North American Energy Standards Board

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NORTH AMERICAN ENERGY STANDARDS BOARD
GAS and ELECTRIC COORDINATION TASK FORCE
ATTACHMENT to FINAL REPORT

(effective June 30, 2004)

Appendix I: GECTF Preliminary Discussion Points List – Expanded & Categorized

Appendix II: GECTF Meeting Minutes since April 5, 2004

- April 13-14, 2004 Meeting in Phoenix, AZ
- April 28, 2004 Conference Call
- May 18-19, 2004 Meeting in Stamford, CT
- June 29-30, 2004 Meeting in Houston, TX

Appendix III: GECTF Presentations since April 5, 2004

April 2004 Meeting

- TVA Timeline Example
- Additional Examples of Natural Gas Industry and Electric Industry Timing Issue

May 2004 Meeting

- NERC Gas/Electric Interdependency Task Force Status Report

Appendix IV: Participants in the GECTF Effort

Appendix V: Comments Received on the Report and on the Issues Identified

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Appendix I: GECTF Preliminary Discussion Points List – Expanded & Categorized

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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

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:

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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?)

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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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1.8. 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

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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.

2.4. 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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E. Gas Contracts/Services Portfolios of Electric Companies

Flexibility/Planning:

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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.

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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:

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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.

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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.

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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.

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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).

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:

2.3. 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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1.3.6 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

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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.

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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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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.

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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.

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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.

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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?)

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Appendix II: GECTF Meeting Minutes since April 5, 2004

- April 13-14, 2004 Meeting in Phoenix, AZ
- April 28, 2004 Conference Call
- May 18-19, 2004 Meeting in Stamford, CT
- June 29-30, 2004 Meeting in Houston, TX

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via email and posting

TO:	NAESB Gas Electric Coordination Task Force (GECTF) Participants and Posting for Interested Parties
FROM:	Todd Oncken, Deputy Director
RE:	GECTF Final Meeting Minutes – April 13-14, 2004
DATE:	April 26, 2004

NORTH AMERICAN ENERGY STANDARDS BOARD
GAS ELECTRIC COORDINATION TASK FORCE
April 13-14, 2004
Hosted by Arizona Public Service in Phoenix, AZ
Final Minutes

1. Welcome

Ms. McVicker called the meeting to order. Mr. Oncken gave the antitrust advice. Participants introduced themselves. Ms. McVicker thanked Mr. Brechtel of Arizona Public Service for hosting the meeting.

The draft agenda was reviewed. Ms. Lauderdale moved, seconded by Ms. Chezar, to adopt the draft agenda as written. The motion passed unanimously.

The revised draft minutes from the March 15-16, 2004 Gas Electric Coordination Task Force (GECTF) meeting were reviewed. Mr. Novak moved, seconded by Ms. Davis, to adopt the revised draft minutes. The motion passed unanimously.

2. Review of status of GECTF Interim Status Report

Ms. McQuade reported on the status of the GECTF Interim Status report. She stated the report was supported by the Executive Committees and has been distributed to the Board Managing Committee for review. It is anticipated the report will be filed by April 19, 2004. Ms. McVicker stated the comments submitted regarding the report will be discussed by the GECTF during this meeting.

3. Continued discussion of comparison of gas timeline versus major electricity timelines

Timeline comparisons were submitted by Tennessee Valley Authority (TVA) and Mr. Johnson. The timelines submitted by Mr. Johnson for day-ahead organized markets were an outgrowth of the March 15-16 meeting. Participants were encouraged to review the timelines submitted by Mr. Johnson at their convenience.

Mr. Porter presented the TVA timeline example, explaining the chart depicted the 24-hour gas timeline, the 16-hour electricity flow timeline, and the supervening schedule. Participants discussed the example at length. Mr. Porter stated the example represents a real life situation faced by TVA where it must accept a daily ratable schedule, but needed a super-peak schedule for eight hours. Ms. Davis suggested the generators should research other pipeline services that meet those needs. Ms. Crockett noted that some pipelines only offer a ratable daily schedule, so in those instances the ability to generate is limited. Mr. Hadden added that the

example contemplates a day-ahead nominations projection and the ability of the generator to generate would be further diminished if the super-peak conditions were not projected.

Mr. Brechtel suggested that the example shows electric utilities are sometimes forced to abuse the pipeline infrastructure to meet the load, and that situation causes difficulties for the pipelines. Mr. Hadden stated that increased nominations opportunities would benefit both pipelines and generators because generators would have more opportunities to take gas or put gas on the system to benefit linepack. Ms. Crockett clarified that it is not the intent of the generators to abuse the system, but the original GISB intraday nominations timelines had negative affects on hourly pipeline service and flexibility in certain circumstances. Ms. Chezar commented that flexibility should not have been sacrificed in the standardization because the standards are designed to be minimums.

To move forward and address those concerns, Ms. Chezar suggested the generators contact the pipelines to discuss their needs and concerns. It was noted that the pipeline infrastructure must be able to support the peak hourly flow rate required. Mr. Griffith stated that although there is not a universal solution, the requirements for the generation market can probably be defined. Mr. Griffith suggested the GECTF describe the market requirement and determine what it will take to serve that market. He went further to say that the question should be how to serve the generators without disrupting service to other markets. Mr. Love added that the some pipelines do not have the facilities to support swings or increased nominations, so the costs for the new facilities would likely be a factor in any solution.

4. Continued discussion of expanded GECTF Discussion Points List

The task force reviewed each of the four sets of comments posted as work papers for this meeting. Discussion on the comments, as well as general discussion on each item of the list, resulted in several changes to the GECTF Preliminary Discussion Points List. Mr. Hadden stated his comments were adequately addressed by the current issues list. Likewise, it was agreed to evaluate whether the AEP comments were adequately addressed after all other changes to the discussion points list had been made. Additionally, it was decided that numbering the bullets in the list would assist in future discussion.

With the GECTF Discussion Points List complete, Ms. Kiselewich stated the next task would be to evaluate each issue to determine whether it is appropriate for standardization, not appropriate for standardization, or needs additional discussion by the regulation community before that determination can be made. Ms. Kiselewich recognized that consensus might not be reached on every issue, but suggested opinions that differ from the final categorization could be expressed through comments on the final GECTF report. Ms. McVicker suggested the final report should be completed and submitted to the Executive Committees for consideration prior to the August Executive Committee meetings.

The meeting recessed at 4:00 p.m.

5. Discussion of comments filed on GECTF Interim Status Report

Please see discussion above. The comments received on the GECTF Interim Status Report were discussed in connection with the expanded GECTF Discussion Points List.

6. Continued discussion of Gas - Electric Coordination Issues

The following categories were developed and applied to the GECTF Discussion Points List:

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

Following the categorization, each of the categories was reviewed for whether the items contained in the category lend themselves to possible standards development. A categorization matrix was prepared and posted. Ms. Chezar suggested that items in categories a, b, c, d, f and j lend themselves to possible standards development. The task force used Ms. Chezar's suggestion as the strawman and discussed each referenced category. On Mr. Bray's suggestion category j was removed from the strawman. It noted that standards requests would be drafted (either by individual organizations or the task force) for the items that were determined to lend themselves to possible standards development and those standards requests would proceed through the established NAESB processes.

A vote on the expanded and categorized GECTF Discussion Points List was scheduled for the May 18-19, 2004 meeting. The method for voting was not determined although it was discussed at length. Ideally the items and sub-items will be reviewed in the context of the categorization. Ms. McVicker noted a consensus on the categorization would be the equivalent of a formal vote. As such, it was suggested that a formal vote might not be required, but participants were put on notice that a vote on the categorized list or a draft final report could happen at any subsequent meeting.

In preparation for the May 18-19 meeting the task force discussed each of the categories. Since the discussion of the categories related more to identifying specific aspects of standards requests, it was agreed that the discussion on the categories would not be incorporated into the final document, but instead would be for informational purposes.

a. Energy Day - a common 24-hour time period for gas and electric transactions and/or operations (including accounting) throughout North America
b. Communications (format, frequency) - information that needs to be exchanged by the parties and associated timing and methods issues
c. Gas Nominations Timelines – issues related to the gas nominations timeline, either the existing timeline or potential modifications
d. Electric Market Timelines - issues related to the electric market timeline, including the lack of a standard timeline, see also Seams Catalog issue 106

e. Gas Contracts/Services Portfolios of Electric Companies – other services that can address timeline mismatches
f. Electric Generation Gas Supply Verification
g. Available Transportation Service Provider Services
h. Natural Gas Industry Infrastructure – limitations of physical pipeline assets, including incremental costs for new assets
i. Electric Market Rules
j. Natural Gas Supply Real Time Flexibility – the ability of natural gas supply to react to changes in demand
k. Electric Industry Infrastructure
l. Electric Industry Organization
m. Energy Reliability
q. Information

7. Other Business

No other business was discussed.

8. Next Meetings

April 28, 2004 – Conference Call to discuss the overlap between GECTF and NERC GEITF

May 18-19, 2004 – Meeting in Stamford, CT hosted by UBS Energy

June 2-3, 2004 – Cancelled

June 29-30, 2004 – Meeting in Houston, TX hosted by NAESB

9. Adjourn

The meeting adjourned on April 14 at 1:20 p.m. MST.

10. Attendance

Name	Organization	Quadrant[1]	Day One	Day Two
Roman Bakke	Southern California Edison	WGQ	In Person	In Person
Judith Barleycorn	PinnacleWest Energy	NP	In Person	
Jeff Bittel	Texas Gas Transmission	NP	Phone	Phone
Mike Bray	Shell Gas Transmission	WGQ	In Person	In Person
Curt Brechtel	Arizona Public Service	WGQ	In Person	In Person
Ken Brown	PSEG	NP	Phone	Phone
Kathryn Burch	Duke Energy Gas Transmission	WGQ	In Person	In Person
Suzanne Calcagno	UBS Energy	NP	Phone	Phone
Yvette Camp	Southern Company	NP	Phone	
Dolores Chezar	KeySpan Energy	WGQ	In Person	In Person
Craig Colombo	Dominion Resources	WGQ		In Person
Valerie Crockett	Tennessee Valley Authority	WGQ	In Person	In Person
Dale Davis	Williams Gas Pipeline	WGQ	In Person	In Person
George Dawe	Duke Energy	NP	Phone	

[1] Quadrant references were indicated on the sign in sheet. Quadrant is listed as NP in instances where the information is not available – ie. phone participants.

Jay Dibble	Calpine	WGQ	In Person	In Person
Mark Gracey	Tennessee Gas Pipeline	WGQ	In Person	In Person
Bob Gray	Arizona Corp. Commission	NP	In Person	In Person
Bill Griffith	El Paso Western Pipeline	WGQ	In Person	In Person
Tom Gwilliam	Iroquois Gas Transmission System	WGQ	In Person	In Person
Ben Hadden	Conectiv Energy	WEQ	In Person	In Person
Bill Heinrich	New York Public Service Commission	NP	Phone	Phone
Judy Hickman	Columbia Pipelines	WGQ	In Person	
Gary Hinners	Reliant Engergy	NP	Phone	
Erin Hogan	Nyserda	NP	Phone	
Steve Irvine	Arizona Corp. Commission	NP	In Person	
Alan Johnson	Mirant	NP	Phone	Phone
Drake Kijowski	PSEG	WGQ	In Person	In Person
Iris King	Dominion Transmission Inc.	WGQ	In Person	In Person
Ruth Kiselewich	Baltimore Gas & Electric	REQ	In Person	In Person
Melissa Lauderdale	EEI	WEQ	In Person	In Person
Paul Love	Natural Gas Pipeline Co.	WGQ	In Person	In Person
Marcy McCain	Duke Energy Gas Transmission	RGQ	In Person	In Person
Paul McKelvey	ChevronTexaco	WGQ	In Person	In Person
Rae McQuade	NAESB	NA	In Person	In Person
Chris McNiff	Con Edison	NP	Phone	Phone
Diane McVicker	Salt River Project	WGQ	In Person	In Person
Chris Maturo	NiSource Inc.	WGQ	In Person	
Janie Nielsen	Kern River	NP	Phone	Phone
Matt Nollenberg	American Electric Power	NP	Phone	Phone
Mike Novak	National Fuel Dist.	WGQ	In Person	In Person
Lou Oberski	Dominion	NP	Phone	Phone
Todd Oncken	NAESB	NA	In Person	In Person
Marjorie Perlman	Energy East Management Corp.	WEQ	In Person	In Person
John Porter	Tennessee Valley Authority	WEQ	In Person	In Person
Tony Reed	Southern Company	WEQ	In Person	In Person
Ken Schubert	Trans Canada Pipelines	WGQ	In Person	In Person
Rodger Schwecke	SoCalGas	WGQ	In Person	In Person
Donna Scott	Transwestern	NP	Phone	Phone
Kim Van Pelt	Panhandle Eastern Pipeline	WGQ	In Person	In Person
Pauline Wah	SoCalGas	WGQ	In Person	In Person
Louann Westerfield	Idaho Public Utilities Commission	NP	Phone	
Brian White	NiSource Pipelines	WGQ	In Person	In Person
Kathy York	Tennessee Valley Authority	WEQ	In Person	In Person
Randy Young	Gulf South Pipeline	WGQ	In Person	In Person

North American Energy Standards Board

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via email and posting

TO:	NAESB Gas Electric Coordination Task Force (GECTF) Participants and Posting for Interested Parties
FROM:	Todd Oncken, Deputy Director
RE:	GECTF Conference Call Final Minutes – April 28, 2004
DATE:	April 29, 2004

NORTH AMERICAN ENERGY STANDARDS BOARD
GAS – ELECTRIC COORDINATION TASK FORCE CONFERENCE CALL
April 28, 2003; 1:00 p.m. to 4:00 p.m. Central
Final Minutes

1. Welcome

Ms. McVicker called the meeting to order. Mr. Oncken gave the antitrust advice. Participants introduced themselves. The draft agenda was reviewed. Mr. Bray moved, seconded by Ms. Perlman to accept the agenda as drafted. The motion passed unanimously.

2. Discussion of overlap between GECTF finding and NERC GEITF findings

Mr. Twitchell provided an update on the status of the NERC GEITF report. He stated the report has been distributed to the NERC Planning Committee for comments and will be reviewed and possibly revised in light of those comments. He said the next steps for the report are resubmission to the Planning Committee for a vote and, assuming approval, presentation to the NERC Board of Directors at its June meeting. Finally, he said if the NERC Board approves the report it will be distributed to the NERC committees for incorporation into their 2005 plans, as appropriate. Although the report is not final, it was noted that the draft report was included in the March Planning Committee meeting agenda.

Mr. Johnson suggested the GECTF review the GEITF recommendations and conclusions to determine if portions of the document should be included or referenced in the GECTF report. Participants agreed the comparison would be valuable to identify potential joint standards development efforts. It was noted that both organizations need to determine how to most efficiently move forward after their reports are complete. As a preliminary matter, Mr. Johnson stated obvious areas of overlap include the need for increased communication and that gas transmission tariffs are not compatible with generation peaking requirements.

Given the procedural status of the NERC GEITF report it was determined this conference call was premature. A discussion of the NERC GEITF report will be added as an agenda item for the May GECTF meeting. A representative from NERC will attend the meeting to either give a presentation or be available to answer any questions. Additionally, Mr. Twitchell agreed to review NERC procedures and determine if it would be appropriate to submit a draft version of the report to NAESB for posting prior to its acceptance by the Planning Committee.

3. Other Business

No other business was discussed.

4. Next Meetings

The next GECTF meeting is scheduled for May 18-19, 2004 in Stamford, CT.

5. Adjourn

The call adjourned at 1:22 p.m. Central.

6. Attendees

Name	Organization	Notes
Mariam Arnaout	American Gas Association	
Joanne Bialas	ISO New England	
Jeff Bittel	Texas Gas	
Mike Bray	Shell Gas Transmission	
Kathryn Burch	Duke Energy Gas Transmission	
Christopher Burden	Williams Gas Pipeline	
Craig Colombo	Dominion Resources	
Pete Connor	NiSource	
Jeffrey Conotask	DC Public Service	
Dale Davis	Williams Gas Pipeline	
George Dawe	Duke Energy Gas Transmission	
Jay Dibble	Calpine Corp	
Scott Hansen	Questar Pipeline	
Alan Johnson	Mirant	
Drake Kijowski	PSEG	
Iris King	Dominion Transmission Inc	
Melissa Lauderdale	Edison Electric Institute	
Greg Maliken	National Fuel Gas Supply Corp	
Chris Maturo	NiSource	
Marcy McCain	Duke Energy Gas Transmission	
Rae McQuade	NAESB	Admin
Diane McVicker	Salt River Project	
Janie Nielsen	Kern River Gas Transmission	
Matt Nollenberg	American Electric Power	
Michael Novak	National Fuel Gas Supply Corp	
Todd Oncken	NAESB	Admin
Marjorie Perlman	Energy East Management Corp	
John Porter	Tennessee Valley Authority	
Marv Rosenberg	FERC	
Donna Scott	Transwestern Pipeline Company	
John Twitchell	NERC	
Brian White	NiSource	
Kathy York	Tennessee Valley Authority	

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via email and posting

TO:	NAESB Gas Electric Coordination Task Force (GECTF) Participants and Posting for Interested Parties
FROM:	Todd Oncken, Deputy Director
RE:	GECTF Meeting Final Minutes – May 18-19, 2004
DATE:	June 2, 2004

NORTH AMERICAN ENERGY STANDARDS BOARD
GAS ELECTRIC COORDINATION TASK FORCE
May 18-19, 2004
Hosted by UBS Energy, LLC in Stamford, CT
Final Minutes

1. Welcome

Ms. Calcagno called the meeting to order. Mr. Oncken gave the antitrust advice. Participants introduced themselves. The draft agenda was reviewed. Ms. Kiselewich moved, seconded by Mr. Porter, to adopt the draft agenda without modification. The motion passed unanimously.

The draft minutes from the April 13-14, 2004 Gas Electric Coordination Task Force (GECTF) were reviewed. Ms. McVicker moved, seconded by Ms. Kiselewich to adopt the draft minutes without modification. The motion passed unanimously.

The draft minutes from the April 28, 2004 GECTF Conference Call were reviewed. Ms. McVicker moved, seconded by Ms. Van Pelt, to adopt the draft minutes with a minor correction to the attendance list. The motion passed unanimously.

2. Presentation on NERC GEITF

Mr. Fedora gave a presentation titled, 'NERC Gas/Electric Interdependency Task Force Status Report.' Mr. Fedora's presentation contained background information on NERC's interest in the increased interdependence of the industries, the role of the NERC Gas/Electric Interdependency Task Force (GEITF), and the GEITF recommendations that NERC's Planning Committee is considering. Mr. Fedora explained the GEITF was established to review the interdependency relationship between the industries and explore the need for future relationships between gas and electric generation and planning. Mr. Fedora clarified the GEITF was not tasked with reviewing gas supply issues, completing a detail study of gas supply sufficiency, or commenting on either industry's operating practices. A chief message of Mr. Fedora's presentation was the recognition by the electric industry of its increased reliance on gas-fired electric generation and the need for the NERC policies to reflect this increased reliance.

Mr. Fedora's presentation highlighted the GEITF's recommendations that are being considered by the NERC Planning Committee, as follows:

> **Recommendation 1:** NERC Regions should include in their regional assessment program a review of the impact of any fuel transportation infrastructure interruption that could adversely impact electric system reliability.
>
> **Recommendation 2:** NERC reliability coordinators or their delegates, subject to appropriate treatment of commercially sensitive information, should develop regular,

real-time communications with pipeline operators about disturbances that could adversely impact the reliability of either the electric systems or the gas pipeline.

Recommendation 3: For planning purposes, gas pipeline outages that could have an adverse impact on the reliability of the electric systems must be coordinated with the electric industry so that plans to mitigate any impacts to the electric systems may be developed.

Recommendation 4: NERC should develop a reliability standard relating fuel infrastructure reliability to resource adequacy.

Recommendation 5: NERC should include analysis of fuel infrastructure contingencies that could adversely impact the reliability of the electric systems in the NERC planning standards.

Recommendation 6: NERC should establish a monitoring system that tracks fuel infrastructure contingencies that have, or could have, an adverse impact on electric system reliability.

Recommendation 7: NERC should, in concert with other energy organizations, formalize communications between the electric industry and the gas transportation industry for the purposes of education, planning, and emergency response.

Mr. Fedora outlined the process for NERC's consideration of the GEITF report. He stated the draft report was in the NERC Planning Committee ballot process, so it was not ready for public release. Following approval by the Planning Committee, the report would be sent to the NERC Board of Trustees for review at the June 15, 2004 meeting. Mr. Fedora stated the NERC Board could take any appropriate action, but it would likely direct that the recommendations be implemented or refer the recommendations to the task force for further clarification. The GEITF report will be posted as an attachment to these minutes when it becomes available.

Mr. Fedora's presentation was discussed at length. During the discussion, it was noted that the GEITF considered a gas system disturbance to be anything that caused a sudden disturbance in gas flow, including both planning and operational aspects. Ms. Chezar stated that the gas industry views some actions, such as Interruptible Transportation Service (IT) not being offered by the pipeline on any day, as something other than a disturbance. Nevertheless, Mr. Fedora said an interruption of IT was an important reliability concern, since most generators rely on IT contracts. This discussion highlighted the different service aspects of the gas and electric industries.

Ms. Westerfield stated the coordination of the industries was important for many Western states and cited Idaho as an example. She said that all proposed incremental electric generation in Idaho over the previous five years had been gas-fired, a fact that was daunting for a state with no natural gas production. Ms. Chezar suggested purchasing gas storage may alleviate the concerns. It was noted that gas storage is tied to transportation. Mr. Fedora stated that there were reliability concerns for any fuel source without on-site storage.

GEITF Recommendations 2, 3, and 4 garnered a lot of discussion. Regarding Recommendation 2, participants were interested in the type of information that would be shared between the pipeline operators and electric reliability coordinators, and how that information exchange would occur when a pipeline spanned several reliability coordination areas. Mr. Fedora explained that operational information was critical to maintain the integrity of both systems, and if shared effectively, could help manage expectations of the counterparties. It was noted

that this information is currently shared with pipeline customers, so the recommendation focused on including the Reliability Coordinators in the communication stream early in the process. Some concern was expressed that the communications would give the electric ISOs more authority since they would be seeing more information on each unit. Mr. Fedora stated that the ISOs are sometimes viewed as responsible for reliability and suggested that any concern could be outweighed by the reliability concerns created by the heavy reliance on natural gas as an input for electricity production. Ms. Paravalos suggested the group in New England that is analyzing the January 2004 occurrence would agree with this recommendation, since one of its findings was that the ISO did not have enough advanced notice of the events to adequately plan generation dispatch.

Regarding Recommendation 3, concern was expressed that the recommendation contemplates informing one customer group of a pending outage before the other customers are notified. Ms. McCain stated that practice is currently prohibited by regulation, because each of the pipeline's customers must be notified of such information contemporaneously. It was clarified that this recommendation contemplates more than just notification. Rather, according to the recommendation, the affected electric industry participants would be a party to the decision on the timing of the planned pipeline outage. This is one of the reasons why the electric industry has RTOs and ISOs – so that information that would normally be considered market sensitive can be used in planning by the ISOs without giving individual market participants an advantage. Market monitors are also employed as a further safeguard.

Regarding Recommendation 4, it was clarified that while the proposed reliability standard would be specific to fuel infrastructure, environmental impacts of backup fuel choices could be implicated. Additionally, it was suggested that the proposed standard would address adequacy and reliability of services to support the input. Mr. Fedora stated the GEITF provided no clear direction on what the reliability standard would encompass, but it could mandate the use of firm gas transportation contracts instead of IT contracts, discount the amount of generation eligible for dispatch based on the reliability of the type of fuel service, or require dual fuel generation capability that could be switched quickly.

3. Discussion of categorized GECTF Discussion Points List and identification of those that lend themselves to standards development by NAESB

Participants discussed how to move forward with the GECTF Discussion Points List (DPL). It was anticipated by some participants that the DPL would be further refined to identify those categories that lend themselves to standards development by NAESB. It was noted that it was difficult to define the characteristics of an item that lends itself to standards development. Ms. Deegan expressed a strong preference, should the refinement by category be done, that key issues regarding coordination of the industries that did not lend themselves to standardization be maintained and highlighted. Ms. Lauderdale noted that participants on an Edison Electric Institute (EEI) conference call to discuss the GECTF DPL found making a determination based on category difficult, since several categories were not specifically defined.

Mr. Bray suggested the task force not attempt to refine the DPL because reaching a working consensus on which categories would lend themselves to standards development by NAESB would be very time consuming and nearly impossible. Instead, Mr. Bray stated the DPL should stand on its own for the final report and interested parties can include discussion on any particular items or categories in their comments on the final report. Ms. Van Pelt supported Mr. Bray's position and noted that any decisions by the task force on which items would lend themselves to standardization by NAESB would not be binding, since any item from the DPL

could be submitted as a standards request that would proceed through the standard NAESB process. Additionally, Mr. Connor expressed concern that any refinement would circumvent the NAESB process.

Before deciding to take no further action on the DPL, the task force discussed whether the current DPL was adequate to meet the expectations of the regulators and other industry stakeholders. Mr. Johnson questioned whether the current DPL fulfilled the mission of the task force, since the task force did not make an attempt at determining the items that lend themselves to standardization by NAESB. Mr. Hadden suggested the next logical step would be to define the categories. Several additional parties, including Mr. Novak and Ms. Westerfield, opposed not further refining the DPL. Ms. Westerfield suggested not taking the next step was passing the buck. Ms. Lauderdale agreed a refined DPL would be a more useful work product. After a lengthy discussion the task force agreed to include the current DPL in the final report. There was general agreement by the participants not to identify which of the 14 categories would lend themselves to standards development.

4. Initial draft of GECTF Final Report

The task force worked through each section of the final report outline. Considerable time was spent during the meeting refining the language and concepts to be included in the report. The suggestion to add a section containing higher-level items that could impede standardization was discussed, but the task force did not make the addition.

The initial report outline proposed the inclusion of any standards requests relating to the Discussion Points List as an appendix. Participants opposed including this item because including the section could make it appear that the requests were part of the task force's work. However, several participants viewed information on pending requests as key to the report and supported the appendix. In the alternative, it was suggested that requests for standards could be referenced in the transmittal letter for the final report, or a subsequent report. While there was not consensus on either approach, participants emphasized that any reference to a pending request for standards should indicate the status of the request.

Given the group's decision not to refine the DPL, Ms. Kiselewich suggested the task force highlight an area that was not controversial but appropriate for NAESB standardization on its face – such as communications standards. Ms. Westerfield supported the concept and noted the connection between an emphasis on communications standards and the NERC GEITF Recommendations. Ms. Westerfield projected that there could be a need for complementary communications standards to the NERC GEITF Recommendation. Mr. Bray and Ms. Chezar opposed Ms. Kiselewich's suggestion. Ms. Chezar stated that highlighting one topic would suggest priority. Participants decided against highlighting any specific issue in the report.

Mr. Kijowski stated the value of the task force's work has been the exchange of information on the industries. Mr. Bray agreed and suggested the proposal to let the current DPL stand on its own was consistent with the marketplace determining the priority of NAESB work items. There was general agreement by the participants not to identify which of the 14 categories would lend themselves to standards development. Mr. Bray and Mr. Johnson drafted language for the report that explains the benefits of the task force's work even though the precise mission of the task force was not completed.

Mr. Conopask provided a regulatory perspective on the sufficiency of the task force's efforts and the report. He stated the education and communication of industry participants was a great accomplishment, and while the regulatory community would like to see a more refined DPL and

areas for standardization identified, perhaps the task force had reached its logical conclusion and was unable to refine the DPL. Ms. Westerfield agreed with Mr. Conopask's statements.

The task force discussed whether it would be appropriate to reference the NERC GEITF report, or any portion of the report, in the GECTF report. While participants agreed the GEITF report given during the meeting contained valuable information on the dependence on gas-fired generation and importance of communication between the industries, there was not agreement on including references into the GECTF report. Ms. Chezar noted that the final GEITF report was not available, and when available, would be subject to subsequent consideration (see NERC procedures outlined above).

The NAESB Office will draft the final report and submit it to the task force leadership prior to distribution to GECTF participants. It is anticipated the final report will be considered and voted on at the next GECTF meeting. Assuming approval, the report will be posted for comment and considered by the Executive Committees of each of the quadrants. Any comments received prior to Executive Committee consideration will be included in the report. Assuming a majority of each of the Executive Committees of each quadrant is reached, the report will be reviewed with final approval by the Board Managing Committee prior to submittal to FERC.

5. Other Business

No other business was discussed.

6. Next Meetings

The current GECTF schedule of activities can be found on the NAESB website at http://www.naesb.org/gas_electric_coordination.asp. The current schedule reflects the cancellation of the July 14-15 meeting.

7. Adjourn

The meeting adjourned at 1:30 p.m. Eastern on May 19, 2004.

8. Attendance

Name	Organization	Day One	Day Two	Quadrant[1]
Mariam Arnaout	American Gas Association	In Person	In Person	RGQ
Roman Bakke	Southern California Edison	In Person	In Person	WGQ
Mike Bray	Shell Gas Transmission	In Person	In Person	WGQ
Curt Brechtel	APS	In Person	In Person	WGQ
Ken Brown	PSEG	In Person	In Person	WEQ
Kathryn Burch	Duke Energy Gas Transmission	In Person	In Person	WGQ
Suzanne Calcagno	UBS Energy	In Person	In Person	RGQ
Yvette Camp	Southern Company	Phone	Phone	NA
Dolores Chezar	KeySpan Energy	In Person	In Person	WGQ
Craig Colombo	Dominion Resources	Phone	Phone	NA
Jeffrey Conopask	DCPSC	In Person	In Person	Govt
Peter Connor	NiSource	Phone	Phone	NA
Mike Coyle	PSEG	In Person		RGQ

[1] Quadrant noted where provided.

Valerie Crockett	TVA	In Person	In Person	WGQ
Dale Davis	Williams Gas Pipeline	In Person	In Person	WGQ
George Dawe	Duke Energy	Phone	Phone	NA
Jennifer Deegan	Washington Gas	In Person	In Person	RGQ
Jay Dibble	Calpine	Phone	Phone	NA
Andrew Dotterweich	Consumers Energy	Phone		NA
Dan Downs	New York State Dept of Public Service	Phone	Phone	NA
Philip Fedora	NPCC	In Person	In Person	WEQ
Lisa Fitzgerald	Columbia Gas	In Person	In Person	WGQ
Mark Gracey	Tennessee Gas Pipeline	In Person	In Person	WGQ
Bill Griffith	Colorado Interstate Gas	In Person	In Person	WGQ
Tom Gwilliam	Iroquois Gas Transmission System	In Person	In Person	WGQ
Ben Hadden	Conectiv Energy	In Person	In Person	WEQ
Judy Hickman	Columbia Gas	In Person	In Person	WGQ
Erin Hogan	Nyserda	Phone		NA
Alan Johnson	Mirant	In Person	In Person	WEQ
Drake Kijowski	PSEG	In Person	In Person	WGQ
Iris King	Dominion Transmission	In Person	In Person	WGQ
Ruth Kiselewich	Baltimore Gas & Electric	In Person	In Person	REQ
Melissa Lauderdale	Edison Electric Institute	Phone	Phone	NA
Paul Love	NGPL	In Person	In Person	WGQ
Marcy McCain	Duke Energy Gas Transmission	In Person	In Person	RGQ
Paul McKelvey	ChevronTexaco	In Person	In Person	WGQ
Rae McQuade	NAESB	In Person	In Person	NA
Diane McVicker	Salt River Project	In Person	In Person	WGQ
Patricia Merville	Public Service Company PNM		Phone	
Janie Nielsen	Kern River Gas Transmission	In Person	In Person	WGQ
Michael Novak	National Fuel	Phone	Phone	NA
Lou Oberski	Dominion Resources	Phone	Phone	NA
Todd Oncken	NAESB	In Person	In Person	NA
Mary Ellen Paravalos	National Grid	In Person	In Person	WEQ
Marjorie Perlman	Energy East Management Corp.	In Person	In Person	WEQ
John Porter	TVA	In Person	In Person	WEQ
Marv Rosenberg	FERC	In Person	In Person	Govt
Donna Scott	Transwestern Pipeline Company	Phone	Phone	NA
Ed Tammy	Florida Power & Light Company	Phone	Phone	NA
Chuck Thompson	Public Service Company New Mexico	Phone		NA
Kim Van Pelt	PEPL	In Person	In Person	WGQ
Louann Westerfield	Idaho Public Utilities Commission	Phone	Phone	NA
Brian White	NiSource	Phone	Phone	NA
Randy Young	Gulf South	In Person	In Person	WGQ
Steve Zavodnick	Baltimore Gas & Electric	Phone	Phone	NA

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via email and posting

TO:	NAESB Gas Electric Coordination Task Force (GECTF) Participants and Posting for Interested Parties
FROM:	Todd Oncken, Deputy Director
RE:	GECTF Meeting Final Minutes – June 29-30, 2004
DATE:	July 6, 2004

NORTH AMERICAN ENERGY STANDARDS BOARD
GAS ELECTRIC COORDINATION TASK FORCE
June 29-30, 2004
Hosted by NAESB in Houston, TX
Final Minutes

1. Welcome

Ms. Kiselewich called the meeting to order and welcomed attendees. Mr. Oncken gave the antitrust advice. Participants introduced themselves.

The draft agenda was discussed at length. Mr. Bray moved, seconded by Ms. Davis, to delete item 5 from the draft agenda, since the WGQ Pipelines segment does not view prioritization as a responsibility of the task force. During discussion, Mr. Bray stated that as part of the proposal the WGQ Pipeline Segment would support the WGQ LDC work paper with some modifications to the last paragraph in an effort to reach an acceptable compromise among the task force members. Also, d(Bray)uring discussion concern was repeatedly expressed that the draft agenda did not reflect the general understanding participants had at the end of the last meeting that the only item for discussion would be finalization of the report. Some people were concerned that the NAESB process and procedures had not been followed. (Bray)There was not agreement with the Pipeline position on the role of the task force and prioritization. Additionally, Ms. Lauderdale noted that Mr. Desselle's written comments specifically address prioritization. On Mr. Connor's suggestion, the motion was amended to include a discussion of the LDC workpaper as agenda item 2. Mr. Bray's motion failed. See Motion 1 in voting record below.

Mr. Novak moved, seconded by Mr. Oberski, to add a discussion of the LDC workpaper after agenda item 2. The motion passed. See Motion 2 in voting record below.

The draft minutes from May 18-19, 2004 were reviewed and changes were made. Ms. Lauderdale moved, seconded by Ms. Westerfield, to adopt the modified draft minutes. The motion passed unanimously by consent.

2. Review of comments submitted related to whether the task force has completed its mission/assigned task

Comments on the draft final report were submitted by the Quadrant Co-Chairs, Mr. Desselle and Mirant.

Quadrant Co-chairs: Mr. Bray spoke in strong opposition to the statement of the Quadrant Co-chairs, stating that it was inappropriate in the NAESB process for Executive Committee leadership to comment on whether a task force had completed its task in the absence of an

Executive Committee meeting or Executive Committee concurrence with the statements. Mr. Oberski stated the comments were not intended to represent Executive Committee concurrence, but instead represented the Executive Committee leadership's support of an efficient standards development process. Mr. Novak, Ms. Kiselewich, and Mr. Buccigross expressed similar views. Mr. Buccigross added that the Executive Committee leadership has a duty to assist in the prosecution of the annual plans. Ms. Davis stated that the statement being labeled as a statement of the Quadrant Co-chairs could imply support of the Executive Committees.

In addition to the concerns stated on the implication of Executive Committee support for the comments, concern was expressed that the agenda was modified in direct correlation to the Quadrant Co-chairs' comments. Mr. Novak suggested the change in the agenda was more directly related to the expectations of the NAESB Board of Directors, as evidenced by Mr. Desselle's comments. Ms. Kiselewich noted that she had raised concerns at the last GECTF meeting that the task force was not meeting expectations, and Mr. Desselle's comments and feedback she had received from the regulatory community supported those concerns. Ms. Kiselewich clarified that while the agenda was posted later than optimal, it was the only agenda that had ever been prepared for the meeting. Ms. Lauderdale noted that all filed comments reflected that theme, and it was appropriate to draft an agenda that considered those comments. Ms. Van Pelt suggested it would be more appropriate to forward the comments that the task force had not completed its assignment to the Executive Committees for their consideration.

While discussing the possibility of prioritizing and voting on the priority of the DPL categories and/or issues, Ms. Chezar stated that the recent FERC conference in New York demonstrated that there was probably something in each of the categories that could be the basis of a standards request. However, many participants felt that prioritization should be done by the Executive Committees after a request for standards had been submitted. Several parties indicated they were not prepared to vote on particular items during this meeting since it was not on the agenda, even though, as Ms. Lauderdale pointed out, voting on the DPL has been contemplated for several meetings.

Mirant: Mirant's comments were discussed during the draft report revision process.

Desselle: Mr. Desselle's comments were not specifically discussed.

3. Discussion and vote on LDC motion

Mr. Novak, seconded by Mr. Brown, presented a motion sponsored by the WGQ LDC segment (see posting). There were several proposed amendments to the motion and Mr. Novak and Mr. Brown addressed each as it was presented. The motion, as amended, reads:

> Whereas, the Gas Electric Coordination Task Force (GECTF) has identified a list of discussion points (Discussion Points List) that have been organized into 14 broad categories ~~of issues~~, each ~~of which~~ category ~~deals~~ dealing with a facet of the coordination between the two industries, thereby concluding the mission of the GECTF:
>
> Now, therefore be it moved that this Task Force adopt the following statement and recommendations to accompany the transmittal of its report:
>
> T ~~As such, t~~he GECTF **affirmatively** states that each of the 14 categories may have at least limited **standards development potential within NAESB**. While some and possibly all of these categories contain elements that are either outside of NAESB's

scope or best resolved elsewhere, the GECTF requests that interested industry participants submit Standards Development Requests (SDR) through the usual NAESB process. Rather than undertaking a protracted effort by this Task Force to work out every detail of the 14 categories to pre-identify potential policy roadblocks, the GECTF believes that the process will be more proper and efficient if NAESB deals with actual requests from stakeholders. Stakeholders may structure SDRs to avoid topics not readily suited to standards development or within the request, self-identify aspects of the request that require a policy decision that needs to be made prior to standards development.

In the case of policy determination, it is not always possible to identify discrete policy issues on the face of the SDR; rather, such policy issues are often discovered through subcommittee discussion. The GECTF recommends that any subcommittees charged with standards development regularly communicate policy roadblocks to the Executive Committees ~~Board, so that they may be forwarded to the appropriate regulatory agency for disposition~~.

In terms of Annual Plan development and prioritization ~~prioritization~~, the GECTF ~~recommends~~ recognizes that in compliance with NAESB's existing procedures, ~~as~~ requests (e.g. R04016) are submitted and processed by Triage, ~~they~~ and could be added to the appropriate NAESB ~~2004 and/or 2005~~ a~~A~~nnual p~~P~~lans at the request of the Executive Committee to the Board. In addition, the GECTF recognizes that t~~T~~he Executive Committee ~~should~~ determines~~d~~ priorities, taking into consideration the existing committee workload at the time the request is made.

There was extensive discussion on the motion. It was noted that if the motion is successful, the last three paragraphs would be inserted into the GECTF final report. Mr. Novak stated the motion would move the task force forward by affirmatively stating that each of the categories has something in it that could be standardized, thus reflecting the intent of the GECTF at the last meeting.

Opinion within the task force was split regarding this motion. Ms. Lauderdale opposed the motion, but instead preferred to analyze each of the categories. She questioned why saying each of the 14 categories is a possibility is different than not saying anything. Mr. Brechtel questioned whether passing the motion would address Mr. Desselle's comments or add substance to the final report. Mr. Oberski, Ms. Westerfield, and Mr. Templeton also questioned the effect of the motion. Mr. Templeton supported the concept of voting on each DPL item, noting that would be a manifestation of the value of the time spent by the task force.

Ms. Van Pelt supported the motion as a compromise and affirmative statement of the task force. Ms. Van Pelt's position on the motion was shared by Mr. Bray and several other attendees. Ms. Chezar questioned the value of voting on each item, since the voting results would not limit an organization's ability to submit a request for standards development.

Ms. Davis stated that if individual votes were taken, the task force would have to get to the details of each individual item to make an informed decision. Mr. White concurred that a more thorough understanding would be required if voting on each of the DPL categories. He said that evaluation would be an evaluation of the merits of each item, which is different than the current approach used by the task force.

Ms. Kiselewich noted that the WEQ Seams Subcommittee (Seams) preformed a similar task to the task asked of the GECTF and suggested the task force look to their process as an example to move forward. (See discussion below.)

The vote on Mr. Novak's motion was taken and the motion failed. See Motion 3 in voting record below.

4. Classification of categories into those which may lend themselves to standards development, which need policy decisions, etc.

Ms. McQuade gave a brief review of the Seams process so the GECTF could determine whether to use a similar procedure. Briefly, she said that Seams developed a broad matrix of issues, categorized those issues – by topic and business/reliability function, prioritized the business issues through industry input, and will proceed with the high priority items through standards requests assigned to participating organizations. Ms. Crockett, as a participant of the Seams Subcommittee, supported using this approach. She noted the report sent to the FERC states that NAESB will begin working on five top priority items in 2005. Mr. Oberski suggested that the fact that the GECTF work impacts the four NAESB quadrants would complicate the workplan used by Seams. Ms. Chezar suggested it would be appropriate for GECTF participants, especially WGQ participants, to review the Seams work and procedures before going further, noting that participants from the WGQ would have to have the opportunity to become familiar with the model before moving forward.

Mr. Love stated the DPL would have to be refined before it could be distributed to the industry for prioritization participation. Mr. Oberski agreed the document would have to be worked on before it was sent out. Mr. Brown added that much of the ground work for Seams had already been done previously because the wholesale electric industry outside of the NAESB process had been working on seams issues to improve the ability for trading for several years and several organizations, including ISOs and RTOs, and there were previously compiled lists of the issues that they were working on.

Ms. Davis noted that the Seams process could be very lengthy. Ms. Kiselewich agreed the Seams process could take some time, but noted the task force was not bound by the goal of producing a final report during this meeting. Mr. Love suggested it would be more efficient to let interested industry participants submit requests and process those requests according to established procedures. Additionally, concern was expressed by other WGQ participants that resources would be expended to take this process further, when those resources could be used for standards development on specific standards requests, like Request R04016.

Ms. Westerfield stated the value of the Seams Catalog, while it was just a catalog of issues and does not force or preclude standards development, was that it provided a framework for industry participants to start to prioritize issues of concern. Ms. Westerfield suggested the GECTF was a similar opportunity for the gas and electric industries to have input on what aspects of coordination they thought were important and ready for standards, prior to the regulatory community making those decisions.

Ms. Lauderdale moved, seconded by Mr. Templeton, that the GECTF review the list of 14 DPL categories and categorize them as follows: 1) contains mostly items and discussion points suitable for standards development discussion within NAESB; 2) contains few, if any, items and discussion points suitable for standards development discussion within NAESB; and 3) GECTF to discuss further. It was noted that this motion generally parallels the approach suggested in the statement of the Quadrant Co-chairs. Ms. Lauderdale suggested the motion

would provide the opportunity to make a rough categorization and identify categories that needed to be discussed further.

During discussion, Ms. Davis, with Mr. Bray's and Ms. Burch's concurrence, opposed the motion stating that it was premature. Ms. Chezar questioned the value that voting would add to the process, if the results of the voting do not presuppose an outcome when a standards request is or is not filed. Ms. Lauderdale said voting would help NAESB meet the expectations of the regulatory community that NAESB could provide input into the discussions, since recent events have highlighted the need for increased coordination between the gas and electric industries. Mr. Love expressed concern that after the categories are voted on, items could end up on annual plans without a standards request to back them. Mr. Templeton reminded participants that development of the annual plans was not a subcommittee or task force function – all annual plans are approved by the NAESB Board of Directors.

Ms. Westerfield supported Ms. Lauderdale's motion, but noted another option would be to file another interim report noting where the task force was and seeking comment. Ms. Westerfield sympathized with the participants whom wanted an alternative to voting on each item. Additionally, there was general concern about attendance at this meeting, and the lack of participation by the electric quadrants in all of the meetings. Ms. Lauderdale noted that while the electric industry was not as extensively represented as the WGQ Pipeline segment, a wide range of companies have participated in the process. Ms. McVicker suggested the GECTF spend more time looking at the big picture – the 14 categories – instead of the sub-issues contained in the expanded DPL.

The vote on Ms. Lauderdale's motion was taken and the motion failed. See Motion 4 in voting record below.

Having taken two approaches to prioritizing and voting on the DPL, the task force discussed how to move forward. One option was to vote on each of the 14 categories individually. Participants generally opposed that option. Ms. Davis reiterated that more work would have to be done defining the DPL before individual votes could be taken. Several participants reiterated that a vote did not really mean anything in the standards development process because the triage process would ultimately prevail. In contrast, Ms. Westerfield reiterated that a vote would have meaning to NAESB's external audience, since many expect the task force to express an opinion about whether it is time for some prioritization of coordination issues between the electric and gas industries. She noted that since there is general agreement on the 14 categories, the real issue is whether the list should take on any further meaning.

Barring a consensus to vote on each of the categories, Ms. Lauderdale suggested the task force work on the final report on Day 2, but include reasoning why the task force was unable to vote on the individual categories and points. There was agreement to move on to agenda item 6.

5. Vote on the classifications

This item was not discussed.

6. Prioritization of those identified for standards development i.e. what should be done in what year

This item was not specifically discussed. Please see discussion above.

7. Editing draft final report

The task force reviewed the draft final report and made extensive edits. Language was added that reflected the votes taken during this meeting. Additionally, the task force developed a list of items indicating reasons the task force did not go further and/or prioritize the DPL. Participants felt including the list would help demonstrate the complexity of the task the group faced. A redlined version of the report, used for voting, is available on the NAESB web site.

8. Vote on report

Mr. Templeton moved, seconded by Mr. Bray to approve the draft final report. During discussion there were additional minor changes. Mr. Templeton and Mr. Bray accepted those changes. The motion passed unanimously absent objection.

9. Other Business

No other business was discussed.

10. Next Meetings

A conference call was scheduled for July 22, 2004 at noon Central to adopt these minutes. No subsequent meetings were scheduled.

11. Adjourn

The meeting adjourned on June 30 at 1:00 p.m. Central.

12. Attendance

Name	Organization	Quadrant	Segment	Day One	Day Two
Mariam Arnaout	American Gas Association	NA	NA	Phone	Phone
Jeffrey Conopask	DC Public Service Commission	NA	NA	Phone	Phone
Kay Morice	FERC	NA	NA	In Person	In Person
Dede Kirby	NAESB	NA	NA	In Person	
Rae McQuade	NAESB	NA	NA	In Person	In Person
Todd Oncken	NAESB	NA	NA	In Person	In Person
Ruth Kiselewich	Baltimore Gas & Electric	REQ	Distributor	In Person	In Person
Yvette Camp	The Southern Company	REQ	Distributor	Phone	Phone
Steve Zavodnick	Baltimore Gas & Electric	RGQ	Distributor	Phone	Phone
Michael Novak	National Fuel	RGQ	Distributor	Phone	Phone
Pete Connor	Nisource	RGQ	Distributor	Phone	
Rose Lennon	Washington Gas	RGQ	Distributor	Phone	Phone
Marcy McCain	Duke Energy Gas Transmission	RGQ	Supplier	Phone	Phone
Suzanne Calcagno	UBS Energy	RGQ	Supplier	Phone	Phone
Jim Templeton	Comprehensive Energy	WEQ	End User	In Person	In Person
LouAnn Westerfield	Idaho PUC (NARUC)	WEQ	End User	In Person	In Person
Lou Oberski	Dominion	WEQ	Generation	Phone	Phone
Melissa Lauderdale	EEI	WEQ	Generation	In Person	In Person

Kathy York	Tennessee Valley Authority	WEQ	Generation	In Person	In Person
Alan Johnson	Mirant	WEQ	Marketer	Phone	
John Porter	Tennessee Valley Authority	WEQ	Marketer	Phone	Phone
Ken Brown	PSEG	WEQ	Transmission	Phone	Phone
Curt Brechtel	Arizona Public Service	WGQ	End User	In Person	In Person
Jay Dibble	Calpine	WGQ	End User	In Person	In Person
Judy Hickman	Nisource Pipelines	WGQ	End User	In Person	
Diane McVicker	Salt River Project	WGQ	End User	In Person	In Person
Roman Bakke	Southern California Edison	WGQ	End User	Phone	Phone
Carl Haga	Southern Company	WGQ	End User	In Person	In Person
Valerie Crockett	Tennessee Valley Authority	WGQ	End User	In Person	In Person
Craig Colombo	Dominion Resources	WGQ	LDC	Phone	Phone
Dolores Chezar	Keyspan	WGQ	LDC	Phone	Phone
Alexander Sarafin	Nisource	WGQ	LDC	Phone	
Drake Kijowski	PSEG	WGQ	LDC	Phone	Phone
Sharon Armstrong	Public Service Company of NM	WGQ	LDC	Phone	Phone
Bill Griffith	Colorado Interstate	WGQ	Pipelines	Phone	Phone
Kathryn Burch	DEGT	WGQ	Pipelines	In Person	In Person
Iris King	Dominion Transmission	WGQ	Pipelines	Phone	Phone
Randy Young	Gulf South	WGQ	Pipelines	In Person	
Paul Love	NGPL	WGQ	Pipelines	In Person	In Person
Lisa Fitzgerald	Nisource Pipelines	WGQ	Pipelines	In Person	
Brian White	Nisource Pipelines	WGQ	Pipelines	In Person	In Person
Mike Bray	Shell Gas Transmission	WGQ	Pipelines	In Person	In Person
Mark Gracey	Tennessee Gas Pipeline	WGQ	Pipelines	In Person	
Jeff Bittel	Texas Gas	WGQ	Pipelines	Phone	Phone
Donna Scott	Transwestern Pipeline	WGQ	Pipelines	In Person	In Person
Dale Davis	Williams Gas Pipeline	WGQ	Pipelines	In Person	In Person
Jim Buccigross	Group 8760	WGQ	Services	Phone	

13. Voting Record

Motion 1: Wholesale Gas Quadrant

Segment	Votes Cast			Balanced Vote		
	YES	NO	TOTAL	YES	NO	TOTAL
Producers				0	0	0
Pipelines	14		14	2	0	2
LDCs	3		3	2	0	2
Services				0	0	0
End Users	1	4	5	0.4	1.6	2
Total				4.4	1.6	6

Wholesale Electric Quadrant

Segment	Votes Cast			Balanced Vote		
	YES	NO	TOTAL	YES	NO	TOTAL
Transmission	1		1	1	0	1
Generation		2	2	0	2	2
Marketers/Brokers		1	1	0	1	1
Distribution/LSE				0	0	0
End Users		1	1	0	1	1
Total				1	4	5

Retail Gas Quadrant

Segment	Votes Cast			Balanced Vote		
	YES	NO	TOTAL	YES	NO	TOTAL
Suppliers				0	0	0
Distributors	4	0	4	2	0	2
End Users				0	0	0
Service Providers				0	0	0
Total				2	0	2

Retail Electric Quadrant

Segment	Votes Cast			Balanced Vote		
	YES	NO	TOTAL	YES	NO	TOTAL
Suppliers				0	0	0
Distributors				0	0	0
End Users				0	0	0
Service Providers				0	0	0
Total				0	0	0

Motion 2:

Wholesale Gas Quadrant

Segment	Votes Cast			Balanced Vote		
	YES	NO	TOTAL	YES	NO	TOTAL
Producers				0	0	0
Pipelines		14	14	0	2	2
LDCs	2		2	2	0	2
Services				0	0	0
End Users	4	0	4	2	0	2
Total				4	2	6

Wholesale Electric Quadrant

Segment	Votes Cast			Balanced Vote		
	YES	NO	TOTAL	YES	NO	TOTAL
Transmission	1		1	1	0	1
Generation	3		3	2	0	2
Marketers/Brokers	1		1	1	0	1
Distribution/LSE				0	0	0
End Users	1		1	1	0	1
Total				5	0	5

Retail Gas Quadrant

Segment	Votes Cast			Balanced Vote		
	YES	NO	TOTAL	YES	NO	TOTAL
Suppliers	1		1	1	0	1
Distributors	4	0	4	2	0	2
End Users				0	0	0
Service Providers				0	0	0
Total				3	0	3

Retail Electric Quadrant

Segment	Votes Cast			Balanced Vote		
	YES	NO	TOTAL	YES	NO	TOTAL
Suppliers				0	0	0
Distributors	1		1	1	0	1
End Users				0	0	0
Service Providers				0	0	0
Total				1	0	1

Motion 3:

Wholesale Gas Quadrant

Segment	Votes Cast			Balanced Vote		
	YES	NO	TOTAL	YES	NO	TOTAL
Producers				0	0	0
Pipelines	12		12	2	0	2
LDCs	3		3	2	0	2
Services				0	0	0
End Users	1	4	5	0.4	1.6	2
Total				4.4	1.6	6

Wholesale Electric Quadrant

Segment	Votes Cast			Balanced Vote		
	YES	NO	TOTAL	YES	NO	TOTAL
Transmission	1		1	1	0	1
Generation		3	3	0	2	2
Marketers/Brokers		1	1	0	1	1
Distribution/LSE				0	0	0
End Users		1	1	0	1	1
Total				1	4	5

Retail Gas Quadrant

Segment	Votes Cast			Balanced Vote		
	YES	NO	TOTAL	YES	NO	TOTAL
Suppliers	1		1	1	0	1
Distributors	4		4	2	0	2
End Users				0	0	0
Service Providers				0	0	0
Total				3	0	3

Retail Electric Quadrant

Segment	Votes Cast			Balanced Vote		
	YES	NO	TOTAL	YES	NO	TOTAL
Suppliers				0	0	0
Distributors	1		1	1	0	1
End Users				0	0	0
Service Providers				0	0	0
Total				1	0	1

Motion 4:

Wholesale Gas Quadrant

Segment	Votes Cast			Balanced Vote		
	YES	NO	TOTAL	YES	NO	TOTAL
Producers				0	0	0
Pipelines		14	14	0	2	2
LDCs		2	2	0	2	2
Services				0	0	0
End Users	4		4	2	0	2
Total				2	4	6

Wholesale Electric Quadrant

Segment	Votes Cast			Balanced Vote		
	YES	NO	TOTAL	YES	NO	TOTAL
Transmission		1	1	0	1	1
Generation	2		2	2	0	2
Marketers/Brokers	1		1	1	0	1
Distribution/LSE				0	0	0
End Users	1		1	1	0	1
Total				4	1	5

Retail Gas Quadrant

Segment	Votes Cast			Balanced Vote		
	YES	NO	TOTAL	YES	NO	TOTAL
Suppliers				0	0	0
Distributors		2	2	0	2	2
End Users				0	0	0
Service Providers				0	0	0
Total				0	2	2

Retail Electric Quadrant

Segment	Votes Cast			Balanced Vote		
	YES	NO	TOTAL	YES	NO	TOTAL
Suppliers				0	0	0
Distributors	1		1	1	0	1
End Users				0	0	0
Service Providers				0	0	0
Total				1	0	1

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Home Page: www.naesb.org

Appendix III: GECTF Presentations since April 5, 2004

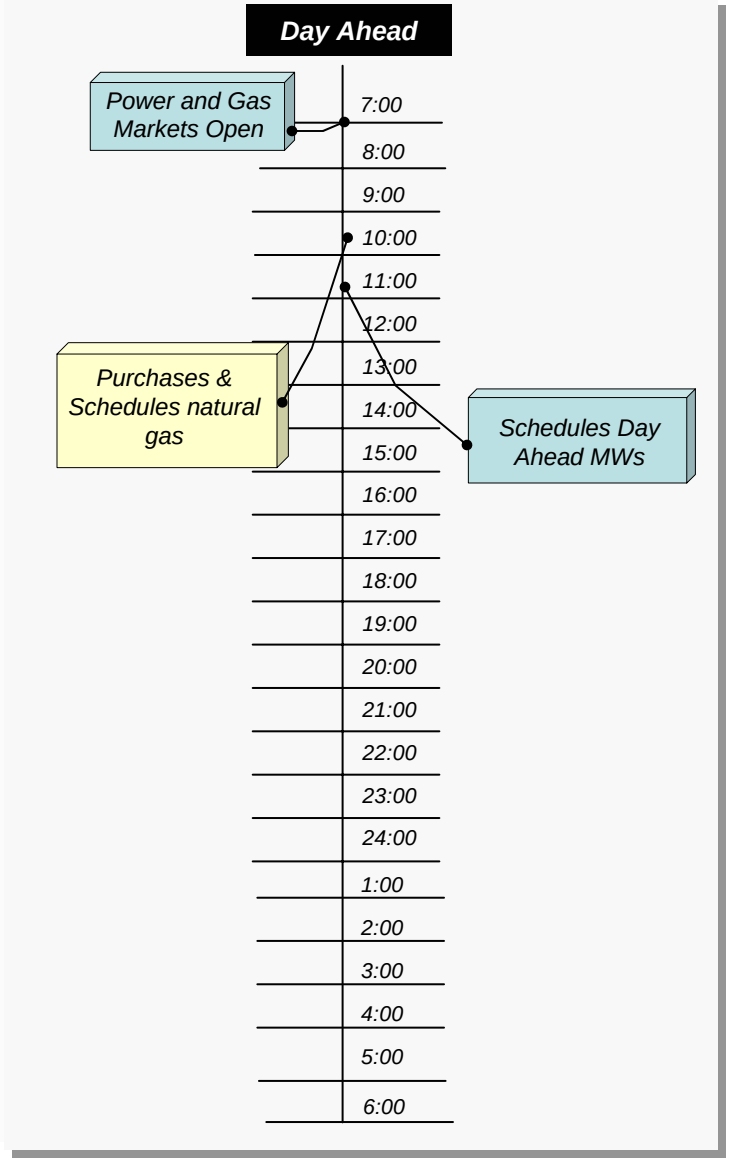
April 2004 Meeting

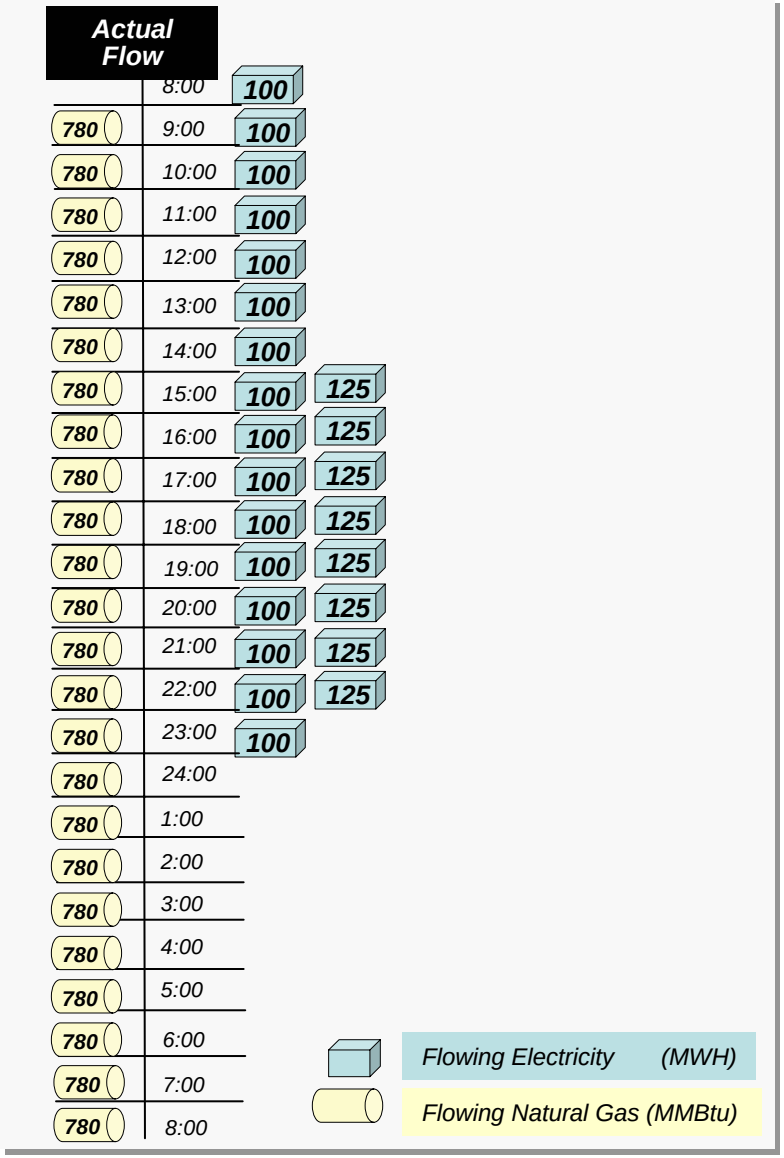
- TVA Timeline Example
- Additional Examples of Natural Gas Industry and Electric Industry Timing Issue

May 2004 Meeting

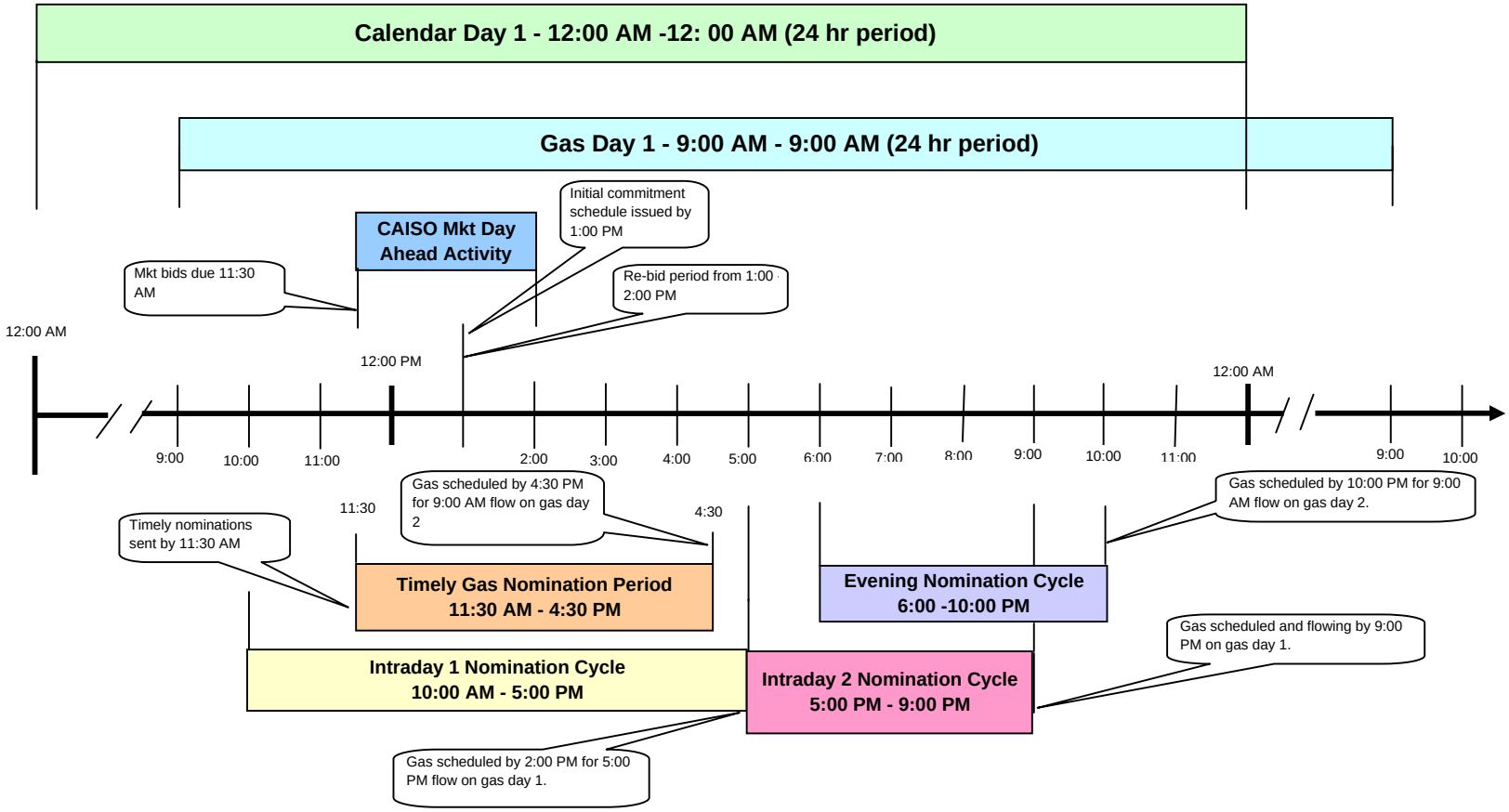
- NERC Gas/Electric Interdependency Task Force Status Report

TVA Day Ahead Bilateral Market Timelines – Summer





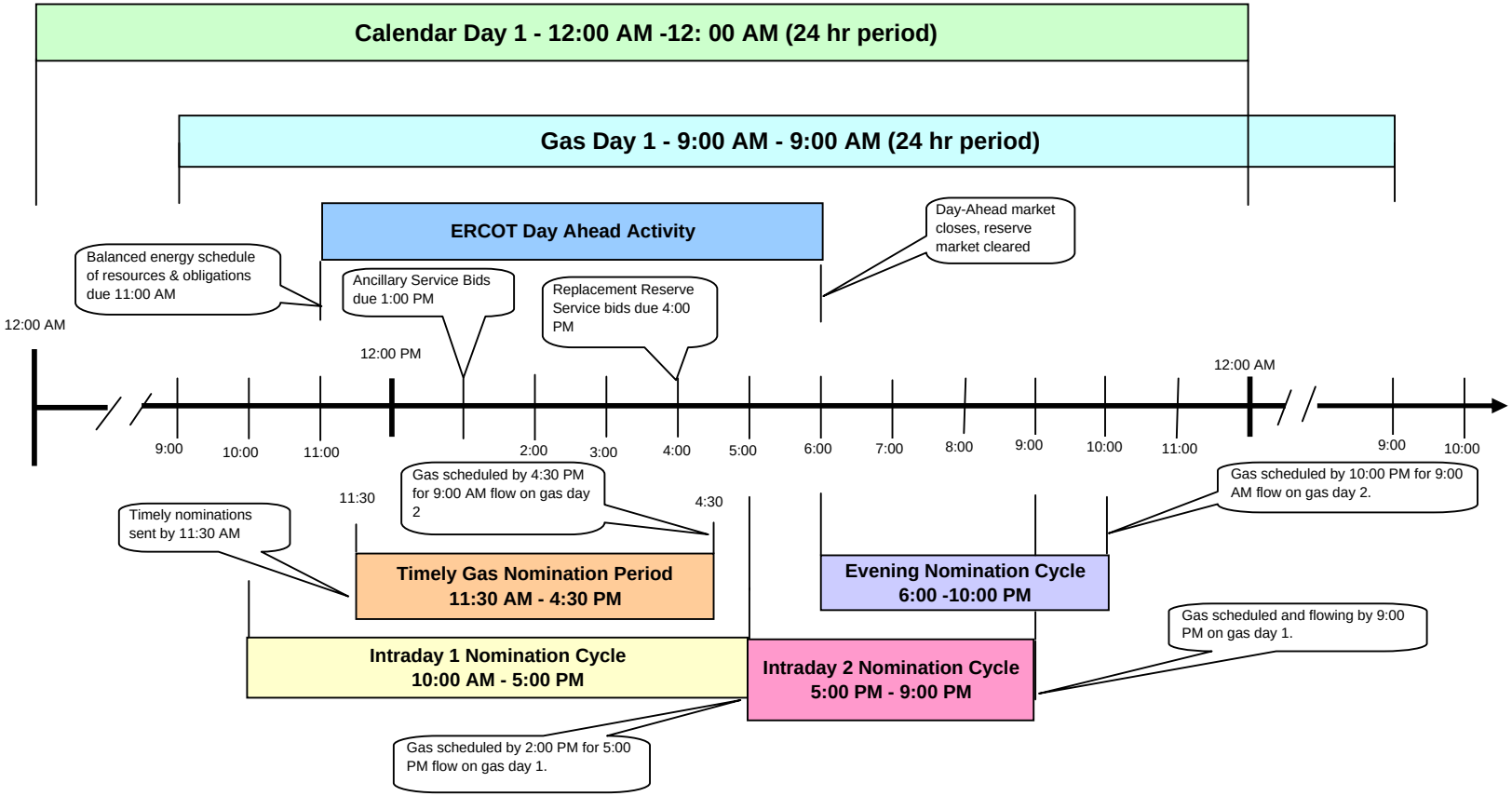
EXAMPLE OF NATURAL GAS INDUSTRY AND ELECTRIC INDUSTRY TIMING ISSUE
GAS NOMINATION VS. CAISO DAY AHEAD MARKET TIMELINE
***** FOR DISCUSSION PURPOSES ONLY *****



Notes:
1. All times are central clock time
2. Timely Nomination/Intraday Nomination Model take from NAESB WGQ Standard 1.3.2
3. California ISO market used for comparison.

Created March 16, 2004

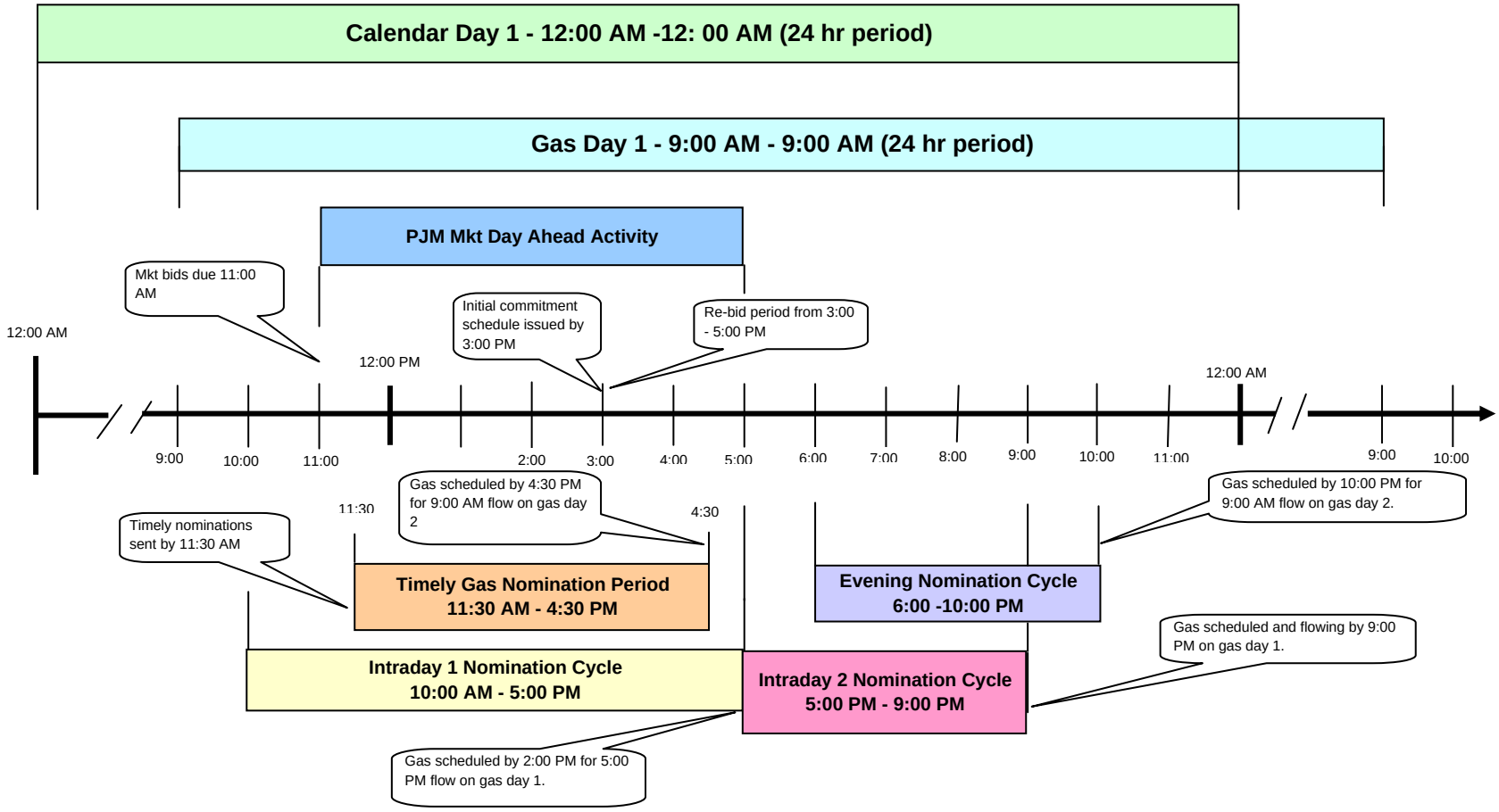
EXAMPLE OF NATURAL GAS INDUSTRY AND ELECTRIC INDUSTRY TIMING ISSUE
GAS NOMINATION VS. ERCOT DAY AHEAD TIMELINE
***** FOR DISCUSSION PURPOSES ONLY *****



Notes:
1. All times are central clock time
2. Timely Nomination/Intraday Nomination Model take from NAESB WGQ Standard 1.3.2
3. ERCOTmarket used for comparison. Timing information taken from ERCOT Protocol 4.0

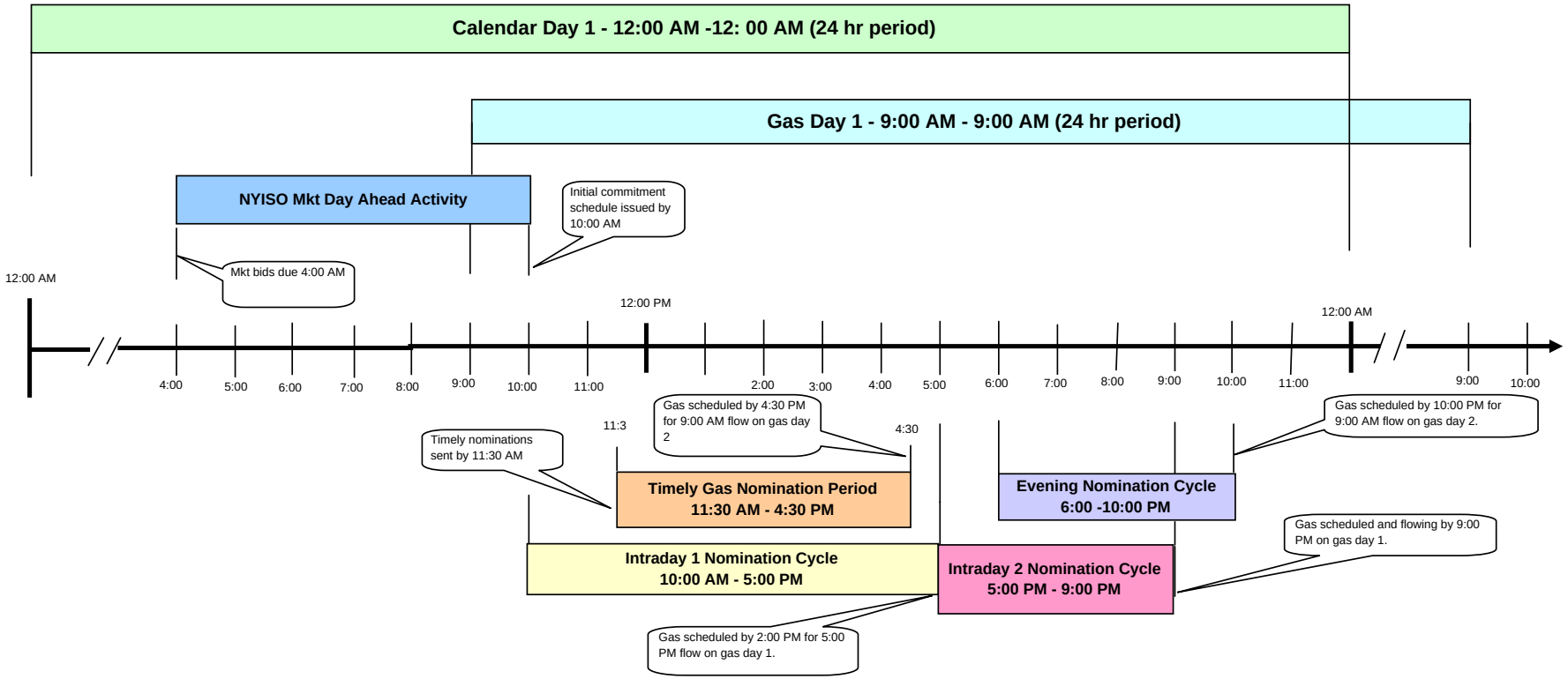
Revised April 1, 2004

EXAMPLE OF NATURAL GAS INDUSTRY AND ELECTRIC INDUSTRY TIMING ISSUE
***** FOR DISCUSSION PURPOSES ONLY *****



Notes:
1. All times are central clock time
2. Timely Nomination/Intraday Nomination Model take from NAESB WGQ Standard 1.3.2
3. Pennsylvania, New Jersey and Maryland (PJM) market used for comparison.

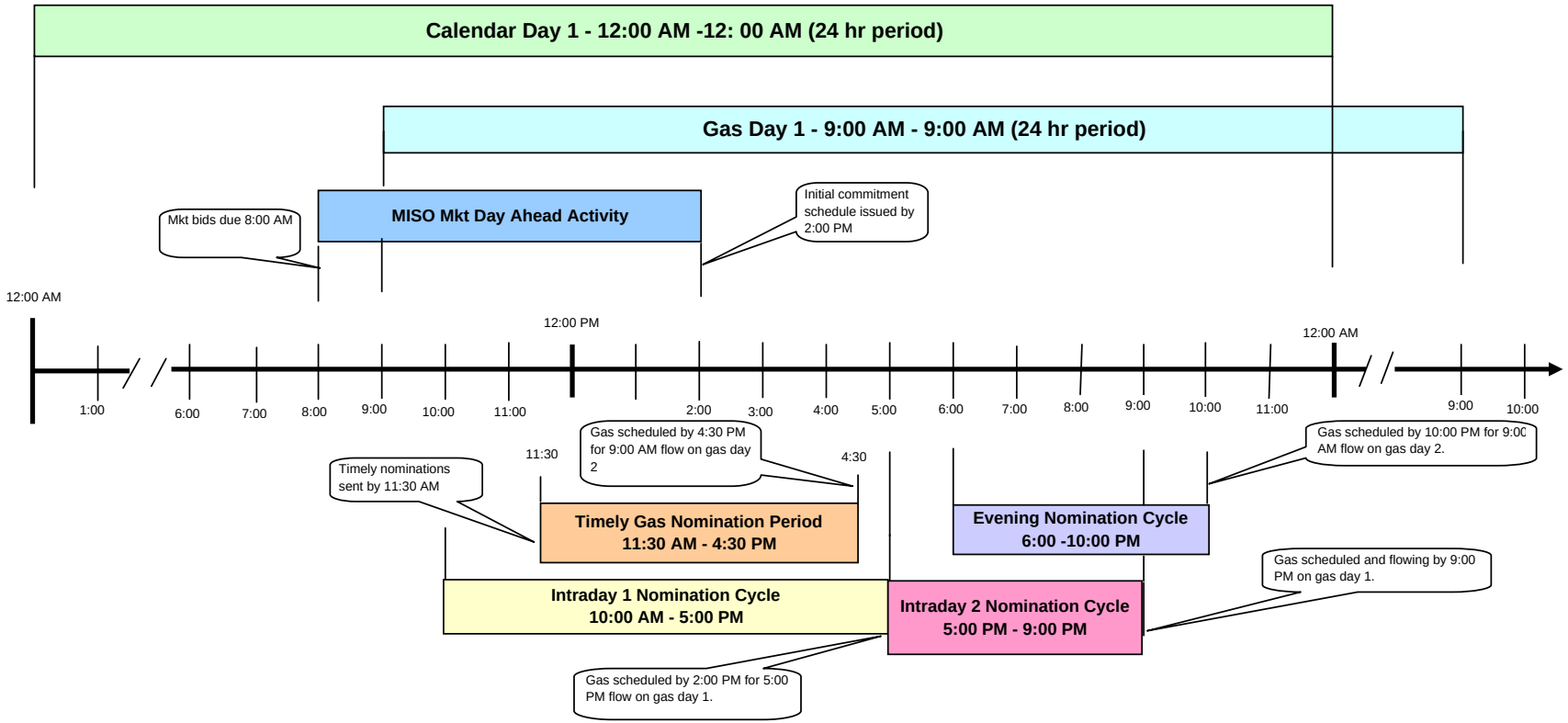
EXAMPLE OF NATURAL GAS INDUSTRY AND ELECTRIC INDUSTRY TIMING ISSUE
GAS NOMINATION VS. NYISO DAY AHEAD MARKET TIMELINE
***** FOR DISCUSSION PURPOSES ONLY *****



Notes:
1. All times are central clock time
2. Timely Nomination/Intraday Nomination Model take from NAESB WGQ Standard 1.3.2
3. New York ISO (NYISO) market used for comparison.

Created March 16, 2004

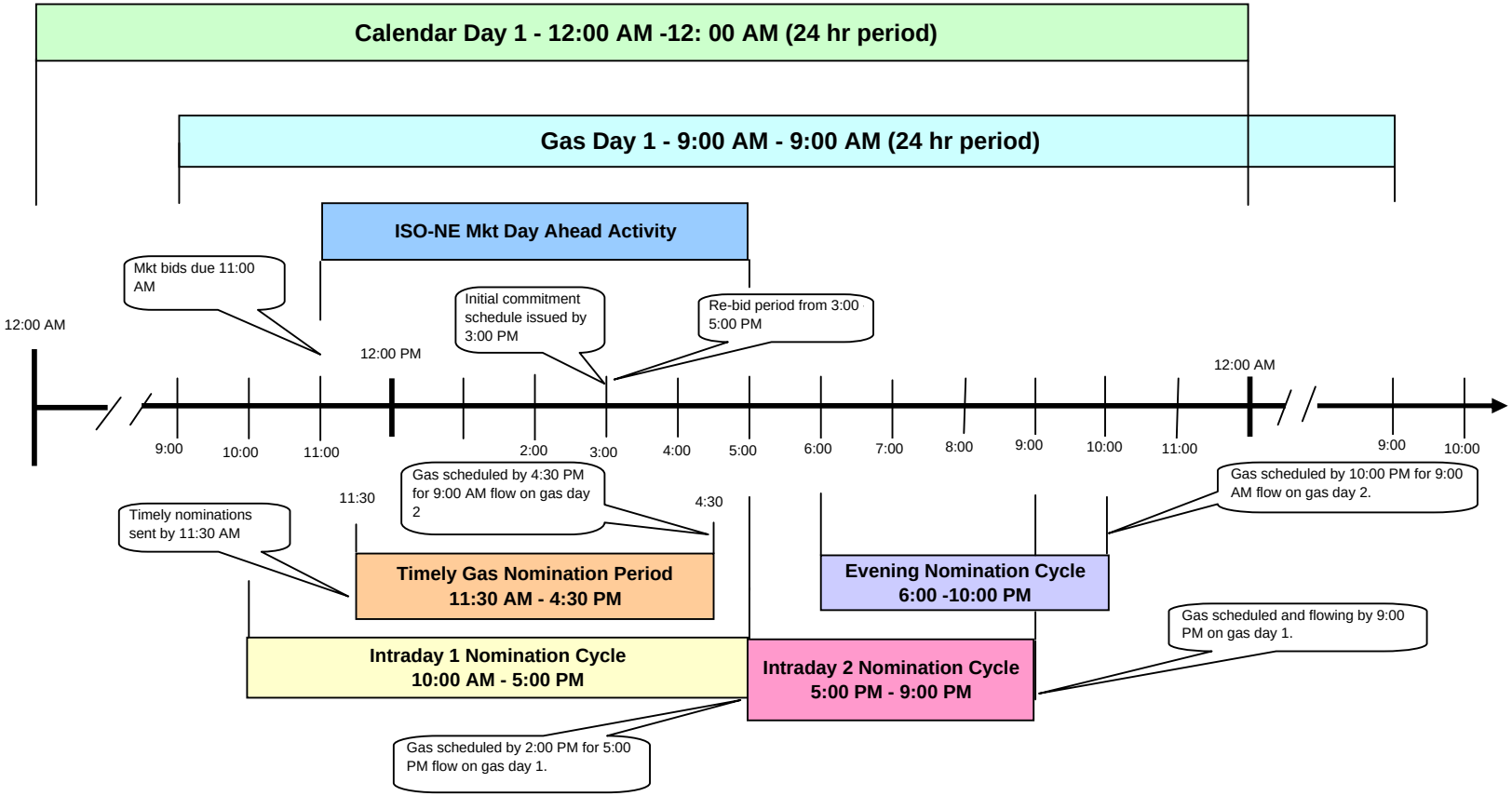
EXAMPLE OF NATURAL GAS INDUSTRY AND ELECTRIC INDUSTRY TIMING ISSUE
GAS NOMINATION VS. MISO DAY AHEAD MARKET TIMELINE
***** FOR DISCUSSION PURPOSES ONLY *****



Notes:
1. All times are central clock time
2. Timely Nomination/Intraday Nomination Model take from NAESB WGQ Standard 1.3.2
3. Proposed Midwest ISO (MISO) market used for comparison.

Created April 1, 2004

EXAMPLE OF NATURAL GAS INDUSTRY AND ELECTRIC INDUSTRY TIMING ISSUE
GAS NOMINATION VS. ISO-NE DAY AHEAD TIMELINE
***** FOR DISCUSSION PURPOSES ONLY *****



Notes:
1. All times are central clock time
2. Timely Nomination/Intraday Nomination Model take from NAESB WGQ Standard 1.3.2
3. ISO New England (ISO-NE) market used for comparison. Timing information taken from ISO-NE Market Rule 1.
4. PJM's day ahead market timeline is identical.

Revised April 1, 2004

Market Timing Issues

NAESB GECTF

****** For Discussion Purposes Only******

4/2/04 - Draft #2 ****** For Discussion Purposes Only **********

	General	NYISO		ISO-NE		IMO	
1	Time Stamp (hour beginning (HB) or Hour Ending (HE))	HB		HE		HB	
2	Beginning of Trading Day	0:00		0:00		0:00	
3	Ending of Trading Day	24:00		24:00		24:00	

	Day-Ahead Markets	NYISO		ISO-NE		IMO (f)	
	Time Zone	EST	CST	EST	CST	EST	CST
1	Market Closing Time (day before)	5:00 AM	4:00 AM	12:00 PM	11:00 AM	N/A	N/A
2	Market Prices Posted (day before)	11:00 AM	10:00 AM	4:00 PM	3:00 PM	N/A	N/A
3	Re-bid Period			4:00 PM - 6:00 PM	3:00 PM - 5:00 PM	N/A	N/A

	Real Time Markets	NYISO (a)		ISO-NE		IMO	
1	Commitment Posting (before the hour)	15 minute					
2	Accept generation offers (before the hour)	60 minutes		60 minutes		120 minutes**	
3	Real Time Dispatch	every 5 minutes		every 5 minutes		every 5 minutes	
4	ex-post or ex-ante pricing (b)	Ex-post		Ex -post		Ex-ante	

(a). The present BME and SCD systems will be replaced in 2004 with the RTS System. The data listed is for the NYISO RTS System

(b). Ex-post pricing is based on acutal performance for prior 5 minute interval, ex-ante which is the expected performance of 5 minute interval.

(c). The ERCOT day-ahead market is designed differently from the others. There is a replacement reserve market (essentially an energy balancing market) and an ancillary se
Balanced energy schedules (resources and obligations) are due by 11:00 AM day ahead. Ancillary service bids are due by 1:00 PM day ahead. Replacement Reserve Se

(d). Not applicable to current market. Part of Midwest Market Initiative for the future market. See MISO column.

(e). Information based upon CAISO's "Comprehensive Market Design Proposal".

***2hours prior for bid changes greater of 10% or 10 MW; 4 hours prior unrestricted*

(f) The IMO does not operate a day-ahead market

PJM		MISO		SPP		CAISO (e)
HE		HE				HB
0:00		0:00		0:00		0:00
24:00		24:00		24:00		24:00

PJM		MISO		SPP		CAIS
EST	CST	EST	CST	CST	CST	PST
12:00 PM	11:00 AM	9:00 AM	8:00 AM	see note (d)	see note (d)	9:30 AM
4:00 PM	3:00 PM	3:00 PM	2:00 PM	see note (d)	see note (d)	11:00 AM
4:00 PM - 6:00 PM	3:00 PM - 5:00 PM	N/A	N/A	see note (d)	see note (d)	11:00 AM - 12:00 PM

PJM		MISO		SPP		CAISO (e)
				see note (d)		30-45 minutes
		20 minutes		see note (d)		45 minutes
every 5 minutes		every 5 minutes		see note (d)		every 10 minutes
		Ex-post		see note (d)		Ex-post

ervices market.

ervice bids are due by 4:00 PM. By 6:00 PM the Day-Ahead market closes and ERCOT publishes clearing prices for the replacement reserve service.

O (e)
CST
11:30 AM
1:00 PM
1:00 PM - 2:00 PM

ERCOT	
HB	
0:00	
24:00	

ERCOT (c)	
CST	CST
4:00 PM	4:00 PM
6:00 PM	6:00 PM
N/A	N/A

ERCOT	
5-10 minutes	
60 minutes	
every 15 minutes	
Ex-post	

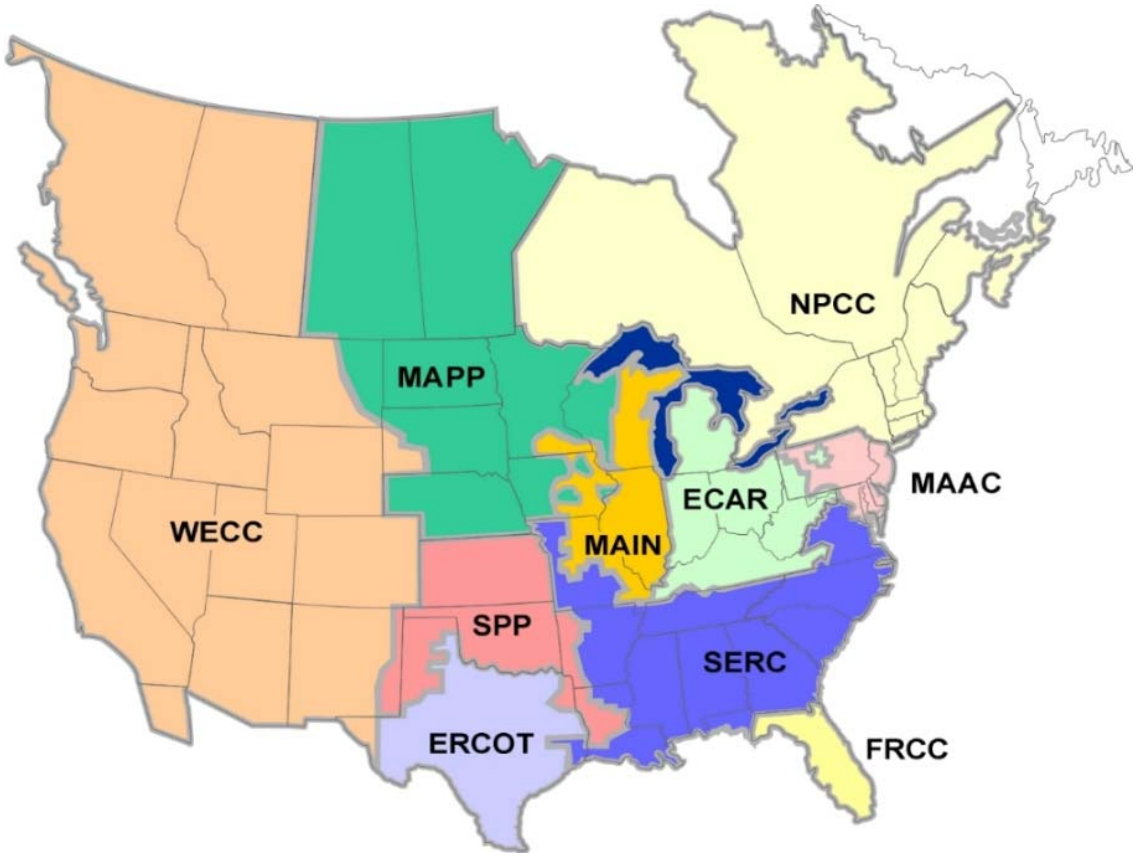
NERC Gas/Electric Interdependency Task Force Status Report

North American Energy Standards Board
Gas Electric Coordination Task Force
Meeting

May 18-19, 2004

Philip A. Fedora
Director, Market Reliability Interface
Northeast Power Coordinating Council

Northeast Power Coordinating Council



NPCC

- One million square miles
- 54 million people
- 50% US
  50% Canadian
- Represents 70% of Canadian Load

http://www.npcc.org/

NERC Reliability Assessment 2002-2011

NERC RAS issues raised:

- **Majority of new generation proposed relies on natural gas**

- **Electric network planned for first contingency – gas industry doesn't have similar standards**

- **Single gas system disturbance may result in the loss of more electrical generation than expected**

http://www.nerc.com/~filez/rasreports.html

NERC Reliability Assessment 2002-2011

NERC RAS issues raised (continued):

- **Natural gas pipelines generally operate independently**

- **Natural gas curtailment procedures have not been rigorously tested (rarely implemented)**

- **Operation of proposed generation units (CTs and CCGTs) depend on high gas pressures**

http://www.nerc.com/~filez/rasreports.html

NERC Gas/Electric Interdependency Task Force

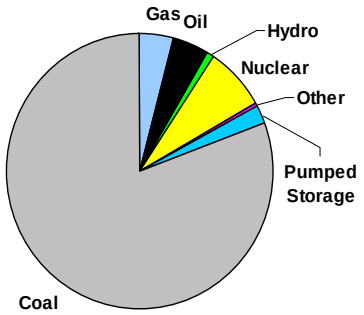
A review of the interdependency relationship between:

- **Gas pipeline operations and planning, and**
- **Electric generation operations and planning**

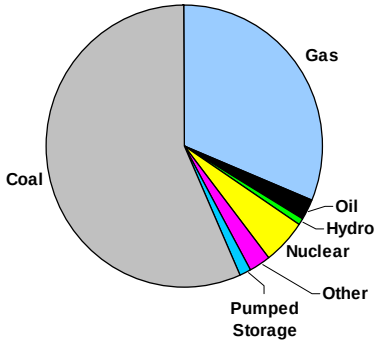
http://www.nerc.com/~pc/geitf.html

NERC Reliability Assessment 2003-2012

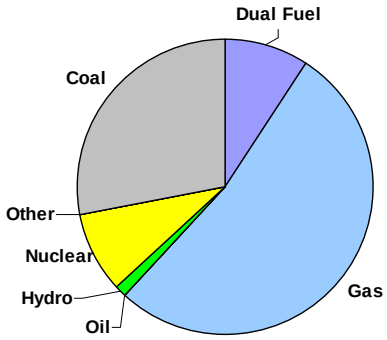
ECAR Capacity Fuel Mix 1998



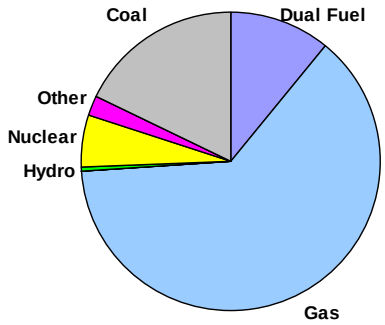
ECAR Capacity Fuel Mix 2008



ERCOT Capacity Fuel Mix 1998



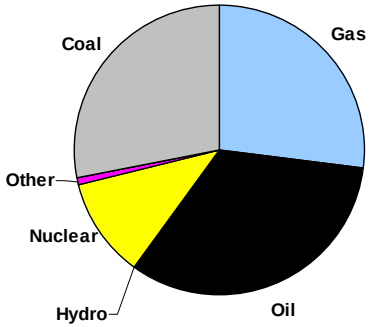
ERCOT Capacity Fuel Mix 2008



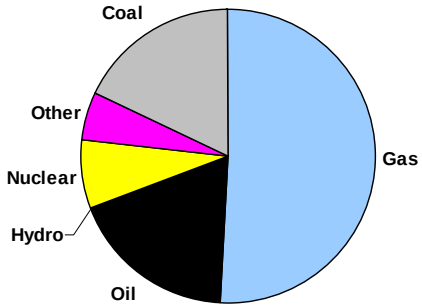
http://www.nerc.com/~filez/rasreports.html

NERC Reliability Assessment 2003-2012

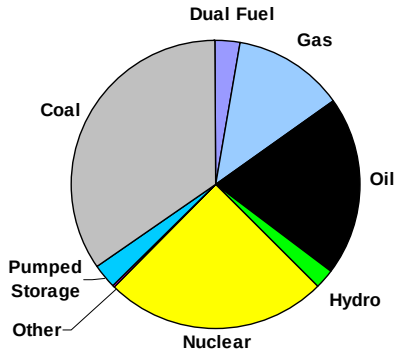
FRCC Capacity Fuel Mix 1998



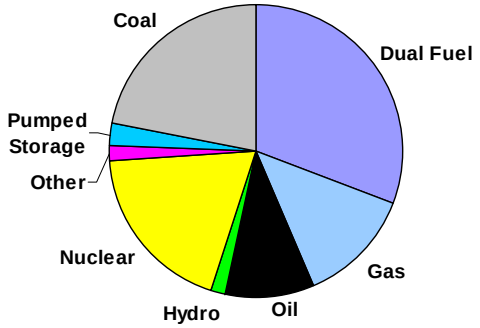
FRCC Capacity Fuel Mix 2008



MAAC Capacity Fuel Mix 1998



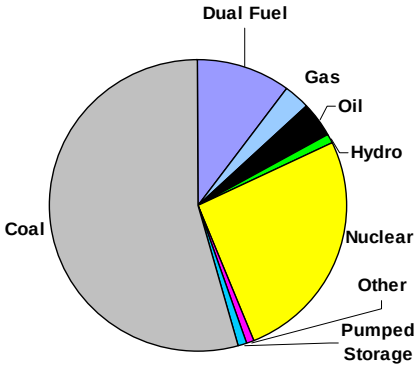
MAAC Capacity Fuel Mix 2008



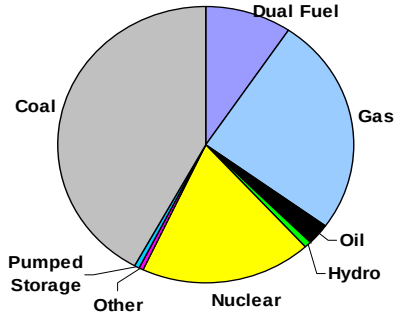
http://www.nerc.com/~filez/rasreports.html

NERC Reliability Assessment 2003-2012

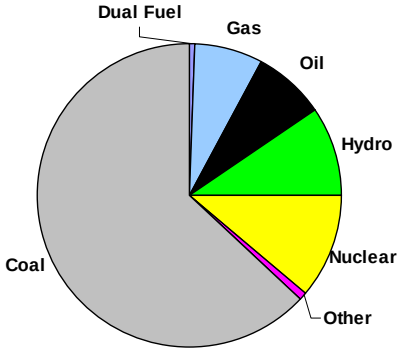
MAIN Capacity Fuel Mix 1998



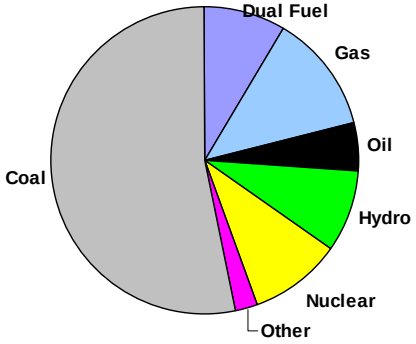
MAIN Capacity Fuel Mix 2008



MAPP US Capacity Fuel Mix 1998



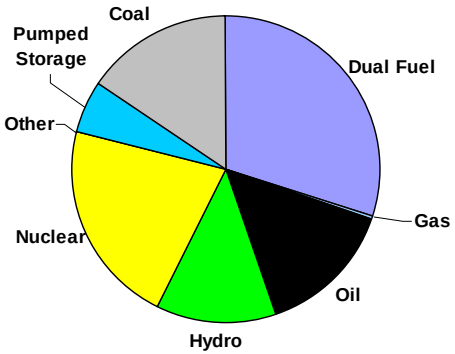
MAPP US Capacity Fuel Mix 2008



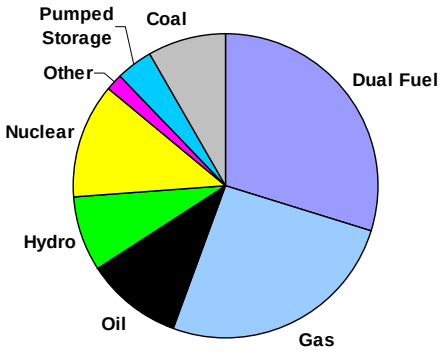
http://www.nerc.com/~filez/rasreports.html

NERC Reliability Assessment 2003-2012

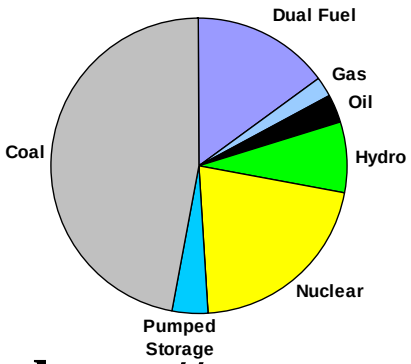
NPCC US Capacity Fuel Mix 1998



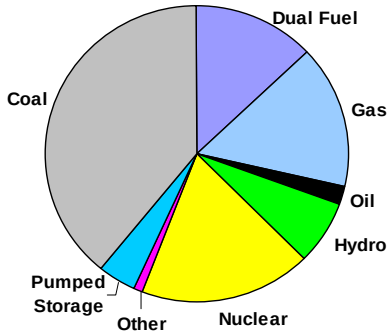
NPCC US Capacity Fuel Mix 2008



SERC Capacity Fuel Mix 1998



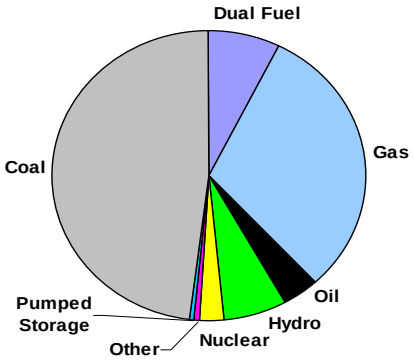
SERC Capacity Fuel Mix 2008



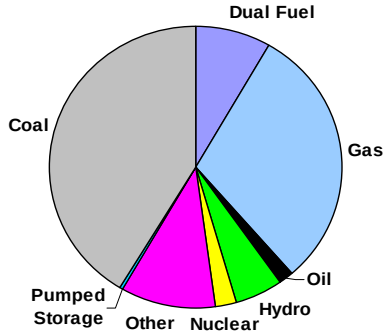
http://www.nerc.com/~filez/rasreports.html

NERC Reliability Assessment 2003-2012

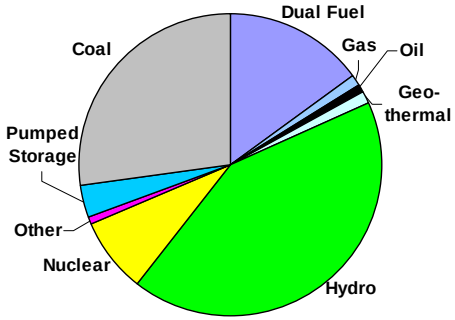
SPP Capacity Fuel Mix 1998



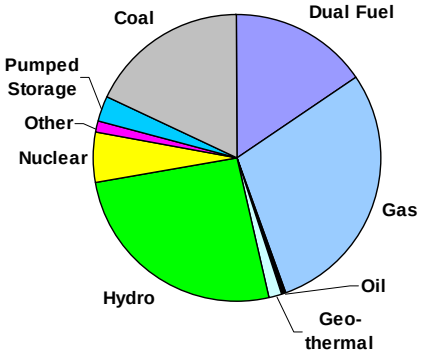
SPP Capacity Fuel Mix 2008



WECC US Capacity Fuel Mix 1998



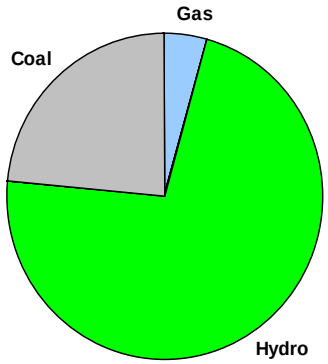
WECC US Capacity Fuel Mix 2008



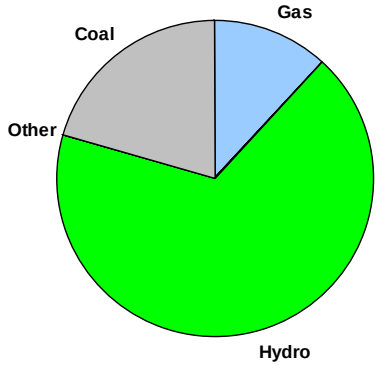
http://www.nerc.com/~filez/rasreports.html

NERC Reliability Assessment 2003-2012

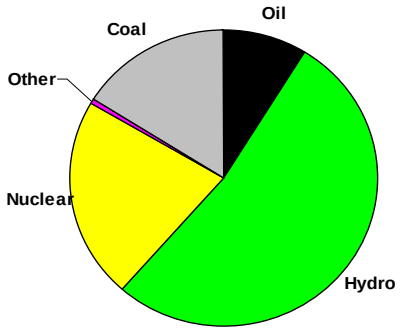
MAPP Canada Capacity Fuel Mix 1998



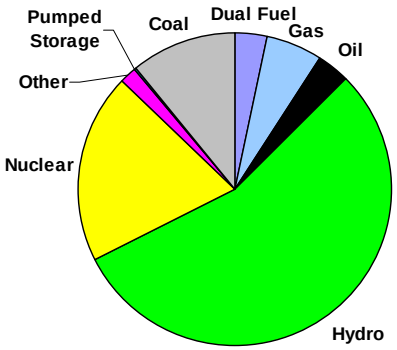
MAPP Canada Capacity Fuel Mix 2008



NPCC Canada Capacity Fuel Mix 1998

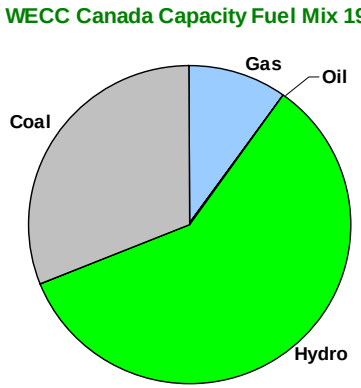


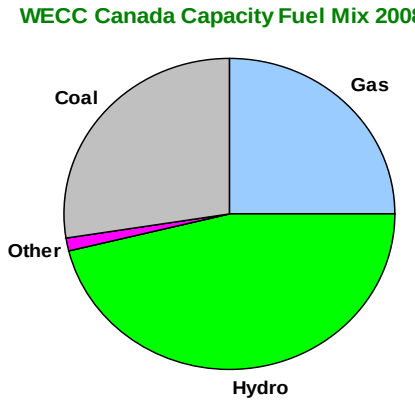
NPCC Canada Capacity Fuel Mix 2008



http://www.nerc.com/~filez/rasreports.html

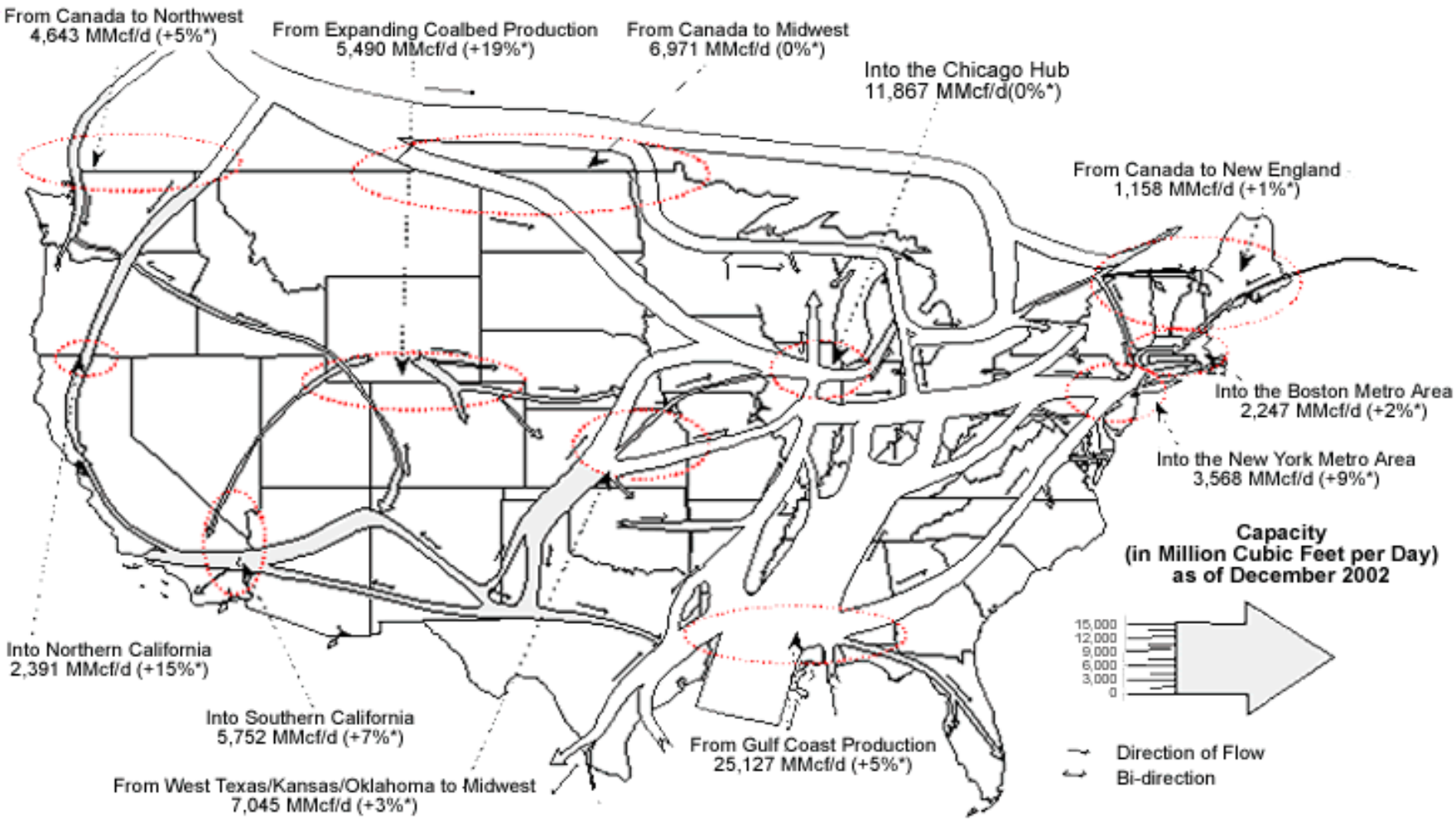
NERC Reliability Assessment 2003-2012





http://www.nerc.com/~filez/rasreports.html

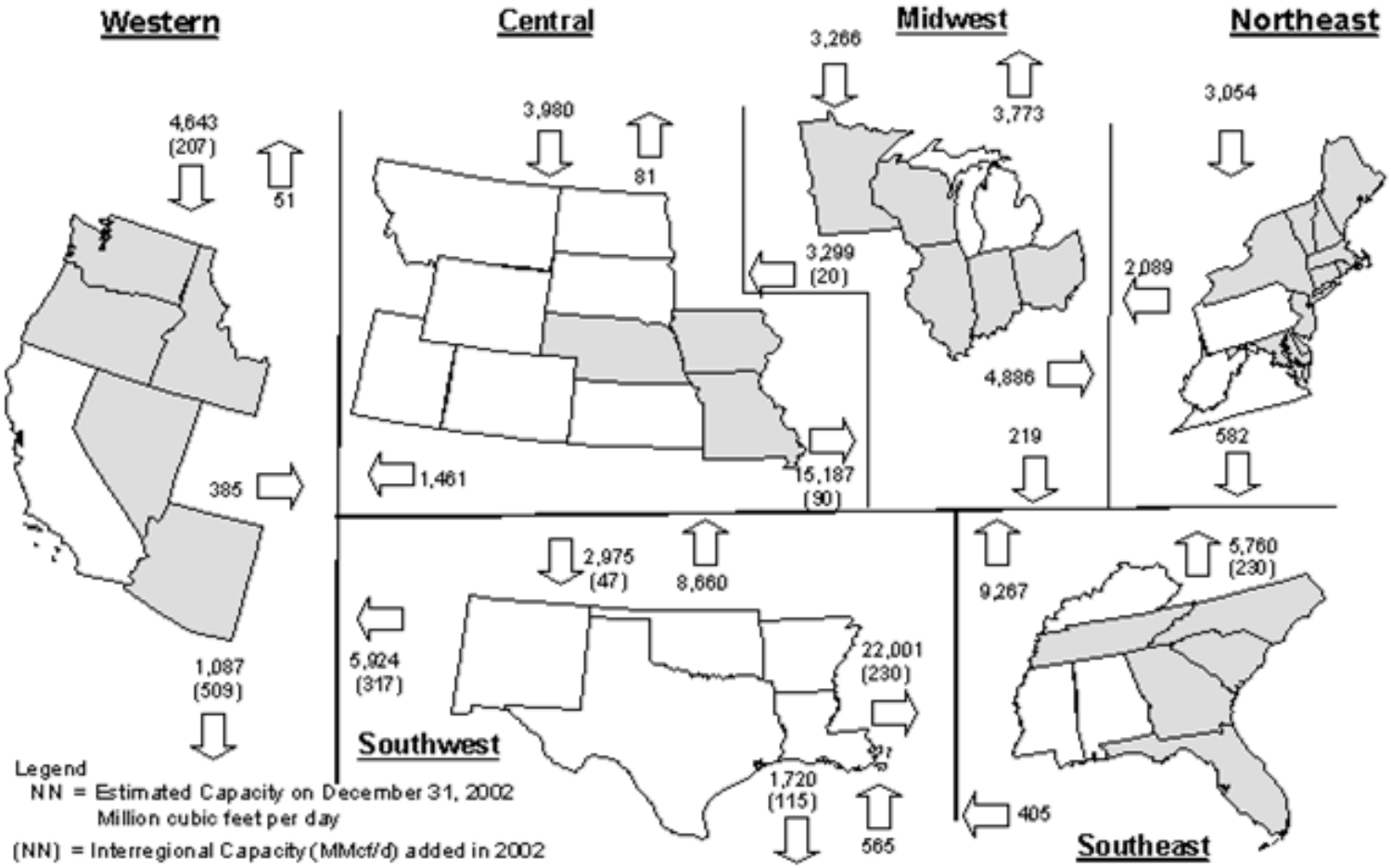
Figure 3. Major Natural Gas Transportation Routes and Capacity Levels at Selected Key Locations, 2002



*Percent change since 2000.
Source: Energy Information Administration, GasTran Gas Transportation Information System, Natural Gas Pipeline State Border Capacity Database.

www.eia.doe.gov/pub/oil_gas/natural_gas/feature_articles/2003/Pipenet03/pipenet03.html

Figure 4. Region-to-Region Natural Gas Pipeline Capacity, 2002



Source: Energy Information Administration, GasTran Gas Transportation Information System, Natural Gas Pipeline Capacity Database.

www.eia.doe.gov/pub/oil_gas/natural_gas/feature_articles/2003/Pipenet03/pipenet03.html

NERC Gas/Electric Interdependency Task Force

Draft Conclusions

- 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 electric markets.
- Modern combustion turbines have stringent fuel delivery and fuel quality requirements.

NERC Gas/Electric Interdependency Task Force

Under Consideration

Recommendation 1 — NERC Regions should include in their regional assessment program a review of the impact of any fuel transportation infrastructure interruption that could adversely impact electric system reliability.

The focus of the GEITF was on gas transportation. However, interruptions to fuel delivery systems other than for gas could also have an adverse impact on electric system reliability.

NERC Gas/Electric Interdependency Task Force

Under Consideration

Recommendation 2 — NERC reliability coordinators or their delegates, subject to appropriate treatment of commercially sensitive information, should develop regular, real-time communications with pipeline operators about disturbances that could adversely impact the reliability of either the electric systems or the gas pipeline.

NERC Gas/Electric Interdependency Task Force

Under Consideration

Recommendation 3 — For planning purposes, gas pipeline outages that could have an adverse impact on the reliability of the electric systems must be coordinated with the electric industry so that plans to mitigate any impacts to the electric systems may be developed.

NERC Gas/Electric Interdependency Task Force

Under Consideration

Recommendation 4 — NERC should develop a reliability standard relating fuel infrastructure reliability to resource adequacy.

Recommendation 5 — NERC should include analysis of fuel infrastructure contingencies that could adversely impact the reliability of the electric systems in the NERC planning standards.

NERC Gas/Electric Interdependency Task Force

Under Consideration

Recommendation 6 — NERC should establish a monitoring system that tracks fuel infrastructure contingencies that have, or could have, an adverse impact on electric system reliability.

Recommendation 7 — NERC should, in concert with other energy industry organizations, formalize communications between the electric industry and the gas transportation industry for the purposes of education, planning, and emergency response.

NERC Gas/Electric Interdependency Task Force

TIMELINE

- **NERC PC approved Recommendations – March 23rd – 24th**
- **NERC PC vote on Final Draft Report due May 20th**
- **Present to NERC Board of Trustees – June 15th**
  - **Approval of Report**
  - **Implementation of Recommendations**

North American Energy Standards Board
1301 Fannin, Suite 2350, Houston, Texas 77002
Phone: (713) 356-0060, Fax: (713) 356-0067, E-mail: naesb@naesb.org
Home Page: www.naesb.org

Appendix IV: Participants in the GECTF Effort

North American Energy Standards Board

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Home Page: www.naesb.org

GAS and ELECTRIC COORDINATION TASK FORCE
Participation Roster

Name	Organization
Sharon Armstrong	Public Service Company of New Mexico
Mariam Arnaout	American Gas Association
Mark Babula	ISO New England
Andrew Bachert	New York ISO
Tom Bacon	Conectiv
Roman Bakke	Southern California Edison
Judith Barleycorn	Pinnacle West Energy
Ed Berman	Baltimore Gas & Electric
Joanne Bialas	ISO New England
Jeff Bittel	Texas Gas Transmission
Mike Bray	Shell Gas Transmission
Curt Brechtel	Arizona Public Service
Ken Brown	Public Services Electric & Gas Co.
Jim Buccigross	Group 8760
Kathryn Burch	Duke Energy Gas Transmission
Christopher Burden	Williams Gas Pipeline
Tina Burnett	The Boeing Company
Suzanne Calcagno	UBS Energy
Yvette Camp	Southern Company
Jack Cashin	Electric Power Supply Association
Craig Chancellor	Calpine
Dolores Chezar	KeySpan Energy
Craig Colombo	Dominion Resources
Pete Connor	NiSource, Inc.
Jeffrey Conopask	DC Public Service Commission
Chuck Cook	Shell Gas Transmission
Mike Coyle	Public Service Electric & Gas
Valerie Crockett	Tennessee Valley Authority
Pat Davidson	Southern California Gas Co.
Dale Davis	Williams Gas Pipeline
George Dawe	Duke Energy Corp.
Jennifer Deegan	Washington Gas
Michael Desselle	American Electric Power
Jay Dibble	Calpine Corp.
Andrew Dotterweich	Consumers Energy
Dan Downs	NY Department of Public Service
Philip Fedora	Northeast Power Coordinating Council
Lisa Fitzgerald	Columbia Gas Transmission
Michael Gildea	Constellation Generation
Karen Gossett	UBS Energy
Mark Gracey	Tennessee Gas Pipeline
Bob Gray	Arizona Corp. Commission

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Home Page: www.naesb.org

Bill Griffith	El Paso
Bill Grygar	Panhandle Eastern Pipe Line
Dona Gussow	Florida Power & Light Company
Tom Gwilliam	Iroquois Gas Transmission
Ben Hadden	Conectiv Energy
Carl Haga	Southern Company
Scott Hansen	Questar Pipeline
Bill Heinrich	New York Public Service Commission
Bruce Henning	Energy and Environmental Analysis
Sheri Heslington	Dominion Exploration & Production
Nancy Hetrick	Northern Natural Gas
Judy Hickman	Columbia Gas Transmission
Gary Hinners	Reliant Energy
Jeff Hodges	UBS Energy
Erin Hogan	Nyserda
Brad Holmes	Transwestern Gas
Jim Ingraham	Tennessee Valley Authority
Steve Irvine	Arizona Corp. Commission
Rick Ishikawa	Southern California Gas Co.
Gary Jackson	Tennessee Valley Authority
Alan Johnson	Mirant
Joe Kardas	National Fuel Gas Supply
Henry Kenchington	U.S. Department of Energy
Drake Kijowski	PSEG Energy Resources & Trade
Iris King	Dominion Transmission
Ruth Kiselewich	Baltimore Gas & Electric
Melissa Lauderdale	Edison Electric Institute
Rose Lennon	Washington Gas
Jane Lewis	American Gas Association
Chuck Linderman	Edison Electric Institute
Paul Love	Natural Gas Pipeline Co. of America
Lynne Mackey	InterGen
Greg Maliken	National Fuel Gas Supply
Ken Mancini	PJM Interconnection
Chris Maturo	NiSource, Inc.
Marcy McCain	Duke Energy Gas Transmission
Jim McGlone	U.S. Department of Energy
Paul McKelvey	ChevronTexaco
Chris McNiff	Consolidated Edison of NY
Diane McVicker	Salt River Project
Patricia Merville	Public Service Company PNM
Randy Mills	ChevronTexaco
Kay Morice	Federal Energy Regulatory Commission
Michael Mount	R. J. Rudden Associates
Sandy Murrey	We Energies
Bill Newbold	Detroit Edison

North American Energy Standards Board

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Janie Nielsen	Kern River Gas Transmission
Leslie Nishida	Wisconsin Public Service Corporation
Matt Nollenberg	American Electric Power
Mike Novak	National Fuel Distribution
Joe Obergfell	American Electric Power
Lou Oberski	Dominion
Bill Oppenheim	Kimball Resources
Arlene Palmerino	NY Department of Public Service
Mary Ellen Paravalos	National Grid
Marjorie Perlman	Energy East Management Corp.
Chris Peterson	Federal Energy Regulatory Commission
John Porter	Tennessee Valley Authority
Tony Reed	Southern Company
Andy Rodriquez	PJM Interconnection
Marv Rosenberg	Federal Energy Regulatory Commission
Richard Rudden	R. J. Rudden Associates
Alexander Sarafin	NiSource
Mark Scheel	Chevron Texaco
Christian Schmolling	Natural Gas Week
Ken Schubert	TransCanada Pipelines
Rodger Schwecke	Southern California Gas Co.
Donna Scott	Transwestern Pipeline
Mike Shepard	Mewbourne Oil Co.
Denise Simpson	Reliant Energy
Albert Small	Downey & Small Assoc.
Jimmy Smith	Entergy
Denise Spensor	Reliant Energy
Steve Sullivan	Consolidated Edison of NY
Ed Tammy	Florida Power & Light Company
Jim Templeton	Comprehensive Energy
Chuck Thompson	Public Service Company of New Mexico
Ed Thompson	Consolidated Edison of NY
Kalim Tippett	The Structure Group
John Twitchell	North American Electric Reliability Council
Kim Van Pelt	Panhandle Eastern Pipe Line
Pauline Wah	Southern California Gas Co.
LouAnn Westerfield	Idaho Public Utilities
Brian White	NiSource Pipelines
Dean Wight	Federal Energy Regulatory Commission
Mark Wilke	Trunkline Gas Company
Kathy York	Tennessee Valley Authority
Jon Young	Columbia Gas Transmission
Randy Young	Gulf South Pipeline
Steve Zavodnick	Baltimore Gas & Electric

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Appendix V: Comments Received on the Report and on the Issues Identified

STATEMENT OF THE QUADRANT CO-CHAIRS

Having reviewed the Gas and Electric Coordination Task Force (GECTF) – Final Report (with an effective date of July 1, 2004), it is the opinion of the Co-Chairs of the NAESB Quadrant Executive Committees that the task force has not completed its mission. More specifically, the lack of a voting record concerning the 14 categories in GECTF will needlessly bog down future standards development.

The GECTF's mission included "… investigating possible standards creation and/or modifications…". Following submission of a Standards Development Request, the first step is the Triage process during which the organization determines, amongst other things, determines whether a request is within scope. By taking votes on the 14 categories within the DPL, the GECTF would provide essential guidance to the triage sub-committee. As drafted, it is unclear whether all 14 categories are suitable for standards development or whether none are suitable. This means that to every time a standards development request is submitted, Triage will have to reconsider the deliberations of the GECTF. Given the nature of some of the DPL categories, it is reasonably foreseeable that Triage may sometimes have difficulty reaching consensus scope determinations which will result in the decisions being forwarded the Board and/or Board Management Committee. Excluding unusual circumstances, it is more efficient and preferable for the Executive Committee and its sub-committees/task forces to prosecute the standards development process. Additionally, FERC has commented that they expect more to be done with the categories and the NAESB Board members were supportive of this expectation.

While GECTF worked very hard, we feel that GECTF could expend greater effort to develop a resolution that could be voted upon instead of simply acknowledging that voting would be difficult. The Co-Chairs suggest that the GECTF conduct a vote at its next meeting to classify each category as follows:

1) Contains mostly items and discussion points suitable for standards development discussion within NAESB.
2) Contains some items and discussion points suitable for standards development discussion with NAESB.
3) Contains few, if any, items and discussion points suitable for standards development discussion within NAESB.

In addition to providing guidance to the organization when it develops its annual plan, this vote will provide guidance to those submitting standards development requests. It is to the benefit of the entire industry to see that NAESB pursue standards development on topics for which it is suited and that non-suitable topics be directed to other organizations better equipped to handle such topics.

Jim Buccigross (WGQ)
Ruth Kiselewich (REQ)
Mike Novak (RGQ)
Lou Oberski (WEQ)

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.

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.

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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.

1.8. 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.

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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:

2.1. 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.

2.4. 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

Flexibility/Planning:

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

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

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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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Timelines / Scheduling:

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E. Gas Contracts/Services Portfolios of Electric Companies

Flexibility/Planning:

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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.

1.4. 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.

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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.

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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.

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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)?

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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.

1.5. 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.

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

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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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1.3.8 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).

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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.

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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.

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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.

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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.

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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?)

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June 23, 2004

North American Energy Standards Board
1301 Fannin, Suite 2350
Houston, TX 77002
Attention: Mr. Todd Oncken

Re: GECTF Draft Final Report

GECTF Leadership & Participants:

Having participated in the Gas Electric Coordination Task Force (GECTF) efforts, I believe that the group should be proud of its work with respect to raising the gas and electric industries level of understanding of each other's business. In this regard, the time spent was productive and the groups' work products, (issues lists and presentations) will set the stage for future work in this area of transaction coordination. However, I feel that the draft final report falls short in being responsive to the task force's mission statement, which reads:

> *"The Gas 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."*

There are many reasonable explanations for this shortcoming and I believe they should be articulated and addressed within the report. Doing so would help the quadrant Executive Committees (the "ECs"), and other readers of the report to understand the complexities of dealing with gas-electric transaction coordination issues.

Some would argue that the Discussion Points List or "DPL", is evidence that the task force completed its mission. I disagree. The purpose of the discussion points list was to "...identify

areas for discussion in an effort to understand and frame the issues." I argue that the DPL represents foundational work, a first step. Unfortunately the task force could not agree how best to move beyond identifying areas of discussion to truly ***framing the issues***. Yes there are some succinct issues included in the list, but it also is loaded with questions and statements of fact. In my opinion, part of this inability to move forward revolved around a concern about raising the importance of one item on the list above another. This is a fair concern, but I believe that the task force became overly concerned with that issue and lost its focus on providing the EC and industry with a recommendation or recommendations regarding possible standards creation (or modification) related to interaction between the scheduling of electric and gas transactions.

I fail to understand how selecting a few items for ***possible*** standards development from a long list of items for the ECs prohibits anyone from submitting their favorite issue for consideration of development as a standard. As those familiar with the NAESB process are well aware, anyone can file a request for the development of a standard at any time. Said request will be given due process and may be assigned for future development if deemed to be within the organization's scope.

In closing I would ask that in completing its final report, the GECTF reconsider the characterization that it has completed its mission. Instead the report could explain that for a number of reasons (which should be identified and explained) the task force has gone as far as possible without further direction from the quadrant executive committees.

Thank you for the opportunity to comment.

Sincerely,

Alan Johnson
Manager Business & Reliability Standards

Attachment – final draft markup

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.

{I disagree with the statement that the task force has completed its assigned task. The work product entitled "Discussion Points List – Expanded" which the TF is providing to the Executive Committees, represents a list of thoughts, ideas, and comments that were brought forward during the group's meetings. No analysis was performed or recommendations created regarding the list and hence there is no guidance included in the final report for the Executive Committees consideration. The other work product, the "Discussion Points List – Expanded and Categorized" goes a little further by placing each of the items into at least one of 14 categories. However, this product should be considered a draft as it was never voted on as a work product of the group. Further it does not provide framed issues, but identifies areas for discussion. Hence the Executive Committees are left to analyze the work products based on their own understanding/interpretation of the work products, without the benefit of the underlying discussion.}

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,~~ In order to form a foundation for discussions, the task force initially focused on the education of gas and electric industry participants. The task force then ~~and identification~~ created a list 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, as to do so was not part of its mission.

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

[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.

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 ~~{The issue for me is not necessarily prioritization, but the need to transition discussion/framing points into succinctly stated issues that impact the scheduling of electric and gas transactions. This is what I as an EC member wanted to see in the final report}~~ for several reasons. One was a concern about raising the priority of any given item above another. Regional differences also made it difficult to reach consensus on the disposition of items contained within the DPL. Accordingly, the Task Force determined that any further work on 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 28-29, 2004.

To accomplish its investigatory and educational goal, numerous presentations were given by representatives of 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 operating characteristics and business practices ~~in~~ of 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 http://www.naesb.org/pdf/gectf012904w3.pdf	Mike Novak, National Fuel Distribution	01/04
Basic Gas Flow Dynamics and Related Scheduling Factors http://www.naesb.org/pdf/gectf012904w4.pdf	Bill Griffith, El Paso Pipelines Paul Love, NGPL	01/04
Gas Producers Presentation http://www.naesb.org/pdf/gectf012904w5.pdf	Paul McKelvey, ChevronTexaco	01/04
Gas Day versus Calendar Day http://www.naesb.org/pdf/gectf031504w7.pdf	Bill Griffith, El Paso Pipelines	03/04
NAESB WGQ Capacity Release Standards and Procedures http://www.naesb.org/pdf/gectf031504w6.pdf	Bill Griffith, El Paso Pipelines	03/04
NAESB WGQ Nominations and Scheduling Standards and Procedures http://www.naesb.org/pdf/gectf031504w8.pdf	Bill Griffith, El Paso Pipelines	03/04

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

Electric Presentations

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

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

df

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~~GECTF participants recognize that continued ~~understanding~~ educational efforts and further 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.

For the reasons noted within the body of this report, ~~The~~ the GECTF is not ~~directing any party~~recommending the Executive Committees to take any particular action. It is suggested that 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 development 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 from items that are included in the Annual Plan process. Additionally, the task force believes this 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