



Highlights of the 2003 New York ISO State of the Market Report

David B. Patton, Ph.D.
Potomac Economics

Independent Market Advisor

April 14, 2004



Introduction to the Annual Report

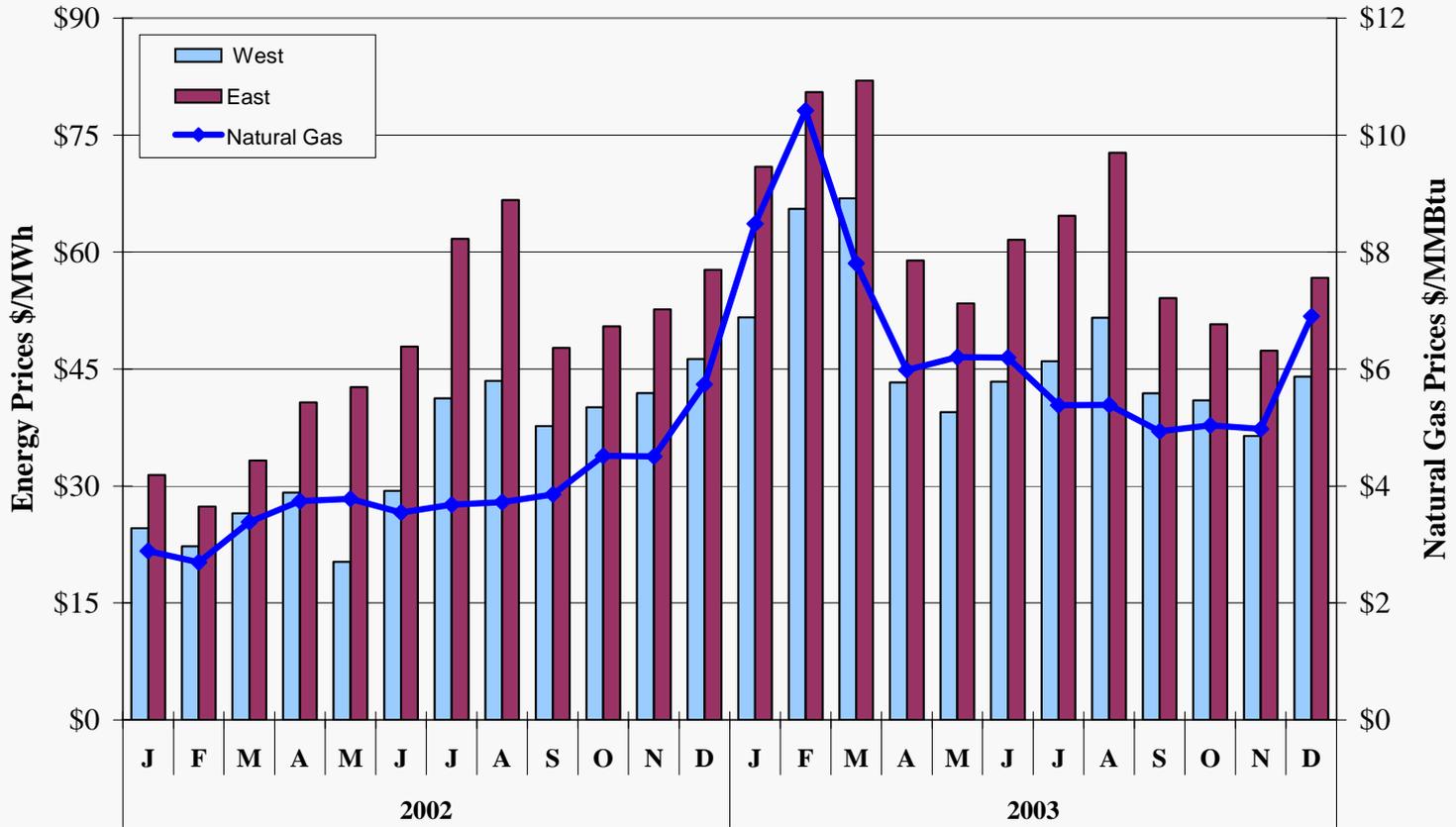
- This presentation provides highlights from the Annual Report on the New York electricity markets for 2003.
- The market assessment addresses the following areas:
 - ✓ Energy market prices and outcomes
 - ✓ Market performance
 - ✓ Market participant bid and offer patterns
 - ✓ External transactions scheduling
 - ✓ Capacity market
 - ✓ Ancillary services
 - ✓ Demand response programs



Fuel Prices and Energy Prices

- Electricity prices tend to be influenced primarily by fuel prices (the largest component of generators' marginal costs) and load levels.
- The next figure shows that monthly energy prices for 2002 to 2003 have been driven by fuel price trends.
 - ✓ Natural gas prices were 70 percent higher than 2002 on average.
 - ✓ Distillate oil prices increased 24 percent on average.
- Electricity prices peaked in February and March as natural gas prices rose to unprecedented levels, and peaked again in August due to summer loads.
- The figure also shows that average prices in east NY exceed prices in west NY by 32 percent due to the Central-East constraint separating west and east NY and the constraints into and within NYC.

Energy and Natural Gas Prices 2001 - 2003



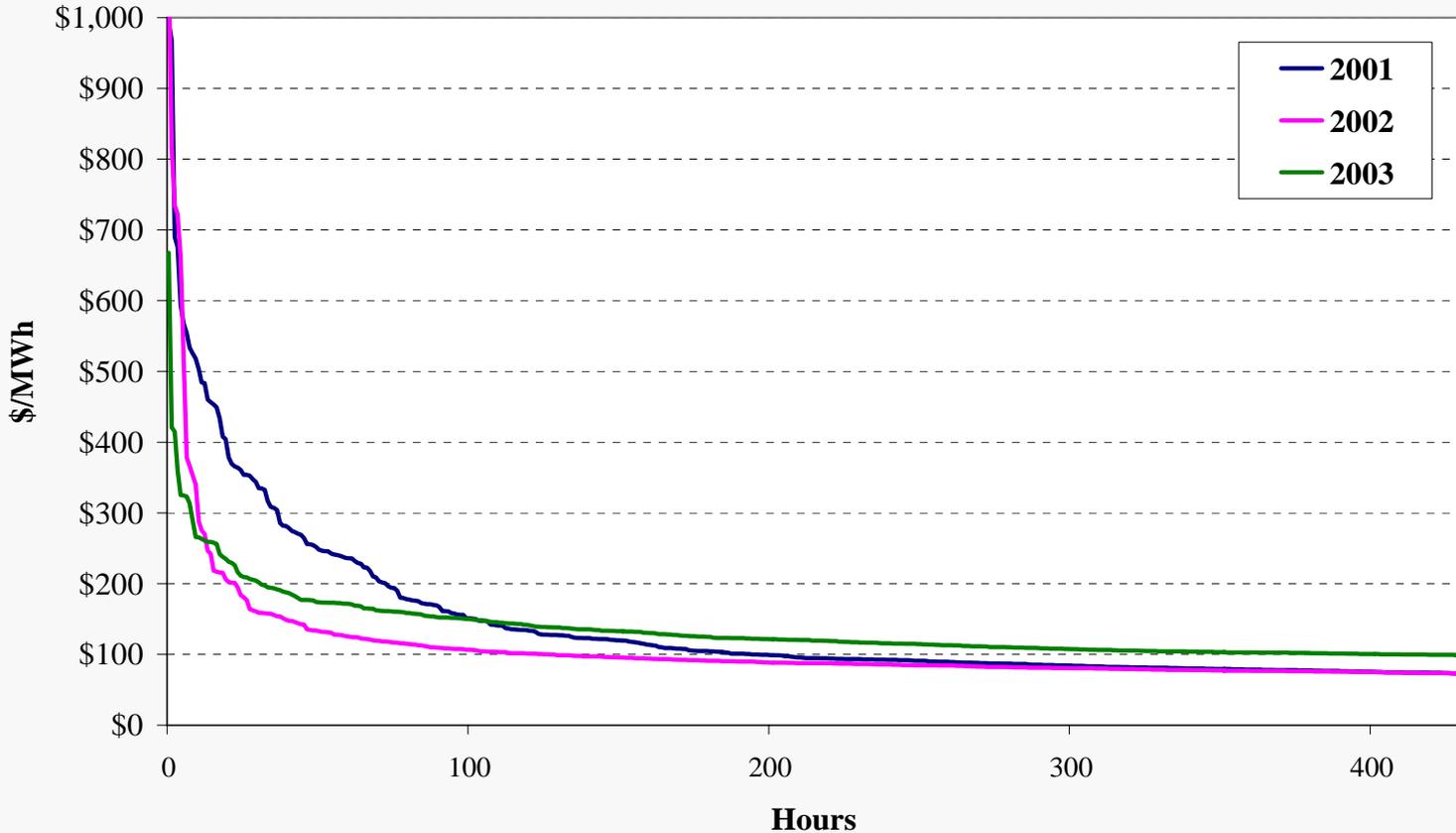


Energy Prices in 2003

- The next figure show real-time price duration curves for 2001 to 2003 in the highest-priced five percent of hours in each year.
 - ✓ These curves show the number of hours when the load-weighted price for New York State is greater than each given price level.
- Price levels were generally higher across all hours in 2003 than in the previous two years due to higher fuel prices.
- In 2003, there were fewer price spikes than the two previous years:
 - ✓ In 2003, real-time weighted prices exceeded \$500 for 3 hours, compared to 6 hours in 2002, and 11 hours in 2001.
 - ✓ The lower quantity of price spikes was primarily due to milder weather and increased imports from New England.
 - ✓ Scarcity pricing provisions were implemented, but were not triggered in 2003.

Price Duration Curves in Highest 5% of Hours

New York State Average Real-Time Price

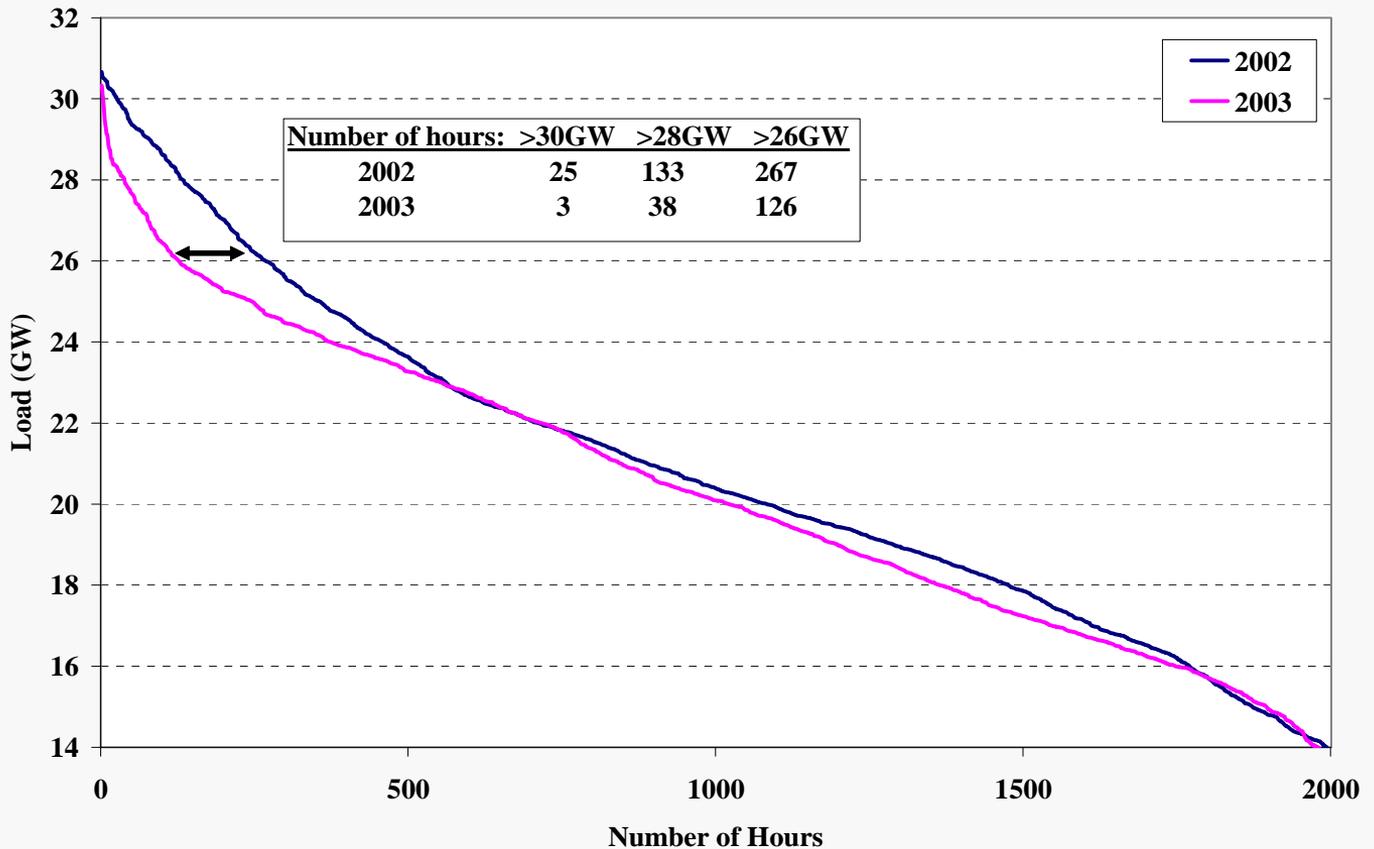




Load Profile

- The next figure shows annual and summer load duration curves for New York.
 - ✓ These curves show the number of hours in which the load is greater than the level indicated on the vertical axis.
- In 2003, peak days had far less impact on average prices than in 2002. The absence of severe price spikes was due to mild summer loads.
 - ✓ There were only 3 hours in 2003 when actual loads exceeded 30,000 MW, compared to 25 hours in 2002 and 17 hours in 2001.
 - ✓ In 2003 there were 38 hours when loads exceeded 28,000 MW compared to 133 hours in 2002 and 66 in 2001.

Load Duration Curves for New York Summer 2002 vs. Summer 2003



* Summer includes June to August each year. The blackout hours in 2003 are not included.

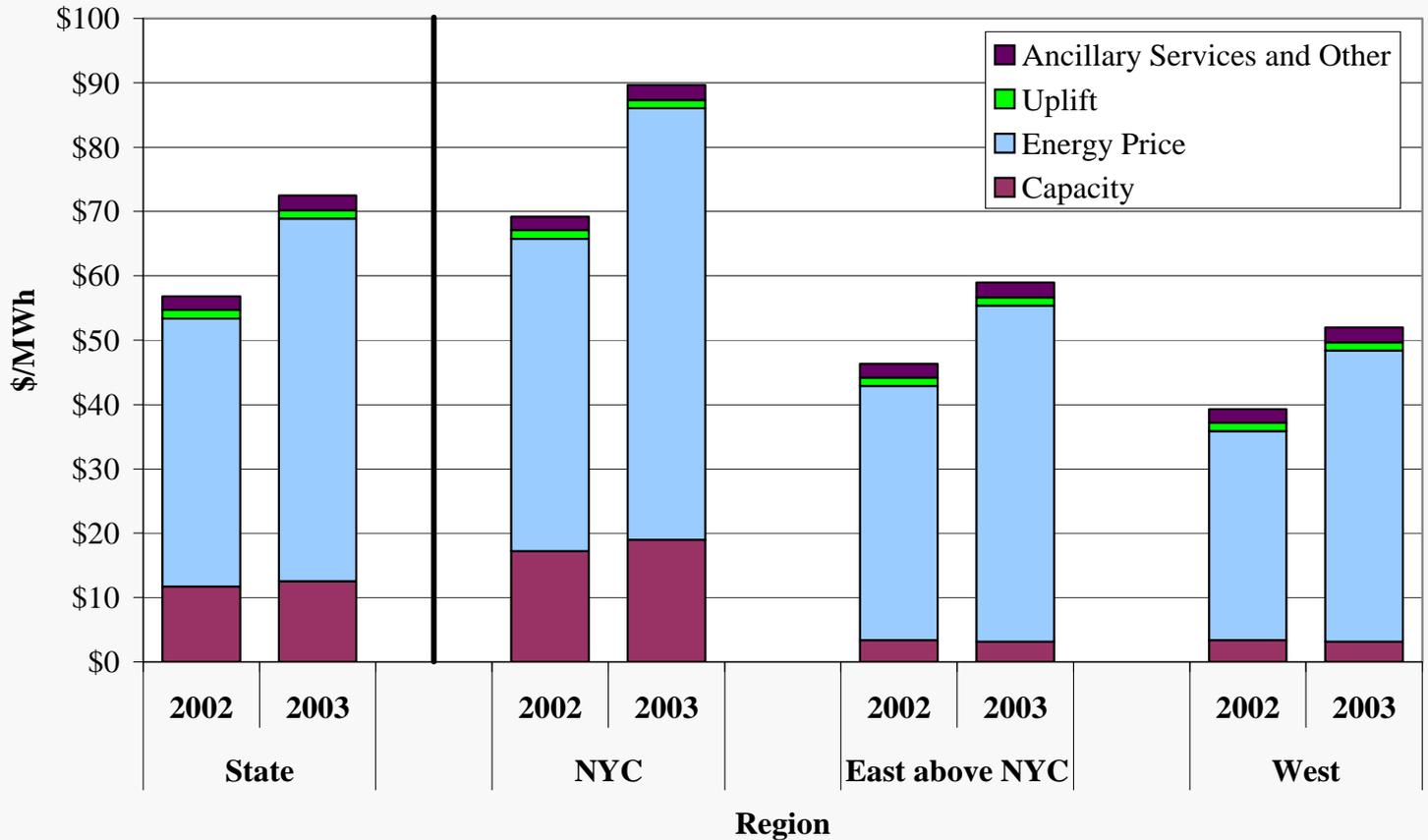


All-In Energy Prices

- The following figure calculates an “all-in” price that includes the costs of energy, ancillary services, capacity, and other costs.
 - ✓ The all-in price is calculated for various locations within New York since both capacity and energy prices vary substantially by location.
 - ✓ For the purposes of this metric, uplift and ancillary services costs are distributed evenly for all locations.
- This figure shows that the all-in price rose for all locations in 2003.
 - ✓ This increase is primarily caused by higher energy prices in 2003, which rose 36 percent in 2003 due to higher fuel prices.
 - ✓ The capacity component also rose in 2003 due primarily to:
 - a) rising forecasted peak load resulting in a higher obligations,
 - and b) additional purchases under the demand curve.

Average All-In Price in 2002 and 2003

Costs per MWh of Load





Economic Incentives for New Investment

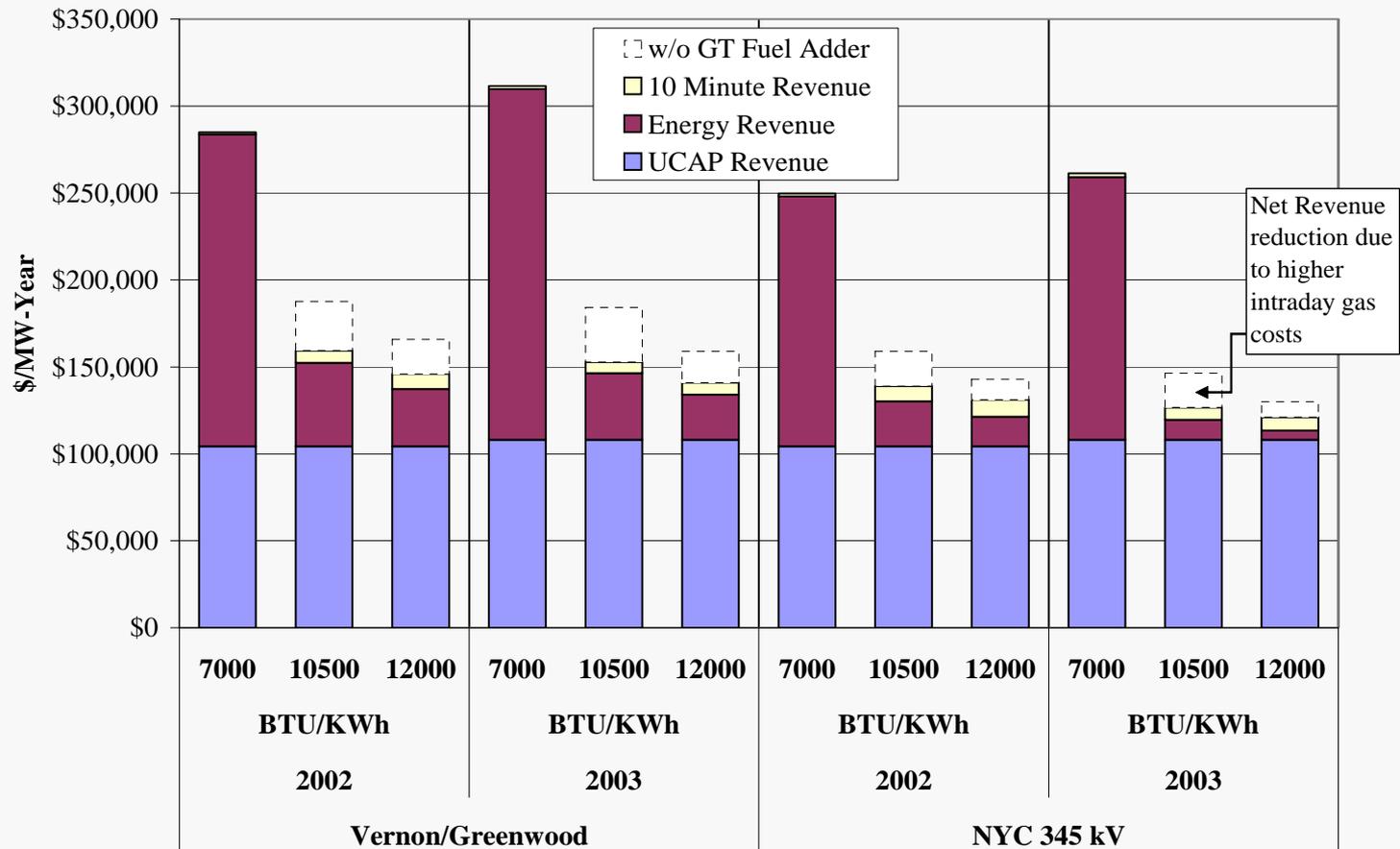
- In long-run equilibrium, the market should support the entry of new generation by providing sufficient net revenues (revenue in excess of production costs) to finance new entry.
- We calculated the net revenue the markets would have provided to different types of units at various locations in 2003.
- The types of units are gas combined-cycle (heat rate = 7000), new gas turbine (heat rate = 10500), old gas turbine (heat rate = 12000).
- For the gas turbines, the figures show the effect on the suppliers' net revenue of incurring higher costs to purchase natural gas intraday.



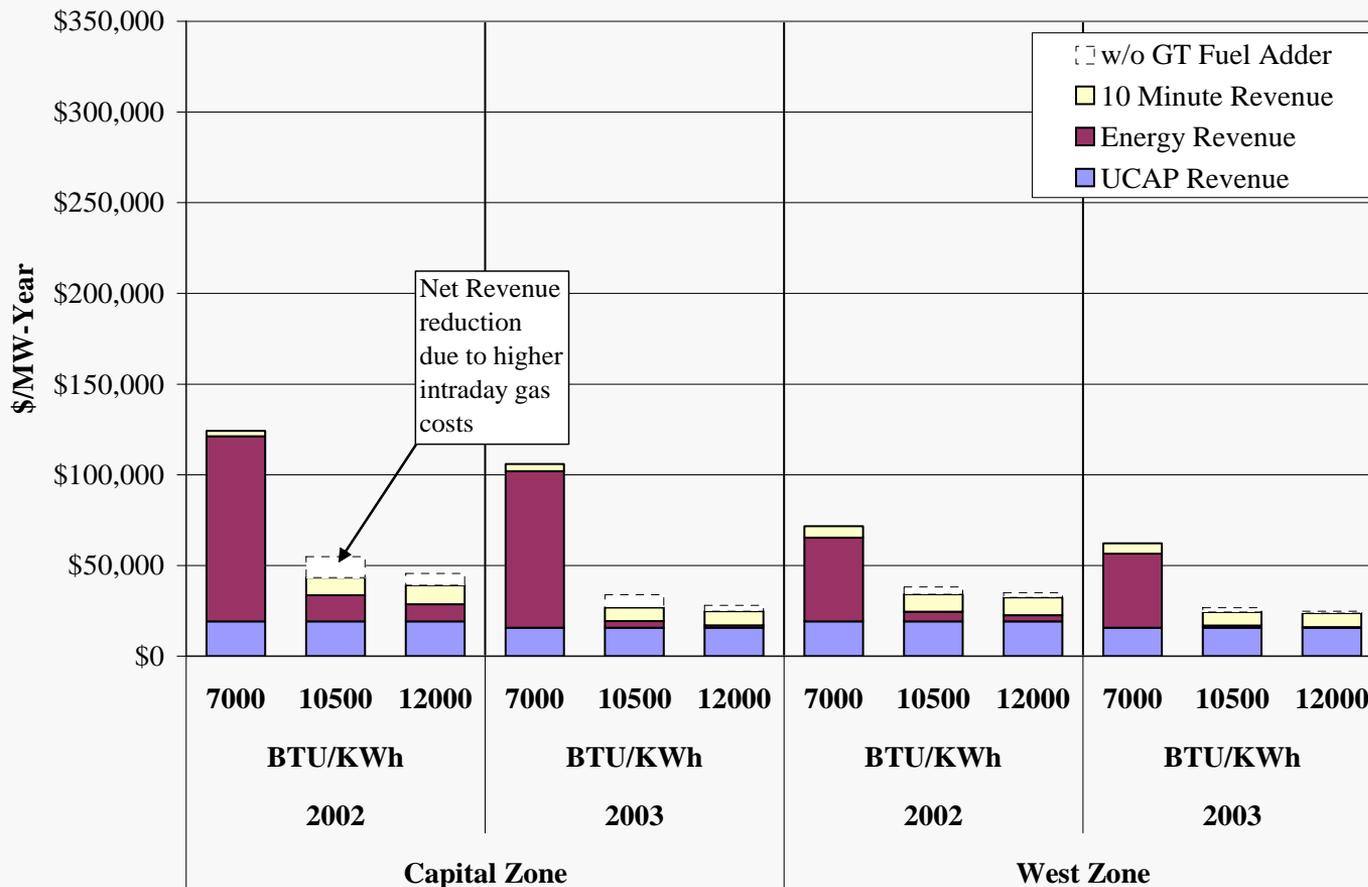
Economic Incentives for New Investment

- Even though prices were higher in 2003, the net revenue for gas-fired units were lower in 2003 due to gas price increases.
- These results indicate that the market in 2003 did not produce sufficient net revenue to support investment in a new gas turbine.
 - ✓ A new gas turbine would have recovered only 30 to 75 percent of annual net revenue needed to support a new gas turbine in 2003.
- These results for a new combined-cycle unit are less clear.
 - ✓ Net revenue for a new CC in NYC ranges from \$250,000 to \$300,000 per MW-year (the required net revenue is unknown).
 - ✓ In upstate New York, a new gas turbine would recover 40 to 80 percent of the required annual net revenue for a new CC.

Estimated Net Revenue in the New York City Day-Ahead Market – 2002 to 2003



Estimated Net Revenue in Upstate New York Day-Ahead Market – 2002 to 2003

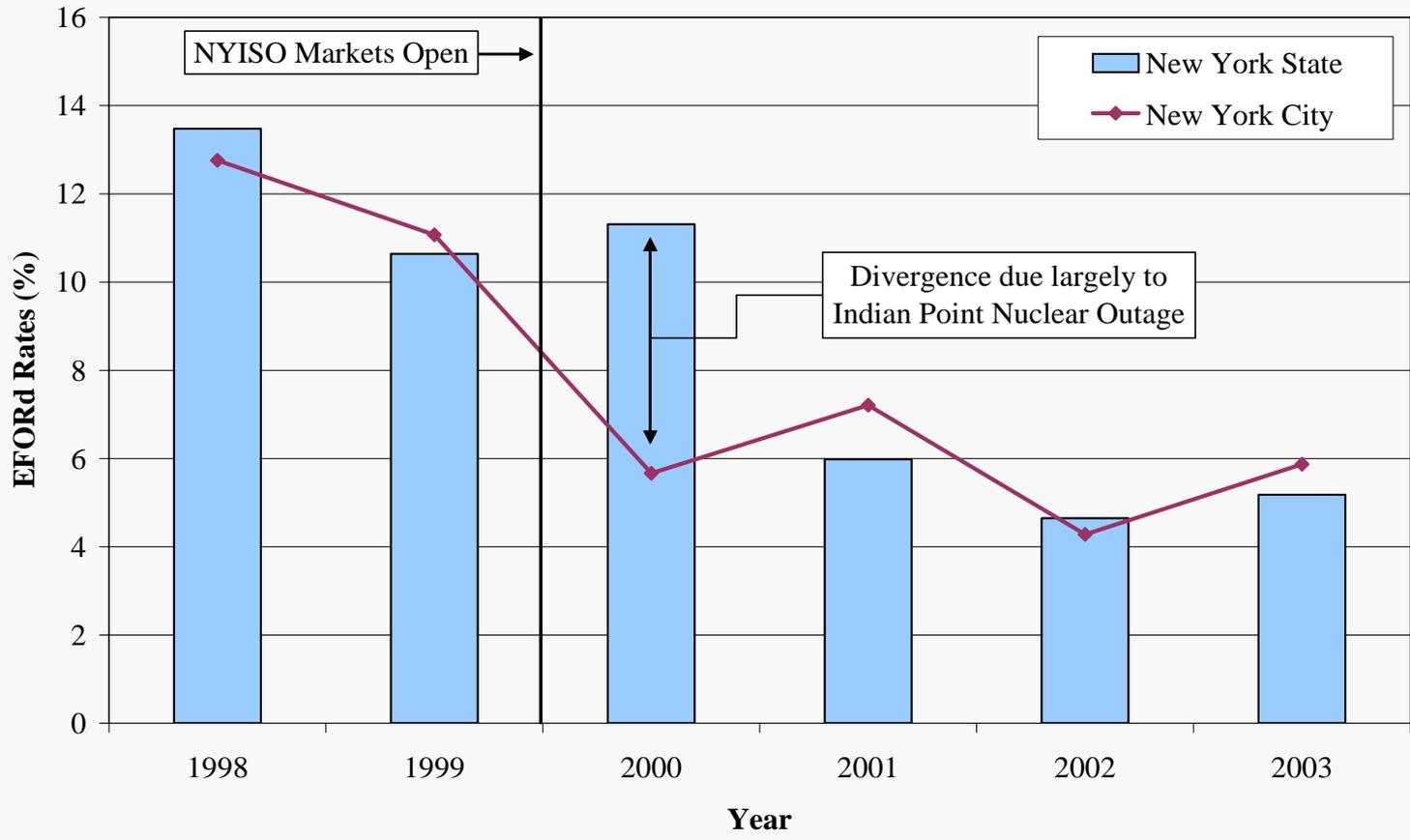




Forced Outages

- The next figure presents the trend in the equivalent forced outage rate from the beginning of the operation of the New York markets.
 - ✓ The Equivalent Forced Outage Rate (EFOR) is the portion of time a unit is unavailable due to full or partial forced outages.
- EFOR declined substantially following the implementation of the NYISO markets.
 - ✓ This is consistent with the incentives the deregulated markets provide to maximize availability, particularly during high load conditions.
 - ✓ EFOR declined again after the change from ICAP to UCAP in the fall of 2001. This increased the incentive to minimize outages since a unit's UCAP amount reflects its forced outage rates.

Equivalent Forced Outage Rates 1998 to 2003



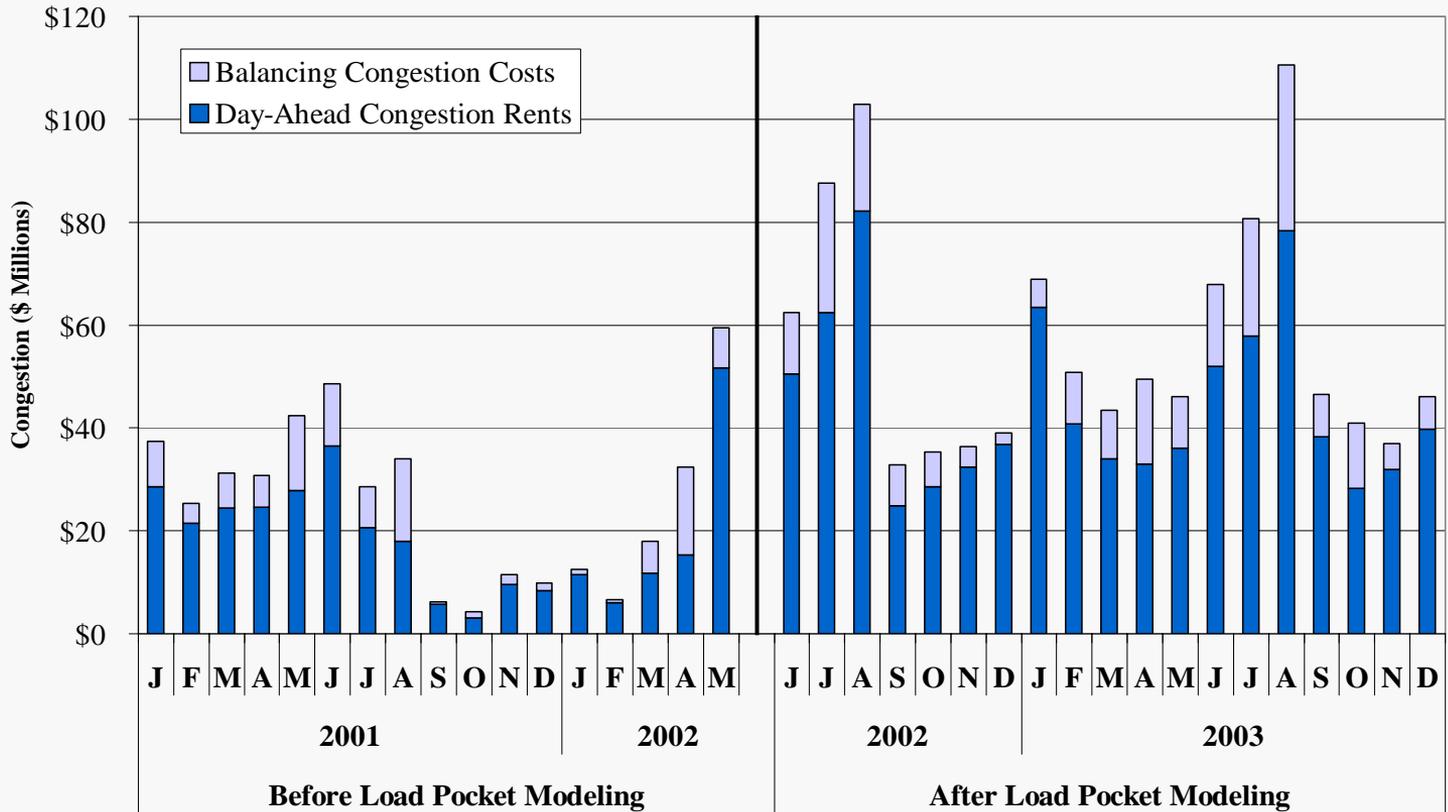


Congestion Costs

- The following figure shows monthly congestion costs collected in the day-ahead and the real-time markets (i.e., balancing congestion costs).
- This figure shows congestion costs have increased from 2001 to 2003:
 - ✓ \$310 million in 2001
 - ✓ \$525 million in 2002
 - ✓ \$688 million in 2003
- The increase in congestion costs from 2001 to 2003 is partly due to the modeling of the load pockets within NYC, which began in June 2002.
- The significant balancing congestion costs are evidence of inconsistencies between the day-ahead and real-time models.
 - ✓ This should be remedied when the new real-time system (“RTS”) is implemented in Fall 2004.



Monthly Congestion Expenses 2001 - 2003

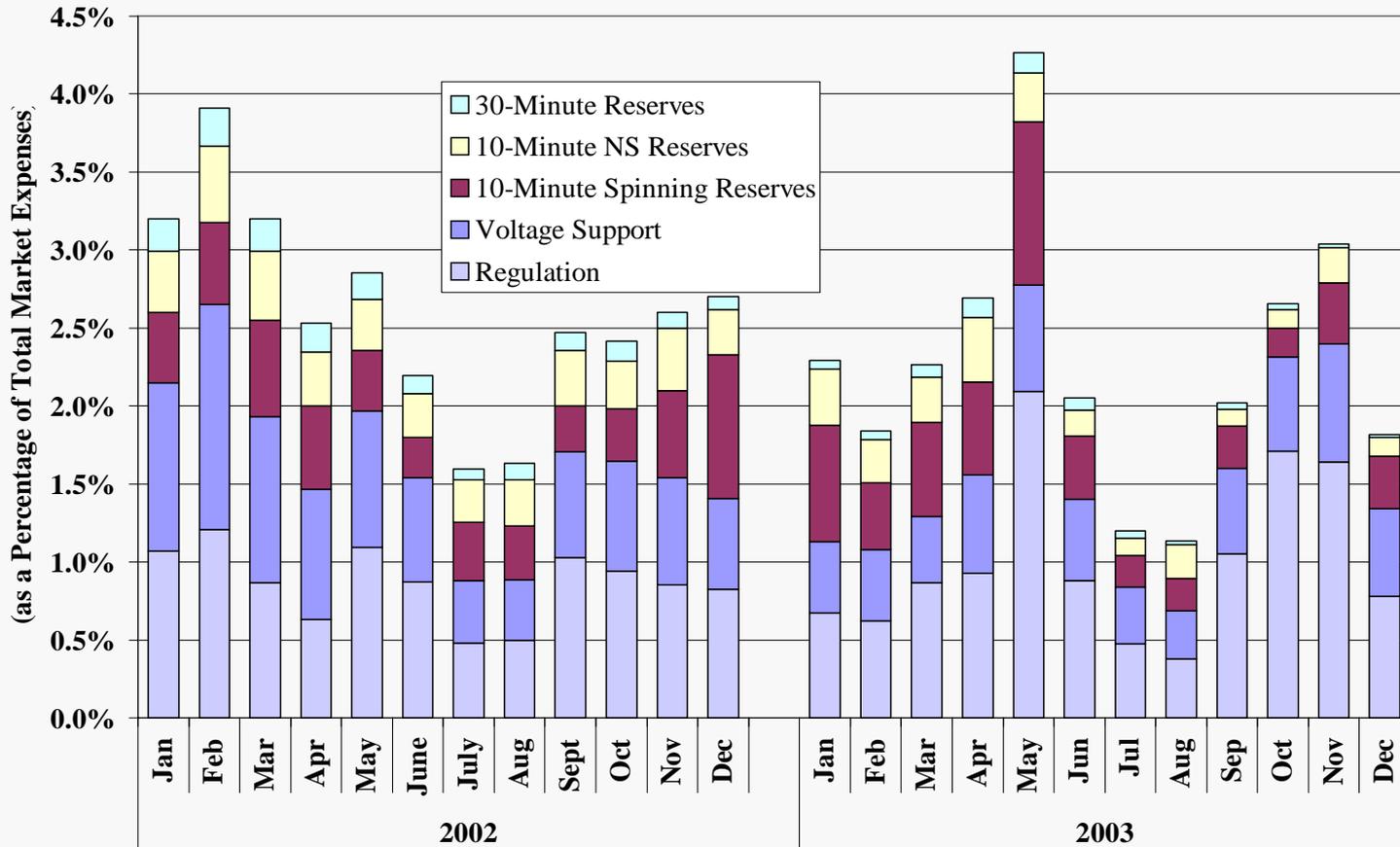




Ancillary Services Costs

- Ancillary services expenses include expenses for regulation, voltage support, and various operating reserves.
- These costs tend to be smaller as a percent of total market expenses in the summer than in other seasons because of the relatively high energy prices during the summer.
- Ancillary services costs declined slightly as a percentage of total market expenses from 2002 to 2003.
 - ✓ However, the amount spent on ancillary services increased by \$20 million to almost \$130 million.
- Increased expenditures for ancillary services was primarily due to the higher cost of regulation.

Expenses for Ancillary Services 2002 - 2003





Other Conclusions and Recommendations

- The NYISO markets continued to perform competitively in 2003 with no evidence of significant economic or physical withholding.
- Day-ahead and real-time energy prices continued to exhibit good convergence.
- Virtual trading volumes increased in 2003, contributing to the good convergence between the day-ahead and real-time prices outside NYC.
- The capacity demand curve implemented in 2003 has been successful in stabilizing capacity prices and facilitating price convergence between the various UCAP auctions.



Other Conclusions and Recommendations

- Real-time prices in adjacent regions continued to not be efficiently arbitrated.
 - ✓ Implementation of the VRD provisions that are under development with New England will address this issue.
 - ✓ Eliminating the export fees with adjacent regions would also help improve the efficiency of the interchange between markets.
- The NYISO's demand response programs provide a substantial amount of real-time load reductions when necessary – however, mild conditions in 2003 limited the need for such reductions.



Other Conclusions and Recommendations

- Apparent reductions in real-time transmission limits has caused substantial congestion costs in real-time.
 - ✓ Introduction of RTS should address this concern because the RTS and SCUC software will operate on the same platform.
- Supplemental commitments for local reliability continue to be significant, which can distort energy prices.
 - ✓ In the long-term, we recommend incorporating the local reliability requirements in the initial commitment.
 - ✓ In the short-run, we recommend that the operators pre-commit units that they know will be required to meet local reliability requirements.