UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Coordination between Natural Gas and Electricity Markets	))	Docket Nos. AD12-12-000 RM96-1-037

(Not Consolidated)

COMMENTS OF THE
NATIONAL RURAL ELECTRIC COOPERATIVE ASSOCIATION
IN RESPONSE TO COMMISSIONER MOELLER'S AND
COMMISSIONER LAFLEUR'S
INQUIRIES REGARDING NATURAL GAS-ELECTRIC INTERDEPENDENCE

Pursuant to the Notice issued in the above-referenced proceeding on February 15, 2012,[1] the National Rural Electric Cooperative Association ("NRECA") submits comments in response to the Request for Comments of Commissioner Moeller on Coordination between the Natural Gas and Electricity Markets issued on February 3, 2012. NRECA appreciates Commissioner Moeller highlighting the need for national and regional policies to improve coordination between the natural gas and electricity markets. NRECA also appreciates the issues raised by Commissioner LaFleur in her statement issued on February 16, 2012 in Docket No. RM96-1-037. Because NRECA's comments here address many of the issues raised by Commissioner LaFleur, NRECA is submitting this single pleading in both dockets.

I. INTRODUCTION

NRECA is the national service organization for more than 900 not-for-profit rural electric utilities that provide electric energy to approximately 42 million consumers in 47 states, or 13 percent of the nation’s population. Kilowatt-hour sales by rural electric cooperatives account for approximately 11 percent of all electric energy sold in the United States. NRECA’s members

[1]Notice Assigning Docket No. and Requesting Comments, issued in Docket No. AD12-12-000 on February 15, 2012.

also include approximately 65 generation and transmission ("G&T") cooperatives, which supply wholesale power to their distribution cooperative owner-members. Both distribution and G&T cooperatives were formed to provide reliable electric service to their owner-members at the lowest reasonable cost. NRECA members' supply portfolios include natural gas-fired generation facilities which, in turn, requires them to rely upon transportation contracts with natural gas pipelines. As such, NRECA has experience with the market and operational issues posed in Commissioner Moeller's Request and Commissioner LaFleur's statement.

II. COMMENTS

As Commissioner Moeller notes in his Request, there is a need for increased urgency – preferably before the next winter heating season – in coordinating efforts between the natural gas and electric generation industries. The impending implementation of changes in environmental regulations has been cited by many owners of coal-fired generating facilities as reason for their decisions to retire coal-fired units.[2] In addition, there is imminent retirement of certain coal-fired generation units that will soon reach the end of their useful lives, as well as economic and national policy factors which all contribute to the increased reliance on natural gas as the fuel source of choice for electric generation. Absent action by the Commission in a short time frame

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[2] An increasing number of generation owners have announced plans to retire coal-fired units because of the U. S. Environmental Protection Agency's ("EPA") Mercury and Air Toxics Standards ("MATS") and its Cross State Air Pollution Rule ("CSAPR"). *See, e.g.,* Ameren Energy Resources Corp., LLC's announcement that it would close its Meredosia and Hutsonville Energy Centers primarily as a result of the cost of complying with the CSAPR (http://ameren.mediaroom.com/index.php?s=43&item=981); American Electric Power's plan to retire nearly 6,000 MW of coal-fired generation based on the EPA regulations (http://www.aep.com/newsroom/newsreleases/?id=1697); Dominion's plan to retire all four of its Salem Harbor units by June, 2014 rather than invest the funds to comply with the EPA regulations (http://dom.mediaroom.com/index.php?s=26677&item=71797); First Energy Corp.'s announcement that its generation affiliates will retire six older coal-fired power plants representing approximately 2,689 MW located in Ohio, Pennsylvania and Maryland by September 1, 2012 due to the cost of compliance with MATS and other EPA regulations (https://www.firstenergycorp.com/content/fecorp/newsroom/news_releases/firstenergy_citingimpactofenvironmentalregulationswillretiresixc.html)

to address the increased reliance on natural gas in electric generation, the risks and failures in maintaining reliability that have been experienced in some regions might be more widespread.

NRECA recognizes that the Commission has in the past made efforts to address natural gas-electric interdependence and coordination.[3] However, as discussed below, the industries are at a point of apparent impasse without further FERC policy or rules guidance in order to improve the communications and coordination between the two industries – as well as between their respective market participants. NRECA's comments below respond to Commissioner Moeller's and Commissioner LaFleur's questions by providing both substantive and procedural suggestions which can be addressed through short- and long-term reforms.

A. Role of the Commission in Overseeing better electric and gas industry coordination.

Commissioner Moeller's Request poses the following question:

"Specifically, what role should the [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 question is an important one because unlike previous efforts at addressing interdependencies between the gas and electricity sectors, market participants cannot afford to invest years in this process. NERC and NAESB each serve an important role in developing standards through their consensus-based processes. However, neither of these organizations has the authority to establish mandatory policy initiatives, nor should they. The first step of establishing the policies or guidelines with which the regulated industries must comply must be taken by FERC, as the only entity with the requisite regulatory authority. To the extent NAESB

[3] *See, Standards for Business Practices for Interstate Natural Gas Pipelines*, 128 FERC ¶ 61,031 (2009); Final Rule, *Standards for Business Practices for Interstate Natural Gas Pipelines*, Order No. 587-U, 130 FERC ¶ 61,212 (2009)

and/or NERC can then assist with carrying out FERC's mandates through their respective standards development processes, NRECA welcomes reliance on these entities to serve in their usual roles. The Commission, as it is squarely in both the electric and gas industries, is the only entity that has the ability to receive direct input from market participants and asset owners operating in both sectors and to take expeditious steps, including compliance monitoring, to improve coordination between the sectors.

As long-time energy industry participants are aware, this is not the first time the Commission has either attempted to address this issue of gas and electric interdependence, either directly or via delegation to NERC or NAESB.[4] Secondly, given the potential for new natural gas generation to replace coal unit retirement, coupled with steady growth in variable, non-dispatchable, intermittent resources, an increased reliance on natural gas-fired generation as both a base load generating capacity and as firming resource to respond to changes in intermittent generation[5] is under way. Concomitantly, the demand for natural gas capacity to supply natural-gas fired electric generation, as well as the percentage of pipeline capacity devoted to supplying gas-fired electric power generation stands to increase over the next decade. Given the time necessary to conduct rulemaking proceedings and implement tariff changes, and the need to

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[4]For example, a 2004 report by the NERC Gas/Electricity Interdependency Task Force identified interdependencies between the gas pipeline and electric generation operations and planning activities. The task force concluded that:

- Gas pipeline reliability can substantially impact electric generation.
- Electric system reliability can have an impact on gas pipeline operations.
- In general, pipeline and electric system operators do not understand each other's business very well.
- Pipeline planning and expansion are substantially different from the electric equivalent.
- Communications between pipeline operators and electric reliability coordinators are generally weak
- Pipeline tariffs for firm delivery service are not compatible with peaking generation economics in many electricity markets.
- Modern combustion turbines have stringent fuel delivery and fuel quality requirements.

See: http://www.nerc.com/docs/docs/pubs/Gas_Electricity_Interdependencies_and_Recommendations.pdf

[5] The INGAA Foundation's March 2011 Study ("Firming Renewable Electric Power Generators: Opportunities and Challenges for Natural Gas Pipeline") at page 2 notes that "[i]n the next 15 years, 105 gigawatts (GW) of renewable power generation are forecast to be constructed; of which 88 GW could be new intermittent wind generation. The natural gas fired generation needed to firm up wind generation could be approximately 33 GW..."

examine interstate pipeline scheduling practices and gas pipeline/generation communication practices to provide improved electric and gas industry coordination, NRECA submits that the Commission must "own" this initiative and not delegate the responsibility to develop standards without clear guidance and a mandate from the Commission. However, the Commission should attempt to advance this cause without using a blanket mandate that could be inefficient to many who have resources or services that improve the interdependence.

1. The Commission Must Exercise Its Authority

Differences in the natural gas and electric industries create obstacles to bringing the two industries more in sync with each other. However, the Commission, as the regulator of both natural gas interstate pipelines and public utilities, has the authority to require and receive input from the electric and gas industries, as well as take expeditious steps in order to improve coordination between the sectors.

The differences in the gas and electric industries which should be taken into account in attempting to coordinate the two industries in a meaningful way include reliability assurance, planning for future reliability and/or economic needs, and rate recovery for infrastructure expansion. On the electric side, reliability of the bulk power system is addressed through a system of (1) FERC as the regulator and overseer of the Electric Reliability Organization ("ERO") under Federal Power Act Section 215 per the Energy Policy Act of 2005;[6] (2) NERC as the ERO to develop and enforce Reliability Standards, monitor the bulk power system, assess adequacy, conduct audits of owners, operators and users of the bulk power system; and educate industry personnel;[7] and (3) regional reliability organizations whose members come from all segments of the electric industry and which have been delegated the authority from NERC to

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[6] Energy Policy Act of 2005, Pub. L. No. 109-58, 119 Stat. 594. (2005)
[7] http://www.nerc.com/page.php?cid=1%7C7%7C114

enforce NERC and regional Reliability Standards and perform other standards-related functions.[8] Transmission planning for regions covered by RTOs or ISOs is conducted on a region-wide basis to address reliability and/or economic needs, and non-RTO/ISO regions coordinate transmission planning to various degrees. In order to incent transmission investment, the EPAct of 2005 required FERC to provide incentive rates for new transmission investment.[9]

The natural gas pipeline industry is less formal and detailed in many of these areas. Natural gas pipelines are each independent transportation providers who respond to market demand. Also, unlike the integrated bulk power system, natural gas pipelines are less (or perhaps not at all) integrated with and dependent upon each other. Because the nature of providing firm transportation service on natural gas pipelines is less complex in these respects than electric transmission, there is not the same need in the natural gas industry for the formalized and detailed central planning as exists for electric transmission. There also does not exist in the gas pipeline industry any formalized and obligatory reliability standards and enforcement regime as exists in the electric industry. NAESB develops business standards and communication protocols for the gas industry.[10] The Department of Transportation Pipeline and Hazardous Material Safety Administration has some enforcement authority over pipeline safety. However, there is not an organization and structure for the gas pipeline industry that is analogous to NERC and the regional councils. Infrastructure development and rate recovery for same are

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[8] *Id.*

[9] *See* FPA Section 219, 16 U.S.C. § 824s; *Promoting Transmission Investment Through Pricing Reform*, Order No. 679, FERC Stats. & Regs. ¶ 31,222, *order on reh'g.*, Order No. 679-A, FERC Stats. & Regs. ¶ 31,236 (2006); *order on reh'g.*, 119 FERC ¶ 61,062 (2007)

[10] NAESB develops standards for the wholesale and retail natural gas and electric industries. NRECA notes that while the Reliability Standards adopted by NERC are publicly available without restriction, NAESB's standards are available only by fee or by very limited 3-day waiver to view the NAESB standards online. This difference is significant in this context because it may hamper or preclude coordination between participants in the natural gas pipeline industry and the electric industry. NRECA has requested unsuccessfully that the Commission reconsider its practice of incorporating by reference the NAESB standards which are not publicly available to anyone, for free. *See Standards for Business Practices and Communication Protocols for Public Utilities*, Order No. 676-E, 129 FERC ¶ 61,162 at P 116 (2009) ("Order No. 676-E").

also different between the natural gas pipeline and electric transmission industries. There is not a federal policy of incentives for natural gas transportation infrastructure expansion. However, pipelines are able to make a filing under Natural Gas Act Section 7 to receive a certificate from FERC which determines whether the pipeline investment is necessary and provides initial rates. The Section 7 process provides natural gas pipeline developers with some level of certainty that their project will be allowed rate recovery.

Because of these differences, it is necessary for this Commission to serve its role as the regulator by requiring the industries to work together in adopting communication protocols, operating standards, and service offerings which will reflect the interdependence between natural gas and electric generation while also ensuring that the industries' differences do not hamper one another. The industries are fast approaching the point where coordination between them must be achieved regardless whether there is consensus.[11] This critical need becomes even more evident for developers of natural gas-fired electric generators when they try to coordinate the need for electric transmission infrastructure development and gas transportation in an efficient and cost-effective manner.

2. The Commission Should Institute a Series of Rulemaking Proceedings with Input But Not Delegation to NERC, NAESB, or Other Entities

In various matters over which it has jurisdiction, the Commission regularly delegates to entities with technical expertise (*e.g.,* NERC and NAESB) the responsibility to develop standards and even enforce FERC-mandated standards. For other matters, like transmission

[11] *See Standards for Business Practices for Interstate Natural Gas Pipelines*, 128 FERC ¶ 61,031 at PP 16, 21 (2009) (FERC directed NAESB to consider whether changes to the existing intra-day schedules for natural gas pipelines would benefit shippers and provide better coordination between gas and electric scheduling, yet later declined to take any action after none of the NAESB proposals achieved sufficient consensus at the subcommittee level (P 18) and FERC was not convinced that there was a better alternative to the existing NAESB timeline, which had achieved consensus.)

planning in RTO and ISO regions, the Commission encourages and allows the industry or regional entities to reach solutions and/or make proposals to the Commission. In all instances, even when the Commission delegates or provides deference to third parties, the Commission retains its statutory obligation to ensure that rates, terms and conditions of jurisdictional service are just and reasonable and not unduly discriminatory or preferential.

On the issue of electric-gas interdependence, the Commission should proceed as it has with other substantive matters and institute a series of rulemaking proceedings, perhaps preceded by subject matter technical conferences or notices of inquiry. The proceedings could be separated into the "baskets" of (1) communication; (2) operation; (3) contracting, and (4) planning/contingency analysis, as posed by Commissioner Moeller.[12] The Commission should take a flexible approach to the rulemaking proceedings and develop either mandatory standards or flexible guidelines based on each subject matter basket. As an example, for technical standards like communication protocols which lend themselves to definite requirements, the Commission could adopt standards and require compliance with same (as it does with the NAESB consensus standards). For other subject matter baskets, like perhaps operations where pipelines, generation owners and transmission owners/developers might require some amount of flexibility in determining how to best comply with the Commission's goals, the Commission could adopt guidelines then require compliance filings which would allow for variation in how the guidelines are met.

A candidate for such a flexible guidelines approach to gas-electric interdependence and coordination is operational issues that would assist in providing natural gas for electric generation. The Commission has previously addressed NAESB's efforts to enhance coordination

[12] Request at page 2.

of scheduling and other business practices between the two industries. In its July 16, 2009 NOPR, the Commission acknowledged that changes to the existing natural gas intra-day schedules might provide better coordination between gas and electric scheduling.[13] However, after NAESB was unable to reach consensus on the issue, the Commission declined to propose any changes. Instead, the Commission decided that it was not possible to develop a one-size-fits-all solution that would completely resolve the issue of coordination between the electric and natural gas industries.[14] The Commission advised that "this is an area best addressed by individual pipelines adding additional nomination opportunities or services to better accommodate specific conditions of their systems and the needs of gas-fired generation within their regions."[15]

Although some pipelines have made filings to implement innovative scheduling options and services to accommodate gas-fired generation, the pace of such filings appears to be surpassed by the increasing reliance on natural gas to fuel generators. Therefore, the Commission cannot delegate this issue away to NAESB, since NAESB does not have authority to mandate changes or adopt binding policy, and was unable to gather the necessary consensus despite FERC's belief that NAESB is the more cost-effective and efficient forum for standards development.[16] Instead, the Commission should adopt guidelines or principles for better

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[13] *Standards for Business Practices for Interstate Natural Gas Pipelines*, 128 FERC ¶ 61,031 (2009).
[14] *Id.* at P 21.
[15] *Id.* at P 22. *See also*, *Standards for Business Practices for Interstate Natural Gas Pipelines*, Order No. 587-U, 130 FERC ¶ 61,212 (2009) (In the Final Rule, the Commission declined requests that it mandate additional intraday scheduling opportunities and instead reiterated its view that "individual pipelines may be able to offer special services or increased nomination opportunities that will better fit the profile of gas fired generation."
[16] *Standards for Business Practices and Communication Protocols for Public Utilities*, Order No. 676-E, 129 FERC ¶ 61,162 at P 116 (2009) ("Order No. 676-E") (the Commission stated, "[f]rom our experience, the NAESB process is far more efficient and cost effective method of developing technical standards for the industries involved than the use of a notice and comment rulemaking process involving numerous technical conferences in Washington that all believe they have to attend.")

coordination between the industries which must be met by pipelines through compliance filings, without prescribing how the guidelines must be met.[17]

The rulemakings for each "basket" could proceed along the following lines: first, the Commission would gather input through perhaps a technical conference and comment procedure or a Notice of Inquiry, from various industry segments, including (1) pipelines, generators, and transmission developers; (2) standards developers including NERC and NAESB; and (3) planning entities including RTOs/ISOs and joint planning agencies. Second, the Commission would institute a rulemaking process (NOPR and Final Rule) to develop for each basket either specific standards to be adopted or guidelines/principles that can be met through individual compliance filings or NERC/NAESB standards development. Third, the Commission would require compliance filings. The compliance filings would require pipelines, working with shippers, to develop services or other operational changes in order to meet the requirements of the Final Rule. To the extent necessary, the compliance filings might also require RTOs, ISOs, planning authorities and/or individual transmission owners in areas without centralized planning, to file proposals to work with pipelines so that transmission expansion plans might include identification of natural gas pipeline infrastructure that will be needed, or at least incorporate certificated, planned pipeline expansion into transmission planning.

[17] For example, in its Order No. 890, the Commission adopted mandatory transmission planning principles and directed that ". . . each public utility transmission provider is required to submit, as part of a compliance filing in this proceeding, a proposal for a coordinated and regional planning process that complies with the planning principles and other requirements in this Final Rule." *Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 437 (2007), *order on reh'g*, Order No. 890-A, FERC Stats. & Regs. ¶ 31,261 (2007), *order on reh'g*, Order No. 890-B, 123 FERC ¶ 61,299 (2008), *order on reh'g*, Order No. 890-C, 126 FERC ¶ 61,228 (2009), *order on clarification*, Order No. 890-D, 129 FERC ¶ 61,126 (2009). Thus, the Commission did not specify how the principles must be met by public utilities, but instead adopted mandatory principles for compliance.

For technical issues where FERC typically defers to NERC and/or NAESB, the Commission should not simply leave it to these entities to develop a proposal or not. Since NAESB acts on a consensus basis and there is no guarantee that consensus will be reached on all issues, the Commission should not let the success of the rulemaking effort depend on what can be achieved through a consensual standards development process. Also, while NAESB's role as a volunteer-based developer of business practices and communications standards is both necessary and appreciated, NAESB is not a reliability organization. For some issues, the Commission might adopt substantive and detailed standards with which the industries must comply. For other issues, such as technical issues where the Commission typically defers to NERC or NAESB, the Commission should adopt clear guidelines or principles for standards development. In order to make sure that standards are in fact developed but also take advantage of the existing processes and substantive expertise of organizations like NERC and NAESB, the Commission should direct that the organizations work with the industry to develop standards for the NOPR on each issue basket, then adopt a Final Rule.

Finally, on this issue, NRECA urges the Commission to require that the rulemaking processes must be transparent and available to all interested persons, without restriction. While the NAESB and NERC standards development processes may be open to interested parties, NAESB standards which might be proposed for incorporation by reference in a FERC rulemaking are only available by fee or limited waiver. The Commission has previously rejected concerns that the ability to access NAESB standards only through either a fee or a limited three-day waiver unfairly disadvantages some industry participants.[18] In these sorts of rulemaking

[18] *See* Order No. 676-E at PP 115-121 (The Commission refused to reconsider its policy of incorporating by reference the NAESB standards and instead found that the benefits of the NAESB consensus process outweigh "whatever costs non-members may incur in having to obtain copies of the standards.")

proceedings, such limitations can only serve as an impediment to development of proposals that will take into account the diversity of interests and complex issues between the natural gas and electric industries.

B. Regional Differences and Deference to Regional Practices

Commissioner Moeller's Request asks "whether or to what extent the Commission should defer to various regions of the country in addressing the interdependency of electric and gas markets. 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?"

To be sure, the issue of electric and gas coordination knows no regional boundaries and does not discriminate between RTO and non-RTO markets. This is most certainly the case when there are extreme weather events. As the Commission is aware, and as documented in an August 2011 joint FERC and NERC report[19], low temperatures in the Southwest during February 2011 caused generator equipment to freeze, resulting in power outages, freeze-offs and other issues resulting in natural gas curtailments. The area impacted by this event spanned both organized markets and areas in which bilateral markets are predominant.

However, the emphasis of Commissioner Moeller's Request is as much on day-to-day electric and gas interdependencies as the necessity of coordination during emergencies. In considering improvements in the day-to-day coordination between electric and natural gas markets, there may be regional differences between RTO and non-RTO regions that merit the Commission's attention.

[19] www.ferc.gov/legal/staff-reports/08-16-11-report.pdf

The reason for this distinction between RTO and non-RTO regions is that, as discussed in Section D below, many interstate pipeline scheduling practices do not permit electric generators with firm transportation ("FT") capacity the flexibility to use their capacity throughout the gas operating day. While this issue is found in non-RTO regions, the problem is exacerbated in RTO markets, due to the interaction between the timeline in which natural gas generators receive Day-Ahead Market ("DA Market") awards and directives from the RTO to operate for the following electric day.

While these types of differences should be accommodated through flexible standards or guidelines, they cannot justify inaction. Instead, as the Commission has done in other forums, the Commission should require compliance filings to demonstrate how the standards or guidelines in the various rulemakings will be met. To the extent there are regional agreements which could be reached that address the Commission's requirements, then the Commission should require those agreements to be filed with the Commission (as they presumably will contemplate or directly impact the rates, terms and/or conditions of FERC-jurisdictional natural gas transportation or electric transmission service) so that FERC can serve its role of making sure the agreements are adhered to.

Commissioner Moeller's Request also questions whether the Commission should view organized electricity markets differently from bilateral electricity markets. As discussed above, there are differences between the two which perhaps exacerbate the adverse impacts of the lack of coordination between the industries. To the extent Commissioner Moller's reference to "bilateral markets" is intended as a reference to bilateral transactions which can occur in both organized (*e.g.*, RTO and ISO) and non-organized markets, there is a need for enhanced communication and coordination between the natural gas and electric industries. Bilateral markets and organized markets are not mutually exclusive; successful organized markets should have robust bilateral markets underlying them. To the extent the lack of coordination between the industries impacts bilateral markets, it likely has an adverse impact as well on an organized market – particularly since a single natural gas transportation pipeline might serve both organized and bilateral markets. While the Commission might view the compliance process differently between organized and bilateral markets, since organized markets offer the potential ability to coordinate/consolidate compliance filings for several companies within the RTO into a single filing, NRECA does not believe the Commission should view bilateral versus organized markets differently in developing flexible standards and guidelines, as discussed in Section A above.

However, if Commissioner Moeller's reference to "bilateral markets" is intended to mean non-organized markets, which NRECA believes to be the case, then there are differences between the two which should be taken into account in a discussion of gas-electric coordination. In an organized market such as an RTO or ISO, scheduling and dispatch instructions are made by the central entity, while individual generation owners are responsible for securing fuel supply to meet the dispatch instruction. The process to clear the DA Market for committing generators to serve load in real-time in an organized market creates an additional level of risk. This issue may be partially mitigated by enhanced communications and greater flexibility in scheduling fuel supply. By contrast, in a non-organized market, where the generation owner has greater control over its dispatch decisions, there might not exist the same level of risk that the divergence between gas and electric will threaten the ability to generate as desired. Therefore, although enhanced coordination is needed in both organized and non-organized markets, the two differ in terms of the need to take into account challenges faced when generation commitment decisions and scheduling of fuel supply are not performed by a single entity.

C. The Commission Should Study the Change in Flows that Will Result from Increased Use of Natural Gas for Electricity Generation, and Include Consideration of Cost Recovery for Pipeline Expansion

The short answer to Commissioner Moeller's question whether FERC should address the change in flows that will result from expanded use of natural gas-fired generation is "yes." The change in flows poses issues for existing generation, but also adds complication and expense for new generation. These issues will be exacerbated as pipelines attempt to retain current levels of service to existing shippers while also trying to meet the needs of new gas-fired generation. The Commission will need to balance the desire to protect existing shippers from the cost of expansions that are necessary to serve these new demands, while also ensuring that new generation is not burdened with pipeline expansion costs that create a disincentive to generation development. For example, if the Commission were to address these issues by mandating that all gas-fired generation be backed with FT, it might require more costly service than is needed for reliable generation and create a disincentive to gas-fired generation investment.

NRECA recommends that the Commission study the issue, relying to the extent it can on studies and reports undertaken by reliable third parties, and then decide whether a rulemaking or further action on the issue is necessary. It may well be that the issue of change in flows and how to ensure reliability as a result fits within one of the "baskets" for rulemaking, (*e.g.*, operation or planning/contingency).

There are at least two contributors to the change in flows as natural gas is increasingly relied upon for electricity generation. First, the reliance on natural gas for electric generation will cause changes in flows as pipelines will need to ensure adequate transportation capacity and pipeline services to reach and meet the needs of electric generators. The Commission should study, or commission a study, of the level of transportation capability and pipeline services that will be needed to address the needs of new gas-fired generators.

Second, there may be changes in flows as a result of new or different production areas for natural gas. For example, since Pennsylvania is not a historical natural gas production area, pipeline infrastructure was not developed in order to export gas from the Pennsylvania region. As Marcellus Shale gas is increasingly relied upon as a resource for natural gas including fuel for electric generators, there must be adequate pipeline capacity to access the Pennsylvania supply. The increased use of non-traditional production areas might also pose threats to pipeline's ability to meet the needs of firm shippers beyond electric generators, because changes in production sources can impact other services and expectations such as storage injections. For example, Columbia Gas Transmission, LLC ("Columbia") recently received approval for an interim Transportation Cost Rate Adjustment ("TCRA") to cover the costs of third party transportation. Columbia explained that increased supply from Marcellus and other sources of production is displacing supply received for Columbia's northeastern markets and, as a result, has adversely affected Columbia's ability to fill its northern Ohio storage fields. Columbia said that it needed third party transportation in order to ensure that it will be able to serve its northern Ohio markets for the winter withdrawal season.[20] In addition to the interim TCRA, Columbia is working with its shippers to develop a long-term solution to these types of operational issues.

For both of these issues, NRECA believes that the Commission can and should look to the industry for analysis, then decide whether further action is necessary. For example, the Eastern Interconnection Planning Collaborative ("EIPC") is considering future transmission

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[20] *See, Columbia Gas Transmission Co., LLC*, 138 FERC ¶ 61,044 at P 4 (January 20, 2012).

expansion under various scenarios, one of which assumes retirement of the overwhelming majority of the Eastern Interconnection's coal-fired generation and replacement with natural gas-fired generation.[21] The EIPC study does not include consideration of whether the existing pipeline infrastructure can meet this demand. However, perhaps the issue of natural gas pipeline infrastructure necessary to accommodate this level of gas-fired generation development could be undertaken by the Eastern Interconnection State Planning Committee, which received a $14 million grant under the American Recovery and Reinvestment Act of 2009. Other industry groups, such as NERC[22], the Interstate Natural Gas Association of America[23], and APPA[24] have undertaken or raised the issue of pipeline expansion to accommodate increased reliance on natural gas for electric generation. RTOs and ISOs are likely considering these issues as well. The Commission should look to the work of these organizations and others in determining whether and what next steps should be taken, provided that any rulemaking or action in this regard should be part of an open and transparent process led by the Commission.

D. FERC Should Adopt a Flexible but Mandatory Approach to Harmonizing the Gas and Electric Trading Days

In prior proceedings, parties including NRECA members have urged the Commission to take action on the issue of revisions to pipeline intraday nomination schedules in order to better coordinate with electric generation scheduling.[25] Given the limited progress in this regard, the

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[21] The EIPC Phase I Report is available at http://www.eipconline.com

[22] *See* NERC's "Special Reliability Assessment: A Primer of the Natural Gas and Electric Power Interdependency in the United States."

[23] *See* Press Release from Don Santa, INGAA President and CEO, issued February 16, 2012, available at www.ingaa.org

[24] *See* APPA's Report: "Implications of Greater Reliance on Natural Gas for Electricity Generation", available at www.publicpower.org

[25] For example, in response to a NOPR issued in Docket Nos. RM96-1-027 on July 16, 2009, Old Dominion Electric Cooperative ("ODEC"), which is an NRECA member G&T cooperative, submitted comments and an Affidavit from John Baileys of ACES Power Marketing (which is owned by and provides gas scheduling service for parties including ODEC) in which Mr. Baileys explained ODEC's inability to effectively nominate and schedule natural gas

Commission should now mandate that pipelines address the scheduling issues and propose reforms to the Commission or explain why none are necessary.

1. The Lack of Harmonization in Schedules Causes Problems for Electric Generators Which Could Threaten Reliability

As context for NRECA's concerns and recommendation on this issue, we offer an explanation of the real-life impacts of the scheduling differences.

As discussed in Section B above, the lack of pipeline flexibility is a problem for gas-fired generators in all areas, but it is particularly difficult in an RTO region with DA/RT Markets. In areas with RTO markets, a generator must clear the DA Market to be committed for dispatch the next operating day. Therefore, the generation owner will not know if the RTO needs its generator to operate the following day *until several hours after* the deadline for the first gas Cycle, the Timely Cycle, for the electric generator/shipper to nominate natural gas on an interstate pipeline start has passed. As can be seen on Table 1, below, the first gas cycle is known as the Timely Cycle; the deadline for nominating gas for the next day's use is 11:30 AM Central Clock Time ("CCT"). The Evening Nomination Cycle ends at 6:00 PM CCT the day before gas flow. The Intra-Day 1 Cycle deadline is 10:00 AM CCT the day of gas flow and Intra-Day 2 deadline is 5:00 PM CCT the day of gas flow.[26]

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for delivery to its generating units due to limitations of the NAESB gas nomination timeline and the lack of flexibility offered by the pipeline from which ODEC takes transportation service.

[26] *See Standards for Business Practices for Interstate Natural Gas Pipelines*, 138 FERC ¶ 61,124 (2012) at P20.

Table 1: Nominating Deadlines on interstate gas pipelines[27]

Cycle	Nomination Time (CCT)	Nomination Effective	Bumping IT	Bumping Notice	Schedule Confirmed
Timely	11:30 a.m.	Day-Ahead	Yes	4:30 p.m.	4:30 p.m.
Evening	6 p.m.	Day-Ahead	Yes	10 p.m.	10 p.m.
Intra-Day 1	10 a.m.	Day of	Yes	2 p.m.	2 p.m.
Intra-Day 2	5 p.m.	Day of	No	NA	9 p.m.

By the time the generator does know whether it has cleared the DA Market, it is well into the afternoon, well into the Evening gas cycle, and it may be too late for the electric generator/shipper to schedule all the gas it may need, using the FT capacity it owns, for the following day.

Moreover, if a electric generator/shipper does not schedule all its FT capacity by the Timely cycle deadline at 11:30 AM CCT before the operating day, the FT shipper is at risk of losing the right to access its unused FT capacity if other shippers schedule natural gas on an secondary, alternate path in a manner that conflicts with the electric generator/shipper's primary path. This gas-electric operating day scheduling mismatch puts gas-fired electric generators into a predicament, with 2 choices, A. and B. In Choice A., the electric generator can forecast whether the RTO will, in the afternoon before the electric operating day, receive a DA Market call from the RTO to run the next day. If it turns out that the electric generator does not clear the DA Market, the generator may need to sell this procured gas into the gas market, inject gas into storage or use pipeline services, such as "parking"[28] to dispose of the forecasted gas usage. Most of these actions will increase costs that the shipper will not recover. In Choice B., the generator. can wait until it actually receives a DA Market award from the RTO, after the Timely gas market

[27] *Id.*; note that "Bumping" in Table 1 refers the ability of a FT nomination to "bump" or displace interruptible, or "IT" in Table 1scheduled quantities through the Intra-Day 1 cycle subject to NAESB elapsed pro-rata rules.
[28] "Parking" is a service offered by a pipeline in which a shipper delivers gas which the pipeline holds for a specified number of days for use by the shipper in the future.

deadline has passed, and attempt to schedule natural gas on the FT capacity remaining to it. With Choice B., because the shipper did not schedule gas in the Timely Cycle, the FT shipper is at risk of losing the right to use its FT capacity if other shippers schedule gas over a secondary path in a manner that conflicts with the FT shipper's primary path.[29] This choice may cause gas not to flow and generation not being available as scheduled. Additionally, if the electric generators FT capacity is available, many times the interstate pipeline may deny the electric generator shipper's request to utilize its entire FT capacity in a less than "ratable" or uniform fashion, due to typical tariff requirements that require pipeline capacity be scheduled in a uniform hourly fashion over the course of the gas day or due to pipeline operational constraints at the time of the request. For instance, if a shipper has contracted for 240,000 Dth/day of FT capacity, the pipeline may require that the shipper take 10,000 Dth (1/24 * 240,000 Dth) per hour, despite the fact that an electric generator's natural gas consumption profile is likely to be concentrated during the peak hours of the day it is called to run.

In sum, current pipeline tariffs/practices may not afford gas-fired generators owning FT capacity adequate operational flexibility to manage their gas supply in response to the varied generation awards and timing of those directives placed on them. However, the Commission should also address the RTO's DA/RT Markets timing for potential generation schedule timing improvements to help address the gas coordination issues to determine if it can better fit within the pipeline generation requirements. As discussed next, the Commission should take action to address the issue, by mandating that the pipelines do so.

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[29] The term "primary path" means the path defined by the receipt and delivery points specified on a shipper's FT contract.

2. NRECA Recommends a Mandatory but Flexible Approach

In its 2009 rulemaking, the Commission declined to address the issue and instead opted to rely on individual pipelines to come forward with proposals to accommodate electric generators.[30] Some pipelines have taken the initiative to propose additional scheduling opportunities and services to accommodate electric generators. For example, in order to accommodate the needs of gas-fired electric generators, Texas Gas Transmission Company has adopted an Enhanced Nomination Service which allows eleven additional scheduling opportunities during the day to accommodate the needs of electric generators and a Winter No-Notice Service. Transcontinental Gas Pipeline Company, LLC's ("Transco") Tariff General Terms and Conditions ("GT&Cs") § 28.1(d) allows customers to submit nominations after the last NAESB nomination cycle, within a reasonable time after the gas day at issue. Transco also allows customer-submitted pre-determined allocations, subject to limitations. (Transco's GT&Cs § 39). Southern Natural Gas Company, LLC's GT&Cs § 13.2(f) provides flexibility for customers using multiple types of transportation services at a single point.

Notwithstanding these types of voluntary pipeline initiatives, there is far from "harmony" between the two markets. Rather than rely on the individual pipelines to address these issues of their own volition, the Commission should mandate that the issue is addressed by all pipelines, not just those who choose to act.

NRECA recognizes that overhauling either generator dispatch schedules, electricity market schedules and/or natural gas trading schedules might be more of an undertaking than can be achieved in a reasonable time period, if at all. Therefore, NRECA recommends a flexible but mandatory approach. Specifically, the Commission should require pipelines to either propose

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[30] *Standards for Business Practices for Interstate Natural Gas Pipelines*, Order No. 587-U, 130 FERC ¶ 61,212 (2009)

service offerings to accommodate the reality that gas and electric schedules do not match, or demonstrate why such services are not necessary on the individual pipeline. Finally, on this point, NRECA notes that in addition to addressing gas-electric coordination issues, such enhanced offerings by pipelines might go a long way in accommodating additional gas-fired generation in a manner that mitigates or avoids the need for costly pipeline expansion while also allowing services to be paid for by those who need the additional flexibility.

E. Coal and Oil-Fired Generation Retirement Creates an Urgency for Gas and Electricity Coordination

By most accounts, the retirement of coal- and oil-fired generation will result in increased reliance on natural gas for electric generation. For example, according to NERC, approximately 100 GW of gas-fired generation will be added to the bulk power system over the next ten years.[31] As NRECA discussed at the start of these comments and in Section C above, the increased reliance on natural gas as coal and oil-fired generation units retire creates a need for the Commission to act, in the short- and long-term, to ensure that there is sufficient pipeline transportation capacity and coordination between the two industries in order to ensure reliability of the bulk power system.

F. The Commission Should Not Modify Its Standards of Conduct

Commissioner Moeller posed the question of the extent to which FERC should consider modifying its Standards of Conduct with regulated utilities – either on an emergency basis or in a more fundamental manner – to assure greater coordination of these industries. NRECA submits that no such modifications should be made at this time. Instead, the Commission should include Standards of Conduct issues in one of the rulemaking "baskets" for further discussion. NRECA

[31] *See* NERC's Special Reliability Assessment: A Primer of the Natural Gas and Electric Power Interdependency in the United States" at page 42.

cautions strongly against any relaxation or modification to the Standards of Conduct, because it might have the unintended consequence of facilitating manipulative or otherwise anti-competitive practices and/or allow pipelines a safety net to rely upon as opposed to taking proactive measures to improve coordination.

The Commission's existing regulations should be sufficient to tide the industries over while the Commission works to make improvements to gas-electric coordination through rulemaking and compliance filings as recommended above. The Commission's Standards of Conduct regulations provide that notwithstanding the independent functioning rule and the no conduit rule, transmission function and marketing function employees can exchange non-public information as needed to comply with Reliability Standards or to maintain or restore operation of the transmission system or generating units, or that may affect the dispatch of generating units, with further exception for emergency circumstances.[32] The Commission should not at this time consider relaxing or modifying its Standards of Conduct.

G. The Issues Should Be Addressed in Baskets

As discussed throughout these comments, NRECA recommends that the Commission proceed with "basket" rulemakings. In order to have in place those reforms that are most needed and/or easily achieved, the Commission could perhaps prioritize the baskets for rulemaking proceedings, and institute concurrent proceedings.

[32] 18 C.F.R. § 358.7(h)(2011).

III. CONCLUSION

WHEREFORE, for the reasons described herein, NRECA respectfully requests that the Commission consider the comments set forth above.

Respectfully submitted,

S – Richard Meyer
Richard Meyer, Senior Regulatory Counsel
Paul McCurley, Senior Principal and Chief Engineer
NATIONAL RURAL ELECTRIC COOPERATIVE ASSOCIATION
4301 Wilson Boulevard
Arlington, VA 22203-1860

Adrienne E. Clair
Stinson Morrison Hecker LLP
1150 18th Street NW, Suite 800
Washington, D.C. 20036
(202) 785-9100
Counsel to the National Rural Electric Cooperative Association

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