UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Coordination between Natural Gas	)	
and Electricity Markets	)	Docket No. AD12-12-000

COMMENTS OF THE NRG COMPANIES ON ELECTRIC-GAS INDUSTRY COORDINATION

The NRG Companies respectfully submit the following comments to the Federal Energy Regulatory Commission ("FERC" or "Commission") in response to the questions posed by Commissioner Moeller on the need for increased coordination between natural gas providers and the organized electricity markets.[1]

I. Introduction

The NRG Companies urge the Commission to reshape the way electricity and natural markets interact. Real "coordination" involves more than just synchronizing the start of the natural gas and electricity trading days. Instead, the Commission should direct its jurisdictional electricity markets to ensure that their electricity pricing and dispatch decisions reflect expected or actual conditions on the natural gas pipeline system, and then allow appropriate recovery of those costs. Specific examples of the type of reforms we advocate include:

- Allowing dual-fueled facilities to offer their energy and set market clearing prices based on liquid fuel costs, on days when the pipeline system is experiencing or is expected to experience stress and constraints;

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[1] *Request for Comments of Commissioner Moeller on Coordination between the Natural Gas and Electricity Markets,* (February 3, 2012) ("Request for Comments") available at: http://www.ferc.gov/about/com-mem/moeller/moellergaselectricletter.pdf.

- Ensuring that generators dispatched after the close of the natural gas trading day are provided sufficient bidding flexibility to reflect higher gas (or alternative fuel) procurement costs in their bids;

- Considering whether new gas-fired generation resources should undergo a "deliverability test" to ensure that there is sufficient gas infrastructure to deliver gas on peak days, or have dual-fuel capability;

- Permitting gas-fired resources to respond to natural gas shortages by selling intraday natural gas to third parties, where doing so would be more economic than burning that gas; and

- Yes, finally, aligning the natural gas trading day more closely with the power day.

While there are no "one size fits all" solutions, this type of enhanced coordination will avoid the scenario where an organized electricity market commits generation resources or sends price signals that ignore, or are inconsistent with, actual and expected conditions on the interstate or LDC natural gas pipeline system.

Further, while the role of market monitoring and mitigation policy and rules may not be an obvious area of concern in gas-electric coordination, it is a critically important aspect of improving the ability of the jurisdictional wholesale markets to function efficiently in the face of constrained gas supplies and increased need for fuel switching.

NRG is particularly concerned about the New York and New England markets, where significant constraints on the gas system exist, and gas supplies may not always be available on peak gas demand days. For example, New England which lacks the geology needed for effective gas storage, which means that ISO New England will be committing and dispatching gas plants that will be highly dependent on finite pipeline capacity. At the same time, we are seeing a significant erosion of baseload coal and nuclear capacity due to low gas prices. Current market fundamentals and environmental regulations make it difficult to replace those resources with anything but gas combined cycle resources.

One example of where improved electric-gas coordination is necessary occurs in New York. Gas supplies on the Consolidated Edison ("ConEd") local distribution company ("LDC") system into New York City are sometimes constrained. The LDC dutifully notifies all customers of the constraint and imposes any necessary limitations on gas burns. While the NYISO is on the distribution list, it does not appear that the NYISO reacts to these notices or alters its electric production resource mix.[2] True electric-gas coordination means that the NYISO should have operational awareness of these limitations and take market-based measures to its security-constrained unit commitment and dispatch mechanisms, so as to reduce the control area's reliance on natural gas resources during the pendency of the gas shortage.

Finally, we note that while the Commission is somewhat limited in its jurisdiction over gas <u>*supply*</u>, it has plenary jurisdiction over the <u>*wholesale electricity*</u> markets. Thus, there is no need for the Commission to defer consideration of reforms that require the wholesale electricity markets to adopt market-based responses to conditions on the pipeline system.

II. Responses to Questions Posed.

The NRG Companies address the questions posed by the Commission below.

- **What role should the Federal Energy Regulatory Commission have in overseeing better coordination? What duties, if any, should be delegated to the North American Electric Reliability Corporation (NERC), the North American Energy Standards Board (NAESB), or other entities?**

The Commission has jurisdiction over many aspects of electric-gas coordination, particularly on the electricity side of the equation, where it has plenary authority over the

[2] Indeed, on more than one occasion, NRG personnel have had to inform the NYISO that gas conservation orders were in effect.

wholesale electricity markets. Further, the Commission is charged with ensuring the reliability of the Bulk Power System by section 215 of the Federal Power Act.[3] NRG recommends that the Commission act pursuant to both sections 206 and 215, to establish objectives for the type of market reforms that would undoubtedly improve the reliability of the bulk electric system and the functioning of the jurisdictional electricity markets, which would then be implemented by each region in accord with its individual market structures.

By contrast, the NRG Companies do not recommend that the Commission rely solely on voluntary industry initiatives to fix the lack of coordination between the electric and natural gas markets. Such voluntary processes can be frustratingly slow and are unlikely to address the increased demands on the natural gas pipeline system that we foresee in the near- and medium-terms, particularly as gas-fired generation becomes an increasing percent of total electricity production. Further, such voluntary efforts are unlikely to result in the type of electricity market reforms that we believe are critical. While certain changes to the natural gas trading day may require such coordination, there are many steps that the Commission can take to fix its jurisdictional markets without waiting for NAESB or other voluntary industry organizations to develop consensus recommendations.

- **To what extent should FERC defer to various regions of the country in addressing these challenges? Should FERC view organized electricity markets differently from bilateral electricity markets? If regional deference is given what role should FERC play to assure that regional agreements are adhered to?**

[3] Section 215 expressly gives the Commission authority over "all users, owners and operators of the bulk-power system" to protect system reliability.

a. <u>The Commission should establish generic electric-gas coordination market principles, but provide deference to regional compliance plans.</u>

The Commission should establish generic market principles and then require each organized market region to make a compliance filing modifying its electricity market pricing structure. While efficient price signals are important tools in guiding the allocation of capital in both market and non-market areas, it is reasonable for the Commission to start this effort by focusing on the organized markets, particularly since the areas of the country with the most severe gas constraints are market areas.[4] In fact, ISO New England has already identified its heavy reliance on natural gas as one of the region's key strategic challenges,[5] while New York has also created a task force dedicated to examining natural gas-electricity coordination issues.

The Commission's goal should be to ensure that each of the Commission's jurisdictional organized markets ensures that, during times of natural gas scarcity, the system sends appropriate prices signaling the need for non-gas fired generation. Setting the marginal cost of electricity at the price of the resource needed to ensure system reliability is entirely appropriate – whether that marginal resource is a demand response resource or a dual-fueled generator offering into the market on oil or kerosene instead of natural gas.

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[4] We note that the concerns in New England or New York, where gas pipeline capacity is sometimes limited, may be very different than areas such as Texas, where gas storage and pipeline capacity tends to be plentiful. Thus deference to the differences between regions is warranted.

[5] *See* ISO New England, Inc., "ISO on Background-Strategic Planning Initiative" at p. 12 (Oct. 6, 2011) available at http://www.iso-ne.com/nwsiss/pr/2011/final_2011_on_background_presentation.pdf

As to implementation, the Commission should continue deferring to the regional needs of individual markets, consistent with its precedent in (among others) Order Nos. 745, 755, 888, 2003 and 2006. In each of those proceedings, the Commission established central tenets of how its jurisdictional markets should function and directed each region to submit a compliance filing that incorporated those principles. We see no reason to deviate from this model here.

- **The expanded use of natural gas for electricity generation is likely to change flows on the natural gas pipeline system. Does FERC need to address this issue?**

Yes. There is no question that the plunging price of natural gas is affecting gas usage across the country, both because of increased demand for electricity generation, and because the gas is originating in new parts of the country. In order to accommodate the increased reliance on natural gas, the Commission should consider two specific reforms:

a. <u>The Commission should consider whether natural gas resources should undergo gas deliverability testing</u>.

Currently, a new generator is required to demonstrate that it does not overload the <u>*electrical*</u> transmission system or create reliability problems under a variety of peak load studies. As natural gas increasingly becomes a baseload fuel, it seems logical that comparable deliverability testing of the <u>*natural gas pipeline*</u> system may be necessary for the addition of incremental natural gas-fired generation capacity. One way to structure such a requirement would be to require that any new gas-fired generation be able to operate on peak gas demand days without adverse impacts to the natural gas delivery system. If there were problems on the system, the natural gas generator would have to contribute to upgrades to the interstate or LDC pipeline system. Dual-fueled generators should be deemed gas-deliverable if they have sufficient liquid fuel to accommodate any peak periods when natural gas pipeline capacity may not be available.

Already, we are hearing anecdotal stories that the influx of combined cycle facilities into New England, combined with additional dispatches for existing facilities, is causing pressures to drop on the LDC pipeline system in some parts of the region. While the relatively mild winter weather in the winter of 2011/2012 prevented this issue from coming to a head, it is not difficult to imagine reliability issues arising on a particularly cold day – when both residential gas usage and electrical load are high. While the Commission will have to grapple with issues of whether to grandfather existing gas-fired resources from such a test, it should also consider whether existing rules are sufficient to ensure that the electric grid is capable of operating reliably or whether additional reforms are necessary.

b. Electricity market reforms are necessary to ensure adequate gas supplies.

While it is important that the Commission ensure that the natural gas pipeline system is sufficient to meet the needs of the electricity sector, it is just as important to make sure that the electricity sector takes all steps necessary to avoid using more natural gas capacity than the system is capable of providing. This means that the electricity markets should reflect any limitations in gas availability in its commitment decisions and in the resultant Locational Marginal Prices ("LMPs") in the both the day-ahead and real-time markets. Doing so will ensure that unit commitments in the day-ahead market recognize these constraints and are reflected in clearing prices and out-of-market uplift costs are minimized.

One common sense example of how to coordinate electricity and natural gas markets would be to encourage dual-fueled resources to bid into the energy markets on a fuel *other than* natural gas during times when the relevant pipeline is experiencing, or is highly probable that it may experience, a gas shortage. Currently, some markets automatically mitigate bids from dual-fueled resources to the *lower* of their costs of offering in on natural gas or liquid fuel – regardless of system conditions. More efficient markets require that market participants be allowed to reflect expected congestion or anticipated shortages in the natural gas system in their bids. Further, fast start peaking units, which typically receive no-notice, real time dispatches, should also be permitted to participate in the electricity markets based on the costs of burning liquid fuel regardless of pipeline conditions. These are the best means of ensuring that prices accurately reflect the actual costs of maintaining system reliability.

As one example: the City of New York often experiences significant restrictions on its ability to import natural gas past the city gate. During such shortages, the NYISO should permit dual-fueled resources to participate in the electricity markets based on the costs of burning liquid fuel. However, current NYISO rules actually discourage this behavior by heavily mitigating units to the lower of their costs of burning gas or liquid fuel. Generators are not allowed to modify their primary bids (referred to as the "reference price") to reflect the price of the liquid fuel until *after* an Operational Flow Order ("OFO") or System Alert is declared by the LDC.[6] Changes to the reference price

[6] While the New York State Reliability Council has a local reliability rule I-R3 known as "Minimum Oil Burn" that requires select units under defined high load conditions to operate on alternative fuel so that the loss of a single gas facility does not result in the loss of electric load within the New York City or Long Island zones, these events do not necessarily coincide with OFO's and gas system limitations that more frequently trigger the need for operation on alternate fuels by generators.

to reflect liquid fuel prices are not automatic, however. Instead, the market must wait until both the Market Monitoring & Analysis and the Marketing Monitoring Unit approve the revised bid, before the proper fuel price is reflected. This puts generators in an untenable position, especially considering the early market close (5 AM) of the NYISO. They are either required to bid into the market at a mitigated price that may not reflect the actual costs of procuring next day or intraday gas (or facing OFO penalties) during a shortage period; or burning liquid fuel, which is typically far more expensive than gas. Both cases involve the NYISO providing out-of-market bid cost recovery to the affected generator, while failing to reflect the actual marginal cost of operating a reliable control area in LMPs.

c. <u>Wholesale market participants should be allowed to sell natural gas when prices warrant.</u>

Prices in the natural gas markets sometimes rise during intraday gas trading, reflecting scarcity of natural gas to supply, for example, home heating demand or industrial processes. In such situations, generators with natural gas nominations can help alleviate those shortages by selling their gas to third parties. Depending on the spread between natural gas and electricity prices, it may be highly economic for the generator to accept imbalance charges in the energy market in exchange for the higher natural gas revenues. The Commission should clarify its market rules to allow generators to respond to intraday price signals in the gas market by selling the natural gas back to the system, so long as such sales can be made consistent with reliability needs of the electric system.

- **Within each day, electricity trading differs significantly from gas trading. Similarly, on a day-to-day basis, the various gas markets may not be open on the same days as the corresponding electricity market, especially over Saturdays, Sundays, and Holidays. How should FERC help to harmonize these markets?**

There is a troubling assumption from most of the organized electricity markets that generators should have "no notice" natural gas service; that is, that a gas-fired generator should have instant access to natural gas at any time during the day, and in any quantity, without prior notice. In most cases, generators do not have access to "no notice" natural gas service.

The problem is most severe in regional markets that rely heavily on out-of-market electricity dispatches. In markets with efficient day-ahead markets, it is generally possible for the generator to reasonably estimate its expected gas burn and to procure sufficient gas to meet the next day's expected dispatch. This is because market prices are a good predictor of when a unit will run or not run based on its relative price competitiveness. However, when electricity markets routinely dispatch units outside of the day-ahead market process, it becomes extremely difficult for the generator to procure sufficient gas, because the day-ahead gas markets have already closed. The problem becomes more difficult for units with low capacity factors when they are dispatched in response to situations that are unpredictable and for which it is impossible for the generator to anticipate.

The CAISO, for example, routinely dispatches low capacity factor units through a host of out-of-merit dispatch actions. Such units are required to either procure intra-day gas, or hope that they can balance their gas schedules in the coming day's gas market (taking the risk that gas prices will move against them). Procuring intra-day gas can be an extremely expensive undertaking. The problem is only exacerbated if the unexpected dispatch occurs over a holiday weekend, when the gas markets are entirely closed. For example, NRG's El Segundo units (two units 335 MW each) received a series of dispatches during the week of Thanksgiving 2009. The dispatches were a combination of economic market clearing dispatches (Integrated Forward Market) and reliability dispatches (both Exceptional Dispatches and Residual Unit Commitment). Over the 4-day Thanksgiving Day weekend, there was limited space available on the gas pipeline which meant that NRG would need to procure same-day gas, in order to avoid the steep penalties associated with a potential OFO on the pipeline, for any dispatches it received. Exacerbating the situation was the fact that November 30th was the end of the 5-day and monthly balancing cycles on the Southern California gas system.

NRG's weighted-average price of gas procured over the weekend was $4.80 / MMBtu. This compared to the CAISO's Proxy Cost option, which calculated gas at $3.40 / MMBtu (both figures omit transportation adders). Since NRG had no way of knowing how long the units would run, or at what dispatch levels, NRG only procured 65,000 MMBtu over the weekend. When it received greater than expected dispatches, it was forced to enter into what is known as an imbalance trade for gas at $6.18 / MMBtu to bring its total volume purchased in line with what was burned (140,000 MMBtu). Thus, in one admittedly non-typical weekend, the CAISO's Proxy Cost calculation deviated from the actual delivered price of gas by almost $3 / MMBtu.

While holiday weekends present unique problems, limited versions of this story occur every day, with unanticipated dispatches on weekends and holidays presenting major problems. In each case, the early close of the day-ahead gas market makes intra-day gas purchases an everyday reality that needs to be addressed in any commitment cost bid caps.

First, the Commission should act to minimize these types of out-of-merit dispatches by requiring that the organized markets include *and price* all appropriate constraints in the day-ahead market. Second, the Commission must ensure that generators have sufficient bidding flexibility to reflect higher gas procurement costs and higher risk profile in their bids.

- **What will be the impact of the expected retirements of coal and oil-fired generation on the need for gas and electricity coordination?**

In some markets, gas is now effectively a baseload resource, while coal is on the margin. NRG, in fact, has already witnessed coal-to-gas switching in some regions where it operates both coal and gas facilities. We expect this trend to continue, particularly if natural gas prices remain substantially under $3.00 / mmBtu. With the increased demand for natural gas, it is critical that the organized electricity markets take constraints on the gas pipelines as seriously as transmission system constraints on the electric system.

- **To what extent should FERC consider modifying its existing Standards of Conduct with regulated utilities – either on an emergency basis or in a more fundamental manner – to assure greater coordination of these industries?**

NRG does not believe that any changes to the Standards of Conduct would be necessary to allow for improved electric-gas coordination. Our experience is that the FERC-regulated interstate pipelines do an excellent job communicating outages or other restrictions (i.e., OFOs, etc.) to all customers on a real-time basis through their Informational Postings, and even through frequent email notices and updates. The same is true of most, if not all, of the LDC pipelines in the markets in which NRG operates.

The only problems that NRG has experienced involve the organized *electricity* markets failing to act proactively to incorporate the information put out by the pipeline in their scheduling and pricing practices. As discussed above, we recommend that the Commission direct each market to consider steps it could take to reconfigure its markets when gas for electricity generation purposes is, or threatens to be, limited.

III. Conclusion

Wherefore, NRG respectfully requests that the Commission consider the comments herein and schedule a technical conference or series of regional technical conferences to better define the problems that need to be resolved on gas-electric coordination. NRG looks forward to being part of the continuing dialogue on these important issues.

Respectfully submitted,

/s/	/s/
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Dated March 30, 2012

Certificate Of Service

I hereby certify that I have served a copy of the foregoing document upon the Applicant in this proceeding.

Dated at Princeton, New Jersey this 30th day of March, 2012.

/s/ Abraham Silverman
Abraham Silverman