 spring and summer. Higher forward contracts were supported by forecasts of colder temperatures for the winter of 2012-2013 than those seen the previous winter, and continued strong demand from natural gas-fired power generators.

**Figure 2-3**

Historical Next-Day Natural Gas Prices



Source: Derived from Platts data

**Record U.S. Natural Gas Supply in 2012**

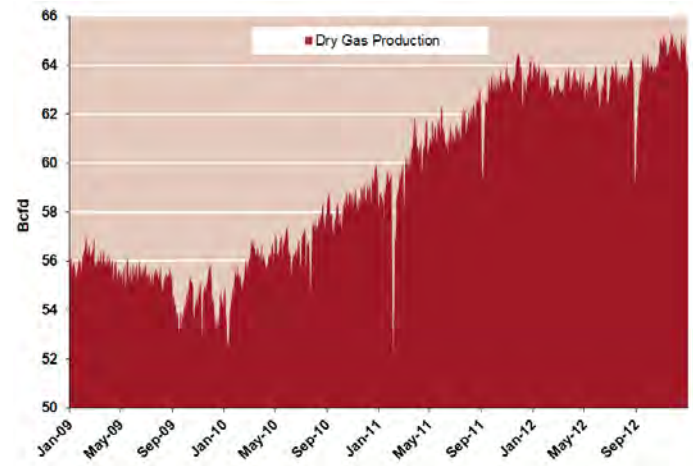
The breakneck rate of U.S. natural gas production growth seen over the past five years slowed during the first half of 2012 due to a combination of low natural gas prices, cutbacks in natural gas drilling, and the shift toward more profitable oil drilling (Figure 2-4). However, U.S. natural gas production began to pick up again in the second half of the year, driven primarily by rapid increases in Marcellus Shale (Pa.) and Eagle Ford Shale (Tex.) natural gas production, and overall U.S. natural gas production rose 5

percent. This led to 3.2 percent growth in total U.S. natural gas supply despite a large fall in natural gas imports via pipelines from Canada and as imported LNG.

Despite an active hurricane season, weather did not have a significant impact on U.S. gas production in 2012. Tropical Storm Debby and Hurricane Isaac both entered the Gulf of Mexico. However, the loss in production due to offshore well shut-ins amounted to only 32 Bcf a tiny fraction of U.S. natural gas production that totaled more than 24 Tcf in 2012.

**Figure 2-4**

U.S. Dry Gas Production Growth Slows in First Half of 2012



Source: Derived from Bentek Energy data

The slowdown in production growth during the first half of 2012 was caused by a 55 percent drop in the rig count. The number of active rigs drilling for natural gas fell from 936 in October 2011 to 416 on December 31, 2012 (Figure 2-5). Despite the drop in rigs, production continued to climb in part due to improved drilling technology and practices. Increased rig efficiency allowed producers to cut the number of days it takes to drill a well and drill more wells per rig (See Box on next page).

### Drilling Rig Efficiencies Offset Falling Natural Gas Rig Count

The drive to exploit shale oil and natural gas reserves coupled with falling natural gas prices touched off a race to reduce drilling costs and improve rig operating efficiency. These improvements resulted in production increases even as the gas-directed drilling rig count fell.

The revolution in drilling began in the early part of the last decade as years of experimentation with horizontal drilling techniques, three-dimensional (3-D) seismic analysis and hydraulic fracturing in the Barnett Shale finally began to yield results. Using enhanced 3-D seismic analysis, drillers perfected the technique of drilling horizontally along a natural gas-bearing formation. This stood in stark contrast to the previous method of drilling vertical wells to try and strike the sweet spot of a known natural gas reservoir. Drilling advances reduced the number of dry holes drilled, thereby increasing the well success rate and reducing the cost of exploration and development. These techniques, once refined, were particularly suited to shale deposits because of their wide geographic extent and easily defined pay zone, where natural gas was abundant.

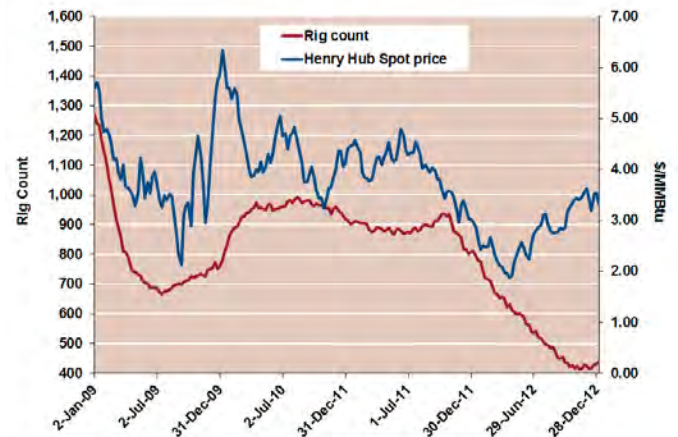
The overall oil and natural gas well success rate in 1998 was 79 percent, meaning 21 percent of oil and gas wells drilled came up dry. By 2002, Barnett Shale natural gas production began to rise, driving success rates of all wells up to 85 percent. As the techniques were applied first to other shale natural gas deposits and later to oil-bearing shales, success rates for wells climbed above 90 percent in 2012.

Rig design has also improved to better exploit shale deposits. Drillers, who use electricity to power their rigs, moved from DC- to AC-powered rigs for greater mobility and reliability, plus quieter operations. Newer rigs have more precise digital controls that result in less downtime from breakdowns. Because of these efficiencies, drilling a well takes less time. In the Barnett Shale, an average of 20 days to drill a well near the end of 2007 fell to only 13 days at the end of 2011. Now, between eight and 25 wells can be drilled on a single well pad. Drilling multiple wells on one pad saves time and money, since the rig does not have to be broken down, moved, and re-assembled between wells.

Technology has extended to drilling bits, which have been improved through new designs and materials. These state-of-the-art bits can be used for longer periods before servicing, and allow companies to drill a horizontal well with one bit, without having to pull the drill to change or service a bit.

**Figure 2-5**

Natural Gas Rig Count Drops with Lower Prices



Source: Derived from Baker Hughes and Platts data

The impact of the declining natural gas rig count on natural gas production was mitigated by new production from wells that had been previously drilled, but not completed and brought into production. By the end of 2011, approximately 2,500 wells had been drilled but not completed due to the lack of available pipeline capacity to transport the natural gas to market. Some of the wells were completed and began producing in 2012 as new gathering systems and pipelines were placed into service. Uncompleted wells are not the same as natural gas in storage, since they are either not yet connected to the pipeline system, or are at different stages of completion, and can take several weeks or months to bring into production. However, once connected they provide an immediate bump in production. Drilling companies also shifted drilling rigs from dry natural gas areas to areas rich in natural gas liquids (NGL). Rigs drilling in oil and NGL areas are generally not counted as natural gas rigs. However, oil and NGL production yields substantial amounts of associated natural gas.



Natural gas production growth in 2012 was driven by large increases from the Eagle Ford and Marcellus Shale formations. Fayetteville Shale also increased moderately in natural gas production, but the other three major shale plays saw production stall or decline (Table 2-1).

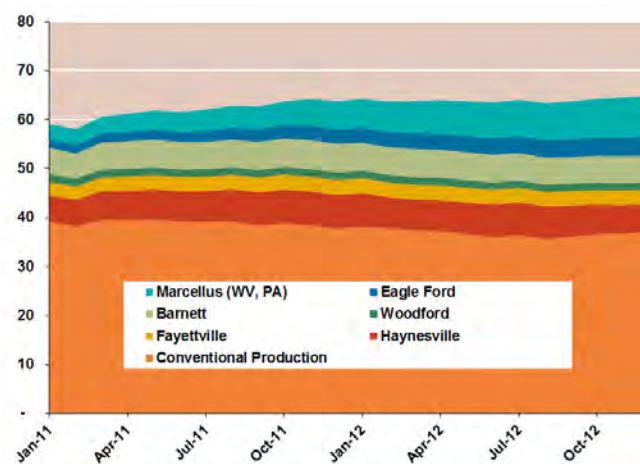
Marcellus Shale natural gas production grew because companies migrated to the NGL-rich regions in western Pennsylvania and West Virginia from dry natural gas areas in northeastern Pennsylvania. Also, Marcellus Shale natural gas is of high value because of its proximity to Northeast natural gas markets. Eagle Ford Shale natural gas production in Texas grew as producers increased drilling in NGL and crude oil-rich areas of the formation.

At the end of 2012 production from the six major shale formations made up 38 percent of total U.S. natural gas production, up from 22 percent at the

beginning of 2011. Overall growth of shale natural gas production and a breakdown by basin is shown in Figure 2-6.

**Figure 2-6**

**Natural Gas Production by Shale Formation**



Source: Derived from Bentek Energy data

**Table 2-1**

**Shale Gas Production by Basin (Bcf/year)**

Basin	Type (Wet/Dry)	2011	2012	Percent Change
Marcellus	Wet/Dry	1,515	2,632	73.7
Haynesville	Dry	2,308	2,295	-0.6
Barnett	Wet/dry	2,062	2,059	-0.15
Eagle Ford	Wet/dry	815	1,250	53.4
Fayetteville	Dry	1,052	1,103	4.9
Woodford	Dry	578	562	-2.8
Total		8,330	9,901	18.9

Source: Derived from Bentek Energy data

### Crude Oil and Natural Gas Liquids Add Value to Natural Gas Production

Much of the new natural gas produced in 2012 was associated with crude oil and NGL production. Drilling companies shifted drilling rigs from dry natural gas areas to areas rich in oil and NGLs, such as the Eagle Ford Shale and Bakken Shale, because the price of U.S. benchmark West Texas Intermediate (WTI) crude oil in 2012 averaged \$94.58/barrel, or \$16.30/

MMBtu. This made WTI over six times more valuable than natural gas on a dollar per MMBtu basis.

Natural gas marketed to and used by consumers is primarily methane. Liquids-rich natural gas formations produce methane in combination with other, higher Btu products such as ethane, propane, butane, isobutane, and natural gasoline. The exact amount of NGLs and other components varies by well. Table 2-2 shows the makeup of a representative NGL barrel, and the main uses for each component.

**Table 2-2**

#### Types and Uses for Natural Gas Liquids

Component	Content in Typical Barrel	Primary Uses
Ethane	40%	Petrochemical feedstock in production of ethylene, which in turn is used to make plastics, detergents, lubricants, etc.
Propane	29%	Heating, cooking, and transportation fuel, petrochemical feedstock
Natural Gasoline (condensate)	16%	Motor gasoline production
Butane	10%	Motor gasoline production, torch fuel, petrochemical production
Isobutane	6%	Refrigerant, aerosol propellant, petrochemical production

Source: Typical barrel content derived from Tudor Pickering data

The price of ethane fell 48 percent in 2012, while the price of propane fell 32 percent. Rapid expansion in NGL production coupled with a drop in processing capacity due to plant maintenance resulted in oversupply. However, prices for higher value NGLs including butane and natural gasoline remained relatively strong, as these products are more closely tied to oil prices, see Figure 2-7. The price of a representative barrel of NGLs averaged \$14.54/MMBtu in 2012 compared to \$17.52/MMBtu in 2011, a 17 percent drop.

**Figure 2-7**

#### Natural Gas Prices Remained Below NGL Prices in 2012

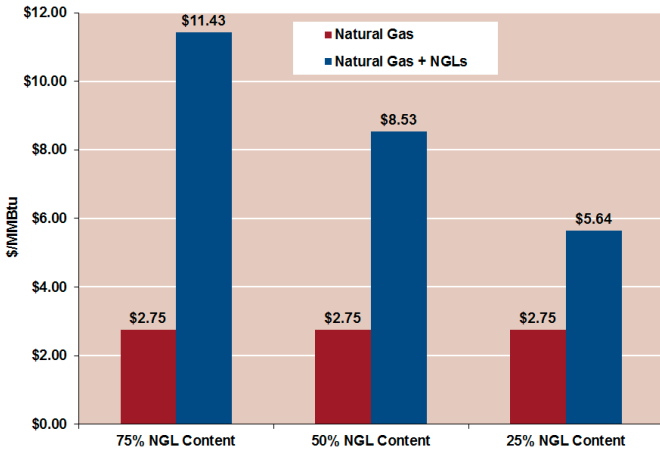


Source: Derived from Bloomberg data

The value NGLs added to a well’s production stream can be significant, although NGL content differs depending on the shale formation, the drilling site within a shale formation, and even the number of wells on a drilling pad. For example, a well producing 75 percent dry natural gas and 25 percent NGLs could sell its production stream for about \$5.64/MMBtu, while a production stream composed of 25 percent dry natural gas and 75 percent NGLs could be sold for \$11.43/MMBtu. Figure 2-8 shows values added to a natural gas/NGL well for three different NGL content levels.

**Figure 2-8**

Value Added to a Production Stream Based on NGL Content



Source: Derived from Bloomberg data

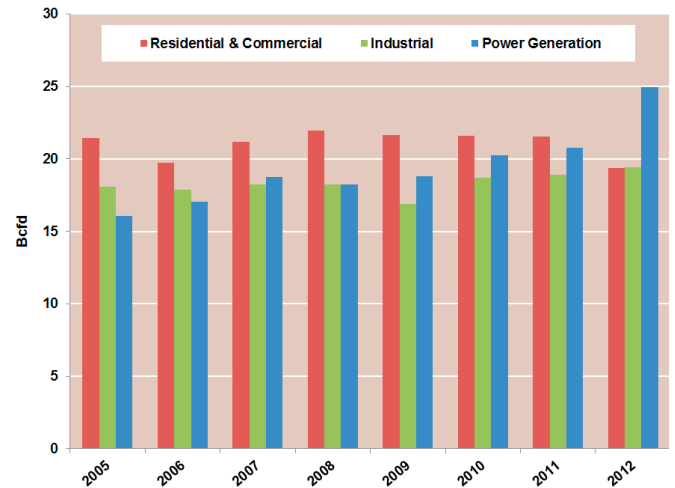
### U.S. Natural Gas Consumption Sets New Record

Low natural gas prices helped drive average daily U.S. natural gas demand up 4.4 percent to a record 70 Bcfd. This occurred despite a 10 percent decline

in residential and commercial natural gas demand brought about by a mild winter in early 2012. Responding to very low natural gas prices, power burn grew 21 percent to 25 Bcfd in 2012. (Figure 2-9). Further discussion of the record use of natural gas in power generation is presented in Chapter 1.

**Figure 2-9**

Growth in Power Burn Drives Gas Demand in 2012



Source: Derived from Bentek Energy

Industrial gas demand grew 3 percent in 2012 to 19 Bcfd. Precious metals, car manufacturing, and petrochemicals drove this growth. The expectation is for industrial gas demand to rise in the next few years as economic growth picks up and new industrial facilities, particularly petrochemical plants, are built to take advantage of expected low domestic gas prices and plentiful NGL supply.

U.S. exports of gas to Mexico rose 25 percent in 2012 to 1.7 Bcfd, primarily to meet increased power and industrial natural gas demand there. Also, exports of Marcellus Shale natural gas to Canada began in November 2012.

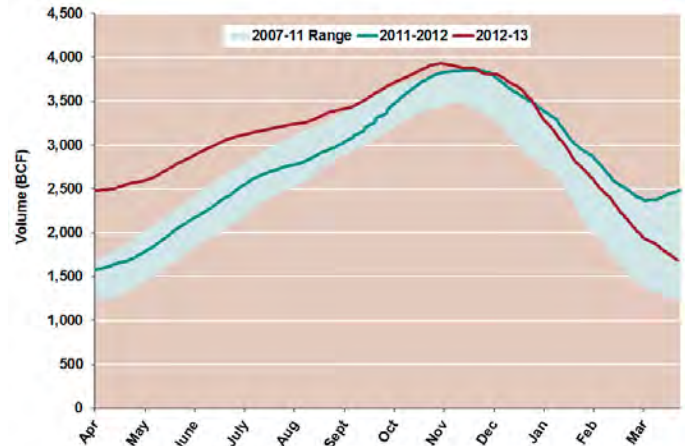
## Natural Gas in Storage Sets New Record

Natural gas storage is an indicator of the overall balance of the U.S. natural gas market. Plentiful storage indicates a market is well supplied relative to natural gas demand, while low storage indicates a market that is undersupplied relative to demand. Overall in 2012, there was plenty of natural gas in storage, particularly at the end of the 2011-2012 winter heating season and the start of the 2012-2013 winter heating season. Robust storage fills during the spring and fall slowed during the summer as competition for natural gas supply grew from natural gas-fired power generators. Underground working natural gas storage capacity increased by more than 43 Bcf in 2012, all of it in the Gulf region.

Working gas in underground storage set a record for the second year in a row, peaking at 3,852 Bcf going into the 2012-13 winter as seen in Figure 2-10. Record storage resulted from a 934 Bcf surplus to the five-year average at the beginning of the refill season and robust spring and fall injections. The surplus was gradually worked off during the third-warmest summer on record and increasing utilization of natural gas for power generation. With less natural gas available for injection, storage injection rates over the summer were low, averaging 46 Bcf/week, when compared to a five-year average summer injection rate of 69 Bcf.

Figure 2-10

Record Natural Gas Storage in 2012



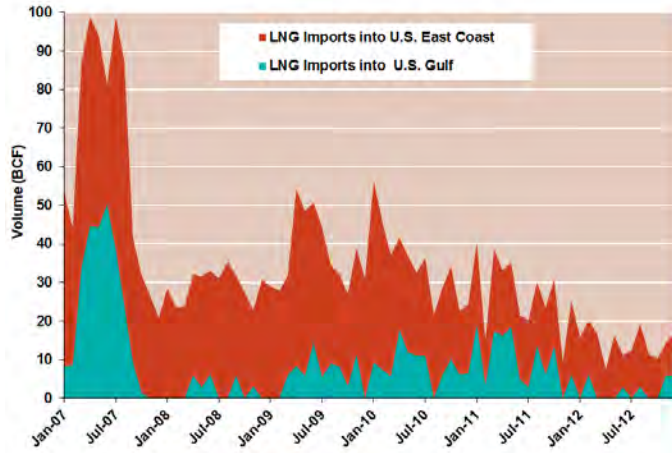
Source: Derived from EIA data

## U.S. Liquefied Natural Gas Imports Fall

U.S. liquefied natural gas (LNG) imports declined substantially in 2012 as low U.S. natural gas prices compared to the rest of the world made it difficult for U.S. import terminals to attract cargoes. Of the 12 active U.S. terminals, only two, Everett LNG in Massachusetts and Elba Island in Georgia, received regular LNG cargoes throughout the year, albeit with lower frequency than in past years. The total volume of net LNG imports (i.e., imports into U.S. LNG terminals minus LNG that is re-loaded into tankers for delivery to other countries) at U.S. terminals in 2012 dropped 77 percent compared to the amount imported in 2007, and 47 percent from 2011 imports, as shown in Figure 2-11 on the next page. In addition, the Canaport LNG import terminal in New Brunswick, Canada, which primarily serves consumers in the Boston market, saw a sharp drop in incoming cargoes.

**Figure 2-11**

**U.S. LNG Imports Fall in 2012**



Source: Derived from U.S. Department of Energy data

LNG prices in international markets are generally priced via long-term contracts linked to oil prices. LNG sold in Asia for around \$15/MMBtu, four to five times higher than in the U.S. Prices were slightly lower in Europe, around \$10-\$11/MMBtu, while in South America imported LNG prices were around \$12-\$13/MMBtu. Figure 2-12 summarizes estimates of landed prices for LNG in global trade as of January 2013.

**Figure 2-12**

**World LNG Estimated Landed Prices for January 2013**



Source: Derived from Waterborne Energy data

The abundance of low-priced U.S. natural gas production, combined with high prices in other regions of the world, created interest in exporting U.S. natural gas as LNG to markets in Asia, Europe, and South America. Attention shifted from LNG imports to future exports of U.S. natural gas as LNG. Table 2-2 shows proposed U.S. LNG export projects and their status. It is unlikely that the U.S. will export any LNG before 2016 due to the long time horizon for building and permitting export facilities.



Table 2-3

## Proposed U.S. LNG Export Projects

U.S. Projects	Location	Quantity (Bcfd)	DOE FTA Approval	DOE Non-FTA Approval	FERC Approval	Capacity Contracted
Sabine Pass LNG	LA	2.20	Approved	Approved	Approved	96%
Freeport LNG	TX	1.40	Approved	Under Review	Filed	50%
Freeport LNG Exp.	TX	1.40	Approved	Under Review	Filed	0%
Lake Charles LNG	LA	2.00	Approved	Under Review	Filed	0%
Cove Point LNG	MD	1.00	Approved	Under Review	Filed	61%
Cameron LNG	LA	1.70	Approved	Under Review	Filed	93%
Gulf LNG	MS	1.50	Approved	Under Review	Filed	0%
Elba Island LNG	GA	0.50	Approved	Under Review	Filed	0%
Golden Pass LNG	TX	2.60	Approved	Under Review	NF	0%
Jordan Cove LNG	OR	1.20	Approved	Under Review	Filed	0%
Oregon LNG	OR	1.25	Approved	Under Review	Filed	0%
Excelerate Liq.	TX	1.40	Approved	Under Review	Filed	0%
Gulf Coast LNG	TX	2.80	Approved	Under Review	NF	0%
Corpus Christi LNG	TX	1.80	Approved	Under Review	Filed	0%
Main Pass Energy Hub	LA	3.22	Approved	NF	NF	0%
CE FLNG	offshore TX	1.10	Approved	Under Review	NF	0%
Pangea LNG	TX	1.10	Approved	NF	NF	0%
<b>TOTAL</b>		<b>28.17</b>				

Source: Derived from DOE data, FERC Docketed Proceedings, and Company Press Releases

In 2012, several organizations released studies assessing the impact of LNG exports on U.S. natural gas prices. The most anticipated was the U.S. Department of Energy (DOE)-commissioned study that analyzed the impact of LNG exports on the U.S. economy.<sup>19</sup> The report was required before DOE would approve U.S. LNG exports to countries with which the U.S. does not have a free trade agreement. Like most other stud-

ies, the DOE report concluded that the impact on U.S. prices would be limited. It also concluded that LNG exports will have a net economic benefit to the U.S., as price effects are more than offset by economic gains that result from trading LNG.

<sup>19</sup> NERA Economic Consulting, "Macroeconomic Impacts of LNG Exports from the United States," Report prepared for DOE, December 3, 2012, DOE website: [http://www.fossil.energy.gov/programs/gasregulation/reports/nera\\_lng\\_report.pdf](http://www.fossil.energy.gov/programs/gasregulation/reports/nera_lng_report.pdf), assessed March 13, 2013.

### The Challenge for U.S. LNG Exports

As of the end of 2012, 16 companies had proposed more than 27 Bcfd of LNG export projects (Table 2-2). This includes exports to countries that have Free Trade Agreements (FTA) with the U.S., and non-FTA countries. If all projects are built and utilized, the U.S. would become the largest exporter of LNG in the world. In order for these projects to proceed, they must receive the necessary financial backing through firm capacity contracts as well as the appropriate Department of Energy approvals as well as an environmental impact assessment from FERC before construction.

Cheniere Energy's Sabine Pass LNG is the sole project with secured financing backed by firm contracts and that has received the necessary regulatory approvals to export to countries with both FTA and non-FTA status. Cheniere contracted nearly all of its export capacity to global customers looking for a cheaper, more secure supply source. Holders of Sabine Pass capacity include Korea's Kogas, India's GAIL, Spain's Gas Natural, and BG. The price of LNG sourced from Sabine Pass will be linked to the U.S. domestic natural gas price indexed at the Henry Hub, with an added liquefaction tolling fee, plus transportation costs.

Even if approved, it is highly unlikely that more than a handful of the proposed projects will be built, and the advantage is likely to go to early entrants such as Cheniere. By one estimate, the total world LNG market adds up to 30 Bcfd, and any U.S. project will have to compete against companies and countries that are already in those markets. Some U.S. competitors, such as Qatar, have the advantage of producing natural gas at nearly no cost.

Although current price spreads between U.S., Asian and European LNG markets support U.S. LNG export project proposals, the dynamics are likely to change as international competitors lower their prices to maintain market share. Despite price uncertainty, some countries such as Japan and Korea value access to stable and politically friendly LNG supplies.

Liquefaction facilities generally need to run at high and stable utilization rates to be economically viable. Liquefaction facilities, on average, run at 88 percent of capacity, and the newest facilities, such as those in Qatar, run at 99 percent. For U.S. LNG exports to be competitive in the global market, demand for U.S. LNG exports would have to be sustainable under firm contracts.

Another obstacle to long-term U.S. LNG exports is the potential for significant natural gas production from shale in other countries, such as China, Argentina, India, and Poland, which have been working to develop their shale natural gas potential. These countries have not yet been able to duplicate the U.S. shale gas success, but significant shale production from these regions would put downward pressure on LNG markets and make U.S. exports less competitive.

### *New Natural Gas Pipelines Concentrated Near the Marcellus Shale*

There were a total of 22 FERC-approved gas pipeline projects completed in 2012, representing 3.1 Bcfd of additional capacity at a cost of \$2.2 billion. The most significant natural gas infrastructure developments in 2012 took place in the Marcellus Shale region (Pennsylvania and points south and west), where a

number of projects, mostly producer-supported, were developed to gather shale gas production and connect it to the interstate pipelines that traverse the region. Examples of large interstate pipelines that added capacity include Tennessee Gas Pipeline, Millennium Pipeline, and Texas Eastern.

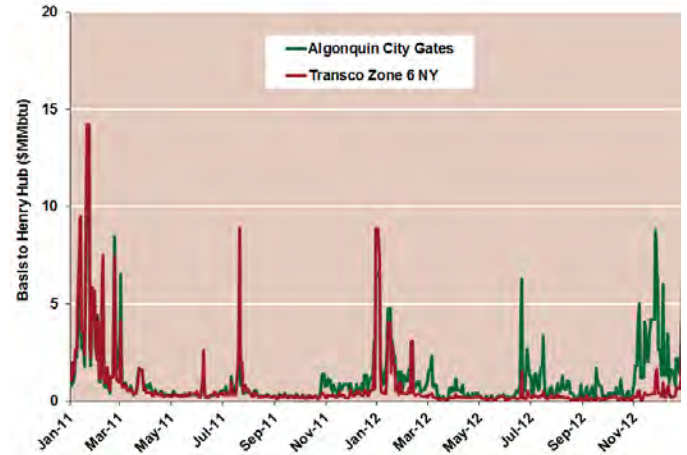
Marcellus Shale natural gas production, along with the new transportation, increasingly displaced Gulf

Coast and Rocky Mountains natural gas from the Northeast. Western Canadian natural gas was also increasingly displaced and, by November 2012, natural gas flows at the Niagara interconnect between TransCanada and TGP reversed as Marcellus natural gas began to flow into Canada.

The New York City area, which had been one of the most constrained and highest-priced markets in the nation, is benefitting from growing Marcellus natural gas production and the new pipelines. New York City is now generally well supplied by several pipelines transporting Marcellus Shale natural gas. As a result, the basis between the Transco Zone-6 NY Hub and Henry Hub shrunk and saw less-frequent price spikes. By the end of 2012, natural gas in New York City became routinely cheaper than in New England (Figure 2-13). However, New England has remained constrained as the new production and infrastructure has simply moved the constraint points further downstream.

**Figure 2-13**

**New Natural Gas Production and Pipelines Help Reduce Prices in New York City**



Source: Derived from Platts data

The most notable pipeline infrastructure developments outside the Northeast did not involve new natural gas pipeline capacity, but the proposed conversion of natural gas pipelines into oil or NGL pipelines. Pipeline operators look for new means to extract value from underutilized natural gas pipeline capacity. Chapter 1 discusses lower utilization of long-haul natural gas pipelines and proposals to convert them to transport crude oil.



## Chapter 3: Electricity Markets in 2012

### SUMMARY

In 2012, electricity prices continued to exhibit the low levels seen since the 2008 financial crisis and, in fact, decreased compared to 2011 in all regions of the U.S. The single prominent driver of this phenomenon was the price of natural gas, the price-setting fuel for most of the nation. Natural gas prices, already low going into 2012, fell even further the first half of the year. Other factors contributing to low electricity prices were the moderate level of electricity demand due to a mild winter, a slow economic recovery, and energy efficiency gains.

The past year saw these additional market trends and influences:

- Most notably, the weather in 2012 was the warmest on record for most of the nation and was consistently warmer in both winter and summer. This weather caused lower demand in the winter. It also contributed to summer peaks, although summer increases in load were more moderate than the decline in winter loads, compared to the recent history of weather or temperature extremes.
- State-level energy efficiency programs contributed to lower growth rates in electricity consumption. In state programs reviewed for recent years, the average annual savings in electric energy

due to efficiency programs was approximately one percent of total electricity sales. While a one percent figure may not seem like a large quantity, if extended to the nation overall, a one percent savings in electricity usage has a value of approximately \$3.5 billion at average retail electricity rates. Some regions explicitly incorporated projected energy efficiency savings as inputs into their ten-year forecasts and regional transmission plans.

- Capacity from renewable energy resources, particularly wind generation, continued to increase in 2012. Some areas, particularly the Midwest and Southwest see periodic market price effects from wind production, providing benefits to the consumer when prices drop and challenges to grid operators when congestion occurs.
- Growth was experienced in the eastern RTOs' and ISOs' capacity-based emergency demand response (DR) programs. The increase in capacity enrolled in the programs has been substantial, rising from 3 GW of capacity in 2007 to 12 GW in 2012 and has become an increasingly important resource for grid operators during periods of system stress. The greater participation of DR resources in capacity markets may lead to an increased frequency of deployments and reliance on DR activations into the future.

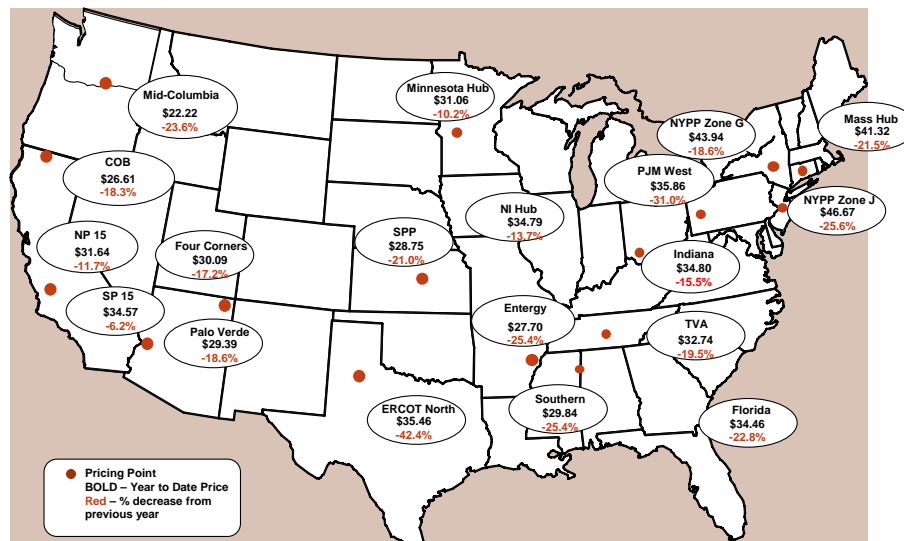
- Three large new high-voltage transmission projects went on line in 2012. Development of these projects involved various parties working together to accomplish planning and construction. The projects are expected to provide substantial benefits by supporting the transmission of power from renewable sources in rural areas to load centers.

### Electricity Prices Decline with Lower Natural Gas Prices

Electricity prices nationwide were lower in 2012 than in 2011. Lower prices followed natural gas prices, which fell to 10-year lows in the first half of 2012 and which are a major determinant of electricity prices. Low natural gas prices have been largely responsible for relatively low electricity prices since the beginning of 2009, but lower electricity demand due to reduced levels of economic activity after the financial collapse was also a contributor. Figure 3-1 shows average electricity prices at principal trading locations across the U.S., along with the change in prices compared to 2011.

Figure 3-1

Average On-Peak Electricity Prices 2012



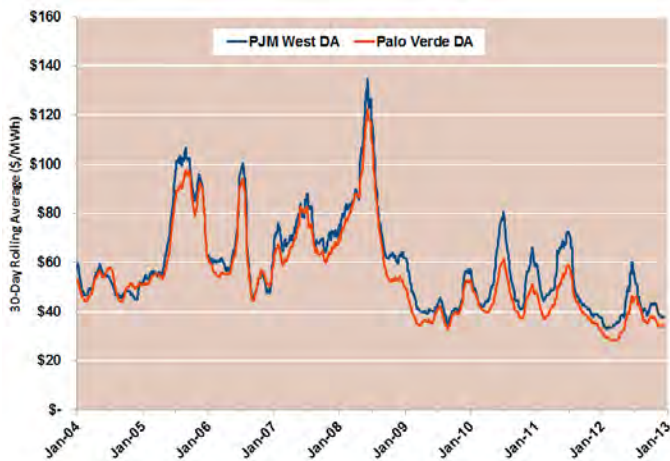
Source: Derived from Platts data.



Generally, electricity prices have been lower since 2009 than they were in the six prior years. This is largely attributable to shale natural gas development and the resulting decline in natural gas prices. A secondary factor includes a slowly recovering economy. Figure 3-2 shows the trend in wholesale electricity prices over the last 10 years at two commonly traded, illustrative locations.

**Figure 3-2**

**10-Year Day-Ahead Spot Electricity Prices**



Source: Derived from ICE data.

All regions of the nation experienced lower power prices in 2012. However, the level of price reduction varied because of region-specific conditions. Prices in the East were between 10 to 31 percent lower, primarily due to lower natural gas prices. Western power prices fell between six and 23 percent. Key factors influencing the regional price changes follow.

The Northeast, particularly New England, experienced brief price increases during cold-weather events. This is normal for this region because limited import capability for natural gas pushed up the natural gas price. Import limitations into New England are discussed

in Chapter 2. However, price effects from the cold weather did not prevent the region from experiencing a drop in average electricity prices for 2012 because of overall lower natural gas prices.

Electricity prices were also significantly lower in the Southeast in 2012 compared to 2011. As discussed in Chapter 1, natural gas-fired generation was dispatched ahead of coal-fired generation for much of the 2012 production. For example, generators such as Southern Company have trended away from coal-fired generation to natural gas generation over the past two years. As more generation comes from power burn, the falling natural gas price between 2011 and 2012 had a greater overall impact. Prices across the Southeast fell 20-25 percent during that period.

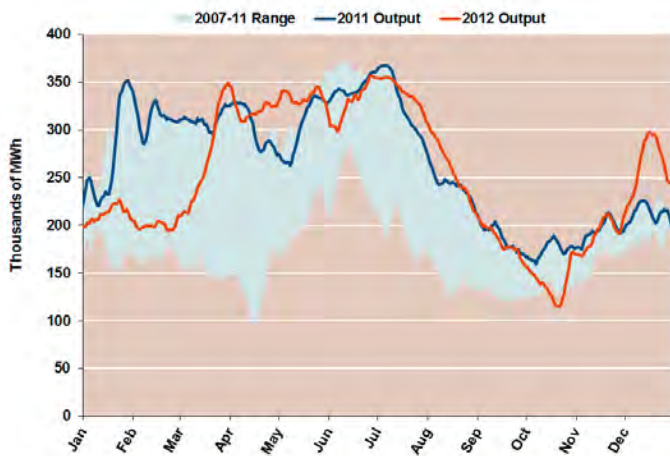
In the Midwest, electricity prices were lower for most of the year compared to 2011. Lower prices reflected moderate temperatures during the heating months and low natural gas prices. Natural gas supplies were unconstricted and occasional high usage did not impact prices. Wind resources increased their penetration in the electricity supply stack which put downward pressure on prices in some periods. However, wind resources also caused congestion in SPP and the western areas of MISO and PJM.

While average electricity prices in the Pacific Northwest in 2011 were already low compared to the past 10 years, in 2012 average prices were even lower. This area's electricity prices were influenced by abundant hydroelectric generation the region receives. Availability of hydro generation is a function of the amount of precipitation. The amount of snow, how fast it melts, and additional rain all contribute to the amount of inexpensive generation available and its effect on prices in the region. In 2012, hydro genera-

tion in the Pacific Northwest was above average and extended further into the summer than normal. This low-cost generation supported lower-than-normal prices in the Northwest during spring and summer. Figure 3-3 shows how hydro production continued at higher-than-normal levels into the summer.

**Figure 3-3**

**Northwest Hydroelectric Production**



Source: Derived from USACE data reflecting the output of the 24 largest facilities in the Northwest.

While electricity prices in California, too, were influenced by lower natural gas prices, electricity prices were generally higher than elsewhere in the West. In contrast to the Pacific Northwest, which saw an increase in hydro generation, hydro generation within California was lower than normal. Further, the outage of the San Onofre Nuclear Generating Station (discussed in Chapter 1), reduced the amount of generation available to serve San Diego and other parts of Southern California.

## Electricity Demand Falls for Second Consecutive Year

Sales of electricity in the U.S dropped by 62.9 TWh or 1.7 percent in 2012 compared to 2011.<sup>20</sup> Demand was down across the nation due to three primary factors: a decline in residential retail sales due to warm winter weather, a lack of demand growth in the commercial and industrial sector tied to economic factors, and increased energy efficiency stimulated by state energy efficiency policies. In addition to lower fuel prices, discussed earlier in this report, decreased demand nationwide placed downward pressure on electricity prices. Thus, in part, lower demand levels yielded electricity prices lower than they otherwise would be because utilities operated at the lower, less costly parts of their supply curves.<sup>21</sup> As discussed later in this section, the warm winter, particularly in the South, was a major driver of the decline in electricity demand in 2012.<sup>22</sup>

Annual consumption of electricity across the three sectors of residential, commercial and industrial customers is shown in Figure 3-4 on the next page. From 2011 to 2012, industrial and commercial demand stayed flat but residential demand showed a steep decline.

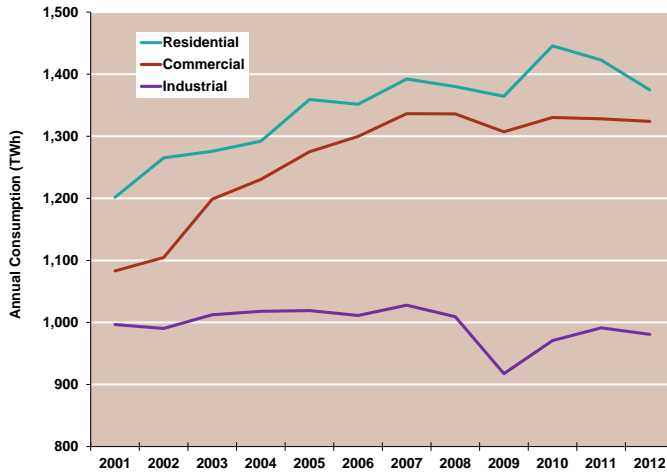
20 Form EIA-826, Monthly Electric Sales and Revenue Report with State Distributions Report and Form EIA-861, Annual Electric Power Industry Report, Table 5.1.

21 Lower demand also typically results in fewer hours that electricity systems operate at higher "stressed" demand levels that can lead to elevated prices or price spikes.

22 Regions in this section are designated by the U.S. Census Bureau as follows: Northeast (New England, Maine, New Hampshire, Vermont, Massachusetts, Rhode Island, Connecticut, New York, Pennsylvania, and New Jersey); Midwest (Wisconsin, Michigan, Illinois, Indiana, Ohio, Missouri, North Dakota, South Dakota, Nebraska, Kansas, Minnesota, and Iowa); South (Delaware, Maryland, District of Columbia, Virginia, West Virginia, North Carolina, South Carolina, Georgia, Florida, Kentucky, Tennessee, Mississippi, Alabama, Oklahoma, Texas, Arkansas, and Louisiana) and, West (Idaho, Montana, Wyoming, Nevada, Utah, Colorado, Alaska, Washington, Oregon, California, and Hawaii).

Figure 3-4

Annual Electricity Consumption by Sector 2001-2012

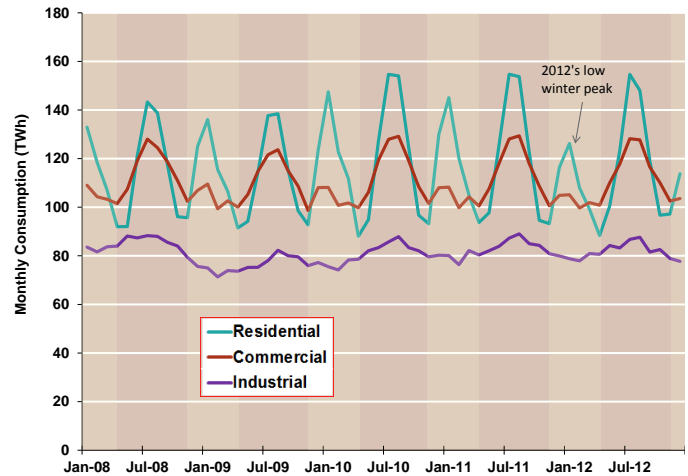


Source: Derived from EIA data.

Low residential consumption was the largest component of the overall decline in electricity demand in 2012. Residential demand dropped 48 TWh (3.4 percent) year over year. The biggest driver of the decline in residential demand was the reduced heating load in the cold-weather months, due to an unusually warm winter. The residential sector generally has higher demand in winter and summer, because this sector relies on electricity for heating, cooling, and increased lighting load in winter. Relative to the winter peaks of prior years, a decline in the 2011-2012 winter peak is seen in Figure 3-5 for residential electricity. In January through April 2012, consumption in the residential sector was down nine percent compared to the same period in 2011. The residential sector used less electricity in that period than in any year since 2007.

Figure 3-5

Monthly Electricity Consumption by Sector 2008-2012



Source: Derived from EIA data.

The first quarter of 2012 broke the January-March average temperature record for the continental U.S. by 1.4 degrees Fahrenheit, a major increase. Heating degree days (HDD) during the first half of 2012 were significantly lower than 12-year averages as shown in Table 3-1.<sup>23</sup>

Table 3-1

Heating Degree Days and Cooling Degree Days by Region, 2012 Compared to 12-year Average

	Heating Degree Days	Cooling Degree Days
Northeast	-12%	17%
Midwest	-13%	20%
South	-18%	6%
West	-9%	9%

Source: Derived from Energy Velocity data

<sup>23</sup> Heating and cooling degree days are measures that track the expected effects of temperature on demand or load. Average daily temperatures are compared to a standard of 65 degrees Fahrenheit. Average daily temperatures below 65 degrees yield HDD. Those days with average temperatures that exceed 65 degrees yield cooling degree days (CDD).

Table 3-2 shows that from 2011 to 2012 more than half of the decline in electricity consumption is attributable to reduced residential electricity demand in the South. Southern residential demand was below average in January through March of 2012 when temperatures were well above average.

**Table 3-2**

**Electricity Consumption Changes from 2011 to 2012 (TWh)**

	Northeast	Midwest	South	West	Sector Total
Residential	-3.3	-7.0	-38.4	0.5	-48.2
Commercial	-2.3	-1.0	0.5	-1.4	-4.2
Industrial	-2.3	0.7	-7.1	-1.8	-10.5
Totals	-7.9	-7.3	-45.0	-2.7	-62.9

Source: Derived from EIA data

The South experienced well below-average demand during the winter (January through March, and December) and only slightly above-average demand in summer, with 18 percent fewer HDD than the 12-year average. That region, which represented 53 percent of all residential retail electricity sales, also had the highest dependence on electric heating of any census region, and therefore the strongest correlation between load and HDD of any region. Thus, the South's drop of more than 38 TWh in electricity sales made up the largest proportion of the fall in overall residential electricity consumption (or 80 percent of the total decline in residential demand).

Nationally, high average temperatures in summer 2012 made it the third hottest on record. As a result, residential electricity consumption driven by cooling load was above average during June and July. However, the increased cooling load did not have as large an influence on overall annual consumption as the decreased heating load in winter. Also, not all

regions experienced the same amount of deviations from normal as seen in Table 3-2.<sup>24</sup>

The South saw an increase of 6.3 percent more cooling degree days than normal. The Midwest and the Northeast also experienced a hot summer, but did not have as high a cooling load as the South.

When controlling for HDD and CDD,<sup>25</sup> and analyzing monthly demand statistics over the past 10 years, residential electricity demand increased throughout the 2001 to 2008 time period, and then leveled off. Since 2010, residential demand has fallen slightly even after controlling for the effects of weather. From 2011 to 2012, demand fell about 11 TWh after controlling for weather compared to a fall of about 37 TWh due to weather. Consumption can fall due to changes in demographics, technology, and, as discussed below, energy efficiency.

Industrial and commercial sales fell by a more modest 10 TWh (1.1 percent) and 4 TWh (0.2 percent) year over year, respectively. Changes in industrial demand generally reflect changes in the economy. Industrial demand in 2012 declined following a slowly recovering economy. Commercial consumption, like residential, is somewhat dependent on weather and creates a smaller, but significant winter peak. The fall in commercial consumption can be attributed to weather, meaning that non-weather related commercial consumption stayed flat compared to 2011 due to weak economic growth. Changes in the gross annual consumption for both sectors have leveled off since the

<sup>24</sup> National Climatic Data Center, "Summer 2012 Recap," National Oceanic and Atmospheric Administration web site, <http://www.climatewatch.noaa.gov/article/2012/summer-2012-recap>, accessed March 11, 2013.

<sup>25</sup> Results are based on a linear regression of monthly residential load statistics from 2001-2012 and controlled for weather (HDD and CDD), weekend days and weekdays, and daylight hours.

2008 recession, and both remain shy of their all-time high annual demand in 2007. Industrial demand fell four percent and commercial demand fell one percent compared to 2007. As energy efficiency programs have been implemented in the industrial and commercial sectors as well as in the residential sector, those programs have also played a role in electricity consumption in certain areas.

### *Energy Efficiency Policies Contribute to Lower Rates of Load Growth*

Energy efficiency improvements have played a role in keeping overall consumption levels nationwide flat during the period 2009 to 2012. In particular, state-level energy efficiency (EE) programs have played a role in curbing growth in electricity consumption. According to a recent DOE-funded Lawrence Berkeley National Laboratory report, “in 2010, electric energy efficiency programs in the U.S. achieved incremental energy savings of 18.4 TWh, equivalent to 0.49 percent of electric utility retail sales nationally.”<sup>26</sup>

A review of selected state EE programs since 2009 shows notable electricity savings in the states of California, Connecticut, Maine, Massachusetts, New Hampshire, New York, Rhode Island, and Vermont.<sup>27</sup> The average annual electricity savings (in energy, or megawatt-hours) from 2009 to 2012 due to EE in these states was approximately one percent of total

electricity sales. If extended to the nation overall, a one percent savings in electricity usage has a value of approximately \$3.5 billion at average retail electricity rates.

### Efficiency Policies

The eight states selected for review are part of a broader set of 30 states with long-term policies that specify EE savings, as depicted in Figure 3-4 on page 44. These policies include Energy Efficiency Portfolio or Resource Standards (EEPS), which require utility reductions in average annual retail sales (in megawatt-hours) over time, a voluntary EE goal assigned to utilities by states public utility commission, or a hybrid EEPS and Renewable Portfolio Standard.

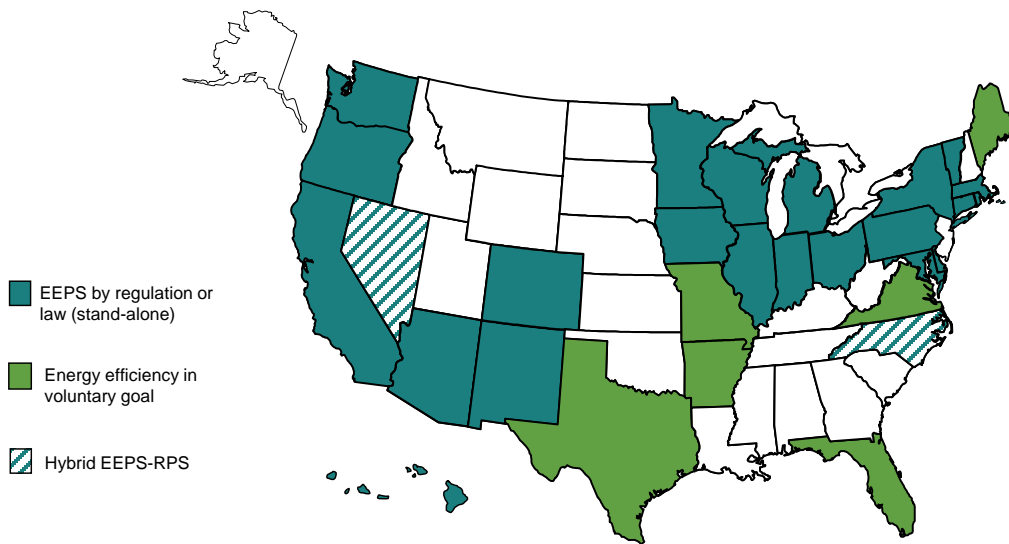
26 Galen Barbose, *et al.*, Lawrence Berkeley National Laboratory (LBNL), *The Future of Utility Customer-Funded Energy Efficiency Programs in the United States: Projected Spending and Savings to 2025* (December 2012).

27 The selected states were chosen because of accessibility to energy efficiency data and because they also include some of the top states in 2012 for EE initiatives. The states were ranked by the American Council for an Energy-Efficient Economy (ACEE) in the 2012 State Energy Efficiency Scorecard (October 2012). Additionally, because the selected states are in three RTO markets (California, New England and New York) additional data was available, and the connection between state-level electricity savings and long-term RTO planning could be assessed.



Figure 3-6

## States with Energy Efficiency Programs



Source: Derived from ACEE, database of State Incentives for Renewables and Efficiency (dsIRE); Institute for Electric Efficiency; state agency report data.

## Electricity Use Savings

Electricity savings in each of the states reviewed contributed to the recent flattening of electricity consumption. Figures 3-7 through 3-9 depict the cumulative electricity savings from 2009 through 2012 as compared to the annual electricity sales reported by

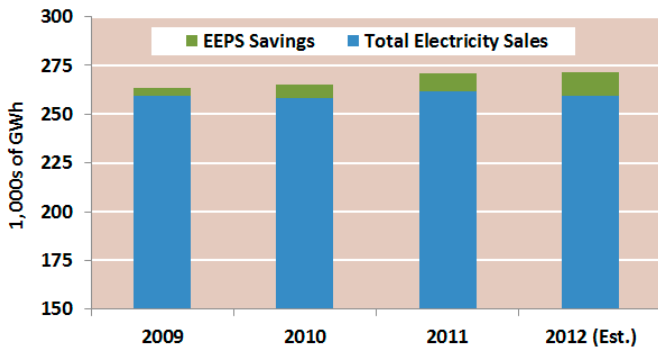
EIA for all customer classes (residential, commercial, and industrial) in the eight states.<sup>28</sup> The lower, blue section of each bar depicts actual electricity sales in each year. The higher, green section shows electricity savings. The total bar height represents what total electricity sales would likely have been but for electricity savings from EE programs.<sup>29</sup>

<sup>28</sup> Electricity savings shown include direct program savings only. That is, savings quantities do not include savings from consumer choices made irrespective of efficiency programs. Graphs show cumulative electricity savings because EE reductions persist for more than one year.

<sup>29</sup> State EEPS often cover only investor-owned utilities (IOUs) but set similar non-binding targets for public power authorities (PPAs). California's graphs include measured savings from its three IOUs. The California Public Utility Commission (CPUC) does not collect energy savings data from the large PPAs. New England includes all measured savings state program administrators reported to the ISO. The New York graph includes data both from the Long Island Power Authority (LIPA) and the Department of Public Service (NY-DPS) for IOU and NYSERDA programs.

**Figure 3-7**

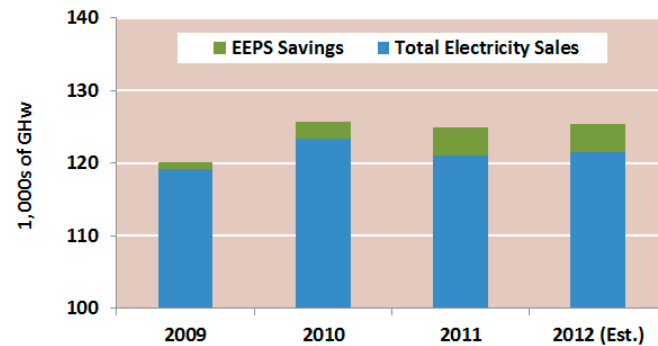
**Energy Efficiency Program Savings - California**



Source: Derived from EIA and California Public Utilities Commission data.

**Figure 3-8**

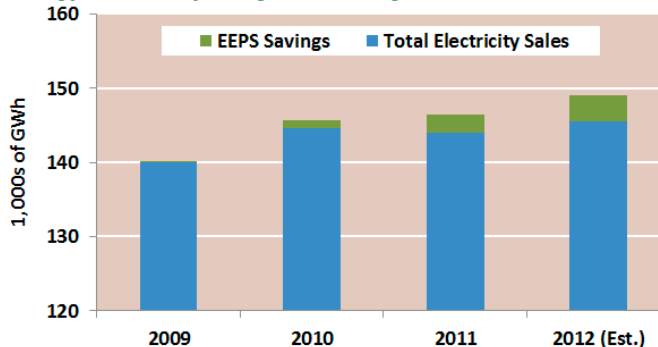
**Energy Efficiency Program Savings - New England**



Source: Derived from EIA and ISO-NE data.

**Figure 3-9**

**Energy Efficiency Program Savings - New York**



Source: Derived from EIA, NY-DPS, and LIPA data.

Overall, the states reviewed have years of experience with energy efficiency programs prior to the period shown.

**Load Forecasts and Wholesale Markets**

Looking ahead, some RTO and ISO long-term plans account for future electricity savings from EE programs. 10 New York and New England explicitly incorporate projected electricity savings by using state-level program data as inputs to both their 10-year forecasts and regional transmission plans. For example, NYISO includes electricity savings in its biennial Reliability Needs Assessment (RNA) and 10-year demand forecasts. In its September 2012 RNA, NYISO determined that, without expected electricity savings, some transmission upgrades may need to be accelerated. In another example, ISO-NE stated last December that expected electricity savings from EE will allow it to defer 10 transmission upgrades that earlier studies deemed necessary for system reliability and save an estimated \$260 million.<sup>31</sup>

**Efficiency Costs and Funding**

Some states have calculated what EE program costs are on a kWh basis for energy saved. Average costs to save a kilowatt-hour of electricity in New England between 2009 and 2011 were 3.5¢.<sup>32</sup> Costs in

30 EIA's latest base-case forecast for the next decade assumed that total U.S. retail electricity sales will grow at an average compound annual growth rate of 0.58 percent, substantially lower than the actual 1.6 percent growth rate during the last two decades. It is notable that the LBNL study found that "EIA's model does not explicitly account for the impact of future utility customer-supported efficiency programs."

31 ISO-NE, "ISO on Background: Energy Efficiency Forecast," December 12, 2012, page 22.

32 Derived from ISO-NE, "Draft 2013 Energy-Efficiency Forecast 2016 – 2022," November 14, 2012, ISO-NE website, [http://www.iso-ne.com/committees/comm\\_wkgrps/othr/enrgy\\_ef-fncy\\_frst/2013mtrls/iso\\_ne\\_draft\\_2013\\_ee\\_forecast\\_2016\\_2022.pdf](http://www.iso-ne.com/committees/comm_wkgrps/othr/enrgy_ef-fncy_frst/2013mtrls/iso_ne_draft_2013_ee_forecast_2016_2022.pdf), accessed April 10, 2013.

New York's Long Island programs averaged 3.9¢.<sup>33</sup> EE programs are funded by a variety of mechanisms including energy bill surcharges, sometimes called system benefit charges. American Recovery and Reinvestment Act grants helped fund some programs in 2010 or 2011. In the Northeast, some proceeds from Regional Greenhouse Gas Initiative (RGGI) auctions (participating states in ISO-NE, NYISO, and PJM) have been set aside to help fund EE programs.

Besides state programs to fund energy efficiency, some participants in energy efficiency efforts are eligible to receive capacity payments that go toward their projects' funding. Utilities in two markets (ISO-NE and PJM) can bid into wholesale forward capacity market auctions. An analysis by ISO-NE's energy efficiency forecast working group projected that about 15 percent of state program funding for EE programs in the seven years beyond the current forward capacity market delivery period will come from designated RGGI and cleared capacity market funds.<sup>34</sup>

### Electricity Supply Additions and Retirements Exhibit Shifts in Fuel Use

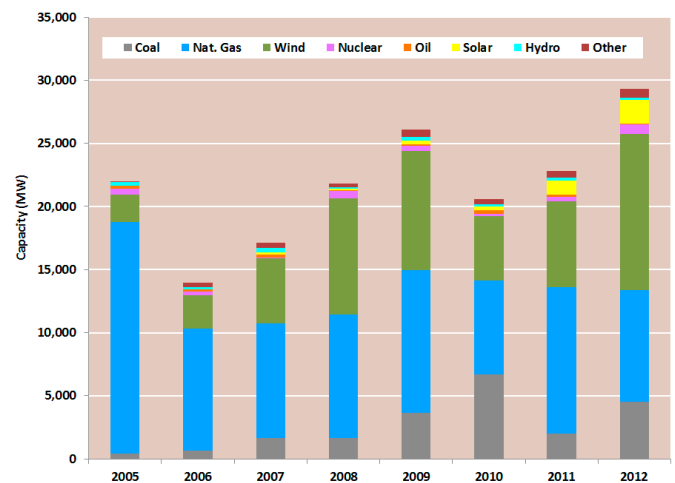
The shift from coal-fired generation to natural gas-fired generation, as discussed in Chapter 1, was further bolstered by additions and retirements of generating capacity. This is part of a longer-term trend that has been accelerated by more recent industry responses to low natural gas prices and environmental regulations. Wind-powered generating capacity

also made up a large share of the new generating capacity, an outcome of Federal and state policies that influenced investment decisions. Increased production from natural gas-fired generation, and to a lesser extent, wind and solar generation, was manifest in greater market shares for these electricity supplies.

During 2012, over 29 GW of new generation capacity, including changes in existing capacity ratings, came into service. Figure 3-10 shows that natural gas-fired and wind generation additions have dominated capacity additions, and that coal-fired generation amounts to a smaller, but notable portion of the new generation. Because of long lead times for the technology, the recent coal-fired additions are the result of decisions made years ago. Market conditions for new electricity supply made it less likely that new coal capacity would be initiated today with current technology.

**Figure 3-10**

#### Generating Capacity Additions by Fuel Type



Source: Derived from Energy Velocity data.

Generator retirements, led by 9.6 GW of coal-fired steam units, amounted to 15 GW for the year. Figure

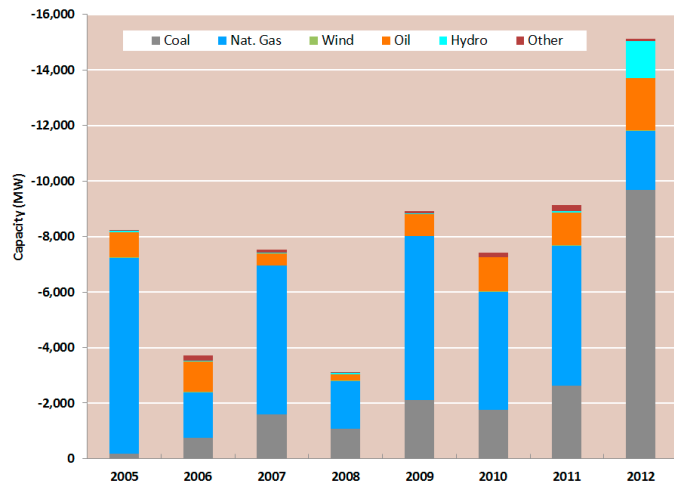
<sup>33</sup> Derived from Opinion Dynamics Corporation, Energy & Resources Solutions Inc. and Megdal & Associates, "LIPA Efficiency Long Island PY2009 Assessment," prepared for Long Island Power Authority, May 2010, and subsequent year reports for 2010 and 2011, Long Island Power Authority website, <http://www.lipower.org/elij/reports.html>, accessed, April 10, 2013.

<sup>34</sup> ISO New England, Energy Efficiency Working Group, "Draft 2013 Energy-Efficiency Forecast 2016-2022", November 14, 2012, and email correspondence with ISO staff.

3-11 shows the acceleration in coal retirements that occurred in 2012.

**Figure 3-11**

**Generating Capacity Retirements by Fuel Type**



Source: Derived from Energy Velocity data.

Table 3-3 shows how these additions and retirements were distributed across the regions.

**Table 3-3**

**2012 Generating Capacity Additions and Retirements (MW)**

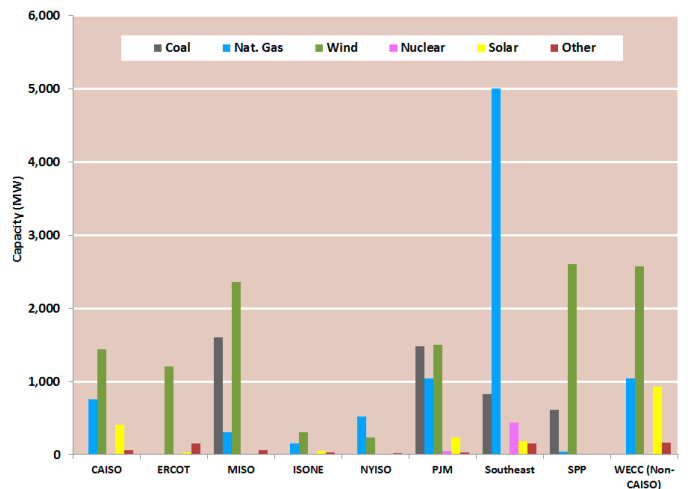
Region	Capacity Additions	Capacity Retirements	Net Additions
WECC (outside-CAISO)	4,766	331	4,435
SPP	3,266	137	3,128
CAISO	2,685	112	2,573
Southeast (outside-RTO)	6,642	4,216	2,427
MISO	4,343	1,827	2,516
ERCOT	1,387	--	1,387
ISO-NE	536	176	360
NYISO	889	398	492
PJM	4,494	7,569	-3,075
<b>Totals</b>	<b>29,007</b>	<b>14,764</b>	<b>14,242</b>

Source: Derived from Energy Velocity data

Regional differences in additions are evident in both the total size of capacity additions and fuel type. Figure 3-12 shows these differences graphically, region by region for major fuel types.

**Figure 3-12**

**Generating Capacity Additions by Region and Fuel Type**



Source: Derived from EEI data

The Southeast stands out as the region where the largest amount of natural gas-fired generation entered service. This capacity addition reinforced the major shift in production (discussed both in Chapter 1 and below) from coal to natural gas in that part of the nation. Wind development was well represented in major parts of the Midwest and the West. Solar-powered generation is achieving a foothold in parts of the West.

Changes in environmental regulations influence electricity supply decisions. Just prior to the beginning of 2012, transmission owners, operators, and Balancing Authorities in the Eastern Interconnect were focused on finding ways to maintain reliability in the face of new EPA regulations under the Cross State Air Pollution Rule (CSAPR). Those regulations were scheduled

to become effective at the beginning of 2012, with more extensive restrictions set to take effect in 2014.<sup>35</sup> The CSAPR was proposed as an allowance-based regulation to reduce sulfur dioxide and nitrous oxide emissions and their interstate transport.<sup>36</sup> In addition, in December 2011, the EPA promulgated the Mercury and Air Toxics Standards (MATS) rule.<sup>37</sup> The MATS rule establishes new emissions control requirements for coal-fired power plants.

At the end of 2011, the United States Court of Appeals for the District of Columbia Circuit stayed the CSAPR rule, and in August 2012 the court vacated the rule. The EPA is rewriting its regulations and the implementation schedule is yet to be determined. The MATS rule remains in place and has a compliance deadline of April 2015. This deadline spurred planning decisions for some owners of coal-fired plants to retire or retrofit with pollution control equipment.

In addition to the impact of new regulations, owners of coal-fired power plants must consider increased competition from natural gas-fired generation. As discussed in Chapter 1, natural gas prices have fallen recently to a level that makes natural gas-fired combined-cycle generation competitive with coal-

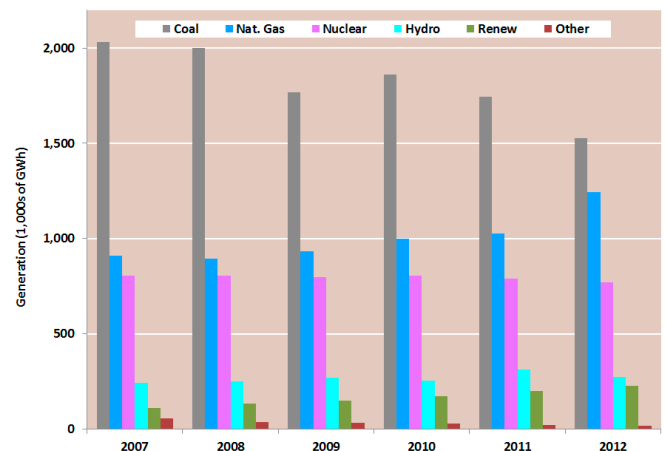
fired steam generation for the first time since the major building boom in combined-cycle plants about a decade ago. The combination of low expected natural gas prices and the MATS rule may accelerate the retirement of many old coal units by April 2015. MISO and PJM each expect over 10 GW of coal capacity to retire by April 2015. However, the two RTOs currently view any system-wide and local reliability issues that result from these retirements as manageable.

### Energy Production

Production statistics also reflect the shift from coal- to natural gas-fired plants. As described in Chapter 1, natural gas-fired combined-cycle plants have moved ahead of coal-fired generation in dispatch order for much of the Eastern Interconnection. This substitution combined with retirements of coal plants are illustrated in Figure 3-13. Coal was still the most used fuel overall with 39 percent of production nationwide in 2012. This figure is down from 43 percent in 2011. Natural gas moved up from 25 percent to 31 percent of production over the same period.

Figure 3-13

#### Generation Produced by Fuel Type



Source: Derived from Energy Velocity data

35 RTOs and other utilities from the Midwest to the Mid-Atlantic described reliability concerns because of the time frame of coal-fired generators that were preparing to retire rather than retrofit to meet new requirements. Also, some operators of coal-fired generators have argued the need to take extensive outages simultaneously to retrofit equipment to comply with new regulations. Examples of communications and initiatives included: PJM 2012 Regional Transmission Expansion Plan Report, Book 2, page 47, <http://www.pjm.com/~media/documents/reports/2012-rtep/2012-rtep-book-2.ashx>, accessed March 12, 2013 and The Brattle Group, "Supply Chain and Outage Analysis of MISO Coal Retrofits for MATS," Report prepared for MISO, May 2012, The Brattle Group web site, [http://www.brattle.com/\\_documents/UploadLibrary/Upload1039.pdf](http://www.brattle.com/_documents/UploadLibrary/Upload1039.pdf), accessed March 14, 2013.

36 Environmental Protection Agency, Cross-State Air Pollution Rule, EPA website, <http://www.epa.gov/airtransport/CSAPR/index.html>, accessed February 28, 2013.

37 Environmental Protection Agency, Regulatory Actions Final Mercury and Air Toxics Standards (MATS) for Power Plants, EPA website, <http://www.epa.gov/airtransport/CSAPR/index.html>, accessed February 28, 2013.



## Renewables

Several government programs influenced the level of investment in wind and solar-powered plants, as well as other renewable sources. Production and investment tax credits for wind-powered generators have been an incentive for the wind capacity expansion over recent years. Since its inception, the production tax credit has a history of short-term renewals. The most recent extension was in the American Tax Relief Act of 2012 on January 1, 2013.

Under this law, solar generation installations are eligible for a 30 percent investment tax credit. This credit is targeted toward small scale residential installations and large commercial facilities. The credit is set to expire on December 31, 2016. From 2009 through 2011, a cash grant was available in lieu of the tax credit. A surge in solar installations occurred as year-end 2011 approached. Capacity in 2012 continued to grow with an addition of approximately 3.3 GW according to industry estimates, the highest one-year increase.<sup>38</sup>

Renewable capacity is also influenced by renewable standards set by the states. These requirements and goals vary markedly from state to state in terms of the percentage of renewable resources involved and specific rules that apply. For example, some programs allow imports from other states to contribute while others do not.

38 Solar Energy Industry Association (SEIA), "U.S. Solar Market Insight 2012 Year in Review," SEIA website, <http://www.seia.org/research-resources/us-solar-market-insight-2012-year-review>, accessed May 21, 2013. This estimate includes grid-connected and behind-the-meter installations. Industry sources vary on the amount of added capacity attributable to solar resources. According to EIA, national solar capacity is growing rapidly and tracking the additions requires accounting for many small, distributed solar installations. U.S. Energy Information Administration (EIA), "New EIA data show total grid-connected photovoltaic solar capacity," October 24, 2012, EIA web site, <http://www.eia.gov/todayinenergy/detail.cfm?id=8510>, accessed April 10, 2013. Ventyx's Energy Velocity database reports approximately 1.8 GW of solar capacity added to the grid in 2012.

## Nuclear Capacity

Increases in nuclear capacity in recent years have come through uprates of existing plants as opposed to new plant construction.<sup>39</sup> However, during the last two years, nuclear power plant capacity in the U.S. declined by more than 1.6 GW in contrast to previous years. Since 2000 there have been 4.6 GW of nuclear capacity uprates. Capacity uprates do not involve construction of new nuclear units but are the result of modifications to existing units, including upgrading existing equipment such as steam generators and improved telemetry, allowing for more accurate and frequent measurement of nuclear reactor conditions.

Much of the capacity benefit from these enhancements may be negated due to equipment problems, suboptimal plant performance, and low natural gas and coal prices. Nearly 3.5 GW of nuclear capacity went into long-term outage between 2009 and 2012 with no firm assurance that operations will resume. To the extent that further nuclear plant capacity is deactivated, the markets will face greater demand for capacity and likely experience new orders for additional natural gas-fired generation.

## *Demand Response Continues to Grow*

Demand response (DR) resources provide a means by which market participants offer to reduce load to help meet resource adequacy requirements, help lower peak demand, and resolve other system constraints, along with other benefits.<sup>40</sup> DR resources are de-

39 Uprate refers to the increase in an existing generator's capacity.

40 Demand response is defined as "(c)hanges in electric use by demand-side resources from their normal consumption patterns in response to changes in the price of electricity, or to incentive payments designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized." Federal Energy Regulatory Commission, "2012 Assessment of Demand Response and Advanced Metering," December 2012, FERC web site, <http://www.ferc.gov/legal/staff-reports/12-20-12-demand-response.pdf>, accessed March 7, 2013.

ployed or activated through programs ISOs and RTOs administer, as well as load serving entities (LSEs). DR programs allow market participants to provide a variety of products such as capacity, energy, and ancillary services. The capacity-based emergency DR programs in the Northeastern ISOs and RTOs are among the largest of these programs.<sup>41</sup> Growth of these programs has been substantial, rising from 3 GW of capacity in 2007 to 12 GW in 2012, and DR programs have become an increasingly important resource for grid operators during periods of system stress. This growth may lead to increased frequency of deployments and reliance on DR activations into the future.<sup>42</sup>

The capacity-based DR program in the NYISO and certain PJM DR programs provide suppliers with payments for both capacity and energy.<sup>43</sup> However, in ISO-NE energy payments will not take effect until 2017 when DR resources will be obligated to bid into the energy markets. In each of these three markets, DR accounted for approximately 10 percent of the installed capacity in the most recent auctions, which include the 2015–2016 forward capacity market auctions for PJM and ISO-NE, and the NYISO's semi-annual reliability period capacity market for 2012.

For participating suppliers of the resources, the majority of overall DR revenues come from capacity payments, which accounted for \$331 million or 95 percent of the amount received by providers in PJM in 2012, while compensation for energy comprised the remainder. This compared to 89 percent in the NYISO and 100 percent in ISO-NE of DR revenue from capacity markets. Between the two revenue streams, participating suppliers receive annual payments for capacity and receive payments for energy in periods when DR activations occur.

Providers in the programs offered their DR resources into the capacity markets as do conventional generation resource, but were typically priced below the market's marginal unit. Thus, in general, the additional supply added by DR resources contributed to overall downward pressure on capacity market clearing prices. In New England, in the Forward Capacity Market auction conducted during 2012 for the delivery period of 2015–2016, the capacity market price cleared at the administratively-set floor price.

There were two emergency DR activations in PJM, six in NYISO and none in ISO-NE in 2012. This is roughly comparable to 2011 in which there were two activations in ISO-NE and three in both PJM and NYISO. Emergency DR activations have historically been infrequent and, in some years, not called upon other than for testing. During events requiring DR activation, real-time prices typically were volatile during the ramp period for the DR resources, coinciding with tight supply-demand conditions.<sup>44</sup> The emergency DR

41 Individual DR programs that comprise emergency DR go by various names and vary by ISO and RTO. Examples include Special Case Resources in NYISO, and Capacity and Energy Load Management in PJM. As discussed in this section, emergency demand response includes load as a capacity resource (LCR). NERC defines LCR as "a resource that commits to pre-specified load reductions when system contingencies arise." North American Electric Reliability Corporation (NERC), "2012 Summer Reliability Assessment – Seasonal Outlook," May 2012, p. 177, NERC web site, <http://www.nerc.com/files/2012SRA.pdf>, accessed March 13, 2013. Shifts have occurred over time in the composition of the demand response programs. FERC, "2012 Staff Report on the Assessment of Demand Response and Advanced Metering," December 2012, p. 24.

42 The RTOs also have economic DR programs which are a smaller category than the emergency programs. The economic program in PJM had revenues of \$9.3 million, which was three percent the size of the emergency program.

43 PJM does not provide energy payments to Capacity Only Emergency Load Response Resources when dispatched during an emergency event; it provides an energy payment (either the submitted bid floor or the LMP, whichever is higher) to Full Program Option Emergency Load Response Resources.

44 Requirements vary for the timing of activation in each of the markets, ranging from 30 minutes in ISO-NE to two hours for certain assets in PJM. The time between deployment of DR resources and the deadline to have all curtailments operational is known as the "ramp period."

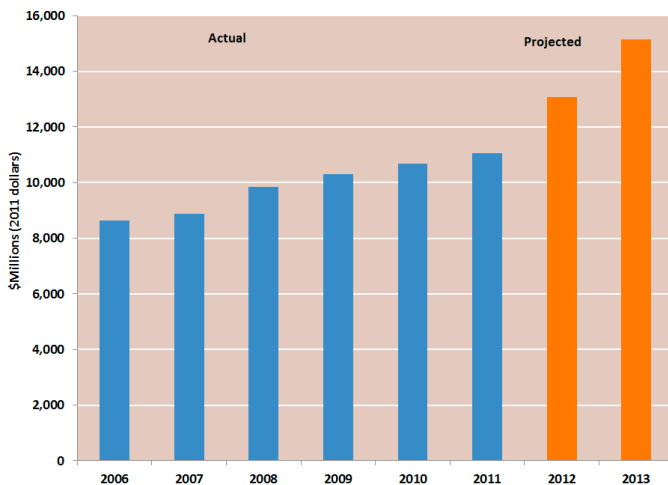
helped reduce real-time load and price volatility, and, ultimately, prices themselves declined. While it is not easy to separate and quantify the effect of DR on the market from other variables, such as weather changes and load variations by non-DR loads, the DR activations contributed, in part, to lower real-time energy costs for LSEs.

### Investment in Electricity Transmission Infrastructure Investment Continued

Electric transmission infrastructure additions continued to grow in 2012 and, in part, help meet the infrastructure needed for integrating renewables and upgrading the grid. According to the Office of Energy Projects Energy Infrastructure Update for October 2012, more than 1,191 miles of transmission lines of 230 kV or greater were added. The Edison Electric Institute (EEI) said this represented more than \$13 billion in capital investment and continued a trend of increased spending that has equaled 12 percent annually for investor-owned utilities from 2005 to 2012. Figure 3-14 shows transmission investment from 2005-2012 (last two years projected).

**Figure 3-14**

#### Transmission Investment 2005 - 2012



Source: Derived from EEI data

Most new power lines that began service in 2012 were in South Central and Western states. Some projects received Commission-approved incentives that allowed for increased return on investment (ROI).<sup>45</sup>

The projects below were brought online in 2012 and were notable because of their scope and importance to the markets. They represent large, high-voltage projects that span substantial distances and required parties to work together for planning and construction. Additionally, the projects are expected to provide substantial benefits by supporting the transmission of power from renewable sources in rural areas to load centers and bolstering reliability of the transmission system.

San Diego Gas and Electric's \$1.9 billion Sunrise Powerlink Transmission project was the most expensive to come on line in 2012. This 117-mile, 500 kV and 230 kV power line has the capacity to transmit 1,000 MW and connects the San Diego region to the Imperial Valley's solar, wind and geothermal resources. Completion of this line was particularly important due to local reliability concerns associated with San Onofre Nuclear Generating Station units now offline. As a response, SDG&E finished and energized the line early to help the region meet its power needs by increasing transfer capacity, voltage stability, and import capability.

SPP activated seven new transmission projects, with 450 miles of transmission lines, making it the region of the nation with the most new facilities and

<sup>45</sup> The ROI incentives are a function of the Commission's Order No. 679, *Promoting Transmission Investment through Pricing Reform*, Order No. 679, 71 FR 43294 (Jul. 31, 2006), FERC Stats. & Regs. ¶ 31,222 (2006), *order on reh'g*, Order No. 679-A, 72 FR 1152 (Jan. 10, 2007), FERC Stats. & Regs. ¶ 31,236, *order on reh'g*, 119 FERC ¶ 61,062 (2007).

growth in miles of new transmission. Oklahoma Gas & Electric's \$200 million, 130-mile, 345 kV Hugo to Sunnyside line, ITC Great Plains and Nebraska Public Power Districts' \$170 million, 125-mile, 345 kV Post Rock to Axtell line, and the \$106 million, 89 mile 345 kV ITC Holdings' Spearville to Post Rock line were the longest and most expensive high voltage projects in the region. All of these projects' costs were allocated across the SPP region under the SPP Highway-Byway or Balanced Portfolio cost allocation methodologies.<sup>46</sup>

Another notable project is the Bonneville Power Administration's (BPA) \$216 million, 500 kV, 79-mile McNary-John Day transmission line. This facility was completed 10 months ahead of schedule and came in \$124 million under its original cost estimate of \$340 million. It received funds through the borrowing authority provided by the American Recovery and Reinvestment Act. The line allows BPA to offer transmission service to 495 MW of additional wind energy awaiting its completion.

<sup>46</sup> Under SPP's Highway Byway and Balanced Portfolio cost allocation methodologies, 100 percent of the costs of projects above 300 kV are allocated on a regional postage-stamp basis.



## Chapter 4: Interplay between Physical and Financial Aspects of the Natural Gas and Electricity Markets

### SUMMARY

In 2012, financial products continued to play an important role in energy markets. The volume of financial trading significantly exceeds physical trading. As discussed in previous State of the Markets reports, financial trading of natural gas including financial basis swaps and prompt month contracts exceeds physical trading by an order of magnitude. Financial trading allows participants to hedge and arbitrage prices without the risk of physical delivery requirements or related costs. Similarly, in electricity markets, financial trading plays a prominent role with approximately 90 percent of financial trading taking place at RTOs' and ISOs' trading hubs. Unlike four years ago when commodity prices were rising, in 2012 traders evaluated trading opportunities in a market environment of declining prices, reduced volatility, and lower profit margins.

In 2012, financial trading volumes for both natural gas and electricity remained substantial overall, and the market remained liquid. There were two key trends in financial trading. First, trading for electricity continued to decline in 2012 even as end use consumption remained flat. The volume of electricity trading on the IntercontinentalExchange, Inc. (ICE)



decreased 19 percent compared to 2011, as part of a longer-term trend. Physical transactions reported in the Electric Quarterly Report have also been in decline since 2008. However, open interest in the markets remained high particularly in the Nymex futures and swaps markets as producer and merchant participation held steady and managed money trading increased to replace declines by banking institutions.

Second, toward the end of 2012, financial trading of both natural gas and electricity shifted as trading platforms offered revised products in response to regulatory changes required under the Dodd-Frank Wall Street Reform and Consumer Protection Act of 2010 (Dodd-Frank Act).<sup>47</sup> A goal of the Dodd-Frank Act is to facilitate increased transparency in the markets; new requirements to place energy derivatives on exchanges should improve data to better gauge financial trading activity and interrelationships that may develop between physical and financial positions.

Participation by banking institutions in physical natural gas and electricity markets continued to wane.<sup>48</sup> The declining activity in asset ownership and physical energy transactions can also be seen as the continuation of a multi-year trend, with banking institutions' participation in the natural gas and electricity markets peaking in the 2007 and 2008 period, and declining since then.

While banking and financial institutions took a smaller role as physical energy market participants, utilities maintained access to investment capital through stable credit ratings. A relatively favorable credit environment existed for utilities that maintained higher credit ratings. With low interest rates available for investment grade utilities, debt issuance by the lowest investment grade (BBB) rated utilities stayed flat while A-rated utilities increased their issuance by 25 percent in 2012.

### *Traded Volumes Declined for Financial Products, Changes Reflected in Products and Locations*

While financial trading volumes for both natural gas and electricity remained substantial, volumes traded in financial products for electricity declined in 2012 based on data from ICE and CME Group.<sup>49</sup> The volume of electricity trading on ICE decreased 19 percent compared to 2011. One possible explanation for the decline is that there was lower volatility in power prices. Lower volatility implies less potential for profit. The decline in potential profits might steer investors away from energy products, and into other assets.

Also, market participants faced uncertainty as to the details of new regulations required by the Dodd-Frank Act. While the Dodd-Frank Act led to new requirements to place energy derivatives on exchanges, the market's experience with this has been limited so far. To address expected customers' trading needs,

<sup>47</sup> The Dodd-Frank Act brought major change to financial regulation. Particularly, as it relates to financial products related to energy, the law implements changes that improve the oversight and supervision of financial institutions, introduce major changes in the regulation of over-the-counter derivatives, tighten requirements on proprietary trading by banks, and set new record keeping and reporting requirements, among other provisions. See Dodd-Frank Wall Street Reform and Consumer Protection Act, Pub. L. No. 111-203, 124 Stat. 1376 (2010) (Dodd-Frank Act).

<sup>48</sup> Banking institutions include entities acting as insured depository institutions with deposits insured by the Federal Deposit Insurance Corporation (FDIC) or receiving Federal Reserve Bank (FRB) services such as access to the discount window.

<sup>49</sup> Financial products for natural gas and electricity are contracts that can be bought and sold. Financial contracts generally do not result in delivery of the commodity; instead, they provide a financial payout. Financial products are derivatives and include such items as swaps and futures contracts.

exchanges that offer financial energy products converted most of their cleared energy swaps into futures contracts. ICE and CME Group made the conversion of cleared energy swaps to futures in October 2012. Between January and September 2012, financial trading (with respect to cleared transactions) on ICE for both natural gas and electricity declined. However, reported volumes of cleared transactions increased in October through December as traders began using futures contracts. In general, futures cleared on exchanges are expected to have lower costs than cleared and uncleared swaps traded over the counter. New requirements from the Dodd-Frank Act should improve data transparency by moving over-the-counter transactions to exchanges (including futures exchanges) and allowing market participants and the public to better assess trends in financial trading.

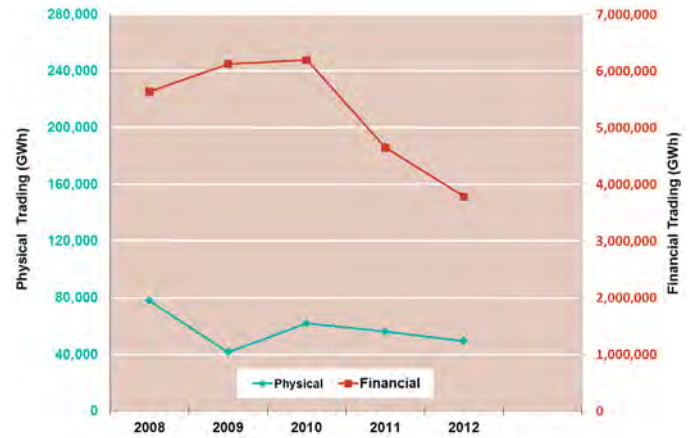
### Electricity Trading on ICE Declines

Total electricity trading volumes cleared on ICE decreased approximately 19 percent compared with 2011 as indicated in Figure 4-1. In addition, trading volumes for financial products were about two thirds of the volumes traded in 2008. Nevertheless, the volume of financial products traded in electricity markets continue to significantly exceed the volume of physical products traded. Financial volumes represented about 100 times the physical volumes in 2011 and 2012.

During 2012, 89 percent of the financial trading for electricity products on ICE took place in an RTO or ISO hub, with most hubs experiencing decreased financial trading volumes compared with 2011. Figure 4-2 shows the financial trading volumes from ICE for key trading locations over the last four years.

Figure 4-1

ICE Electricity Trading Volumes Continue to Decline

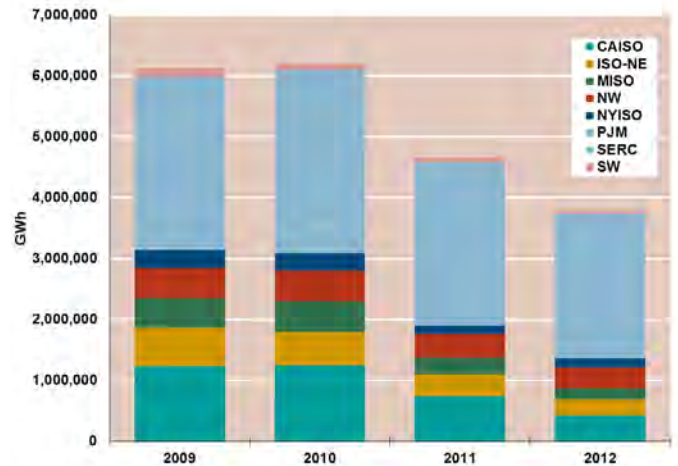


Source: Derived from ICE data

Trading Volumes include U.S. non-ERCOT hubs only.

Figure 4-2

Financial Trading Volumes in all Areas except NYISO Declined in 2012



Source: Derived from ICE data

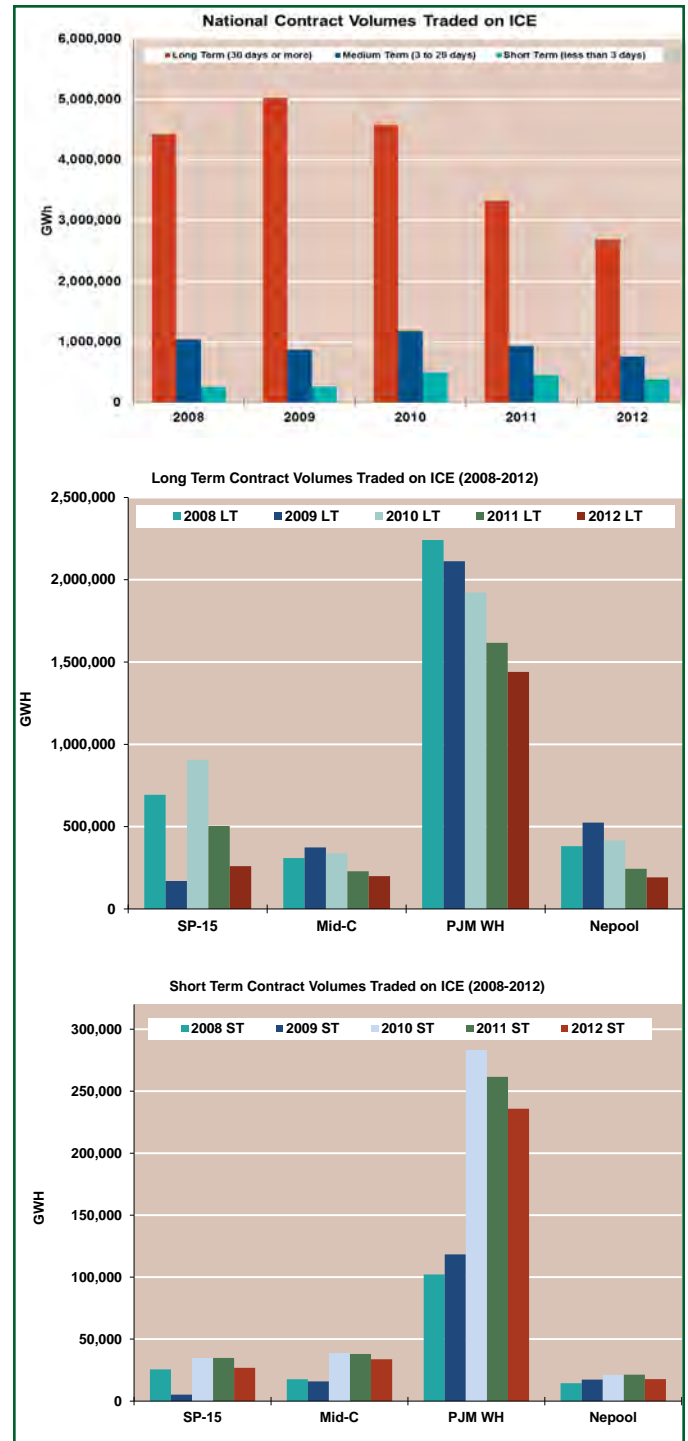
PJM’s financial products continued to be the most traded electricity products on ICE, with 63 percent of total financial trades involving a PJM product. PJM West Hub was the most popular trading hub; in 2012, its volumes represented 85 percent of the total PJM market and 53 percent of the total financial trading on ICE for the U.S. power market.

However, from 2009 through 2012, long-term (30 days or more) trading for all regions experienced an average 14 percent annual decline while short-term (less than three days) trading rose an annual average of nine percent. As illustrated in Figure 4-3, the change in short-term and long-term trading volumes varied significantly between regions. For example, in 2012, PJM’s West Hub experienced a similar decline in short-term and long-term trades from 2011 while SP-15’s decline was mostly concentrated in the long- and medium-term (three to 29 days) trades. Overall, trading volumes in 2012 versus 2011 declined 19 percent for long- and medium-term trading and 16 percent for short term trading. On the other hand, open interest in the markets remained high particularly in the Nymex futures and swaps markets as producer and merchant participation held steady and managed-money trading increased replacing declines by banking institutions.

Price volatility for electricity declined in 2012, signaling a decrease in risk and profit margins. Price volatility levels are key factors that drive speculative trading profits. Figure 4-4 on the next page shows that for the PJM West Hub, the 30-day window historical price volatility was near four-year lows in May 2012 and by December 2012 was 34 percent of its peak.

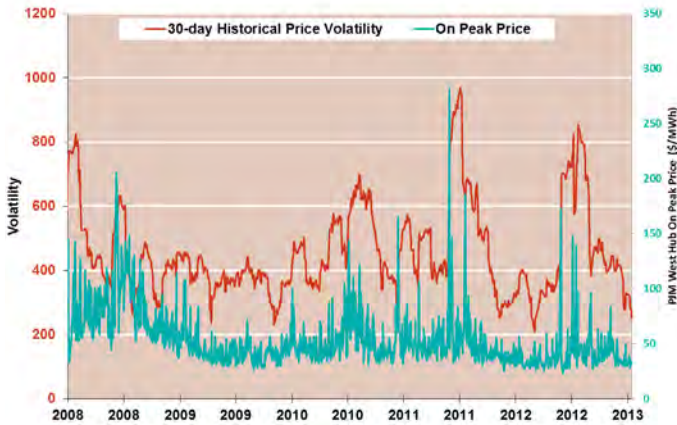
Figure 4-3

Trading Volumes Decreased in 2012 for All Contract Durations



Source: Derived from ICE data

**Figure 4-4**  
PJM West Hub On-Peak Price Volatility Declines



Source: Derived from Bloomberg data

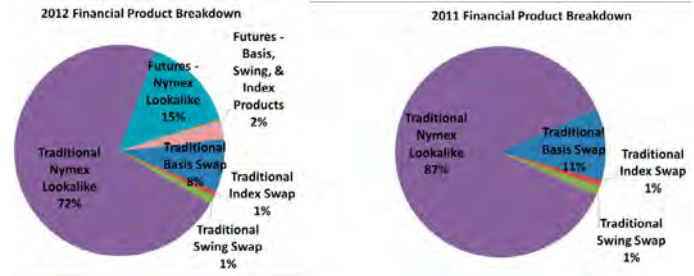
**Markets Shifts to Futures from Swaps**

During 2012, the markets transitioned from swap products to the converted futures product. The distinction between a swap and a future ultimately determines the costs for producers, end users, exchanges, and brokers. In October 2012, ICE and CME Group converted cleared energy swaps to futures to address regulatory requirements raised by the Dodd-Frank Act. The conversion required financial transactions to be cleared and to have standardized units, resulting in increased transparency.

In natural gas trading on ICE, the revised futures products traded 17 percent of total annual financial volumes (over 116,000 Bcf) in the fourth quarter of 2012 as shown in Figure 4-5.<sup>50</sup> In electricity trading on ICE, the revised futures products traded over 1,141 TWh in the fourth quarter of 2012 or 30 percent of total annual financial volumes as shown in Figure 4-6.

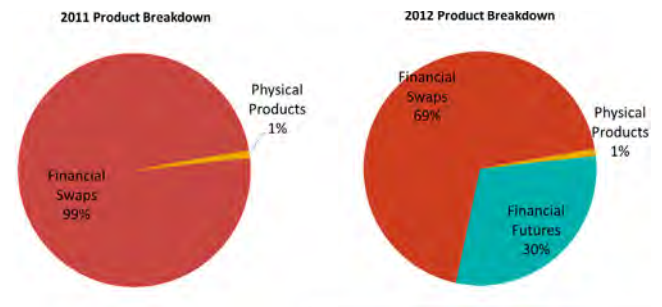
<sup>50</sup> The settlement price for most of ICE's financial contracts for natural gas is tied to the natural gas futures settlement price on Nymex. The trend described may vary with other trading platforms.

**Figure 4-5**  
Natural Gas Trading on ICE Transitions from Swaps to Futures



Source: Derived from ICE data

**Figure 4-6**  
Electricity Trading on ICE Transitions from Swaps to Futures



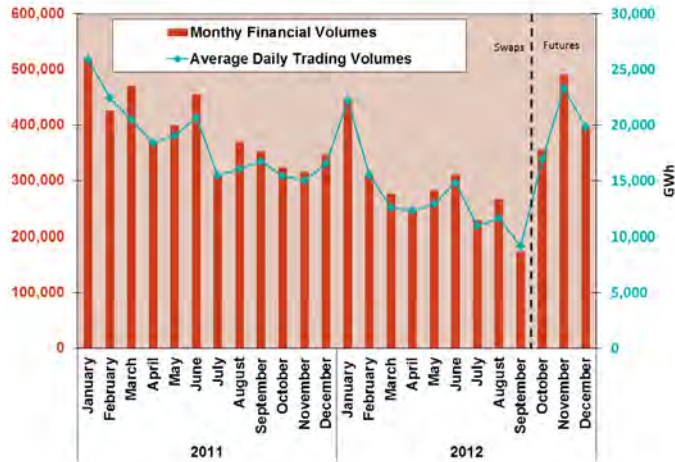
Source: Derived from ICE data

Between January and September 2012, financial trading on ICE for both natural gas and electricity declined. However, reported transaction volumes increased in October through December as traders began using the futures contracts. In general, futures cleared on exchanges are expected to have lower costs and regulatory requirements than cleared and uncleared swaps traded over the counter. As shown in Figure 4-7, average daily volumes of financial electricity products increased 26 percent in the fourth quarter of 2012 over the same period in 2011.



**Figure 4-7**

Average National Daily Volumes Rebounded at the End of 2012



Source: Derived from ICE data

While volumes of financial products traded for natural gas and electricity remain substantial, small movements in physical positions can have large influences on the value of financial positions. Greater ability to assess market trends should be possible through access to data on financial trading activity facilitated by the market’s use of exchanges.

**Participation by Banking Institutions in the Natural Gas and Electricity Markets**

The continued economic downturn, decreased profit margins in trading, and new trading restrictions and compliance requirements have caused some market participants to scale back operations or exit the energy trading business. For example, in January 2012, Société Générale Energy Corp. sought waivers of capacity release and tariff provisions to facilitate sales of assets and thus allow the parent company, Société

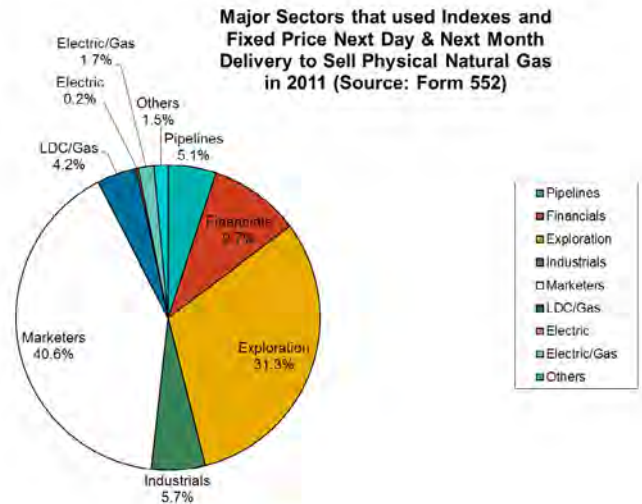
Générale SA, to depart from the physical natural gas and electricity trading business in North America.<sup>51</sup>

**Physical Wholesale Natural Gas Sales by Banking Institutions Decline**

Physical natural gas trading by banking institutions peaked in 2007 and 2008. However, this trading activity has steadily declined since that time, according to data from the Commission’s Form No. 552 Annual Natural Gas Transactions Reports.<sup>52</sup> As shown in Figure 4-8, financial companies, which include banks, accounted for 10 percent of natural gas purchase and sales volumes in 2011.

**Figure 4-8**

Financial Companies Account for Ten Percent of Natural Gas Volumes



Source: Derived from FERC Form 552 data  
2012 annual physical natural gas market data observed by FERC Form 552 will be available after May 2013.

51 Recent examples include the Royal Bank of Scotland Group Plc and Sempra Energy which exited their RBS Sempra Commodities LLP joint venture in 2010. Also that year, FERC approved temporary waivers of capacity release rules and related tariff provisions requested by Nexen Marketing USA Inc. to facilitate its exit from the marketing and trading business.

52 The FERC Form No. 552 collects transactional information from natural gas market participants. Calendar year 2012 data will be available after the May 1, 2013 filing deadline. Thirteen financial companies filed Form No. 552 reports for calendar year 2011, and three reported transactions to index publishers that used the transactions to form daily and monthly indexes.



Natural gas sales volumes for many individual financial companies have declined since 2008.<sup>53</sup> Several financial companies, such as UBS AG, exited the physical natural gas market after 2010. Despite these companies' exit, and a general decrease in the remaining financial companies' exposure to the gas market, trading volume that the financial sector contributed to the total physical gas market remained relatively unchanged between 2008 and 2011. A reason for the unchanged volume is that J.P. Morgan stepped in to replace those exiting the market. J.P. Morgan's natural gas sales more than doubled between 2008 and 2011.

Eleven banking institutions participated materially in the physical natural gas markets in 2011. Table 4-1 lists the participating banks.

### Physical Wholesale Electricity Sales by Banking Institutions Decline

Physical trades of electricity by banking institutions also peaked in 2007 and 2008. This trading activity has steadily declined since that time.<sup>54</sup> A year-over-year decline in market-based sales by banks or bank affiliates is shown in Figure 4-9 on the next page.

<sup>53</sup> Id.

<sup>54</sup> Derived from Electric Quarterly Reports (EQR) filed with FERC.

**Table 4-1**

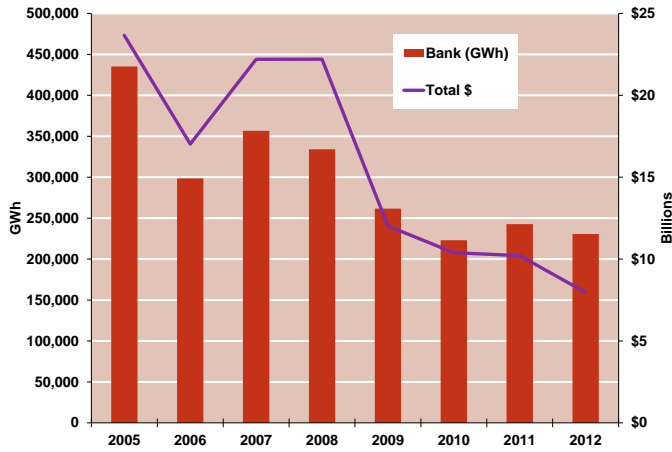
#### Bank Participation in the Physical Natural Gas Market is Limited

Respondent	Bank	Purchases (Trillion Btu)	Sales (Trillion Btu)	Reports to Index Publisher
JPMorgan Ventures Energy Corp	JPMorgan Chase	1,536.2	1,414.2	No
Citigroup Energy Inc	Citigroup Inc	959.6	960.8	Yes
Barclays Bank PLC	Barclays Bank PLC	408.0	412.9	No
DB Energy Trading LLC	Deutsche Bank AG	389.7	404.3	No
J Aron & Co	Goldman Sachs	457.2	402.9	Yes
Wells Fargo Commodities LLC	Wells Fargo & Co	92.6	97.3	No
Merrill Lynch Commodities Inc	Bank of America	316.3	262.0	Yes
Credit Suisse Energy LLC	Credit Suisse	111.1	91.0	No
Morgan Stanley Capital Group	Morgan Stanley	172.2	68.5	No
Royal Bank of Canada	Royal Bank of Canada	59.5	59.5	No
Sempra Energy Trading	Royal Bank of Scotland	44.5	10.2	Yes

Source: Derived from FERC Form 552 data

**Figure 4-9**

**Electricity Sales Reported by Banks Have Been in Decline**



Source: Derived from EQR data volumes (assume kWh to MWh conversion)

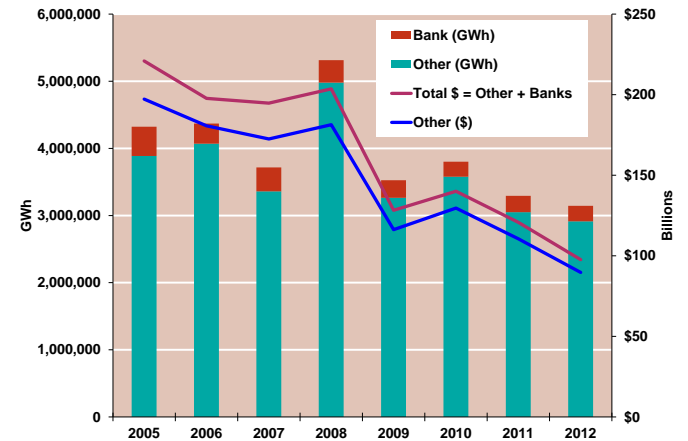
After the 2001 collapse of Enron, many market participants withdrew from merchant projects that relied on robust trading. Some assets were transferred to lending banks as owners defaulted on debt obligations. Other assets were sold to hedge funds at distressed values as owners monetized units to secure credit ratings and trim portfolios. By the end of 2004, banking institutions and financial entities had acquired five to 10 percent of U.S. generating capacity.<sup>55</sup> As generation owners, financial institutions made significant wholesale sales, and some ranked among the top electricity traders including Morgan Stanley Capital, J. Aron, and Merrill Lynch. Today, banking institutions only own a fraction of the assets used to enable those sales.

Reduction in traded volume is not unique to banking institutions. Overall, energy volumes reported in the

EQR have declined in line with revenue. There was a slight resurgence in 2008, coincident with high prices and favorable conditions in the market. The decline continued in later years as shown in Figure 4-10.

**Figure 4-10**

**Electricity Sales and Revenues in Decline Since 2005**



Source: Derived from EQR data volumes (assume kWh to MWh conversion)

**Capital Spending Up and New Debt Issued Where Utilities Possessed Favorable Credit Ratings**

Capital markets provide the money to make investments in infrastructure such as power plants or natural gas pipelines, to operate plants and companies and to trade or conduct transactions. Access to capital depends both on the health of capital markets and also on the perceived risk of the entity seeking the capital. To measure relative riskiness, many providers of capital consider varied measures, including credit ratings.

In 2012, the industry experienced low interest rates, an abundance of low-cost natural gas, and, in most

<sup>55</sup> FERC, Division of Energy Market Oversight, "2004 State of the Markets Report," June 2005, Federal Energy Regulatory Commission web site, <http://www.ferc.gov/market-oversight/reports-analyses/st-mkt-ovr/som-rpt-2004.pdf> at pages 31, 62 and 63, accessed March 11, 2013.

areas, reductions in electricity consumption. Many utilities experienced reduced levels of revenue. In this business environment, companies with favorable credit invested in new capital projects and refinanced older debt. These companies were able to increase capital spending because investment grade credit ratings allowed borrowing and refinancing on better terms in current markets.

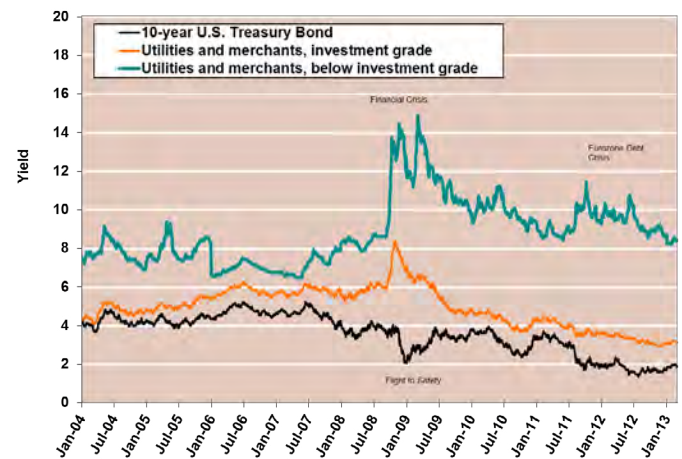
Overall net capital expenditures for electric utilities reported on FERC Form 1 grew at an average annual rate of eight percent from 2005 to 2011. According to SNL's index of 48 natural gas and electric utility parent companies, utility capital spending was projected to reach \$90 billion in 2012, a 19 percent increase over 2011.<sup>56</sup> The new spending was directed at transmission and distribution enhancements, new baseload generation projects, and environmental upgrades.

Yields on corporate debt instruments such as corporate bonds, a measure of the cost of debt, declined for investment grade utilities after a spike during the 2008 financial crisis. Figure 4-11 shows that, while low at the beginning of the year, yields for corporate debt on investment grade utilities declined over the course of the year. Note that while the nominal yields declined, the credit spread (the difference between corporate bonds and a 10-year Treasury bond) remained at about 1.3 percent for investment-grade utilities, indicating that the risk of investment-grade utilities' corporate debt had not fundamentally changed as a whole. However, for noninvestment grade utilities as of early November, the credit spread was a relatively high 7.5 percent.

The electricity and natural gas sector reflected a relatively stable credit situation since its deterioration from the average A rating earlier in the decade. According to Standard and Poor's (S&P) data, 86 percent of regulated natural gas and electric utilities were expected to maintain an investment grade rating of BBB or better.<sup>57</sup>

**Figure 4-11**

**Yields for Investment Grade Utilities Continue to Decline**



Source: Derived from Bloomberg data

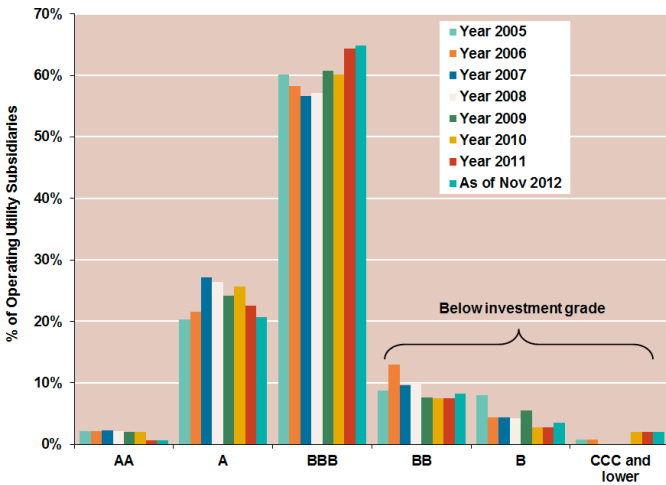
Most utilities maintained a BBB rating in 2012. Figure 4-12 shows how the distribution of credit ratings changed over the last eight years for utilities in the natural gas and electricity sector. Six percent of companies in the overall sector have experienced downgrades from the top AA and A ratings since 2010. Only two percent of companies migrated to below-investment grade. Downgrades may be partially explained by adverse economic conditions, an increase in debt burden, and changes in regulations.

<sup>56</sup> Regulatory Research Associates, Inc., Capital Expenditure Update, "Spending up in 2011 – heading higher in 2012" SNL Energy, May 25, 2012, p. 1.

<sup>57</sup> S&P issues short-term and long-term credit ratings based on S&P's opinion of a bond issuer's creditworthiness. Long-term credit ratings are ranked on scale from AAA (extremely strong capacity to meet financial commitments) to D (payment default on financial commitments). Between these extremes S&P ratings from AA to CCC may include a (+) or (-) sign to show relative standing within the major rating categories.

In 2012, S&P issued only 50 upgrades compared with 136 downgrades. Still, S&P expected the sector to maintain its stable outlook despite the economy's projected slow growth rate.

**Figure 4-12**  
Natural Gas and Electricity Sector Hold Investment Grade Rating

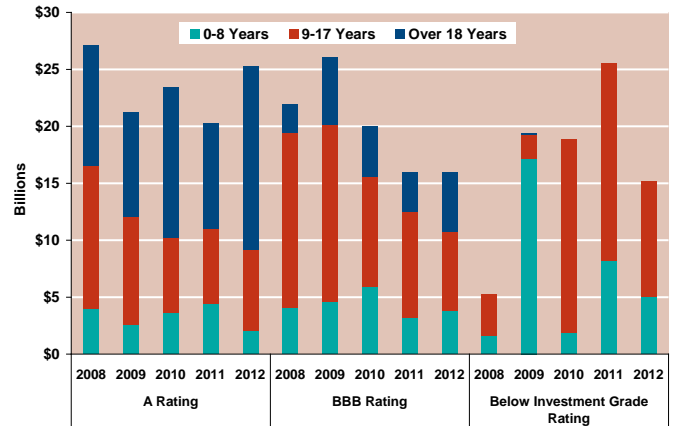


Source: Derived from Standard & Poor's data  
Note: Major rating categories are grouped by base rating and include all ratings with (+) to (-) modifiers

A-rated utilities increased debt issuance in 2012.<sup>58</sup> Since the 2008 financial crisis, investment-grade-rated utilities increased borrowing levels or refinanced previous debt for longer durations. Companies sought to issue longer-term debt to lock in low interest rates. In 2008, 39 percent of the bonds issued by A-rated U.S. utilities in the Bank of America Merrill Lynch Investment Grade Utilities Index had maturities longer than 18 years. In 2012, this percentage rose to 64 percent. Utilities with A ratings increased their issuance by 25 percent to \$25 billion in 2012 while the rate of debt issuance by BBB-rated utilities stayed flat.

<sup>58</sup> Capital comes from two general sources of financing (equity and debt). Debt financing involves borrowing money to be repaid over time, along with interest at a fixed or variable interest rate. Some common types of debt include bonds, which are securities that companies issue in financial markets with maturities of more than a year.

**Figure 4-13**  
The Amount of Debt Issued by A-Rated Utilities Increased in 2012



Source: Derived from Bloomberg data

Despite increases in debt issued by companies at the A credit ratings, overall utility debt issuance fell nine percent compared to 2011. Utilities rated below investment grade (BB and under) decreased their issuances by 41 percent in 2012 as illustrated in Figure 4-13. In 2011, the below-investment-grade utilities benefited from increased investment in high-yield bonds as investors sought higher interest rate alternatives to government and investment-grade corporate bonds. Below investment-grade utilities, too, experienced a previous record-breaking surge in 2009 due to high-yield utility bond issuances.



## Chapter 5: Significant Regulatory Developments in 2012

### SUMMARY

Several market reforms enacted since 2011 sought to improve wholesale electricity market performance through better market power mitigation methods, resource compensation rules, transaction scheduling, and multi-party coordination and information sharing. These changes are intended to improve market transparency, boost inter-control area transaction efficiencies, and better compensate and accommodate a variety of resources. Some may also reduce anticompetitive behavior and price and generator output uncertainty. Reforms occurred through a combination of Commission rules and RTO and ISO actions.



## *NYISO and ISO-NE Interchange Scheduling Plan*

On April 19, 2012, the Commission accepted tariff revisions for NYISO and ISO-NE markets, with effective dates on or after August 1, 2013, designed to improve scheduling of electricity sales and reduce consumer costs in both regions.<sup>59</sup> The revisions implement Coordinated Transaction Scheduling (CTS) between NYISO and ISO-NE. CTS is intended to enable market participants to optimize cross-border transactions by providing scheduling mechanisms that take into account price differences between the regions. Among other measures, CTS will allow for 15-minute scheduling between NYISO and ISO-NE. Today, scheduling occurs every hour. The external market monitor for both regions estimates that CTS will result in \$129 million to \$139 million in annual consumer savings.

CTS allows market participants in NYISO to import or export energy at the NYISO/ISO-NE border by submitting a single bid, using a common bid submission platform, to indicate a desire to simultaneously buy in one control area and sell in the other. CTS further enhances efficient exchanges by increasing the frequency of scheduling energy transactions. Bids clear if the offered price is less than the expected LMP difference across the external interface at the time the interface is scheduled. Both ISOs schedule the proposed transactions. Tariff revisions also eliminated transaction fees that inhibited efficient inter-regional exchanges.

## *NYISO 15-Minute Scheduling with Hydro Quebec and PJM*

In 2012, NYISO enacted provisions, as part of a multi-phase effort, to enable 15-minute transaction scheduling at its borders.<sup>60</sup> These initial actions targeted borders with Hydro Quebec and PJM. NYISO stated that the actions are consistent with a broader regional action plan proposed by NYISO, MISO, PJM, and the Ontario Independent System Operator. Further, as discussed previously, the Commission has approved tariff provisions that will allow for 15-minute scheduling between NYISO and ISO-NE.

Enhanced interregional transaction coordination intends to enable more frequent scheduling of interbalancing authority transactions than on an hourly basis. Reducing the lag time between the scheduling commitments of participants and subsequent pricing determination may lower the resulting price risk. These transactions occur at interfaces known as “proxy generator buses,” which are twinned pairs of modeled import and export buses between neighboring control areas.

In June 2012, NYISO implemented 15-minute variable scheduling at the PJM Keystone Proxy Generator Bus and in July, NYISO implemented 15-minute variable scheduling at its interface with Hydro Quebec at its Chateauguay Proxy Generator Buses.

## *Market Power Mitigation*

In 2012, ISO-NE and CAISO launched new automated market power mitigation systems, and the Commis-

<sup>59</sup> *New York Independent System Operator*, 139 FERC ¶ 61,048 (2012), *ISO New England, et al.*, 139 FERC ¶ 61,047 (2012).

<sup>60</sup> *New York Independent System Operator*, 134 FERC ¶ 61,186 (2011).

sion approved mitigation reforms for MISO and SPP. An entity that has market power has the ability to bid into a market in an uncompetitive manner and inflate market prices. To detect and guard against such occurrences, market monitors have developed and continue to enhance market power mitigation practices.

## ISO-NE

In April 2012, ISO-New England launched an automated mitigation system.<sup>61</sup> The system replaces a manual process used for several mitigation procedures, particularly for pivotal suppliers, who own resources required to meet demand. The new system looks ahead in five-minute intervals at supply offers with respect to two separate conduct and impact tests. From January through March 2012, the number of mitigations averaged seven per month. Following the automated mitigation, the number of mitigations jumped to an average of 33 per month for the rest of 2012. It is not surprising that, with the new automated mitigation procedures, the triggers for mitigation may be more sensitive than in the prior manual process. While greater capabilities to screen and review market offers should be possible through the automation process, further reviews of the new process should be useful for assessing the changes.

## CAISO

CAISO implemented the first phase of a new automated market power mitigation system on April 11, 2012.<sup>62</sup> This phase applies to the day-ahead market. The second phase, for the hour-ahead scheduling process and real-time market, is scheduled for spring

2013. Transmission paths determined to be uncompetitive are subject to market power mitigation. Previously, the market monitor conducted quarterly competitive path assessments to assess transmission paths with the potential market power. The new methodology uses a market run in the day-ahead market process to dynamically determine congested paths. Since assessment of transmission path congestion is done in conjunction with each day-ahead market run, it better reflects current grid conditions than the previous quarterly process. The new process allows for mitigation of those paths. Further, the mitigation run now includes virtual as well as physical bids and clears the market to bid-in demand instead of forecast load. Finally, the automated approach bases mitigation on the higher of LMP or the mitigated generator's cost (default energy bid), whereas previous mitigation only used cost.

The ISO's Department of Market Monitoring (DMM) reported that the automation improved mitigation accuracy. In the second quarter of 2012, the predicted congestion in the new system was accurate 93 percent of the time, up from 45 percent for the same quarter in 2011. The new methodology over-predicted congestion three percent of the time and under-predicted four percent of the time, a significant improvement from over the 18 percent and 37 percent, respectively, that occurred in the second quarter of 2011. Under-prediction is under-identification of potential local market power. In such cases, the exercise of local market power may occur but not be mitigated.

The Commission also approved a proposal by CAISO to expand mitigation of exceptional dispatches and residual imbalance energy in specific circumstances when there is the potential to exercise market power.<sup>63</sup>

61 *ISO New England Inc.*, Docket No. ER12-1242-000 (2012) (unpublished letter order).

62 *California Independent System Operator Corp.*, 138 FERC ¶ 61,154 (2012). See also "California ISO Q2 2012 Report on Market Issues and Performance", August 14, 2013, CAISO web site, <http://www.caiso.com/Documents/2012SecondQuarterReport-MarketIssues-Performance-August2012.pdf>, accessed March 28, 2013.

63 *California Independent System Operator Corp.*, 141 FERC ¶ 61,069 (2012).

Exceptionally dispatched resources are those generators dispatched manually outside the market model runs. The ISO issues exceptional dispatch instructions primarily to manage transmission constraints that are not modeled in market software, but may also do so for reliability reasons or because of software failures.

## MISO

In August 2012, the Commission approved a mitigation mechanism for MISO with regard to offers for resources committed to address voltage or local reliability concerns.<sup>64</sup> This change allows MISO to use conduct thresholds to prevent market participants from abusing their market power by submitting bid levels or bidding parameters substantially different from those in their reference levels.

## SPP

In October 2012, the Commission approved a revised market power mitigation plan for SPP as part of its new Integrated Marketplace.<sup>65</sup> The plan seeks to reduce anticompetitive behavior in the day-ahead market. Once implemented in 2014, the Integrated Marketplace will include day-ahead and real-time energy and operating reserve markets. Therefore, the Commission stated that a more comprehensive monitoring and mitigation program is appropriate, including the addition of frequently constrained area mitigation.

## Order No. 755: Frequency Regulation

In October 2011, the Commission issued Order No. 755, which revised regulations governing compensation of frequency regulation resources.<sup>66</sup> Frequency regulation is an ancillary service that protects the grid by correcting frequency deviations through balancing resources with load. An automatic control signal directs resources to adjust output to maintain system frequency. Besides electric generators, resources that can provide this service include demand response, flywheels, and other storage devices.<sup>67</sup> The Commission found that existing compensation methods for such service in RTO and ISO markets failed to acknowledge key elements such as the degree of output change provided by resources whose output is able to increase or decrease rapidly. The Commission also found that the practices of some RTOs and ISOs resulted in economically inefficient dispatch of frequency regulation resources.

The rule revision ensures frequency regulation service providers receive just and reasonable compensation by requiring RTOs and ISOs to compensate frequency regulation resources based on the actual service provided using a two-part payment methodology. Providers will receive a capacity payment that includes the foregone revenue of standing ready to provide service when needed. In addition, a performance payment will reflect the amount of work resources perform in real-time in response to the grid operator's signal. The market rule changes that followed the

<sup>64</sup> *Midwest Independent Transmission Operator*, 140 FERC ¶ 61,171 (2012)

<sup>65</sup> *Southwest Power Pool*, 141 FERC ¶ 61,048 (2012), *order on reh'g*, 142 FERC ¶ 61,205 (2013).

<sup>66</sup> *Midwest Independent Transmission Operator*, 140 FERC ¶ 61,171 (2012).  
*Southwest Power Pool*, 141 FERC ¶ 61,048 (2012), *order on reh'g*, 142 FERC ¶ 61,205 (2013).

<sup>66</sup> *Frequency Regulation Compensation in the Organized Wholesale Power Markets*, Order No. 755, FERC Stats. & Regs. ¶ 31,324 (2011), *order denying reh'g*, Order No. 755-A, 138 FERC ¶ 61,123 (2012), *order on compliance filings*, 141 FERC ¶ 61,105 (2012).

<sup>67</sup> A flywheel is an energy storage device capable of rapidly responding when needed. This makes it suitable to moderate fluctuations in grid demand.

order should result in improved ability to align compensation with a resource's rapid output adjustment ability and accuracy.

Compliance filings submitted by CAISO and MISO have been approved by the Commission.<sup>68</sup> NYISO, ISO-NE, and PJM submitted amended compliance filings on January 15, February 6, and February 22, 2013, respectively, which are pending before the Commission.

### **Order No. 764: Integration of Variable Energy Resources**

In June 2012, the Commission issued a final rule, Order No. 764, to facilitate the integration of variable energy resources in electricity markets.<sup>69</sup> A variable energy resource is an electricity generator whose output variability is beyond a facility owner or operator control. The difficulty of predicting and controlling the output of variable resources presents challenges to their operators and grid operators. The rule reformed existing market rules designed for resources whose output could be held relatively constant and increased or decreased to follow load changes.

Implementation of the rule will reduce costs and removes barriers to the integration of variable energy resources through two new reforms. The rule requires each public utility transmission provider to offer transmission scheduling on 15-minute intervals. By offering scheduling in intervals of less than an hour, transmission customers should be better equipped to

manage changes in wind output. Specifically, shorter offering schedules reduce transmission customers' exposure to excessive imbalance service charges caused by an inability to adjust service schedules within an operating hour. The rule also requires interconnection customers using variable energy resources to provide meteorological and forced outage data to the transmission provider for power production forecasting. The Commission found that such data should improve transmission providers' ability to manage resource variability.

### **Order No. 768: Electricity Market Transparency Provisions**

In September 2012, the Commission issued Order No. 768, to facilitate price transparency in electricity markets.<sup>70</sup> Public access to electric sales and transmission information improves market participants' ability to evaluate supply and demand fundamentals and price interstate electric market transactions. It also enhances the Commission's ability to evaluate price formation and market concentration and to detect exercises of market power or manipulation.

The rule revised the Commission's regulations by requiring entities that are excluded from the Commission's jurisdiction under Federal Power Act (FPA) section 205 and have more than a *de minimis* market presence to file EQRs with the Commission.<sup>71</sup> These entities include publicly-owned utilities, municipal utilities, public utility districts, rural cooperatives, and Federal entities (*i.e.*, non-public utilities).

<sup>68</sup> *California Independent System Operator Corp.*, 142 FERC ¶ 61,233 (2013). *Midwest Independent Transmission Operator*, Docket No. ER12-1664-001 (2013) (unpublished letter order).

<sup>69</sup> *Integration of Variable Energy Sources*, Order No. 764, 139 FERC ¶ 61,246 (2012). 77 FR 41482 (July 13, 2012), FERC Stats. & Regs. ¶ 31,331 (2012), *order on reh'g*, Order No. 764-A, 141 FERC ¶ 61,232 (2012).

<sup>70</sup> *Electricity Market Transparency Provisions of Section 220 of the Federal Power Act*, Order No. 768, 77 FR 61896 (Oct. 11, 2012), FERC Stats. & Regs. ¶ 31,336 (2012), *order on reh'g*, Order No. 768-A, 143 FERC ¶ 61,054 (2013).

<sup>71</sup> 16 U.S.C. 824d.

### ***Order No. 770: Revisions to Electric Quarterly Report Filing Process***

In November 2012, the Commission issued a final rule, Order No. 770, which amends the process for filing EQRs to accommodate changes in technology while providing flexibility for EQR filers.<sup>72</sup> Among other measures, the EQR provides transparency with respect to electricity prices and contract information. Because technology changes will render the current filing software ineffective, outmoded, and unsustainable, the rule discontinued use of Commission-distributed software and adopted a web-based EQR filing approach. This will allow a public or non-public utility to file directly through the Commission's website via a web interface or by submitting an Extensible Markup Language-formatted file. Dual options provide added flexibility to accommodate EQR filers' technical preferences.

### ***Order No. 760: Enhancement of Market Surveillance and Analysis through Ongoing Electronic Delivery of Data***

In April 2012, the Commission issued a final rule, Order No. 760, which requires ongoing data delivery from RTOs and ISOs to enhance the Commission's electric market surveillance and analysis functions.<sup>73</sup> Improved market oversight will facilitate the Commission's development and evaluation of its policies and regulations. Also, it will bolster Commission efforts to detect ineffective market rules and anti-competitive or manipulative behavior. The required data includes

physical and virtual offers and bids, marginal cost estimates, financial transmission rights, and uplift and interchange prices. The rule attempts to minimize the burden on RTOs and ISOs by phasing-in implementation requirements, not requiring uniform data formatting, and replacing burdensome ad hoc data requests.

### ***Order No. 771: Availability of E-Tag Information to Commission Staff***

In December 2012, the Commission issued a final rule, Order No. 771, to provide itself with access to complete electronic tags (e-Tags) to enhance its market surveillance and enforcement endeavors.<sup>74</sup> E-Tags are used to schedule the transmission of electric power interchange transactions in electricity markets.

Access to e-Tag data will aid the Commission in monitoring market efficiency, better inform Commission policies and decision-making, and help in detecting market manipulation and anticompetitive behavior. Specifically, e-Tag data better equips Commission staff to identify interchange schedules that appear anomalous or inconsistent with rational economic behavior. E-Tag access also provides more complete information for audits, investigations, and evaluating power flows and market rules.

<sup>72</sup> *Revisions to Electric Quarterly Report Filing Process*, Order No. 770, 77 FR 71288 (Nov. 30, 2012), 141 FERC ¶ 61,120 (2012).

<sup>73</sup> *Enhancement of Electricity Market Surveillance and Analysis through Ongoing Electronic Delivery of Data from Regional Transmission Organizations and Independent System Operators*, Order No. 760, FERC Stats. & Regs. ¶ 31,330 (2012).

<sup>74</sup> *Availability of E-Tag Information to Commission Staff*, Order No. 771, 77 FR 76367 (Dec. 28, 2012), FERC Stats. & Regs. ¶ 31,339 (2012).



## ACKNOWLEDGEMENTS

Development of the 2012 State of the Markets Report was a group effort that required the teamwork and substantial efforts of staff in the Office of Enforcement's Division of Energy Market Oversight.

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