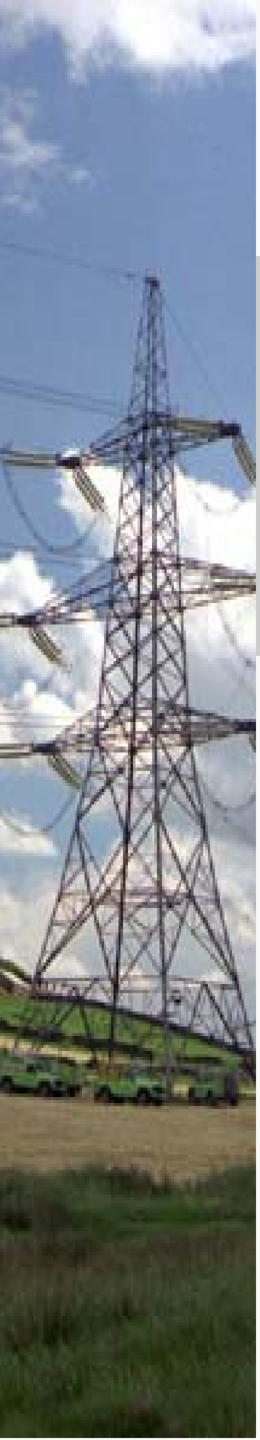


2002 State of the Market Report New York Electricity Markets:

Executive Summary

Presented to:

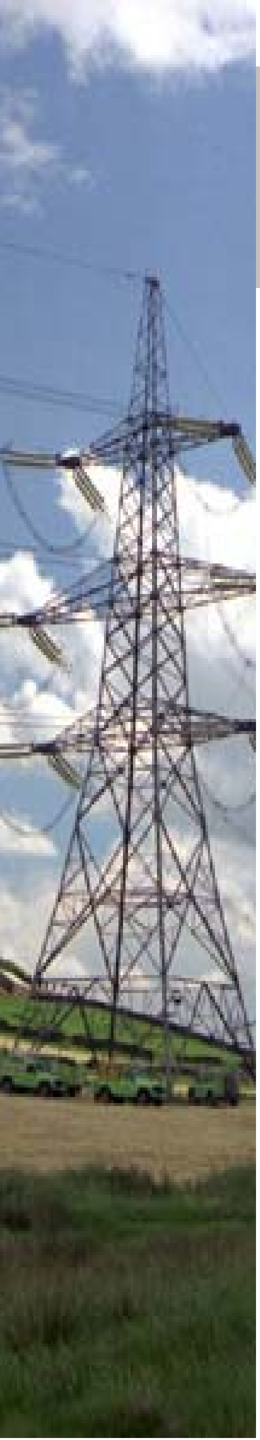
Joint NYISO Board of Directors and
New York Management Committee

David B. Patton, Ph.D.
Independent Market Advisor

April 15, 2003

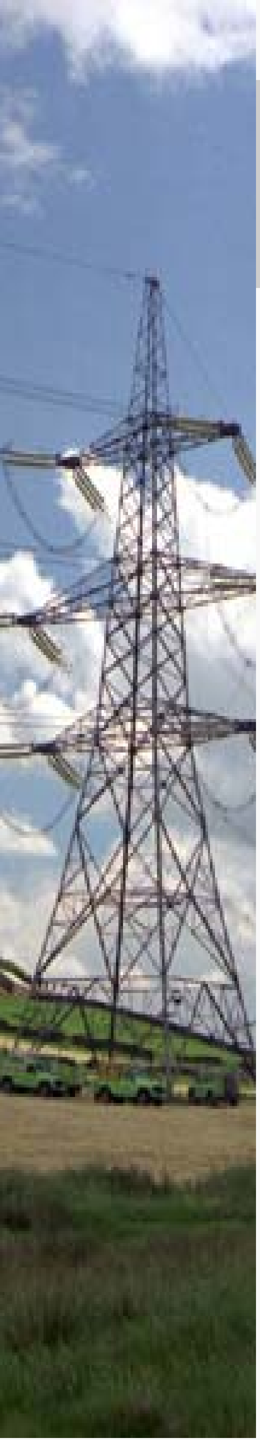
Summary of Conclusions

- The New York markets continued to operate competitively in 2002.
- Significant market improvements were achieved in the following areas:
  - ✓ Uplift costs were reduced substantially through improvements to the market models;
  - ✓ Prices within New York City more accurately reflected transmission congestion within the city due to load pocket modeling;
  - ✓ Out of merit dispatch was reduced through changes to operating and pricing procedures;
  - ✓ Virtual trading and increased price-capped load bidding improved convergence between day-ahead and real-time prices.
- The report identifies areas where further improvement is needed:
  - ✓ Pricing during peak demand conditions (i.e., scarcity pricing);
  - ✓ Interchange with adjacent markets;
  - ✓ Ancillary services market participation and pricing;



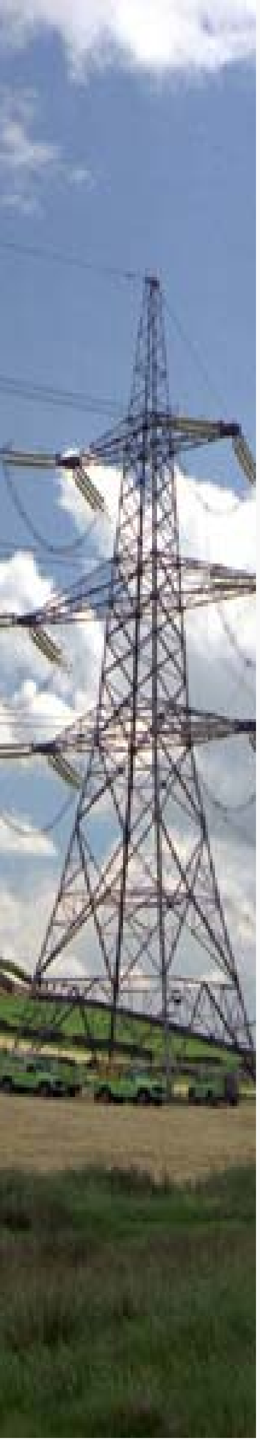
Summary of Recommendations

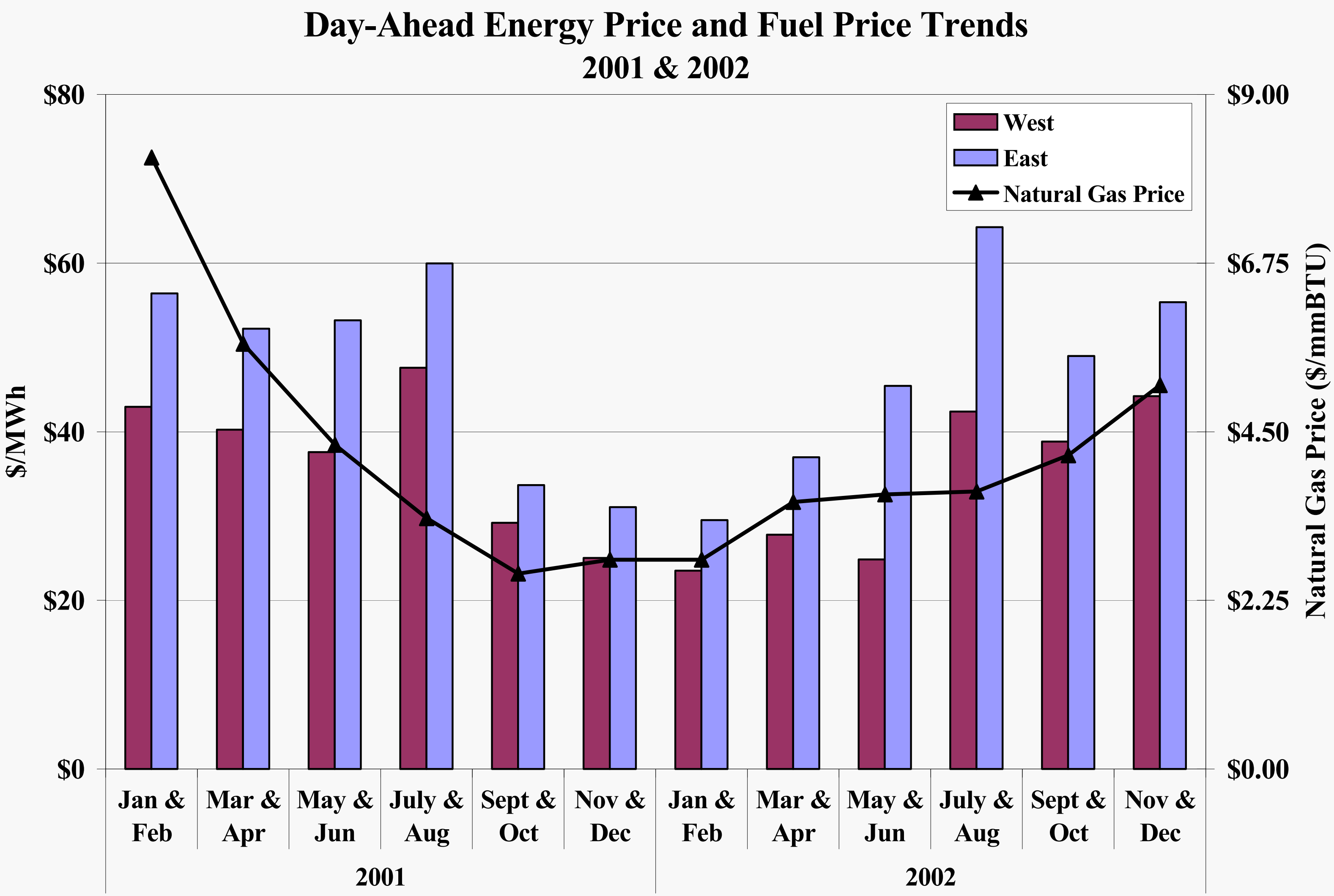
- The report recommends that the NYISO make the following improvements to its markets:
  - ✓ Implement scarcity pricing provisions that would set prices at $1000 (excluding losses) in reserve-deficient areas.
  - ✓ Modify its pricing rules to allow emergency demand response resources to set energy prices when they are needed to avoid a shortage.
  - ✓ Coordinate the physical interchange with adjacent ISO’s to maximize the utilization of the external interfaces.
  - ✓ Disaggregate the virtual trading and price-capped load bidding within New York City to the load pocket level or the 345 kv/138 kv level at a minimum.
  - ✓ Address the virtual trading scheduling and settlement rules to ensure that they are scheduled consistent with their bid prices.



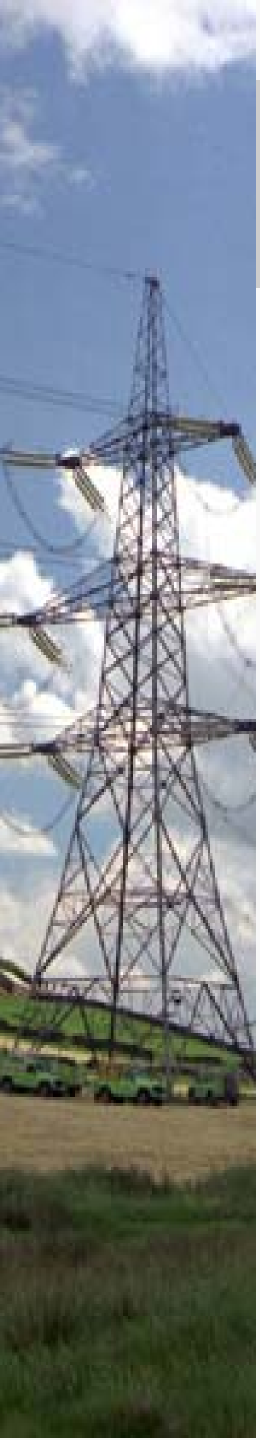
Energy Prices in the Day-Ahead Market

- The following chart shows average prices during all hours in 2001 and 2002.
- The trend in electricity prices in 2001 and 2002 was driven by fuel prices.
  - ✓ In 2002, electricity prices in New York increased 86% from January to December in contrast to decreasing trend in 2001.
  - ✓ This is primarily due to substantial increases in the prices of input fuels over the same period, fuel oil increased 71% and natural gas increased 99%.
- In 2002, peak days had far less impact on average prices than in 2001.
  - ✓ The lower price volatility in 2002 was due, in part, to more active price-capped load bidding and the introduction of virtual trading.
- The average price was 41% higher in eastern New York than in western New York. This was due to:
  - ✓ Continued congestion on the Central-East and Con-Ed Cable Interfaces; and
  - ✓ The introduction of load pocket modeling, making congestion more visible within New York City (shifting costs from uplift to congestion).



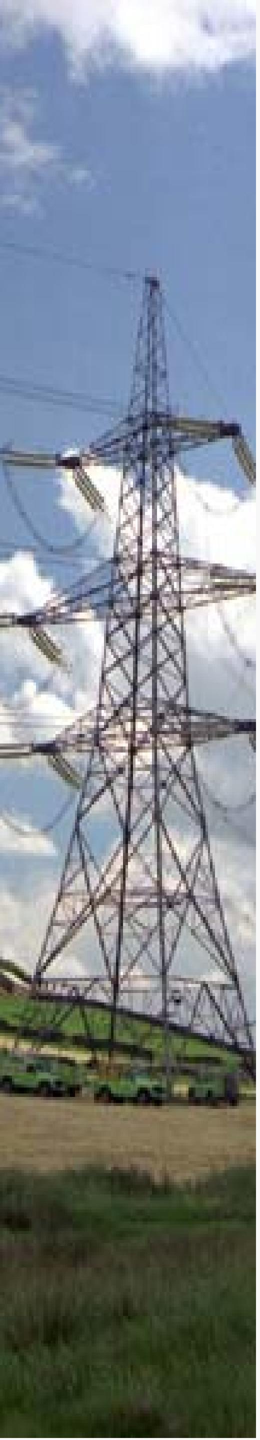


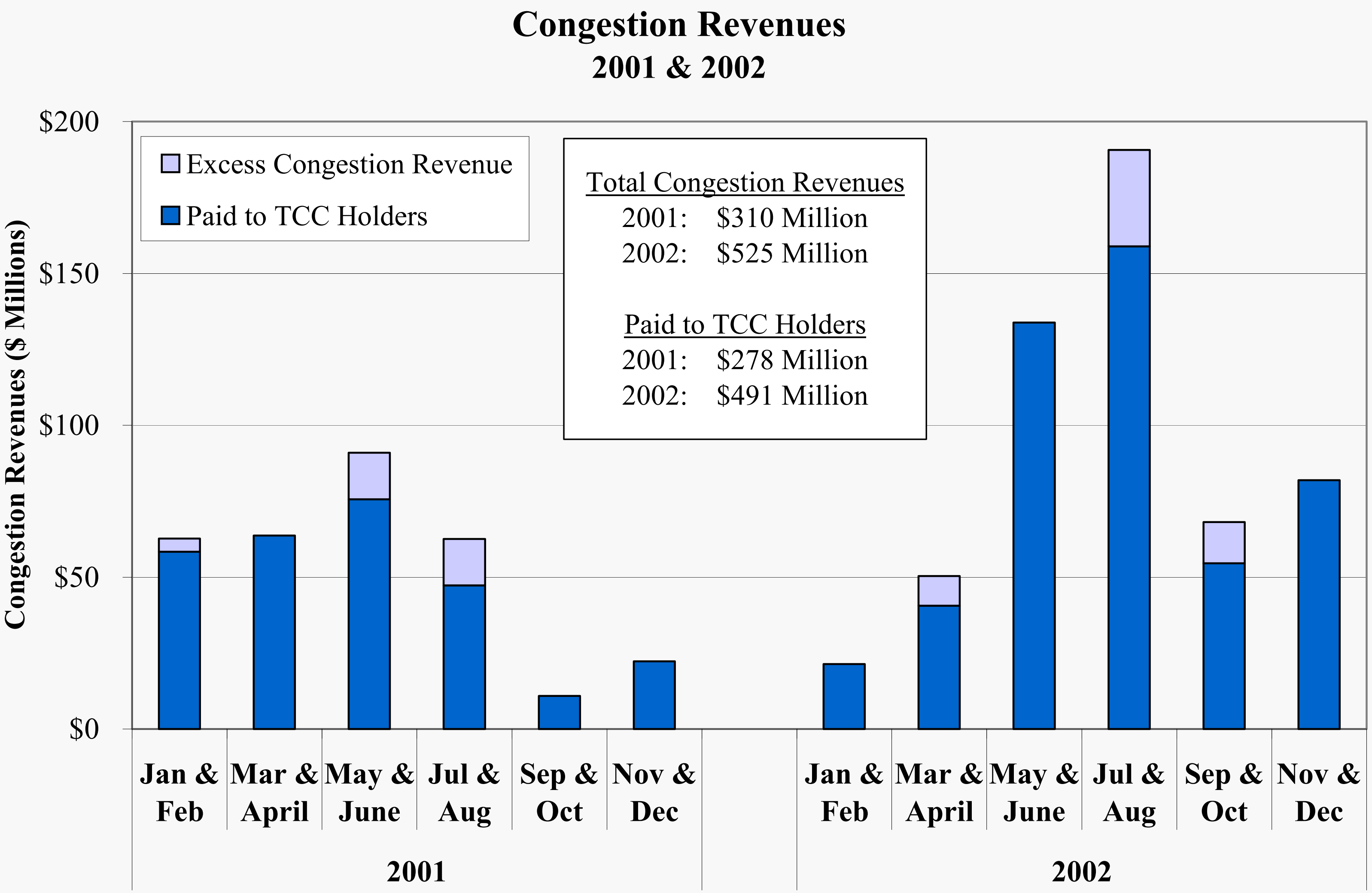
Day-Ahead Energy Price and Fuel Price Trends
2001 & 2002
$80
$60
$40
$20
$0
$/MWh
$9.00
$6.75
$4.50
$2.25
$0.00
Natural Gas Price ($/mmBTU)
West
East
Natural Gas Price
Jan & Feb
Mar & Apr
May & Jun
July & Aug
Sept & Oct
Nov & Dec
Jan & Feb
Mar & Apr
May & Jun
July & Aug
Sept & Oct
Nov & Dec
2001
2002

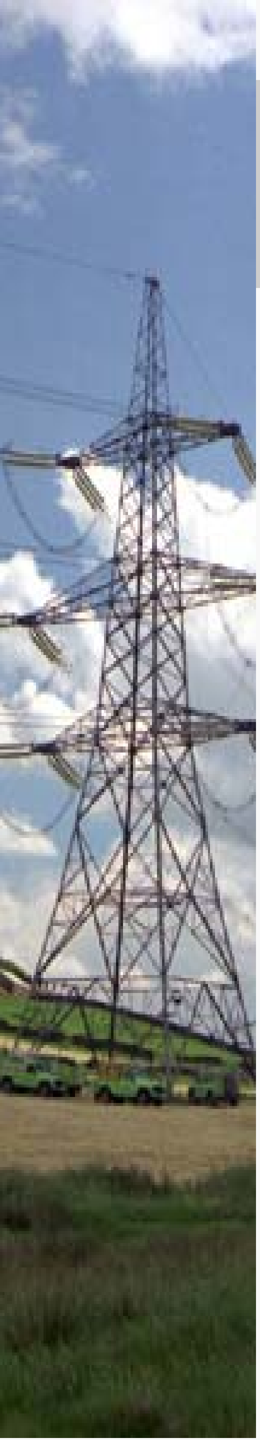


Congestion Costs

- The following chart shows how congestion costs have increased from 2001 to 2002:
  - ✓ $310 million in 2001;
  - ✓ $525 million in 2002;
- The increase in congestion costs from 2001 to 2002 is primarily due to the modeling of the load pockets within New York City.
- 90% and 94% of congestion expenses were paid out to TCC holders in 2001 and 2002, respectively.
  - ✓ Congestion expenses that are not paid to TCC holders are rebated against transmission customers’ Schedule 1 charges.

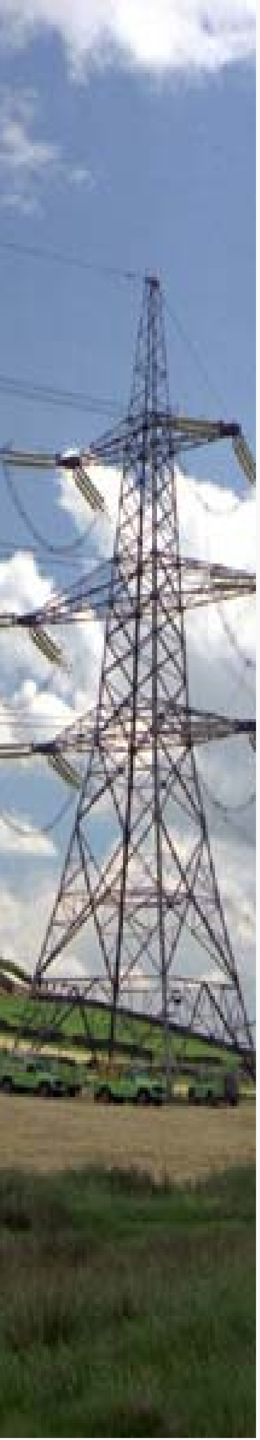


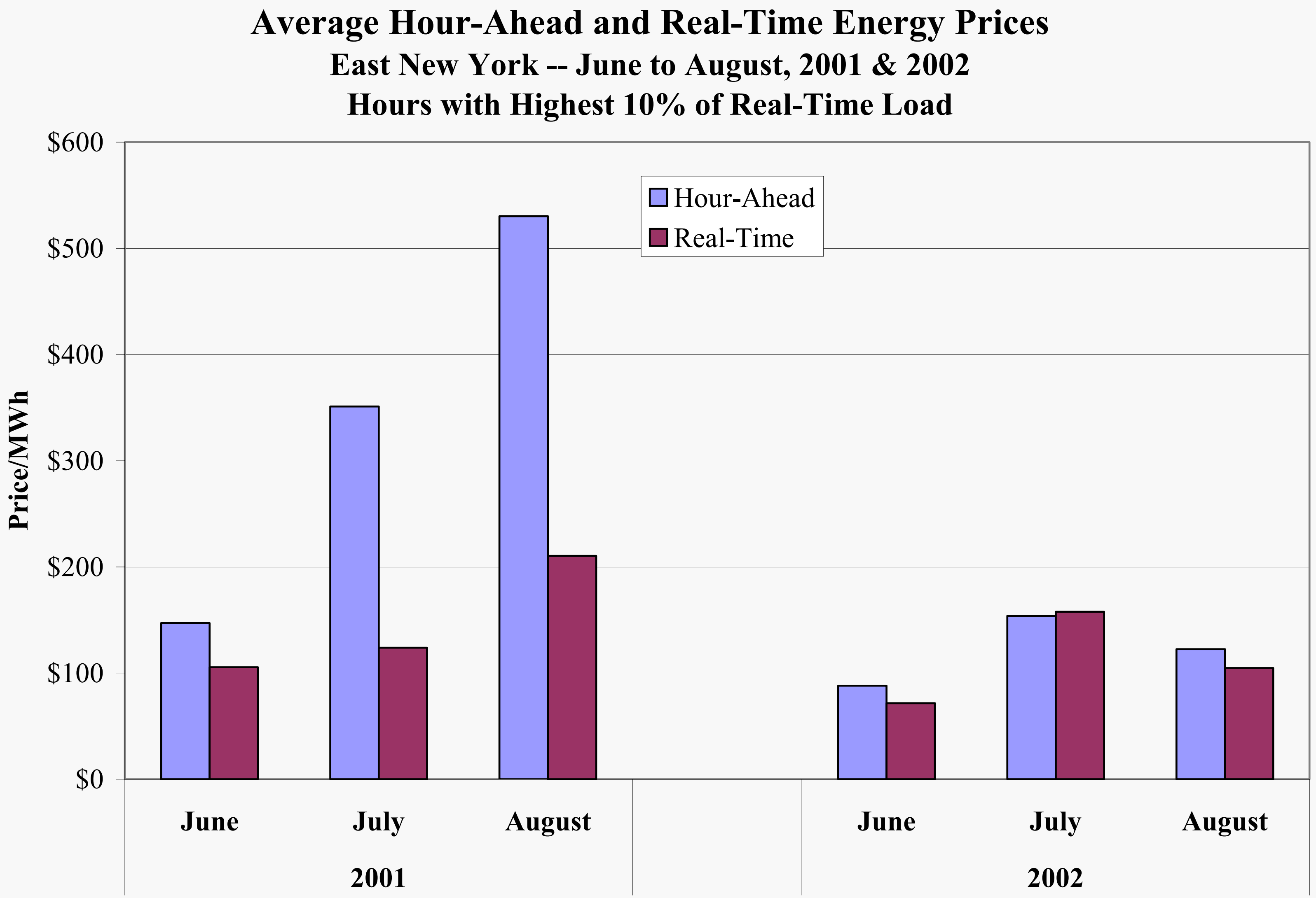

Congestion Revenues
2001 & 2002
Excess Congestion Revenue
Paid to TCC Holders
Total Congestion Revenues
2001: $310 Million
2002: $525 Million
Paid to TCC Holders
2001: $278 Million
2002: $491 Million
Congestion Revenues ($ Millions)
$200
$150
$100
$50
$0
Jan & Feb
Mar & April
May & June
Jul & Aug
Sep & Oct
Nov & Dec
2001
2002

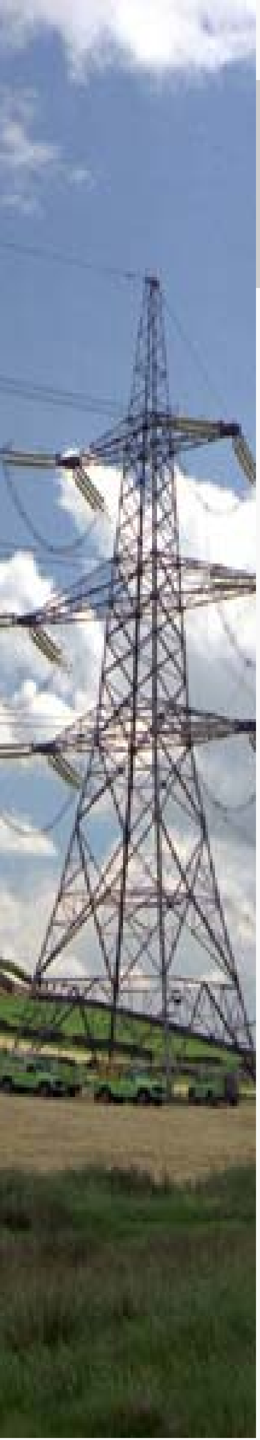


Hour-Ahead and Real-Time Prices

- Lack of convergence between hour-ahead and real-time prices prior to 2002 has been a concern because large price differences can:
  - ✓ Cause external transactions and off-dispatch generation to be scheduled inefficiently; and
  - ✓ Result in increased uplift costs and inefficiently affect real-time prices.
- Several changes to market rules and the BME model were made to improve the price convergence prior to the summer of 2002.
  - ✓ Counting exports as 30-minute reserves at specific shadow price levels.
  - ✓ Crediting latent 30-minute reserves on on-dispatch units in real time.
- The following chart shows remarkable improvement in the price convergence in eastern New York during the highest load hours
  - ✓ Extraordinarily high BME prices in 2001 resulted in substantial scheduling of uneconomic transactions.
  - ✓ The appendix includes additional scatter plots that show the improvement in hour ahead to real time convergence relative to load levels.

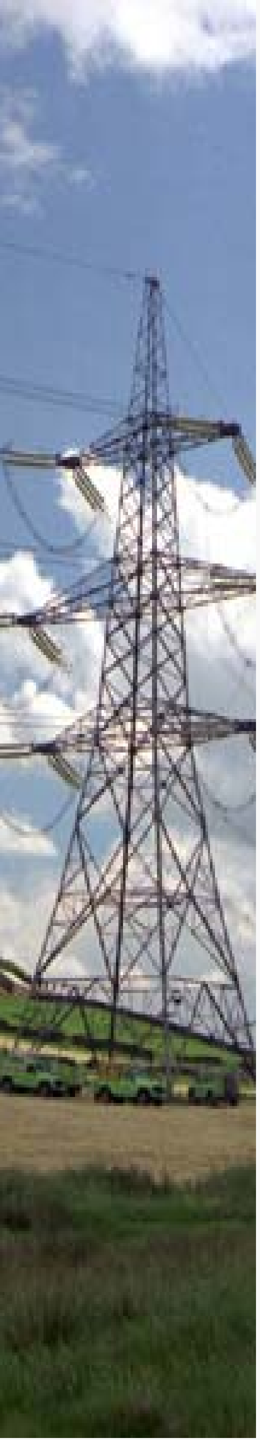


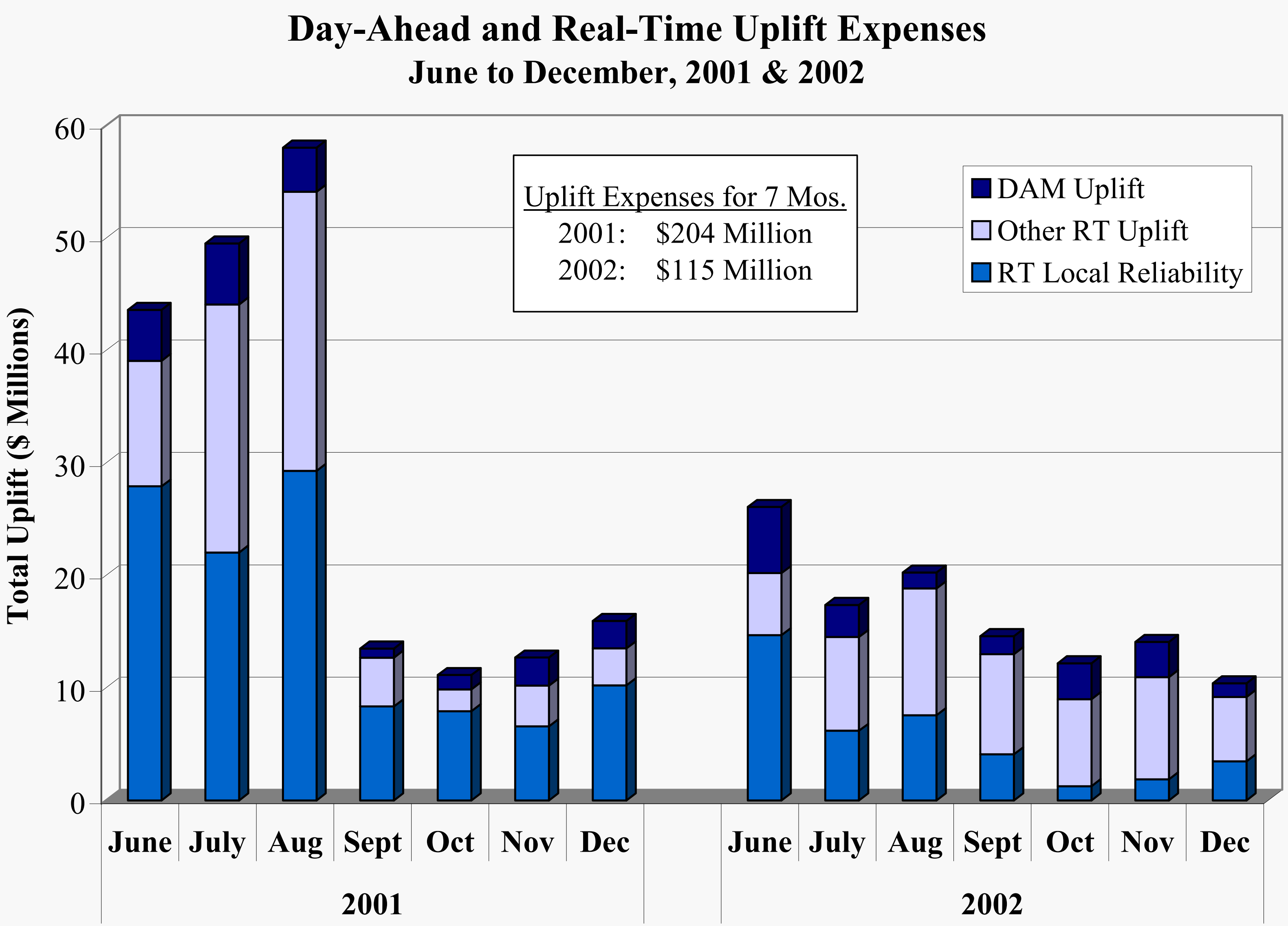

Average Hour-Ahead and Real-Time Energy Prices
East New York -- June to August, 2001 & 2002
Hours with Highest 10% of Real-Time Load
Price/MWh
$600
$500
$400
$300
$200
$100
$0
Hour-Ahead
Real-Time
June
July
August
2001
June
July
August
2002



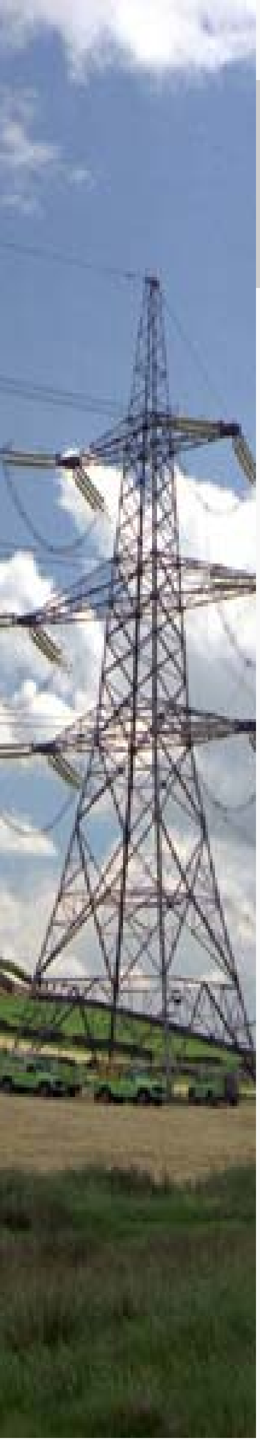
Uplift Expenses

- Uplift costs have fallen sharply as shown in the following chart.
  - ✓ Uplift costs were $89 million lower in June to December 2002 than the same time period in 2001 -- a reduction of 44%.
  - ✓ High fuel prices at the end of 2002 reduced the apparent savings relative to 2001.
- This reduction in costs was comprised of reductions in the following areas:
  - ✓ Real-time local reliability uplift: Reduction of 82% or $73 million resulting from implementing load pocket modeling.
  - ✓ Other real-time uplift: Reduction of 20% or $14 million resulting from improved BME performance.
  - ✓ Day-ahead uplift: Reduction of 10% or $2 million resulting, caused in part from the load pocket modeling in day-ahead.



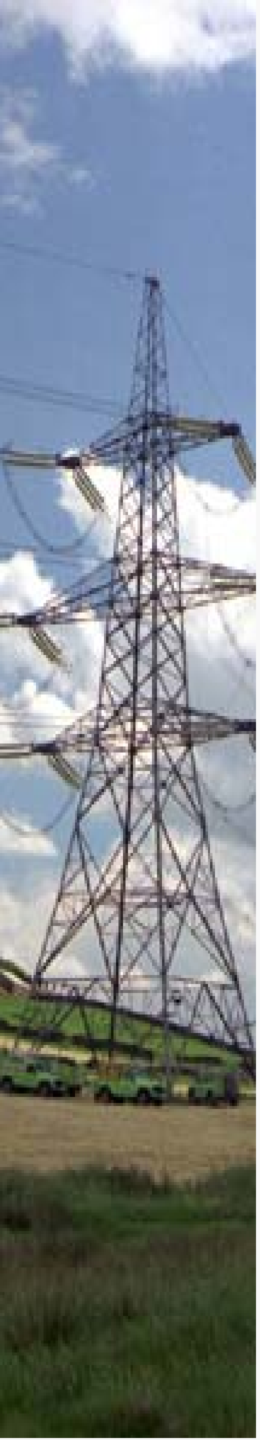


Day-Ahead and Real-Time Uplift Expenses
June to December, 2001 & 2002
Total Uplift ($ Millions)
0
10
20
30
40
50
60
Uplift Expenses for 7 Mos.
2001: $204 Million
2002: $115 Million
DAM Uplift
Other RT Uplift
RT Local Reliability
June
July
Aug
Sept
Oct
Nov
Dec
June
July
Aug
Sept
Oct
Nov
Dec
2001
2002



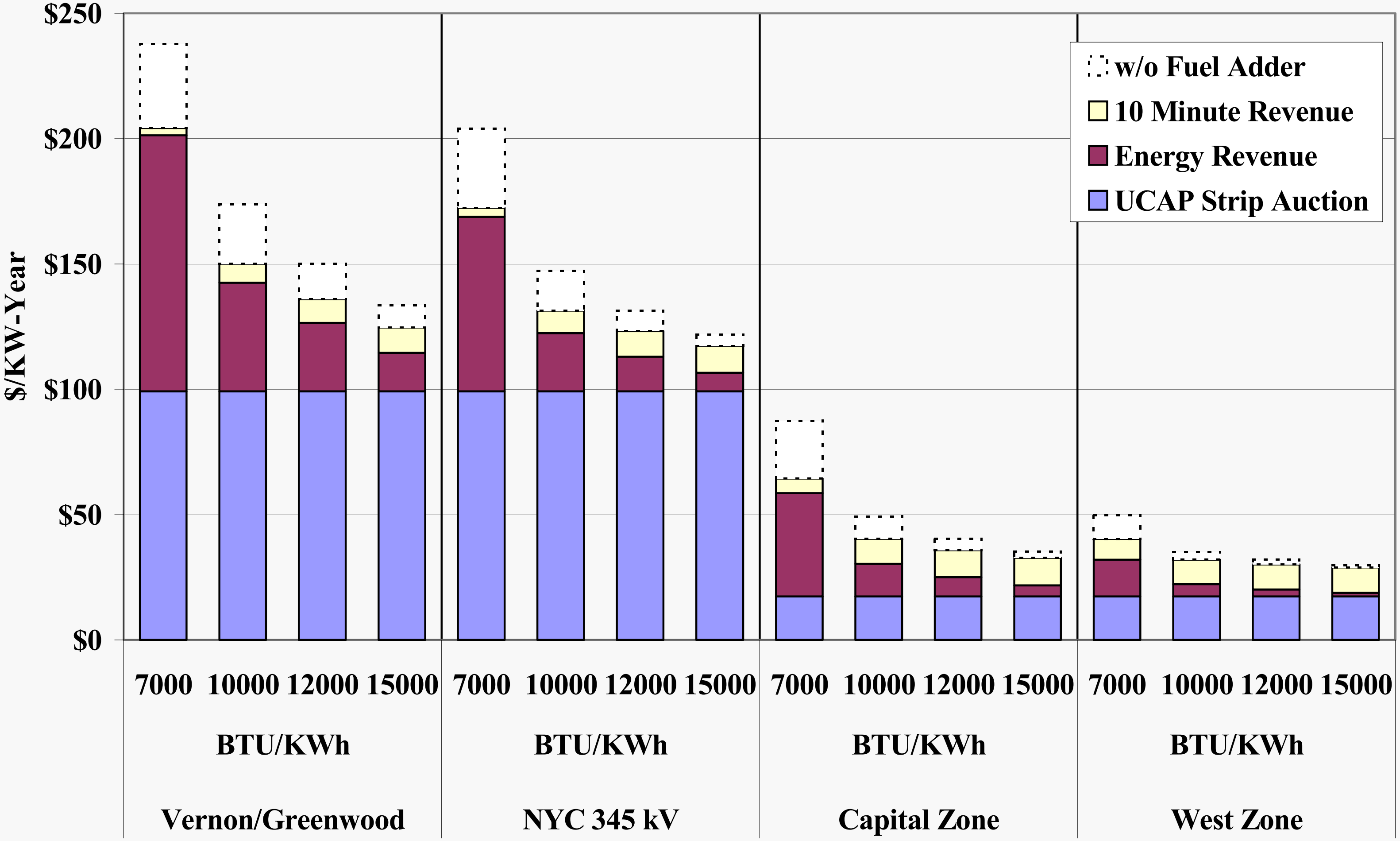
Economic Incentives for New Investment

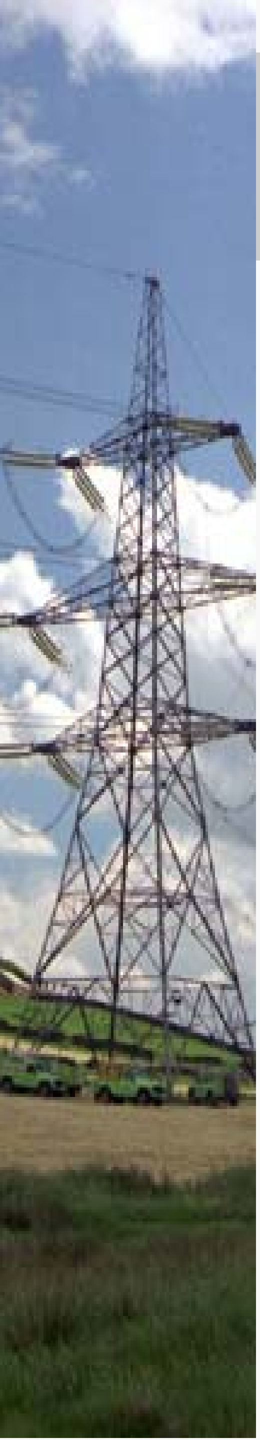
- The following analysis measures the economic signals produced by the markets in 2002. In long-run equilibrium, the market should support the entry of new generation.
- This analysis shows the net revenue the markets would provide to generators with different heat rates at various locations in New York.
- The chart also shows that the market in 2002 would not support new investment in gas turbines, although other investments may be more economic than gas turbines:
  - ✓ The annual cost of a new gas turbine is shown to be approximately $80 per kw-year outside of NYC versus net revenue ranging from $32 to $40 per kw-year outside NYC in the day ahead (assuming a 10000 heat rate).
  - ✓ Costs of installing a new GT in NYC are likely significantly higher – NYISO has estimated costs of approximately $180 per kw-year, while net revenues in 2002 ranged from $130 to $150 per kw-year in the two zones shown.
- The peak pricing changes being implemented for this summer should help address this issue.



Estimated Net Revenue in the New York Markets

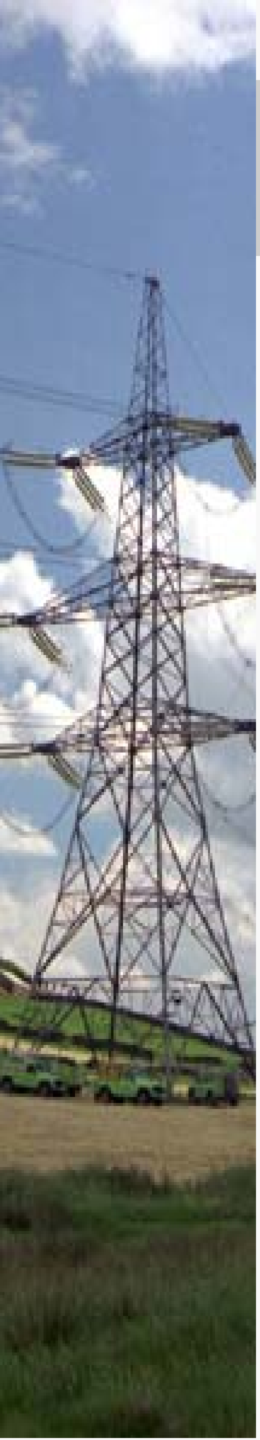
DAM - 2002





Energy Price Convergence

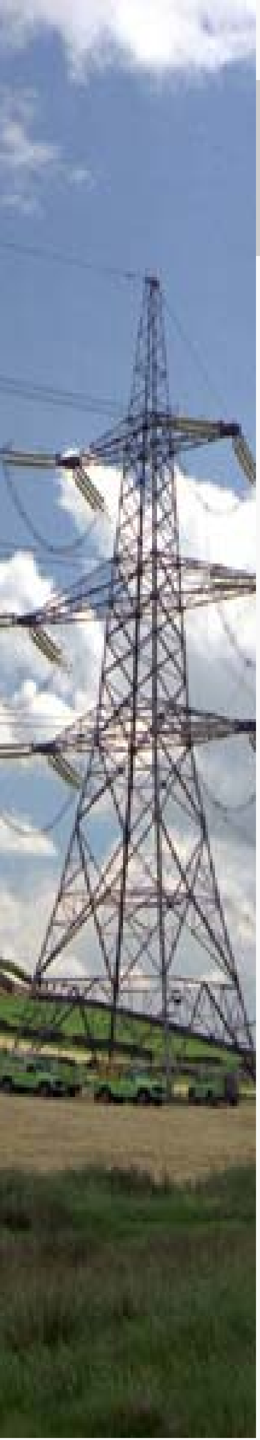
- Prices converged relatively well between day-ahead and real-time markets, although a slight premium in day-ahead prices remains (2% to 4%).
- These premiums are not surprising due to
  - ✓ The higher risk to loads of purchasing in the more volatile real-time market and lack of TCC's to hedge congestion in real-time, and
  - ✓ The outage risk of generators associated with day-ahead schedules.
- Price convergence within the New York City was poorer.
  - ✓ Rather than the 2-4 percent premium on other locations, the NYC load pockets exhibited day ahead prices ranging from a 13 percent premium to a 20 percent discount relative to real-time prices.
  - ✓ This was due, in part to the fact that virtual bidding and price-capped load bidding can only be done on a zonal basis, which limits the ability of participants to arbitrage large price differences in specific pockets.
  - ✓ Virtual trades that improve convergence in one pocket will generally worsen convergence in other pockets.



Analysis of Bid and Offer Patterns

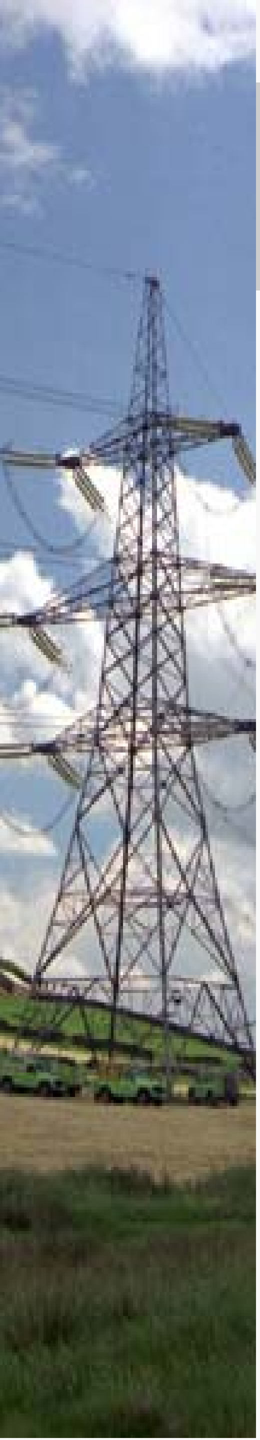
- The report includes an analysis of participant conduct that could suggest physical or economic withholding.
  - ✓ Based on this analysis, the report concludes that withholding has not been a significant concern during 2002.
  - ✓ However, certain isolated instances of potential withholding required further investigation by the MMU and Potomac Economics.

- We also monitor the bidding patterns of load-serving entities as specified in the monitoring and mitigation plans.
  - ✓ The report concludes that loads were not bid in a manner suggesting an attempt to distort energy market prices.
  - ✓ Price-capped load bidding has become more prevalent since the implementation of virtual bidding in November 2001.
  - ✓ The percent of the actual load supplied through physical bilaterals has been relatively constant throughout the state (at roughly 50 percent).
    - Physical bilaterals do not include all bilaterals since those structured as “Contract for Differences” will be shown as day-ahead bid load.



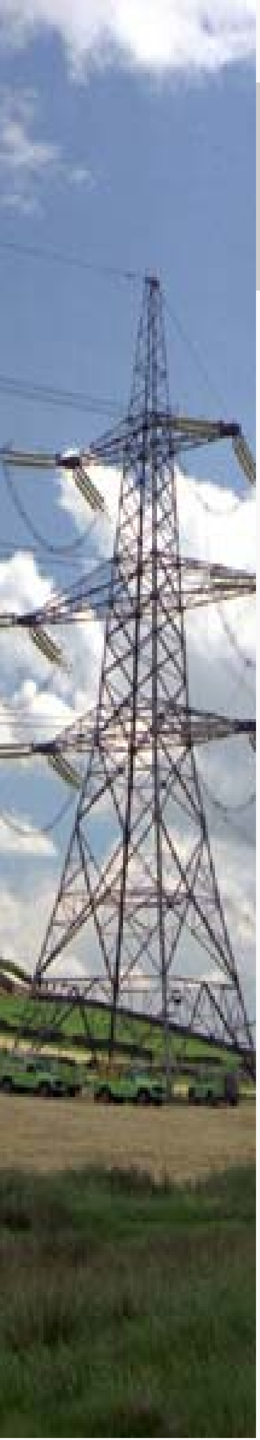
Virtual Trading Patterns

- Virtual bidding was introduced in November 2001 to allow participation in the day-ahead market by entities other than LSE’s and generators.
- The magnitude of the virtual load offers and supply bids and the quantity scheduled increased significantly throughout 2002.
- Most virtual bids and offers were price-sensitive (ranging from 70 to 90 percent on a monthly basis), suggesting little concern that participants attempted to use virtual trading to distort day-ahead prices.
- Finally, the report indicates that a small portion of virtual trades have continued to not be scheduled consistently with their bid price
  - For example, virtual load bid not scheduled when the LBMP < bid price, or scheduled when LBMP > bid price.
  - Close to 5% of *unscheduled* virtual trades and less than 1% of *scheduled* virtual trades and price-capped load bids are scheduled inconsistently.
  - Results from a known inconsistency between the scheduling, pricing, and settlement rules – report recommends NYISO resolve the inconsistency.



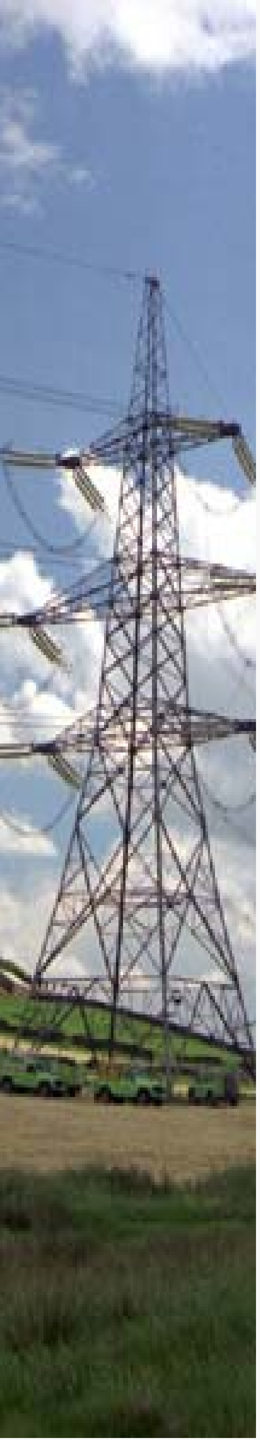
Peak Energy Pricing

- This report evaluates the price signals established under peak demand conditions in 2002, which play a critical role
  - ✓ Allowing existing high-cost units to recover their costs of remaining on the system; and
  - ✓ Establishing efficient incentives for new investment.
- Analysis of the highest demand conditions during 2002 shows that prices were inefficiently reduced during peak conditions by:
  - ✓ Gas turbines dispatched out-of-merit for reliability reasons;
  - ✓ Load reduction through the emergency demand response and special case resources programs; and
  - ✓ The dispatch of operating reserves to provide energy during shortages.
- The NYISO has already taken actions to address the out-of-merit issues and will be filing pricing changes to address the other issues.



Pricing During Reserve Deficiencies

- The locational pricing market design employed in New York does not preclude efficient scarcity pricing.
  - ✓ There are significant quantities of generating resources with offer prices (based on legitimate costs) ranging from $200 to the safety-net bid cap at $1000 per MWh. When these resources are dispatched to meet energy demands, they will set energy prices at relatively high levels.
  - ✓ However, when operating reserves are released, the NYISO markets will not reliably set efficient scarcity prices.
- The following table shows the actual prices in eastern New York that prevailed in the intervals exhibiting a 10-minute operating reserve deficiency, showing:
  - ✓ Real-time energy prices were relatively unpredictable during these intervals, ranging from $99 to $1097 per MWh.
  - ✓ In only one quarter of the hours was the price above $500 per MWh.
  - ✓ Most of the prices in these intervals range from $100 to $200 per MWh – well below the implicit value of 10-minute reserves of $1000 per MWh.

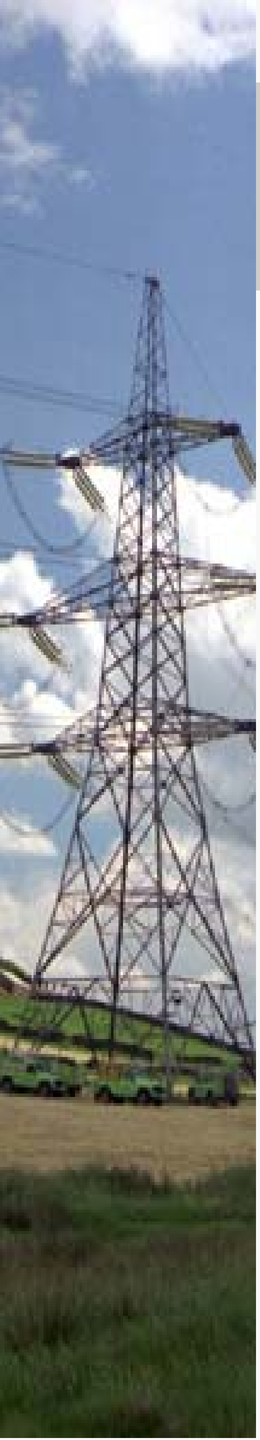


Average Real-Time Prices in Eastern New York During Periods with 10-Minute Reserve Deficiency

	Hour	*Price ($/MWh)*
June 27	15	$210
	16	$106
	17	$115
July 2	15	$580
	16	$228
July 29	12	$157
	13	$143
	14	$740
	15	$837
	16	$1,097
	17	$812
	18	$227

	Hour	*Price ($/MWh)*
July 30	16	$121
July 31	13	$265
	14	$99
August 1	13	$101
August 13	13	$130
	16	$144
August 14	14	$101
	15	$103

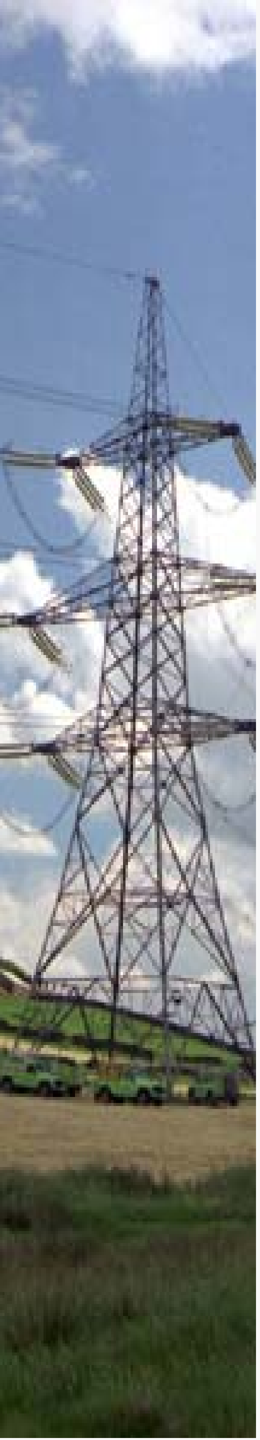
Note: Prices are averages of only the deficient intervals during the 20 hours shown. The intervals of shortages in these hours sum to approximately 13 full hours of deficiency.



Analysis of External Transactions

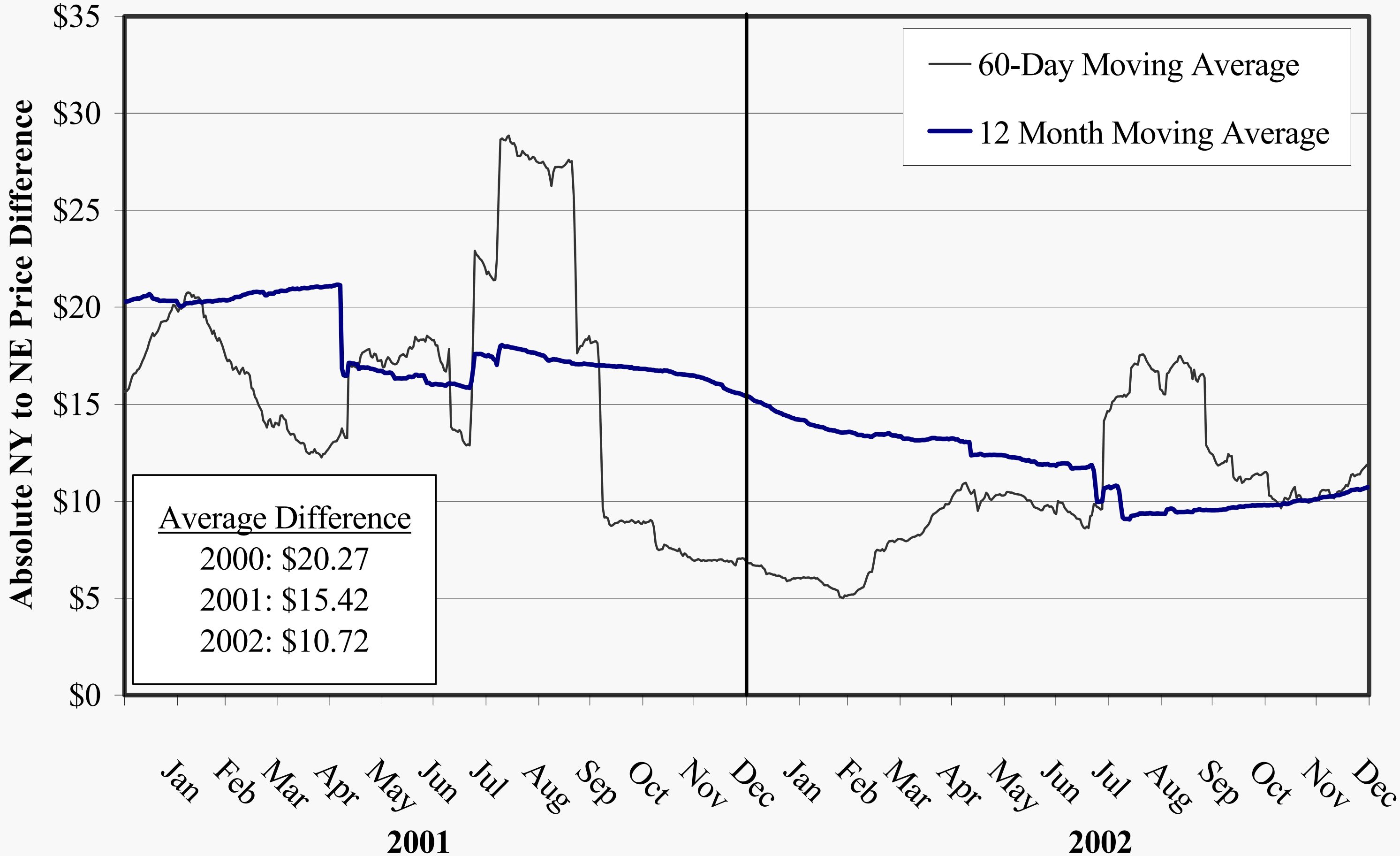
Conclusions of the report regarding external transactions and utilization of the external transmission interfaces:

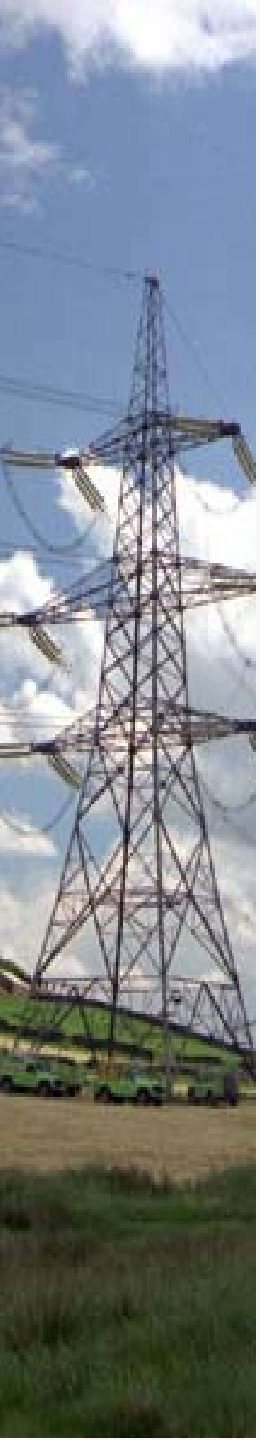
- Several changes in the transaction scheduling rules and procedures have been made that have improved the utilization of the interfaces.
  - ✓ This is evident on the following chart showing the trends in the average price differences between New York and New England over the past two years.
  - ✓ These improvements have resulted in cumulative production cost savings relative to 2000 of $22 million and $70 million in 2001 and 2002, respectively.
- However, substantial price differences between New York and adjacent markets have continued to occur under peak demand conditions.
  - ✓ This is shown in the next chart, indicating the direction and magnitude of physical schedules in real time when price differences exceed $100 per MWh.
  - ✓ In more than 63 percent of these hours, the net interchange reflects power scheduled from the higher-priced market to the lower priced market;
  - ✓ Inefficient inter-regional arbitrage during peak periods has had substantial economic impacts in some hours on New York and its neighbors.



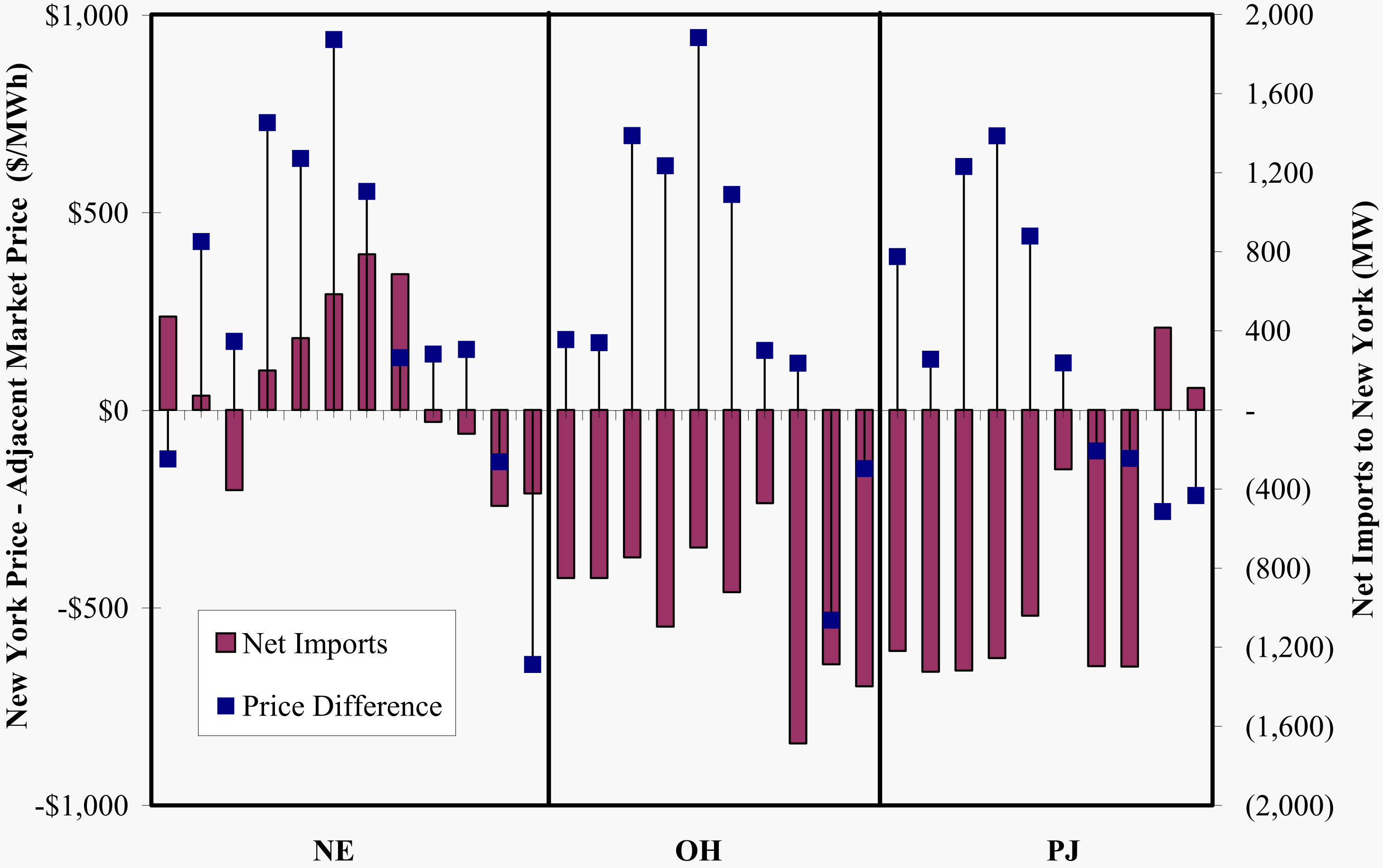
Average Price Difference Between New York and New England During Uncongested Hours

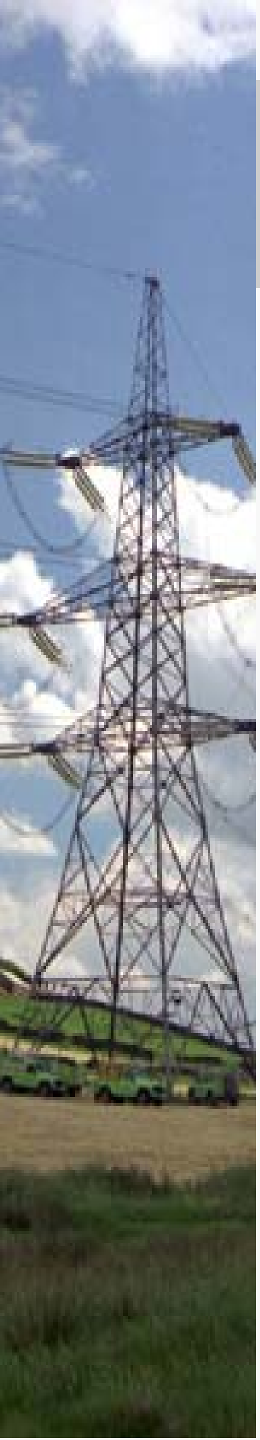
Moving Average -- 2000 through 2002





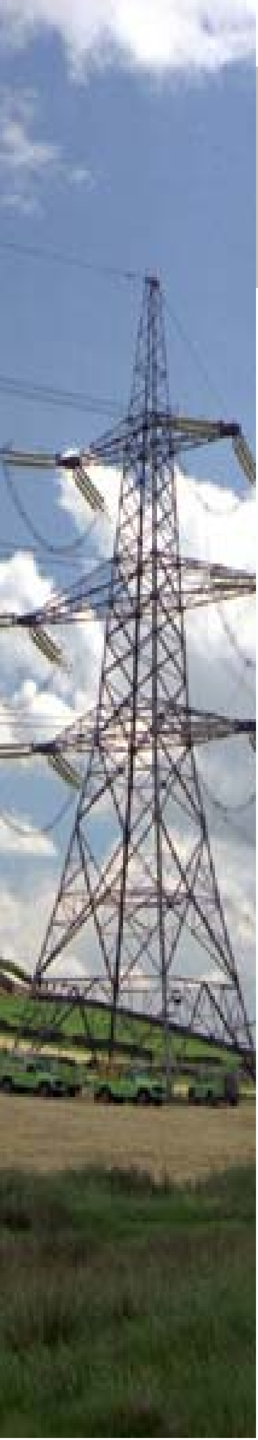
Relationship of Real-Time Prices to Net Imports from Adjacent Areas
Unconstrained Hours with Price Differences > $100 per MWh





External Transaction Recommendations

- Improvements have been made to address the seams issues, but further improvements are needed.
- To address these issues, I have recommended:
  - ✓ The New York ISO and the adjacent ISOs coordinate their physical interchange by automatically adjusting it in small increments every 5 to 15 minutes based on the prices in the two markets at the border.
  - ✓ These adjustments should continue until the prices equalize or until the interface constraint is binding.
  - ✓ The adjustments would be incremental to the transactions scheduled by the participants in the day-ahead or prior to real-time.
  - ✓ Congestion revenue will be collected when the interface is constrained – a transmission right (CRR) could be created to receive these revenues.
  - ✓ Although not necessary, I would recommend eliminating the export fees. The interface congestion revenue (or CRR auction revenue) would provide an offset for this revenue.



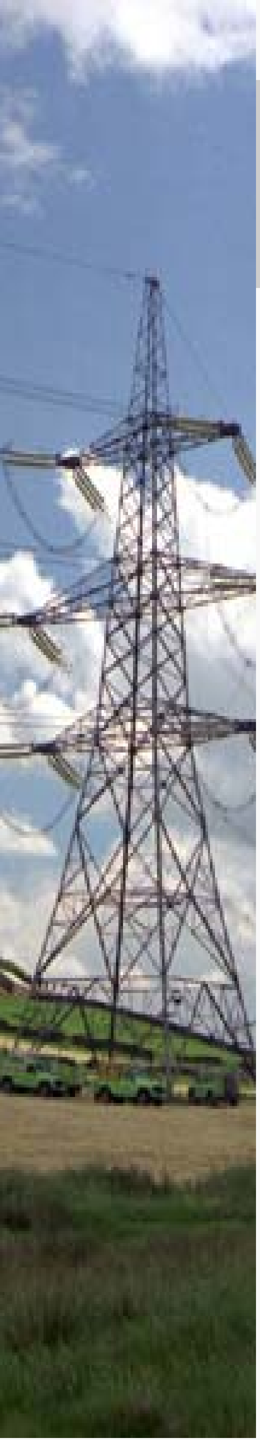
Coordinated Interchange Recommendation

This does not mean that the ISOs will be taking positions in the market

- Allowing the ISOs to dispatch the seam is analogous the ISO's dispatch of internal generation to manage flows on internal interfaces – the physical flow would be determined entirely by the load and generator bids in the two regions.
- Coordinating the dispatch would be similar to and capture most of the benefits of a single dispatch in the Northeast.
- The proposal would actually <u>reduce</u> the ISO's participation in the market.
  - ✓ The ISOs schedule imports and exports more than an hour prior to the market.
  - ✓ If these schedules turn out to be uneconomic, the ISO must pay the supplier its bid price, uplifting the costs of the uneconomic purchase to loads.

The proposed changes should improve participant's ability to transact:

- ✓ To the extent that prices are rationalized between markets, the financial risk participants face will be reduced.
- ✓ If CRRs are created for the interface, participants will have the ability to engage in completely hedged financial transactions throughout the Northeast.



Ancillary Services

- Ancillary services costs decreased significantly in 2002, from 1.5 percent of total market expenses in 2001 to less than 1 percent in 2002;
  - ✓ This was primarily related to changes in the hour-ahead software, allowing it to recognize latent 30 minute reserves that are on the system in real time.
  - ✓ However, regulation costs have increased, generally caused by software changes in SCUC and BME to recognize that units cannot regulate downward below their minimum generation level (this reduces the supply of regulation to the model).
- Ancillary services markets are generally not tight because offers to supply typically exceed approximate demand:
  - ✓ 30 minute reserves: offers exceed demand by approximately 150 percent.
  - ✓ Total 10-minute reserves in the east: offers exceed demand by 170 percent.
  - ✓ Regulation and 10 minute spinning reserves: offers exceed demand by 90 to 100 percent – but ignores that some spinning reserves can be purchased in the West.
- However, the offers for each of the services have been substantially less than the market capability (except 10-minute NSR), which can affect both the energy and ancillary services markets when they approach shortage.
- The pricing changes proposed under RTS should improve the incentives to supply operating reserves and are consistent with prior recommendations.