Investigation of New England
Gas-Electric Market Events
January 13-16, 2004

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Investigation approach

- Initiated January 14 after gas prices spiked
- Coordinated with ISO-NE market monitor, Connecticut Attorney General, CFTC
- Requested data from Northeast LDCs, ISO-NE, Intercontinental Exchange, generators, gas marketers, pipelines
- Interviews with generators, LDCs, marketers, pipelines, state PUCs, market monitors
- Analyzed:
  1. How well did market mechanisms function in matching supply and demand?
  2. Did participants behave competitively and comply with the market rules?
  3. What lessons were learned from market operations under stress?

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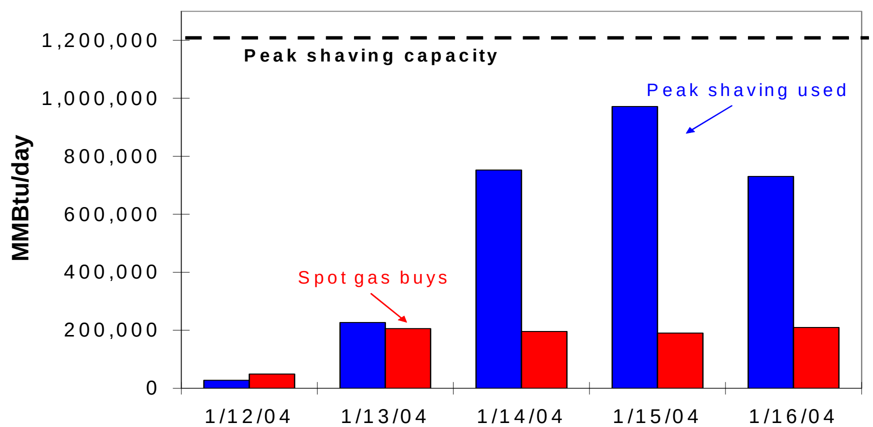
Overview of FERC Findings

- **Natural gas market responded well under stress.**
  - Delivery system ran at capacity, spot market supply was short, but all firm users got gas.
  - Spot prices, driven by short positions, reached record levels, determined in part by penalties
  - Market mechanisms worked to allocate supply to the highest value uses.
  - Customers' effects were minor. Gas spike added an estimated 2-3% to customer monthly bills.
  - Generator sales of fuel gas were critical to meeting heating needs.
  - Integration of U.S. and eastern Canadian gas markets suggests the need for a broader regional infrastructure assessment.
- **Electric market players followed the rules and kept the lights on.**
  - No service interruptions, all load served
  - Customers largely insulated from power price spikes in spot market due to forward contracting
  - Gas sales by generators complied with market rules
  - Price spike was not the result of physical or economic withholding or manipulation
  - No misbehavior or exercise of market power
- **Electric market performance under gas supply stress points to areas for further policy and market design review**
  - Gas-fired power needed but electric market price cleared below marginal cost of gas-fired generation.
  - Under-scheduling in day-ahead market increased dependency on the supply-short real-time market. Under-scheduling does not appear to be intentional.
  - Gas and electric commitment timelines exposed generators to commitment timing risks.
  - ISO dispatched high cost gas-fired generators out-of-merit for reliability purposes without raising the market clearing price
  - Public service announcements may have led to helpful conservation, but blackout warning may have caused unnecessary alarm.

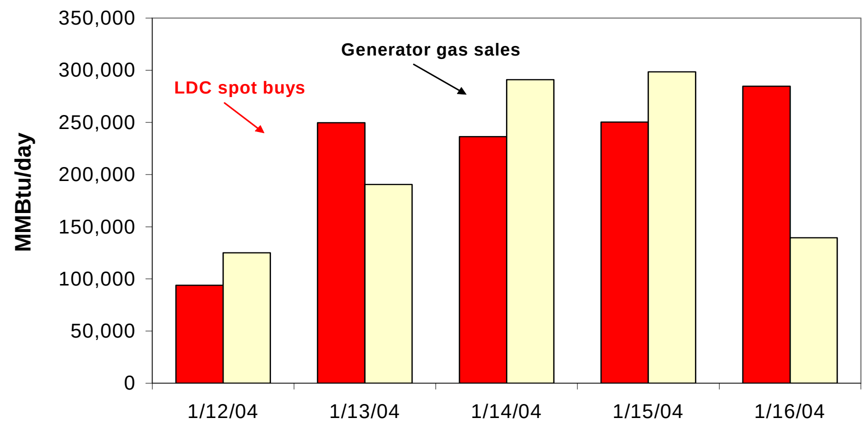
Gas market hit its capacity limit

- **Pipelines into New England and eastern Canada region were full**
  - Algonquin, Tennessee at capacity
  - TransCanada full into eastern Canada
  - Iroquois and Portland not full due to high demand in eastern Canada
  - Maritimes not full due to Sable Island production problems
  - No withholding, full contract demand served
  - Critical notice procedures limit flexibility, raise penalties
- **LDCs exceeded design heating degree days**
  - Pipeline and storage fully scheduled
  - Spot gas supplemented peak shaving to protect inventory
  - Paying premium spot price costs less than year-round pipeline capacity
  - 210,000 MMBtu/day x $0.50 x 365 = $38.3 million
  - Added cost for week $10.7 million (avg. spot of $21 vs. $8 base)
  - Generator gas sales roughly equal to LDC spot buys

LDCs pulled hard on peak shaving



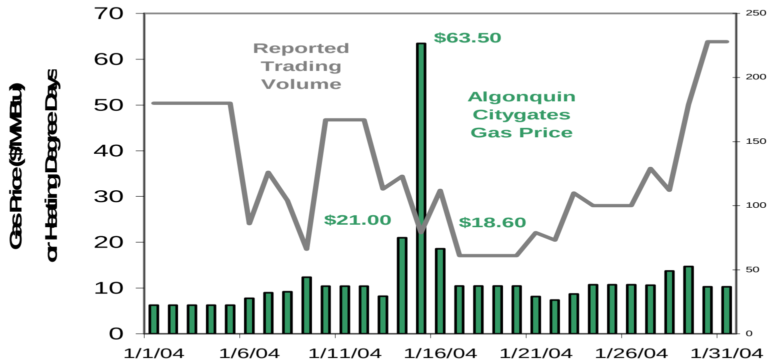
Generator gas sales were key to serving heating demand



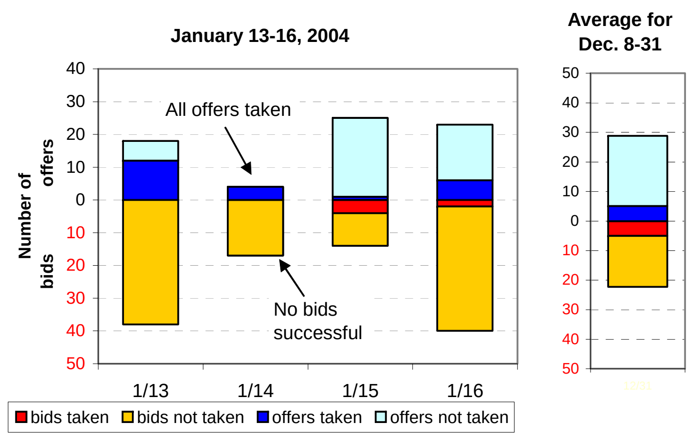
No manipulation found in gas market trading

- Gas spot prices spiked on heavy demand, low supply. January 15 price averaged $63, a few trades as high as $75/MMBtu.
- No indication of supply or capacity withholding.
- Supply down due to Sable Island production problems, high demand in eastern Canada.
- When demand exceeded limited spot gas supplies, spot prices spiked reflecting buyers' valuation to fill out a supply package, avoid imbalance penalties, and avoid draining peak shaving inventory.
- Seller offers were all taken regardless of price; no bids to buy at lower prices were successful.
- No indication of unusual trading patterns or concentrations Largest seller on ICE had an 11% market share.
- Trades indicated a demand-driven market with buyers scrambling to cover short positions.

New England gas spot market hit record high prices



On January 14, Algonquin city gate trading on ICE was driven by buyer demand

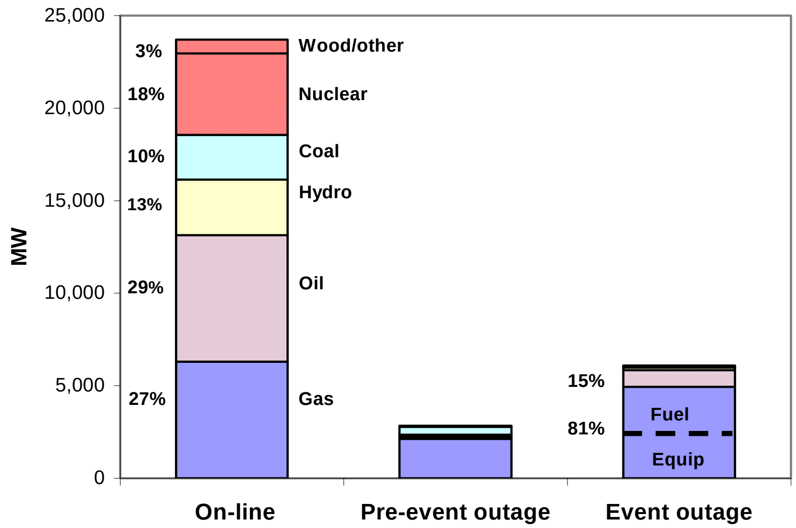


Electric market struggled to deal with market and weather conditions

- Record winter power demand exceeded forecasts.
  - January 14 peak load of 22,419 MW exceeded forecast by 444 MW
  - January 15 peak load of 22,817 MW set winter record
  - Blackout warning January 15
  - All load served despite slight reserve deficiency on January 14
- Generators couldn't afford risk exposure.
  - Risk of buying gas before power schedule too much for financially stressed generators
  - Imbalance penalty risks under restricted pipeline flexibility
  - Some declared economic outages and sold firm gas after approval by ISO
- Energy market clearing price was below gas-fired marginal cost.
  - Day-ahead prices limited by load price bids
  - Day-ahead clearing price were set before full outage levels were apparent
- ISO out-of-merit dispatch was needed to maintain reliability.
  - Market failed to attract sufficient gas-fired generation
  - Administrative solution back-stopped market, but did not send an accurate price signal

- Mechanical and fuel-related reached 8,927 MW
  - 36 percent of outages were fuel related of which 81 percent were gas-capable units
  - Half of fuel outages involved generators selling firm gas into the spot market
  - Gas still served 27% of load
  - ISO-NE has investigated these outages in depth
- Some dual fuel units couldn't burn oil due to emissions permit restrictions

Gas served 27% of load, but dominated outages January 14



Power market did not signal gas would be needed
Risk and price imbalance undermined supply certainty

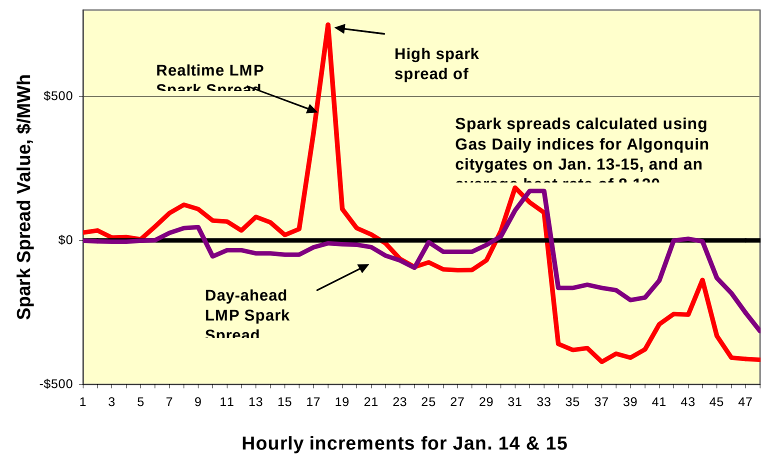
- Fuel cost and commitment timing exposed generators to high risks.
  - Gas purchased by 10 am, power offer at 12 noon, power award at 4 pm
  - Risk of being stuck with high cost gas if offer not selected in day-ahead market
  - Real-time dispatch uncertainty forces reliance on higher cost, illiquid intra-day gas market
  - Pipeline constraints limit ability to respond to real-time dispatch
- Day-ahead market didn't send price signal that gas-fired generation would be needed.

	Gas price $/MMBtu	Fuel cost $/MWh	DA price $/MWh
Jan 14	$21.0	$168	$113
Jan 15	$63.5	$508	$316
Jan 16	$18.6	$149	$145

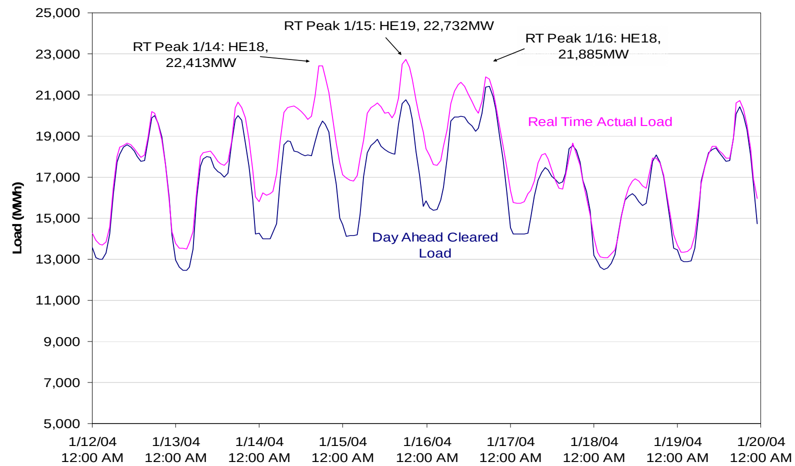
*8,000 Btu heat rate

- Real time market price hit $920/MWh Jan 14, but only for one hour
- Day-ahead under-scheduling due to low load bid prices increased dependence on real-time market when it was least able to respond.
- Sale of gas made business sense given the lack of a market signal, lack of advance commitment by load, and economic risks.

Spark spreads were negative for most hours



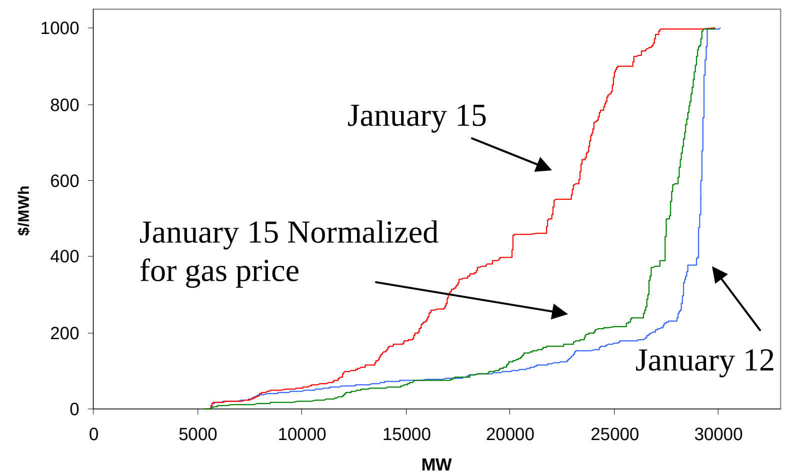
Under-scheduling day-ahead increased reliance on real-time market



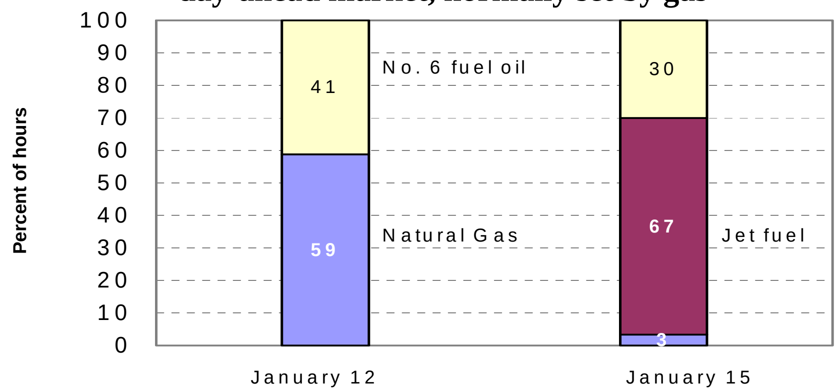
Generators bidding behavior does not appear manipulative

- Significant shift in market supply curve on January 15 resulting from higher energy offers from both natural gas and non-gas fired generators
- Normalizing supply offers by natural gas cost explains majority of divergence between January 15 and selected reference day, January 12
- High gas-related bids and outages did not influence the market clearing price
- Non-gas units account for the remaining divergence
  - Some hydro pondage, pumped storage, and No. 6 oil units increased their offers relative to Jan 12 and set energy clearing prices for some hours.
  - Some oil bids were above marginal cost but were not high enough to trigger price mitigation

High Natural Gas Price On January 15 Explains Majority Of Change In Supply Curve



January 15 oil units set clearing price in day-ahead market, normally set by gas



Marginal Price Setting by Hydro & No. 6 Oil

	Day-Ahead Market		Real-Time Market	
	% Hours	LMP ($/MWh)	% Hours	LMP ($/MWh)
Hydro	None	N/A	11%	$100 - $389
No. 6 oil	30%	$148 - $373	34%	$54 - $373

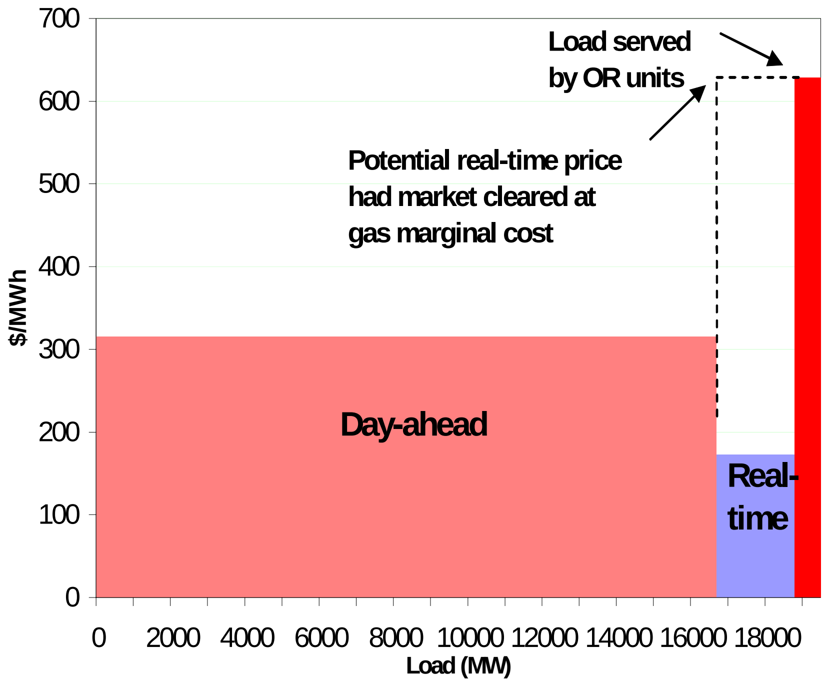
No evident rules violations in generators' sales of natural gas

- Sale of gas supply is permitted by ISO-NE rules
  - "Participants may make decisions affecting the availability of a Resource for reasons relating to the economics of operating that Resource. Such decisions may include, but are not limited to, sale of gas available to the Participant as fuel for such Resource . . .so long as it provides the ISO timely information that accurately describes the nature of the Participant's decision."
- Generators notified ISO-NE of decision not to generate for economic reasons
- Subject to recall by ISO-NE, generators are free to maximize return from their assets
- FERC Market Behavior Rules emphasize following organized market rules
  - "seller's compliance with Market Behavior Rule 1 … should be sufficient to meet a seller's obligations concerning bidding … absent seller's participation in manipulative conduct."
  - To find manipulation, generators' actions must be (1) without a legitimate business purpose and (2) intended to, or foreseeably could, manipulate market prices

How did customers fare?

- No electric service interruptions, all firm gas load served
- Gas spot market functioned well in reallocating supply to heating customers
  - Limited effects on bills, spot gas was only 5 percent of LDC supply Jan 12-16
  - Gas sales by generators helped meet heating load, preserved peak shaving supply
  - Spot gas cost, while high, was less than cost of new pipeline capacity used only on peak
- Electric market clearing prices set by non-gas offers, mostly oil
  - Gas units used for reliability reserves rather than for real-time energy market
  - 671MW out-of-merit dispatch at $628/MWh
- Out-of-merit dispatch saved customers money
  - Had these generators been dispatched through the real-time market, it would have cleared at the marginal cost of gas
  - Lower clearing prices reduced intra-marginal generator income
  - Long-term impact of lower generation income not clear

Operating reserve units dispatched out-of-merit covered peak load, but didn't set the market clearing price
January 15



Recommended follow-up

- Explore changes in winter peak electric planning to better anticipate the competing demands for gas for power and for heating.
  - Non-gas backup fuel sources would improve service reliability, avoid high, gas-driven market clearing prices during winter peaks
- Work to increase flexibility in air emissions rules to allow oil units to run for electric system reliability when gas supply is in short supply
- Determine if changes in power market pricing mechanisms and timelines are can allow the power market to better respond to volatile gas market prices.
  - Coordinate day-ahead bidding with gas commodity trading
  - Limit under-scheduling during winter peak periods
  - Advance timeline for operating reserve commitment to reduce gas supply risk
- Review the effect of gas imbalance penalties in managing gas markets.
- The ISO should assess relying more on market mechanisms and less on “out of market” reliability measures to assure sufficient real-time supply.
- PUCs and ISO-NE should work together to prepare public service announcements when needed to urge conservation without causing undue alarm.