ISO New England
State of the Market Report 2004

NEPOOL Annual Meeting
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Presentation Overview

• Benefits realized over 5 years of markets
  – Markets were competitive throughout 2004
• Cold Snap conditions impacted markets
• Low loads from mild weather
• Prices reflected competitive markets
  – Overall energy costs similar to 2003
  – Fuel costs up, driving energy costs
  – Uplift and ASM costs up
• Generator availability improving
• Forward Reserve Market new in 2004
• Challenges Ahead
  – Need incentives for new entry
• Increased curtailment by Demand Response resources
  – More enrollment needed
Updates From Last Year’s Meeting

• Suggestions from participants were added into the 2004 Annual Markets Report
  – Report analyzes Renewable Portfolio Standards relative to installed capacity
  – Report discusses each of the OP4 events during 2004
  – Report covers information on capacity delisting by load zone
  – Report incorporates a section on ISO operations
    • Specifically market-rule enhancements and audits
  – Report includes a calculation of monthly implied heat rates
2004 Is 5th Full Year of Market Operations

• Over that time, some important improvements:
  – 9,480 MW of new, clean, generation
  – Average heat rate of oil and gas units has declined by 5.6%
  – Unit availability has increased from 81% to 88%
  – Fuel Adjusted spot prices have decreased 5.7%
  – Improved regulation performance has decreased requirements by 29%

• Market enhancements led to efficiencies
  – SMD in 2003
  – Biggest change in 2004 was introduction of Forward Reserve Market

• Resource Adequacy solution (LICAP) still needed
Biggest Test for Markets in 2004: January Cold Snap

• Stressed New England energy infrastructure
  – Markets generally operated well
• Analysis of period led to numerous improvements
  – Improved information exchange between the ISO, gas pipelines and electricity market participants
  – Additional dual-fuel operating flexibility
  – Revised market timing under extreme conditions
• On-going work
  • LMPs need to consistently reflect marginal needed resources
    – 2005 results much improved
  • Need increased availability incentives
Load Profile

• Low summer loads
  – Summer peak was 2.3% lower than 2003
  – Annual total load was 1.3% higher than 2003

• Mild summer weather in 2004
  – Peak days had far less impact on average prices than year with normal weather due to absence of severe price spikes
    • 2003 had a similar pattern

• Only 2 hours when actual loads exceeded 24,000 MW
  – Compared to 19 hours in 2003 and 34 hours in 2002

• There were 177 hours when loads exceeded 21,000 MW
  – Compared to 200 hours in 2003 and 263 hours in 2002

• Overall, load is growing
Energy Prices in 2004

• 2004 price levels generally similar to 2003
• More price spikes than in 2003, and fewer than in 2002 and 2001:
  – Real-time prices exceeded $500 in 3 hours, compared to 1 hour in 2003, 4 hours in 2002 and 15 hours in 2001
  – Infrequent price spikes primarily due to milder summer weather and relatively robust capacity margins
• Scarcity pricing provisions not triggered
• Day-Ahead Hub prices $1.59/MWh higher than Real-Time prices
• High percentages of Real-Time load obligations for all load zones cleared in Day Ahead Market
  – 92%-100% (Maine to SEMA)
Comparison of Higher-Priced Hours

System Price Duration Curves, Prices in Most Expensive 5% of Hours
2001-2004

Energy Price ($/MWh)

Percent of Hours

2004 Average Nodal Prices, $/MWh
LMP’s in Day-Ahead and Real-Time

Average Day-Ahead and Real-Time Energy Market LMPs at the Load Zones and Internal Hub, 2004

$/MWh

- Internal Hub
- Maine
- New Hampshire
- SEMASS
- Rhode Island
- NEMA/Boston
- WCMASS
- Vermont
- Connecticut

Avg DA LMP ($/MWh)  Avg RT LMP ($/MWh)
Fuel Prices and Energy Prices

- Fuel-Adjusted prices lower than previous years
- Electricity prices were driven by high fuel prices, the largest component of generators’ marginal costs
  - Natural gas prices were 5% percent higher than 2003 on average, and 82% higher than 2002
  - Nearly half of New England capacity is gas-fired or gas capable
  - These units were marginal in approximately 86% of pricing intervals
- Electricity prices peaked in January as natural gas prices rose
Electricity Prices and Fuel Costs

Daily Average Real-Time System Price of Energy vs. Variable Production Costs*

*System Energy Prices and Variable Cost of Gas Plant exceeded $150 on January 14 and 15.
Gas Plants Set Price Most Frequently

Marginal Input Fuels in Real-Time, 2004
All-in Energy Prices

• Following slides show “all-in” prices
  – Cost of energy, capacity, uplift costs and ancillary services
    • Energy is load-weighted average of locational real-time prices
    • Ancillary services include reserves and regulation prior to SMD, regulation in 2003, and regulation and forward reserves in 2004

• All-in prices rose slightly in 2004
  – Energy costs similar in 2003 and 2004
  – Uplift and ancillary services costs higher in 2004
    • Introduction of the Forward Reserve Market and an increase in VAR tariff reliability payments
  – Capacity costs very small in 2004
Components of Electricity Markets


*Energy: Interim Markets period = ECP * System Load, SMD period = RT Load Oblig * RT LMP.
Low Prices in Capacity Market

Capacity Auction Clearing Prices
April 2003 - December 2004

Supply Auction Clearing Price
Demand Auction Clearing Price

Obligation Month

$/MW-Month

$450
$400
$350
$300
$250
$200
$150
$100
$50
$0

Apr-03
May-03
Jun-03
Jul-03
Aug-03
Sep-03
Oct-03
Nov-03
Dec-03
Jan-04
Feb-04
Mar-04
Apr-04
May-04
Jun-04
Jul-04
Aug-04
Sep-04
Oct-04
Nov-04
Dec-04
Delisted MWs Increased from 2003

Total Delisted Capacity, April 2003 to December 2004
Uplift Payments Remain Significant

Uplift Payments by Quarter, 1999 - 2004

- RMR ORC
- Economic ORC
- NCPC
- Energy Uplift
- Congestion Uplift Costs

ISO New England
Congestion and Marginal Loss Costs

- Differences between LMPs at Hub and load zones reflect impact of congestion and marginal losses.

- Maine had negative congestion
  - Due to export constraints

- Connecticut had significant positive congestion
  - Periodically import constrained

- Note that these numbers understate congestion costs
  - Exclude significant out-of-merit local operating reserve costs
Major Market Changes: Forward Reserve Market

• What is the Forward Reserve Market?
  – Advanced purchase of fast-start capacity
  – 10-minute non-spin and 30-minute non-spin
  – Units must offer above a strike price based on natural gas costs
  – Liquidated damages incent delivery

• Market experienced adequate participation and reasonable outcomes
Forward Reserve Market: Results and Observations

- Purchased approximately 1,900 MW each auction
- Clearing prices of $3.90 to $4.50/KW-Mo.
- Auction worked
  - Unit availability good
  - “Right” resources won
  - Participants responded to incentives by adding dual-fuel capability, buying firm gas, offering less efficient combined-cycles as 2 peaking units, bringing unit out from “behind the meter,” and offering more unit flexibility (Min. Run Times < 1 hour)
Increasing Supply of 10-Minute Reserves in Forward Reserve Market
Forced Outages

• Next slide presents trends in forced outage rates from the beginning of the New England Markets
  – Forced outage rate is percentage of time capacity is unavailable due to full or partial forced outages
  – The decrease in availability 1996-1998 was due to the extended outages of several nuclear units

• Total outage rates have declined substantially following implementation of markets in New England
  – Consistent with deregulated market incentives improve availability
  – Previous analysis suggests initial high outage rates in new combined-cycle units
    • New England has many new combined-cycle units
    • Improvements in outage rates may be expected as these units mature
Generator Performance Remains Steady

Average Generator Outages as a Percentage of Total System Generating Capacity: Weekdays

Planned Outages as a % of Capacity
Unplanned Outages as a % of Capacity
Fewer Outages During Peak Conditions
Biggest Challenges Ahead: Out-of-Market Payments and Demand Response

• Daily out-of-merit operations due to voltage and 2\textsuperscript{nd} contingency coverage
  – Transmission upgrades needed
  – Unit flexibility: Constrained areas need additional quick start units

• Large increase in Reliability Agreements
  – 2,200 MW under agreements, 4,625 MW additional seeking treatment
  – Reliability Agreements do not send signals for most existing generators and do not provide incentives for new entry

• Demand Response Participation flat over last two years
  – Need improved incentives
  – Retail access to real-time prices
Increasing Out-of-Market Units

MW Covered by Reliability Agreements

- 2002
- 2003
- 2004
- 2005 1st Qtr
- 2005, including pending
Economic Incentives for New Investment

• In long-run equilibrium, market should support the entry of new generation
  – Need sufficient net revenues (revenue in excess of production costs) to finance new entry
• We calculated the net revenue the markets would have provided to different types of units in 2004
  – A gas-fired combined-cycle “CC” (heat rate= 7,000)
  – A gas-fired combustion turbine “GT” (heat rate=10,500)
• Combustion-turbines that participated in the Forward Reserve Market had increased revenues over 2003
Economic Incentives for New Investment (Continued)

- Net revenue for gas-fired combined-cycle units lower than 2003 and 2002, despite higher Energy and All-In prices in 2004
  - Due to gas price increases
  - Also due to new capacity added in 2002 and 2003
- Indicates insufficient net revenue from market to support investment in new GT or CC units
  - GT would only recover 66% - 88% of estimated 2004 annual fixed costs
  - CC would only recover 50% -64% of estimated 2003 annual fixed costs
- Existing units also financially stressed
  - Consistent with surge in Reliability Agreements
Net Revenue Metric 2004

Combustion Turbine

<table>
<thead>
<tr>
<th>Year</th>
<th>CT Energy</th>
<th>Capacity</th>
<th>Ancillary</th>
<th>CT Total</th>
<th>CT Run Hours</th>
<th>Estimated Annual Fixed Cost Range</th>
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<td></td>
<td></td>
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<td>High</td>
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<tr>
<td>2002</td>
<td>$22,387</td>
<td>$12,000</td>
<td>$1,781</td>
<td>$36,168</td>
<td>1825</td>
<td>$80,000</td>
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<td>2003</td>
<td>$11,293</td>
<td>$1,972</td>
<td>$1,767</td>
<td>$15,032</td>
<td>773</td>
<td>$80,000</td>
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<td>2004</td>
<td>$8,058</td>
<td>$360</td>
<td>$44,466</td>
<td>$52,884</td>
<td>620</td>
<td>$80,000</td>
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Combined Cycle

<table>
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<tr>
<th>Year</th>
<th>CC Energy</th>
<th>Capacity</th>
<th>Ancillary</th>
<th>CC Total</th>
<th>CC Run Hours</th>
<th>Estimated Annual Fixed Cost Range</th>
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<td></td>
<td>High</td>
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<tr>
<td>2002</td>
<td>$79,006</td>
<td>$12,000</td>
<td>$1,781</td>
<td>$92,787</td>
<td>7115</td>
<td>$125,000</td>
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<tr>
<td>2003</td>
<td>$72,739</td>
<td>$1,972</td>
<td>$1,767</td>
<td>$76,478</td>
<td>5741</td>
<td>$125,000</td>
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<tr>
<td>2004</td>
<td>$62,697</td>
<td>$360</td>
<td>$1,350</td>
<td>$64,407</td>
<td>5420</td>
<td>$125,000</td>
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Energy revenues are calculated as the revenue per MW of a hypothetical unit assumed to be dispatched during each hour when the market clearing price equals or exceeds the unit's marginal cost, adjusted for a 5% forced outage rate. Revenues are calculated based on the real-time Hub LMP. Capacity sales revenue is based on ISO ICAP Supply Auction clearing prices. Ancillary services revenue is Regulation for combined-cycle, and Regulation and Forward Reserves for combustion-turbine. Forward Reserve revenues equal auction revenues minus average penalties.
Competitive Benchmark Analysis

• Evaluated actual energy clearing price and cumulative bid-in capacity
  – Ascending price ("aggregate bid-intercept") vs. marginal cost-based simulated dispatch

• Simulated dispatch designed to produce estimate of perfectly competitive market outcome
  – Estimate is subject to an unknown error

• Metric is % increase over “perfect” market outcome
  – “Quantity-weighted Lerner Index”

• Market continues to function well
  – Modest differences from competitive baseline
### Competitive Benchmark Results: 2003 vs. 2004

<table>
<thead>
<tr>
<th>Price Measure</th>
<th>2004 Price ($/MWh)</th>
<th>Quantity-Weighted Lerner Index</th>
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<tr>
<td></td>
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<td>2003</td>
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<tr>
<td>Competitive Benchmark Price</td>
<td>$54.49</td>
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<tr>
<td>Real-Time Hub Price</td>
<td>$48.95</td>
<td>9%</td>
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<tr>
<td>Aggregate Bid-Intercept Price</td>
<td>$52.13</td>
<td>-4%</td>
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Demand Response

• New England offers range of price and reliability-based response programs
• Total enrollment around 350 MW at end of 2004
• Total hours of curtailment increased in 2004 due to increased number of events
  – Many curtailment hours in winter months due to high gas prices
  – 4,223 MWh in 2003
  – 13,475 MWh in 2004
• Program enrollment roughly constant from 2003 to 2004
  – Need much greater levels of demand response in the long run
Demand Response Participation

Total MW Enrolled in Demand Response Programs

MW

Jan-03 Mar-03 May-03 Jul-03 Sep-03 Nov-03 Jan-04 Mar-04 May-04 Jul-04 Sep-04 Nov-04 Jan-05 Mar-05
External Transactions

• New England has 3 major interties
  – New Brunswick
  – Hydro Quebec
  – NY ISO

• Two Canadian Ties are primarily import-only interfaces

• NY Interface is only connection with another electricity market

• New England imports decreased in 2004
New England Primarily Imports on Ties

New England Imports and Exports by Interface 2004

GWh

-2,000 -1,500 -1,000 -500 0 500 1,000 1,500 2,000 2,500 3,000 3,500

Highgate Hydro Quebec Phase I/II New Brunswick NY-AC NY-CSC

Exports
Imports

Interface

New England Primarily Imports on Ties
Conclusions

• 2004 characterized by low summer loads and ample generation

• The New England markets continued to perform competitively
  – No evidence of significant economic or physical withholding

• Cold Snap experience led to important market improvements

• Little incentive to add capacity, even in constrained areas
  – Participants responded to Forward Reserve Market signals

• Out-of-market payments require on-going attention
  – LICAP solution needed

• Additional Demand Response needed