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Who's on First? The Coordination of Gas and Power Scheduling

With the dramatic drop in the price of natural gas in North America, the tightening of environmental regulations and the drop in demand for electricity through much of the US and Canada, the need for coordination of natural gas and electricity markets has become more acute. FERC has a significant role to play in the coordination of the timing of these markets and is the entity that can oversee both economic and physical efficiency of operation.

Richard D. Tabors, Scott Englander and Robert Stoddard

I. Background

The physical and economic (market) characteristics of the electric and natural gas markets increasingly overlay one another along two critical dimensions:

• Market timing: The timing of natural gas and electricity markets is significantly different. While electricity is, to a first order, produced and consumed at the same time, is clocked in cycles, and its markets operate in minutes to hours, natural gas is stored through both pipeline packing and in central storage facilities. Gas markets operate daily (generally not on weekends or holidays), with illiquid intra-day markets.

• Regulation: The regulation of the two energy sources differs at the federal level. The Federal Energy Regulatory Commission (FERC) regulates the gas market, gas pipeline development (siting), and gas quality. FERC also regulates power markets including transmission tariffs but does not

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oversee transmission siting. The Commission with and through the North American Electric Reliability Corporation (NERC) oversees the reliability and quality of supply. The states regulate pricing to end users including the costs of distribution pipes and wires. While the electric utility has the ''obligation to serve,'' at the local distribution company (LDC) level, the gas supplier competes for customers with other suppliers of thermal energy including the power company.

Prior to 2008 it was clear that the electric power industry would come under increased pressure to reduce hazardous air pollutants and probably carbondioxide as well. At that time the industry could be confident that the *relative* prices of their fuels—primarily gas and coal, with some oil at the margin—would hold rank. In 2008 that ranking began to reshuffle at the same time that increased environmental air rules were becoming increasingly inevitable. Improvements were made in horizontal drilling and thereby the hydraulic fracturing of shale deposits for both enhanced oil recovery and more dramatically increased production of natural gas and associated high value liquids. The result has been to push natural gas prices sharply downward, with prompt-month futures now trading at \$2.14/MMBtu, more than \$10 lower than 2007 levels.

With the most recent (March 26, 2012) announcement of highly stringent New Source Performance rules on carbon emissions from power generation facilities, the probability that new coal generation will be built is close to zero. Older, less efficient coal generating units are likely to be decommissioned based on EPA Hazardous Air Pollution Rules (HAP) and Cross State Air Pollution Rules (CSAPR), where unit life expectancy is too short to justify the capital investment in clean-up equipment. Mid-life units with moderate heat rates are now being challenged by extremely low natural gas prices that are forcing coal to the competitive margin with gas.

In 2008 that price ranking began to reshuffle at the same time that increased environmental air rules were becoming increasingly inevitable.

Natural gas is rapidly becoming not simply the fuel of choice but the only fuel choice for new generation within the North American grid. Operational, economic, and regulatory issues abound.

- System operators are finding themselves in the unusual position of having the price advantage of coal reduced to the point of equity per kWh generated with that of natural gas. Stated differently, within many of the regions of the U.S., coal and natural gas are equally likely to find themselves on the margin at any given time, not merely on a day-ahead basis, but also on an hour-by-hour basis. From the perspective of the gas supply system, the resulting large variability of gas demand by power causes uncertainties in gas scheduling and operations.
- A mid-range coal-fired unit with a heat rate of 11,000 Btu/kWh and coal prices of \$2.77 per MMBtu generates at a (fuel only) cost of \$30.47/MWh. A relatively efficient natural gas combined cycle plant at 7,000 Btu/kWh at a fuel cost of only \$2.20 per MMBtu generates a cost of \$15.40/MWh.
- The resulting uncertainty in knowing the marginal fuel and therefore the marginal units —as well as the structure and timing of the natural gas market relative to the electricity market— means that the quantity of natural gas needed hour to hour is more a function of electricity demand (requirements to supply load) than to supply the traditional consumers of natural gas.
- With the expectation of increased environmental pressure, loss of revenue to coal-fired units is anticipated to reduce further the viable generating stock. This is a long-term impact brought about by low gas prices that are expected to hold through much of the decade.
- Environmental uncertainty, the economic downturn, and pressure for green technologies

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have conspired to limit new investments in thermal (primarily gas) generation.

- Some shale gas production is not well accessed with the existing interstate pipelines, but new pipelines require firm transmission contracts, which non-utility power producers are unlikely to sign given the uncertainty about future levels of gas dispatch at their facilities.

II. Economic and Physical Issues in Electric Natural Gas Market Coordination

The most obvious illustration of coordination challenges is the situation faced by a typical natural-gas-fueled generator in an ISO/RTO market.[1] The operator of such a generator finds itself daily trying to bridge the gap between two mismatched sets of business rules and operating timelines, one for gas and the other for power. The consequences are significant: economic inefficiencies, resulting in added costs to consumers, increased environmental impacts, and reduced flexibility of the system and of the ISO's ability to respond to events in real time. As more and more generators run on natural gas, these negative impacts will increase.

Unless the natural-gas-fired generator is connected directly to the gas transmission pipeline, it will take delivery through its local distribution company (LDC). The generator operator can purchase the commodity through a competitive supplier or broker, or it can manage its own purchases and shipment at the wholesale level. Typically, the generator operator will contract for or hedge some or all of its anticipated needs weeks, months, or years in advance. Both day-ahead (DA) and within the operating day, the generator operator needs to anticipate its needs with accuracy, establish corresponding physical gas schedules in adherence with pipeline and LDC scheduling requirements, and then follow the gas schedules it established. Withdrawing more or less gas than scheduled will subject the generator to imbalance penalties.

Some shale gas production is not well accessed with the existing interstate pipelines, but new pipelines require firm transmission contracts.

In parallel with arranging for gas supply and delivery, the generator operator participating in an organized spot market and being committed and dispatched by the ISO must formulate its electricity supply offers based on its anticipated fuel costs, submit those offers day-ahead to the ISO, wait to receive financially binding schedules from the ISO, and operate in accordance with ISO instructions.

The challenge arises because the generator's timelines for scheduling gas do not align with those for scheduling its electricity generation, because gas purchases must be scheduled before actual fuel needs based on electricity generation are known, and because the cost of misestimating either gas schedules or electricity offer prices can be significant.

A 24-hour gas flow day spans parts of two 24-hour electricity operating days: the gas flow day generally runs from 10 a.m. to 10 a.m. Eastern Time (ET, regardless of regional location) while an ISO's electricity commitment period runs from midnight to midnight. When day-ahead electricity offers are due and when day-ahead schedules are made available varies by ISO:

- NYISO requires DA offers by 5 a.m. and posts DA schedules and prices by 11 a.m.
- ISO-NE and PJM require DA offers by noon ET and post DA schedules and prices by 4 p.m.
- MISO requires DA offers by 11 a.m. CT, and posts DA schedules and prices by 16:00 CT.
- CAISO requires DA offers by 10 a.m. PT, and releases DA schedules and prices by 1 p.m. PT.

''Timely'' next-day pipeline capacity nominations in the East are due by 12:30 p.m. ET, the same deadline for next-day gas trades on the Intercontinental Exchange (ICE).[2] A generator operator who buys gas from a supplier will generally need to submit its requirements to the supplier in

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Table 1: Illustrative NYISO Generator Gas and Electricity Activities Related to Wednesday Operating Day

Time (ET)	Gas Activity for Wednesday	Power Activity for Wednesday
Mon 09:00	Forecast gas needs for Tuesday and submit to supplier	
Mon 12:30	Adjust nominations as needed for Tuesday segment	
	Purchase or sell next-day gas as needed for Tuesday segment	
Mon 19:00	Adjust nominations as needed for Tuesday segment (evening next day nomination)	Prepare Wednesday electricity offers, based on gas and electricity forwards
Tue 05:00		Submit Wednesday electricity offer to NYISO
Tue 09:00	Forecast gas needs for Wednesday and submit to supplier	
Tue 10:00	Tuesday gas flow day begins	
Tue 11:00	Adjust nominations as needed for Tuesday segment (Tue Intraday 1)	Receive Wednesday DA schedules from NYISO
Tue 12:30	Adjust nominations as needed for Wednesday segment, based on ISO DA schedule	
	Purchase or sell next-day gas as needed	
Tue 18:00	Last chance to adjust nominations as needed for Tuesday segment, based on ISO DA schedule (Tuesday Intraday 2)	
Tue 19:00	Adjust nominations as needed for Wednesday segment, based on ISO DA schedule (evening next day nomination)	
Wed 00:00	Tuesday gas flow day continues	Wednesday operating day begins. Begin following ISO dispatch instructions
Wed 10:00	Wednesday gas flow day begins	
Wed 11:00	Adjust nominations as needed for Wednesday segment based on RT operation so far and anticipated for rest of day (Wed Intraday 1)	
Wed 18:00	Last chance to adjust nominations as needed for remainder of Wed segment, based on RT operation so far and anticipated for rest of day (Wednesday Intraday 2)	
Thu 00:00		Wednesday operating day ends
Ex post	Pay gas imbalance penalties for Tuesday and Wednesday	

time for the supplier to arrange purchase and delivery to the LDC, e.g., by 9 a.m.

After the Timely nomination deadline, there is generally one more opportunity to adjust next-day pipeline capacity schedules: the Evening deadline (19:00 ET); within the day, there are two opportunities: Intraday 1 (11:00 ET), and Intraday 2 (18:00).[3]

Adjustments to the next day's purchased gas quantity can be made using bilateral trades after the 12:30 p.m. ET ICE deadline, but they can become very expensive, given the lack of market liquidity. The later it gets, the more expensive making a change can become, as volatility and bid-ask spreads increase.

A generator in NYISO, for example, facing scheduling for a normal Wednesday operating day beginning at midnight must schedule the first part of Wednesday, from midnight to 10:00, as part of the gas flow day beginning Tuesday at 10:00 (the Tuesday segment) while scheduling the segment of Wednesday from 10:00 to midnight within the Wednesday gas day. Scheduling for the electric day runs midnight to midnight. To add complexity, the electric scheduling in NYISO differs from ISO-NE and PJM. In Table 1, we show an hour-by-hour example of the scheduling mismatches for the

Table 2: Illustrative ISO-NE or PJM Generator Gas and Electricity Activities Related to Wednesday Operating Day.

Time (ET)	Gas Activity for Wednesday	Power Activity for Wednesday
Mon 09:00	Forecast gas needs for Tuesday and submit to supplier	
Mon 12:30	Adjust nominations as needed for Tuesday segment	
	Purchase or sell next-day gas as needed for Tuesday segment	
Mon 19:00	Adjust nominations as needed for Tue segment (evening next day nomination)	
Tue 09:00	Forecast gas needs for Wednesday and submit to supplier	
Tue 10:00	Tuesday gas flow day begins	
Tue 11:00	Adjust nominations as needed for Tuesday segment (Tue Intraday 1)	Prepare Wednesday electricity offers, based on gas and electricity forwards
Tue 12:00		Submit Wednesday electricity offer to ISO
Tue 12:30	Adjust nominations as needed for Wednesday segment	
	Purchase or sell next-day gas as needed	
Tue 16:00		Receive Wednesday DA schedules from ISO
		ISO Rebid period opens
Tue 18:00	Last chance to adjust nominations as needed for Tuesday segment, based on ISO DA schedule (Tue Intraday 2)	ISO Rebid period closes
Tue 19:00	Adjust nominations as needed for Wednesday segment, based on ISO DA schedule (evening next day nomination)	
Wed 00:00	Tuesday gas flow day continues	Wednesday operating day begins.
		Begin following ISO dispatch instructions
Wed 10:00	Wednesday gas flow day begins	
Wed 11:00	Adjust nominations as needed for Wed segment based on RT operation so far and anticipated for rest of day (Wed Intraday 1)	
Wed 18:00	Last chance to adjust nominations as needed for remainder of Wed segment, based on RT operation so far and anticipated for rest of day (Wednesday Intraday 2)	
Thu 00:00		Wednesday operating day ends
Ex post	Pay gas imbalance penalties for Tuesday and Wednesday	

NYISO. Table 2 provides similar information for the mismatch in ISO-NE and PJM.

In both cases the generator must purchase the gas it will need before it knows its electricity operating schedule, so is taking considerable quantity risk. In NYISO, the generator must submit offers for power to the ISO based on prices for two days into the future, so it is taking considerable price risk.

The cost of quantity risk is borne in several ways. The next-day gas market is at its highest liquidity between 08:00 and 10:30 ET. After mid-morning, however, the gas market becomes increasingly illiquid, so if scheduled quantities are not known until ISO schedules are released at 11:00 or 16:00, bilaterally purchasing or selling gas and moving gas to and from liquid hubs for the next day will be expensive, and yet more expensive on the intraday market. Moreover, the last chance to adjust same-day pipeline nominations is at ET 18:00, and being out of balance at the end of

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the gas flow day will mean paying expensive imbalance penalties to the LDC.[4] Imbalance penalties under short conditions reportedly can be as high as $45/DTh ($45/MBtu) or more.[5] When an LDC or pipeline is under an Operational Flow Order (OFO), the tolerances used to measure imbalances are tighter, and penalties increase.

The weekday scenario also does not capture the difficulties that arise because the gas markets are closed on weekends and holidays. Gas for weekend days and Monday (as well as Tuesday, when Monday is a holiday) must be purchased and pipeline capacity nominated by Thursday or Friday. In the West, Friday and Saturday are packaged together and traded/nominated on Thursday; Sunday and Monday are packaged and nominated on Friday. In the East, a three-day package (Saturday–Monday) is traded/nominated on Friday.

These issues become more critical when high gas and electricity demands coincide—e.g., in the Northeast, on a very cold day. Under these conditions, both pipeline capacity (held predominantly by the LDCs) and gas supplies must somehow be allocated or ''shared'' between the LDC and the power consumer. With LDCs owning the majority of the capacity rights on pipelines, at times of stress the conflict in use will be extreme.[6] To add further to the potential for system failure, much of the natural gas pipeline system uses electricity for pumping.
If there is no gas for power generation, there may well be no gas at all.

There are few scheduling remedies available to generators. They can self-schedule their electricity generation to match their gas schedules—effectively a ''take or pay'' strategy. Doing so, however, risks running when uneconomic or not running when economic.

It is relatively common for generators with dual fuel capability to be prepared to exercise that capability with the knowledge that generating with #2 oil when natural gas is not available is a very expensive alternative and one that may lead generators, depending on the market and market rules, to be able to meet their supply obligations, yet unable to recover the cost difference.

The final scheduling remedy available to a generator is to put a premium on its power via its offer price, designed to manage the risks described above. Assuming such costs do not get mitigated by the RTOs, these are ultimately passed on to end users. In fact, however, most RTOs limit real-time offer prices based on day-ahead offers or cost-based metrics that do not reflect the actual prices of intra-day gas. Such rules are designed to deter opportunistic bidding, should a local reliability issue arise, but they also may have the effect of preventing recovery of the costs of intra-day gas. Regardless of whether this gap leads to a financial loss to the generator or unavailability of the generation, this issue highlights the need to coordinate RTO and gas pipeline rules to allow real-time electricity prices to appropriately reflect the cost of intra-day gas.

On the natural gas side, remedies are available in a number of areas, all with the possibilities of increased costs for delivery or increased uncertainties in the structuring of pipeline tariffs. Certainly the addition of gas storage, especially close to loads, could greatly increase the ability of the natural gas system and gas-fired generation to respond to weather events and resource variability in the electricity system.

Increased flexibility in timing of the gas day to harmonize with timing of the electricity day will remove inefficiencies in the electric markets but would need to be implemented so as not to increase inefficiencies in the gas markets. Compressing

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the time needed by ISOs to clear day-ahead markets (four to six hours) would facilitate the harmonization of market timing.

The structure of pipeline tariffs and control of pipeline capacity has favored a strategy by LDCs (and the pipelines) to commit to long-term capacity agreements that assure supply to critical customer loads while at the same time assuring revenue to support the pipelines. This leads to flexibility in capacity through releases at times of lighter LDC demand but limits the possibilities for generators to acquire non-firm capacity during periods of high demand.

While one might assume that generators served by an LDC structure would be protected from curtailments during times of high demand because the LDC holds the capacity, the reverse will often be true. Generators inside an LDC system will be the first to be curtailed by the LDC, in favor of supplying residential heating loads. Generators connected directly to the transmission pipeline may be in a better position to argue for gas delivery before the gas arrives at the LDC.

There is arguably significant room for reevaluation of pipeline tariff structures and the rules for release of capacity by LDCs that would improve the economic and physical efficiency of the combined systems. Finding the points of sufficient economic benefit to both systems that justifies the changes will be key.

III. Issues Facing the Commission in the Coordination of Electricity and Natural Gas Markets

FERC is the only regulatory body with relevant oversight of the wholesale markets for both electricity and natural gas sufficient to identify and deal with both the economic issues causing inefficiencies in both markets and the anticipated delivery issues at the LDC/ non-LDC boundaries as well as at the seams between the ISO/RTOs and the national and regional pipelines.

Unlike the continuously evaluated electricity markets of the nation's RTOs, the natural gas market structures have tended to evolve with practice. Changes to trading practices that have been developed by industry are far more common than those that have been directed by or overseen by the FERC. Trading practices appear more focused on the pragmatic than on the theoretically most efficient (though these objectives need not be at odds).

While the Commission's mandate is ''just and reasonable'' rates, its most visible responsibilities lie in assuring that gas and electricity markets deliver energy with adequacy and reliability.

Coordination and delivery is at no time more challenging than at critical peaks. For example, when one gas-fired plant trips and another is dispatched to replace it, the needed gas may be in the wrong place, and it certainly will not be available at the same price. RTO dispatch algorithms may need to be enhanced to consider gas deliverability. Also, offer price mitigation rules should be reexamined to ensure that energy prices are compensatory to generators dispatched in real-time.

Furthermore, with an increase in the role of natural gas in the generation mix, questions of adequacy of supply of pipeline capacity and natural gas for electricity generation have become paramount. New gas pipelines are built only to meet firm, long-term requirements of specific customers. In competitive wholesale power markets, however, because no individual power producer knows with sufficient certainty what its long-term gas needs will be, few are willing to enter into long-term firm gas transportation contracts. At present, there is no

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mechanism to bridge the gap between the collective need for new gas pipelines and the (commercially sensible) reluctance of individual companies to commit to long-term gas contracts.

One of the most critical implications of the lack of coordination is that as long as the electric power and gas system schedules are done sequentially and independently, it will not be possible to optimize the operation of the system from an economics perspective. From a near-term reliability perspective, as gas delivery becomes constrained, it will be necessary to account for these constraints in the unit commitment and dispatch of the electric system.

The fact that gas transmission is often significantly booked by LDCs with obligations to serve residential and commercial load and generally in the coldest winter periods – precisely the times when electric utilities are reaching their winter peak – is likely to bring periods of intense constraints in gas pipeline capacity (and possibly gas supply quantities as well). The result will be competition for pipeline capacity and for natural gas in an environment where both capacity ownership and humanitarian concerns (heating) may prioritize deliveries to households and commercial buildings over those to power generation.

IV. Conclusion: FERC Has a Near-Term Role

As we have discussed, with the dramatic drop in the price of natural gas in North America, the tightening of environmental regulations, and the drop in demand for electricity through much of the U.S. and Canada, the need for coordination of natural gas and electricity markets has become more acute. No longer can one assume that it will be gas on the margin with coal as base load. Regionally, gas and coal now can both be on the margin. Uncertainty in demand for gas and specifically for pipeline capacity makes the coordination of markets critical if economic efficiency is to be achieved. This article has focused on the need for coordination, or harmonization in the vocabulary of the North American Energy Standards Board (NAESB), of market timing – likely a major challenge for both federal and state regulators as well as for the NAESB.

FERC (with NAESB) has a significant role to play in the coordination of the electricity and natural gas markets, to assure that the markets operate as efficiently as possible from an economic and a physical perspective and that consumers in both markets are not harmed by incompatibilities in market timing and their concomitant constraints in physical delivery.■

Endnotes:

1. We use the term ''ISO,'' in these comments interchangeably with ''RTO,'' unless specifically noted.

2. The ICE products referred to are either next-day natural gas trades for physical delivery or financial swaps, and are location-specific.

3. Nominations can also be made ex post, but many if not all LDCs do not allow their customers to participate.

4. Generators connected directly to the gas transmission line generally have more flexibility with regard to imbalances than do generators behind an LDC.

5. ConEdison, for example, reportedly charges generators for imbalances the ''absolute high'' price of published daily trades, i.e., the price of the highest-priced single transaction at Transco Zone 6 for the delivery day.

6. For example, one of the most significant contingencies in the delivery of electricity to New York City is the delivery of gas to generators there and in Long Island.

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