North American Energy Standards Board

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

(effective 3/16/04)

Section I: Preliminary Discussion Points List

Section II: Meeting Minutes

- December 16, 2003 Conference Call
- January 29-30, 2004 Meeting in Washington, DC
- February 10-11, 2004 Meeting in San Diego, CA
- March 15-16, 2004 Meeting in Houston, TX

Section III: Gas Presentations

January 2004 Meeting

- Gas Nomination Timeline Impact Upon LDC Operations
- Basic Gas Flow Dynamics and Related Scheduling Factors
- Gas Producers Presentation

March 2004 Meeting

- Gas Day versus Calendar Day
- NAESB WGQ Capacity Release Standards and Procedures
- NAESB WGQ Nominations and Scheduling Standards and Procedures

Section IV: Power Presentations

January 2004 Meeting

- Electricity 101
- Generation Dispatch 101
- A Retail Electric Perspective on Billing & Settlement

March 2004 Meeting

- Transmission Timing Analysis
- Example of Natural Gas Industry and Electric Industry Timing Issue
- Market Timing Issues

Section V: Comments Submitted on Interim Status Report

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Section I: Preliminary Discussion Points List

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GECTF Preliminary Discussion Points List

Purpose: The purpose of this list is to identify the areas for discussion in an effort to understand and frame the issues.

Flexibility/Planning:

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

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.

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

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

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

1.5. The implications that changes allowing more flexibility to non-firm gas shippers might have on the service levels and contractual rights of existing / traditional firm shippers.

1.6. Identify Examples of the service characteristics that could meet the market needs for increased delivery flexibility.

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

Timelines / Scheduling:

2.1. How does the NAESB WGQ standard gas day interact with the various power days? There is one NAESB WGQ standard gas day and there are many regional power days that create associated difficulties in cross-commodity standardization.

2.2. How do the NAESB WGQ standard nomination deadlines interact with the various power deadlines? Identify the impact of regional power timeline differences.

2.3. 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.

2.4. Identify the impact of the timing of peaking requirement differences between natural gas markets and power markets.

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

Reliability:

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

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

Terminology:

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

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TO: NAESB Gas Electric Coordination Task Force, Posting for Interested Industry Participants

FROM: Meghan McMillan, NAESB Staff

RE: Draft Minutes from the NAESB Gas Electric Coordination Task Force Conference Call – December 16, 2003

DATE: December 18, 2003

Gas Electric Coordination Task Force (GECTF)
December 16, 2003 (1:00 p.m. – 4:00 p.m. Central)
Draft Minutes

1. Administrative

Ms. McVicker opened the meeting. Ms. McMillan gave the antitrust advice. Ms. Kiselewich moved, seconded by Ms. Chezar to adopt the agenda as written. The agenda was adopted absent objection.

2. Develop and Review Overall Deliverables and Milestones for the Task Force

The group briefly discussed and edited the mission statement. It was agreed that the mission statement should avoid referencing other documents, and it was agreed to delete the footnote attached to the mission statement. There was some discussion regarding the deliverables to be produced by the task force. It was suggested that the purpose of the GECTF is to develop a deliverable that suggests to the Executive Committees various courses of action concerning the coordination of gas and electric standards developed by NAESB. Ms. Chezar asked if the mission statement should refer to a report to be developed and/or to a date by which it would be finished. It was noted that there would be status reports given to the ECs and to the FERC and there will be a final report to FERC. The group agreed that a tentative completion date for the final report would be the last EC meeting of the year. Concerns were voiced that this date would not meet FERC's suggested deadline of June 2004. The Task Force noted that an interim report will be given in June and the NAESB office has previously volunteered to draft a letter to FERC noting that the June date is not feasible for a finishing a final report. Ms. Chezar stated it should be noted under meetings and voting that this task force will employ balanced voting.

3. Develop Agenda for First Meeting

Ms. McVicker stated this first meeting will be focused on familiarizing the participants with the issues on both the gas and electric sides. Ms. Chezar suggested it might be useful to block out specific blocks of time for agenda items, and she suggested an hour for the first three items on this agenda. It was agreed to allow, during day one of the meeting, one hour for the first three items, forty-five minutes for item four, and then after lunch have the gas and electric representatives discuss the first two items on each of their presentations. Day two will consist of the remainder of the agenda. It was suggested that the gas side representatives meet on a separate call to coordinate their presentation for the January meeting. Mr. Jackson noted that the electric side has been working on the coordination of their presentation. It was agreed to try and extend the meeting time on the first day until 6:00 p.m. Eastern, and to end the meeting on the second day at 3:00 p.m. Eastern. Mr. Novak will verify with Ms. Arnaout that the meeting facilities can accommodate the schedule change.

4. Set Meetings and Times for Task Force

Concerns were voiced regarding the February 23 meeting date, and it was noted this meeting is a conference call and will probably be cancelled. The group discussed the hosting of the February 10-11 face-to-face meeting, but no official decision was made.

5. Assign Responsibilities for Presentations at the First Face-to-Face Meetings

See discussion under item 3.

6. Discuss Coordination of Work with NERC and ISO/RTO Task Forces

It was noted that representatives from these groups might be able to participate in the GECTF meetings, and that it would be beneficial for these participants to exchange information that might be valuable for this task force.

7. Provide Background Documents to NAESB for Posting on the Web Site

It was noted that any documents relevant to these meetings should be sent to the NAESB office by the 22nd of January for the February meeting.

8. Other Discussion

There was no additional discussion.

9. Adjourn

Mr. Novak moved, seconded by Mr. Zavodnick to adjourn the meeting on December 16, 2003 at 2:22 p.m. Central.

10. Attendees

Name	Company
Bacon, Tom	Conectiv
Bray, Mike	Shell Gas Transmission
Burch, Kathryn	Duke Energy
Burden, Christopher	Williams Gas Pipeline
Calcagno, Suzanne	UBS Warburg Energy
Chezar, Delores	KeySpan
Colombo, Craig	Dominion Resources
Connor, Pete	NiSource
Crockett, Valerie	TVA
Davis, Dale	Williams Gas Pipeline
Gracey, Mark	Tennessee Gas Pipeline
Gussow, Dona	Florida Power & Light Co.
Heslington, Sheri	Dominion
Ingraham, Jim	TVA
Jackson, Gary	TVA
Kijowski, Drake	PSE&G
King, Iris	Dominion Trans
Kiselewich, Ruth	Baltimore Gas
McMillan, Meghan	NAESB
McVicker, Diane	Salt River Project
Nishida, Leslie	Wisconsin Public Service Corp.
Novak, Michael	National Fuel
Perlman, Marjorie	Energy East

Reed, Tony	Southern Company
Scheel, Mark	Chevron Texaco
Schwecke, Roger	Southern California Gas Company
Shepard, Mike	Mewborne Oil Company
Van Pelt, Kim	Panhandle Eastern
Young, Randy	Gulf South Pipeline LP
Zavodnick, Steve	Baltimore Gas & Electric

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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 Kickoff Meeting Final Minutes – January 29-30, 2004
DATE:	February 6, 2004

NAESB Gas Electric Coordination Task Force
January 29-30, 2004
Hosted by American Gas Association, Washington, DC

1. Welcome

Ms. Kiselewich called the meeting to order and introductions of the co-chairs were made. Ms. Kiselewich thanked Ms. Arnaout and the American Gas Association for hosting the meeting. Ms. Kiselewich reviewed the mission statement of the task force and the FERC's interest in the topic as evidenced by Chairman Wood's letter (as shown in the winter 2003-2004 NAESB Review). The draft agenda was reviewed and an REQ presentation was added. Ms. Van Pelt moved, seconded by Ms. Chezar to approve the modified agenda. The agenda was approved absent objection.

Ms. Kiselewich noted the meeting was intended to serve as an educational forum where all participants could learn about the basics of the electric and gas industries. All presentations are available on the NAESB website as work papers for this meeting. Ms. Kiselewich reviewed the ground rules document, which was available as a work paper for this meeting.

2. Gas Presentation

Pipelines: Mr. Griffith and Mr. Love gave a presentation titled, 'Basic Gas Flow Dynamics and Related Scheduling Factors.' Mr. Griffith stated the goal of the presentation was to talk about the physical properties of gas and how they fit together and may affect getting gas to market. Mr. Griffith introduced the concepts of linepack, firm/interruptible transportation, Gas Day (a 24-hour period beginning at 9:00 a.m. CCT), and key terms used in scheduling. Mr. Love's part of the presentation focused on the scheduling process, including capacity allocation, confirmations, timelines, priorities and bumping. Mr. Love explained that there are three major inputs into the scheduling process: determine operating capabilities (on the given day, what capacity is available), contract rights / capacity release (what are the customers' rights); and customer nominations. Mr. Love noted that the pipelines struggle with scheduling deadlines daily and the bulk of transactions tend to occur during the timely nominations cycle.

Mr. Love summarized the Pipeline presentation, as follows:

- Pipeline operating dynamics vary from pipeline to pipeline yielding different capabilities to deal with flow variations.
- Current WGQ standards are the result of careful/reasoned compromise among the five WGQ segments.

- Current WGQ standards are very interdependent so that one seemingly small change could have significant impact throughout their entirety (ex. capacity release and nominations timelines).
- Scheduling processes are repetitive and highly interactive with all segments.
- Scheduling/flow reliability are influenced by the cycle in which changes are initiated.
- Any change to the processes/timelines must be weighed against reliability impacts and the need to be cost effective.
- Pipelines operate under specific rules regarding scheduling (scheduling timeline, Firm vs. Interruptible, capacity release and recalls, and allocation/balancing).

Questions on the presentation revealed that there are other services besides Firm and Interruptible transportation, including no-notice firm service and storage. Mr. Griffith noted that a pipeline's ability to support the alternative services is primarily based on the physical capabilities of the individual pipeline. Additionally, it was noted that electric generation is generally considered commercial consumers or customers of LDCs (see slide 4). A question was raised regarding the order of gas scheduling functions performed by pipelines. Ms. McVicker noted the potential conflict of some pipelines allocating first and then confirming, and others using the opposite process, could appear on the issues list. Mr. Griffith explained the order of the process is dependent on the physical characteristics of the pipeline, but the end result is an appropriate schedule with the system in balance.

3. Electric Presentations

Mr. Rodriquez and Mr. Tippit gave a presentation titled, 'Electricity 101,' which provided an overview of electricity, the electricity scheduling process, settlement and credit issues, and possible points of gas and power collaboration. Mr. Rodriquez noted that his first thought was the commodities were very different, but he could draw several parallels from the first presentation.

Highlights of the presentation included:

- Electricity is complex because there is no real storage, it requires the coordination of fuel (gas) management, there are highly interconnected transmission systems, there are many entities (170 different transmission providers) and few standardized rules, and finally, the conflicts between federal and states rights.
- Open Access Same-time Information System (OASIS) is a communication protocol mandated by FERC Order 889 which allows electric transmission customers to conduct business through electronic means. OASIS postings include: Available Transmission Capacity (ATC), Total Transmission Capacity (TTC), transmission products and prices, ancillary service offerings and prices, specific requests and responses, and transmission service schedules.
- Transmission is rated on a scale of 7-0 with firm being priority 7 and non-firm priority being from priority 6-0 based on duration. Priority 7 is the highest priority.
- When a request for transmission is submitted on OASIS, providers perform calculations according to flowgates to determine if transmission is available.

Available Transfer Capability is limited by the most constrained Available Flowgate Capacity.

- While it can be projected, it is impossible to determine on which path electricity will flow.
- The Transaction Information System (Electronic Tagging or e-TAG) documents interchange transactions by identifying source to sink flows, providing a common link for all parties, and indicating losses, transmission reservation, and contract information.
- A power transaction has day-ahead, real time, and settlement components. Power is traded on peak, off peak, super peak, balance of week, balance of month, monthly or term, with delivery hours quoted in Hour Ending (HE).
- For day-ahead transactions, daily firm requests (on most providers) must be entered in no later than 10 am CST the day prior to the start of service. Most day-ahead business is conducted from 6:00 am to noon, with checking out (a final verification process) and preparing books for the hourly desk and next day being from noon to the end of the day.
- Independent System Operators (ISOs) have their own procedures and timelines.
- For real time transactions, hourly transactions occur the day-of flow, with transmission constraints and unit outages partly driving the need for real time trading.
- Existing inconsistent trading and scheduling timelines between gas and power make it impossible to unwind/enter a position.
- The intention of OASIS Phase II (currently under development and being led by the NAESB Electronic Scheduling Subcommittee and Information Technology Subcommittee) is to develop a robust platform that can be easily integrated into enterprise systems, including EMS systems, market systems, transmission auctions, scheduling systems, position management systems, deal blotters and billing and settlements systems. There is an expected two year timeframe for the development of OASIS Phase II.
- In general, standardization and cross commodity standardization (where appropriate) will help the power industry.

Questions on the presentation revealed that the transmission availability analysis currently performed are essentially based on a contract path, but some ISOs and RTOs are shifting their models to treat it like a pool. Participants discussed the electric trading day and it was noted that the times varied by market. Through an example, it became clear that the day-ahead market was actually 12 hours, not 24 hours. It was also noted that to simplify the process many organizations use block accounting, which obviates the need to carry a 24-hour transactions over three days to reconcile for ramping. Additionally, it was noted that in the power world there is firm energy and firm transmission, and they have two different meanings.

Possible gas/electric conversion issues were noted during discussion. A large issue identified was that the gas timeline and electric timeline don't match, which means higher risk for power companies. Further, it was noted that mismatch made it difficult to mitigate unexpected

weather-related issues. Mr. Gildea suggested that a trend in the energy industry is a move towards spot markets, and as that develops the need to make decisions real time is increased. Mr. Mancini stated that for planning purposes it was important to understand whether there would be gas to support a request for generation to be put on the system.

Retail Electric: Mr. Berman gave a presentation titled, 'A Retail Electric Perspective on Billing and Settlement.' Highlights of the presentation included:

- Two market transactions are valued based on hourly patterns of retail megawatt-hour usage: wholesale supply of retail customers settled by the regional pool; and wholesale supply of local distribution companies billed out by the wholesale supplier.
- Both transactions rely on hourly electric usage data to price up the value of the supply and both transactions are settled, explicitly or implicitly, by real time accounting of hourly usage on a day-after basis.

Questions on the presentation revealed that changes to the wholesale electric timelines would trickle down to the retail burden to supply the data.

4. Gas Presentations

Producers: Mr. McKelvey gave a presentation on the Producers' Perspective. He noted that his presentation represents the views of his company, not necessarily the views of the whole producer community. Mr. McKelvey's presentation addressed: producer priorities, first of month process schematic, production forecast process, marketing and trading, transportation and exchange, nominations and confirmation, and the accounting process. Mr. McKelvey noted that a goal of producers is to design supply sources for maximum efficient flow. Mr. McKelvey stressed that there is no way to adjust production in a real-time manner - it is either on or off.

Mr. McKelvey summarized his presentation, as follows:

- The cooperative efforts of the last several years have allowed the producers and other industry segments to create a very reliable nomination/confirmation process.
- The current 4-cycle nomination process allows a producer to ensure product flows with high reliability.
- Producers and natural gas consumers have varying needs for volume management flexibility. All are important!
- We look forward to working with the Task Force to consider the needs of all parties along the value chain.

Questions on the presentation addressed the different production characteristics of traditional reservoirs vs. coal seam methane. Ms. Heslington explained that it can take some development time before a coal seam well is ready to produce, and a shut in of a coal seam well would likely mean a total loss. Ms. Heslington said information from the market and pipelines is key in managing the productivity of a coal seam well for the reasons noted above. It was also noted that the 'maximum level' flow of a well could be set by field rules or regulatory obligations.

LDCs: Mr. Novak gave a presentation titled, 'Gas Nomination Timeline Impact Upon LDC Operations.' Mr. Novak's presentation addressed: LDC goals and obligations; LDC/customer

load characteristics; general concepts; gas supply planning/nomination timeline; no-notice service; third party transportation on LDCs; regional pipeline grid considerations; important gas scheduling 'Rules of the Road'; and the impact of gas-fired generation behind the city gate (the custody transfer point).

Key points of Mr. Novak's presentation included:

- The goal of an LDC is to provide safe, economic and reliable service to customers.
- Natural gas consumption varies according to several variables, including type of customer, weather, and time.
- The gas nomination timeline is a key tool in helping to match system supplies with customer demand. To that end, the LDC contracts for a mix of firm services, (including no-notice services) and supplies to meet its requirements.
- Concerning the gas nomination timeline and transportation on the gas grid, LDCs have multiple roles: pipeline shipper (nomination role); transportation scheduling (operator role); and point operator at the city gate (confirmation role).
- The impact of gas-fired electric generation behind the city gate depends on the character of service provided by the LDC and the operating profile of the generating facility: base load, intermediate load, or peaking.
- The key to successfully sharing the gas grid is a combination of appropriate gas supply and transportation contracting decisions (for services on both the pipelines and the LDC) and ensuring that operators are never surprised. Good communication is essential to ensure that gas systems can respond with short notice to increase or decreases in generating plant consumption.

5. Update on the Gas-Electric Interdependency Task Force

Ms. McVicker reported on the Gas-Electric Interdependency Task Force, a NERC group which focuses on the electricity reliability impacts of the interdependency of the industries. She noted the goal of the task force is to make recommendations to NERC regarding reliability issues. The GECTF leadership took it as a task item to contact the task force leadership. It was noted that the next meeting of the group has not been scheduled, but a preliminary report was issued in November 2003.

6. Presentation on Power Plant Dispatching

Ms. McVicker gave a presentation on Power Plant Dispatching. She explained dispatching relies on load forecasts, and weather can heavily impact the forecasts. Highlights of Ms. McVicker's presentation included:

- Utilities have base, intermediate and marginal generation facilities, with base facilities running all the time and marginal facilities running only when needed. The marginal facilities typically run on gas purchased according to the NAESB timelines.
- Utilities are faced with two possible scenarios on load deviation: Having excess gas that is not usable due to forecasting too high, or not having enough gas and not being able to purchase gas because the NAESB timelines have passed.

- Utilities have 10 minutes to balance when their load drops. That means gas generation is the only practical supply source to create adequate response. Otherwise, the load drop impacts reliability. If gas is not available, the utility is forced to shed load, which has huge impacts since it has the same obligation to serve that LDCs have.
- Most utilities with the obligation to serve will have firm transportation.

During discussion, Mr. Linderman noted that a recent study has indicated that 85% of cogeneration facilities are single fuel (gas). Additionally, it was suggested that it is more challenging for the utilities to use flexible pipeline products and services to meet their needs, because the utilities are usually the new load and the flexible pipeline products and services are being used to serve the existing load.

7. Question & Answer on all presentations

All questions were addressed during the individual presentations.

8. Drafting of Preliminary Issues list

To facilitate the next GECTF meeting, the task force developed a preliminary issues list for future discussion. The list shown below is not exclusive and participants were welcomed to submit additional items to the NAESB Office prior to the next meeting, or to raise additional issues during the next meeting. Concern was raised on the process for approval of the issues list. That discussion was deferred to a subsequent meeting.

1. The GECTF should coordinate with the NERC GEITF to ensure that both groups are informed as to the other's progress and goals.
2. The GECTF Chairs should clarify the voting procedures to be used for the approval of the Final Issues list to be voted out of the subcommittee.
3. Impact of weather and other factors on generation and gas load swings..
4. The national Gas Day does not 'sync' with the various Power Days.
5. The nomination deadlines do not sync with the power deadlines.
6. Discuss the desire of certain parties to allow for cross-commodity netting in contractual arrangements.
7. Regional power timelines differ from region to region. WEQ members to provide additional information on various regions.
8. Notice requirements to be provided to pipelines / service providers by shippers (i.e., generators, LDCs, producers, marketers) of load and flow change.
9. Discuss ways to accommodate the natural gas requirements of new generation as it comes online in various regions. New gas generation coming on line:
   a. New gas-fired generation comes on line without realizing the impact on the gas infrastructure
   b. Non-scheduled generation comes on line without notice or nomination to the pipeline

10. There is one national "gas day", there are many regional "power days", creating associated difficulties in cross-commodity standardization.
11. The impact of any changes on natural gas requirements for power reliability concerns that are dependent on pipeline redundancy of facilities.
12. Dispatch priorities - power generation is dispatched off of price and time where as gas is dispatched off of contract rights.
13. Is the issue relating to power generation needs due to the structure of the portfolios for transportation contracts by power generators versus the need for changes to the natural gas day?
14. Communication protocols between natural gas and power operations / control room personnel – what information can be shared.
15. The timing of peaking requirements between natural gas markets and power markets is different.
16. Cost allocation for new gas infrastructure to support peaking. Notes: NAESB can discuss what the cost recovery mechanism is and not go into who pays for what.
17. There may not be proper market incentives to encourage entities with peaking requirements to diversify their transportation contract portfolios to support those requirements.
18. The implications that changes allowing more flexibility to non-firm shippers might have on the service levels and contractual rights of existing / traditional firm shippers.
19. Is there a need for new pipeline and LDC tariff service offerings to accommodate the need for additional scheduling flexibility for power generators?
20. The ability of the natural gas producers to be able to react to within the day requirement changes.
21. Is there a need for more intraday flexibility in gas scheduling to match / support power scheduling. (Tied to 5 and 13)
22. Does "Firm" mean the same thing in both commodities?

9. Next Meetings

The next GECTF meeting will be held in San Diego, CA on February 10 – 11, 2004 from 10:00 a.m. to 5:00 p.m. Pacific on day one and 8:00 a.m. to 3:00 p.m. Pacific on day two. Please note the times have changed from those originally posted.

10. Adjourn

The meeting adjourned at 2:00 p.m. Eastern on January 30, 2004.

11. Attendance

Name	Organization	Day One	Day Two
Arnaout, Mariam	American Gas Association	In Person	In Person
Bachert, Andrew L. R.	NYISO	In Person	In Person
Bakke, Roman	Southern California Edison	In Person	In Person
Berman, Ed	Baltimore Gas & Electric	In Person	In Person
Bittel, Jeff	Texas Gas Transmission	Phone	Phone
Bray, Mike	Shell Gas Transmission	In Person	In Person
Brechtel, Curt	Arizona Public Service	In Person	In Person
Brown, Ken	PSEG	Phone	Phone
Buccigross, Jim	Group 8760	In Person	In Person
Burch, Kathryn	Duke Energy Gas Transmission	In Person	In Person
Burden, Christopher	Williams Gas Pipeline	Phone	Phone
Burnett, Tina	Boeing	Phone	Phone
Calcagno, Suzanne	UBS Energy	In Person	In Person
Camp, Yvette	Southern Company	Phone	Phone
Cashin, Jack	EPSA	In Person	In Person
Chancellor, Craig	Calpine		In Person
Chezar, Dolores	KeySpan Energy	In Person	In Person
Colombo, Craig	Dominion Resources	In Person	In Person
Connor, Pete	NiSource, Inc.	In Person	In Person
Crockett, Valerie	Tennessee Valley Authority	In Person	In Person
Davidson, Pat	Southern California Gas Co.	In Person	In Person
Davis, Dale	Williams Gas Pipeline	In Person	In Person
Dawe, George	Duke Energy Corp.	In Person	In Person
Deegan, Jennifer	Washington Gas	In Person	In Person
Downs, Dan	NY Department of Public Service	In Person	In Person
Gildea, Michael	Constellation Generation	In Person	Phone
Gracey, Mark	Tennessee Gas Pipeline	In Person	In Person
Griffith, Bill	El Paso	In Person	In Person
Grygar, Bill	Panhandle Eastern		In Person
Gussow, Dona	Florida Power & Light Company	In Person	In Person

Gwilliam, Tom	Iroquois Gas Transmission	In Person	In Person
Hadden, Ben	Conectiv Energy	In Person	In Person
Haga, Carl	Southern Company	In Person	
Hansen, Scott	Questar Pipeline	In Person	In Person
Henning, Bruce	Energy and Environmental Analysis	In Person	
Heslington, Sheri	Dominion E & P	In Person	In Person
Hetrick, Nancy	Northern Natural Gas	Phone	Phone
Hickman, Judy	Columbia Gas Transmission	In Person	In Person
Hinners, Gary	Reliant Energy	Phone	Phone
Holmes, Brad	Transwestern Gas	In Person	In Person
Johnson, Alan	Mirant	In Person	In Person
Kardas, Joe	National Fuel Gas Supply	In Person	In Person
Kenchington, Henry	U.S. Department of Energy	In Person	
Kijowski, Drake	PSEG Energy Resources & Trade	In Person	
King, Iris	Dominion Transmission	In Person	In Person
Kiselewich, Ruth	Baltimore Gas & Electric	In Person	In Person
Lauderdale, Melissa	Edison Electric Institute	In Person	In Person
Lewis, Jane	American Gas Association	In Person	
Linderman, Chuck	Edison Electric Institute	In Person	In Person
Love, Paul	Natural Gas Pipeline Co. of America	In Person	In Person
Mancini, Ken	PJM Interconnection	In Person	In Person
Maturo, Chris	NiSource, Inc.	In Person	In Person
McCain, Marcy	Duke Energy Gas Transmission	In Person	In Person
McGlone, Jim	U.S. Department of Energy	In Person	
McKelvey, Paul	ChevronTexaco	In Person	In Person
McQuade, Rae	NAESB	In Person	In Person
McVicker, Diane	Salt River Project	In Person	In Person
Mills, Randy	ChevronTexaco	In Person	In Person
Mount, Michael	R. J. Rudden Associates	In Person	In Person
Murrey, Sandy	We Energies		Phone
Newbold, Bill	Detroit Edison	Phone	Phone
Nielsen, Janie	Kern River Gas Transmission	Phone	Phone

Nishida, Leslie	Wisconsin Public Service Corporation	Phone	Phone
Novak, Mike	National Fuel Distribution	In Person	In Person
Oberski, Lou	Dominion	In Person	In Person
Oncken, Todd	NAESB	In Person	In Person
Oppenheim, Bill			In Person
Palmerino, Arlene	NY Department of Public Service	Phone	Phone
Perlman, Marjorie	Energy East	In Person	In Person
Peterson, Chris	FERC	In Person	In Person
Porter, John	Tennessee Valley Authority	In Person	In Person
Rodriquez, Andy	PJM	In Person	
Rosenberg, Marv	FERC	In Person	In Person
Rudden, Richard	R. J. Rudden Associates	Phone	
Schmolling, Christian	Natural Gas Week	In Person	
Schubert, Ken	TransCanada Pipelines	In Person	In Person
Schwecke, Rodger	Southern California Gas Co.	In Person	In Person
Shepard, Mike	Mewbourne Oil Co.	In Person	In Person
Simpson, Denise	Reliant Energy	Phone	Phone
Small, Albert	Downey & Small Assoc.	In Person	
Smith, Jimmy	Entergy	In Person	
Sullivan, Steve	Consolidated Edison of NY	Phone	
Thompson, Chuck	PJM	Phone	Phone
Thompson, Ed	Consolidated Edison of NY	Phone	
Tippett, Kalim	The Structure Group	In Person	
Van Pelt, Kim	Panhandle Eastern Pipe Line	In Person	In Person
Wah, Pauline	Southern California Gas Co.	In Person	In Person
White, Brian	NiSource Pipelines	In Person	In Person
Wight, Dean	FERC	In Person	In Person
Wilke, Mark	Trunkline Gas Company	In Person	In Person
Young, Jon	Columbia Gas Transmission	In Person	In Person
Young, Randy	Gulf South Pipeline	In Person	In Person
Zavodnick, Steve	Baltimore Gas & Electric	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 Meeting Final Minutes – February 10-11, 2004
DATE:	February 25, 2004

NAESB Gas Electric Coordination Task Force
February 10-11, 2004
Hosted by SoCal Gas, San Diego, CA

1. Welcome

Ms. McVicker called the meeting to order. Mr. Oncken gave the antitrust advice. Introductions were made. Approval of the minutes from the last GECTF meeting was deferred until day two. The agenda was adopted unanimously, as modified.

As follow-up to the last meeting, Ms. McVicker reviewed recent communications with NERC's Gas Electric Interface Task Force (GEITF). Ms. McVicker read an email from Mr. Twitchel, a NERC representative, as follows: We agree that NERC should be coordinating its activities with other industry groups, especially NAESB, that are related to the important issue of fuel supply of power plants. Ms. McVicker noted that the GEITF has asked her to present an update on the GECTF at the next GEITF meeting.

The minutes from the January 29-30, 2004 GECTF meeting were reviewed on day two and modifications were offered. Mr. Novak moved, seconded by Ms. Chezar, to adopt the amended minutes. The minutes were adopted absent objection.

Ms. McQuade reviewed the voting procedures for the GECTF. She stated the GECTF will follow balanced voting where each quadrant has to pass the motion independently. The balanced voting within the quadrant will operate according to standard procedures used for single quadrant issues. Key aspects of balanced voting are one person/one vote and one vote per organization per segment. Quadrant and segment membership should be declared at the beginning of the meeting, and once declared would not change for the duration of the meeting.

2. Review of Current Preliminary Issues List

During the last GECTF meeting, a preliminary list of issues was developed and subsequently categorized according to topic. Ms. Davis questioned whether the preliminary issues list appropriately reflected the results of the last meeting. Accordingly, Ms. Davis offered a redlined alternate workpaper. It was agreed to work through the workpaper provide by Ms. Davis in the category order of the original workpaper. Both workpapers, as well as subsequent versions of the preliminary issues list, are posted for the meeting.

Significant time was spent discussing each of the items on the preliminary issues list. In evaluating and refining each item, the task force worked to provide a level of detail that would provide context for the issues, noting that it will likely be some time before several of the issues are discussed. It was noted that items included in the preliminary issues list were for discussion purposes only and would not necessarily result in new standards or modifications to existing standards. Ms. McVicker also encouraged the task force to be open in their

discussion to the possibility of a solution to meet the needs of the power industry that would not require standards changes.

The nature of the items was discussed. It was noted that some items, such as item 7, were items for informational purposes that would provide background information for the general topic or other items on the preliminary issues list. Likewise, it was suggested that some items, such as items 10 and 17, could be viewed as basic facts rather than discussion issues.

In line with his submitted comments, Mr. McKelvy proposed a new item identifying a distinction between coordination issues originated by reliability issues versus trading risk management practices. He indicated the producers would be more accepting of changes due to the former than the latter.

At the end of day one, a revised preliminary issues list was prepared. Looking forward to day two, the revised list will be reviewed for scope, areas of consolidation, and prioritization. Additionally, the importance of diverse representation on the task force from all NAESB quadrants was highlighted.

Participants reviewed the revised draft issues list. There were several wording modifications, instances where two issues were combined, and two deletions. A revised draft issues list was prepared during lunch. Details of significant changes are shown below.

Mr. Bray moved, seconded by Ms. Chezar, to delete item 16, *cost allocation for new gas infrastructure to support peaking*, from the preliminary issues list due to its conflict with existing NAESB standard 1.1.16. During discussion on the motion, Ms. Calcagno proposed to maintain the item as an inclusion in the report. Mr. Bray opposed that treatment of the item. Discussion on the motion revealed that participants differed on the meaning of the item. From one perspective, the issue was seen as dealing with cost issues involved in a new pipeline. From the other perspective, the issue was seen as whom should bear the costs of changes that benefit the power industry and whether there is policy guidance that could be given by FERC on that point. Mr. Love suggested the latter perspective would be fleshed out during the individual discussions of the issues – both the associated costs and risks. Ms. McVicker agreed and noted that deletion did not remove the topic of costs from this task force. The motion passed unanimously absent objection.

Ms. Chezar moved, seconded by Ms. Burnett, to delete item 6, *discuss the desire of certain parties to allow for cross-commodity netting in contractual arrangements*, from the preliminary issues list because it is clearly outside the scope of the task force. The motion passed unanimously absent objection. It was noted that it would be appropriate for the topic to be submitted as an individual request for standards not associated with the GECTF.

The preliminary issues list was reviewed in light of the scope of the task force. While it was understood that any changes were made they would benefit all market participants, the task force was clear that this was not the forum for unrelated concerns regarding gas scheduling flexibility. No issues remaining at this point were deleted due to scope considerations.

After extended discussion on the implications of discussing pipeline services, significant changes were made to issue 19, *is there a need for new pipeline and LDC tariff service offerings to accommodate the need for additional scheduling flexibility for power generators?* Several participants felt it was important to maintain the possibility that modifications to NAESB WGQ standards would not be required. It was also noted this could be the opportunity for the power industry to identify important elements that are lacking from existing service offerings. Other

participants felt it was not NAESB's role to discuss pipeline service offerings. Mr. Gwilliam, seconded by Ms. Chezar, to change the wording of issue 19 to read: *Identify examples of the service characteristics that could meet the market needs for increased delivery flexibility.* The motion passed unanimously.

Participants reviewed the categorizations for each of the issues. It was suggested categorization was necessary so that like issues could be considered together to facilitate future discussions. Several categorizations were changed and several issues were reassigned.

3. Additions to the Preliminary Issues List

Please see discussion above.

4. Discussion of Preliminary Issues List topics

Item 22: Clarify the differences in terminology between natural gas and power (e.g., does "Firm" mean the same thing in both commodities?)

Discussion of Item 22 highlighted some differences in the definition of firm in each of the commodities. Likewise, it became apparent that firm is viewed differently across the segments of each commodity. Mr. Oberski stated that there was not currently a standard treatment of firm power among the regions, and that issue has been identified by the NAESB WEQ Seams Subcommittee and included in the Seams Catalog. Ms. Calcagno explained a principle difference between firm power and firm gas from a supplier's perspective was that firm power is more of a financial concept, rather than a physical concept. It was noted that if a power supplier was unable to perform to their obligations, it was accepted within the industry to pay the power pool participant who provided the electricity. Ms. McVicker summarized the concept of firm gas as follows: for the supplier, firm gas is the obligation to deliver gas into the pipeline; and for the pipeline, firm gas means firm transportation capacity. Mr. Love further defined firm as capacity that has been reserved for a particular use and is made available as used by the customer and as scheduled by the customer.

The discussion of item 22 led into a more generic discussion of the operation and marketing of gas and power. The following points were made regarding the power industry:

- The power pool, or ISO, does not own generation facilities; instead, it matches requests for service to bids for generation and dispatches generation according to the most efficient use of resources.
- Independent generators bid into the pool to be the next entity to provide the next megawatt of service, without advanced knowledge of whether they will be dispatched to serve the load. The effect of short notice is greater for peaking and intermediate load units. An intermediate generation facility might only have a 20% load factor.
- The power dispatch authority dispatches generation on the assumption that all predicates have been met by the bidding entity prior to the bid (e.g. gas transportation has been arranged to support any electric generation required).
- Power is supplied to end users without the need for a firm contract. While some firm contracts are served, other users are just connected to the power grid and take power from any provider.
- When firm power contracts are used, they are typically between an end user and marketer. The marketer will aggregate the load requirements of all his contracts and

then will contract with specific generators to supply the power. When a marketer is unsuccessful from either side of the contracts, the load is served as if no contract exists and the marketer is subject to the market price of the day.

- The electric grid is designed with reserves to ensure there is enough power to serve the load for any given hour. While electricity might always flow, it might not flow from the intended facilities.
- Interruptible power is different in different areas. Often a lower rate will accompany interruptible power, but the provider has the ability to suspend service in emergency situations.
- The electric day runs from midnight to midnight, depending on the time zones.
- The NERC reliability standards and operation of the Joint Interface Committee impact NAESB WEQ standards development.
- Non-firm power can be the result of lack of firm delivery rights.
- The power markets are currently operating in two paradigms: RTO/ISO markets and bilateral markets. The operations and generation dispatch could vary depending on the paradigm.
- The current portfolio of pipeline services available to generators is not sufficient to respond to the needs of a peaking generator. It was suggested the portfolio of services available to generators has changed with the evolution of the gas industry – and some generators are viewed as new customers and offered different products than those historically offered.
- A peaking unit is called to serve to maintain reliability and must be on line within ten minutes.
- Information on available power transmission capacity is available on the OASIS system on an hour-ahead basis.
- Power control rooms process hundreds of scheduled changes per hour, sometimes with ten minutes notice. It was noted that changes to power schedules do not impact the service provided to other customers.
- In instances when a generation unit unexpectedly goes offline, implementing prearranged contractual arrangements for gas supply can be difficult, and potentially impossible, due to timing constraints.
- The gas market closes before the power market clears, so gas must be scheduled before generation schedule is known. If the generation bid is not dispatched, the underlying gas schedule would have to be resold or not used. The timing mismatch creates increased risk in the power market.
- An example was provided that demonstrated that even if a generator had the gas and a transportation contract, scheduling the gas when it was needed was still a problem. The need for gas for generation purposes does not necessarily coincide with the gas timelines. It was suggested that the only solution to the problem posed by this example would be to have the capacity available at all times and not used for other purposes.

The following points were made regarding the gas industry:

- It is possible that gas could not flow depending on the inputs and physical nature of the commodity.
- An LDC faces difficulties forecasting load, but has built a portfolio of services to address those needs.
- From a pipeline point of view, information on the gas supply needs of power generators is very valuable for planning purposes.
- An hourly gas nomination process during the day of flow is possible on some pipeline systems, but might not produce the results or flexibility desired.
- The gas scheduling process is complicated and includes notice, bumping, priority and dispatching. It was estimated it takes at least 2 to 3 hours to complete the process. Nesting of requests for service – an issue currently addressed by the nominations timeline – could also complicate the process.
- Changing to an hourly gas nomination process could require a change in measurement practices because there are some meters that do not provide hourly data.
- The ability of a pipeline to offer additional services is contingent on the pipeline's physical and existing contractual characteristics.
- Information on available pipeline capacity is available on pipeline websites. This is a FERC mandated requirement. It is updated four times a day in connection with the nominations timeline. It was noted that capacity used for certain services, such as instantaneous service, is not necessarily reflected in the posted number.
- Increased levels of service to one segment of the industry should not impact the level of service provided to other participants on the gas grid.

The following points were made regarding both industries:

- The deregulation of the two industries into competitive markets occurred without much planning between them. This has implications for facility citing and planning.
- Part of the difficulty in addressing these issues is the creation of a bridge between something that is economically dispatched (power) and something that is contractually dispatched.
- It is difficult for an input (gas) of power generation, which operates in a real time market based on hourly increments, to be supplied through a daily market.

5. Next Meetings

The next GECTF meeting will be held in Houston, TX on March 15-16, 2004 from 10:00 a.m. to 6:00 p.m. Central on day one and 9:00 a.m. to 3:00 p.m. Central on day two.

The format for the next meeting was discussed. Mr. Bray suggested a panel discussion would be a good format to use for the next meeting to continue the discussion started at this meeting and provide more opportunity for participants to better understand the issues and question. Mr. Griffith volunteered to present at the next meeting the reasoning behind the gas nominations timeline and cycles, including the issues of bumping and priority. Mr. Oberski

took on the task of coordinating an electric presentation that would compare the gas timeline with each of the major electric markets (for day-ahead) to demonstrate the disconnect between the industries. A contrast of the peaking patterns for gas and electric was also identified as a pertinent topic, but an assignment was not made.

6. Adjourn

The meeting adjourned at 2:30 p.m. Pacific on February 11, 2004.

7. Attendance

Name	Organization	Day One	Day Two
Mariam Arnaout	American Gas Association	In Person	In Person
Roman Bakke	Southern California Edison	In Person	In Person
Ed Berman	Baltimore Gas & Electric Co.	In Person	In Person
Jeff Bittell	Texas Gas Transmission	Phone	Phone
Mike Bray	Shell Gas Transmission	In Person	In Person
Curt Brechtel	Arizona Public Service	In Person	In Person
Kathryn Burch	Duke Energy Gas Transmission	In Person	In Person
Christopher Burden	Williams Gas Pipeline	Phone	Phone
Tina Burnett	The Boeing Company	In Person	In Person
Suzanne Calcagno	UBS Energy	Phone	Phone
Yvette Camp	Southern Company	Phone	Phone
Dolores Chezar	KeySpan Energy	In Person	In Person
Craig Colombo	Dominion Resources	Phone	Phone
Pete Connor	NiSource	Phone	Phone
Valerie Crockett	Tennessee Valley Authority	In Person	In Person
Dale Davis	Williams Gas Pipeline	In Person	In Person
Pat Davidson	SoCal Gas	In Person	In Person
George Dawe	Duke Energy Corp.	In Person	In Person
Michael Desselle	American Electric Power		In Person
Jay Dibble	Calpine	In Person	In Person
Dan Downs	New York State Department		Phone
Karen Gossett	UBS		Phone
Mark Gracey	Tennessee Gas Pipeline	In Person	In Person
Bill Griffith	El Paso Western Pipeline	In Person	In Person
Tom Gwilliam	Iroquois Gas Transmission	In Person	In Person

Carl Haga	Southern Company	In Person	In Person
Scott Hansen	Questar Pipeline	In Person	In Person
Nancy Hetrick	Northern Natural Gas	Phone	Phone
Gary Hinners	Reliant Energy Services	Phone	Phone
Jeff Hodges	UBS		Phone
Bradley Holmes	TransWestern Pipeline	Phone	Phone
Rick Ishikawa	SoCal Gas	In Person	In Person
Alan Johnson	Mirant	Phone	Phone
Joe Kardas	National Fuel Supply	In Person	In Person
Drake Kijowski	PSEG Energy Resources & Trade	In Person	In Person
Iris King	Dominion Transmission	In Person	In Person
Melissa Lauderdale	Edison Electric Institute	Phone	Phone
Chuck Linderman	Edison Electric Institute	In Person	In Person
Paul Love	NGPL	In Person	In Person
Marcy McCain	Duke Energy Gas Transmission	In Person	In Person
Paul McKelvey	ChevronTexaco	In Person	In Person
Rae McQuade	NAESB Executive Director		In Person
Diane McVicker	Salt River Project	In Person	In Person
Ken Mancini	PJM Interconnection	Phone	Phone
Chris Maturo	NiSource Inc.	In Person	In Person
Janie Nielsen	Kern River Gas Transmission	In Person	In Person
Mike Novak	National Fuel Distribution	In Person	In Person
Lou Oberski	Dominion	In Person	In Person
Todd Oncken	NAESB Deputy Director	In Person	In Person
Arlene Palmerino	NY State Department of Public Service	Phone	Phone
Marjorie Perlman	Energy East Management Corp.	In Person	In Person
John Porter	Tennessee Valley Authority		Phone
Marv Rosenberg	FERC	In Person	In Person
Ken Schubert	TransCanada Pipeline	In Person	In Person
Rodger Schwecke	SoCal Gas		In Person
Denise Spensor	Reliant	Phone	
Ed Tammy	Florida Power & Light	In Person	In Person

Kim Van Pelt	Panhandle Eastern Pipeline	In Person	In Person
Pauline Wah	SoCal Gas	In Person	In Person
Brian White	NiSource Pipelines	In Person	In Person
Randy Young	Gulf South Pipeline	In Person	In Person
Steve Zavodnick	Baltimore Gas & Electric Co.	Phone	Phone

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Preliminary GECTF Issues List as of February 11, 2004 - noon

Flexibility/Planning:

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

9. 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.

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

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

13. Distinguish between the need for changes to the NAESB WGQ Standards and the need to make adjustments to contract portfolios and/or infrastructure requirements. Additional incentives may be needed to encourage entities to diversify their contract portfolios to meet their market requirements.

18. The implications that changes allowing more flexibility to non-firm gas shippers might have on the service levels and contractual rights of existing / traditional firm shippers.

19. Identify Examples of the service characteristics that could meet the market needs for increased delivery flexibility.

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

Timelines / Scheduling:

4. How does the NAESB WGQ standard gas day interact with the various power days? There is one NAESB WGQ standard gas day and there are many regional power days that create associated difficulties in cross-commodity standardization.

5. How do the NAESB WGQ standard nomination deadlines interact with the various power deadlines? Identify the impact of regional power timeline differences.

8. 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.

15. Identify the impact of the timing of peaking requirement differences between natural gas markets and power markets.

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

Reliability:

11. Identify the impact of any contemplated changes on natural gas and power reliability.

23. 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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Terminology:

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

Note: Original numbering was maintained from the January 29-30, 2004 GECTF meeting.

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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 Draft Minutes – March 15-16, 2004
DATE:	March 25, 2004

NAESB Gas Electric Coordination Task Force
March 15-16, 2004
Hosted by NAESB, Houston, TX

1. Welcome

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

The draft agenda was reviewed and a discussion on process was added as item 2. Ms. Lauderdale moved, seconded by Ms. Van Pelt, to adopt the modified agenda. The agenda was adopted by consent.

The minutes of the February 10-11, 2004 GECTF meeting were reviewed and minor modifications were offered. Ms. Davis moved, seconded by Ms. Lauderdale, to approve the draft minutes as modified. The minutes were adopted by consent.

2. Process Discussion

Ms. Kiselewich stated the work of the GECTF has been noticed by State Regulatory Commissions, as evidenced through comments at the NARUC Winter Meeting. Ms. Westerfield, WEQ GECTF co-chair and NARUC representative, echoed Ms. Kiselwich's comments on the awareness of the regulatory community regarding this issue and its desire to understand the GECTF's status and plans for moving forward. She said it has become clear that an interim report would be appropriate to help manage the expectations of the industry.

Procedures for the interim report include: 1) the GECTF will approve the preliminary report through balanced voting procedures; 2) the interim report will be posted for a short comment period; 3) after the comment period it will be submitted to the Executive Committees for approval; 4) then it will be submitted to the Board Managing Committee for final approval before it is sent to the FERC. It was noted that both the Executive Committees and Board Managing Committee have the ability to edit the report during their approval processes.

3. Review of Preliminary Issues List

The GECTF Preliminary Issues List was reviewed. The list was renumbered and retitled as: GECTF Preliminary Discussion Points List. It was noted that the numbers in no way indicate priority.

4. Presentation on WGQ nominations issues (including timelines, cycles, bumping, priority, etc.)

Mr. Griffith prepared the following documents for the meeting: 1) Gas Day vs. Calendar Day; 2) NAESB WGQ Capacity Release Standards and Procedures; and 3) NAESB WGQ Nomination

and Scheduling Standards and Procedures. Mr. Griffith entertained questions on documents two and three, but discussed the graphical representation in document one. During the discussion, Ms. Davis noted that other timelines, which can be found in documents two and three, are contained within the timeline shown in document one.

5. Presentation on comparison of gas timeline versus major electricity timelines

Mr. Johnson prepared the following documents for the meeting: 1) Market Timing Issues; 2) Transmission Timing Analysis; and 3) Example of Natural Gas Industry and Electric Industry Timing Issue. Mr. Johnson reviewed each of the documents and each of the documents was briefly discussed.

Market Timing Issues: Mr. Johnson explained this document was created in the WEQ Electronic Trading Task Force (ETTF) last year. The document outlines market timelines for several ISOs and RTOs, including NYISO, ISO-NE, IMO, PJM, MISO, SPP, CAISO and ERCOT. It was noted that for areas without an operating ISO or RTO, similar information can be found in the Transmission Timing Analysis document. Ms. Westerfield commented that the issue of gas delivery could provide the catalyst for moving towards a more standardized electric day.

Transmission Timing Analysis: Mr. Johnson reviewed the document and noted that it was also created during the ETTF process. He noted that the timelines displayed are a result of different timelines filed in their FERC-approved Open Access Transmission Tariffs (OATTs).

During discussion of the first two documents it was estimated that 80% of the generation load was served through bilateral or day-ahead transactions. Additionally, it was noted that a long-term electric contract generally lasts for one year.

Example of Natural Gas Industry and Electric Industry Timing Issue: Mr. Johnson reviewed the graphical representation of the WGQ Nominations timeline and ISO-NE Market day-ahead activity (as represented in the Market Timing Issues document). During discussion it was noted that even if a generator is not scheduled to dispatch, every generator has the responsibility to be available to participate in the real-time market. Participants agreed this document was very descriptive of the challenges faced by a gas-fired electric generator.

6. Discussion of peaking patterns for gas and electric industries

This item was not discussed.

7. Continued discussion of Gas – Electric Coordination Issues

The GECTF Preliminary Discussion Points List was reviewed. The structure of the list was discussed. Participants agreed this was a high-level document that would be used to guide future discussion, not a traditional issues list. A purpose statement was also added to clarify the document.

The GECTF reviewed each item on the Preliminary Discussion Points List and brainstormed in an effort to understand and frame the issues. The results of the brainstorming session are shown in the GECTF Preliminary Discussion Sub-Points List. Subsequent to the creation of the list it was determined to expand the GECTF Preliminary Discussion Points List to include the sub-points. Both documents are posted as work papers for this meeting.

During discussion it was noted that while NERC and individual states are responsible for electricity reliability, numerous organizations are responsible for natural gas reliability according to the impacted segment. Some participants thought it might be informative to

catalog those responsibilities. Additionally, Ms. Westerfield stated that the regulatory view point on the coordination of the gas and electric markets is that efficiencies could be gained – particularly in instances of anomalous market conditions – such as the situation in the Northeast in January 2004. Further, it was noted that the GECTF's work is not restricted to federally-jurisdictional pipelines, given the interest that NARUC has shown in the topic. Mr. Love suggested the underlying issue is coordinating the dispatch, physical capabilities and requirements of the two industries when one operates on real time and the other does not.

Ms. Lauderdale volunteered to prepare a presentation on weather impacts for generators. The determination on the timing of the presentation was deferred.

8. Discussion/Preparation of Interim Report

The GECTF discussed the draft interim report prepared by Ms. Kiselewich and made modifications, as appropriate. It was agreed that the interim status report would be fact-based and would not include observations or opinions. Additionally, it was agreed to include all presentations given at the meetings as an attachment. The revised draft interim report was prepared to incorporate all changes and posted as a work paper for this meeting.

Mr. Bray moved, seconded by Mr. Young, that the GECTF approve the revised draft interim status report. The motion passed unanimously by consensus. The report will be processed pursuant to the procedures outlined above.

9. Other Business

No other business was discussed.

10. Next Meetings

The next GECTF meeting is scheduled for April 13 - 14 in Phoenix, AZ. During that meeting discussions will continue on refining the issues of flexibility and planning. Participants were encouraged to review the expanded GECTF Preliminary Discussion Points List to prepare for the meeting. Additionally, Mr. Johnson will present additional diagrams depicting the overlay of timing issues for the remaining ISOs and RTOs contained in the Market Timing Issues document.

11. Adjourn

The meeting adjourned on March 16 at 2:00 p.m. Central.

12. Attendance

Name	Organization	Day One	Day Two	Quadrant[1]
Mariam Arnaout	American Gas Association	Phone	Phone	
Mark Babula	ISO New England	Phone	Phone	
Roman Bakke	Southern California Edison	In Person	In Person	WGQ
Jeff Bittel	Texas Gas	Phone	Phone	
Mike Bray	Shell Gas Transmission	In Person	In Person	WGQ
Ken Brown	PSEG	Phone	Phone	
Kathryn Burch	Duke Energy Gas Transmission	In Person	In Person	WGQ
Tina Burnett	NW Industrial Gas Users	In Person	In Person	RGQ
Suzanne Calcagno	UBS Energy	Phone		
Yvette Camp	Southern Company	Phone	Phone	
Craig Chancellor	Calpine Corp.	In Person		WGQ
Dolores Chezar	Keyspan	Phone	Phone	
Craig Colombo	Dominion Resources	In Person	In Person	WGQ
Chuck Cook	Shell Gas Transmission	In Person	In Person	WGQ
Dale Davis	Williams Gas Pipeline	In Person	In Person	WGQ
George Dawe	Duke Energy	Phone	Phone	
Jennifer Deegan	Washington Gas	In Person		WGQ
Jay Dibble	Calpine Corp.	In Person	In Person	WEQ
Mark Gracey	Tennessee Gas Pipeline	In Person	In Person	WGQ
Bill Griffith	El Paso Western Pipeline	In Person	In Person	WGQ
Dona Gussow	Florida Power & Light	In Person	In Person	WGQ
Tom Gwilliam	Iroquois Gas Transmission	In Person	In Person	WGQ
Carl Haga	Southern Company	In Person	In Person	WGQ
Gary Hinners	Reliant Energy	In Person	In Person	WGQ
Alan Johnson	Mirant	In Person	In Person	WEQ
Joe Kardas	National Fuel Gas	In Person	In Person	WGQ
Drake Kijowski	PSEG Energy Resources & Trade	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	EEI	In Person	In Person	WEQ
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	
Diane McVicker	SRP	In Person	In Person	WGQ
Lynne Mackey	InterGen	In Person		WEQ
Janie Nielsen	Kern River Gas	In Person	In Person	WGQ
Matt Nollenberg	American Electric Power	Phone	Phone	
Mike Novak	National Fuel Distribution	In Person	In Person	RGQ

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

Joe Obergfell	American Electric Power		Phone	
Todd Oncken	NAESB	In Person	In Person	
William Oppenheim	Kimball Resources	In Person	In Person	WGQ
Marjorie Perlman	Energy East	In Person	In Person	WEQ
John Porter	Tennessee Valley Authority	In Person	In Person	WEQ
Ken Schubert	TransCanada Pipelines	In Person	In Person	WGQ
Rodger Schwecke	SoCal Gas	In Person	In Person	WGQ
Donna Scott	Transwestern Pipeline	In Person	In Person	WGQ
Jimmy Smith	Entergy	Phone		
Chuck Thompson	PNM		Phone	
Kim Van Pelt	Panhandle Eastern Pipe Line	In Person	In Person	WGQ
Pauline Wah	SoCal Gas	In Person	In Person	WGQ
Louann Westerfield	Idaho Public Utilities	Phone	Phone	
Brian White	NiSource Pipelines	In Person	In Person	WGQ
Mark Wilke	Trunkline Gas Company	In Person		WGQ
Kathy York	Tennessee Valley Authority	In Person	In Person	WEQ
Randy Young	Gulf South Pipeline	In Person	In Person	WGQ

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Section III: Gas Presentations

January 2004 Meeting

- Gas Nomination Timeline Impact Upon LDC Operations
- Basic Gas Flow Dynamics and Related Scheduling Factors
- Gas Producers Presentation

March 2004 Meeting

- Gas Day versus Calendar Day
- NAESB WGQ Capacity Release Standards and Procedures
- NAESB WGQ Nominations and Scheduling Standards and Procedures

Gas Nomination Timeline Impact Upon LDC Operations

Presentation Overview:

LDC Goals and Obligations

LDC/Customer Load Characteristics

General Concepts

Gas Supply Planning/Nomination Timeline

No-Notice Service

Third Party Transportation on LDCs

Regional Pipeline Grid Considerations

Important Gas Scheduling "Rules of the Road"

Impact of Gas-fired Generation Behind the City Gate

Questions?

Gas Nomination Timeline Impact Upon LDC Operations

Local Distribution Company´(LDC) Goal:

Provide Safe, Economic and Reliable Service to Customers.

Most LDCs have a statutory Obligation to Serve.

Gas Control/Dispatch has a central role ensuring that customers are served:

- Monitoring system pressures and flows, deploying contingencies as needed.
- Keeping the system in balance to avoid an adverse impact on reliability and to promote structural integrity.
- Maintaining constant contact with pipelines and suppliers.

´ From Section 5 (a) of the Natural Gas Act … "gas distributing company"

Gas Nomination Timeline Impact Upon LDC Operations

LDC/Customer Load Characteristics

LDC Customers, for the most part, take gas on demand.

Most Customers, particularly residential and small commercial customers, have weather responsive consumption profiles. Even the largest industrial customers sometimes have a weather responsive demand component.

Industrial Customers typically have a process dependent load profile, consuming the bulk of their daily requirement during the hours their manufacturing process is running, for example, 24/7, M-F 9-5, or based upon product pricing.

Gas-fired Electric Generation can be a large component of the LDC's load with the potential to create large load swings. Some generators have no base load.

Most customers have a base load component, that is, a portion of the load that is neither weather or process dependent. The base load component can sometimes be seasonal.

Gas Nomination Timeline Impact Upon LDC Operations

LDC/Customer Load Characteristics (continued)

As a whole, the cumulative customer load does not occur on an even-hourly basis. A common LDC load profile has a major peak from 7 A.M. to 9 A.M. local time and a secondary peak from 5 P.M. to 7 P.M. local time.

Every LDC is a little different. The presence of on-system balancing or gas-fired electric generation behind the city gate can alter the LDC load profile described above.

LDCs balance the load throughout the day by relying upon system line pack (usually very minimal on LDCs) and a mix of firm pipeline services, for example, No-Notice, peaking, storage and other balancing services.

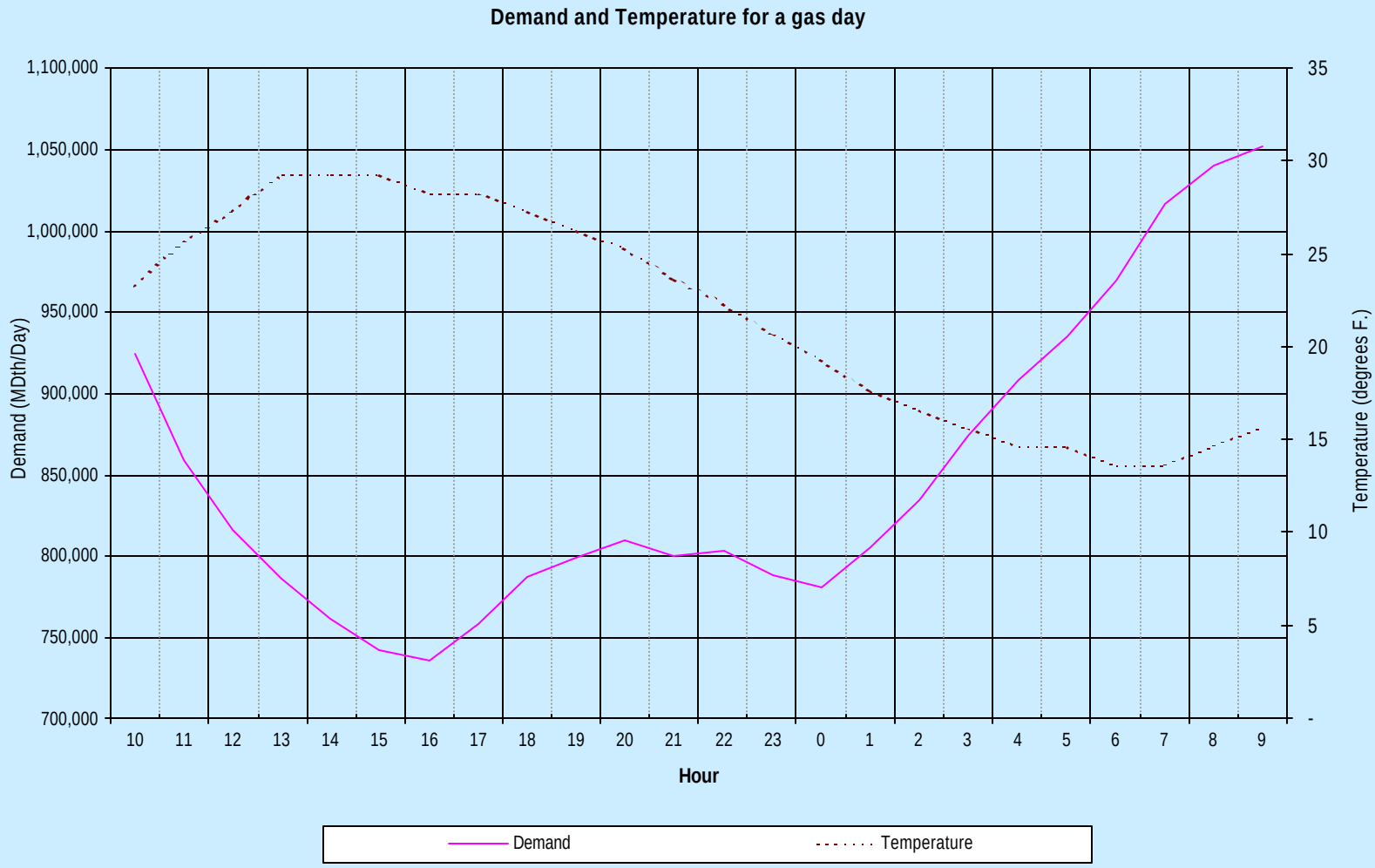
Some LDCs also have storage assets, LNG and/or other peaking facilities attached to their systems. Flexible pipeline takes and interruptible services can also make a contribution towards balancing.

Gas Nomination Timeline Impact Upon LDC Operations

The Gas Nomination Timeline is a key tool, helping to match system supplies with customer demand.

To determine how much should be nominated, an LDC forecasts market demand and projects deliveries by third-party suppliers for transportation customers.

In order to provide its backstop function at the city gate, the LDC contracts for a mix of firm services and supplies to meet its (the market's) requirements. Firm supply contracts will sometimes provide for flexibility in terms of daily take obligations.


Demand and Temperature for a gas day
1,100,000
1,050,000
1,000,000
950,000
900,000
850,000
800,000
750,000
700,000
Demand (MDth/Day)
35
30
25
20
15
10
5
-
Temperature (degrees F.)
10 11 12 13 14 15 16 17 18 19 20 21 22 23 0 1 2 3 4 5 6 7 8 9
Hour
Demand
Temperature

Gas Nomination Timeline Impact Upon LDC Operations

Concerning the gas nomination timeline and transportation on the gas grid, LDCs have multiple roles:

Pipeline Shipper (nomination role)

- LDCs place nominations on pipelines to move supplies from receipt points to the city gate and/or other delivery points.

Transportation Scheduling (operator role)

- LDCs process nominations from their End User customers and/or their suppliers to transport gas from the city gate to the customer burner tip.

Point Operator at the City Gate (confirmation role)

- LDCs reconcile nomination information with the pipeline to develop a schedule for the city gate.

Gas Nomination Timeline Impact Upon LDC Operations

Gas Supply Planning/Nomination Timeline:

Based upon the weather forecast and other consumption intelligence, the LDC develops a consumption forecast for the next gas day - 9 A.M. to 9 A.M. Central Clock Time (CCT).

Gas Supplies and transportation services are nominated in quantities sufficient to meet forecasted customer demand by 11:30 A.M. CCT the day before gas flows (Timely Cycle).

– Note1: The gas nominated at the Timely Cycle does not begin to flow for another 21 ½ hours.

– Note 2: Except for western LDCs, the peak morning burn falls at the end of the gas day or approximately 44 hours from the time the nomination is placed. The creates a balancing challenge because the morning peak is the largest source of load forecasting error and it occurs well after the last intraday nomination deadline.

Gas Nomination Timeline Impact Upon LDC Operations

Gas Supply Planning/Nomination Timeline (continued):

By 4:30 P.M. CCT, the LDC learns whether gas (including third party gas) nominated at the timely cycle was scheduled.

– Nominated gas is not scheduled (at any cycle) for a variety of reasons including insufficient transportation priority, loss of supply and confirmation errors.

Additional nominations to accommodate changed forecasts and to replace timely nominations that were not scheduled are placed by 6:00 P.M. CCT the day before gas flows (Evening Cycle) by the LDC and in some cases, third parties.

Note: The gas nominated at the Evening Cycle does not begin to flow for another 15 hours.

Gas Nomination Timeline Impact Upon LDC Operations

Gas Supply Planning/Nomination Timeline (continued):

By 9:00 P.M. CCT, the LDC learns whether gas nominated at the evening schedule was scheduled. If gas scheduled at the timely cycle utilized interruptible transportation, it may become unscheduled or "bumped" by gas scheduled under a firm transportation schedule.

Additional intraday nominations (Intraday 1 cycle) can be placed during the gas day at 10:00 A.M.CCT to begin flow at 5:00 P.M.CCT. As with the evening cycle, gas scheduled at prior cycles utilizing interruptible transportation may be "bumped" by gas scheduled under a firm transportation schedule. An intraday 1 nomination can provide at least two-thirds of the contract maximum daily quantity.

And finally, additional intraday nominations (Intraday 2 cycle) can be placed during the gas day at 5:00 P.M. CCT to begin flow at 9:00 P.M.CCT. No gas scheduled at prior cycles may be "bumped" by gas scheduled regardless of service priority. An intraday 2 nomination can provide at least one-half of the contract maximum daily quantity.

Gas Nomination Timeline Impact Upon LDC Operations

No-Notice Service – the descendant of pre-Order 636 bundled pipeline sales services.

LDCs, in most cases, are more likely to depend upon the timely and evening cycles to schedule gas. Each of these cycles results in a full day's quantity.

When capacity is tight, that is, situations where no interruptible gas is flowing and the pipeline is flowing at or near capacity, no gas can be bumped. Depending upon a variety of operational factors and assets on hand, intraday nomination cycles 1 and 2 provide less value to some LDCs.

While intraday nominations could be used to approximate the daily load profile, LDCs most often rely upon No-Notice used to balance hourly flow fluctuations and to accommodate the difference between supply scheduled to the system and market demand on a daily basis.

No-Notice also reduces staffing requirements – more intraday nomination deadlines would require additional staff to handle the nomination/confirmation process.

Gas Nomination Timeline Impact Upon LDC Operations

No-Notice Service (continued)

No-Notice Service varies from pipeline to pipeline often relying upon pipeline storage assets. The pipeline may have unique rules fashioned around its capabilities and assets.

Sometimes, the combination of a firm transportation service and a firm storage service create the no-notice service. In addition to providing hourly balancing, the daily difference between gas scheduled and gas delivered at the city gate is injected into storage or withdrawn from storage.

In other cases, multiple balancing services can be tied to the city gate imbalance. The LDC instructs the pipeline through a ranking mechanism which services to utilize in high burn or low burn situations.

While the amount of no-notice service is often proportional to the primary delivery capacity contracted to a primary delivery point, lower priority deliveries (such as secondary firm) that are scheduled to the same delivery point, in some cases displace or decrease no-notice and unscheduled primary firm rights.

Gas Nomination Timeline Impact Upon LDC Operations

Third Party Transportation on LDCs

Increases the complexity and uncertainty of supply planning and balancing. LDCs may operate under three broad regulatory and/or business paradigms:

1. LDCs that provide bundled sales service to all of their customers.
2. LDCs providing transportation services that permit their largest customers (industrial and commercial) to arrange for their own supplies.
3. LDCs providing transportation services that permit all customers (including residential) to arrange for their own supplies.

LDCs often coordinate with transportation customers and their suppliers to balance the system. In some cases, LDCs require third party suppliers to hold firm transportation capacity and can direct them to bring additional supplies. Those suppliers will place intraday nominations, if necessary, to meet their share of the market.

Gas Nomination Timeline Impact Upon LDC Operations

Third Party Transportation on LDCs (continued)

Depending upon business circumstances and the regulatory environment, LDC's support the Gas Nomination Timeline (and Intraday nominations) in varying degrees:

– Some LDCs provide all balancing at the city gate – transportation customers (if present) do not place intraday nominations.

– Other LDCs provide their transportation customers with limited intraday nominations.

– Finally, some LDCs fully support the gas timeline (including all intraday nominations) and have full-blown nomination systems. In effect, these LDCs schedule like a pipeline.

No matter which model, in the end, the LDC is responsible for seeing that its system is in balance on both an hourly and daily basis.

Gas Nomination Timeline Impact Upon LDC Operations

Regional Pipeline Grid Considerations

In some areas of the continent, transportation capacity is tight, that is, delivery capacity approximates market demand at peak periods.

In other areas of the continent, transportation capacity may exceed market demand at peak periods which makes the gas nomination timeline more forgiving in terms of scheduling, that is, intraday nominations can be more reliable. Even then, a supply constraint could undo a successful nomination.

The best way to ensure gas flow is to contract for firm capacity and firm supplies, to nominate gas at primary receipt point (where the firm supply is located) and primary delivery points (where the load is located), to nominate without error at the timely nomination cycle and match nominated flow to the best possible consumption estimate.

Gas Nomination Timeline Impact Upon LDC Operations

Important Gas Scheduling "Rules of the Road":

The "Lesser Of" Rule

When two confirming parties have different nomination quantities for the same transaction at an interconnect, the smaller quantity will be confirmed and/or scheduled. This means zero in some cases.

Supply reliability is key. A loss of supply at any nomination cycle can un-schedule or reduce any transaction depending upon the cycle. If the loss occurs at the intraday 1 or intraday 2 confirmation cycles, one-third and one-half of the gas originally scheduled, respectively, continues to flow (elapsed pro-rata).

Gas Nomination Timeline Impact Upon LDC Operations

Important Gas Scheduling "Rules of the Road" (continued):

Transportation Priority: Primary Firm, Secondary Firm, Interruptible.

- At the Timely Cycle primary capacity has the highest priority and secondary capacity has priority over interruptible capacity.
- Starting with the Evening Cycle (and applicable to the Intraday 1 cycle), secondary firm capacity that has been scheduled at a prior cycle becomes equivalent to primary capacity. New nominations for primary or secondary capacity can bump scheduled interruptible capacity but primary firm cannot bump scheduled secondary firm. For unscheduled capacity, timely priorities still apply.

This leads to the rule: **Secondary Firm, once scheduled, is Firm.**

When transportation is bumped, it creates a loss of supply for a downstream party, creating a need for intraday nominations to replace the supply and/or creating a balancing demand on the LDC.

Gas Nomination Timeline Impact Upon LDC Operations

Important Gas Scheduling "Rules of the Road" (continued):

Transportation Priority: Primary Firm, Secondary Firm, Interruptible.

- At the Intraday 2 cycle, the priority of all gas scheduled at a prior cycles (including interruptible) becomes equivalent to primary capacity. New nominations cannot bump any scheduled capacity. For unscheduled capacity, timely priorities still apply.

Each of these rules impacts an LDC from both Shipper and Operator perspectives. Even though it may be possible for the LDC or a third party to place an intraday nomination, that nomination may not have a chance of being scheduled. The LDC still bears the balancing responsibility – it will most often utilize its no-notice service to balance the system when additional nominations cannot be scheduled.

Gas Nomination Timeline Impact Upon LDC Operations

Impact of Gas-Fired Electric Generation Behind the City Gate

Much depends on the operating profile of generating facility:

– Baseload plants are much like large process customers – in effect, they dampen the LDCs load profile.

– Intermediate load generators alter the load profile depending upon the timing and duration of operation. When adequate lead-time is provided, gas supplies can be arranged in advance (often by the generator itself) and LDC operations are manageable. Usually, Generators will schedule some gas and then attempt to adjust based upon actual dispatch.

– Peaking plants, which can be dispatched with little or no advance notice, can radically alter the LDCs load profile. Due to the uncertainty of dispatch, nominations are difficult. Generator operations coincident or just in advance of LDC peak periods can significantly reduce system pressure creating operational challenges for the LDC.

Gas Nomination Timeline Impact Upon LDC Operations

Impact of Gas-Fired Electric Generation Behind the City Gate (continued)

Much depends on the character of service provided by the LDC to the generating facility, for example, a restriction on or interruption of operation when temperatures are below a certain level.

For LDCs, whether a gas-fired generator is behind the city gate or immediately upstream, unplanned/unscheduled operation could lead to a rapid drop in pipeline pressure, which in turn, could hinder an LDC's ability to meet its Obligation to Serve.

Rapid and/or unexpected changes in consumption can also lead to increased costs for LDCs in terms of storage operations or in some cases, penalties. LDC tariffs often only contemplate monthly or daily imbalances and not hourly imbalances.

In the end, the key to successfully sharing the gas grid is a combination of appropriate gas supply and transportation contracting decisions (for services on both the pipeline and the LDC) and ensuring that operators are never "surprised".

Gas Nomination Timeline Impact Upon LDC Operations

Impact of Gas-Fired Electric Generation Behind the City Gate (continued)

A natural tension exists between between generation plant operators that want to provide minimal advance notice and gas system operators that need time to reconfigure their system. Gas moves slowly – maybe 15 to 30 miles per hour in pipelines.

Each LDC responds to sudden load changes differently depending upon its asset mix and upstream services. Even if intraday nominations are made, due the slow speed of gas, pressures can continue to drop for a period because generator consumption occurs at a faster rate.

Planning and advance notice are critical. There are operational constraints on the pipelines to deliver and the LDCs to accept a large quantity of gas within a flow day. A very large shipper cannot wait to nominate all or a significant portion of their gas needs until flow day. Operationally the gas may not physically be deliverable depending upon the hourly capabilities and/or configuration of the gas system.

Good communication is essential to ensure that gas systems can respond with short notice to increases or decreases in plant consumption. Generators, Pipelines, LDCs and RTO/ISOs need to be "on the same page" to help avoid problems and ensure the gas system is responsive to all customers.

Gas Nomination Timeline Impact Upon LDC Operations

Questions?

Basic Gas Flow Dynamics and Related Scheduling Factors

Pipeline Segment

Wholesale Gas Quadrant
North American Energy Standards Board

Gas Electric Coordination Task Force

January 29, 2004

Overview

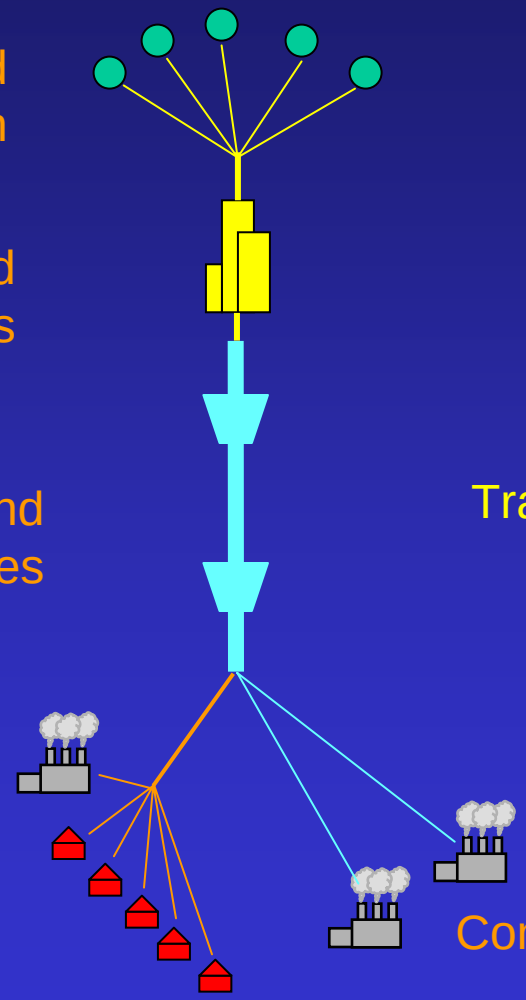
- Gas flow
- Gas day
- Gas scheduling basis
- Gas scheduling process

Factors Involved in Delivering Gas to Market

- **Supply source**
  - Producer
  - Marketer
- **Contracts (types, credit)**
- **Transportation facilities**
  - Gathering
  - Transmission
  - Distribution
- **Timing (physical, administrative)**
- **Coordination**

The Industry Today

Corporate Entities	*Function*
Exploration and Production	Find, drill and complete wells
Field Services	Gather and process
Interstate and Intrastate Pipelines	Transport
Distribution (LDC) Commercial Consumers Other End Users	Distribute / End Use
	Commercial Consumers



Transportation Infrastructure

- **Pipeline facilities**
  - Supported by firm contracts
    - New pipelines are usually fully subscribed
    - Terms are generally for 10 to 20 years
  - One to four years for in-service
    - Regulatory/environmental
    - Material/construction
- **Operating rules**
  - DOT (safety)
  - FERC (tariffs)
    - Firm contracts
    - IT contracts

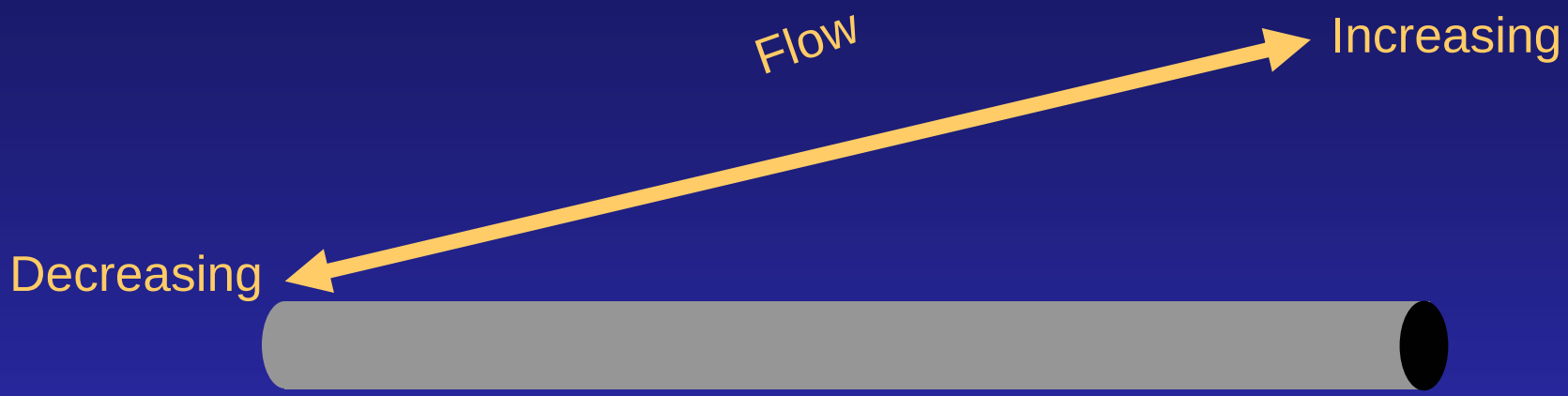
Physical Gas Movement

- **Physical commodity**
- **Flow speed ~ 25 mph**
  - 1500 mi Gulf to NYC
  - 2+ days for transportation
- **Pressure**
  - High to low
  - Interconnect coordination

Gas Flow Dynamics
Determinants Affecting Flow

- **Pipeline properties**
  - Diameter (20” to 42”)
  - Length
  - Strength (800# to 1400#)
  - Efficiency/roughness
- **Delivery and facility pressures**
- **Gas temperature and specific gravity**
- **Elevation change**

Gas Flow Dynamics
Flow Variation



Smaller diameter	Larger diameter
Longer length	Shorter length
Lower Upstream Pressure	Higher Upstream Pressure
Higher Downstream Pressure	Lower Downstream Pressure
Higher roughness	Lower roughness
Higher gas temperature	Lower gas temperature

Gas Flow Dynamics
Flow Rates

- **Manage flows to**
  - Deliver target quantity in specified period (day)
  - Meet pressure obligations
  - Meet gas quality requirements
- **Manage modifications to flow rates**
  - Notification
  - Capacity
  - Coordination

Gas Flow Dynamics
Transportation Operating Terminology

- ***Receipts*** – Gas entering pipeline
  - also Supply
- ***Deliveries*** – Gas exiting pipeline
  - also demand
  - also load
  - also market
- ***Throughput*** – Flow rate of gas through pipeline
- ***Linepack*** – Amount of gas in the pipeline
- ***Packing*** – Increasing linepack
- ***Drafting*** – Decreasing linepack

Gas Charaacteristics Related To Flow Flexibility

- **Natural gas is compressible**
- **Pipes and compression can provide**
  - Variability in delivery rates
  - While receipts are constant

Operating Flexibility from Linepack

Linepack

- **Definition: Amount of gas in pipe**
- **Function of:**
  - Pipe size - length, diameter
  - Pressure
    - Higher pressure - more linepack
    - Lower pressure - less linepack
- **Usage Limits**
  - Delivery pressure obligations
  - Maximum Allowable Operating Pressure (MAOP)
  - Available compression

Usable Linepack

- **Maximum variation in linepack while...**
  - Moving scheduled *daily* quantities
  - Meeting all pressure requirements

Operating Flexibility from Linepack

Linepack and Intra-day Flexibility

Daily Supply equals *Daily* Delivery

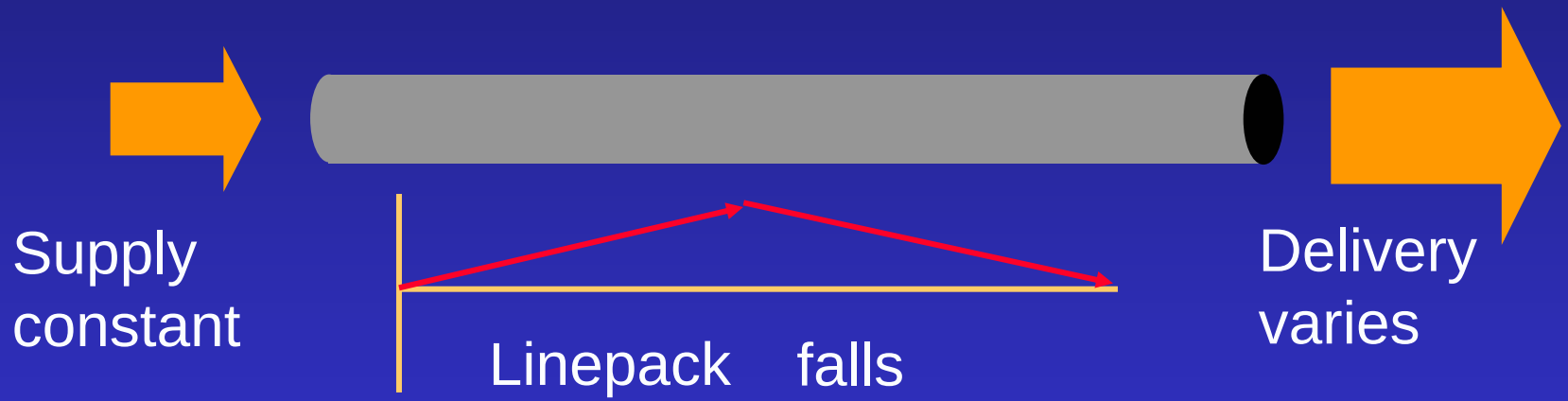
Operating Flexibility from Linepack

Linepack and Intra-day Flexibility

Daily Supply equals *Daily* Delivery

Operating Flexibility from Linepack

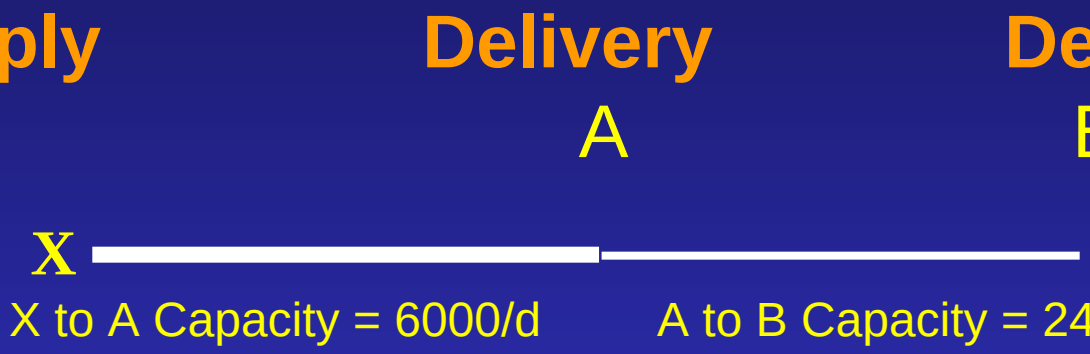
Linepack and Intra-day Flexibility



Daily Supply equals *Daily* Delivery

Operating Flexibility from Linepack

Variable Flow Example



Point capacities:

A = 3600/d or 150/hr

B = 2400/d or 100/hr

Shippers A and B each nominate for daily deliveries of 2400 (X to A and X to B)

Scheduled Flow = 4800/d = 200/hr

Operating Flexibility from Linepack

EXAMPLE

Nominations: Shipper A = 2400/d Shipper B = 2400/d

Gas supply: 4800/d = 200/hr

Hours	Flow Rate		Total Flow	
	A	**B**	**A**	**B**
1 – 6	50	100	300	600
7 – 18	150	50	1800	600
19 – 24	50	100	300	600
Totals			**2400**	**1800**

Scheduling Terminology

- **Operator – pipeline, producer, LDC, Plant**
- **Shipper (Contract Holder)**
- **Receipt and delivery points (contractual/secondary)**
- **Capacity**
  - Mainline (flowing)
  - Point (specific location)
- **Capacity allocation (match of nominations to physical)**
- **Pools (supply aggregation)**
- **Nomination (request for space to transport gas)**
- **Confirmation (verification of space downstream and gas supply upstream)**
- **Scheduled quantity (commitment of volume to transport)**
- **Imbalance**

Origin of Existing Standards

- **Gas Day – March 1996**
- **Scheduling Timeline – December 1997 (Intra-day)**
- **Standards were based on**
  - Compromise (the “Greater Good”)
  - Safety
  - Impact to operators
  - Impact to shippers
  - Impact to markets

NAESB's National Gas Day

- **Standard 1.3.1 – Standard time for the gas day should be 9:00 a.m. to 9:00 a.m. (central clock time)**

  Resulted in coordinated and consistent transactions (nominations), measurement and gas flows across the grid

Gas Day Criteria

- **National Standard**
  - Single times/periods for all parties
  - Consistent measurement at interconnects
  - Minimize timing-related imbalances
  - Promote operational safety
  - Availability of marketers and financial markets
  - Minimized maintenance impact
- **Operational Basis**
  - Time when flow changes will occur
  - Time convenient to all time zones
  - Compromise to achieve “best fit.”

Scheduling Timeline Origins
(Daily / Intra-Day)

- **1995 – Original single nomination for the gas day (adopted in March 1996)**
  - One intra-day with no specific timeline
- **FERC Order 587C directed intra-day nominations (March 1997)**
  - GISB Task Force
    - More than 20 meetings in 1997
    - Many compromises
    - Final proposal in December 1997

Scheduling Timeline Criteria

- Conform to Gas Day
- Permit changes when operationally supportable
- Provide for grid-wide coordination
- Prior cycle information known before next cycle
- Minimize imbalances
- Staffing considerations

Scheduling Timeline

Nomination Deadline for Shippers / Poolers	Point Operator Confirmation Deadline	Receipt of Final Scheduled Quantities by Shippers & Point Operators	Effective Start Time for Gas Flow
11:30 a.m. CCT* Timely	3:30 p.m. CCT	4:30 p.m. CCT	9:00 a.m. CCT on the next gas day
6:00 p.m. CCT Evening	9:00 p.m. CCT	10:00 p.m. CCT	9:00 a.m. CCT on the next gas day
10:00 a.m. CCT Intraday 1	1:00 p.m. CCT	2:00 p.m. CCT	5:00 p.m. CCT on the same gas day
5:00 p.m. CCT * Intraday 2	8:00 p.m. CCT	9:00 p.m. CCT	9:00 p.m. CCT on the same gas day

*** IT Bumping not allowed during these nomination cycles**

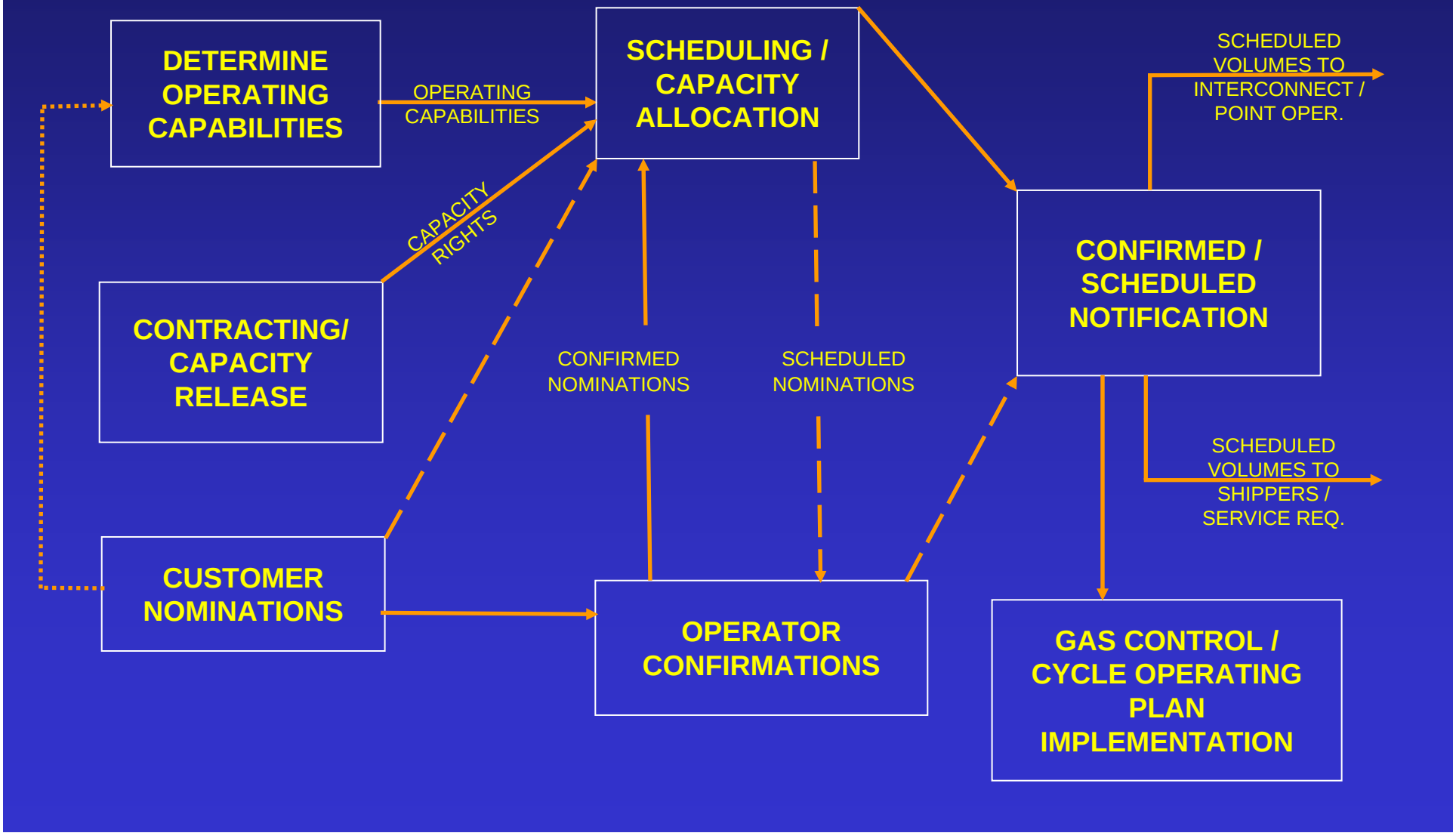
Scheduling Timeline
Other Issues

- **Daily nominations / flow rate responsibility**
  - Standard 1.3.9 –
    - Nominations in daily quantities
    - Interconnected parties agree on flow rates
- **Firm vs IT (Tariff rules)**
- **Capacity Release/Recalls**
- **Intra-Day modifications**
  - Bumping
  - EPSQ

Gas Flow / Scheduling Summary

- **Natural Gas is a physical resource**
  - Gas flow must be planned
  - Physical factors impact delivery rates
- **Pipelines operate under specific rules**
  - Scheduling timeline
  - Firm vs IT
  - Capacity release and recalls
  - Allocation/balancing
- **Reliability is a key issue**
  - Communication
  - Repetitive process

Scheduling Process Overview
(Four Times Daily)



Determine Operating Capabilities

- Design capabilities
- Availability of facilities
- Temperature / specific gravity changes
- Location / level of inputs/outputs (nominations) for the cycle
- Required system operating adjustments

Scheduling / Capacity Allocation

- **Nominations compared to operating capabilities to identify points of constraint**
- **Capacity allocated to contracts nominated at or through the point of constraint on the basis of tariff rules. Typical rules are:**
  - Firm within the path (primary)
  - Firm out of path (secondary)
  - IT / Overrun
- **Nominations are allocated capacity at points based on tariff rules. Typical rules are:**
  - Primary contract point within the path
  - Secondary contract point within the path
  - Secondary contract point outside the path
  - IT / Overrun

Operator Confirmations

- Confirm with operator using “lesser of rules”
- Confirm pooling transactions are complete and balanced
- Resolve mismatches if possible
- “Cut” volumes which cannot be confirmed indicating with a “reason code” why they could not be confirmed as nominated
- Consider Elapsed Prorata Scheduled Quantity (EPSQ) calculation before confirming nomination reductions during the intraday cycles

Gas Control Cycle Operating Plan Implementation

- Make “set point” changes
- Communicate with field / measurement and interconnect operators
- Monitor operations and make changes to meet operating conditions and / or request nomination changes if flows do not match confirmed nominations

Capacity Scheduling Considerations

- **Nomination Validations**
  - Contract rights
  - Impact of displacement transactions
- **Pooling and Title Transfer Tracking**
  - Additional requirement to match on – pipe transactions
  - Strictly an administrative function
- **Intra-day Complexities**
  - Elapsed Prorata Scheduled Quantity calculations
  - Adjustment of nominated flow rates for cycle
  - Intra-day releases / recalls
- **Confirmation Imbalances**
  - Mismatch between confirmed receipts and deliveries
  - Confirmation deadline issue

Nomination Cycle Shippers / Service Requester Considerations

- **Nomination cycle considerations**
  - Capacity availability in cycles other than timely cycle
  - No bumping in Intraday two (2) cycle
  - Inability to nominate full contract MDQ
  - EPSQ limits on nomination reductions during the intraday cycles
- **Firmness of upstream supplies**
- **Coordination of transactions across transportation grid points**
- **Latency / Transportation Grid ripples**
- **Availability of key knowledgeable shipper/supplier business personnel. More problematic during “off” hours, evenings, weekends and holidays.**

Capacity Scheduling Process Challenges

- **Maintain operational integrity of system**
  - Safety
  - Ability to meet contractual entitlements
- **Interdependence with suppliers, transporters and markets**
- **Balancing the pipeline (shippers and operators)**
- **Volume of transactions - timeline (meeting deadlines)**
- **Iterative nature of process (can result in imbalances being created)**
- **Forward look**
  - Customer behaviors
  - Weather
  - Pipeline & electric grid operating conditions (non-ratable flow issues)

Summary

- Pipeline operating dynamics vary from pipeline to pipeline yielding different capabilities to deal with flow variations.
- Current WGQ standards are the result of careful / reasoned compromise among the five WGQ segments.
- Current WGQ standards are very interdependent so that one seemingly small change could have significant impact throughout their entirety.
- Scheduling processes are repetitive and highly interactive with all segments.
- Scheduling/flow reliability influenced by the cycle in which changes are initiated.
- Any change to processes/timelines must be weighed against reliability impacts and need to be cost effective.

NAESB Gas/Electric Coordination Task Force

Paul McKelvey

Manager, Transportation and Scheduling

ChevronTexaco Natural Gas

A Division of Chevron USA, Inc

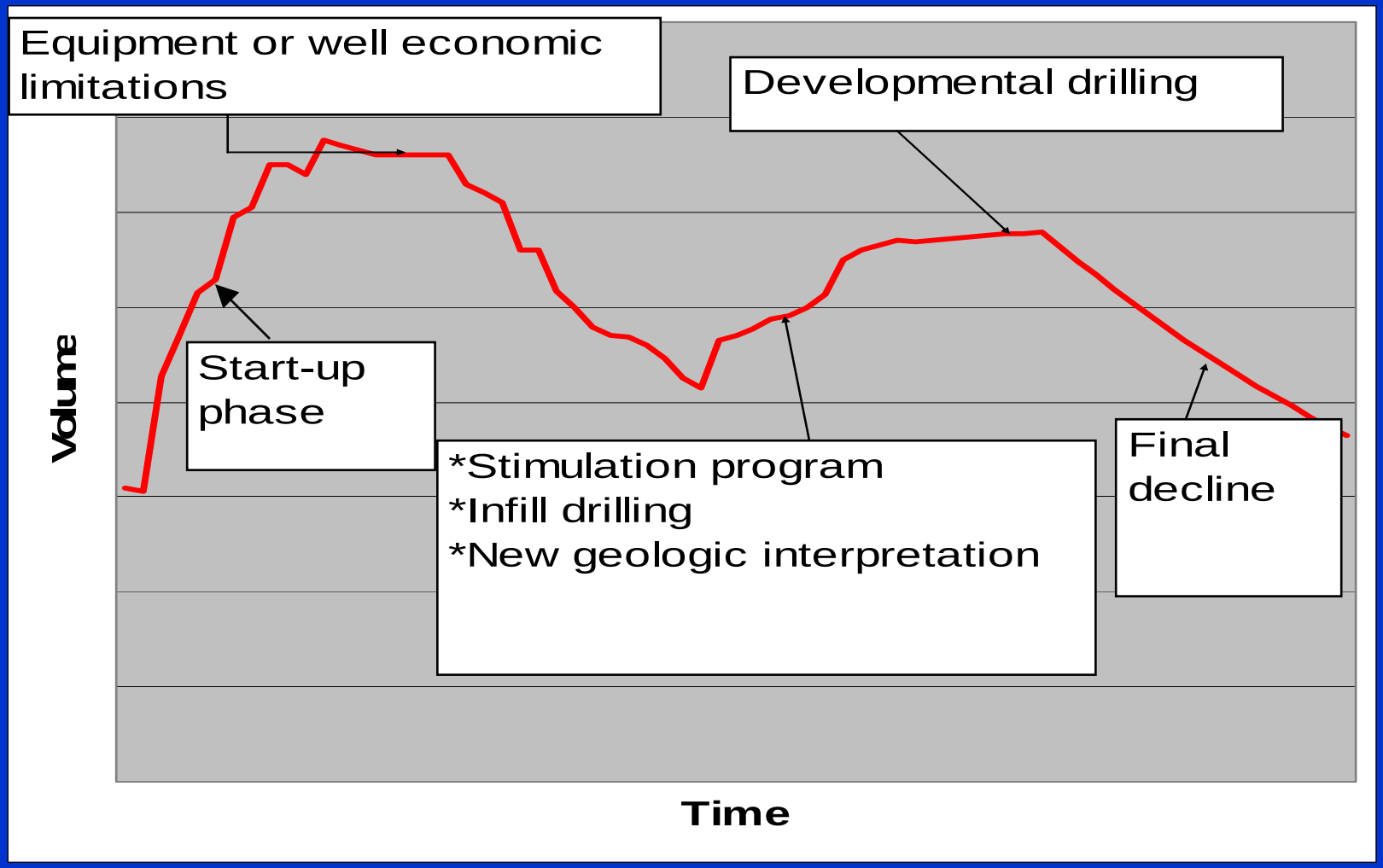
NAESB Gas/Electric Coordination Task Force
A PRODUCER PERSPECTIVE - OVERVIEW

- Producer Priorities
- First of Month Process Schematic
- Production Forecast Process
- Marketing and Trading
- Transportation and Exchange
- Nominations and Confirmations
- Accounting Process
- Summary/Questions

NAESB Gas/Electric Coordination Task Force
A PRODUCER'S PRIORITIES

1. Safety/Environmental protection
2. Flow certainty at best flow rate
   - Equipment limits
   - Reservoir limits
   - Stakeholder obligations
     - ✓ Leases
     - ✓ Taxing authorities
     - ✓ Partners
3. Pricing and portfolio management
   - Diverse customer mix
   - Credit issues

NAESB Gas/Electric Coordination Task Force
Typical Field Production Profile



NAESB Gas/Electric Coordination Task Force FOM Process Schematic

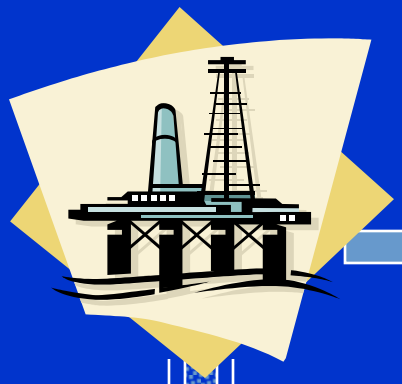
NAESB Gas/Electric Coordination Task Force Production Forecast Process - Art or Science?

- **Communications with Field**
  - **Software, phone, telemetry**
  - **Thousands of wells, hundreds of sales points**

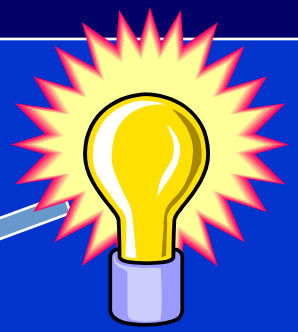
- **Adjustments for:**
  - **Partner balancing**
  - **Fuel, Liquids processing**
  - **Planned downtime**
    - ✓ **Pipelines**
    - ✓ **Field**

- **Production flow dynamics**
  - **Flow typically at maximum rate**
  - **Flow impacted by:**
    - ✓ **Weather**
    - ✓ **Pipeline Pressure**
    - ✓ **Unplanned maintenance**
  - **Reservoir protection is crucial**
    - ✓ **Ultimate recovery optimization**
    - ✓ **Liquids unloading in well bores**

NAESB Gas/Electric Coordination Task Force
Liquids Impact in Upstream Operations



Interstate pipeline



Separation facility

Any disruption of downstream flow which causes wells to shut in, can be damaging to the reservoir

Distribution to generators or "burners"

Well bore

Reservoir

NAESB Gas/Electric Coordination Task Force Marketing and Trading Process

- Bid Week Begins
  - Ain't what it used to be
- NAESB Base Contract
  - Consistent Terms
  - Enhances Liquidity
  - Expedites Negotiation
  - Increases Efficiency
- Portfolio management
  - Term requests (>30 days)
  - Sales/purchases (<30 days)
  - Volume balancing at Pools
  - Storage planning

NAESB Gas/Electric Coordination Task Force Transportation and Exchange Process

- Producers need firm transportation for:
  - Flow certainty
  - Term customer requirements
- Monthly discount requests
  - Posted
  - Negotiated
  - Firm/interruptible
- New or amended contracts
  - Quantity, points
- Firm capacity release
- Park and Loan services
- Long term storage

NAESB Gas/Electric Coordination Task Force CONTROL LOOP WITH PRODUCTION

HOW IT DOES NOT WORK…

ChevronTexaco Gas Scheduler's phone call to Field Office:

"Hey John, I need 15 Dth to balance my pool. Can you crank up well #6?"

ChevronTexaco Trader phone call to Customer:

"Jim, I have that same 8 Dth to sell at the XYZ Field. Can you take it this month?

No, that is not 8,000…that was 8!"

NAESB Gas/Electric Coordination Task Force Nominations and Confirmations Process

- **Control loop with Production**
  - **Volume outages/revisions**
  - **Point Operator balancing**
- **Control loop with pipelines**
  - **4 Standard Cycles**
    - ✓ **2 cycles for day-ahead**
    - ✓ **2 cycles for intraday**
  - **Interactive Web Sites**
    - ✓ **Informational Postings Page**
      - **Critical Notices**
      - **Operational Flow Orders**
    - ✓ **Customer Activities Page**
      - **Nomination revisions**
      - **Scheduled Quantity Report**
      - **Pool balancing**

NAESB Gas/Electric Coordination Task Force Accounting Process

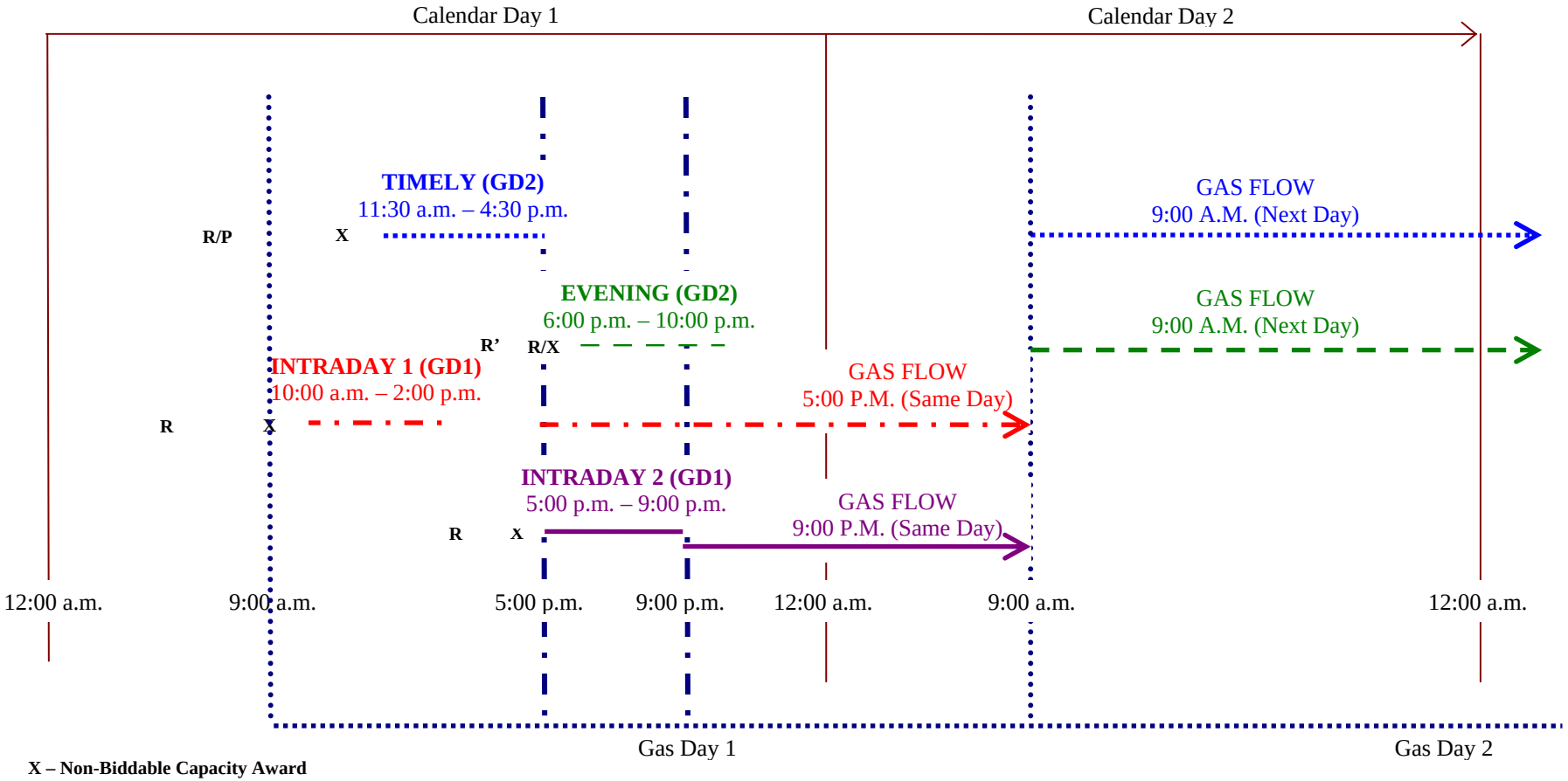
- Three simultaneous processes
  - Prior month's accounting
  - Current month operations
  - Next month planning
- Prior month activities include:
  - Closeout
  - Customer sales invoices
  - Transportation invoice validation
  - Storage/Imbalance inventory
  - Cashout imbalances
  - Imbalance trading

NAESB Gas/Electric Coordination Task Force
A PRODUCER PERSPECTIVE - SUMMARY

- The cooperative efforts of the last 4 years have allowed the producers and other industry segments to create a very reliable nomination/confirmation process.
- Current 4-cycle nomination process allows a producer to ensure product flows with high reliability.
- Producers and natural gas consumers have varying needs for volume management flexibility. All are important!
- We look forward to working with the Task Force to consider the needs of all parties along the value chain.

QUESTIONS?

GAS DAY VS. CALENDAR DAY



X – Non-Biddable Capacity Award
R – Capacity Recall Notice (R' is Early Evening)
TSP Notice – One hour later
P – Reput Notice (8:00 a.m. Timely only)

	TIMELY	EVENING	INTRADAY 1	INTRADAY 2
NON-BID CAP REL AWARD POSTING	10:30 a.m.	5:00 p.m.	9:00 a.m.	4:00 p.m.
CAPACITY RECALL NOTICE	8:00 a.m.	3:00 p.m. (Early)/5:00 p.m.	7:00 a.m.	2:30 p.m.
NOMINATION	11:30 a.m.	6:00 p.m.	10:00 a.m.	5:00 p.m.
NOM CONFIRM	3:30 p.m.	9:00 p.m.	1:00 p.m.	8:00 p.m.
NOM REPORT	4:30 p.m.	10:00 p.m.	2:00 p.m.	9:00 p.m.
GAS FLOW	9:00 a.m. (Next Day)	9:00 a.m. (Next Day)	5:00 p.m. (Same Day)	9:00 p.m. (Same Day)

NAESB WGQ CAPACITY RELEASE STANDARDS AND PROCEDURES

CAPACITY RELEASE SUMMARY

A firm shipper (releasing shipper) may sell all or any portion of its capacity rights to another party (replacement shipper). This process is referred to as "capacity release". At a minimum, all capacity release deals must be openly posted for informational purposes.

The first step in the capacity release process is initiated when the releasing shipper offers capacity to be released. Through the offer process, the releasing shipper sends information about the release to the Transportation Service Provider (TSP) for posting. There are two distinctly different types of offers: prearranged and non-prearranged. The offer provides a mechanism for the releasing shipper to transmit to the TSP the terms of the capacity to be released (including the criteria to be used to determine the winning Bidder(s) for non-prearranged releases or the identity of the replacement shipper for prearranged releases). Prearranged deals comprise the majority of released capacity transactions. A prearranged replacement shipper must send a confirming transaction to the TSP to validate the release.

Step two of the process begins when the capacity which is being offered is available for bid. At that time any party seeking to acquire such capacity (Bidder) makes a bid through the TSP's system.

In the third step of the release process, the TSP evaluates all valid bids and picks the winning bid based upon criteria selected by the releasing shipper – this is called an "award." The winning Bidder is then referred to as the "replacement shipper." The replacement capacity award contains specific information about the released capacity which is available for the replacement shipper's use.

Except as noted below for capacity recalls, the replacement shipper may use the released capacity in the same manner as the original capacity holder during the term of the release. At the end of the term of a release deal, the capacity usually reverts back to the releasing shipper.

A condition that the releasing shipper may include in the release offer is that the capacity may be recalled. A recall indicates that the releasing shipper has asked to have the released capacity returned to them at a specified time. Recalls may be effective at any of the standard nomination cycles. In some instances, recalled capacity may be returned to the replacement shipper through use of a "reput" by the releasing shipper if that right was provided for in the release.

CAPACITY RELEASE

The NAESB standardized Capacity Release timeline can be used to support the release of firm capacity if two (2) criteria are met:

1. all information provided by the releasing and replacement shippers is valid and the replacement shipper is creditworthy when the bid is tendered; and

2. there are no special terms or conditions associated with the release.

Capacity Releases offered at the maximum tariff rate or offered for a term of 31 days or less can be accomplished on a non-biddable basis (i.e. the replacement shipper is designated by the releasing shipper). All other releases are considered biddable (i.e. required to be posted for bid). Biddable releases for less than one year have a separate timeline from releases with a term of one year or more. Since non-biddable releases do not have to accommodate a bidding process, they also have a separate timeline which is the same for both short term and long term non-biddable releases. Releases are always for full gas-day quantities regardless of the time (or nomination cycle) when the release is made.

If there are any special terms and/or conditions applied to the release by the releasing shipper, the TSP is not required to follow the standardized timelines described below.

CAPACITY RELEASE TERMS

Release Offer: A release offer must state all the parameters of the release such as the begin and end dates, the receipt and delivery points, the quantity and the release rate.

Bid Period: The Bid Period is the time between the Offer Posting and the Bid Deadline. Replacement shipper "bids" (including a verification of agreement to the release terms) are due by the Bid Deadline. Generally, the minimum Bid Period is one hour.

Bid Evaluation Period: The TSP must evaluate each replacement shipper's bid to be sure it meets the requirements of the release, tariff requirements and operational considerations. The TSP then determines the winning bid. Generally, the minimum Bid Evaluation Period is an hour after the latest Bid Deadline.

Capacity Award: Upon completion of the Bid Evaluation, the released capacity is awarded to the winning replacement shipper(s). Upon the posting of the award, the replacement shipper may submit a nomination in the next available nomination cycle for the release effective date.

Match: A "match" applies when a designated replacement shipper has been given the right to match the winning bid. The capacity is awarded to the designated replacement shipper if he matches the winning bid. If the designated replacement shipper does not match the bid, the capacity is awarded to the highest bidder among the other bidding shippers. The minimum period of time for a matching bid is one hour.

BIDDABLE RELEASE TIMELINE

1. For Releases with a term of less than one year

a. Offer Deadline – 12:00 p.m. on a Business Day
b. Bid Deadline – 1:00 p.m.
c. Analysis Deadline
    i. With/Without Match Analysis – 2:00 p.m.
    ii. Match Analysis – 3:00 p.m.

d. Award and Match Deadlines –
    i. Non-Match Award – 2:00 p.m.
    ii. Match – 2:30 p.m.
    iii. Match Award – 3:00 p.m.

2. For Releases with a term of one year or more

a. Offer Deadline – 12:00 p.m. four Business Days before award
b. Bid Deadline – 1:00 p.m. on Business Day before nominations can begin
c. Analysis Deadline
    i. With/Without Match Analysis – 2:00 p.m.
    ii. Match Analysis – 3:00 p.m.
d. Award and Match Deadlines –
    i. Non-Match Award – 2:00 p.m.
    ii. Match – 2:30 p.m.
    iii. Match Award – 3:00 p.m.

On all Biddable Releases, the contract is to be issued within one hour of award posting with a new contract number if applicable.

PREARRANGED NON – BIDDABLE RELEASES

The prearranged non-biddable capacity release timeline closely follows the nomination scheduling cycles and related timelines. However, the award posting of these releases is required to be completed not less than one hour before the nomination deadline for the applicable cycle. Prior to the posting of completed prearranged, non-biddable release, the releasing shipper must have offered the capacity for release and the replacement shipper must have validated that offer. Upon the release being posted, nominations may be submitted for the released capacity in the next available nomination cycle. The replacement shipper's contract must be issued within one hour of the award posting (including a new contract number when applicable).

1. Releases to be available for nomination in the next Timely Cycle
    a. Releases must be posted no later than 10:30 a.m. on a Business Day.
    b. Nominations may be made for the Timely Cycle (11:30 a.m. deadline).

2. Releases to be available for nomination in the next Evening Cycle
    a. Releases must be posted no later than 5:00 p.m. on a Business Day.
    b. Nominations may be made for the Evening Cycle (6:00 p.m. deadline).

3. Releases to be available for nomination in the next Intraday 1 Cycle
    a. Releases must be posted no later than 9:00 a.m. on a Business Day.
    b. Nominations may be made for the Intraday 1 Cycle (10:00 a.m. deadline).

4. Releases to be available for nomination in the next Intraday 2 Cycle
    a. Releases must be posted no later than 4:00 p.m. on a Business Day.
    b. Nominations may be made for the Intraday 2 Cycle (5:00 p.m. deadline).

CAPACITY RECALLS

Like the non-biddable release timeline, the capacity recall timeline essentially follows the nomination and scheduling cycles and related timelines. The applicable recall deadlines for each nomination cycle are shown below. Note that there is an additional "Early Evening" recall cycle that permits an earlier notification of a recall for the Evening Cycle. However, no changes to the nomination deadline or the effective gas flow times result from the use of this option. Additionally, the capacity available for recall in the ID1 and ID2 Cycles is limited to the amount of usable capacity remaining in the gas day based on the effective gas flow time of the scheduling cycle.

1. Recalled Capacity available for nomination in the next Timely Cycle
   a. Capacity recall notices to the TSP and replacement shipper must be completed no later than 8:00 a.m.
   b. TSP notification of recall to all affected replacement shippers must be completed no later than 9:00 a.m.
   c. Nominations for the recalled capacity may be made for the Timely Cycle (11:30 a.m. deadline).
2. Recalled Capacity available for nomination in the next Evening Cycle (Early Evening Recall)
   a. Capacity recall notices to the TSP and replacement shipper must be completed no later than 3:00 p.m.
   b. TSP notification of recall to all affected replacement shippers must be completed no later than 4:00 p.m.
   c. Nominations for the recalled capacity may be made for the Evening Cycle (6:00 p.m. deadline).

3. Recalled Capacity available for nomination in the next Evening Cycle
   a. Capacity recall notices to the TSP and replacement shipper must be completed no later than 5:00 p.m.
   b. TSP notification of recall to all affected replacement shippers must be completed no later than 6:00 p.m.
   c. Nominations for the recalled capacity may be made for the Evening Cycle (6:00 p.m. deadline).
4. Recalled Capacity available for nomination in the next Intraday 1 Cycle
   a. Capacity recall notices to the TSP and replacement shipper must be completed no later than 7:00 a.m. on the day that Intraday 1 Nominations are due.
   b. TSP notification of recall to all affected replacement shippers must be completed no later than 8:00 a.m. on the day that Intraday 1 Nominations are due.
   c. Nominations for the recalled capacity may be made for the Intraday 1 Cycle (10:00 a.m. deadline).
5. Recalled Capacity available for nomination in the next Intraday 2 Cycle
   a. Capacity recall notices to the TSP and replacement shipper must be completed no later than 2:30 p.m. on the day that Intraday 2 Nominations are due.
   b. TSP notification of recall to all affected replacement shippers must be completed no later than 3:30 p.m. on the day that Intraday 2 Nominations are due.

c. Nominations for the recalled capacity may be made for the Intraday 2 Cycle (5:00 p.m. deadline).

CAPACITY REPUTS

Notification of a reput, the return of recalled capacity to the replacement shipper, must be provided to the TSP by the releasing shipper no later than 8:00 a.m. to support nominations by the replacement shipper in the next Timely Cycle. The right to reput capacity must have been specified in the terms of the release.

NAESB WGQ NOMINATION AND SCHEDULING
STANDARDS AND PROCEDURES

GAS DAY

Standard time for the NAESB grid-wide Gas Day is based on the period from 9:00 a.m. through 9:00 a.m. **(central clock time)** the next day. The use of the "clock time" Gas Day standard requires a semi-annual adjustment to the usual 24-hour Gas Day – when daylight savings is initiated and again when it is stopped. In the spring, as daylight-saving time becomes effective, a 23-hour Gas Day occurs. Conversely, when standard time is reinstated in the fall, a 25-hour Gas Day results. Over the year, the correct number of hours is accounted for, but on the two transition days, measurement and set points (flow rates) must be adjusted to match the time change. The 9:00 a.m. Gas Day start time was a compromise to provide a common grid-wide time at which gas flow changes (to match scheduled quantities) could be coordinated and effected in all time zones.

SCHEDULING TIMELINE

Natural gas grid-wide scheduling is a continuous process that is conducted 365 days per year during 17 hours each day.

The Gas Day is divided into four separate scheduling cycles which, at least to some extent, are supported by essentially all transportation service providers (TSPs). All times used in the scheduling timeline are expressed as Central Clock Time. Nominations are formal requests to transport gas and, regardless of which cycle they are entered, are represented in full-day quantities. Among other things, nominations include the requested receipt and delivery points, the quantity to be transported, the upstream party providing the gas and the downstream party receiving the gas. The TSP is responsible for determining the necessary flow rates for nominations in the two true intra-day cycles (ID1 and ID2).

The grid-wide scheduling cycles are as follows:

1. **The Timely Nomination Cycle.** This is the initial cycle for the Gas Day. Nominations are made on the day prior to the gas flow day. When scheduled, Timely Nominations have an effective flow time at the beginning of the Gas Day (9:00 a.m.)

   A. Nomination: The deadline for submission of Timely Nominations is 11:30 a.m. No scheduled quantities are carried over from the previous Gas Day, so all nominations compete for the full amount of available capacity on the TSP's system.

   B. Scheduling: All nominations received by the nomination deadline must be compared to available capacity. If the nominated quantities exceed the available capacity, reductions are made to the nominations until they match the available capacity. These reductions must follow the scheduling priorities stated in the TSP's tariff. (See description of scheduling priorities.)

C. Confirmation: At each point of interconnection, the operators (pipelines, LDCs, producers, etc.) compare nomination records to match supplies and markets. When mismatches occur, the "lesser-of rule" (i.e., the larger quantity is reduced to match the smaller quantity) is applied to balance the nominations across the interconnect point. Confirmations must be completed by 3:30 p.m.

D. Reporting: No later than 4:30 p.m., the TSP is responsible for making scheduled quantity reports available to both customers (shippers) and interconnected operators. For each nomination, these reports indicate the quantities that have been scheduled to flow at the beginning of the next Gas Day as well as reasons for any reductions to the originally nominated quantities.

2. The Evening Nomination Cycle. Similar to the Timely Cycle, Evening Nominations are for gas flow on the succeeding day. When scheduled, Evening Nominations have an effective flow time at the beginning of the Gas Day (9:00 a.m.).

A. Nomination: The deadline for submission of nominations is 6:00 p.m. Scheduled quantities are carried over from the Timely Cycle. Bumping is required for previously scheduled interruptible (IT) nominations. Bumping means that IT nominations can be reduced to serve new, higher priority nominations. Therefore, all new Evening Nominations compete for the available capacity remaining after the Timely Cycle plus any capacity held by IT nominations that were scheduled in the Timely Cycle.

B. Scheduling: All nominations received by the nomination deadline must be compared to available capacity, as described above. If the nominated quantities exceed the available capacity, reductions are made to the nominations until they match the available capacity. These reductions must follow the scheduling priorities stated in the TSP's tariff.

C. Confirmation: The confirmation process is the same as described for the Timely Cycle, above. Confirmations must be completed by 9:00 p.m.

D. Reporting: No later than 10:00 p.m., the TSP is responsible for making scheduled quantity reports available to both customers (shippers) and interconnected operators. For each nomination, these reports indicate the quantities that have been scheduled to flow at the beginning of the next Gas Day as well as reasons for any reductions to the originally nominated or previously scheduled quantities.

3. The Intraday 1 (ID1) Nomination Cycle. This cycle is the first opportunity to modify previously scheduled quantities after gas flow has commenced for a Gas Day. When scheduled, ID1 Nominations have an effective flow time of 5:00 p.m. (8 hours after the start of the Gas Day).

A. Nomination: The deadline for submission of nominations is 10:00 a.m. Scheduled quantities are carried over from the Evening Cycle. Bumping is required for previously scheduled interruptible (IT) nominations. Therefore, all new ID1 Cycle nominations compete for the available capacity remaining after the Evening Cycle plus any capacity held by IT nominations that were scheduled in the earlier cycles (Timely and/or Evening).

B. Scheduling: All nominations received by the nomination deadline must be compared to available capacity, as described above. If the nominated quantities exceed the available capacity, reductions are made to the nominations until they match the available capacity. However, because gas is already flowing on previously scheduled nominations, reductions are limited by the amount of gas that would have flowed up to the effective time of the ID1 changes (5:00 p.m.). Therefore, eight hours or one-third of the daily nominated flow is protected from reduction. For example, if 24,000 had been scheduled as IT in the Timely or Evening Cycles, the most that nomination could be reduced in the ID1 Cycle is by 16,000 to 8,000. This process is referred to as the Elapsed Prorated Scheduled Quantity (EPSQ) process. After allowing for the EPSQ limitations, reductions must follow the scheduling priorities stated in the TSP's tariff.

C. Confirmation: The confirmation process is the same as described for the Timely Cycle, above. Confirmations must be completed by 1:00 p.m.

D. Reporting: No later than 2:00 p.m., the TSP is responsible for making scheduled quantity reports available to both customers (shippers) and interconnected operators. These reports indicate the quantities that have been scheduled for effective flow at 5:00 p.m. as well as reasons for any reductions to the originally nominated or previously scheduled quantities.

4. The Intraday 2 (ID2) Nomination Cycle. This is the second and final opportunity to modify previously scheduled quantities during the Gas Day. When scheduled, ID2 Nominations have an effective flow time of 9:00 p.m. (12 hours after the start of the Gas Day).

A. Nomination: The deadline for submission of nominations is 5:00 p.m. Scheduled quantities are carried over from the three previous scheduling cycles. However, because no additional opportunities to nominate changes for the Gas Day are available, Bumping is not permitted. Therefore, all ID2 Nominations compete for the available capacity remaining after the ID1 Cycle.

B. Scheduling: All nominations received by the nomination deadline must be compared to available capacity, as described above. If the nominated quantities exceed the available capacity, reductions are made to the nominations until they match the available capacity. As with reductions in the ID1 Cycle, ID2 reductions are limited by EPSQ. However the EPSQ calculation for ID2 includes an adjustment for the additional four hours of

effective flow after ID1. After allowing for the EPSQ limitations, these reductions must follow the scheduling priorities stated in the TSP's tariff.

C. Confirmation: At each point of interconnection, the operators (TSPs) compare nomination records to match suppliers and markets. When mismatches occur, the lesser-of rule is applied to balance the nominations across the interconnect point. Confirmations must be completed by 8:00 p.m.

D. Reporting: No later than 9:00 p.m., the TSP is responsible for making scheduled quantity reports available to both customers (shippers) and interconnected operators. These reports indicate the quantities that have been scheduled for effective flow at 9:00 p.m. as well as reasons for any reductions to the originally nominated or previously scheduled quantities.

TRANSPORTATION SERVICE PROVIDER SCHEDULING PRIORITIES

Scheduling priorities are used by Transportation Service Providers (TSPs) to differentiate between customer (shipper) transactions when more transportation has been requested (nominated) than can be accommodated by the available capacity. The following scheduling priorities are listed from highest to lowest. When the priority level is reached that equates to the capacity available for scheduling, the reduction process for that priority level is used to make the necessary reductions.

1. **Primary Firm Capacity.** Firm capacity is based on a shipper agreeing to purchase a specific amount of capacity (quantity) that is sourced from certain receipt points and delivered at certain delivery points. Firm shippers pay a reservation fee for the capacity for which they have contracted. This fee "reserves" their right to use this capacity with the highest scheduling priority of all transportation transactions. Firm capacity nominations using the contracted receipt and delivery points and/or the contracted flow path are considered primary up to the capacity limit of the contract. Once scheduled, primary capacity nominations may not be bumped.

2. **Secondary Capacity.** Firm Shippers nominating at points other than the primary points of capacity, or in some cases, nominating in excess of their contractual rights at a point specified in their contract are utilizing secondary capacity. Secondary capacity has a priority for access to pipeline capacity below primary capacity. In most cases, secondary capacity nominations may not be bumped. Therefore, scheduled secondary capacity may prevent nominations for primary capacity that are submitted in a later cycle from being scheduled.

3. **Interruptible Capacity.** Interruptible capacity is provided to shippers who hold an interruptible transportation (IT) agreement. IT agreements generally have no specific entitlement or right to transport gas on the TSPs system and are only able to use system capacity when it is available after service has been provided to all firm requests. IT capacity is only paid for when it is actually used.

4. Other Priorities.

A. **Authorized Overrun**: Overrun quantities are those nominated firm quantities that exceed the contract's firm entitlement. Overrun nominations become "Authorized" when they are scheduled. In most cases, overrun is only scheduled after all firm and IT nominations have been served. Not all TSPs offer overrun services.

B. **Imbalance**: Imbalance quantities are those nominated to clear up over- or under-supply situations. Imbalance nominations are usually the last transactions to be scheduled when capacity is available.

Some TSPs offer alternate types of firm and interruptible services which may be inserted among the priorities listed above. These services and their respective scheduling priorities are described in the TSP's tariff.

In summary, transportation nominations are generally scheduled in the following order when available capacity is limited:

1. Primary Firm
2. Secondary Firm
3. IT
4. Authorized Overrun
5. Imbalance

SCHEDULING AND BUMPING IN PRACTICE

When nominations exceed the capacity of the pipeline, capacity allocations must be conducted to be sure the appropriate parties are scheduled to flow. Once a nomination deadline has passed, the TSP organizes all of the nominations it has received according to the priorities discussed above. Then, nominations in the lower priority tiers are dropped until the remaining nominated quantities equal the available capacity.

Generally, once a nomination has been scheduled for a Gas Day, it is protected from being reduced later in that day except for operational changes. However, the exception to this rule is that, scheduled interruptible transportation (IT) nominations can be reduced ("bumped") in the Evening and ID1 Cycles to make room for new firm nominations. In the Evening Cycle, bumping can cause an IT (or other lower priority nomination) nomination to be reduced to zero because no gas has flowed. However, because the effective flow time of the ID1 Cycle is eight hours into the Gas Day, the assumption is that 1/3 of any scheduled quantity has already flowed and cannot be reduced. Since this IT capacity is protected, there is less capacity available for new, firm nominations. This process is referred to as the Elapsed Prorated Scheduled Quantity (EPSQ) calculation.

The following two examples demonstrate this process:

Base Data

Gas Day: December 25 (9:00 a.m. 12/25 to 9:00 a.m. 12/26)
ID1 effective flow time: 5:00 p.m. 12/25
Pipeline Capacity = 15,000 Dth

Timely Nominations/Scheduled Quantities (to begin flow at 9:00 on 12/25)

Nom	Quantity
PF1	3600
PF2	2400
SF1	4800
SF2	1800
IT1	2400
	15000

Example 1

New Evening Nominations

Nom	Quantity
PF3	1200

Evening Scheduled Quantities

Nom	Quantity	
PF1	3600	
PF2	2400	
PF3	1200	
SF1	4800	
SF2	1800	
IT1	1200	Bumped by 1200
	15000	

Example 2

New ID1 Nominations

Nom	Quantity
SF3	1200

ID1 Scheduled Quantities

Nom	Quantity	
PF1	3600	
PF2	2400	
PF3	1200	
SF1	4800	
SF2	1800	
SF3	800	
IT1	400	(1200 X 1/3 = 400 EPSQ) Bumped by 800
	15000	

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Section IV: Power Presentations

January 2004 Meeting

- Electricity 101
- Generation Dispatch 101
- A Retail Electric Perspective on Billing & Settlement

March 2004 Meeting

- Transmission Timing Analysis
- Example of Natural Gas Industry and Electric Industry Timing Issue
- Market Timing Issues

Electricity 101

Presented to the GECTF

January 29th, 2004

Electricity 101

- Agenda
  - Overview of Electricity
  - The Scheduling Process
    - “Day in the Life of a Transaction”
    - Congestion Management Overview
  - Settlement Credit Overview
  - Summation

Introductions

- Kalim Tippitt - The Structure Group
- Andrew Rodriquez - PJM

- Michael Gildea – Constellation

Why Is Electricity So Difficult Compared to Gas?

- No Real Storage
  - Need to match Supply and Demand in Real Time
- Requires the coordination of fuel management
- Highly interconnected transmission systems
- Many Entities, Few Standardized Rules
  - 170 different Transmission Providers and Open Access Transmission Tariffs (OATTs)
- Complexity of the Commodity
  - Reactive Power, Pumped Storage, Loop Flows, etc…
- Conflicts between Federal and States Rights
  - Is deregulation good or evil

Overview

- Concepts and Historical Background
- Open Access Same-time Information System
- Transaction Information System

Entities

- North American Energy Standards Board (NAESB)
  - Market-based Standards
- North American Electric Reliability Council (NERC)
  - Reliability Standards
- Regional Reliability Organizations (RROs)
  - The 10 Regional Councils that make up NERC. Focused on regional/local reliability concerns
  - ECAR, SERC, MAIN, MAPP, MAAC, FRCC, NEPOOL, ERCOT, WECC, SPP

Entities

- Federal Energy Regulatory Commission (FERC)
  - Wholesale Transactions and Markets, Interstate Commerce
- Public Utility Commissions (PUCs)
  - Retail Transactions and Consumer Choice

Entities

- Transmission Providers (TPs)
  - Administer Local Transmission Tariffs and Provide Grid Operations. Approximately 150.
- Regional Transmission Organizations (RTOs)

  and
- Independent System Operators (ISOs)
  - Generally Operate Regional Markets, Administer Regional Transmission Tariffs, and Provide Grid Operations. Typically created by several TPs giving control to an independent entity.
  - ERCOT, PJM, MISO, ISO-NE, NYISO, Cal ISO, IMO

Entities

- Control Areas (CAs)
  - Metered areas required to maintain balanced generation and load (maintain Area Control Error (ACE)). Approximately 120.
- Purchasing/Selling Entities (PSEs)
  - Entities that purchase and sell energy. May or may not own generation or have obligation to serve load. Approximately 900.
- Generation Provider Entities (GPEs),
- Non-Utility generators (NUGs)

  and
- Independent Power Producers (IPPs)
  - Owners of generation that sell energy and/or capacity.

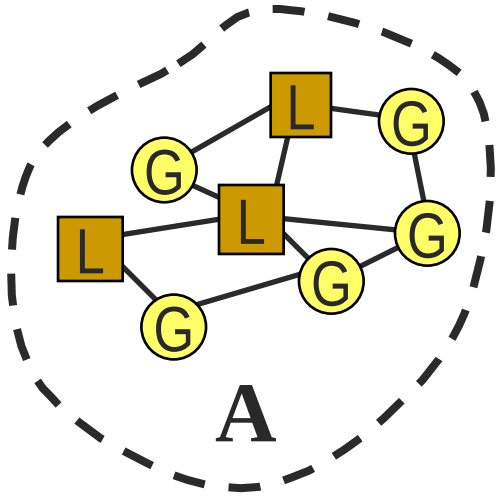
Entities

- Load Serving Entities (LSEs),
- Large Industrial Customers,

  and
- Transmission Dependent Utilities (TDUs)
  - Wholesale consumers of Power.
- Non-Jurisdictional Entities (NJEs)
  - TVA, BPA, WAPA
- Municipals, Cooperatives

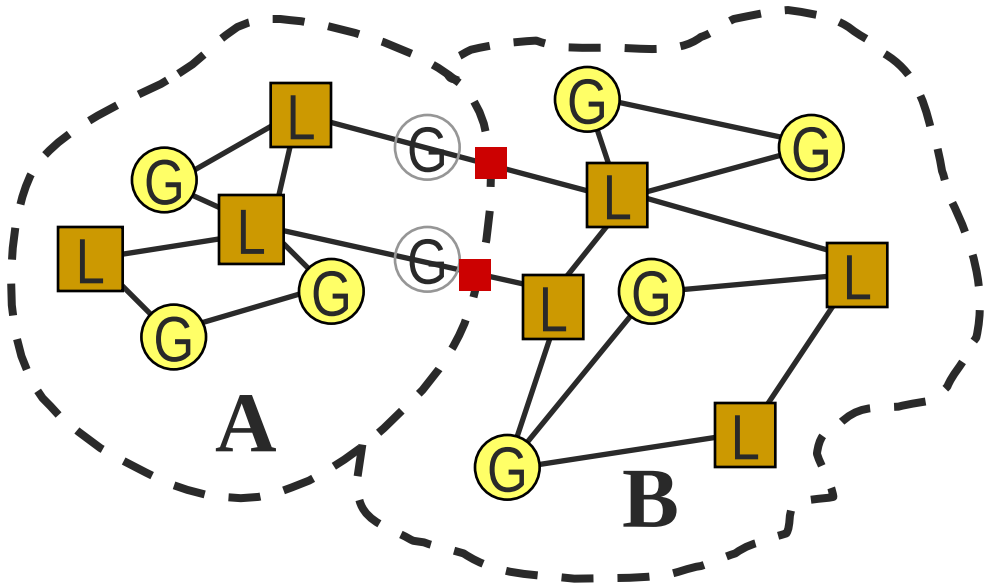
Historical Background

- Electrically Isolated Systems
  - Expensive to Address Reserve Needs
  - Not as Reliable due to Transient Effects



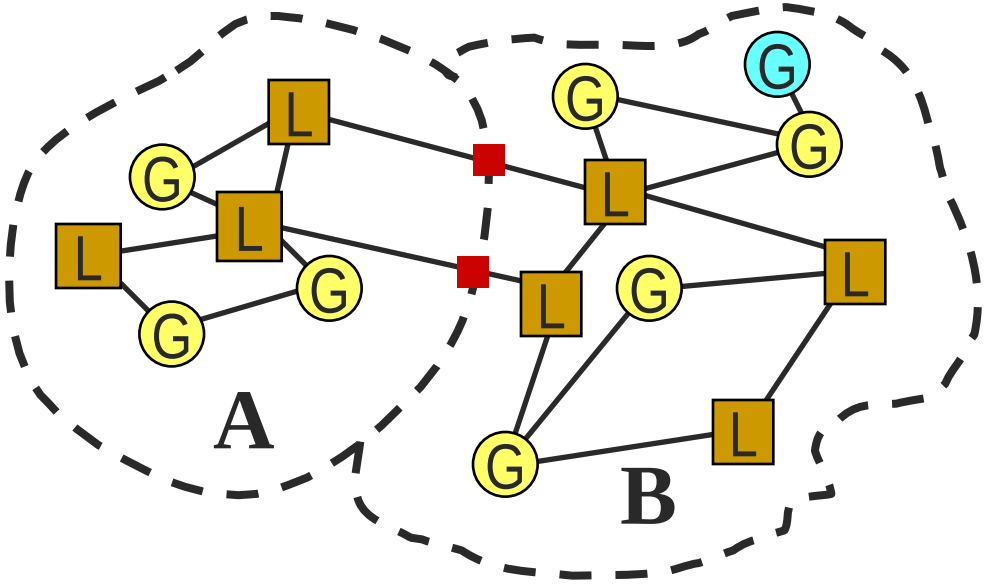
Historical Background

- Interconnected Systems
  - Allows for “Reserve Sharing”
  - Distributes Transient Effects
  - Allows for Purchase/Sale of Economy Energy



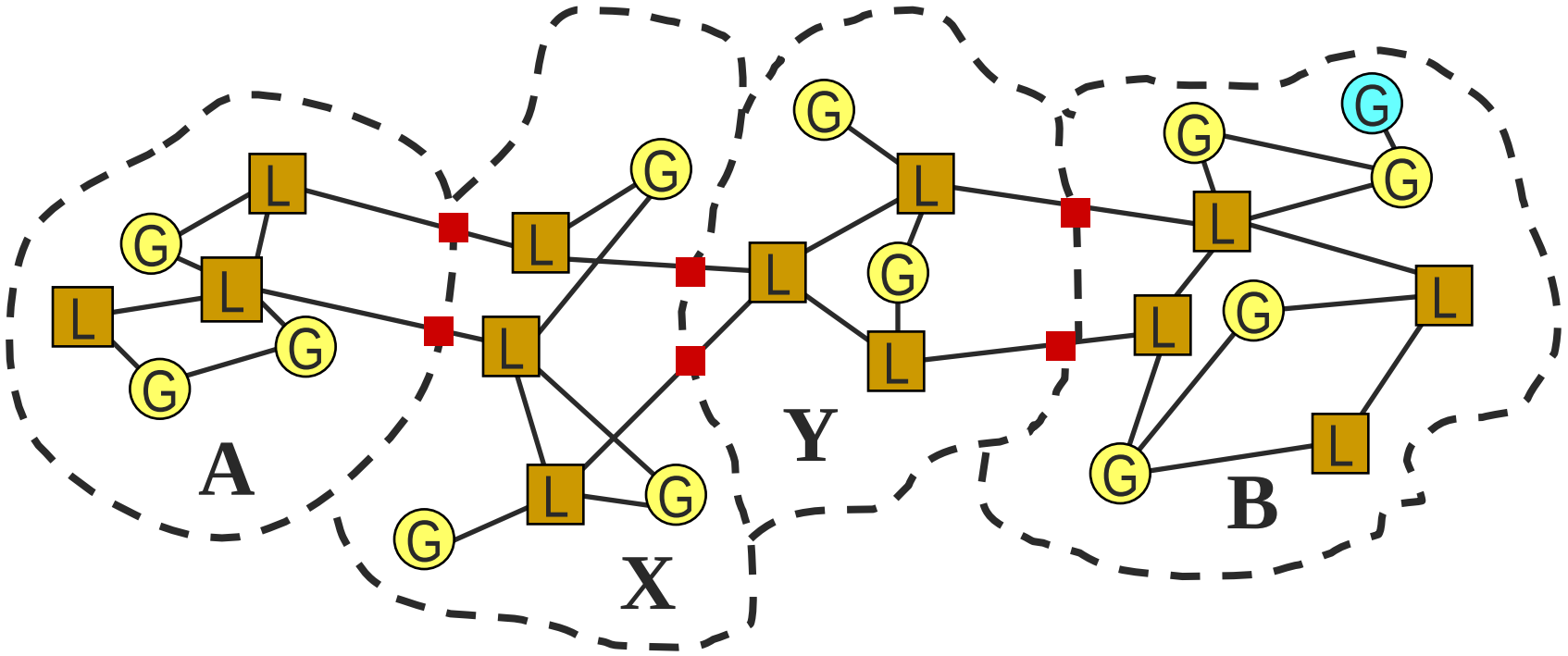
Historical Background

- The Energy Policy Act
  - Exempt Wholesale Generators
  - Wholesale Wheeling

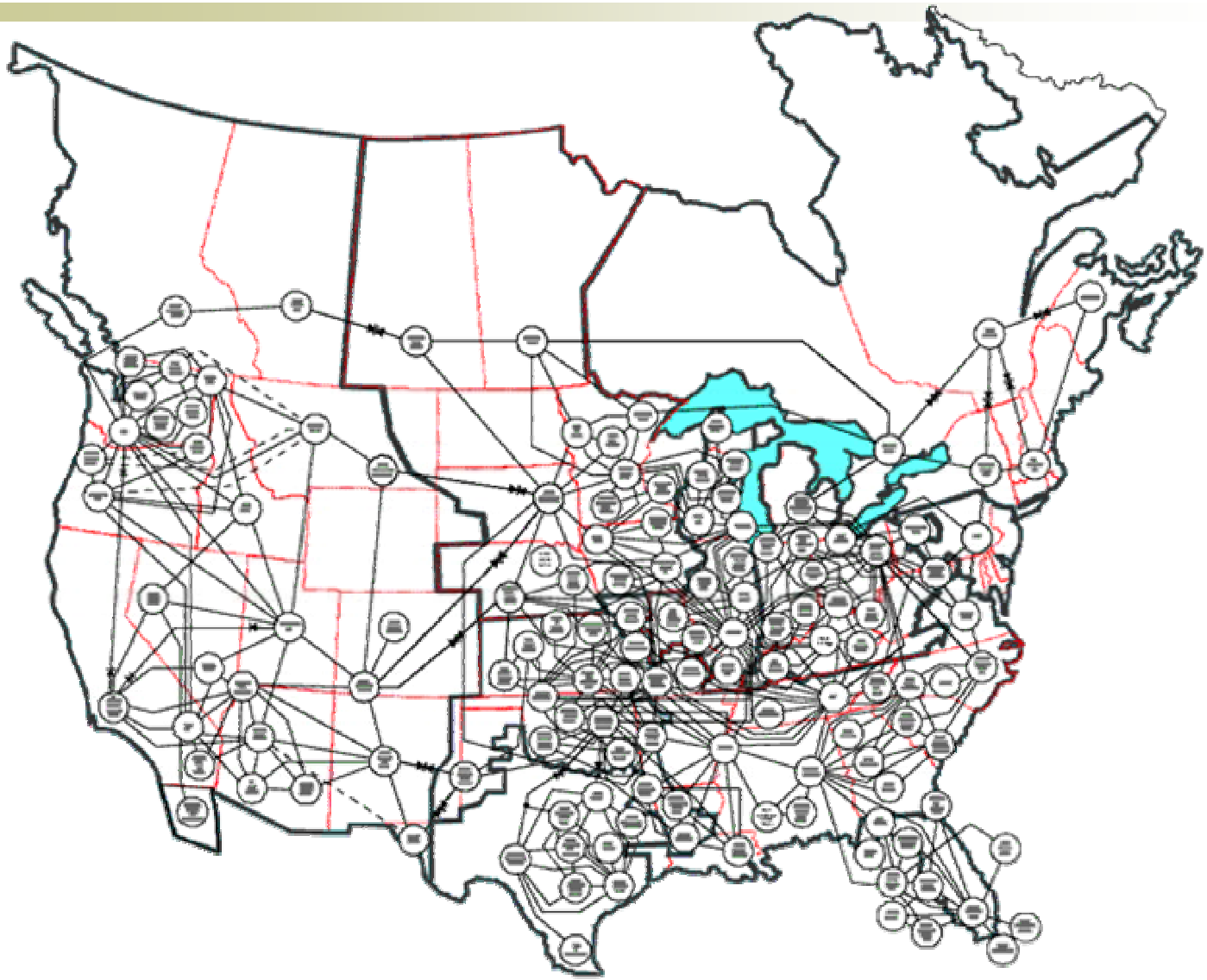


Historical Background

- Wholesale Wheeling



NERC Control Areas



Historical Background

- FERC Order 888
  - Functional Unbundling
  - Pro Forma Tariff
- FERC Order 889
  - Standards of Conduct
  - Open Access Same-time Information System
  - Standards and Communications Protocols

Goals of the OASIS

- Allow transmission customers to :
  - Request and offer service
  - Obtain transmission system information
  - Obtain product information
  - View denials and curtailments
  - Obtain data for modeling and audit purposes

OASIS Postings

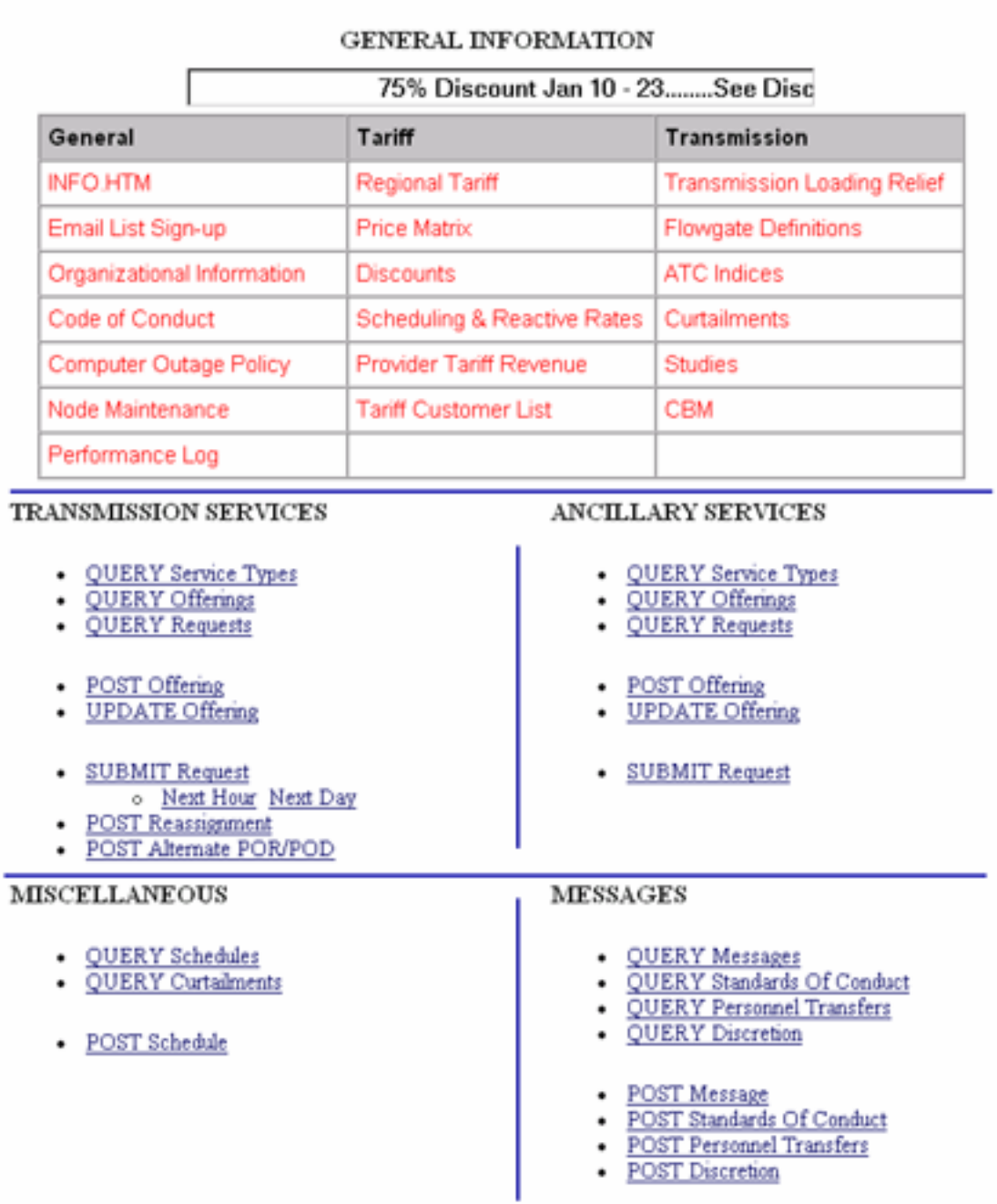
- Available Transmission Capacity
- Total Transmission Capacity
- Transmission Products and Prices
- Ancillary Service Offerings and Prices
- Specific Requests and Responses
- Transmission Service Schedules

OASIS

- Accessed over the Internet
- Several nodes across North America
- One node may host several providers

Typical OASIS Site

- General Information
- Transmission Services
- Ancillary Services
- Miscellaneous
- Messages



GENERAL INFORMATION

75% Discount Jan 10 - 23.....See Disc

General	Tariff	Transmission
INFO.HTM	Regional Tariff	Transmission Loading Relief
Email List Sign-up	Price Matrix	Flowgate Definitions
Organizational Information	Discounts	ATC Indices
Code of Conduct	Scheduling & Reactive Rates	Curtailments
Computer Outage Policy	Provider Tariff Revenue	Studies
Node Maintenance	Tariff Customer List	CBM
Performance Log		

TRANSMISSION SERVICES

- QUERY Service Types
- QUERY Offerings
- QUERY Requests
- POST Offering
- UPDATE Offering
- SUBMIT Request
  - Next Hour Next Day
- POST Reassignment
- POST Alternate POR/POD

ANCILLARY SERVICES

- QUERY Service Types
- QUERY Offerings
- QUERY Requests
- POST Offering
- UPDATE Offering
- SUBMIT Request

MISCELLANEOUS

- QUERY Schedules
- QUERY Curtailments
- POST Schedule

MESSAGES

- QUERY Messages
- QUERY Standards Of Conduct
- QUERY Personnel Transfers
- QUERY Discretion
- POST Message
- POST Standards Of Conduct
- POST Personnel Transfers
- POST Discretion

Transmission Firmness

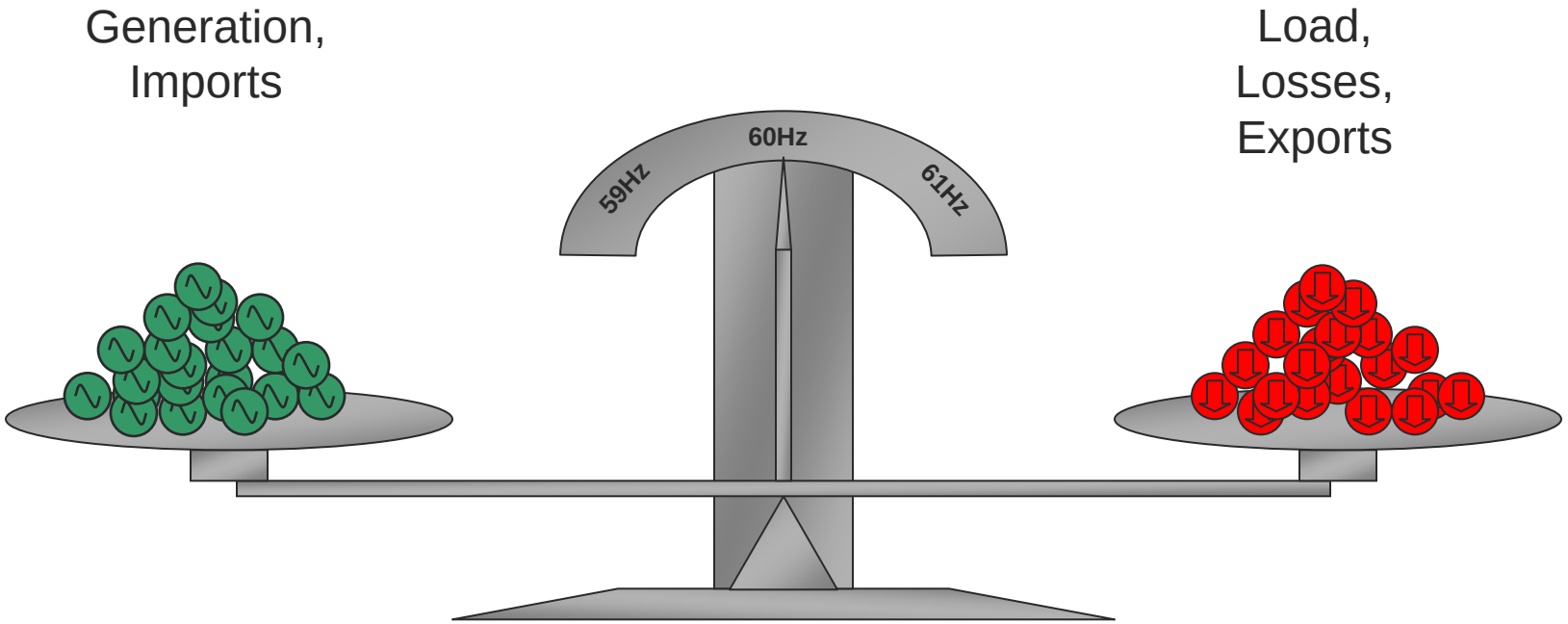
- Firm
  - Priority 7
- Multiple Levels of ‘Non-Firmness”
  - Based on duration
    - Network, Monthly, Weekly, Daily, Hourly, Secondary (Redirected), Next-Hour
    - Priorities 6-0

Ancillary Services

- Required of Load to support system
- Transmission provider is Provider of Last Resort (POLR)
- Tradable Capacity (different names per market)
  - Spinning Reserves - < 10 Minute Product
  - Supplemental Reserves - < 30 Minute Product
  - Regulation & Frequency Control
- Centrally Managed (typically)
  - Scheduling & Dispatch
  - Reactive Power & Voltage Support
  - Imbalance
  - Black Start

Frequency

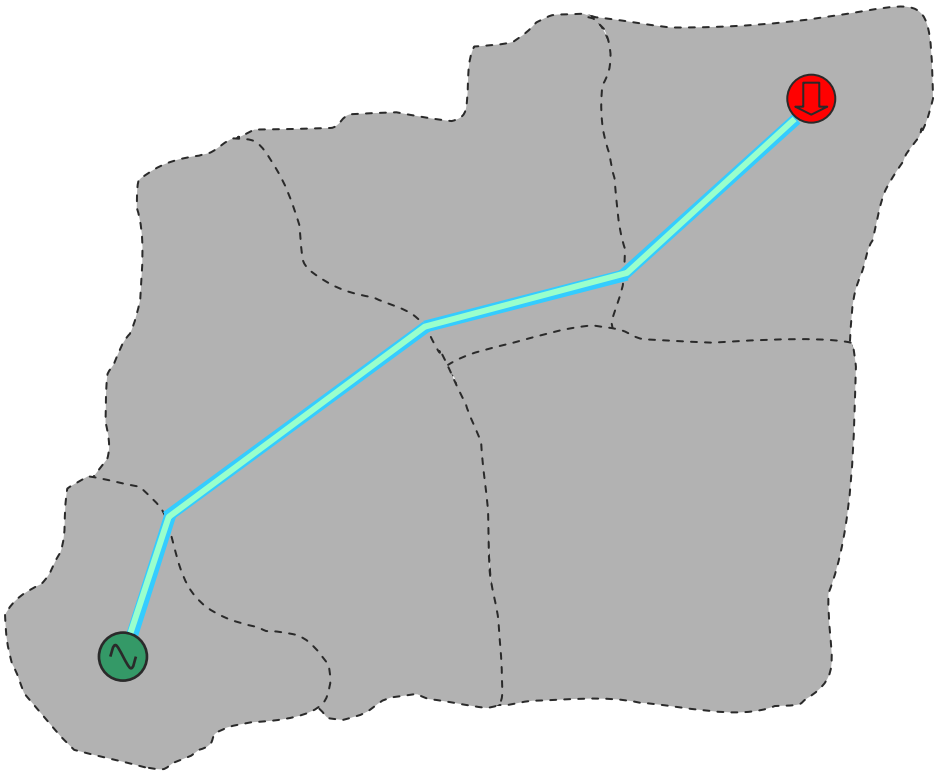
Maintaining the Energy Balance
60Hz



Transmission Service

- Point to Point Transmission service
  - PTP refers to the kind of service use in *interchange transactions* (moving energy from one Control Area to another)
    - Interchange transactions are Tagged (i.e., NERC mandates information describing the transaction be reported to the IDC)
    - Point to Point service is what most people think of when you talk about *transmission reservations* on the *OASIS*

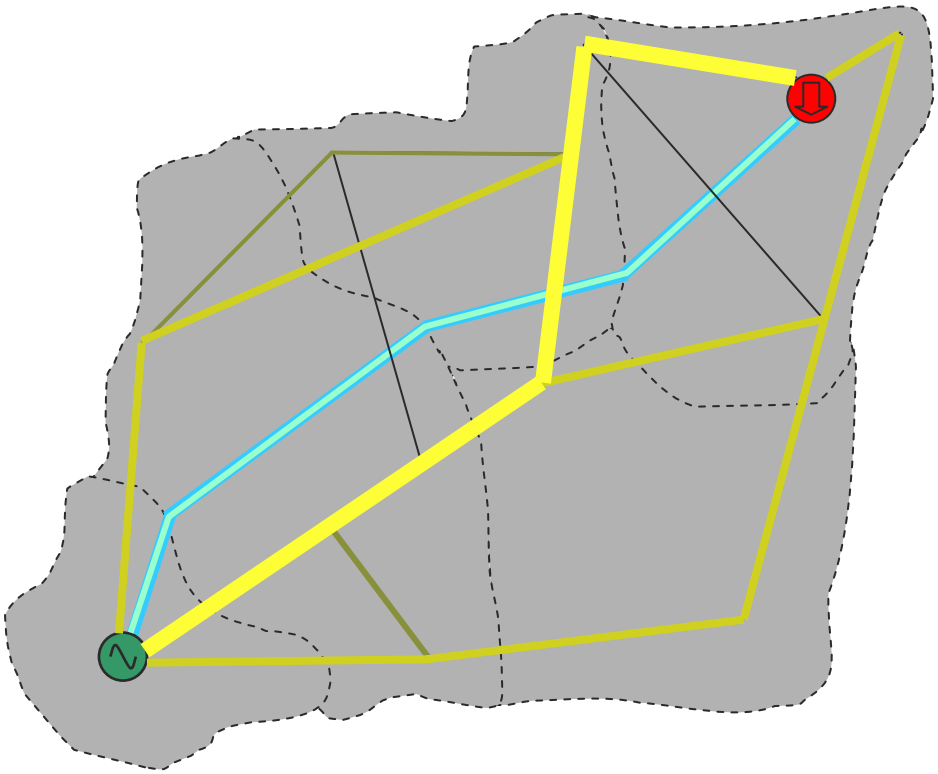
PTP - Example



4 “legs” of PTP service

1 “Contract Path”

PTP - Example



4 “legs” of PTP service

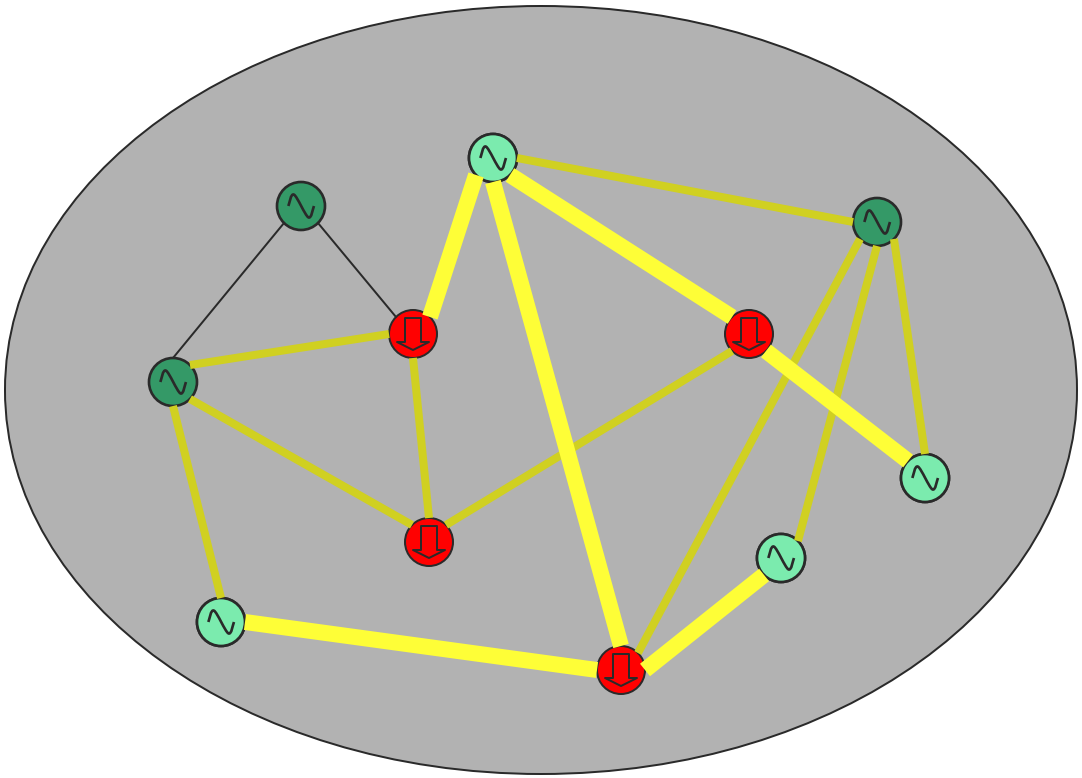
1 “Contract Path”

Flows due to Point to Point

Transmission Service

- Network Integrated Transmission Service
  - NITS is transmission service used to serve *native load with designated network resources*
    - Designated resources are generators that have met certain deliverability criteria and been specified by the transmission customer as used to serve their customers
    - Native load is load *internal* to the Control Area that would historically be served by the incumbent utility

NNL - Example



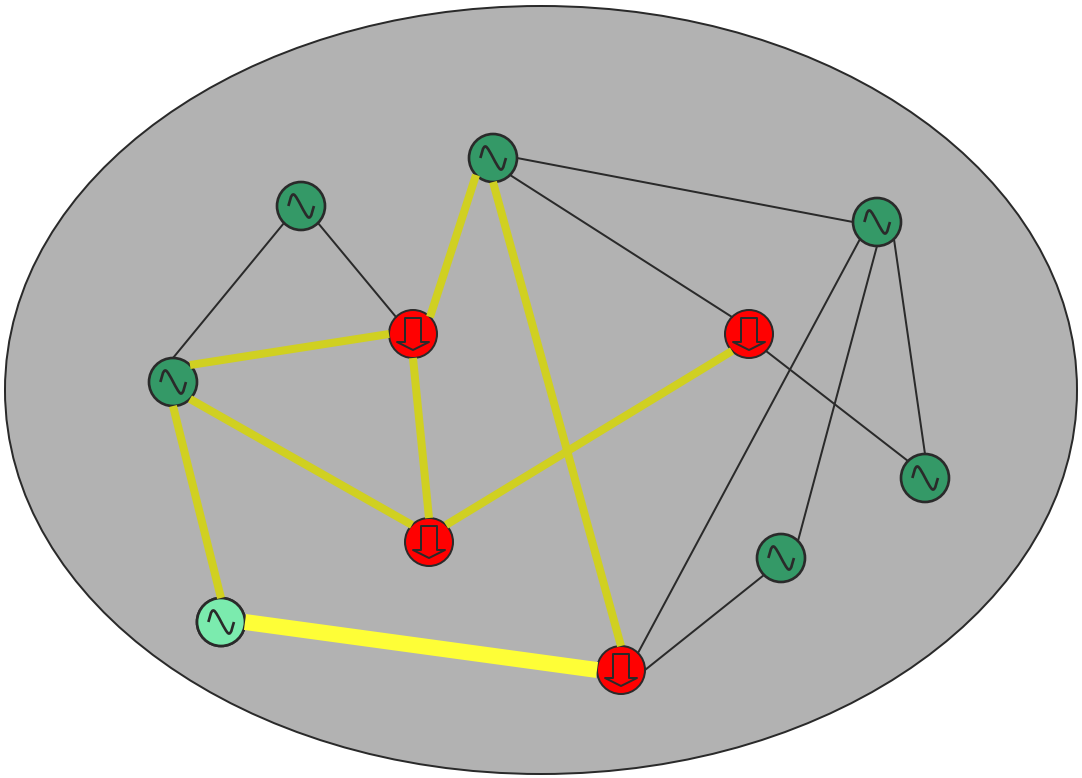
Designated Resources

Flows due to NNL

Flowgates

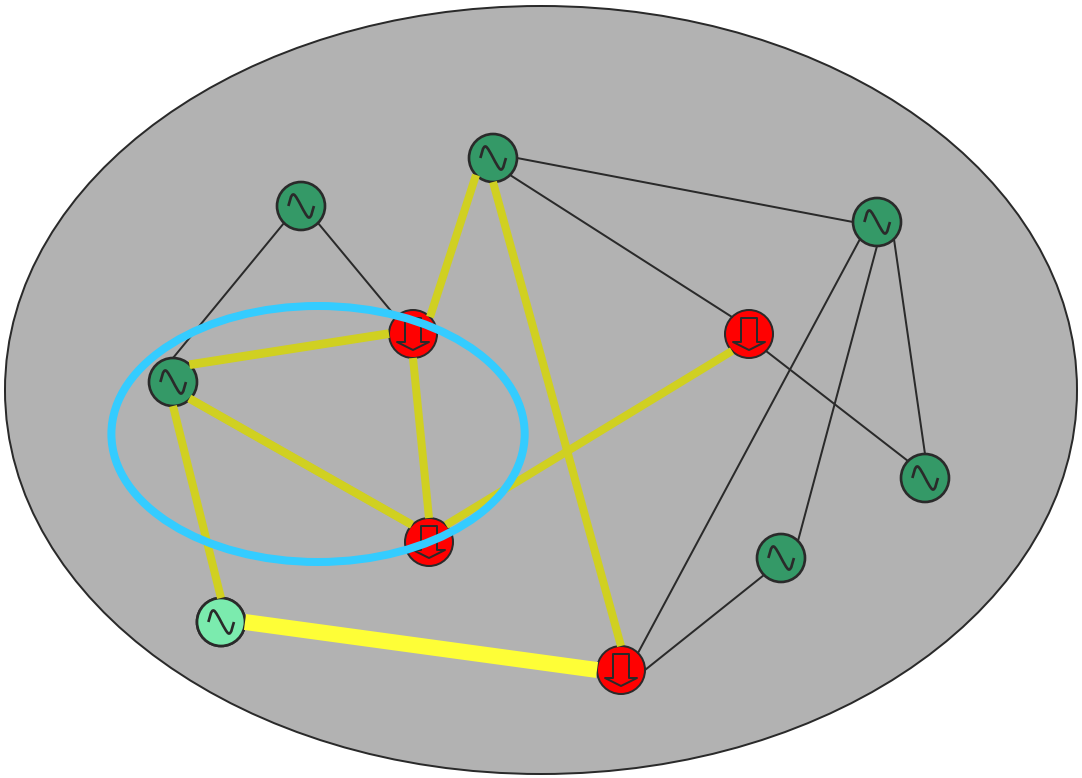
- A *flowgate* is a representative aggregate of one or more transmission elements to be used in the analysis of the transmission system

Flowgates



Impact of this specific designated resource

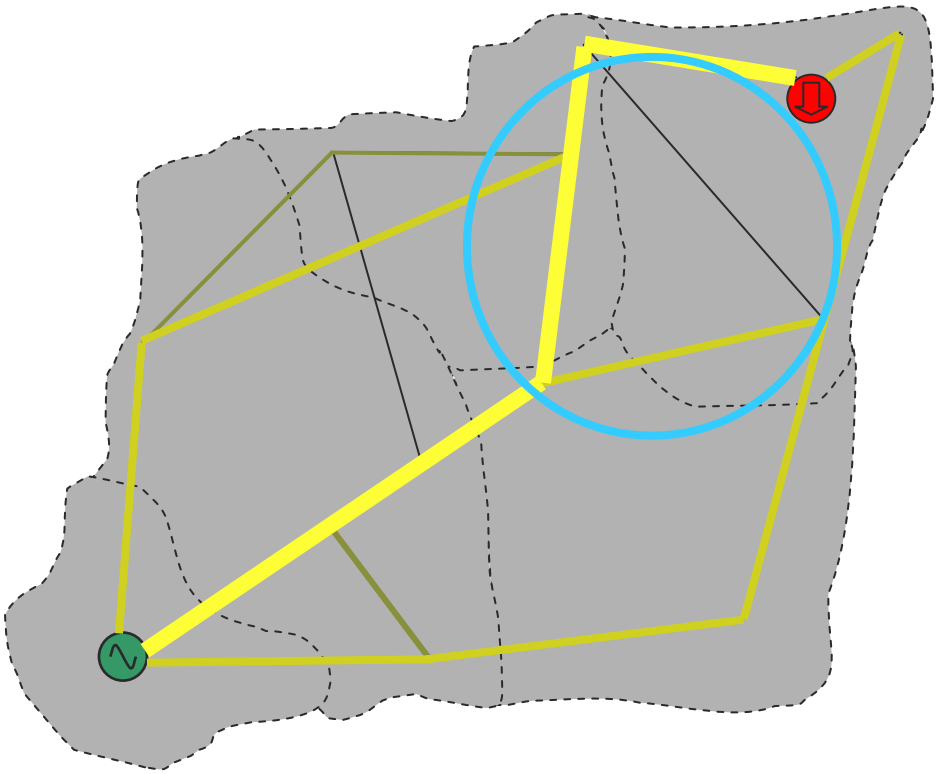
Flowgates



Impact of this specific designated resource

On this specific flowgate

Flowgates



Impact of this Interchange Transaction on this particular flowgate

AFC/ATC and TTC

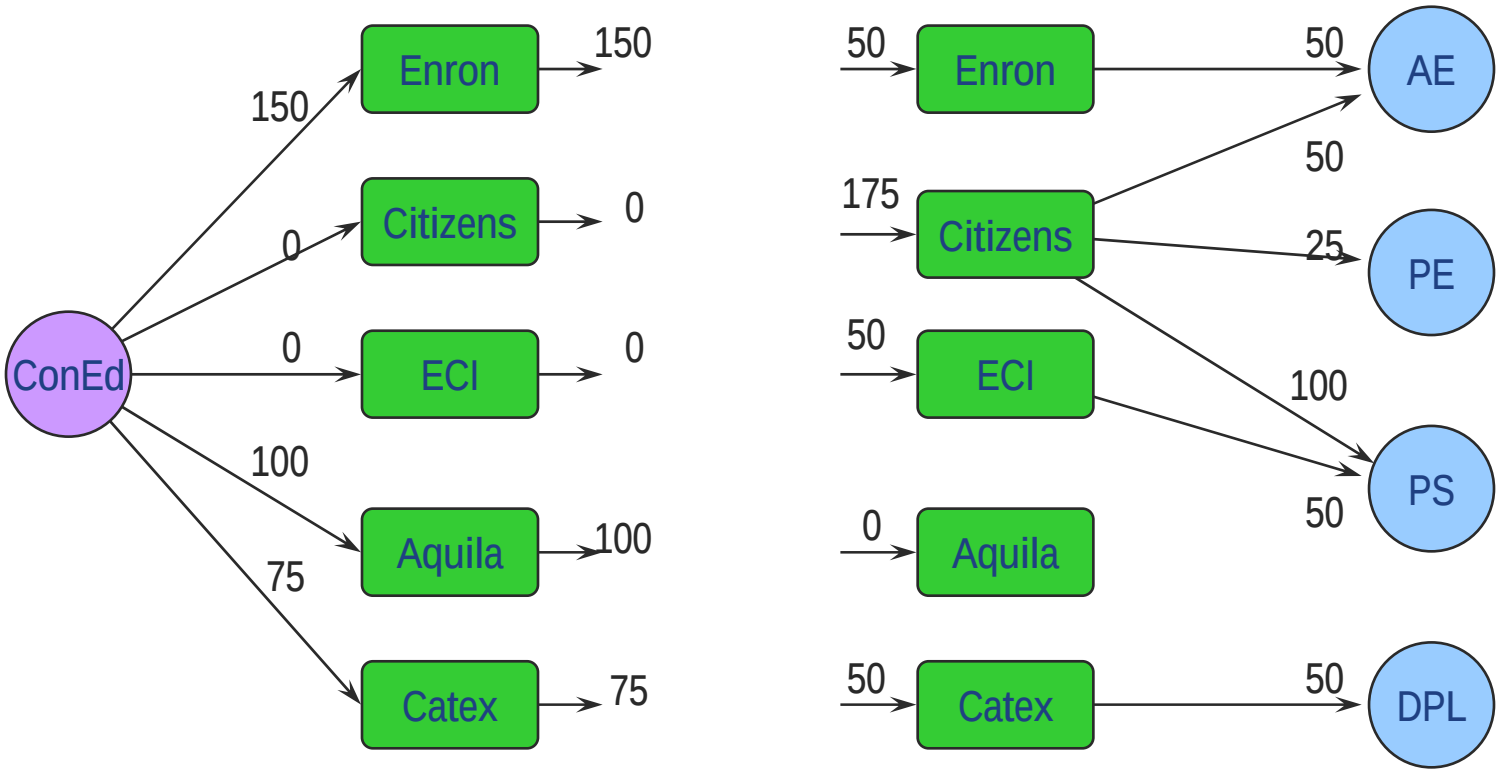
- Flowgates are used to discuss the flows of energy transfers
- When someone requests transmission on the OASIS, providers:
  1. Identify affected flowgates
  2. Determine Available Flowgate Capacity for each flowgate
  3. Limit Available Transfer Capability based on the most constrained AFC
  4. If the ATC is less than the impact of the transmission request, the request is denied

Transaction Information System (Electronic Tagging)

- Documents Interchange Transactions
  - Identifies “Source to Sink” flows
  - Provides common link for all parties
  - Indicates
    - Losses
    - Transmission Reservation
    - Contract Information

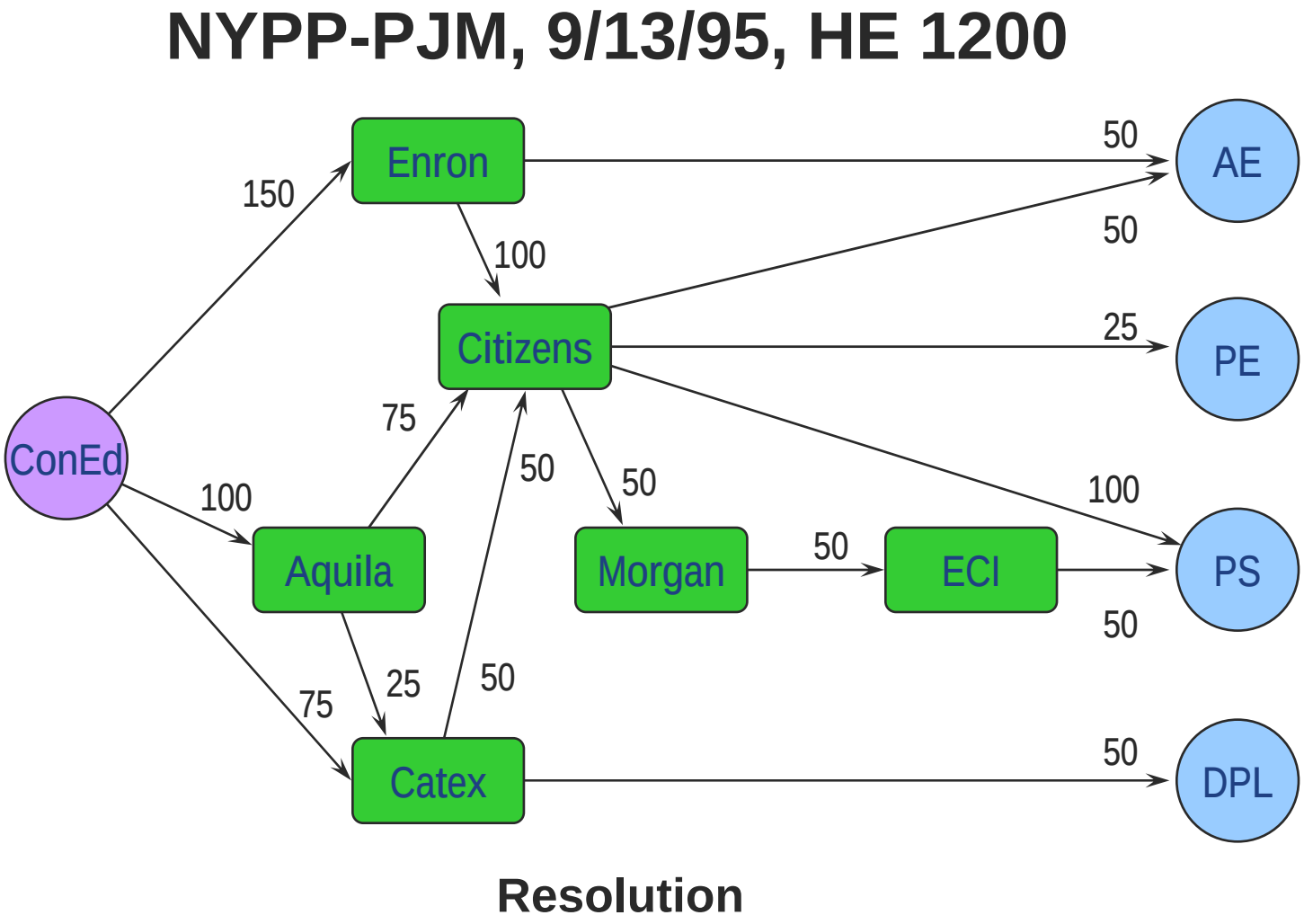
Transaction Information System

NYPP-PJM, 9/13/95, HE 1200



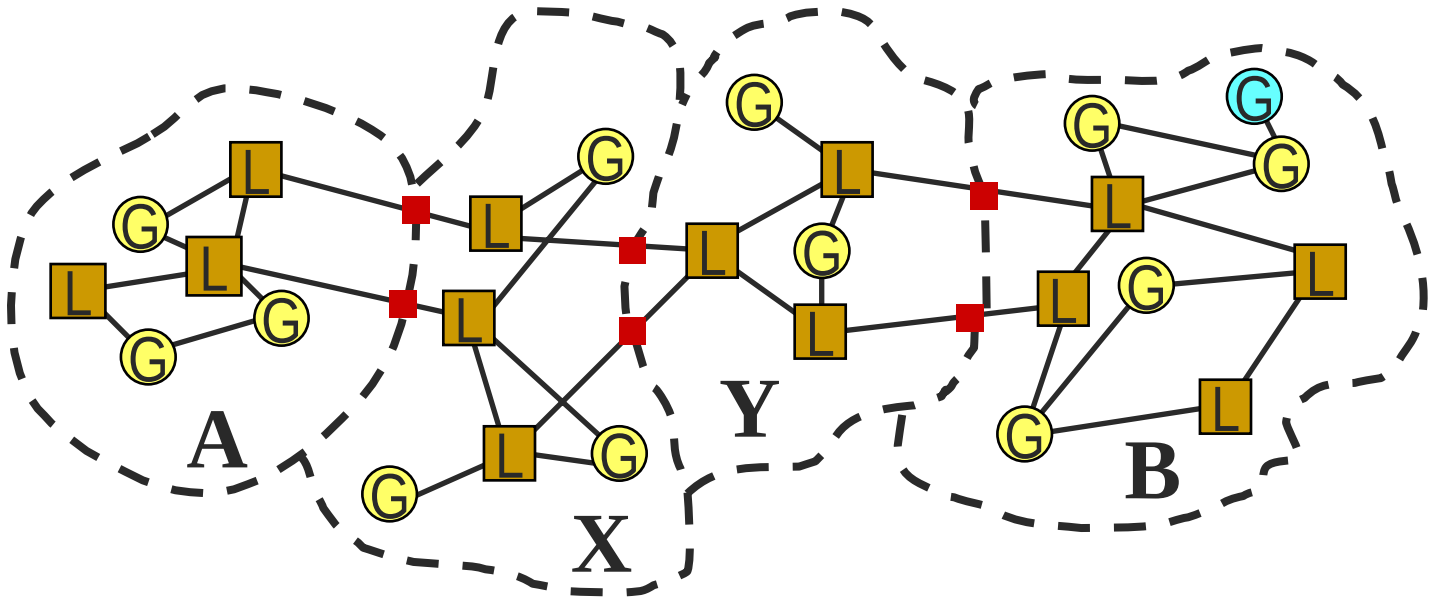
Reported by NYPP **Reported by PJM**

Transaction Information System



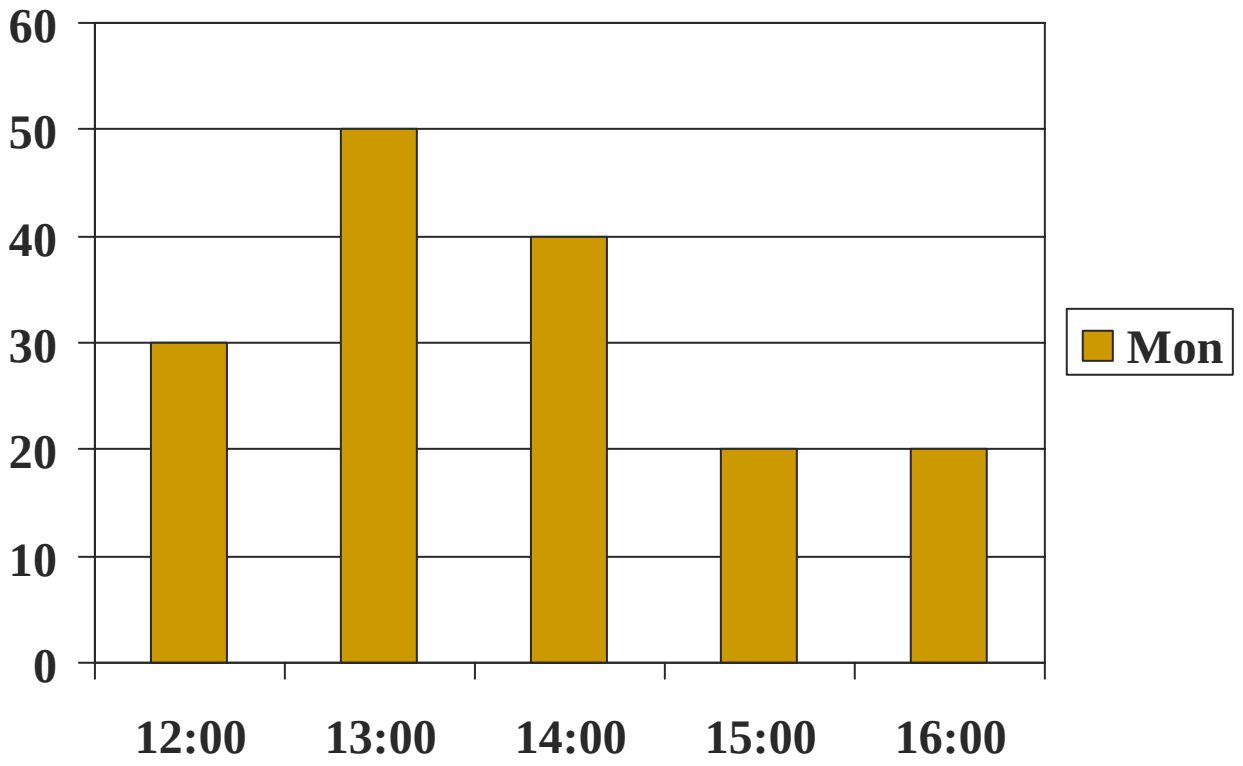
Transaction Information System

- Transaction Path



Transaction Information System

- Energy Profile



Transaction Information System

- Information exchanged over the Internet
- Transaction “Tags” are Approved or Denied by Control Areas and Transmission Providers
- Approved transactions are forwarded to the Interchange Distribution Calculator

Interchange Distribution Calculator

- Accepts Tags as Input
- Uses source/sink data from tag to model actual physical flows
- Identifies need for curtailments to mitigate line overload conditions

A Day In the Life of a Transaction

- Day Ahead Perspective
  - Trading
  - Scheduling
- Real Time Perspective
  - Trading
  - Scheduling
- Settlement Overview
  - Credit Implications

Trading Overview

- Real Time, Short Term, Long Term
- Day Ahead - Evaluate Position by Control Area/ISO/Trading Hub
  - Unit Status
  - Fuel Availability
  - Load Forecast
  - Weather Forecasts
  - Transmission Outages/Availability

Trading Overview

- Traders will flatten out or take a Long or Short position in the market
- Scheduler left with physical transaction – What to do?

Tag Timeline

- Most day ahead business is conducted from 6:00 am to Noon (Tags and schedules typically have a 12:00 noon deadline)
- From noon to end of day is primarily spent checking out and preparing books for hourly desk and next day.

Timing Conventions

- Power is traded
  - On Peak – 7 to 22, 8 to 23
  - Off Peak – everything else
  - Super Peak
  - Hourly
  - Balance of Week
  - Balance of Month
  - Monthly
  - Term
- Delivery hours are quoted in Hour Ending (HE)
  - HE1 is Hour Ending 1, or 12:00 midnight to 1:00am
- Day Light Savings Time

Scheduling

- Transmission Availability
- Booking Out
- Purchasing Transmission
- Tagging
- ISO Scheduling

Checking Availability

- In order to determine if a path is viable for scheduling, ATC or AFC must be checked on the OASIS

Closing Out Physical Positions

- Scheduler has unmatched buys and sells per trading hub
- Bookouts – attempt to match buys and sells to eliminate delivery risk and cost of transmission (net the position to zero; booked out financially)
- Physical Schedules – that which could not be booked out must be physically scheduled and delivered
- ATC/AFC must be kept in mind, along with existing transmission portfolio

Submit Transmission Requests

- Daily Firm requests (on most providers) must be entered in no later than 10am CST the day prior to the start of service.
- Once a request is submitted it is given an “Assignment Reference” number (A-Ref or OASIS Number).
- Request may be granted or refused based on TP evaluation.

Losses

- Similar to Shrinkage associated with Compressor Stations
- Transmission Lines utilizes some energy based on friction as electricity is transported
- Each Transmission Provider has their own loss rate/calculation and rules
- Financial or Physical

Tags

- All day ahead transaction information resides in Tag
  - Energy Profile
  - Loss Profile
  - Transmission Reservation A-Refs
- As well as contract path (wheeling) and title path (ownership) of energy
  - Generator/Seller/Source
  - Transmission Provider(s)
    - Imports, Exports, and Wheels
    - POR/PODs and Firmness
  - Marketer(s)
  - Load/Buyer/Sink

TAG ID	CPL_PMXC9999999_PJM	TAG TYPE: Normal	SENT BY: Joe Scheduler	COMPANY: PMXC	PHONE: 800-555-1212	DATE/TIME: 2/2/2004

NOTES

Sample Tag for Illustrative Purposes only

PATH

INSTRUCTIONS: Indicate the Market Path in the left three columns. Indicate the Generator-TP-Load Path in the center columns. Indicate the Scheduling Path in the rightmost column. All reservations are assumed to match the energy profile. Stacking may be accomplished by leaving empty TX Provider rows, specifying only OASIS, TX Customer and TX Prod. Note that stacks are assumed to consume the reservations in order as they are listed. Relationships across rows should be maintained (I.e., the scheduling CA for a particular TP should be on the same row with that TP).

TITLE **HOLDER**	ENERGY PROD.	CONTRACT NUMBER	GENERATOR						SCHEDULING CA
IPP1	Non-Firm	11884462-KK	Some Generator in Carolina Power and Light						CPLE
			TX PROVIDER	POR	POD	OASIS NUMBER	TX CUSTOMER	TX PROD.	
			CPL	CPL	VAP	998446	IPP1	ND-2	CPLE
PMXC	Non-Firm	JH-7748D-17	VAP	CPL	PJM	992021	PMXC	ND-2	VAP
			PJM	VAP	PJM	774482	LSE1	NN-6	PJM
			LOAD						
LSE1	Non-Firm	GH-LL0093372.12	PJM System Load						PJM

PROFILE

INSTRUCTIONS: Circle the month and day(s) for which the profile should run. Indicate the upstream and downstream transmission providers and their associated schedules at POR and POD. You MUST complete the first row. To carry values to the next row, draw a line form the value to that row – only specify values as they change.

TIME ZONE: CST

MONTH

1	**(2)**	3	4
5	6	7	8
9	10	11	12

DAYS

1	2	**(3)**	4
5	6	7	8
9	10	11	12
13	14	15	16
17	18	19	20
21	22	23	24
25	26	27	28
29	30	31	

UPSTREAM/DOWNSTREAM	INTERFACE	HE1	HE2	HE3	HE4	HE5	HE6	HE7	HE8	HE9	HE10	HE11	HE12	HE13	HE14	HE15	HE16	HE17	HE18	HE19	HE20	HE21	HE22	HE23	HE24
GEN CPL	GEN/POR						100	100	100	100	100														
CPL/VAP	POD/POR						98	98	98	98	98														
VAP/PJM	POD/POR						96	96	96	96	96														
/	POD/POR																								
/	POD/POR																								
/	POD/POR																								
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/	POD/POR																								
/	POD/POR																								
PJM LOAD	POD/LOAD																								

Tagging Nuances

- Horizontal Stacking
  - Utilizing multiple reservations over multiple hours (i.e., one reservation for off peak, one for on-peak)
- Vertical Stacking
  - Utilizing multiple reservations over the same hours (i.e., reservation 1 for 75MW, reservation 2 for 25MW, total transfer for the hour 100MW)

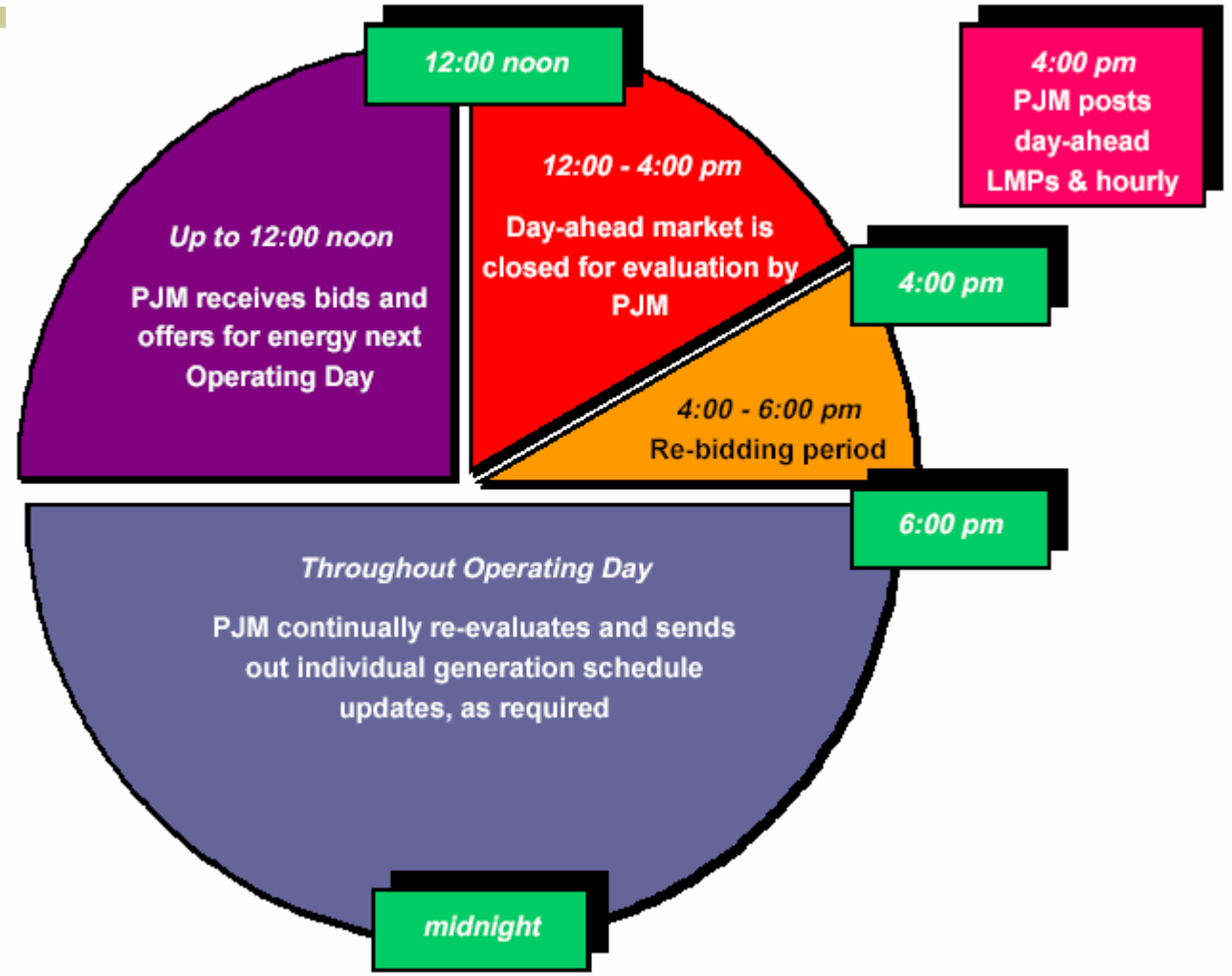
RTO/ISO Schedules

- RTOs and ISOs have their own scheduling requirements
- Ramp – PJM , for example, requires all imports to verify that there is room on the interface
  - PJM allows you to move the schedule if ramp not available (745-2145)
- Contract – PJM, NE require a contract exists between the two transacting parties

RTO/ISO Schedules

- ISO Schedule
  - Some ISOs require a schedule be submitted in addition to the Tag
  - Including your energy profile
- Resource Plan
  - For each unit, provide all operating parameters
- More confirmations
  - Both counterparties confirm their schedules

PJM Day-Ahead -Timeline



Checking Out

- Following scheduling, values are confirmed one final time to ensure everything is balanced

Real Time

- We spent all this time scheduling Units and Transmission, Booking out, etc…
- Then everything falls apart in Real Time

- Hourly transaction occur “day-of” flow

Real Time

- Each hour, trading “opportunities” are identified and utilized
  - Unplanned Unit Outage
  - Arbitrage Opportunities
  - Adjust for deviations between forecasted load and generation
- Transmission Constraints and Curtailments also drive need for real time trading
- Typically, trading is done from the top of the hour to the bottom of the hour (xx:00 to xx:30)

Tag Timelines

Transaction Duration	PSE Submit Deadline	Actual Tag Submission Time	Provider Assessment Time	Time to Start of Transaction
Less than 24 Hours	20 Minutes prior to start	≤1 Hour prior to start	≤ 10 Minutes from tag receipt	≥ 10 Min
		>1 to <4 hours prior to start	≤20 Minutes from tag receipt	≥ 40 Min
		≥ 4 Hours prior to start	≤ 2 Hours from tag receipt	≥ 2 Hours
24 Hours or longer	4 Hours prior to start	Any	≤ 2 Hours from tag receipt	≥ 2 Hours

OASIS Timelines

Class	Service Increment	Time Queued Prior to Start	Provider Evaluation Time Limit	Customer Confirmation Time Limit After Accepted or Counteroffer	Provider Counter Time Limit After Rebid
Non Firm	Hourly	<1 Hour	Best effort	5 mins	5 mins
		>1 hour	30 minutes	5 mins	5 mins
		Day ahead	30 minutes	30 mins	10 mins
	Daily	N/A	30 minutes	2 hours	10 mins
	Weekly	N/A	4 hours	24 hours	4 hours
	Monthly	N/A	2 days	24 hours	4 hours
Firm	Daily	<24 hours	Best Effort	2 hours	30 mins
		N/A	30 days	24 hours	4 hours
	Weekly	N/A	30 days	48 hours	4 hours
	Monthly	N/A	30 days	4 days	4 hours
	yearly	60 days	30 days	15 days	4 hours

Congestion Mgmt

- Due to imperfect analysis and the gap between contract path and reality, it can be difficult to ensure the system is capable of meeting the demands placed upon it
- Procedures used to mitigate anticipate or unforeseen overloads are called Congestion Management

Eastern Interconnection - NERC TLR

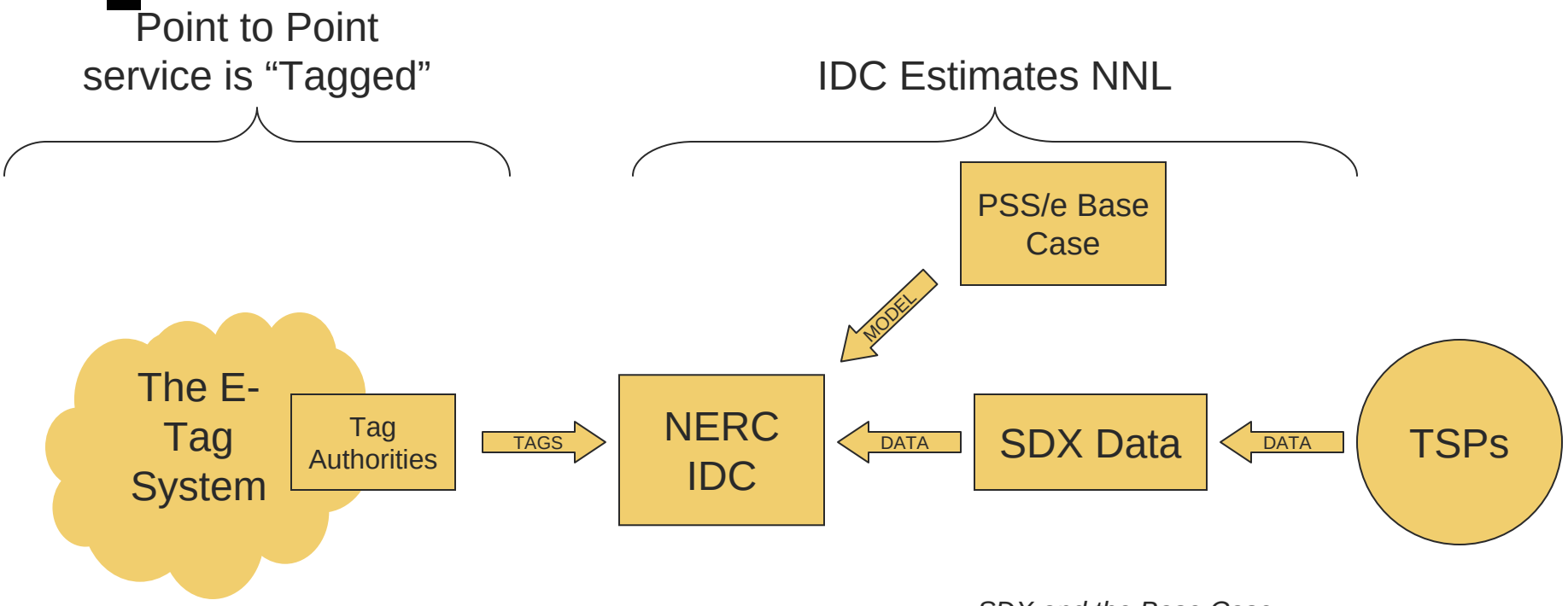
- Marketers write tags that document energy flow from Generator to Load
- Tags are uploaded to the Interchange Distribution Calculator
- The IDC analyzes each tag for impacts on various flowgates using TDFs
- The IDC also analyzes expected NNL flows using GLDFs
- When congestion occurs (TLR), the IDC tells which transactions and flows to cut based on service priority and impact
- As the transactions and congestion change, the IDC tells how to reload and reallocate
- TLR 3 curtails non-firm (priorities 0-6)
- TLR 5 curtails firm (priority 7)

The IDC

- Uses various *Distribution Factors* to estimate relief requirements
- Additional Complexity
  - The IDC looks at *Transmission Priority,* the location of the constraint, the path of the transaction, and numerous other factors when utilizing TDFs for Point-to-Point service
  - Transmission Priority refers to the “firmness” of the service. NERC recognizes 8 levels of firmness:

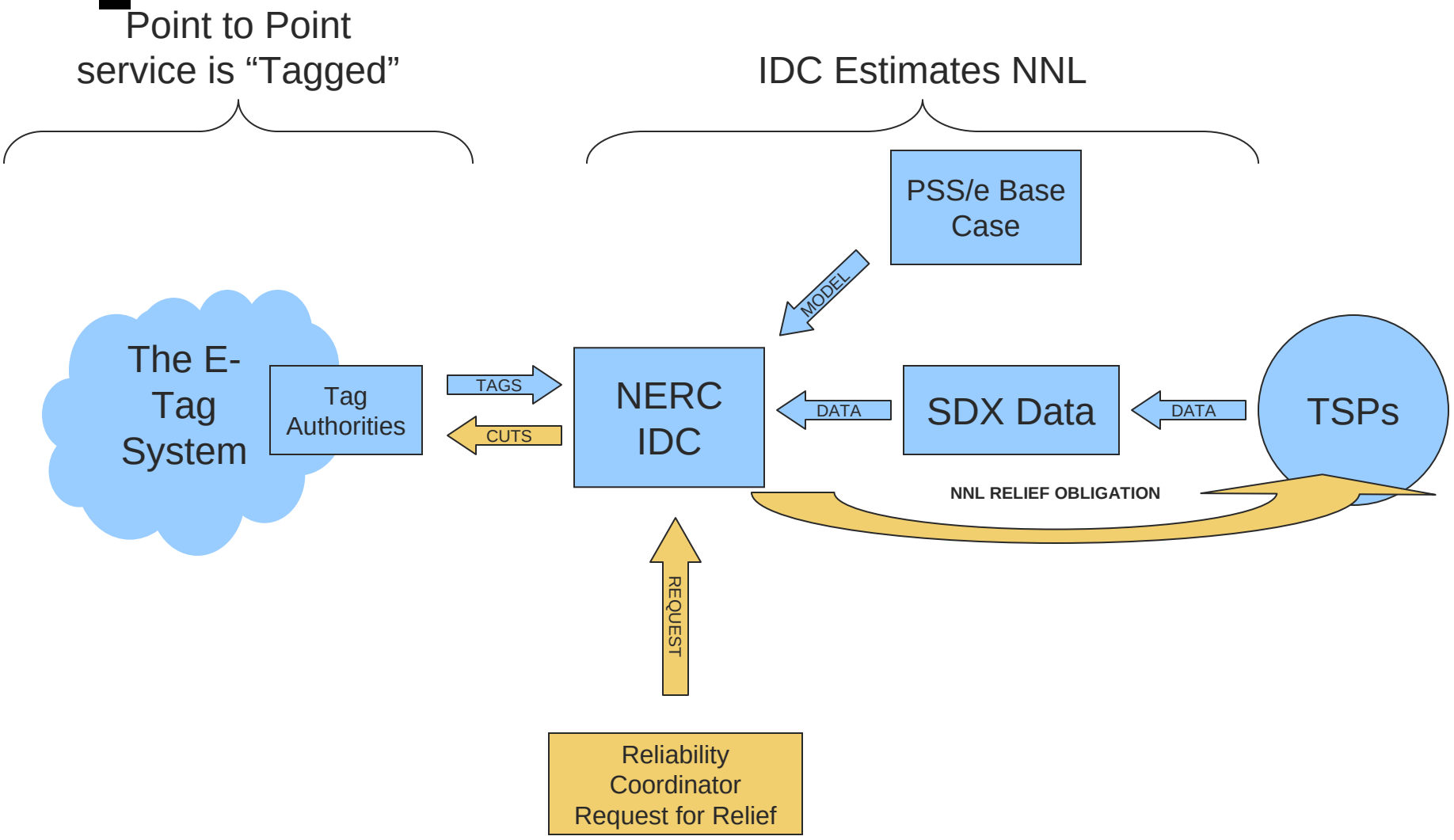
    7-Firm, 6-Non-Firm-Network, 5-Non-Firm-Monthy, 4-Non-Firm-Weekly, 3-Non-Firm-Daily, 2-Non-Firm-Hourly, 1-Non-Firm-Redirected, and 0-Non-Firm-Next-Hour

How TLR Works Today

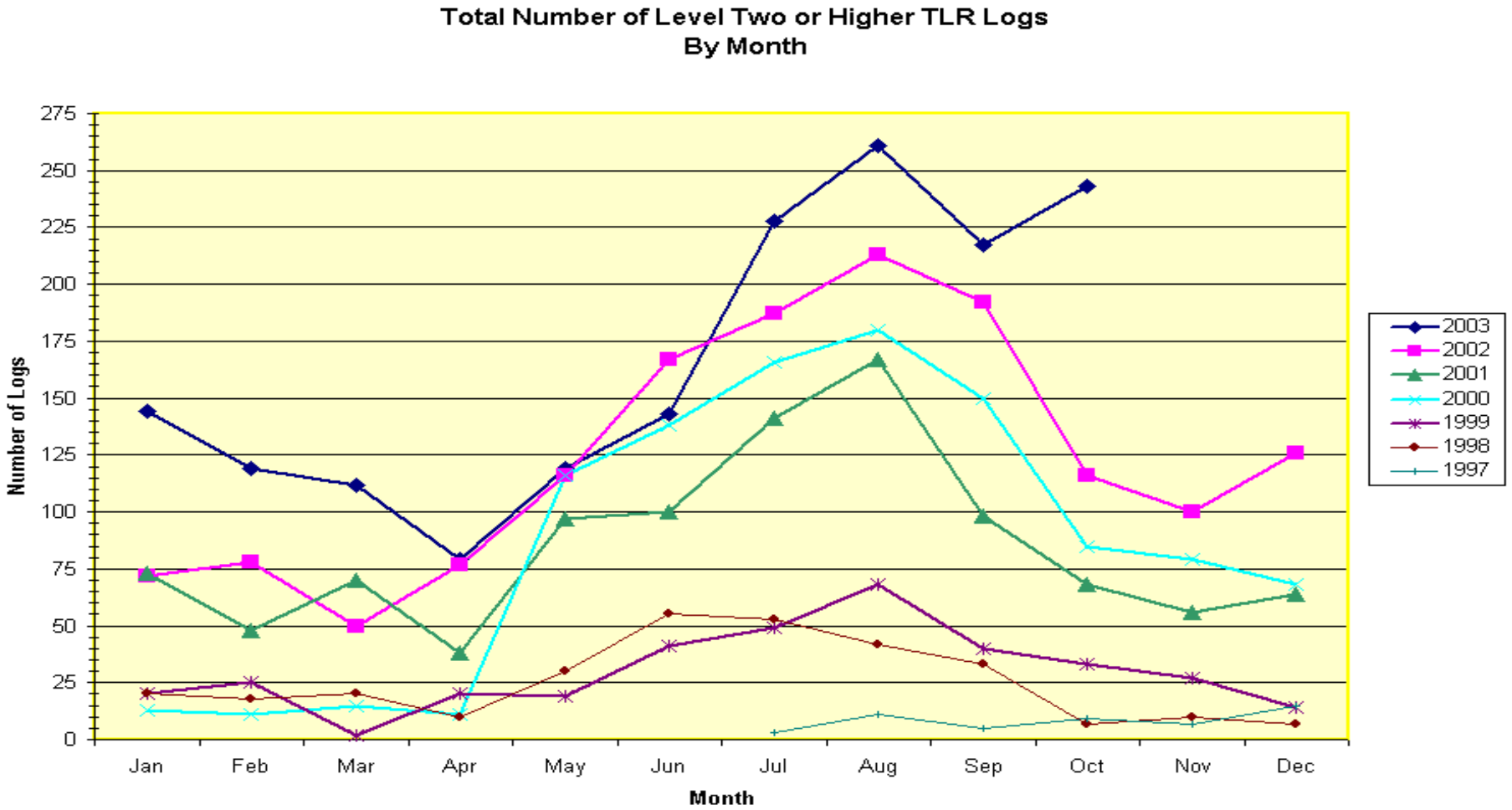


SDX and the Base Case also used to determine PTP Impacts based on tags

How TLR Works Today



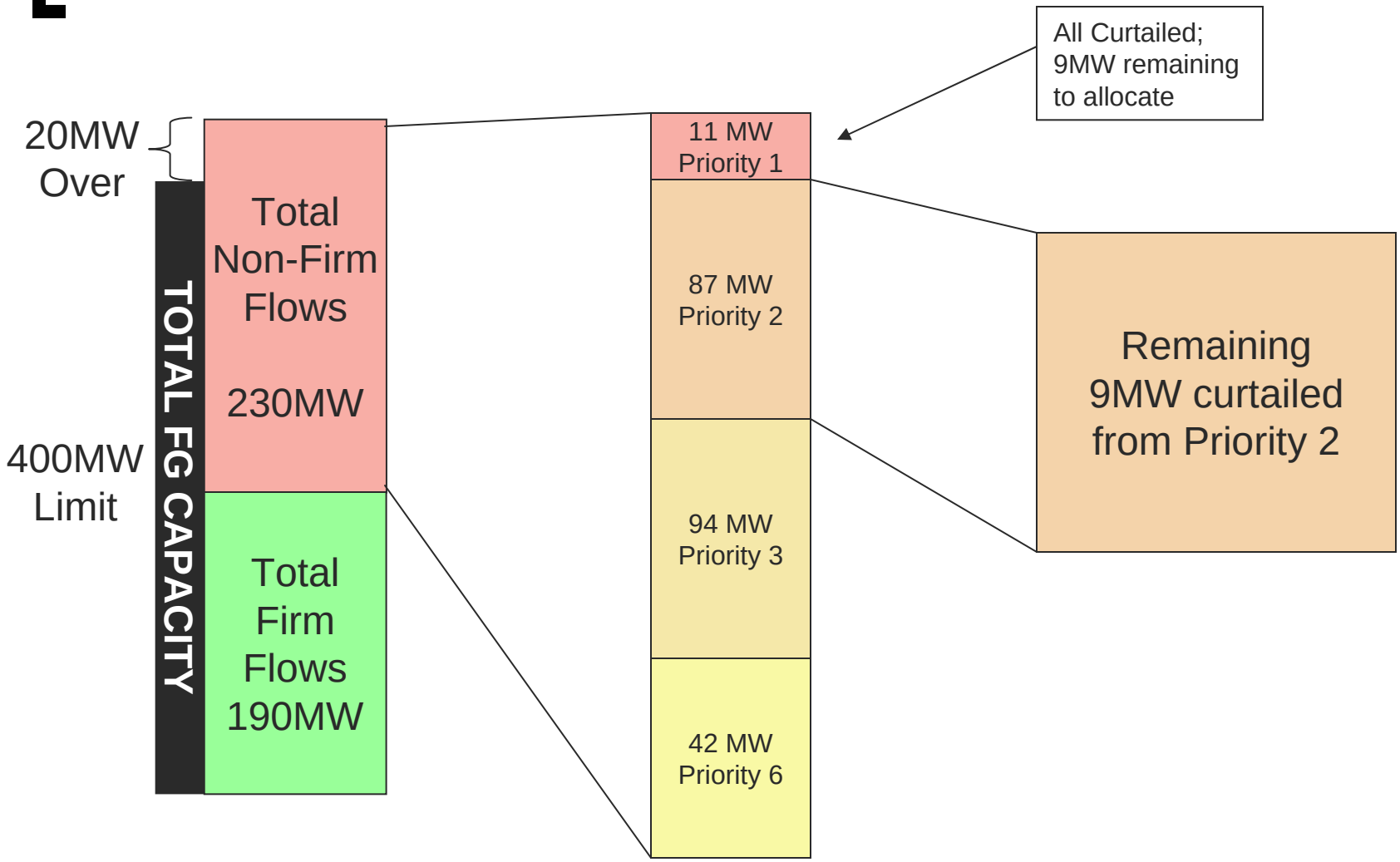
Year Over Year TLR



How the IDC Determines Relief Obligation

- The IDC is given a total relief obligation
- The IDC looks at total impacts
- The IDC allocates the relief obligation on a pro-rata basis per impacts per transmission priority
- If the relief can be provided using non-firm, the TLR stays at a level 3; if necessary, it will escalate to a TLR 5

How the IDC Determines Relief Obligation



The Western Interconnection Unscheduled Flow Mitigation

- Similar to TLR, but without the IDC
  - West is much less densely interconnected, so much easier to determine impact of transaction on a specific path
  - Reconfiguration of Current System
  - Flow Reductions

Some ISO/RTOs Locational Marginal Pricing

- To manage internal congestion problems, some entities utilize centralized markets and Locational Marginal Pricing (LMP)
- LMP fights congestion by incenting generation patterns based on price signals
- Instead of curtailing transactions to alleviate congestion, the RTO makes it uneconomical to create congestion (or lucrative to alleviate it)

Financial Hedging Instruments

- Just as Transmission Priority provides a physical hedge against congestion (firmer service), LMP markets often provide financial hedges (FTRs, TCCs, CRRs, etc…)
- These ensure that the economic signals used to mitigate congestion can be ignored by people willing to purchase “price protection” up front
- Only a fixed amount of Financial Hedges are made available (i.e., capacity is not infinite)
- Offsetting protection revenues are funded by congestion charges to unhedged entities

Post-flow Checkout

- After flow, at end of day and end of month, checkouts are confirmed again to verify what actually flowed
- What actually happened?
  - Cuts
  - TLR Impacts on volumes
  - LD
  - Over/Under Generated Consumed
  - Dispatches
  - Capacity Payments
  - Differences in ISOs, timeframes disputes

Settlements

Accounting processes all data for billing/payment

- Bilateral Settlement
- RTO/ISO Settlement
- Transmission Provider Settlement
- Capacity Auctions

Credit - Before Enron Collapse

- Credit not an issue
  - Everyone was AAA
  - Lots of Players
- Multiple agreements per Counterparty:
  - Energy Master Agreement
  - Capacity or A/S Master Agreement
  - Full Requirements/PPA Master Agreement
  - Coal Master Agreement
  - Natural Gas Master Agreement
- Each Contract could specify credit or collateral requirements
- Some netting
- Some Sleeve deals being done to “help out”
- Contracts had credit rating trigger – seldom used

Credit - After Enron Collapse

- Everyone is concerned about credit
  - Not only fewer AAA rated Companies, but
  - Fewer Companies Marketing Power
- Move to consolidate agreements
  - Reduce credit requirement
  - Reduce collateral posting
  - Help manage cash flow
- Netting Prevalent
- AAA Counterparties no longer sleeving deals for free

Credit - Future Today

- Target - Not Only Netting Agreements, But Cross Commodity Netting
  - Different Legal Entities
  - Coal and Fuel Providers Independent
- Clearing Houses – credit limits and collateral
  - Cross Commodity
  - AND Cross Counterparty
- Major Information Technology Headache - Great to have the agreements in place, how do you implement?
  - Natural Gas -Trade Capture, Accounting, and Scheduling Systems
  - Power - Trade Capture, Accounting, and Scheduling Systems
  - All Ends up in your GL system

Credit With ISOs

- We have discussed the efforts to streamline bilateral settlement and reduce credit requirements
- What About ISOs?
  - Each ISO has its own settlement calendars and credit requirements

RTO/ISO Settlement Timelines

- Midwest ISO
  - TD – 1 thru TD + 1
    - Operational and market data downloaded from loaded from MOS systems
    - Perform shadow settlements
  - TD + 7 Days
    - Settlement Reports and supporting details are available generated by COS
    - Composed of a at least 3 XML file containing all required data
- PJM
  - TD – 1 thru TD + 5
    - Operational data downloaded from PJM systems
    - “Preliminary” statements for ancillary services available for downloading
    - Market information available from PJM website
    - Perform shadow settlements
  - Next Month + 5-6 Business Days
    - Invoice, Settlement Statements, and supporting details are available for download.
    - Composed of 12+ files per day

RTO/ISO Settlement Timelines

- NY
  - TD – 1 thru TD + 3
    - Operational and market data downloaded from loaded from NY ISO systems
    - Perform shadow settlements
  - TD + 3 Days
    - Settlement Reports and supporting details are available.
    - Composed of a two .csv files containing all required data
    - Endless true ups

Final Settlement

- Final Settlements Posted
  - CA – 60 business days, disputes continue
  - ERCOT – 6 months, disputes continue
  - MISO – 55 days after flow
  - PJM – 60 days after flow

Day in the Life

- Questions?

Where We Are Today

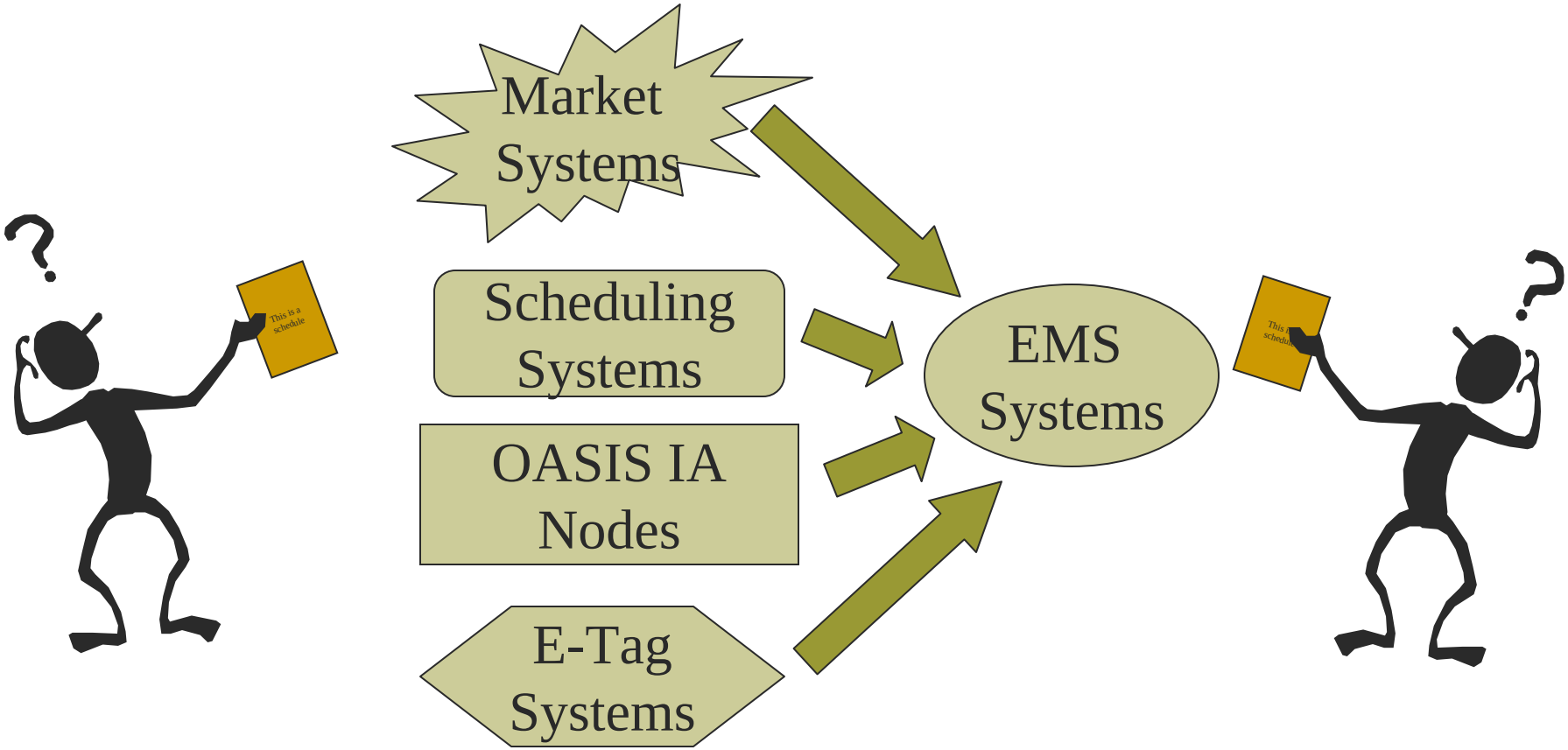
- General concern that existing process are unwieldy
- Conflicting business rules between regions introduce inefficiencies, or “seams”
- Industry Initiatives
  - OASIS Phase II
  - NERC/NAESB Transition
  - The NERC Functional Model
  - NERC Standards Development
  - RTO/ISO Seams Coordination Activities
  - IDC Granularity Changes

OASIS Phase II and Electronic Scheduling

- NERC started developing ideas through Industry Forums and Working Groups
- Now being led by NAESB, due to market impacts
- Goal – allow customers to directly request both Energy and Transmission schedules through one consistent interface

Current Process

- Several components:



Current Process - Flaws

- This process is burdensome to the marketplace, as there is no “simple” way to transact business
  - Each provider may have their own systems to deal with
  - Longer transaction become increasingly complex
  - Overhead and associated risk make the transaction “not worth the trouble”

Current Process - Flaws

- This process is prone to errors, because it relies on linking these systems together manually (they were not designed to be linked)
  - Tags use OASIS Numbers, Contract Refs
  - Reservations may be tied to Tag IDs
  - Contracts may be tied to other Contracts
  - Scheduling Systems may be tied to tags
  - Etc…

Current Process - Flaws

- Timelines - Existing inconsistent trading and scheduling timelines between gas and power make it impossible to unwind/enter a position

OASIS Phase II

- Intention is to develop a robust platform that can be easily integrated into enterprise systems
  - EMS Systems
  - Market Systems
  - Transmission Auctions
  - Scheduling Systems
  - Position Management systems
  - Deal Blotters
  - Billing and Settlements Systems

NERC/NAESB Transition

- As NAESB grows, NERC will transition its market-based components to NAESB
- Still discussion on the best approach for this transition

NERC Functional Model

- Redefining traditional model of “CA, TP, PSE”
- Defining functional responsibilities, then certifying entities on their ability to meet that responsibility
- Ideally, will help delineate boundary between market and reliability

NERC Standards Development

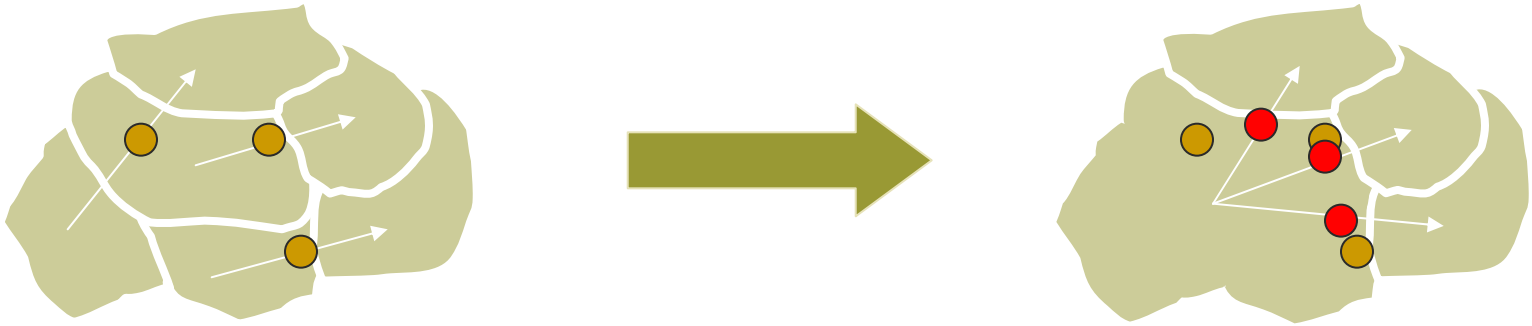
- As transition is occurring, NERC is rewriting existing policies to be “reliability focused”
- New documents will be measurable standards
- Will only focus on measurable reliability criteria – not process or rules, just results

RT/ISO Seams Coordination Activities

- Inter-RTO Council
- Regional Seams Agreements
  - MISO/PJM JOA
    - Reciprocal Agreements
  - PJM/MISO “Joint and Common Market”
  - WECC SSGWI

IDC Granularity Weakness

- IDC is based on “Control Area” model
- For historic system, this is acceptable – historic CA configuration is small enough to where granularity is not a problem
- Growing RTOs lead to larger CAs, and granularity becomes more and more coarse.



3 Transactions

6 CAs

Easily identified impacts

Same Transactions

Only 3 CAs

Impacts are shifted due to CA Expansion

IDC Granularity Weakness

- Plans to change IDC
- Focus on determining wide area relief obligation
- No more reliance on tags – just on generator output, system load, and network topology
- RTOs would be told to provide relief – but not obligated to do so in any specific way
  - TLR-style Curtailments
  - Centralized Redispatch
  - Load Shedding

Conclusion

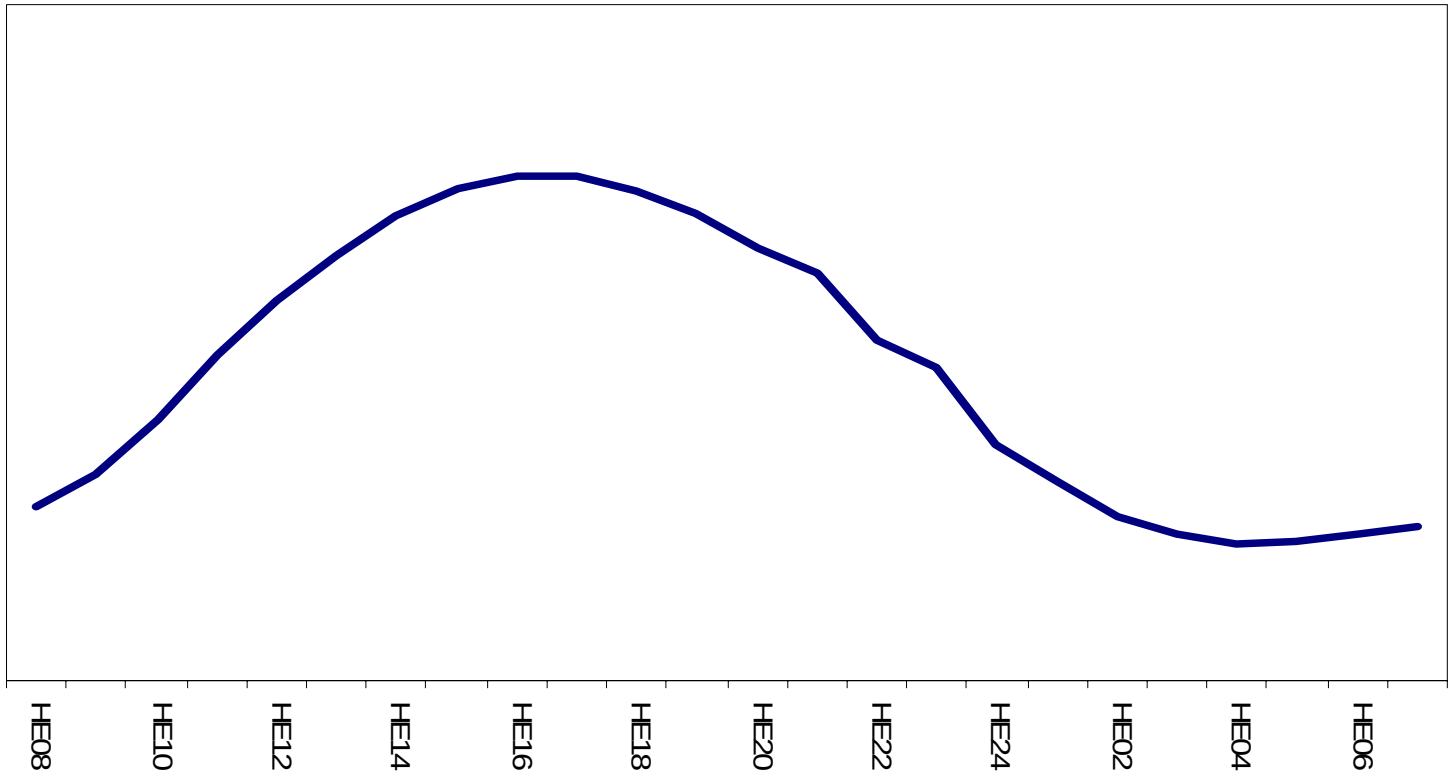
- Power is complex
- In general, standardization (where appropriate) will help
- Cross Commodity Standardization (where appropriate) will help
- NAESB, NERC, and Industry efforts are underway to mitigate inefficiencies

Questions?

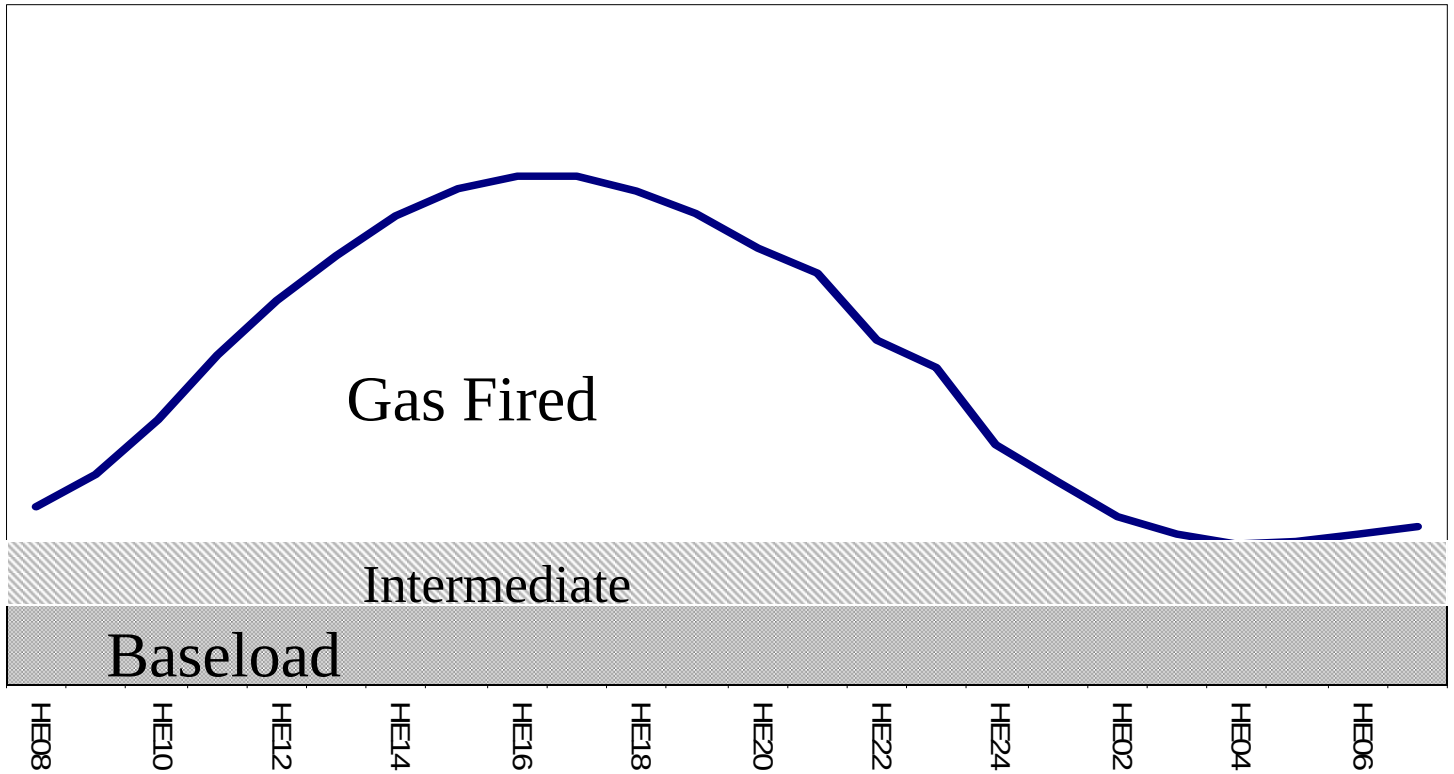
Generation Dispatch 101
GECTF

Diane McVicker
Salt River Project
January 30, 2004

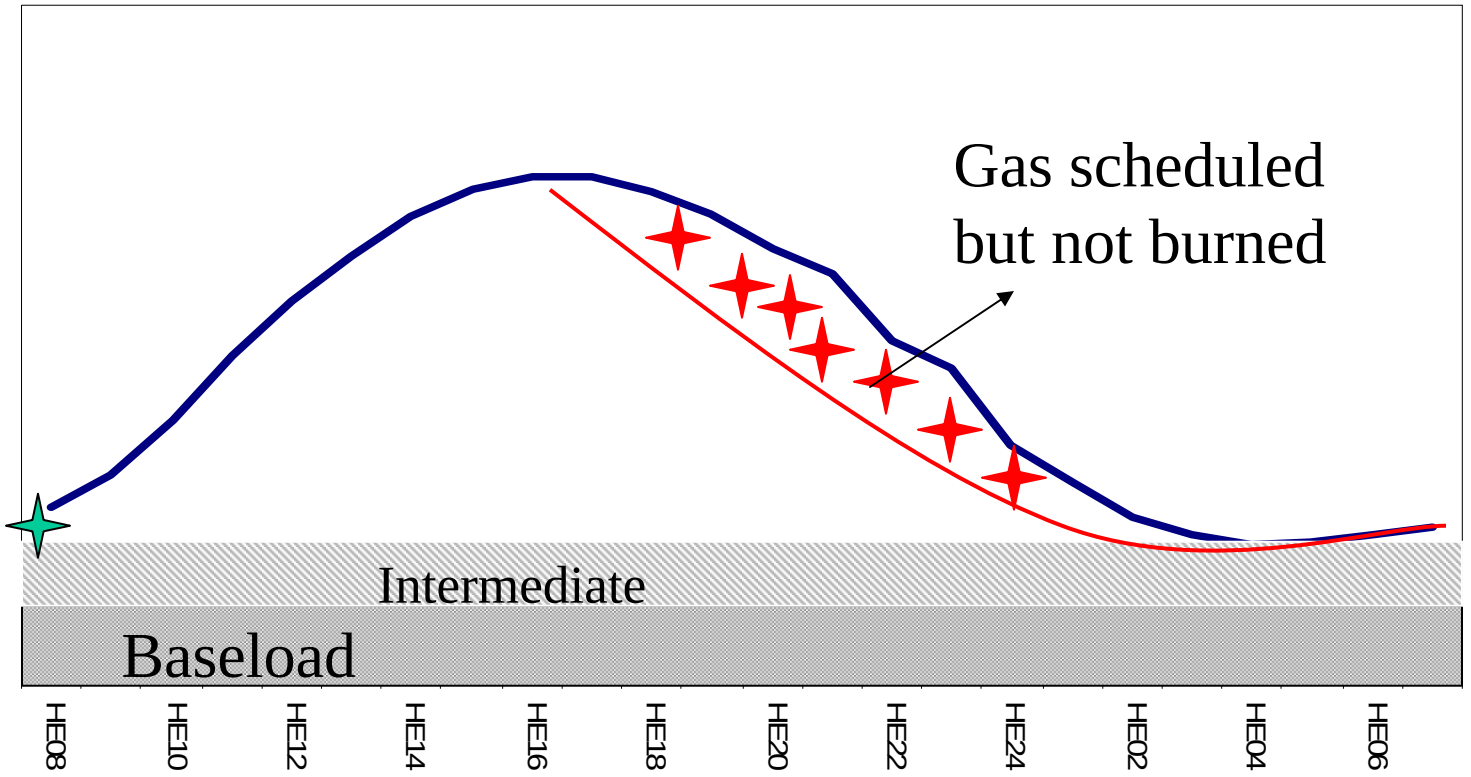
Load Forecast
Summer, Day Ahead



Dispatch Order
Day Ahead Plan



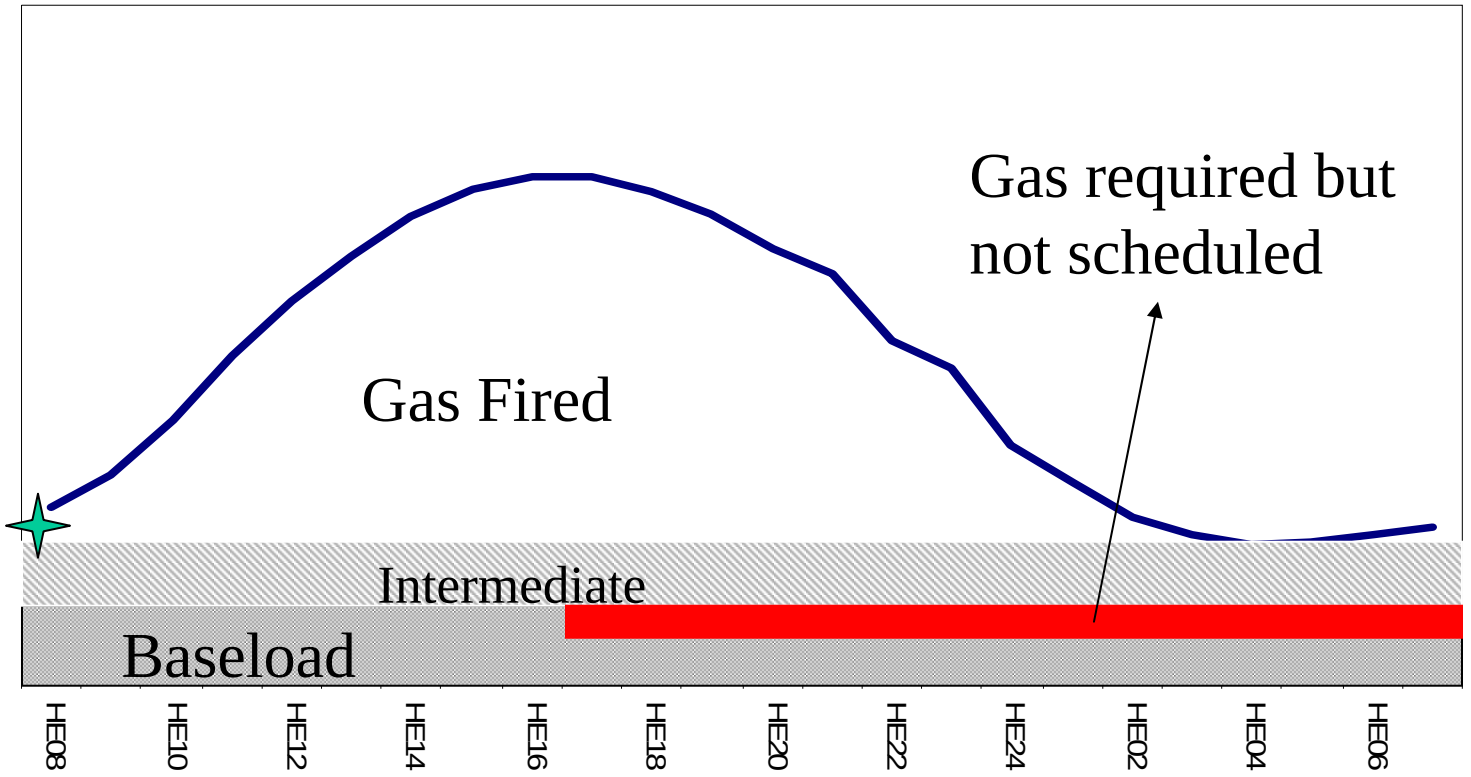
Changes Due to Loss of Load



Schedulers compare daily load projection with day ahead and make adjustments as necessary using intraday nomination cycles.

Loss of load requires schedulers to try to divert gas to other markets or storage

Changes Due to Increase in Load



Schedulers compare daily load projection with day ahead and make adjustments as necessary using intraday nomination cycles.

For increases in load, schedulers try to divert gas from other markets or storage; usually requires adjustments to next day gas schedules

Important Concepts

- Electric utilities have 10 minutes to match generation to load
- Gas fired generation is usually the resource used to match sudden changes in load, at least in the short term
  - Shortest lead time to “come on line”
  - Other resources are already at maximum load

A Member of the
Constellation Energy Group

Constellation Energy Group

A Retail Electric Perspective on Billing and Settlement

Presented to the NAESB GECTF

by Ed Berman

January 2004

Importance of Hourly Accounting In The Context of Wholesale-Retail Interaction

- Two market transactions are valued based on hourly patterns of retail megawatt-hour usage
  - Wholesale supply of retail customers settled by the regional pool
  - Wholesale supply of local distribution companies billed out by the wholesale supplier
- Both transactions rely on **hourly** electric usage data to "price up" the value of the supply
- Both transactions are settled, explicitly or implicitly, by real time accounting of hourly usage on a day-after basis (and sometimes day-ahead basis)

Transaction 1: Wholesale Supply of Retail Customers Settled By The Regional Pool

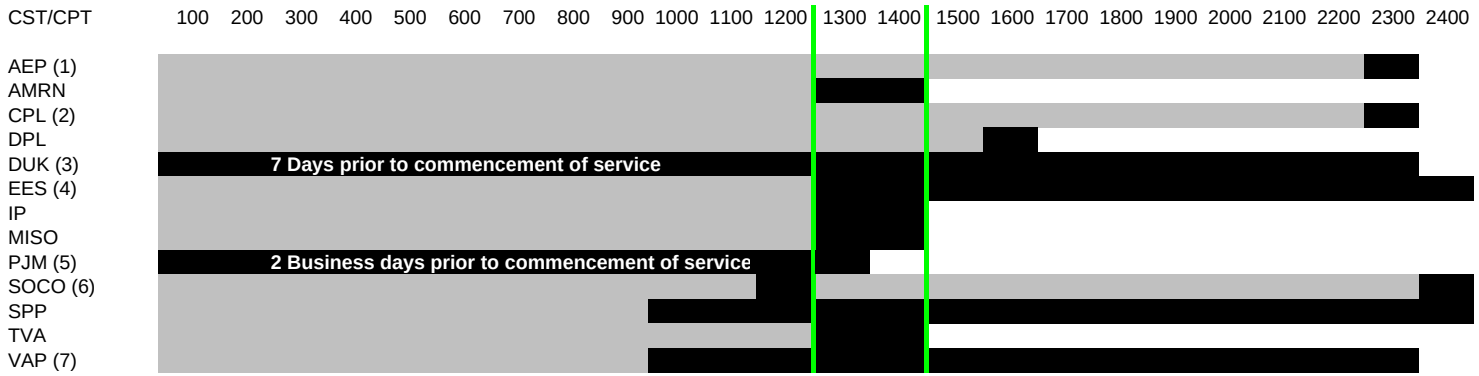
- PJM LDCs “settle” the wholesale supply of retail customers by estimating and reporting hourly usage values for each supplier to the regional pool
- Load estimation and reporting is a data- and time-intensive process performed each day
- Firm deadlines (12 Noon at PJM) require daily settlements organized around a “day after” template
- The settled hourly load values are used by the regional pool to ensure that the monthly bill generated to each participating wholesale supplier accurately accounts for supplier load responsibility

Transaction 2: Wholesale Supply Of LDCs Billed Out By The Wholesale Supplier

- Wholesale suppliers bill the LDCs
  - This **billing is often based on the same hourly usage accounting** described under Transaction 1
- **Settled hourly usage should match the system load** served by the supplier; energy, capacity, transmission, and ancillary **charges should balance with daily power pool accounting**
- **The main point**: the time-sensitive, daily settlement of hourly load values on a day-ahead basis are used to ensure correct accounting for all wholesale-retail market interactions (energy, capacity, transmission, and ancillary)

Transmission Timing Analysis

Daily Firm P/P



AEP (1)

Acceptance of reservations with limited notification time prior to the start of the service, may be accommodated provided the System Operators have sufficient time to complete all arrangements with all parties involved in the transaction prior to the start of service

CPL (2)

within negotiated time frame
In order to implement interchange schedules, tags must be accurate, complete, and time-stamped no later than 20 minutes prior to the start of the schedule.

DUK (3)

7 days prior to service start
In order to implement interchange schedules, tags must be accurate, complete, and time-stamped no later than 20 minutes prior to the start of the schedule.

EES (4)

New schedules or schedule changes must be submitted no later than 20 minutes prior to start. New schedules or schedule changes received after the twenty minute deadline will be deemed LATE and will be denied for anything other than emergency reliability reasons

PJM (5)

no later than noon, 2 PJM business days prior to the commencement of service
Pre-Scheduled Real-Time Transactions, (i.e. those transactions that will receive the Real-time LMP), must be submitted to the PJM OI by 1400 EPT (1200 on non-business days) of the day before the Operating Day Pre-Scheduled Real-time with Price Transactions, must be submitted to the PJM OI by 1200 noon EPT of the day before the Operating Day. These transactions are analyzed identically to unit-specific resources. For this reason, they are not permitted to change after 1200 noon EPT of the day before operations

SOCO (6)

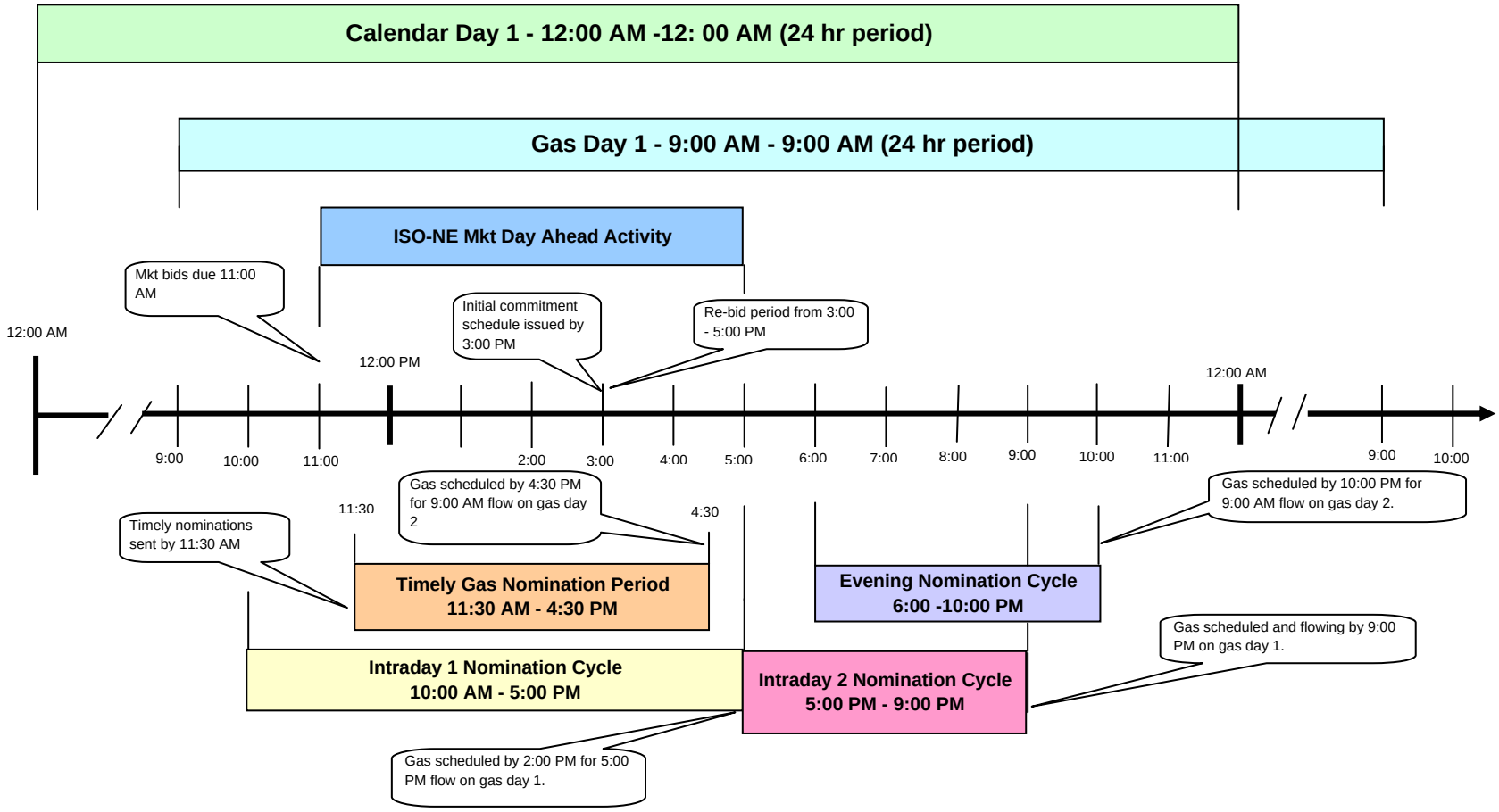
Reservations for the Transmission Customers Firm Point-To-Point Transmission Service must be submitted to the Transmission Provider no later than 12 noon of the day prior to commencement of such service. Reservations submitted after 12 noon will be accommodated if practicable
In order to implement interchange schedules, tags must be accurate, complete, and time-stamped no later than 20 minutes prior to the start of the schedule.

VAP (7)

not later than day ahead by 10:00
Schedules for the Transmission Customers Firm Point-To-Point Transmission Service must be submitted to the Transmission Provider no later than 10:00 a.m. of the day prior to commencement of such service. Schedules submitted after 10:00 a.m. will be accommodated if practicable

Disclaimer: This document is for comparative purposes only. The information herein is the interpretation of Tariff filings and actual business practices, and is not intended to be an official representation of service timings.

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. ISO New England (ISO-NE) market used for comparison. Timing information taken from ISO-NE Market Rule 1.

Created March 8, 2004

Market Timing Issues

WEQ Market Operations Subcommittee / Electric Trading Task Force ****** For Discus**

2/27/03 - Draft #2 ****** For Discussion Purposes Only **********

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

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

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

(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). Market clearing prices for the four ancillary services markets are published. Replacement Reserve clearing prices posted at 4:30 PM.

(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*

sion Purposes Only****

IMO		PJM		MISO	
HB		HE		HE	
0:00		0:00		0:00	
24:00		24:00		24:00	

IMO		PJM		MISO	
EST	CST	EST	CST	EST	CST
N/A	N/A	12:00 PM	11:00 AM	12:00 PM	11:00 AM
N/A	N/A	4:00 PM	3:00 PM	4:00 PM	3:00 PM
N/A	N/A	4:00 PM - 6:00 PM	3:00 PM - 5:00 PM	4:00 PM - 6:00 PM	3:00 PM - 5:00 PM

IMO		PJM		MISO	
120 minutes**				20 minutes	
every 5 minutes		every 5 minutes		every 5 minutes	
Ex-ante				Ex-post	

SPP		CAISO (e)		ERCOT	
		HB		HB	
0:00		0:00		0:00	
24:00		24:00		24:00	

SPP		CAISO (e)		ERCOT	
CST	CST	PST	CST	CST	CST
see note (d)	see note (d)	9:30 AM	11:30 AM	4:30 PM	4:30 PM
see note (d)	see note (d)	11:00 AM	1:00 PM	1:30 PM (c)	1:30 PM (c)
see note (d)	see note (d)	11:00 AM - 12:00 PM	1:00 PM - 2:00 PM	4:30 PM until beginning of Hour Ahead period	4:30 PM until beginning of Hour Ahead period

SPP		CAISO (e)		ERCOT	
see note (d)		30-45 minutes		5-10 minutes	
see note (d)		45 minutes		60 minutes	
see note (d)		every 10 minutes		every 15 minutes	
see note (d)		Ex-post		Ex-post	

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Section V: Comments Submitted on Interim Status Report