North American Energy Standards Board

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via email and posting

TO:	NAESB Gas Electric Coordination Task Force Leadership
CC:	NAESB Managing Committee, NAESB Executive Committee Quadrant Chairs
FROM:	Michael Desselle, Chairman, NAESB Board of Directors
RE:	Comments on draft GECTF Final Report and Suggestions for Improvement
DATE:	June 22, 2004

Dear Gas Electric Coordination Task Force Leadership,

First let me thank you for all the time and effort spent in meetings regarding gas-electric coordination. Our industries are in the midst of a transition that requires more coordination and cooperation between the natural gas and electric markets and the procedures and services by which they interact. Standards can play a vital role in this coordination – which is recognized by FERC and by the North American Electric Reliability Council.

The NERC Board of Trustees recently approved its Gas Electricity Interdependencies report. In quoting from its conclusions:

> "Based on the information gathered at its meetings, the GEITF was able to draw the following conclusions: (1) Gas pipeline reliability can substantially impact electric generation; (2) Electric system reliability can have an impact on gas pipeline operations; (3) In general, pipeline and electric system operators do not understand each other's business very well; (4) Pipeline planning and expansion are substantially different from the electric equivalent; (5) Communications between pipeline operators and electric reliability coordinators are generally weak; (6) Pipeline tariffs for firm delivery service are not compatible with peaking generation economics in many electric markets and that (7) Modern combustion turbines have stringent fuel delivery and fuel quality requirements."

This is evidence of the importance of the coordination needed between the industries – that will grow in importance, rather than diminish in the future.

Also Chairman Wood of the FERC in the recent Northeastern Energy Infrastructure Technical Conference noted in questions to Ms. McQuade that:

> "As we saw from the initial presentation Jeff did, how much of a bigger role gas is playing in this part of the country and throughout the whole sunbelt, and certainly the west as well. Please reiterate to your board how strongly this agency has depended on their work over the last ten years to get better answers than the regulators could ever get to ourselves. And how important an integrated approach that we all did in your name two years needs to lead to a work product and thought process because we are counting on it."

Similarly, this is further evidence that the two industries should move forward and the FERC expects NAESB to play a role in such movement. To be responsive, we must show through this report, which efforts lend themselves to standardization, hold a priority and should be considered in the 2004-2005 timeframe. The value of your efforts in developing this report on behalf of NAESB will be in identifying actions for our organization to consider undertaking.

As such, I would urge you not only to provide the "Expanded and Categorized Discussion Points" in the report you are preparing for approval by the Managing Committee, but also include which items could be considered through standardization efforts, and a level of priority for those items that should be considered both this year and also in 2005. This format was used in the

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recent FERC filing of the Seams Subcommittee. Also I urge you to identify where policy determinations are needed from regulators before standards development can commence.

Of course, consideration for standards development would take the form of industry participants submitting requests and processing those requests through our ANSI accredited standards development process. I applaud KeySpan and Duke Energy for taking the first step and preparing a request for Energy Day. However, more such requests are needed, and an indication from your subcommittee on priorities and actions expected to be taken in 2004 and 2005 are critical if we are to establish our credibility as an organization that can develop standards supportive of both industries.

I look forward to the submittal of your report for the Managing Committee's approval, and again thank you for all the hard work expended to date. This report can serve as a pivotal document for both industries – one that highlights areas where standards can facilitate coordination and move our two industries to a more seamless market –

Best Regards,

Michael Desselle
Chairman, NAESB Board of Directors

cc: Roger Cooper, AGA
Bert Kalisch, APGA
David Penn, APPA
David Owens. EEI
Lynne Church, EPSA
David Sweet, ILNGA
Don Santa, INGAA
Barry Russell, IPAA
Bill Museler, ISO-RTO Council
Chuck Gray, NARUC
Charles Acquard, NASUCA
Michehl Gent, NERC
Skip Horvath, NGSA
David Mohre, NRECA

attach: GECTF Draft Final Report Cover
GECTF Draft Appendix 1: GECTF Preliminary Discussion Points List – Expanded & Categorized

North American Energy Standards Board
Gas and Electric Coordination Task Force
Final Report
(effective July 1, 2004)

This is the final report of the Gas and Electric Coordination Task Force (GECTF) to advise the Executive Committees of all four NAESB quadrants that the task force has completed its assigned task and request that the task force be disbanded.

History

The GECTF was established in December 2003 with co-chairs representing the Wholesale Gas, Wholesale Electric, Retail Gas and Retail Electric Quadrants to address specific issues related to its mission. The mission of the task force is:

> "The Gas and Electric Coordination Task Force (GECTF) is an ad hoc task force reporting to the four quadrant Executive Committees. The GECTF is tasked with reviewing and investigating possible standards creation and/or modifications related to additional coordination of the interaction between the scheduling of electric and gas transactions."

The GECTF prepared an Interim Status Report[1] on March 16, 2004, which was subsequently approved by the Executive Committees of all four NAESB quadrants on April 5, 2004 and distributed to interested industry stakeholders on April 16, 2004.

Accomplishments & Deliverables

Based on its mission statement, the task force focused on the education of gas and electric industry participants and identification of discussion points that could provide opportunities to improve gas/electric scheduling and transactional coordination, and grouped those points into broad categories. The task force did not develop any standards or requests for standards.

The principal work product of the task force is the GECTF Discussion Points List (DPL) (Appendix A), which is organized into 14 broad categories.[2] The DPL is a representation of areas of coordination between the gas and electric industries that the GECTF identified as potential items that could be further investigated by the appropriate organizations in order to enhance and improve operational coordination between the electric and gas industries.

The DPL is intended to reflect task force participants' opinions with respect to points that have some impact on gas and electric coordination and each of the categories is defined by the context of the detailed DPL. While the final DPL reflects input from all members of the task force, each of the items in the list should not be considered by itself a consensus work product. [Please note we did not take a vote that this was not a consensus work product – the vote could be that we do not find consensus or we take a vote to reach consensus and it fails]. Additionally, organization of the DPL does not indicate: 1) the relative importance of the items; 2) that any of the items are or are not appropriate for standardization; and/or 3) that all coordination matters can be addressed through standardization. While it was anticipated by some participants that the DPL would continue to be refined, the task force determined that reaching a working consensus on prioritization was not possible. Accordingly, any further work on

[1] The Interim Status Report is available at http://www.naesb.org/pdf/ferc041604.pdf.

[2] The DPL categories are: energy day; communications; gas nominations timelines; electric market timelines; gas contracts/service portfolios of electric companies; electric generation gas supply verification; available transportation service provider services; natural gas industry infrastructure; electric market rules; natural gas supply real time flexibility; electric industry infrastructure; electric industry organization; energy reliability; and information.

the DPL, including prioritization or determining which items lend themselves to standardization, should occur through a combination of stakeholder response to the GECTF report and/or industry action, through submittal of a request or through regulatory action.

The DPL provides a starting point for industry stakeholders interested in submitting standards requests or pursuing resolution in forums other than NAESB to address gas and electric coordination. Any requests for standards submitted as a result of the DPL will be processed in accordance with established NAESB procedures. For the items that may ultimately be submitted to NAESB for standards development, some points may need to be addressed in other forums prior to consideration of standards development in NAESB.

Process & Procedures

The GECTF has met a total of eight times over fourteen days: six two-day meetings in person and twice via conference call. The meetings since the filing of the interim report were held on:

- April 13-14, 2004;
- April 28, 2004;
- May 18-19, 2004
- June 29-30, 2004.

To accomplish its investigatory and educational goal, numerous presentations were given by both the gas and electric industries. Additionally, in recognition that the GECTF was not the sole group addressing industry coordination, the GECTF invited NERC's Gas/Electric Interdependency Task Force (GEITF) to present its findings. The presentations created a better understanding of the characteristics and practices in both the gas and electric industries and provided a common understanding for the development of the DPL.

Gas Presentations

Title	Presenter(s)	Date[3]
Gas Nomination Timeline Impact Upon LDC Operations	Mike Novak, National Fuel Distribution	01/04
http://www.naesb.org/pdf/gectf012904w3.pdf		
Basic Gas Flow Dynamics and Related Scheduling Factors	Bill Griffith, El Paso Pipelines Paul Love, NGPL	01/04
http://www.naesb.org/pdf/gectf012904w4.pdf		
Gas Producers Presentation	Paul McKelvey, ChevronTexaco	01/04
http://www.naesb.org/pdf/gectf012904w5.pdf		
Gas Day versus Calendar Day	Bill Griffith, El Paso Pipelines	03/04
http://www.naesb.org/pdf/gectf031504w7.pdf		
NAESB WGQ Capacity Release Standards and Procedures	Bill Griffith, El Paso Pipelines	03/04
http://www.naesb.org/pdf/gectf031504w6.pdf		
NAESB WGQ Nominations and Scheduling Standards and Procedures	Bill Griffith, El Paso Pipelines	03/04
http://www.naesb.org/pdf/gectf031504w8.pdf		

[3] Presentations presented before April 2004 were included in the GECTF Interim Status Report.

Electric Presentations

Title	Presenter(s)	Date[4]
Electricity 101	Andy Rodriquez, PJM	01/04
http://www.naesb.org/pdf/gectf012904w7.pdf	Kalim Tippitt, The Structure Group	
Generation Dispatch 101	Diane McVicker, Salt River Project	01/04
http://www.naesb.org/pdf/gectf012904w9.pdf		
A Retail Electric Perspective on Billing & Settlement	Ed Berman, Baltimore Gas & Electric	01/04
http://www.naesb.org/pdf/gectf012904w8.pdf		
Transmission Timing Analysis	Alan Johnson, Mirant	03/04
http://www.naesb.org/pdf/gectf031504w2.pdf		
Example of Natural Gas Industry and Electric Industry Timing Issue	Alan Johnson, Mirant	03/04
http://www.naesb.org/pdf/gectf031504w4.pdf		
Market Timing Issues	Alan Johnson, Mirant	03/04
http://www.naesb.org/pdf/gectf031504w3.pdf		
TVA Timeline Example	John Porter, TVA	04/04
http://www.naesb.org/pdf/gectf041304w6.pdf		
Additional Examples of Natural Gas Industry and Electric Industry Timing Issue	Alan Johnson, Mirant	04/04
http://www.naesb.org/pdf/gectf041304w8.pdf		
http://www.naesb.org/pdf/gectf041304w9.pdf		
http://www.naesb.org/pdf/gectf041304w10.pdf		
http://www.naesb.org/pdf/gectf041304w11.pdf		
http://www.naesb.org/pdf/gectf041304w12.pdf		
http://www.naesb.org/pdf/gectf041304w13.pdf		
NERC Gas/Electric Interdependency Task Force Status Report	Philip Fedora, NPCC	05/04
http://www.naesb.org/pdf/gectf051804w2.pdf		

Consistent with the NAESB Certificate, Bylaws and Operating Procedures, all of the GECTF meetings were open and posted on the NAESB website. Representatives from all four quadrants and industry trade associations participated in each of the meetings. The meeting minutes and presentations at the above-referenced meetings are attached.

Conclusion

Participants of the GECTF recognize that continued understanding and communication are to the benefit of both the electric and gas industries, especially as the dynamics of both industries continue to evolve. In fact, several GECTF participants also participated in NERC's GEITF and other regional coordination efforts.

The GECTF is not directing any party to take any particular action. NAESB and its members should continue to participate in other industry groups' educational efforts. The task force encourages industry participants to take advantage of the NAESB process by submitting requests for standards relating to the business practices associated with gas and electric industry coordination. Future standards development activity by NAESB will result from requests that are submitted to the NAESB Office or are included in the Annual Plan process. Additionally, the task force believes this

[4] Presentations presented before April 2004 were included in the GECTF Interim Status Report.

report provides a foundation for the regulatory community to determine whether further action on their part is required.

Supporting Documentation

Appendix I:	GECTF Preliminary Discussion Points List – Expanded & Categorized
Appendix II:	GECTF Meeting Minutes since April 5, 2004
Appendix III:	GECTF Presentations since April 5, 2004
Appendix IV:	Participants in the GECTF Effort
Appendix V.	Comments Received on the Report and on the Issues Identified

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GECTF Preliminary Discussion Points List – Expanded & Categorized

Purpose: The purpose of this document is to reflect the GECTF Preliminary Discussion Points List in the categorization developed during the April 13-14, 2004 GECTF meeting. Categories include:

A. Energy Day

B. Communications (format, frequency)

C. Gas Nominations Timelines

D. Electric Market Timelines

E. Gas Contracts/Services Portfolios of Electric Companies

F. Electric Generation Gas Supply Verification

G. Available Transportation Service Provider Services

H. Natural Gas Industry Infrastructure

I. Electric Market Rules

J. Natural Gas Supply Real Time Flexibility

K. Electric Industry Infrastructure

L. Electric Industry Organization

M. Energy Reliability

Q. Information

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A. Energy Day

Flexibility/Planning:

1.3. Identify differences in the factors driving dispatch priority between natural gas and power.

1.3.1 If multiple priority of service levels are used in a nomination chain, the lowest service level may dictate the priority of the entire chain. eg. Firm service on an upstream service provider (commodity or transportation) tied to interruptible service on a downstream service provider may result in gas not being scheduled to flow as nominated. The converse is also true.

1.3.2 Electric dispatch is subject to contractual and tariff commitments but is also impacted by: availability of prescheduled generation assets; congestion at bottlenecks on the transmission system; availability of incremental/decremental energy at various points in the transmission system; and the economic value of real time incremental/decremental energy at various points in the transmission system. Electric transmission tariffs (OATTs) contain curtailment policies.

1.3.3 Natural gas dispatch is subject to contractual commitments including the confirmation of the gas supply and tariff requirements, including priority of service and or curtailment procedures. Generally, natural gas dispatch is not impacted by the price of the natural gas supply.

1.3.4 In organized electric markets, the ISOs or RTOs work to maintain the balance between generation and load. Outside ISOs and RTOs, integrated utilities usually fulfill this function.

1.3.5 Electric Generators have an obligation to perform, but the determination of which generation resources are used is sometimes based on pricing but also on availability of generation inputs.

1.3.6 When does a generator know gas is needed to serve a particular market (quantity and time)?

1.3.7 RTOs/ISOs don't verify a generator's gas supply or firm capacity arrangements before accepting a generator's bid due to the fact that a generator is obligated in the real time market to generate or to purchase the generation to cover the obligation.

1.3.8 Market rules and/or market mitigation (price caps) can negatively impact the availability of generation assets.

Timelines / Scheduling:

2.1. There is one NAESB WGQ standard gas day and a standard nomination/scheduling timeline and there are many regional power days and power scheduling timelines that may contribute to difficulties in cross-commodity standardization. Identify the impact of the differences between the WGQ standard gas day and nomination/scheduling timeline and the multiple regional power market timelines.

2.1.1 There are obvious mismatches between the gas day and electric day-ahead and real time markets.

2.1.2 Each electric market has its own timeline.

2.1.3 Can the multiple electric timelines be consolidated?

2.1.4 Gas pipelines may serve multiple regional power markets, therefore individual market timelines would significantly complicate gas scheduling.

B. Communications (format, frequency)

Flexibility/Planning:

1.3. Identify differences in the factors driving dispatch priority between natural gas and power.

1.3.1 If multiple priority of service levels are used in a nomination chain, the lowest service level may dictate the priority of the entire chain. eg. Firm service on an upstream service provider (commodity or transportation) tied to interruptible service on a downstream service provider may result in gas not being scheduled to flow as nominated. The converse is also true.

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1.3.8 Market rules and/or market mitigation (price caps) can negatively impact the availability of generation assets.

1.7. The impact on the gas infrastructure of non-scheduled gas-fired generation coming on or going off without notice.

1.7.1 Lack of planning for peaking needs.

1.7.2 Alignment of purchase of proper services, if available.

1.7.3 An increase in gas-fired generation coming on line could result in gas flow control which would limit the gas flow at particular points.

1.7.4 New services and/or procedures (such as 'real time' natural gas service) may be needed.

1.7.5 What are the current solutions for handling the needs of peaking generation facilities?

1.7.6 If a market takes unauthorized gas deliveries, other scheduled shippers may be adversely impacted.

1.9. Is there a need for more intraday flexibility in gas scheduling?

1.9.1 The need for intraday flexibility in gas scheduling should be weighed for the needs of both industries.

1.9.2 If a change is only for the benefit of the electric industry, then the change should not occur.

1.9.3 Additional intraday nominations opportunities increase the availability of feedback data for the pipelines and would make the industries more transparent.

1.9.4 There is the need for something closer to real time or same day flexibility, but the facilities are currently not in place.

1.9.5 LDCs cannot manage additional flexibility (logistical issues).

1.9.6 Flexibility has economic value.

1.9.7 The physical nature of the commodities is different. It takes 2.5 to 3 days for gas input in the gulf to travel to New York. Electricity is instantaneous and cannot be stored.

Timelines / Scheduling:

2.2. Identify notice requirements that are to be provided to pipelines and/or service providers by shippers regarding load and flow changes. Identify the need for increased and/or more formal communication protocols between natural gas and power operations / control room personnel.

2.2.1 Communication procedures should be formalized. This could include informing the pipelines of a day ahead generation plan and projected gas needs in MMBtu or MCF. This should include both daily and hourly requirements.

2.2.2 Modifications should be communicated when known.

2.2.3 There are potential confidentiality and code of conduct issues.

2.2.4 There is a potential for coordinated maintenance outages.

Terminology:

4.1. There are differences in terminology between natural gas and power (e.g., does “Firm” mean the same thing in both commodities?)

C. Gas Nominations Timelines

Flexibility/Planning:

1.1. Identify the impact of weather and other uncontrollable factors on generation and gas load swings.

1.1.1 Issues may include pricing, unknown generation needs, and gas units being turned on or off with short notice.

1.1.2 While there may not be available services to mitigate, there could be market-based tools available.

1.1.3 There is a lack of historical statistics with respect to extreme weather on generation unit availability.

1.3. Identify differences in the factors driving dispatch priority between natural gas and power.

1.3.1 If multiple priority of service levels are used in a nomination chain, the lowest service level may dictate the priority of the entire chain. eg. Firm service on an upstream service provider (commodity or transportation) tied to interruptible service on a downstream service provider may result in gas not being scheduled to flow as nominated. The converse is also true.

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1.3.8 Market rules and/or market mitigation (price caps) can negatively impact the availability of generation assets.

1.8. Identify examples of the service characteristics that could meet the market needs for increased delivery flexibility.

1.8.1 Service Characteristics:

1.8.1.1 Firm vs. IT

1.8.1.2 Firm Balancing

1.8.1.3 Should be developed to work for both uniform flow markets and non-uniform flow markets without producing negative impacts on other markets.

1.8.1.4 Any service offerings are tied to operational characteristics.

1.8.1.5 Storage based services (non-notice or short notice).

1.8.1.6 Park & Loan

1.8.1.7 Linepack

1.8.1.8 Communication mitigation RFP procedure by pipeline.

1.8.1.9 There are economics to providing any service.

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1.9.1 The need for intraday flexibility in gas scheduling should be weighed for the needs of both industries.

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2.1.3 Can the multiple electric timelines be consolidated?

2.1.4 Gas pipelines may serve multiple regional power markets, therefore individual market timelines would significantly complicate gas scheduling.

2.4. Can the natural gas producers and marketers react to 'within the day' requirement changes?

2.4.1 There is a lag between gas scheduling and the related change in gas flow rates.

2.4.2 Producers will not nominate or confirm gas at well heads to markets requiring irregular flows. Marketers are willing to use all available services to serve the needs of all customers.

2.4.3 What is the reasonable minimum amount of notice necessary to affect a change of supply to meet load?

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D. Electric Market Timelines

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E. Gas Contracts/Services Portfolios of Electric Companies

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1.3.8 Market rules and/or market mitigation (price caps) can negatively impact the availability of generation assets.

1.4. Distinguish between the need for changes to the NAESB WGQ Standards and the need to make adjustments to gas contract portfolios (supply, transportation and/or other services) and/or gas infrastructure requirements. Additional incentives may be needed to encourage entities to diversify their gas contract portfolios to meet their market requirements.

1.7. The impact on the gas infrastructure of non-scheduled gas-fired generation coming on or going off without notice.

1.7.1 Lack of planning for peaking needs.

1.7.2 Alignment of purchase of proper services, if available.

1.7.3 An increase in gas-fired generation coming on line could result in gas flow control which would limit the gas flow at particular points.

1.7.4 New services and/or procedures (such as 'real time' natural gas service) may be needed.

1.7.5 What are the current solutions for handling the needs of peaking generation facilities?

1.7.6 If a market takes unauthorized gas deliveries, other scheduled shippers may be adversely impacted.

1.8. Identify examples of the service characteristics that could meet the market needs for increased delivery flexibility.

1.8.1 Service Characteristics:

1.8.1.1 Firm vs. IT

1.8.1.2 Firm Balancing

1.8.1.3 Should be developed to work for both uniform flow markets and non-uniform flow markets without producing negative impacts on other markets.

1.8.1.4 Any service offerings are tied to operational characteristics.

1.8.1.5 Storage based services (non-notice or short notice).

1.8.1.6 Park & Loan

1.8.1.7 Linepack

1.8.1.8 Communication mitigation RFP procedure by pipeline.

1.8.1.9 There are economics to providing any service.

Timelines / Scheduling:

2.4. Can the natural gas producers and marketers react to 'within the day' requirement changes?

2.4.1 There is a lag between gas scheduling and the related change in gas flow rates.

2.4.2 Producers will not nominate or confirm gas at well heads to markets requiring irregular flows. Marketers are willing to use all available services to serve the needs of all customers.

2.4.3 What is the reasonable minimum amount of notice necessary to affect a change of supply to meet load?

Reliability:

3.2. Distinguish between coordination issues that are originated by 1) true reliability issues versus 2) those caused by trading risk management practices.

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F. Electric Generation Gas Supply Verification

Flexibility/Planning:

1.3. Identify differences in the factors driving dispatch priority between natural gas and power.

1.3.1 If multiple priority of service levels are used in a nomination chain, the lowest service level may dictate the priority of the entire chain. eg. Firm service on an upstream service provider (commodity or transportation) tied to interruptible service on a downstream service provider may result in gas not being scheduled to flow as nominated. The converse is also true.

1.3.2 Electric dispatch is subject to contractual and tariff commitments but is also impacted by: availability of prescheduled generation assets; congestion at bottlenecks on the transmission system; availability of incremental/decremental energy at various points in the transmission system; and the economic value of real time incremental/decremental energy at various points in the transmission system. Electric transmission tariffs (OATTs) contain curtailment policies.

1.3.3 Natural gas dispatch is subject to contractual commitments including the confirmation of the gas supply and tariff requirements, including priority of service and or curtailment procedures. Generally, natural gas dispatch is not impacted by the price of the natural gas supply.

1.3.4 In organized electric markets, the ISOs or RTOs work to maintain the balance between generation and load. Outside ISOs and RTOs, integrated utilities usually fulfill this function.

1.3.5 Electric Generators have an obligation to perform, but the determination of which generation resources are used is sometimes based on pricing but also on availability of generation inputs.

1.3.6 When does a generator know gas is needed to serve a particular market (quantity and time)?

1.3.7 RTOs/ISOs don't verify a generator's gas supply or firm capacity arrangements before accepting a generator's bid due to the fact that a generator is obligated in the real time market to generate or to purchase the generation to cover the obligation.

1.3.8 Market rules and/or market mitigation (price caps) can negatively impact the availability of generation assets.

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G. Available Transportation Service Provider Services

Flexibility/Planning:

1.2. Discuss ways to accommodate the natural gas requirements of new generation as it comes online in various regions.

a. The impact on the gas infrastructure of new gas-fired generation facilities.

1.2.1 Gas input supply, transportation capacity availability, and capacity contract rights (types of available services) are relevant to new gas-fired generation facilities.

1.2.2 Type of generation facility and physical location of the facility are relevant issues.

1.2.3 Lack of North American electric scheduling standards is problematic.

1.2.4 Electric generation facility citing is a regulated process.

1.3. Identify differences in the factors driving dispatch priority between natural gas and power.

1.3.1 If multiple priority of service levels are used in a nomination chain, the lowest service level may dictate the priority of the entire chain. eg. Firm service on an upstream service provider (commodity or transportation) tied to interruptible service on a downstream service provider may result in gas not being scheduled to flow as nominated. The converse is also true.

1.3.2 Electric dispatch is subject to contractual and tariff commitments but is also impacted by: availability of prescheduled generation assets; congestion at bottlenecks on the transmission system; availability of incremental/decremental energy at various points in the transmission system; and the economic value of real time incremental/decremental energy at various points in the transmission system. Electric transmission tariffs (OATTs) contain curtailment policies.

1.3.3 Natural gas dispatch is subject to contractual commitments including the confirmation of the gas supply and tariff requirements, including priority of service and or curtailment procedures. Generally, natural gas dispatch is not impacted by the price of the natural gas supply.

1.3.4 In organized electric markets, the ISOs or RTOs work to maintain the balance between generation and load. Outside ISOs and RTOs, integrated utilities usually fulfill this function.

1.3.5 Electric Generators have an obligation to perform, but the determination of which generation resources are used is sometimes based on pricing but also on availability of generation inputs.

1.3.6 When does a generator know gas is needed to serve a particular market (quantity and time)?

1.3.7 RTOs/ISOs don't verify a generator's gas supply or firm capacity arrangements before accepting a generator's bid due to the fact that a generator is obligated in the real time market to generate or to purchase the generation to cover the obligation.

1.3.8 Market rules and/or market mitigation (price caps) can negatively impact the availability of generation assets.

1.4. Distinguish between the need for changes to the NAESB WGQ Standards and the need to make adjustments to gas contract portfolios (supply, transportation and/or other services) and/or gas infrastructure requirements. Additional incentives may be needed to encourage entities to diversify their gas contract portfolios to meet their market requirements.

1.5. Allowing more flexibility to non-firm gas shippers may impact the service levels and contractual rights of existing / traditional firm shippers.

1.7. The impact on the gas infrastructure of non-scheduled gas-fired generation coming on or going off without notice.

1.7.1 Lack of planning for peaking needs.

1.7.2 Alignment of purchase of proper services, if available.

1.7.3 An increase in gas-fired generation coming on line could result in gas flow control which would limit the gas flow at particular points.

1.7.4 New services and/or procedures (such as 'real time' natural gas service) may be needed.

1.7.5 What are the current solutions for handling the needs of peaking generation facilities?

1.7.6 If a market takes unauthorized gas deliveries, other scheduled shippers may be adversely impacted.

1.8. Identify examples of the service characteristics that could meet the market needs for increased delivery flexibility.

1.8.1 Service Characteristics:

1.8.1.1 Firm vs. IT

1.8.1.2 Firm Balancing

1.8.1.3 Should be developed to work for both uniform flow markets and non-uniform flow markets without producing negative impacts on other markets.

1.8.1.4 Any service offerings are tied to operational characteristics.

1.8.1.5 Storage based services (non-notice or short notice).

1.8.1.6 Park & Loan

1.8.1.7 Linepack

1.8.1.8 Communication mitigation RFP procedure by pipeline.

1.8.1.9 There are economics to providing any service.

1.9. Is there a need for more intraday flexibility in gas scheduling?

1.9.1 The need for intraday flexibility in gas scheduling should be weighed for the needs of both industries.

1.9.2 If a change is only for the benefit of the electric industry, then the change should not occur.

1.9.3 Additional intraday nominations opportunities increase the availability of feedback data for the pipelines and would make the industries more transparent.

1.9.4 There is the need for something closer to real time or same day flexibility, but the facilities are currently not in place.

1.9.5 LDCs cannot manage additional flexibility (logistical issues).

1.9.6 Flexibility has economic value.

1.9.7 The physical nature of the commodities is different. It takes 2.5 to 3 days for gas input in the gulf to travel to New York. Electricity is instantaneous and cannot be stored.

Timelines / Scheduling:

2.4. Can the natural gas producers and marketers react to 'within the day' requirement changes?

2.4.1 There is a lag between gas scheduling and the related change in gas flow rates.

2.4.2 Producers will not nominate or confirm gas at well heads to markets requiring irregular flows. Marketers are willing to use all available services to serve the needs of all customers.

2.4.3 What is the reasonable minimum amount of notice necessary to affect a change of supply to meet load?

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H. Natural Gas Industry Infrastructure

Flexibility/Planning:

1.2. Discuss ways to accommodate the natural gas requirements of new generation as it comes online in various regions.

a. The impact on the gas infrastructure of new gas-fired generation facilities.

1.2.1 Gas input supply, transportation capacity availability, and capacity contract rights (types of available services) are relevant to new gas-fired generation facilities.

1.2.2 Type of generation facility and physical location of the facility are relevant issues.

1.2.3 Lack of North American electric scheduling standards is problematic.

1.2.4 Electric generation facility citing is a regulated process.

1.3. Identify differences in the factors driving dispatch priority between natural gas and power.

1.3.1 If multiple priority of service levels are used in a nomination chain, the lowest service level may dictate the priority of the entire chain. eg. Firm service on an upstream service provider (commodity or transportation) tied to interruptible service on a downstream service provider may result in gas not being scheduled to flow as nominated. The converse is also true.

1.3.2 Electric dispatch is subject to contractual and tariff commitments but is also impacted by: availability of prescheduled generation assets; congestion at bottlenecks on the transmission system; availability of incremental/decremental energy at various points in the transmission system; and the economic value of real time incremental/decremental energy at various points in the transmission system. Electric transmission tariffs (OATTs) contain curtailment policies.

1.3.3 Natural gas dispatch is subject to contractual commitments including the confirmation of the gas supply and tariff requirements, including priority of service and or curtailment procedures. Generally, natural gas dispatch is not impacted by the price of the natural gas supply.

1.3.4 In organized electric markets, the ISOs or RTOs work to maintain the balance between generation and load. Outside ISOs and RTOs, integrated utilities usually fulfill this function.

1.3.5 Electric Generators have an obligation to perform, but the determination of which generation resources are used is sometimes based on pricing but also on availability of generation inputs.

1.3.6 When does a generator know gas is needed to serve a particular market (quantity and time)?

1.3.7 RTOs/ISOs don't verify a generator's gas supply or firm capacity arrangements before accepting a generator's bid due to the fact that a generator is obligated in the real time market to generate or to purchase the generation to cover the obligation.

1.3.8 Market rules and/or market mitigation (price caps) can negatively impact the availability of generation assets.

1.4. Distinguish between the need for changes to the NAESB WGQ Standards and the need to make adjustments to gas contract portfolios (supply, transportation and/or other services) and/or gas infrastructure requirements. Additional incentives may be needed to encourage entities to diversify their gas contract portfolios to meet their market requirements.

1.5. Allowing more flexibility to non-firm gas shippers may impact the service levels and contractual rights of existing / traditional firm shippers.

1.8. Identify examples of the service characteristics that could meet the market needs for increased delivery flexibility.

1.8.1 Service Characteristics:

1.8.1.1 Firm vs. IT

1.8.1.2 Firm Balancing

1.8.1.3 Should be developed to work for both uniform flow markets and non-uniform flow markets without producing negative impacts on other markets.

1.8.1.4 Any service offerings are tied to operational characteristics.

1.8.1.5 Storage based services (non-notice or short notice).

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1.8.1.8 Communication mitigation RFP procedure by pipeline.

1.8.1.9 There are economics to providing any service.

1.9. Is there a need for more intraday flexibility in gas scheduling?

1.9.1 The need for intraday flexibility in gas scheduling should be weighed for the needs of both industries.

1.9.2 If a change is only for the benefit of the electric industry, then the change should not occur.

1.9.3 Additional intraday nominations opportunities increase the availability of feedback data for the pipelines and would make the industries more transparent.

1.9.4 There is the need for something closer to real time or same day flexibility, but the facilities are currently not in place.

1.9.5 LDCs cannot manage additional flexibility (logistical issues).

1.9.6 Flexibility has economic value.

1.9.7 The physical nature of the commodities is different. It takes 2.5 to 3 days for gas input in the gulf to travel to New York. Electricity is instantaneous and cannot be stored.

Timelines / Scheduling:

2.3. Identify the impact of coincident and near coincident peaks of natural gas markets and power markets. For example, the winter gas and electric usage peaks are early in the morning or late in the afternoon.

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I. Electric Market Rules

Flexibility/Planning:

1.3. Identify differences in the factors driving dispatch priority between natural gas and power.

1.3.1 If multiple priority of service levels are used in a nomination chain, the lowest service level may dictate the priority of the entire chain. eg. Firm service on an upstream service provider (commodity or transportation) tied to interruptible service on a downstream service provider may result in gas not being scheduled to flow as nominated. The converse is also true.

1.3.2 Electric dispatch is subject to contractual and tariff commitments but is also impacted by: availability of prescheduled generation assets; congestion at bottlenecks on the transmission system; availability of incremental/decremental energy at various points in the transmission system; and the economic value of real time incremental/decremental energy at various points in the transmission system. Electric transmission tariffs (OATTs) contain curtailment policies.

1.3.3 Natural gas dispatch is subject to contractual commitments including the confirmation of the gas supply and tariff requirements, including priority of service and or curtailment procedures. Generally, natural gas dispatch is not impacted by the price of the natural gas supply.

1.3.4 In organized electric markets, the ISOs or RTOs work to maintain the balance between generation and load. Outside ISOs and RTOs, integrated utilities usually fulfill this function.

1.3.5 Electric Generators have an obligation to perform, but the determination of which generation resources are used is sometimes based on pricing but also on availability of generation inputs.

1.3.6 When does a generator know gas is needed to serve a particular market (quantity and time)?

1.3.7 RTOs/ISOs don't verify a generator's gas supply or firm capacity arrangements before accepting a generator's bid due to the fact that a generator is obligated in the real time market to generate or to purchase the generation to cover the obligation.

1.3.8 Market rules and/or market mitigation (price caps) can negatively impact the availability of generation assets.

Timelines / Scheduling:

2.1. There is one NAESB WGQ standard gas day and a standard nomination/scheduling timeline and there are many regional power days and power scheduling timelines that may contribute to difficulties in cross-commodity standardization. Identify the impact of the differences between the WGQ standard gas day and nomination/scheduling timeline and the multiple regional power market timelines.

2.1.1 There are obvious mismatches between the gas day and electric day-ahead and real time markets.

2.1.2 Each electric market has its own timeline.

2.1.3 Can the multiple electric timelines be consolidated?

2.1.4 Gas pipelines may serve multiple regional power markets, therefore individual market timelines would significantly complicate gas scheduling.

Reliability:

3.2. Distinguish between coordination issues that are originated by 1) true reliability issues versus 2) those caused by trading risk management practices.

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J. Natural Gas Supply Real Time Flexibility

Flexibility/Planning:

1.2. Discuss ways to accommodate the natural gas requirements of new generation as it comes online in various regions.

a. The impact on the gas infrastructure of new gas-fired generation facilities.

1.2.1 Gas input supply, transportation capacity availability, and capacity contract rights (types of available services) are relevant to new gas-fired generation facilities.

1.2.2 Type of generation facility and physical location of the facility are relevant issues.

1.2.3 Lack of North American electric scheduling standards is problematic.

1.2.4 Electric generation facility citing is a regulated process.

1.3. Identify differences in the factors driving dispatch priority between natural gas and power.

1.3.1 If multiple priority of service levels are used in a nomination chain, the lowest service level may dictate the priority of the entire chain. eg. Firm service on an upstream service provider (commodity or transportation) tied to interruptible service on a downstream service provider may result in gas not being scheduled to flow as nominated. The converse is also true.

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1.3.5 Electric Generators have an obligation to perform, but the determination of which generation resources are used is sometimes based on pricing but also on availability of generation inputs.

1.3.6 When does a generator know gas is needed to serve a particular market (quantity and time)?

1.3.7 RTOs/ISOs don't verify a generator's gas supply or firm capacity arrangements before accepting a generator's bid due to the fact that a generator is obligated in the real time market to generate or to purchase the generation to cover the obligation.

1.3.8 Market rules and/or market mitigation (price caps) can negatively impact the availability of generation assets.

1.7. The impact on the gas infrastructure of non-scheduled gas-fired generation coming on or going off without notice.

1.7.1 Lack of planning for peaking needs.

1.7.2 Alignment of purchase of proper services, if available.

1.7.3 An increase in gas-fired generation coming on line could result in gas flow control which would limit the gas flow at particular points.

1.7.4 New services and/or procedures (such as 'real time' natural gas service) may be needed.

1.7.5 What are the current solutions for handling the needs of peaking generation facilities?

1.7.6 If a market takes unauthorized gas deliveries, other scheduled shippers may be adversely impacted.

1.8. Identify examples of the service characteristics that could meet the market needs for increased delivery flexibility.

1.8.1 Service Characteristics:

1.8.1.1 Firm vs. IT

1.8.1.2 Firm Balancing

1.8.1.3 Should be developed to work for both uniform flow markets and non-uniform flow markets without producing negative impacts on other markets.

1.8.1.4 Any service offerings are tied to operational characteristics.

1.8.1.5 Storage based services (non-notice or short notice).

1.8.1.6 Park & Loan

1.8.1.7 Linepack

1.8.1.8 Communication mitigation RFP procedure by pipeline.

1.8.1.9 There are economics to providing any service.

1.9. Is there a need for more intraday flexibility in gas scheduling?

1.9.1 The need for intraday flexibility in gas scheduling should be weighed for the needs of both industries.

1.9.2 If a change is only for the benefit of the electric industry, then the change should not occur.

1.9.3 Additional intraday nominations opportunities increase the availability of feedback data for the pipelines and would make the industries more transparent.

1.9.4 There is the need for something closer to real time or same day flexibility, but the facilities are currently not in place.

1.9.5 LDCs cannot manage additional flexibility (logistical issues).

1.9.6 Flexibility has economic value.

1.9.7 The physical nature of the commodities is different. It takes 2.5 to 3 days for gas input in the gulf to travel to New York. Electricity is instantaneous and cannot be stored.

Timelines / Scheduling:

2.2. Identify notice requirements that are to be provided to pipelines and/or service providers by shippers regarding load and flow changes. Identify the need for increased and/or more formal communication protocols between natural gas and power operations / control room personnel.

2.2.1 Communication procedures should be formalized. This could include informing the pipelines of a day ahead generation plan and projected gas needs in MMBtu or MCF. This should include both daily and hourly requirements.

2.2.2 Modifications should be communicated when known.

2.2.3 There are potential confidentiality and code of conduct issues.

2.2.4 There is a potential for coordinated maintenance outages.

2.4. Can the natural gas producers and marketers react to 'within the day' requirement changes?

2.4.1 There is a lag between gas scheduling and the related change in gas flow rates.

2.4.2 Producers will not nominate or confirm gas at well heads to markets requiring irregular flows. Marketers are willing to use all available services to serve the needs of all customers.

2.4.3 What is the reasonable minimum amount of notice necessary to affect a change of supply to meet load?

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K. Electric Industry Infrastructure

Flexibility/Planning:

1.2. Discuss ways to accommodate the natural gas requirements of new generation as it comes online in various regions.

a. The impact on the gas infrastructure of new gas-fired generation facilities.

1.2.1 Gas input supply, transportation capacity availability, and capacity contract rights (types of available services) are relevant to new gas-fired generation facilities.

1.2.2 Type of generation facility and physical location of the facility are relevant issues.

1.2.3 Lack of North American electric scheduling standards is problematic.

1.2.4 Electric generation facility citing is a regulated process.

1.3. Identify differences in the factors driving dispatch priority between natural gas and power.

1.3.1 If multiple priority of service levels are used in a nomination chain, the lowest service level may dictate the priority of the entire chain. eg. Firm service on an upstream service provider (commodity or transportation) tied to interruptible service on a downstream service provider may result in gas not being scheduled to flow as nominated. The converse is also true.

1.3.2 Electric dispatch is subject to contractual and tariff commitments but is also impacted by: availability of prescheduled generation assets; congestion at bottlenecks on the transmission system; availability of incremental/decremental energy at various points in the transmission system; and the economic value of real time incremental/decremental energy at various points in the transmission system. Electric transmission tariffs (OATTs) contain curtailment policies.

1.3.3 Natural gas dispatch is subject to contractual commitments including the confirmation of the gas supply and tariff requirements, including priority of service and or curtailment procedures. Generally, natural gas dispatch is not impacted by the price of the natural gas supply.

1.3.4 In organized electric markets, the ISOs or RTOs work to maintain the balance between generation and load. Outside ISOs and RTOs, integrated utilities usually fulfill this function.

1.3.5 Electric Generators have an obligation to perform, but the determination of which generation resources are used is sometimes based on pricing but also on availability of generation inputs.

1.3.6 When does a generator know gas is needed to serve a particular market (quantity and time)?

1.3.7 RTOs/ISOs don't verify a generator's gas supply or firm capacity arrangements before accepting a generator's bid due to the fact that a generator is obligated in the real time market to generate or to purchase the generation to cover the obligation.

1.3.8 Market rules and/or market mitigation (price caps) can negatively impact the availability of generation assets.

Timelines / Scheduling:

2.3. Identify the impact of coincident and near coincident peaks of natural gas markets and power markets. For example, the winter gas and electric usage peaks are early in the morning or late in the afternoon.

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L. Electric Industry Organization

Flexibility/Planning:

1.3. Identify differences in the factors driving dispatch priority between natural gas and power.

1.3.1 If multiple priority of service levels are used in a nomination chain, the lowest service level may dictate the priority of the entire chain. eg. Firm service on an upstream service provider (commodity or transportation) tied to interruptible service on a downstream service provider may result in gas not being scheduled to flow as nominated. The converse is also true.

1.3.2 Electric dispatch is subject to contractual and tariff commitments but is also impacted by: availability of prescheduled generation assets; congestion at bottlenecks on the transmission system; availability of incremental/decremental energy at various points in the transmission system; and the economic value of real time incremental/decremental energy at various points in the transmission system. Electric transmission tariffs (OATTs) contain curtailment policies.

1.3.3 Natural gas dispatch is subject to contractual commitments including the confirmation of the gas supply and tariff requirements, including priority of service and or curtailment procedures. Generally, natural gas dispatch is not impacted by the price of the natural gas supply.

1.3.4 In organized electric markets, the ISOs or RTOs work to maintain the balance between generation and load. Outside ISOs and RTOs, integrated utilities usually fulfill this function.

1.3.5 Electric Generators have an obligation to perform, but the determination of which generation resources are used is sometimes based on pricing but also on availability of generation inputs.

1.3.6 When does a generator know gas is needed to serve a particular market (quantity and time)?

1.3.7 RTOs/ISOs don't verify a generator's gas supply or firm capacity arrangements before accepting a generator's bid due to the fact that a generator is obligated in the real time market to generate or to purchase the generation to cover the obligation.

1.3.8 Market rules and/or market mitigation (price caps) can negatively impact the availability of generation assets.

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M. Energy Reliability

Flexibility/Planning:

1.2. Discuss ways to accommodate the natural gas requirements of new generation as it comes online in various regions.

a. The impact on the gas infrastructure of new gas-fired generation facilities.

1.2.1 Gas input supply, transportation capacity availability, and capacity contract rights (types of available services) are relevant to new gas-fired generation facilities.

1.2.2 Type of generation facility and physical location of the facility are relevant issues.

1.2.3 Lack of North American electric scheduling standards is problematic.

1.2.4 Electric generation facility citing is a regulated process.

1.3. Identify differences in the factors driving dispatch priority between natural gas and power.

1.3.1 If multiple priority of service levels are used in a nomination chain, the lowest service level may dictate the priority of the entire chain. eg. Firm service on an upstream service provider (commodity or transportation) tied to interruptible service on a downstream service provider may result in gas not being scheduled to flow as nominated. The converse is also true.

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1.3.4 In organized electric markets, the ISOs or RTOs work to maintain the balance between generation and load. Outside ISOs and RTOs, integrated utilities usually fulfill this function.

1.3.5 Electric Generators have an obligation to perform, but the determination of which generation resources are used is sometimes based on pricing but also on availability of generation inputs.

1.3.6 When does a generator know gas is needed to serve a particular market (quantity and time)?

1.3.7 RTOs/ISOs don't verify a generator's gas supply or firm capacity arrangements before accepting a generator's bid due to the fact that a generator is obligated in the real time market to generate or to purchase the generation to cover the obligation.

1.3.8 Market rules and/or market mitigation (price caps) can negatively impact the availability of generation assets.

1.5. Allowing more flexibility to non-firm gas shippers may impact the service levels and contractual rights of existing / traditional firm shippers.

1.6. If a pipeline is fully subscribed to firm shippers and an interruptible shipper is scheduled, it is because a firm shipper is not using the capacity or additional capacity is available on a temporary basis.

1.7. The impact on the gas infrastructure of non-scheduled gas-fired generation coming on or going off without notice.

1.7.1 Lack of planning for peaking needs.

1.7.2 Alignment of purchase of proper services, if available.

1.7.3 An increase in gas-fired generation coming on line could result in gas flow control which would limit the gas flow at particular points.

1.7.4 New services and/or procedures (such as 'real time' natural gas service) may be needed.

1.7.5 What are the current solutions for handling the needs of peaking generation facilities?

1.7.6 If a market takes unauthorized gas deliveries, other scheduled shippers may be adversely impacted.

Timelines / Scheduling:

2.1. There is one NAESB WGQ standard gas day and a standard nomination/scheduling timeline and there are many regional power days and power scheduling timelines that may contribute to difficulties in cross-commodity standardization. Identify the impact of the differences between the WGQ standard gas day and nomination/scheduling timeline and the multiple regional power market timelines.

2.1.1 There are obvious mismatches between the gas day and electric day-ahead and real time markets.

2.1.2 Each electric market has its own timeline.

2.1.3 Can the multiple electric timelines be consolidated?

2.1.4 Gas pipelines may serve multiple regional power markets, therefore individual market timelines would significantly complicate gas scheduling.

2.2. Identify notice requirements that are to be provided to pipelines and/or service providers by shippers regarding load and flow changes. Identify the need for increased and/or more formal communication protocols between natural gas and power operations / control room personnel.

2.2.1 Communication procedures should be formalized. This could include informing the pipelines of a day ahead generation plan and projected gas needs in MMBtu or MCF. This should include both daily and hourly requirements.

2.2.2 Modifications should be communicated when known.

2.2.3 There are potential confidentiality and code of conduct issues.

2.2.4 There is a potential for coordinated maintenance outages.

2.3. Identify the impact of coincident and near coincident peaks of natural gas markets and power markets. For example, the winter gas and electric usage peaks are early in the morning or late in the afternoon.

2.4. Can the natural gas producers and marketers react to 'within the day' requirement changes?

2.4.1 There is a lag between gas scheduling and the related change in gas flow rates.

2.4.2 Producers will not nominate or confirm gas at well heads to markets requiring irregular flows. Marketers are willing to use all available services to serve the needs of all customers.

2.4.3 What is the reasonable minimum amount of notice necessary to affect a change of supply to meet load?

Reliability:

3.1. Identify the impact of any contemplated change on natural gas and power reliability.

3.1.1 How will it impact the availability of peaking power?

3.2. Distinguish between coordination issues that are originated by 1) true reliability issues versus 2) those caused by trading risk management practices.

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Q. Information

Flexibility/Planning:

1.3. Identify differences in the factors driving dispatch priority between natural gas and power.

1.3.1 If multiple priority of service levels are used in a nomination chain, the lowest service level may dictate the priority of the entire chain. eg. Firm service on an upstream service provider (commodity or transportation) tied to interruptible service on a downstream service provider may result in gas not being scheduled to flow as nominated. The converse is also true.

1.3.2 Electric dispatch is subject to contractual and tariff commitments but is also impacted by: availability of prescheduled generation assets; congestion at bottlenecks on the transmission system; availability of incremental/decremental energy at various points in the transmission system; and the economic value of real time incremental/decremental energy at various points in the transmission system. Electric transmission tariffs (OATTs) contain curtailment policies.

1.3.3 Natural gas dispatch is subject to contractual commitments including the confirmation of the gas supply and tariff requirements, including priority of service and or curtailment procedures. Generally, natural gas dispatch is not impacted by the price of the natural gas supply.

1.3.4 In organized electric markets, the ISOs or RTOs work to maintain the balance between generation and load. Outside ISOs and RTOs, integrated utilities usually fulfill this function.

1.3.5 Electric Generators have an obligation to perform, but the determination of which generation resources are used is sometimes based on pricing but also on availability of generation inputs.

1.3.6 When does a generator know gas is needed to serve a particular market (quantity and time)?

1.3.7 RTOs/ISOs don't verify a generator's gas supply or firm capacity arrangements before accepting a generator's bid due to the fact that a generator is obligated in the real time market to generate or to purchase the generation to cover the obligation.

1.3.8 Market rules and/or market mitigation (price caps) can negatively impact the availability of generation assets.

1.6. If a pipeline is fully subscribed to firm shippers and an interruptible shipper is scheduled, it is because a firm shipper is not using the capacity or additional capacity is available on a temporary basis.

Terminology:

4.1. There are differences in terminology between natural gas and power (e.g., does "Firm" mean the same thing in both commodities?)