U.S. Department of Energy
Washington, DC 20585

Date: **July 24, 2014**

To: **Members of the Public**

From: **Quadrennial Energy Review Task Force Secretariat and Energy Policy and Systems Analysis Staff, United States Department of Energy**

Re: **July 28 Stakeholder Meeting on Natural Gas – Electricity Interdependence**

1. Introduction

On January 9, 2014, President Obama issued a Presidential Memorandum establishing a Quadrennial Energy Review (QER). The Secretary of Energy provides support to the QER Task Force, including coordination of activities related to the preparation of the QER report, policy analysis and modeling, and stakeholder engagement.

On Monday, July 28, 2014, at 9:00 a.m. MDT, the U.S. Department of Energy (DOE), acting as the Secretariat for the QER Task Force, will hold a public meeting to discuss and receive comments on issues surrounding the growing interdependence of natural gas and electricity. Two expert panels will explore interdependencies between the natural gas and electricity sector, and there will be an opportunity for public comment via an open microphone session beginning at 12:15 p.m. The event will take place in the St. Cajetan's Center of the Auraria Campus of the University of Colorado at Denver, 1190 9th Street, Denver, Colorado. The session will also be webcast at www.energy.gov/live. Written comments can be submitted to QERcomments@hq.doe.gov.

The Secretariat will also convene related meetings to discuss infrastructure constraints (August 8 in Bismark, North Dakota); infrastructure siting (August 21 in Cheyenne, Wyoming); and electricity transmission, storage, and distribution issues in the eastern U.S. electricity interconnection (September 8 in Neward, New Jersey). More information on these and other QER public meetings will be posted at www.energy.gov/qer as it becomes available.

2. Framing the Issues

The natural gas and electricity infrastructure networks are vital to the country's economy and way of life. Natural gas is directly used in our homes, businesses, and industry, and is also increasingly used to generate electricity. This increased use in the power sector has been driven by lower natural gas prices spurred by advances in unconventional natural gas extraction techniques, the retirement of an aging coal fleet, various environmental regulations, and the use of fast-ramping natural gas power plants to back up increasing amounts of intermittent wind and solar power.

Though the electricity and natural gas pipeline industries have operated together for decades, the increasing absolute demand for natural gas in the power sector and the fuel's increased share in the power generation mix have heightened the interdependence between systems. That growing interdependence has created more frequent reliability challenges in recent years, in which power generators have to curtail electricity services for lack of natural gas, leading to blackouts or rolling brownouts. Interdependence issues often come to the fore during extreme cold weather, electricity outages, or gas supply disruptions.

In February 2011, severe cold weather increased heating demand for natural gas while simultaneously increasing natural gas consumption for electricity production in the Southwest. At the same time, wellhead freeze-offs – during which small amounts of water and other liquids in production wells freeze and block the flow of natural gas – in West Texas reduced natural gas availability in the region. This combination of lower supply and higher demand led to curtailments of natural gas deliveries to 50,000 customers with firm and interruptible capacity contracts, including several power generators. In all, 4.4 million electric customers were affected by rolling blackouts.[1]

More recently, the weather events of January 2014 illustrated the challenges of electricity and natural gas coordination. On January 7, in the midst of the polar vortex cold weather event, electricity system operators across the eastern half of the United States struggled to maintain reliability. In particular, PJM, the electricity system operator (ISO) responsible for the Mid-Atlantic region, experienced record demand and simultaneous high forced-outage rates of generators due to mechanical failures and fuel supply issues. Of the 22% of PJM's generation capacity that was unavailable to meet peak load, a quarter of the outages were due to the inability or unwillingness of gas generators to secure natural gas transportation nominations (gas nominations will be discussed below), a result of the tremendous heating load and commensurate lack of available interruptible capacity on the pipeline system.[2]

3. Drivers of Gas–Electricity Interdependence Challenges

Demand for natural gas from the power sector has grown dramatically over the past two decades. In 1990, natural gas generated just 12% of electrical energy in the United States; that number steadily increased 27% in 2013. Meanwhile, coal has seen its share fall from 52% to 39% over the same period (Figure 1).[3]

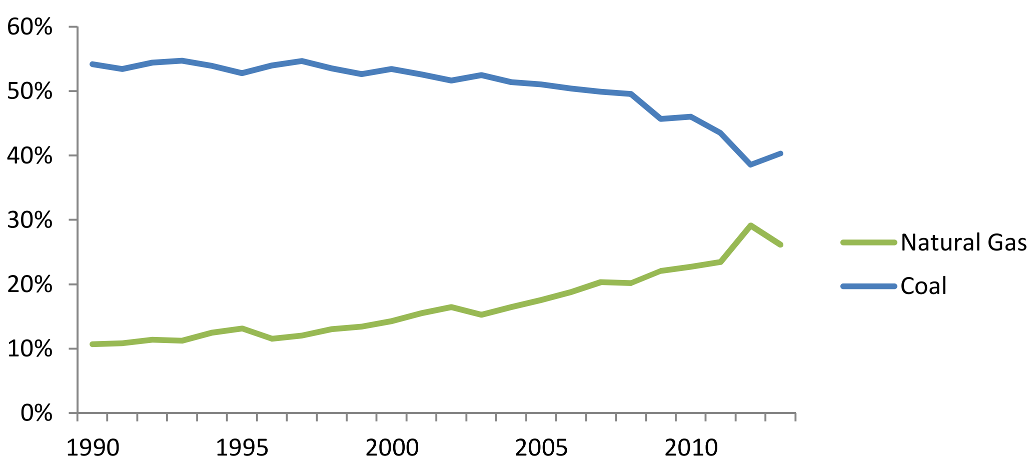

Figure 1: Annual electricity production by coal and natural gas as a percentage of total.[4]

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[1] Federal Energy Regulatory Commission & North American Electric Reliability Corporation, "Report on Outages and Curtailments During the Southwest Cold Weather Event of February 1-5, 2011," August 2011, http://www.ferc.gov/legal/staff-reports/08-16-11-report.pdf (accessed July 7, 2014).
[2] PJM Interconnection, "Analysis of Operational Events and Market Impacts During the January 2014 Cold Weather Events," May 8, 2014.
[3] U.S. Energy information Administration, "Table 7.2a Electricity Net Generation: Total (All Sectors)," *Monthly Energy Review,* June 2014.
[4] Ibid.

The shale gas revolution, perhaps the major driver of increased natural gas use in power generation, has resulted a 35 percent rise in dry natural gas production between 2005 and 2013, about a 55 percent fall in average annual spot natural gas prices (Figure 2). Between 2003 and 2007, the United States appeared to have entered a time of increasing scarcity of natural gas. Prices stayed mostly in a range between $4 and $7 per MMBtu – except for an excursion into considerably higher prices after Hurricanes Katrina and Rita (Figure 2). In 2008, prices for almost all commodities rose to extremely high levels duirng the first half of the year and then crashed to very low levels as a result of the financial crisis. This extreme volatility masked a fundamental change in natural gas prices. Between 2007 and 2009, the "Shale Era" arrived in earnest. As a result, after 2008, natural gas prices have traded mainly in a band between $2 and $5 per MMBtu. Very low prices in the spring of 2012 reflected a warm winter that left storage considerably fuller than usual. This meant less demand for natural gas to inject into storage in the spring and summer of 2012, and spot prices fell to the point that natural gas sometimes competed with inexpensive Western coals for electric generation loads in markets like the Southeast. Conversely, after the "Polar Vortex" of 2013-2014, demand for gas to inject into storage has been high, and prices have remained at the high end of their multi-year range. Even as prices fell in the Shale Era, production continued to rise, reaching 69 Bcf per day in April 2014, an increase of 35 percent over the January 2004 level.

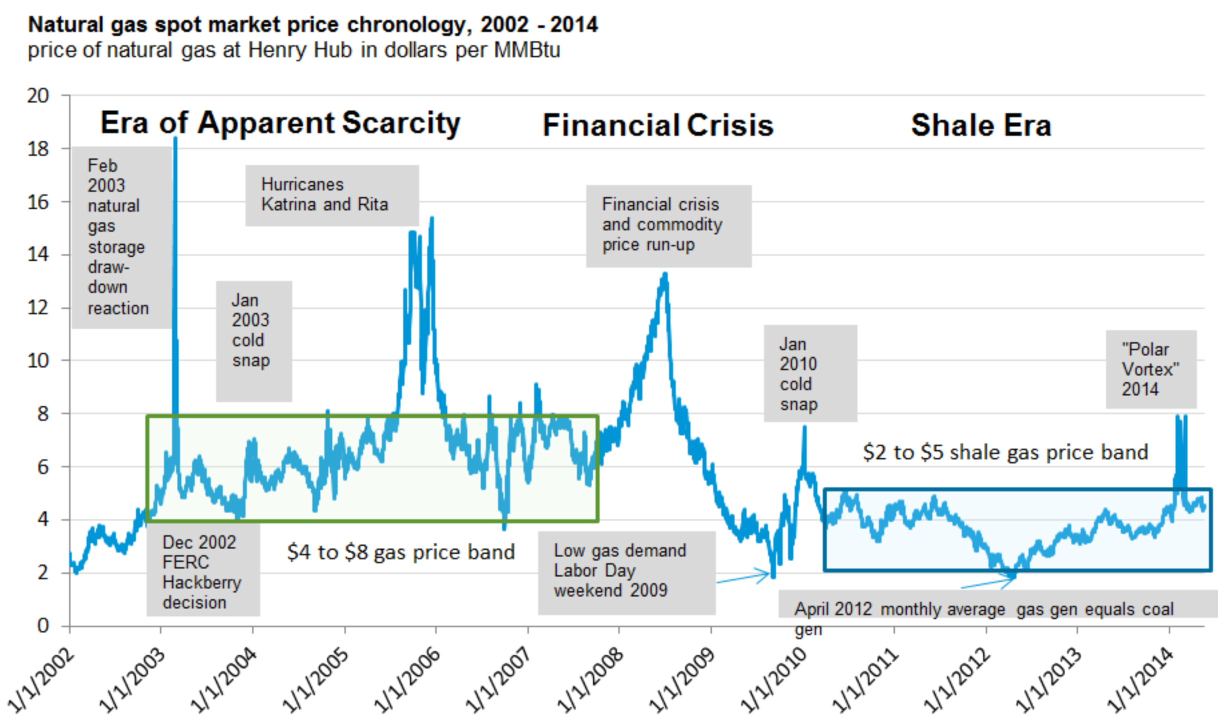

Figure 2. Natural gas spot market price chronology, 2002–2014. ***Source: U.S. Energy Information Administration based on Ventyx.***

Natural gas prices have not been the only driver of fuel switching by power plants. Recent environmental regulations at the local, state, regional, and federal levels have encouraged switching to fuels with lower carbon emissions profiles, including natural gas and renewables. Implementation of the Regional

Greenhouse Gas Initiative (RGGI), the country's first voluntary emissions cap-and-trade program, by New England states coincided with a further decline in coal generation and a commensurate increase in natural gas use: states in the RGGI program saw coal's share of their generation mixes fall from 23% to 9% from 2005 to 2012, while natural gas rose from 25% to 44% over the same period.[5]

Balancing intermittent renewable resources requires complementary power generation that can quickly ramp up and down to follow net load – a key advantage of natural gas technologies. As system planners and operators look to a future of higher penetration of renewables, the importance of natural gas in their fleet is likely to grow. NREL's Renewable Electricity Futures Study forecasts that natural gas combustion turbines will be the predominant complementary generation capacity for intermittent renewables, owing to their relatively low capital cost and high degree of operational flexibility.[6] Some solar plants in the United States already use natural gas for back up power, and new hybrid technologies combine natural gas combined cycle plants with solar and wind.[7]

The same economic, environmental, and grid flexibility factors that led to past investment in natural gas generation will likely continue to drive a shift away from coal and nuclear generation. The U.S. Energy Information Administration projects coal-fired generator retirements of 60 gigawatts (GW) between now and 2020, representing 7% of 2013 peak demand and projects new generation capacity investments to be dominated by natural gas (Figure 3).[8]

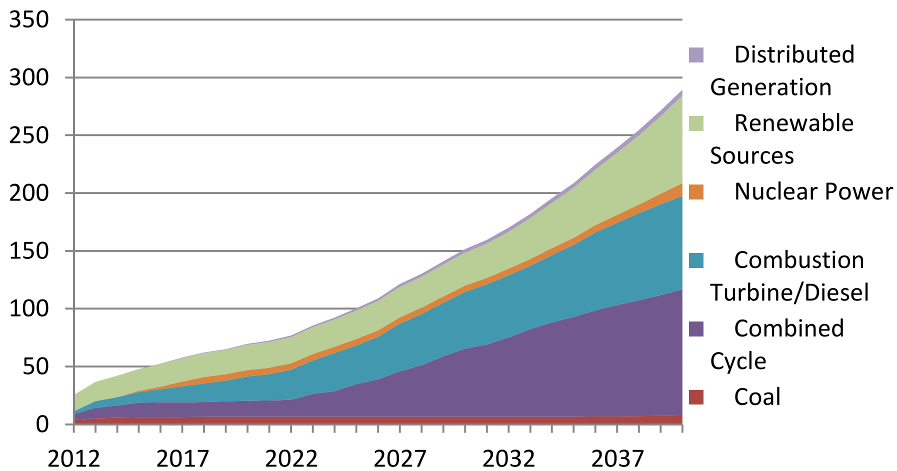

Figure 3: Predictions of the U.S. Energy Information Agency, depicting little new investment in coal in the next few decades.[9]

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[5] U.S. Energy Information Administration, "Lower emissions cap for Regional Greenhouse Gas Initiative takes effect in 2014," *Today in Energy,* February 3, 2014, available at: http://www.eia.gov/todayinenergy/detail.cfm?id=14851 (accessed July 7, 2014).

[6] NREL, "Renewable Electricity Futures Study Volume 1, Exploration of High-Penetration Renewable Electricity Futures," 2012.

[7] http://www.energybiz.com/magazine/article/234777/natural-gas-working-renewables

[8] U.S. Energy Information Administration, "AEO2014 projects more coal-fired power plant retirements by 2016 than have been scheduled," *Today in Energy*, February 14, 2014, available at: http://www.eia.gov/todayinenergy/detail.cfm?id=15031# (accessed July 7, 2014).

[9] U.S. Energy Information Administration, "Table 9. Electricity Generating Capacity," *Annual Energy Outlook*, 2013.

In addition to the growing absolute demand for natural gas in the long term, the way in which natural gas generators consume gas causes operational challenges for the interstate pipeline system. Power plants use large amounts of natural gas over short periods of time throughout the day. A generator that is only needed to meet daily peak demand may not be dispatched until early afternoon, consuming no gas in one moment then drawing very large volumes the next. These swings in natural gas demands from pipeline infrastructure can be very large: at full output, one 700 megawatt (MW) natural gas power plant consumes as much natural gas on an hourly basis as the entire heating demand of a small city.[11]

Natural gas demand from the power sector and local distribution companies (LDCs) was traditionally complementary over the course of a year (Figure 4): LDC demand peaked during the winter as residential consumers used gas to heat their homes, while power demand peaked in the summer, with natural gas power plants traditionally providing peak generation on the highest-demand days. Now, however, natural gas power plants are increasingly dispatched year-round, causing these two largest consumers of natural gas to compete for pipeline capacity over the winter months when reliability events are most likely to occur. Furthermore, unlike coal, oil, and nuclear resources, natural gas is often uneconomical to store onsite, requiring generators to consume fuel as soon as it arrives. This just-in-time aspect of natural gas exacerbates the impacts of possible disruptions along the transmission, storage and distribution network.

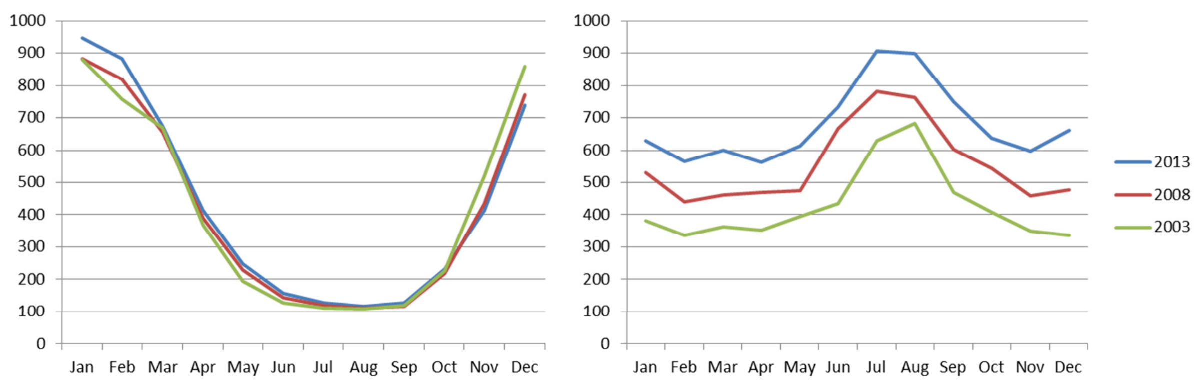

Figure 4: Monthly natural gas consumption in billion cubic feet (Bcf) by the residential sector (left) and power sector (right).[12]

As pipeline operators continue to accommodate the needs of all classes of customers, the changing characteristics of gas supply and demand has led to reliability challenges for both industries that are likely

[11] A 700 MW power plant with a heat rate of 8,039 British thermal units per kilowatt hour (Btu/kWh) consumes approximately 5,600 million Btu of natural gas per hour. The average American household consumed 198,000 Btu per day in 2009. Therefore a 700 MW power plant would hourly consume the same amount of gas as 38,000 homes. U.S. Energy Information Agency, "How much coal, natural gas, or petroleum is used to generate a kilowatt hour of electricity?" *Frequently Asked Questions,* available at: http://www.eia.gov/tools/faqs/faq.cfm?id=667&t=2 (accessed July 10, 2014); American Gas Association, "How to Measure Natural Gas," available at: http://www.aga.org/KC/ABOUTNATURALGAS/ADDITIONAL/Pages/HowtoMeasureNaturalGas.aspx (accessed July 10, 2014).

[12] U.S. Energy Information Agency, "Natural Gas Consumption by End Use," available at: http://www.eia.gov/dnav/ng/ng_cons_sum_dcu_nus_m.htm (accessed July 11, 2014).

to worsen unless regulatory and policy changes are made to harmonize these two interdependent systems. What those changes are and which stakeholders are best suited to improve gas and electricity coordination challenges are outstanding questions that have garnered national attention.

Regionality of Interdependence Issues

Though reliance on natural gas for power generation has grown nationwide, the nature of interdependence issues varies widely across regions. Some regions rely on organized electricity markets operated by an Independent System Operator or a Regional Transmission Organization (ISO/RTO). Each of these regional electricity markets has unique rules that constrain the operation of merchant natural gas generators and their communications with the pipelines that serve them. Areas that do not rely on markets are dominated by vertically integrated utilities without the constraints imposed by RTO/ISOs. These utilities have more options for passing on costs addressing interdependence issues to their ratepayers.

In addition to varying rules and regulations, different regions have varying levels of natural gas dependence, penetration of intermittent renewable, gas production capacity, and pipeline infrastructure. Natural gas generation contribution to electricity demand is as low as 6% in some regions and as high as 52% in others (Figure 5). The geographic dispersion of recently tapped unconventional natural gas supplies has radically changed production locations, leaving some regions more or less dependent on interstate pipelines to meet the needs of the power sector.

New England, often cited as having the most acute and longest-running challenges with electricity and natural gas interdependence issues, has experienced a large increase in natural gas use in all sectors over the last several decades. Despite large volumes of new unconventional gas resources flowing from the Marcellus Shale in nearby Pennsylvania, severe pipeline constraints are putting upward pressure on prices and threatening system reliability.[13]

In the Midwest, the Midcontinent Independent System Operator (MISO) forecasts significant coal plant retirements in the near future; these plants will likely be replaced by natural gas power plants – a process that will potentially be accelerated by federal air regulations. Alarmed by projections of a much more natural gas-dependent generation portfolio and the changing utilization of interstate pipelines, MISO conducted a thorough review of pipeline infrastructure adequacy. Results projected that new investments of over $3.0 billion dollars will be required to serve the incremental natural gas transmission needs of the power sector.[14]

[13] For more detailed discussion of infrastructure constraints in the New England area, see the documents relating to April 21, 2014, Quadrennial Energy Review Stakeholder Meeting, "New England Regional Infrastructure Constraints," located at: http://energy.gov/epsa/downloads/qer-public-meeting-providence-ri-hartford-ct-new-england-regional-infrastructure.

[14] Midcontinent Independent System Operator, "Gas-Electric Infrastructure Analyses I, II," February 2, 2013, available at: https://www.misoenergy.org/Library/Repository/Communication%20Material/One-Pagers/Gas%20Infrastructure%20Analyses.pdf (accessed July 22, 2014).

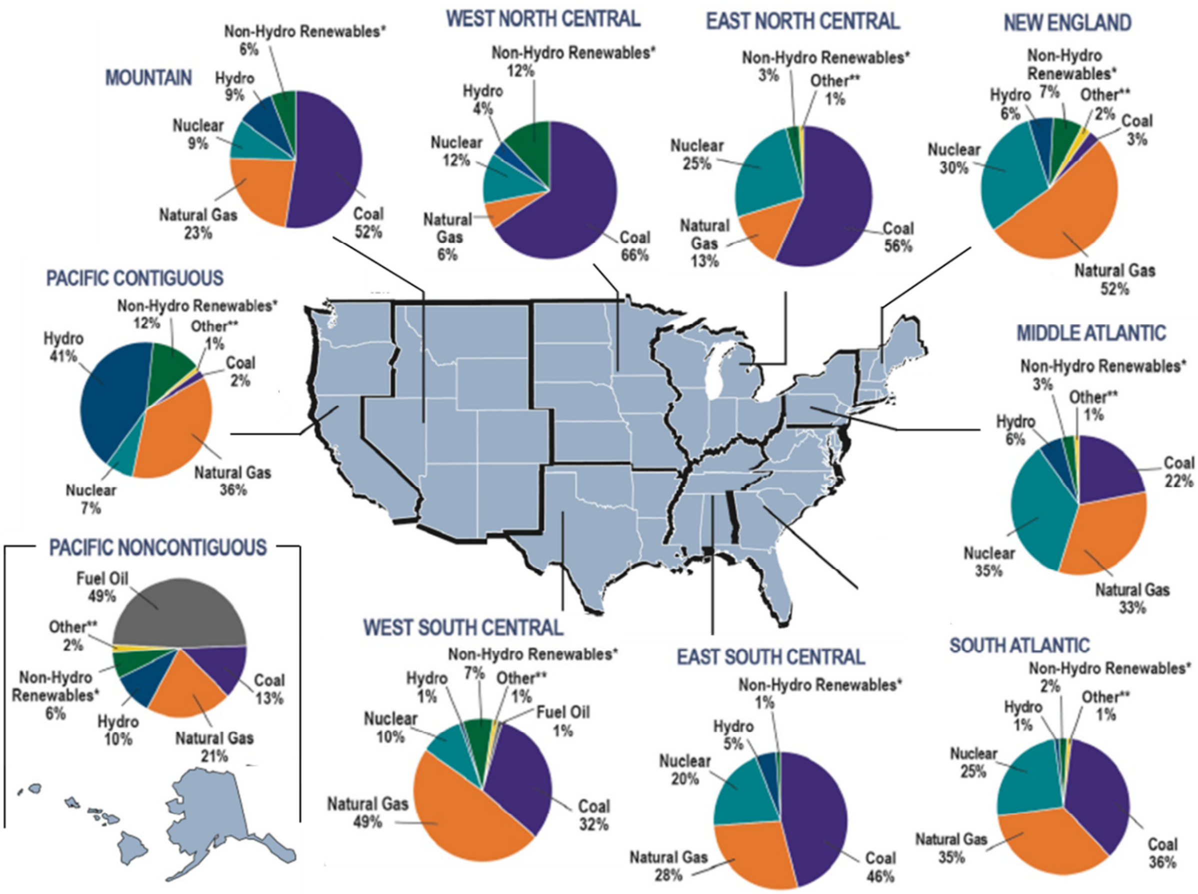

Figure 5: Regional reliance on natural gas (indicated with orange) as a percentage of generation varies widely across the United States.[15]

In Texas, reliability concerns are driven by extreme weather events: tropical cyclones in the Gulf of Mexico can massively reduce natural gas availability, and rare extreme cold events have resulted in large loss of generation capacity coupled with high natural gas demand in the residential sector.

The Southeast has largely avoided reliability challenges posed by gas-electric interdependence. The region is characterized by the absence of a regional wholesale electricity market. The, large, vertically integrated utilities in the Southeast , therefore operate withoutregional wholesale market rules and have greater autonomy over their natural gas transportation contract portfolios, which exerts a direct impact on infrastructure investment and operation, as discussed below.

Given the wide variations in regional vulnerabilities to gas and electricity interdependence, as well as the regional variation in market and operational structures, the question remains as to what role the federal government should play in advancing meaningful solutions to these coordination challenges.

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[15] Edison Electric Institute, "Different Regions of the Country Use Different Fuel Mixes to Generate Electricity," February 2014, available at: http://www.eei.org/issuesandpolicy/generation/fueldiversity/Documents/map_fuel_diversity.pdf (accessed July 16, 2014).

4. Operational Issues: Mismatched Electricity and Pipeline Capacity Markets

The electricity and natural gas pipeline industries both recognize that each speaks another language; distinct meanings exist for common terms such as transportation, capacity, and day, and operators of both systems rely on some unique words for industry-specific operational concepts.[18] The differences in their language reflect the differences in their system operations. Each industry has a unique scheduling procedure, market timings, communication protocols, and service mandates. Despite these differences, the two industries have operated in parallel for decades with relative ease, but the changing nature of electricity sector demand on natural gas infrastructures has made these differences increasingly problematic for maintaining reliability of both systems.

Large-scale consumers of natural gas schedule fuel transportation daily through a nomination process that is uniform across the interstate pipeline industry. According to this common scheduling process, customers have the opportunity every morning, during the Timely Nomination Cycle, to nominate their natural gas shipments for the next day. The following morning, the gas flows to those customers whose nominated capacity was confirmed by the pipeline operator. The common nomination schedule also includes an evening nomination opportunity and regular intra-day opportunities that allow customers to change or request nominations on a shorter time horizon, but these can only be fulfilled if the pipeline has the operational flexibility to meet these requests.

Electricity operation and market days are set on a regional basis. In the morning, generators submit their offers to the electricity system operators. Those offers are confirmed in the afternoon, and the electricity operations begin very early the following morning. Figure 6 includes the timeline for both the natural gas and electricity scheduling processes.

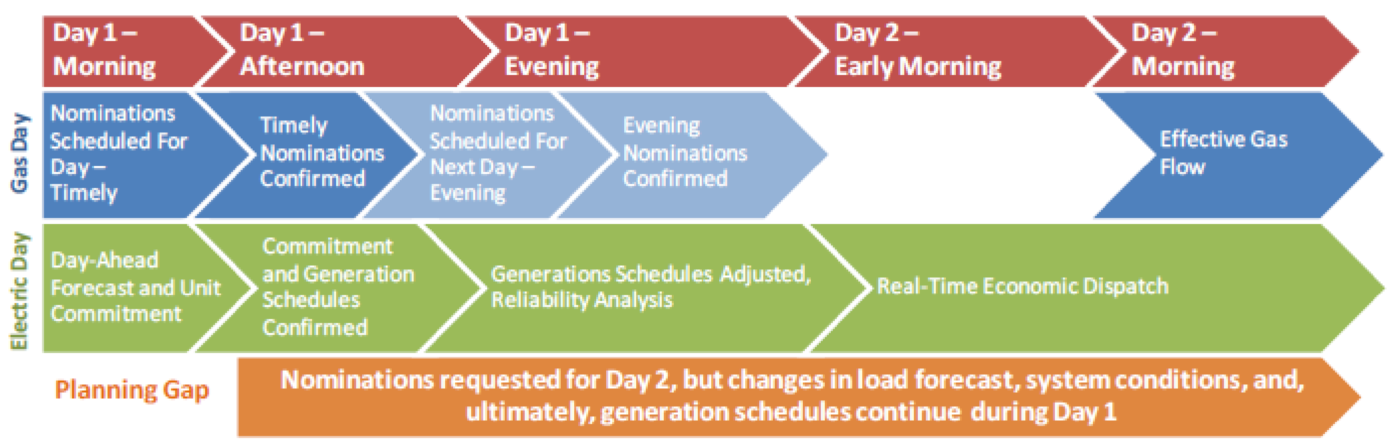

Figure 6: An example of gas and electric day scheduling processes.[19]

[18] For several examples of the distinct vocabularies used by the electricity and natural gas industries, see Cochrane, Anna, "Gas-Electric Interdependencies: Introduction," presented at NARUC Winter Committee Meetings, February 5, 2012, available at: http://www.narucmeetings.org/Presentations/Interdependencies%20Cochrane.pdf (accessed July 22, 2014).

[19] NERC (North American Electric Reliability Corporation), "2011 Special Reliability Assessment: A Primer of the Natural Gas and Electric Power Interdependency in the United States," December 2011.

There are two commonly acknowledged problems with the alignment of these two markets. The first is that the gas day begins mid-morning, well after the electricity day begins. To accommodate the morning load ramp, generators must schedule gas for two consecutive gas days: one nomination to accommodate the very early morning and a second that begins sometime mid-morning, near the electricity system peak (Figure 7). When gas supplies or electricity generation are tight, unexpected system failures can arise simply through the burden of complex coordination procedures.

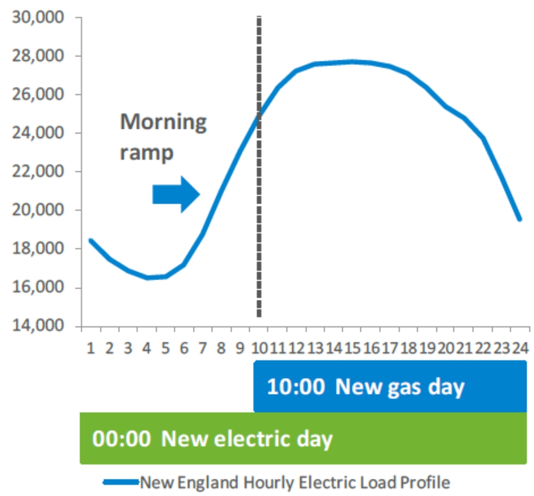

Figure 7: The natural gas day, which starts during the electricity morning demand ramp, a critical point in the electricity dispatch scheduling day.[20]

Another commonly cited operational coordination issue is that generators are forced to submit their gas offers before they know what their electricity generation obligations will be, and they must submit their electricity offers before they know the price at which they will be able to secure natural gas. If either of the markets does not clear in the generator's favor, the operator is forced to trade gas on the intraday market, where prices where markets are less liquid and not as efficient because of a paucity of counterparts.

To aid in harmonizing the electricity and natural gas markets, the Federal Energy Regulatory Commission (FERC) has recently issued a Notice of Proposed Rulemaking (NOPR) that seeks to better align the gas and electric days and to offer generators more opportunities for intraday trading. The proposed market changes are to move the natural gas day earlier to be more in line with that of electricity, move the Timely Nomination Cycle to a later time, and increase opportunities for intraday capacity nominations.[21]

[20] Kevin Kirby, "Working to Solve Gas-Electric Challenges in New England," ISO New England, presentation, November 15, 2013, available at: http://www.iso-ne.com/pubs/pubcomm/pres_spchs/2013/kirby_roundtable_nov2013.pdf (accessed July 14, 2014).
[21] U.S. Federal Energy Regulatory Commission, "FERC Proposes Reforms to Improve Gas-Electric Coordination," news release, March 20, 2014.

Operational Flow Orders

Much as power system operators work to maintain a particular grid frequency for reliability, pipeline operators work to maintain minimum pressures on their pipelines for the same reason. When operational pressure is threatened because of unscheduled demands on the pipeline or unplanned operational contingencies, pipeline operators can issue operational flow orders that restrict the amount of fuel that customers consume to pre-specified increments. For example, if a natural gas power plant operator is scheduled to have 24 units of gas delivered on a particular day to generate electricity for only a few hours, the pipeline operator could – when pipeline system reliability is threatened – restrict the generator's consumption to one unit per hour, dramatically lowering the electricity generator's potential output. Though often necessary to maintaining pipeline integrity during emergency events, this type of usage restriction can inhibit the ability of many generators over a large geographic area to meet their changing gas demands throughout the day, threatening power system integrity.

Contracts and Fuel Delivery Priorities

Pipeline operators offer several types of pipeline transportation contracts to provide a range of services and delivery priorities, and each of these contracts has repercussions for deliverability of fuel and long-term pipeline investment. Three types of transportation contracts are widely available and are used to transport the vast majority of natural gas on interstate pipelines: primary firm, secondary firm, and interruptible.[22]

Primary firm contracts are the highest priority and the most expensive of the three common contract types.[23] Holders of primary firm capacity sign long-term agreements for the right to transport fuel daily up to their contracted capacity and pay a fixed subscription fee for that capacity. Holders of primary firm capacity can sell unused portions of their transportation allotments on a secondary capacity release market. Once sold, these contracts are called secondary firm and are second in delivery priority only to primary firm contracts. Unlike primary firm, these contracts are bought and sold on a short-term basis and require no subscription fee for their use. Interruptible contracts are for pipeline capacity that remains available after all firm contracts are honored. As the name implies, these contracts are of the lowest delivery priority and can be interrupted during high demand periods or emergencies to maintain obligations to higher-priority customers or to maintain pipeline reliability. As with secondary firm, interruptible transportation is generally short-term, and it is the least expensive of the three main types of transportation options.

LDCs rely on primary firm capacity to cover the needs of their residential and commercial customers. Many gas-fired power plants rely on short-term interruptible and secondary firm capacity contracts to meet their daily gas shipping needs. ISOs/RTOs that operate regional wholesale electricity markets allow

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[22] In addition to these three primary contracting types, the natural gas pipeline industry offers an array of natural gas transportation options for their customers that vary in cost, flexibility, and delivery priority. Most of these other options can be considered sub-classes of the three mentioned here. For a more in-depth discussion of the range of contract types offered to pipeline customers, see Levitan & Associates, Inc., "Gas-Electric System Interface Study: Existing Natural Gas-Electric System Interfaces," Eastern Interconnection Planning Collaborative, April 4, 2014.

[23] No-notice primary firm capacity is the highest priority of all, allowing the subscriber to make no announcement of what the subscriber intends to move along the pipeline. However, the class of firm contracts in aggregate is the most expensive and highest priced of the three classes discussed here.

generators to offer only their variable cost into the electricity markets, and short-term capacity contracts can be included in these bids.

Operationally, reliance on short-term interruptible capacity contracts exacerbates constraints that can occur during unexpected reliability events. Natural gas generators can be first to lose their shipping privileges when pipeline capacity is limited. This is problematic, as natural gas constraints often occur during precisely the time when electricity is needed the most; high heating demand for natural gas during extreme cold weather events can prevent the power system from providing the electricity needed to operate residential and institutional heating systems.

5. Efforts to Address Natural Gas and Electricity Interdependencies

The reliance on short-term contracts in the power sector, particularly in areas with regional electricity markets, has serious implications for pipeline capacity investment. A key question for policy makers is whether the correct market and regulatory incentives exist to ensure that adequate pipeline infrastructure is built to reliably and affordably meet evolving electricity and natural gas industry needs over the coming years and decades.

When planning a new pipeline expansion project, investors and regulators look for pipeline customers willing to sign long-term contracts to minimize the risk of these capital-intensive assets becoming stranded and unused; primary firm contracts held by LDCs have historically paved the way for new infrastructure investment. However, the growing use of natural gas in the power sector and generator reliance on interruptible contracts does not incentivize new pipeline investment; these circumstances have instead led to higher competition for short-term capacity and diminishing available pipeline resources.

Consumers bear the cost of reliability incidents and higher energy prices that result from pipeline scarcity. In regions lacking electricity markets, vertically integrated utilities can buy natural gas capacity on behalf of electricity consumers. In regions with electricity markets, however, consumers have no way to reflect their willingness to pay for new pipelines, though the cost of new infrastructure investment might vastly outweigh the congestion costs that it alleviates. In this context, some industry participants advocate for electricity system operators to buy pipeline capacity on their generators' behalf, while others suggest that electricity market design should be changed to encourage generators to purchase capacity directly. For example, to address the natural gas infrastructure constraints that led to severe electricity curtailments over the last decade in New England, the region's six governors came together under the auspices of the New England States Committee on Electricity to conduct a comprehensive study of interdependence issues and propose a unique capacity purchasing concept whereby the electricity system operator buys, on behalf of consumers, capacity that is centrally apportioned to generators.[24]

Currently, there are a number of national, regional, and local efforts under way, both by industry and government, to improve forecasting, nominations, schedules, and other forms of operational coordination between the natural gas and electricity sectors. FERC has produced several rulemakings on aspects of

[24]. See http://www.nescoe.com/uploads/GasforElectricReliabilityGraphic_April2014.pdf (accessed July 22, 2014).

operational issues; a FERC rulemaking now under way proposes to revise the natural gas operating day and scheduling practices used by interstate pipelines to schedule natural gas transportation service.[25]

The North American Electric Standards Board (NAESB), which is a voluntary organization that includes representatives of both gas and electric industries, sponsors work to develop better operating standards between the two industries. Among other activities, its Gas-Electric Harmonization Forum seeks "to forge a consensus of natural gas and electric industry stakeholders in response to FERC's Notice of Proposed Rulemaking (NOPR) addressing gas-electric coordination."[26]

Further regional studies and planning processes by regional electricity system operators, reliability entities, and interconnection groups are ongoing. With support from the DOE, all three of the nation's electricity interconnections have conducted, or are conducting, comprehensive natural gas and electricity interdependence studies that cover a large geographic scope.[27] Additional work is being conducted by individual ISOs/RTOs and other regional entities; that work is not discussed herein.

8. Key Questions

Key questions for stakeholder input regarding gas-electricity interdependence include:

1. Are there additional gas-electric interdependencies, in both directions, and both now and through 2030, that are not mentioned in this paper? What are they?
2. There are a number of national, regional and local efforts underway, both by industry and government, to improve forecasting, nominations, schedules and other forms of operational coordination between the two sectors. Are those efforts sufficient? If not, what additional efforts may be needed, and by whom? Are there any actions that the Federal government should take, and if so, please identify.
3. What, if any, reforms should happen in RTO/ISO electricity markets to both improve operations and ensure adequate future pipeline capacity?
4. Same question, but for non-RTO/ISO electricity regions, if any.
5. Are there any transferable practices from some electric utilities in regions outside of RTO/ISOs, such as those in the southeast, who note little if any interdependency issues due to how they contract for gas service, or other business practices? If so, what are they?
6. Are efforts underway in your region to assure the appropriate amount and type of natural gas infrastructure, or alternatively, appropriate changes in electricity infrastructure, operations or end use, now, and through to 2030, sufficient for both sectors to reliably and affordably meet their evolving

[25] FERC's current efforts are summarized at their gas-electric webpage. The page includes access to their recent rulemakings, various technical conferences and Commission meetings, and a quarterly status report on the issue. See http://www.ferc.gov/industries/electric/indus-act/electric-coord.asp.
[26] See "NAESB Group Moves Toward Response to FERC Gas-Electric NOPR," Wright & Talisman blog, May 1, 2014, http://www.wrightlaw.com/ferc-alerts/NAESB_Group_Moves_Toward_Response_to_FERC_GasElectric_NOPR/.
[27] Western Interstate Energy Board: http://westernenergyboard.org/natural-gas/study/; Eastern Interconnection Planning Collaborative: http://www.eipconline.com/Gas-Electric.html. The Electric Reliability Council of Texas: http://www.ercot.com/content/committees/other/lts/keydocs/2013/BV%20ERCOT%20Gas%20Study%20Executive%20Summary.pdf.

needs? If not, what additional efforts and steps may be needed, and by whom? Are there any actions that the Federal government should take, and if so, please identify.

7. Are the current types of gas storage used the right kind for expected increased use of natural gas for electric generation, and additionally with new gas-fired generation now becoming available with faster ramping availability? If no, what is needed?
8. Are there greater opportunities for efficiency in the end uses of natural gas that could alleviate demand, and thus free up some natural gas? For example, several states have natural gas energy efficiency resource standards (EERSs). Are there lessons from these state experiences? Similarly, are there other opportunities to increase electric grid flexibility besides new fast ramping natural gas-fired generation that will be needed should wind and solar generation expand?