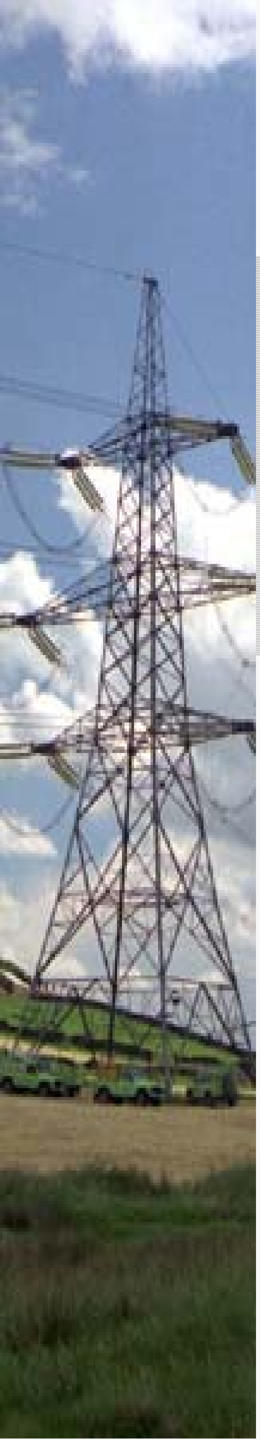


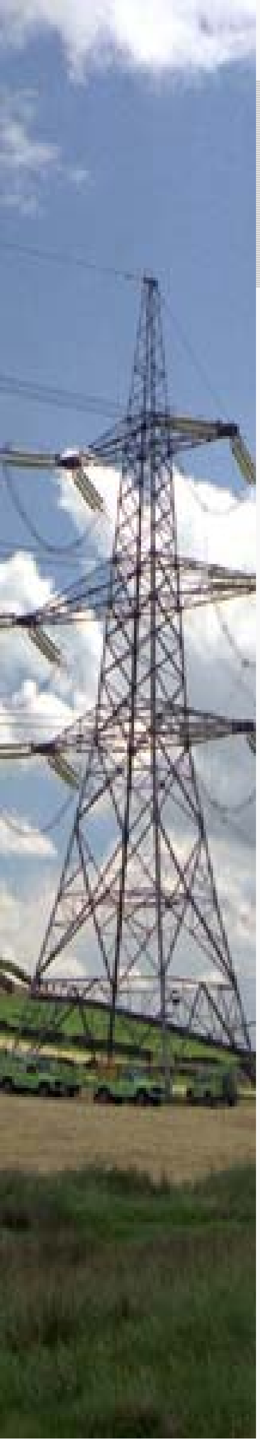
2001 Annual Report on the New York Electricity Markets

Presented to:

New York ISO Joint Board of Directors/
Management Committee Meeting

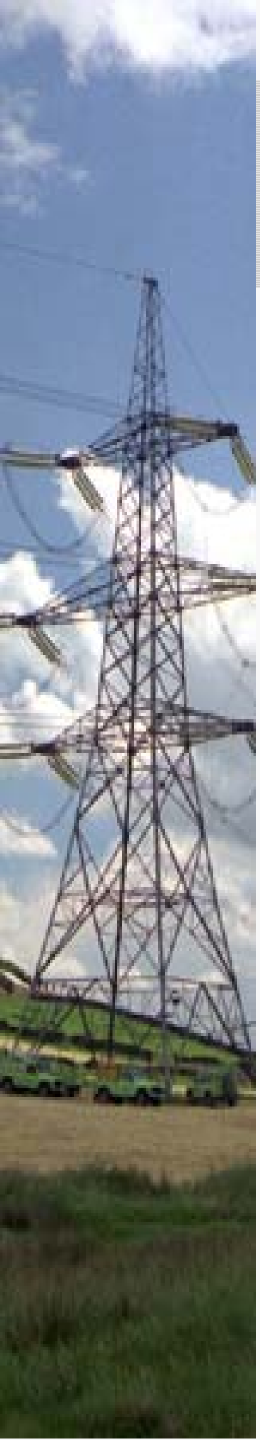
David B. Patton, Ph.D.
Independent Market Advisor

April 16, 2002



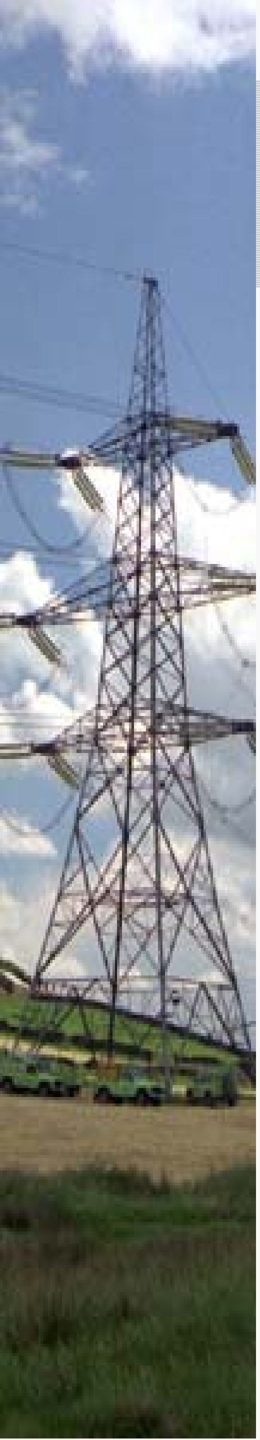
Conclusions and Recommendations

- The markets performed relatively well during 2001.
- Lower fuel prices and reduced generation outages in Eastern New York led to lower prices and substantially less congestion.
- Analysis of the market conduct of both the suppliers and the load-serving entities indicates that the markets have been workably competitive.
- Price convergence between the day-ahead and real-time has improved.
- Prices will likely be slightly higher this summer than last summer, although uplift costs should be substantially reduced.



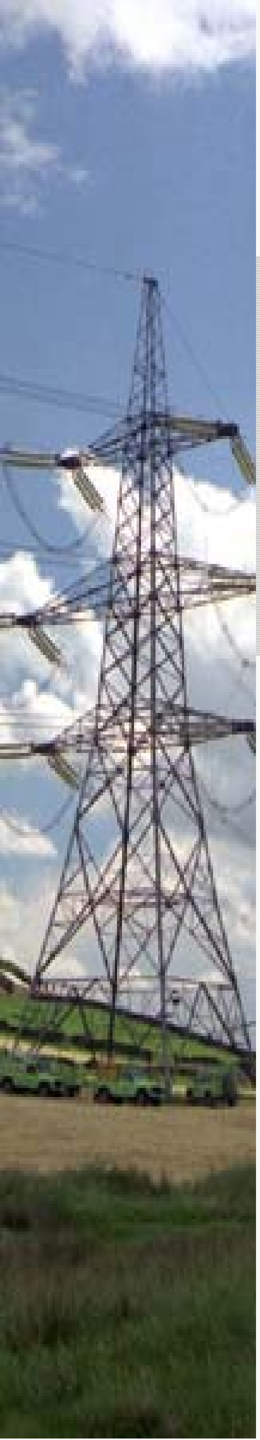
Conclusions and Recommendations

- The following issues are apparent from the analysis in this report and the Summer 2001 report, for which changes are underway.
  - Apparent impediments to trading remain, particularly with New England. Changes in market rules and procedures should reduce these issues in 2002.
  - Poor convergence of prices produced by the BME and SCD models under peak conditions led to reduced real-time prices and considerable uplift.
  - Out-of-merit dispatch of generation increased in 2001, depressing prices and raising uplift in NYC.
- However, concerns are also indicated by this analysis in the following areas that require further work.
  - Relatively low participation in the ancillary services markets remains an issue that can create significant inefficiencies in the energy market under peak conditions – pricing reforms are recommended to improve incentives.
  - The ICAP results in NYC have not been consistent with competitive expectations – consideration of alternative designs is warranted.

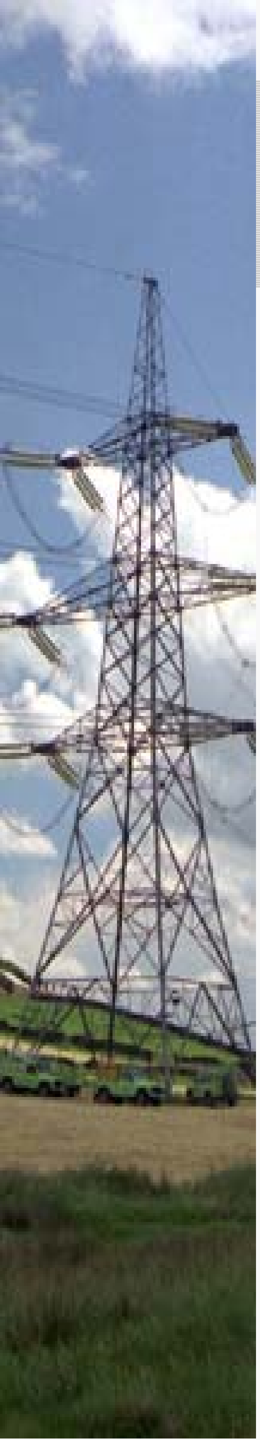


Introduction to the Market Assessment

- This presentation provides highlights from the Annual Report on the New York electricity markets for 2001.
- The market assessment addresses the following areas:
  - ✓ Energy market prices and outcomes
  - ✓ Market participant bidding patterns
  - ✓ Installed capacity market
  - ✓ External transactions
  - ✓ Ancillary services

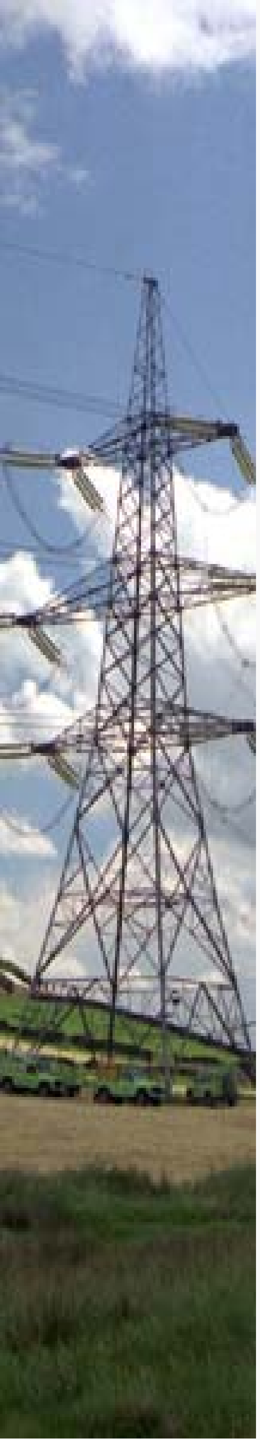


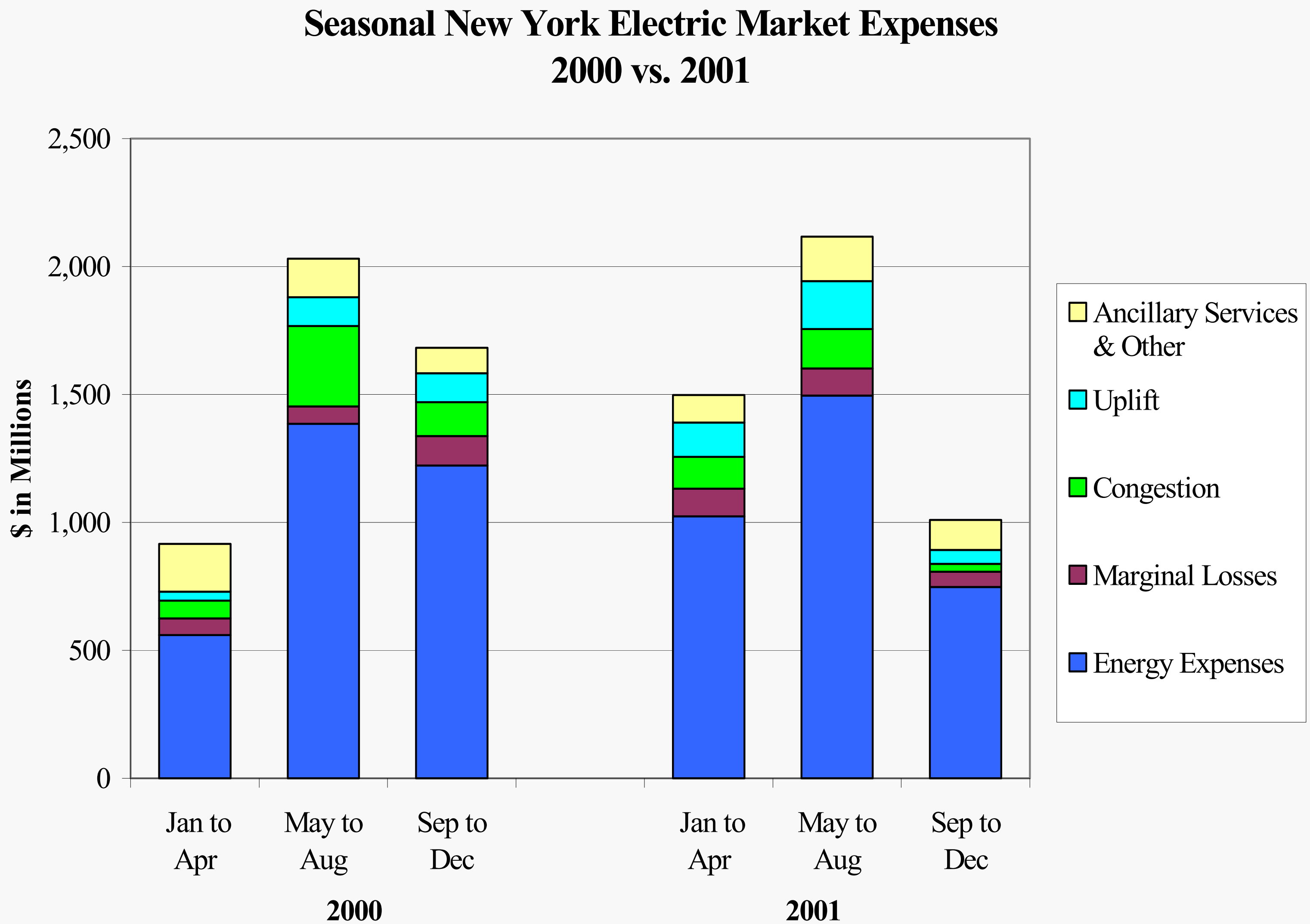
Market Prices and Outcomes



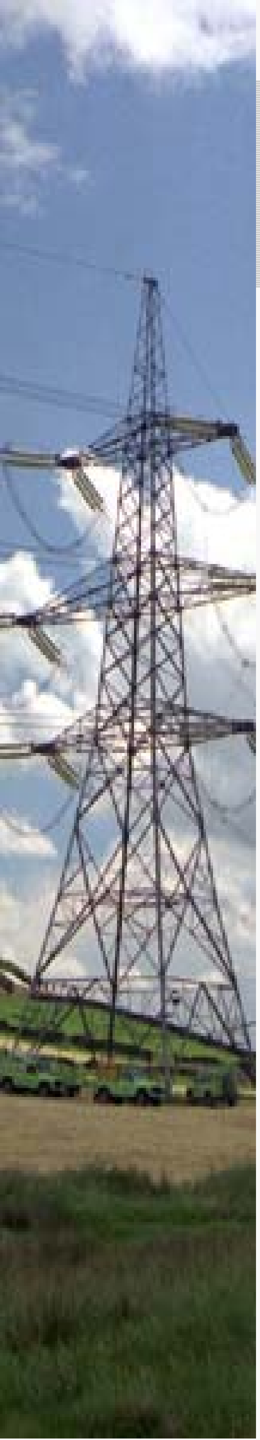
Total Electricity Costs in the New York Markets

- The following chart shows the total seasonal expenses for market participants of the NYISO in 2000 and 2001.
- The total market expenses for 2001 were approximately equal to the levels in 2000. However, changes from 2000 to 2001 included:
  - ✓ Congestion rent fell by 40 percent.
  - ✓ Uplift costs rose by more than 40 percent due to increases in real-time local reliability uplift costs.
  - ✓ Although average prices were lower in 2001, higher loads and lower reliance on physical bilaterals increased settlements through the NYISO markets.



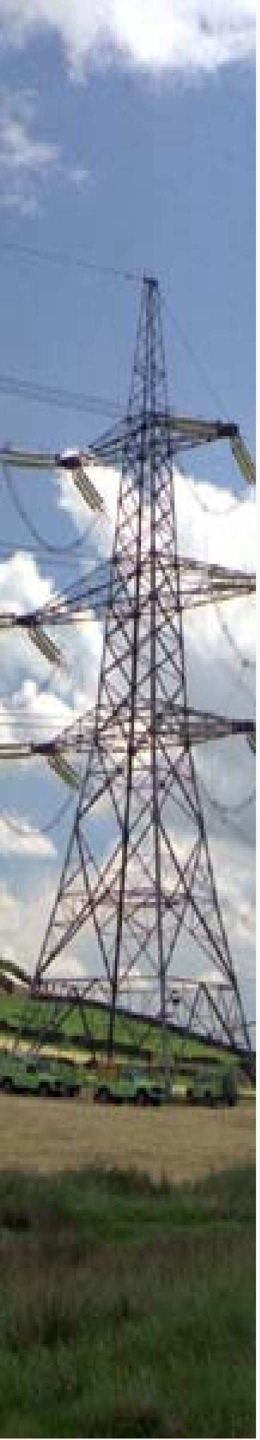


Seasonal New York Electric Market Expenses
2000 vs. 2001
$ in Millions
2,500
2,000
1,500
1,000
500
0
Jan to Apr
May to Aug
Sep to Dec
Jan to Apr
May to Aug
Sep to Dec
2000
2001
Ancillary Services & Other
Uplift
Congestion
Marginal Losses
Energy Expenses

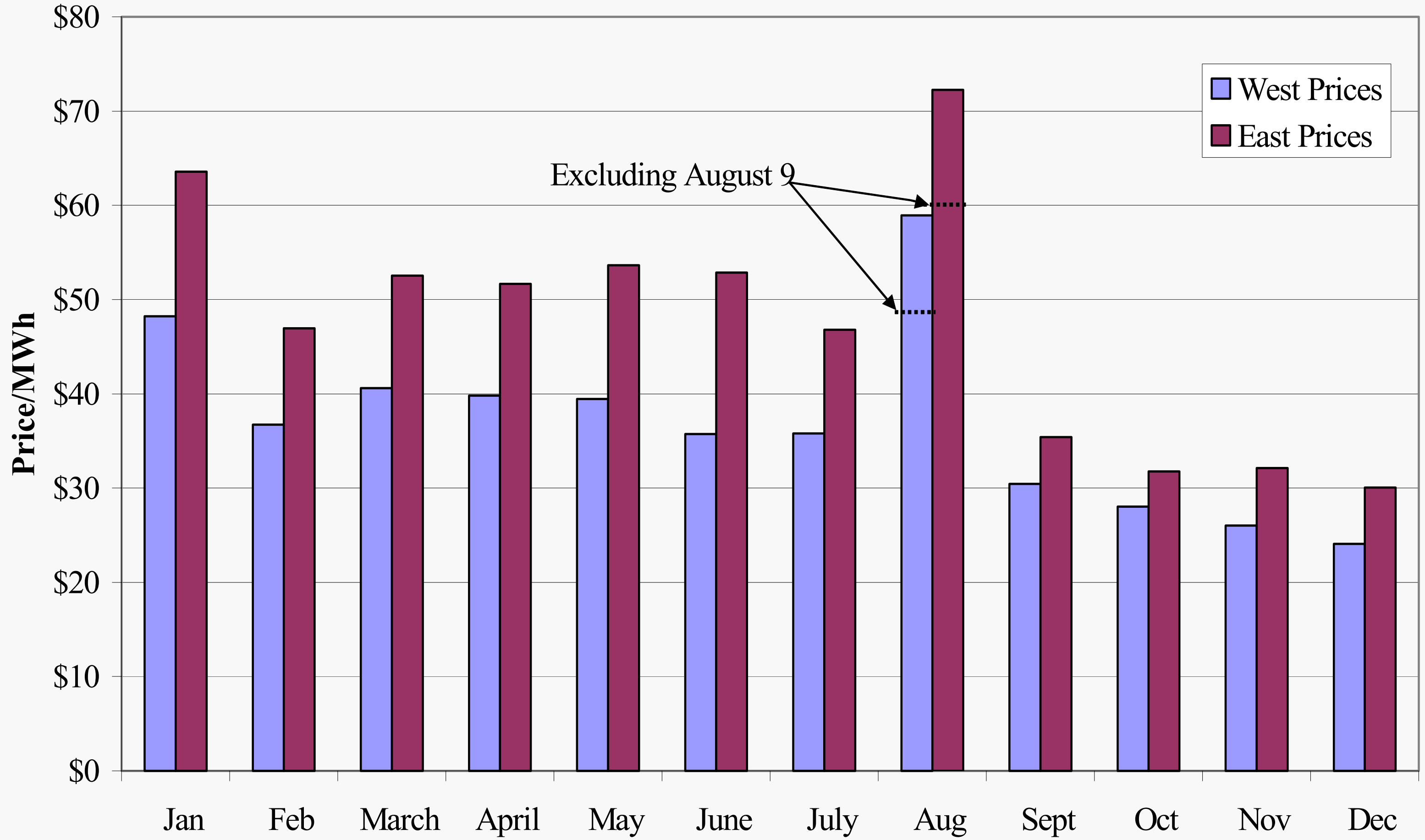


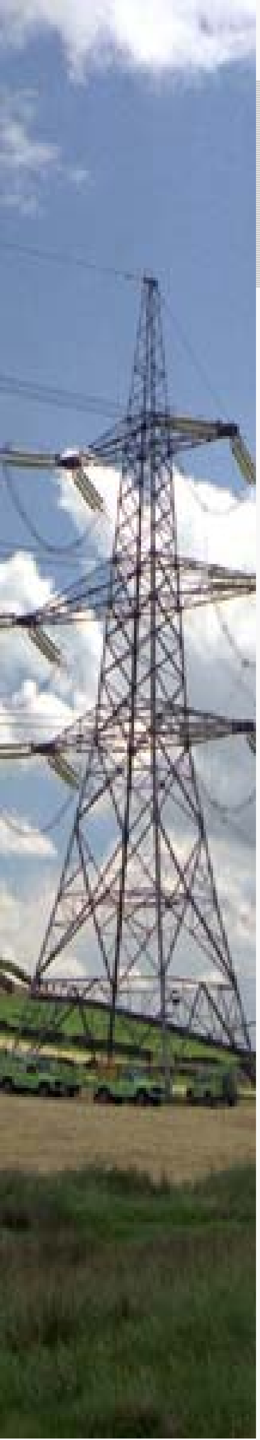
Energy Prices in the Day-Ahead Market

- The following chart shows average prices during all hours in 2001.
- Prices are shown with and without the August 9, 2001 price spike, which shows the importance of this event on overall prices.
- There was a decreasing trend in prices from January to December 2001.
  - ✓ In December 2001, prices in New York were 52% lower than in January 2001.
  - ✓ This is primarily due to substantial decreases in the prices of input fuels over the same period, 40% for fuel oil and 70% for natural gas.
- Although congestion decreased in 2001, the average price in the East remained almost 30% higher than in the West due to the continued congestion on the Central-East Interface and into New York City.



Monthly Average Day Ahead Prices in New York
January to December 2001





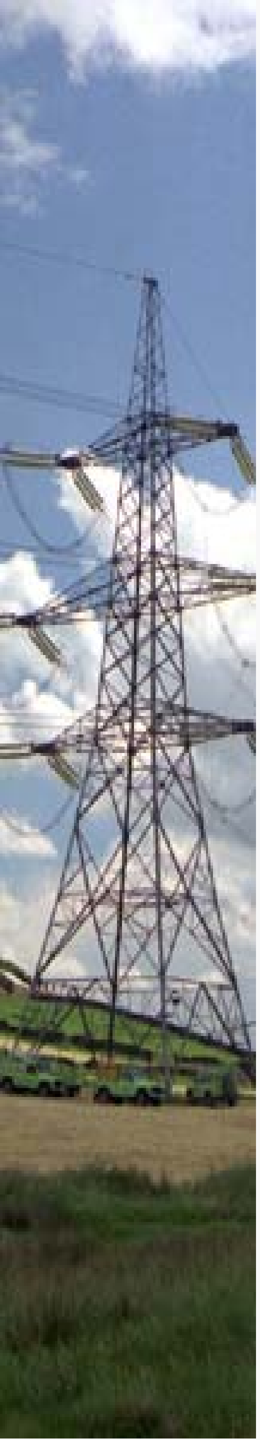
Fuel Price Changes During 2001

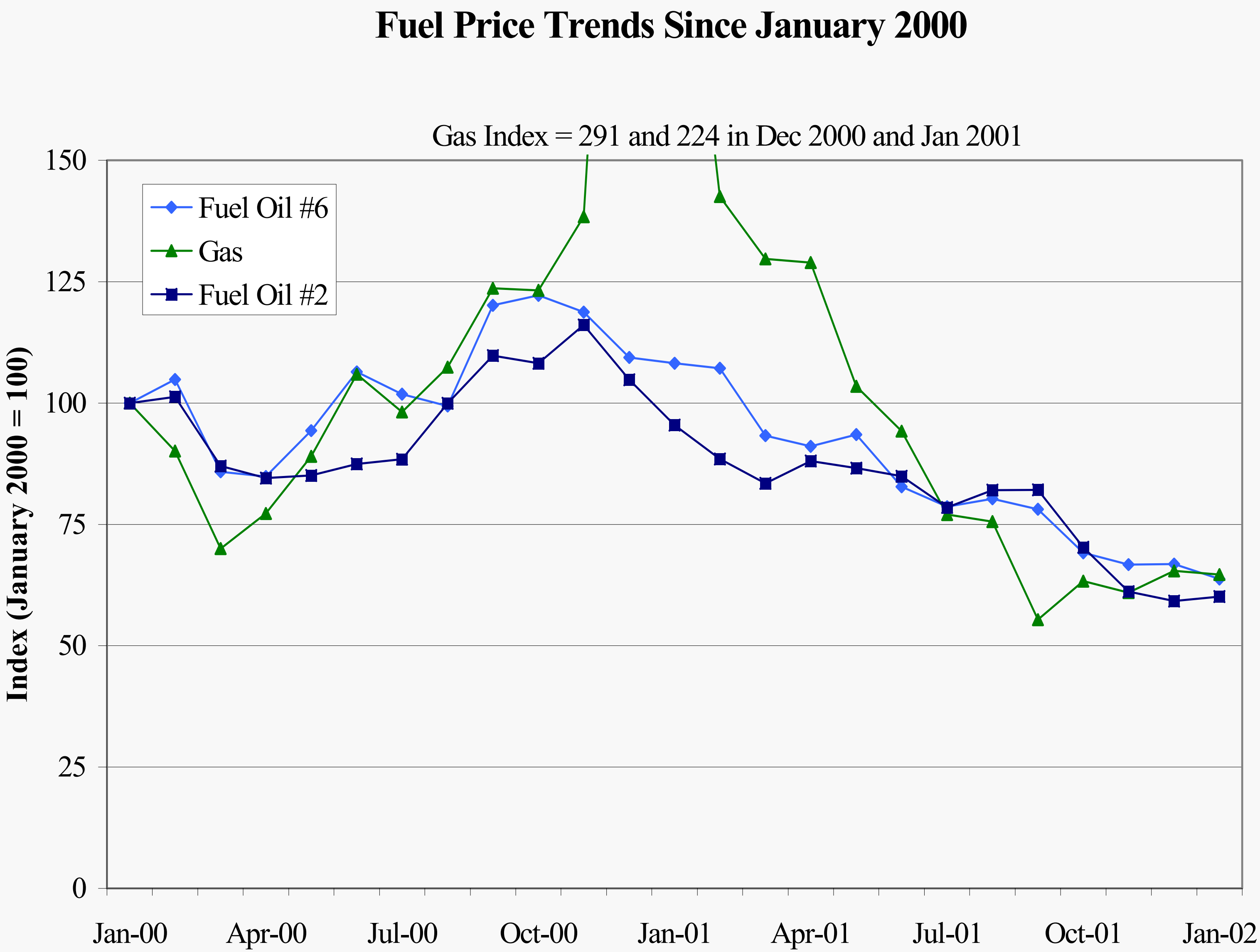
- The prior figures showed that energy prices have fallen substantially from January 2001 to December 2001 – more than 50 percent.

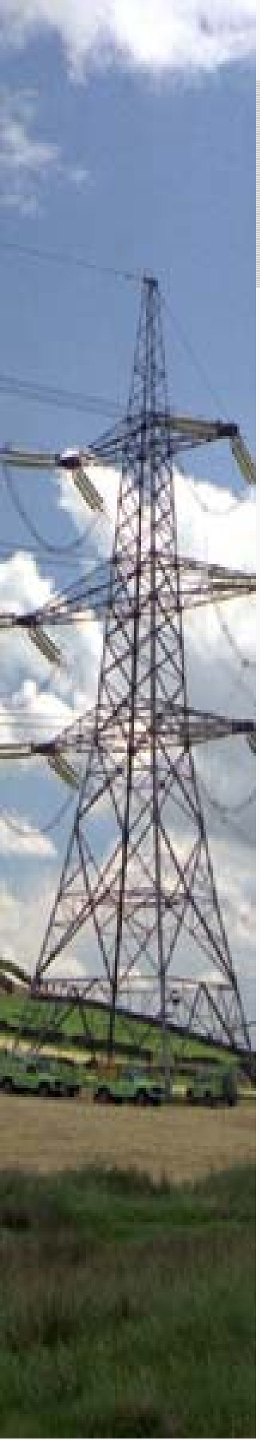
- One of the primary factors contributing to this price reduction is the sharp decline in fuel prices over the year, shown in the following figure.

  - ✓ Natural gas fell by more than two-thirds;

  - ✓ Fuel oil prices decreased by approximately 40%;

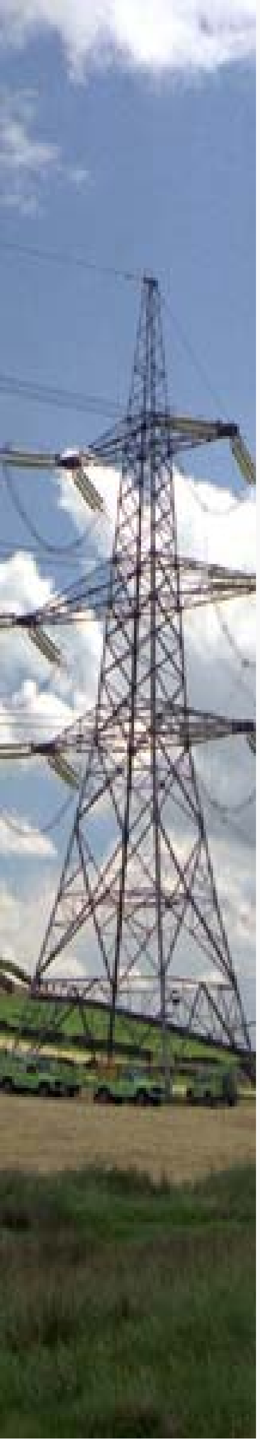


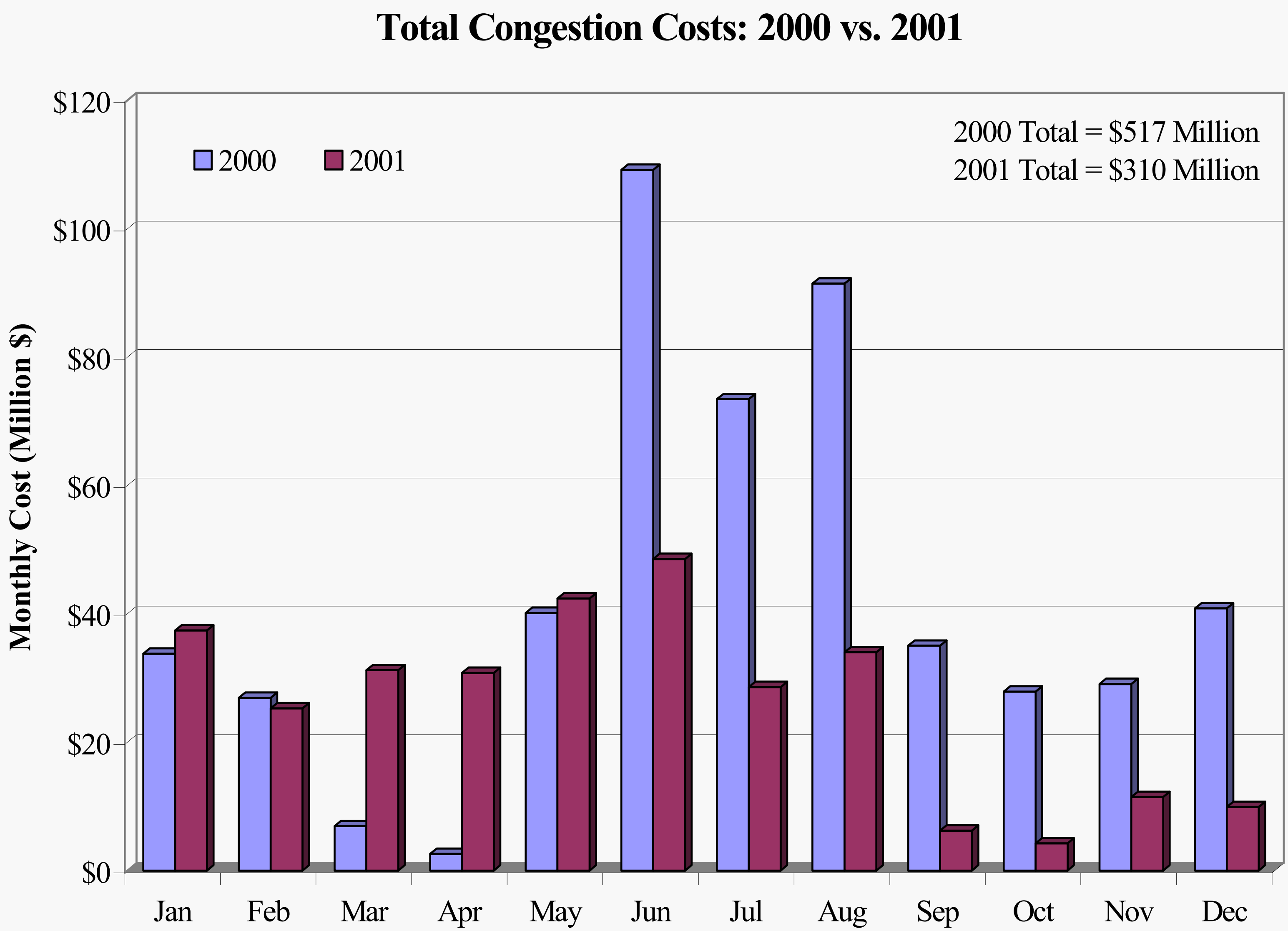

Fuel Price Trends Since January 2000
Gas Index = 291 and 224 in Dec 2000 and Jan 2001
Fuel Oil #6
Gas
Fuel Oil #2
Index (January 2000 = 100)
150
125
100
75
50
25
0
Jan-00
Apr-00
Jul-00
Oct-00
Jan-01
Apr-01
Jul-01
Oct-01
Jan-02

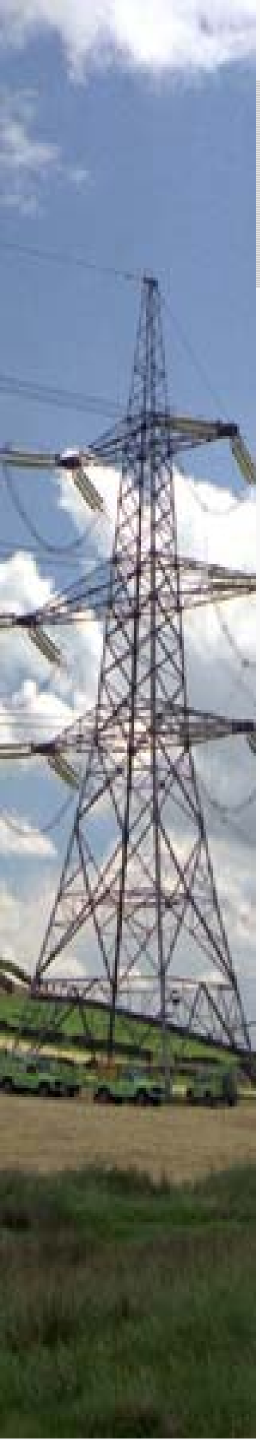


Congestion Revenue

- The following chart compares the monthly congestion revenue generated in 2000 with 2001.
- Congestion revenue is net revenue collected from loads and bilaterals (net of congestion payments to generators).
- The reduction in congestion is due to:
  - ✓ The return of Indian Point 2 (1000 MW) in Eastern New York;
  - ✓ Increased imports from New England;
  - ✓ Lower oil and gas prices in 2001; and
  - ✓ Reduced limit on imports over the HQ proxy bus.

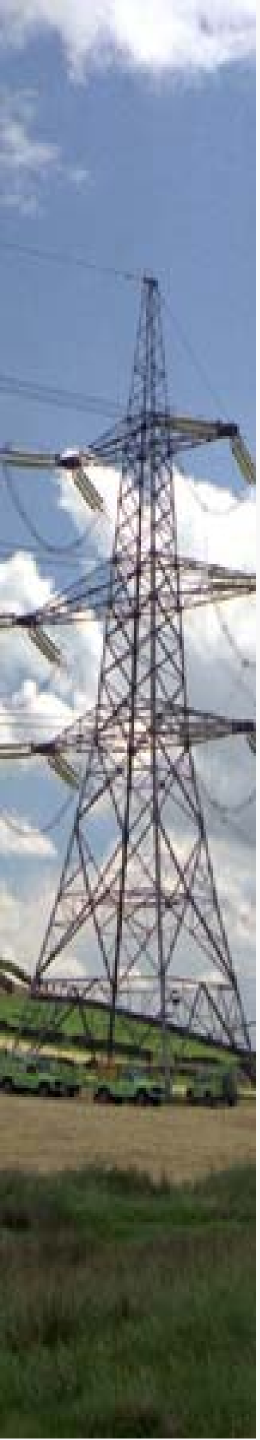


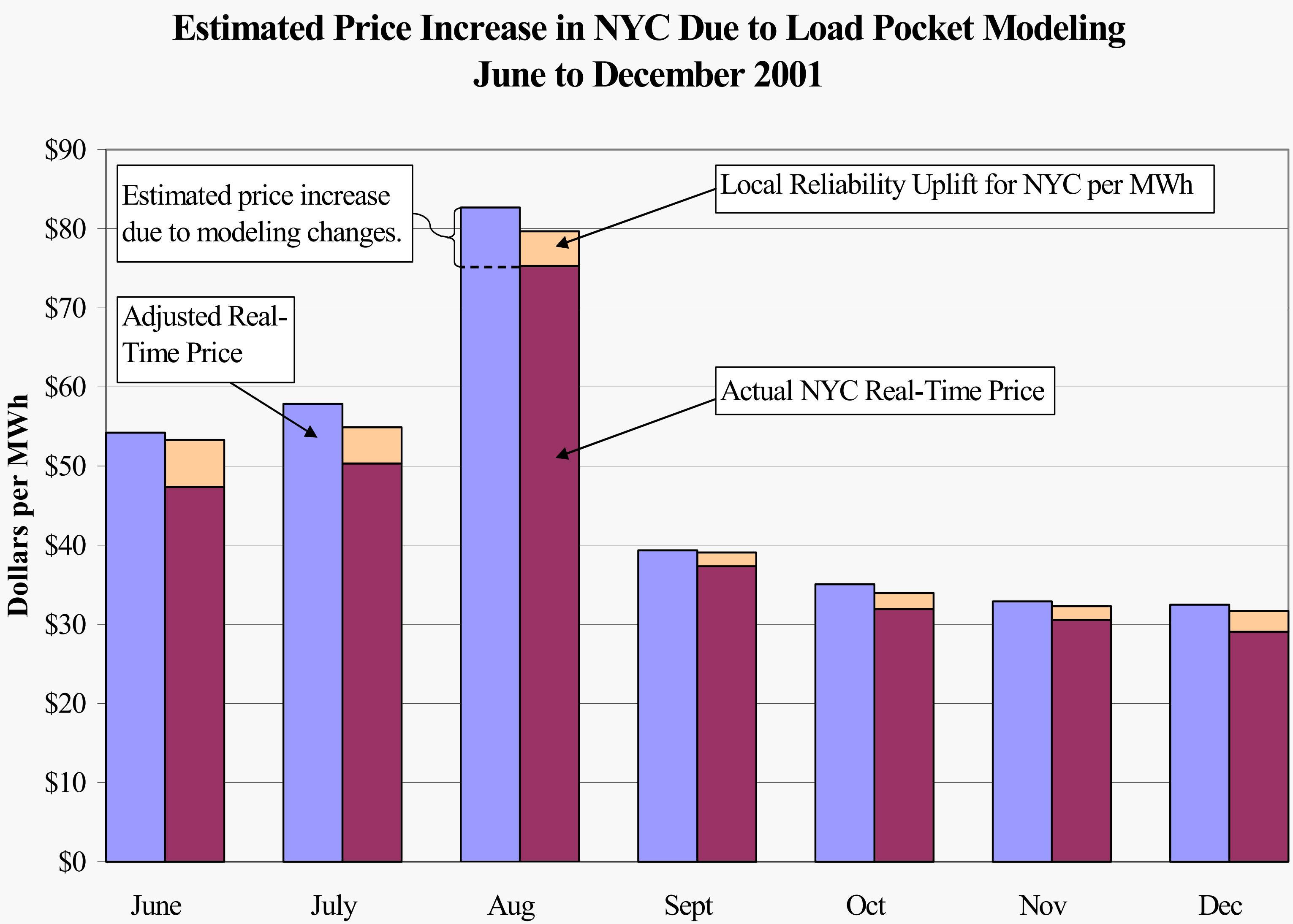

Total Congestion Costs: 2000 vs. 2001
2000
2001
2000 Total = $517 Million
2001 Total = $310 Million
Monthly Cost (Million $)
$120
$100
$80
$60
$40
$20
$0
Jan
Feb
Mar
Apr
May
Jun
Jul
Aug
Sep
Oct
Nov
Dec



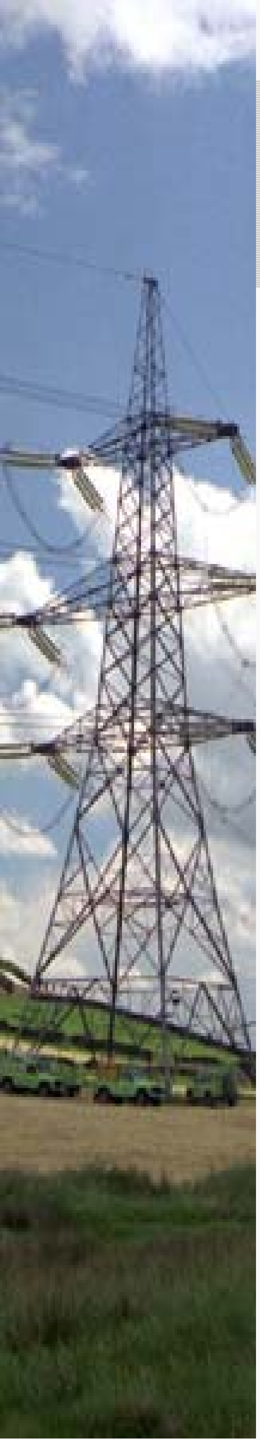
Price Impacts of Out-of-Merit Dispatch in NYC

- One of the key changes to the market for 2002 involves making changes to SCUC, BME, and SCD to recognize the transmission constraints within NYC.
- The addition of new constraints will raise the locational prices in the constrained areas (load pockets) and reduce the out-of-merit dispatch previously used to manage the constraints.
- The following chart shows my estimate of the price impact of these modeling changes in the real time market. The chart includes:
  - An adjusted price for NYC, computed by estimating a locational price in each load pocket equal to the highest priced (lower of ref. price or bid) generator dispatched out-of-merit in the pocket.
  - The local reliability uplift for NYC on a MWh basis, computed by dividing the real time uplift by the total MWhs consumed.
- These changes will provide more accurate price signals to generators within the NYC load pockets and a greater ability for participants to hedge these costs.



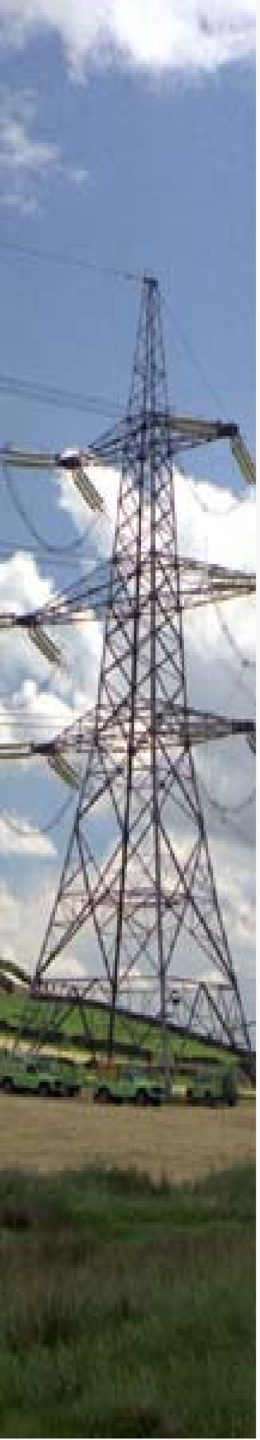


Estimated Price Increase in NYC Due to Load Pocket Modeling
June to December 2001
Estimated price increase due to modeling changes.
Local Reliability Uplift for NYC per MWh
Adjusted Real-Time Price
Actual NYC Real-Time Price
Dollars per MWh
$90
$80
$70
$60
$50
$40
$30
$20
$10
$0
June
July
Aug
Sept
Oct
Nov
Dec

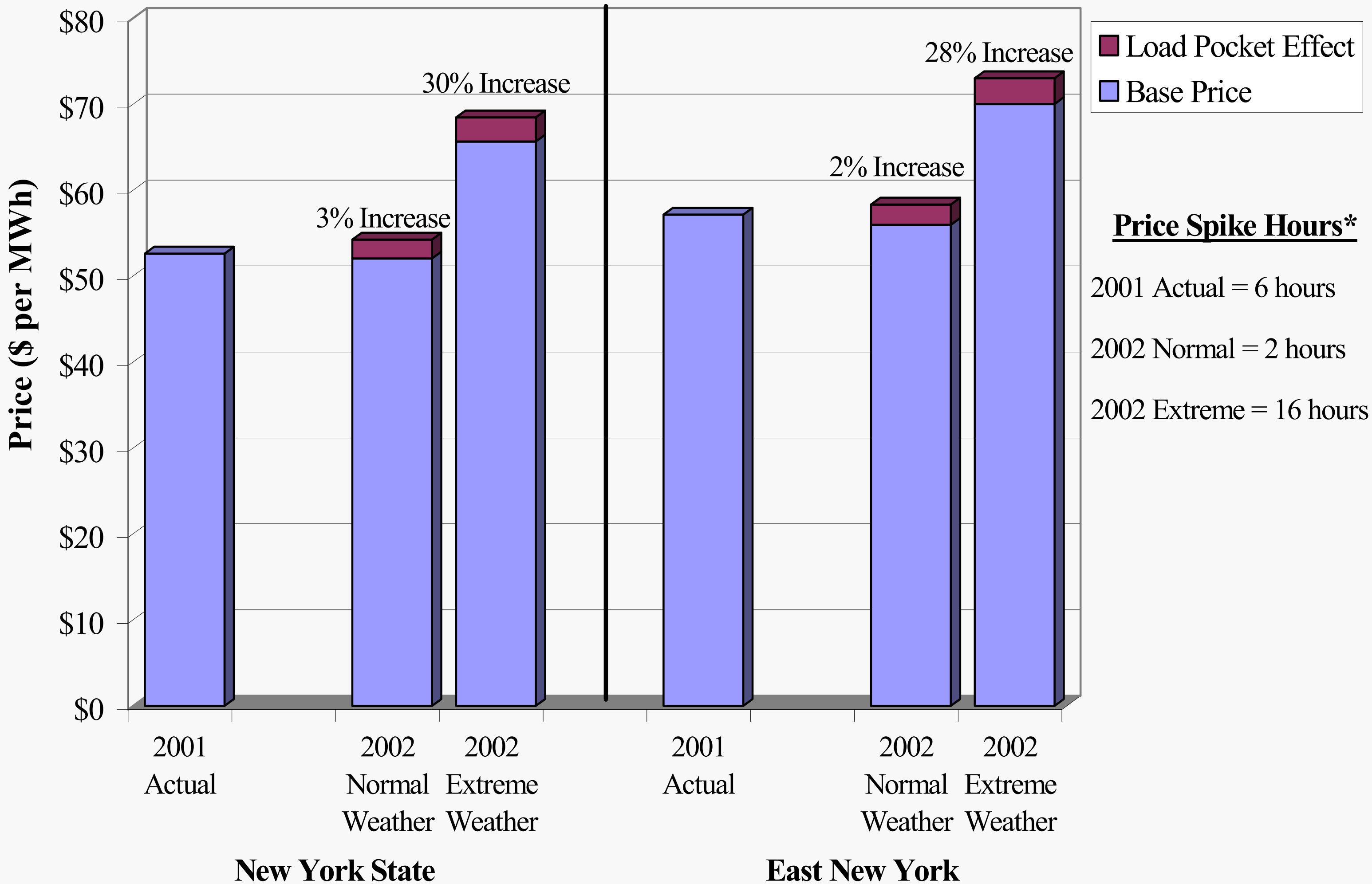


Summer 2002 Price Forecasts

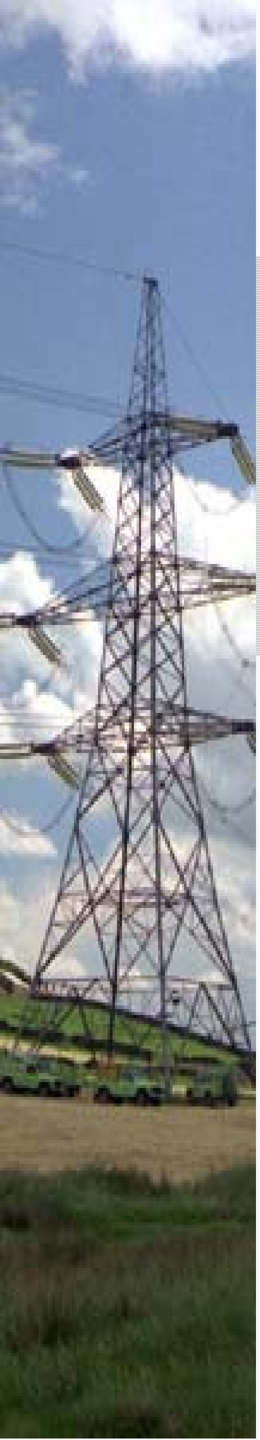
- The following figure provides a forecast for prices this summer, given the changes in supply and demand that have occurred over the past year.
- This analysis is based on the NYISO’s load forecasts for the summer – the extreme weather case increases the peak demand by 900 MW over the normal forecast.
- Fuel prices are assumed in each of the forecasts to be unchanged from last summer since the current fuel prices are close to last summer’s average levels.
- A load pocket effect on NYC of 12.5 percent is included based on the prior analysis (the anticipated reduction in uplift costs is not included).
- While changes in overall loads levels are also important, the figure shows that frequency of price spikes is a key determinant of the price levels.



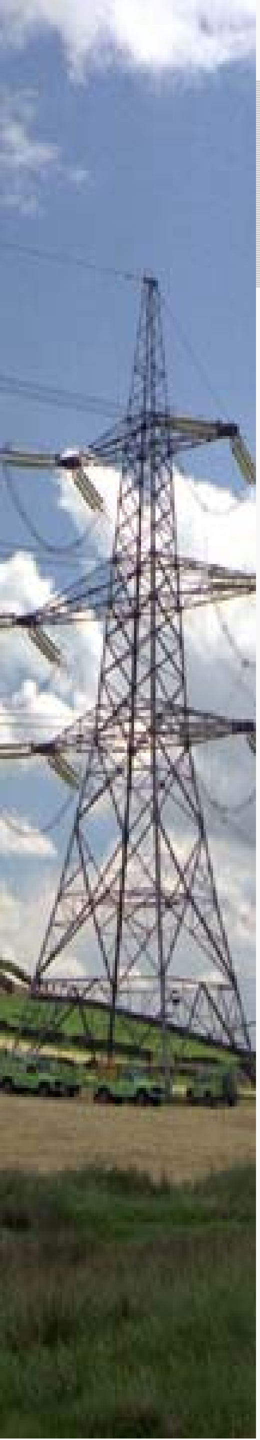
Summer 2002 Energy Price Forecast
June to August -- All Hours



* Price spike hours are defined as hours with projected prices greater than $500 per MWh. Hours shown are for East New York.
Sources: NYISO actual day-ahead price data and load forecasts; Potomac Economics analysis. All Prices shown are load-weighted.

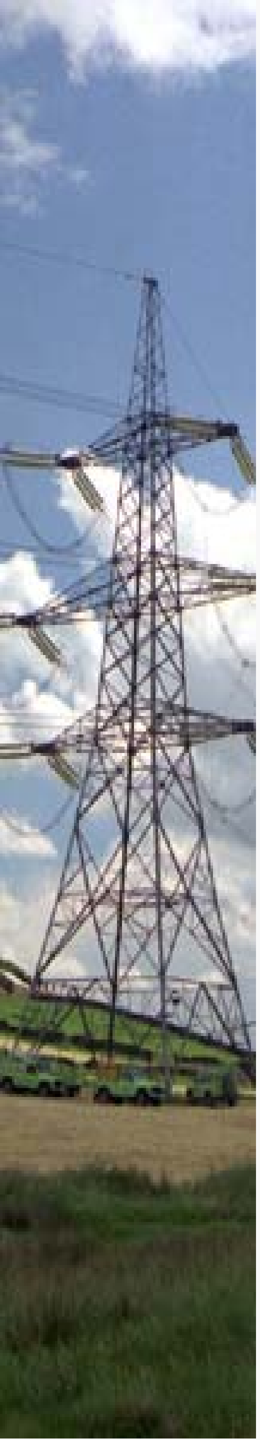


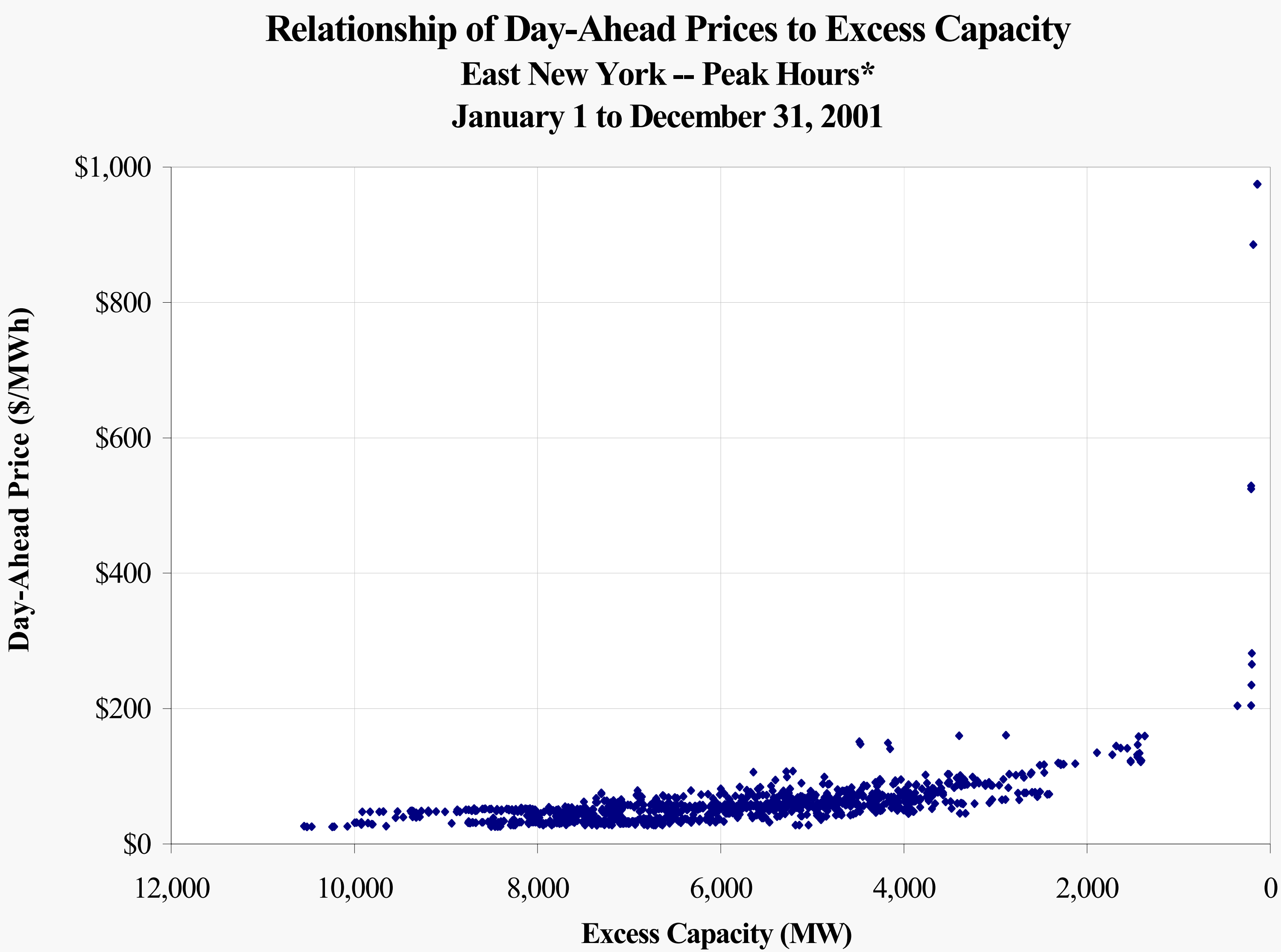
Market Performance



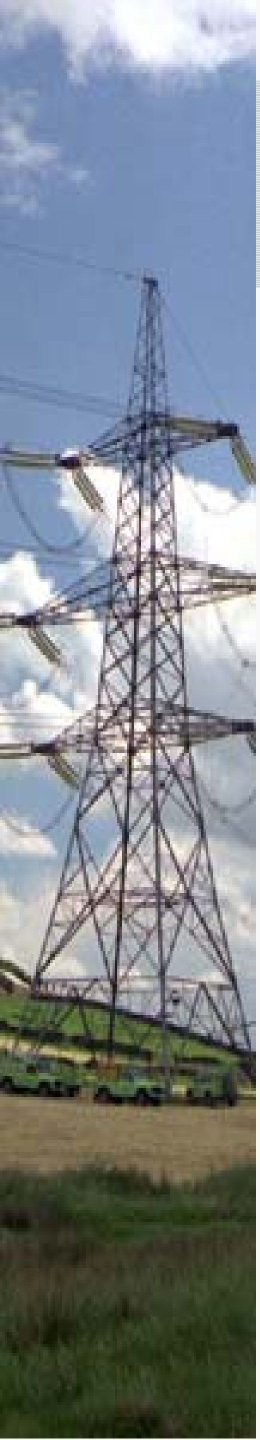
Supply Conditions and Prices in New York

- The typical "L" shape of the supply curve should cause prices in a well functioning market to rise sharply under high load conditions when excess capacity is close to zero (i.e., shortage conditions).
- I define excess capacity as the derated capability minus scheduled energy, ancillary services, and economically unavailable resources.
  - ✓ This formula incorporates the effects of scheduled exports and imports.
  - ✓ Economically unavailable resources are those whose offer prices were substantially above accepted offer prices during workably competitive periods.
- Therefore, all substantial increases in prices should occur when the excess capacity quantities are very low, which has been the case during 2001.



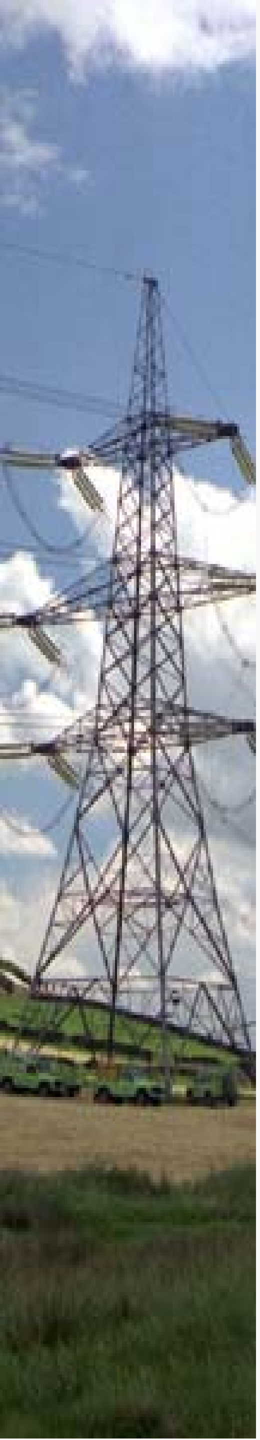


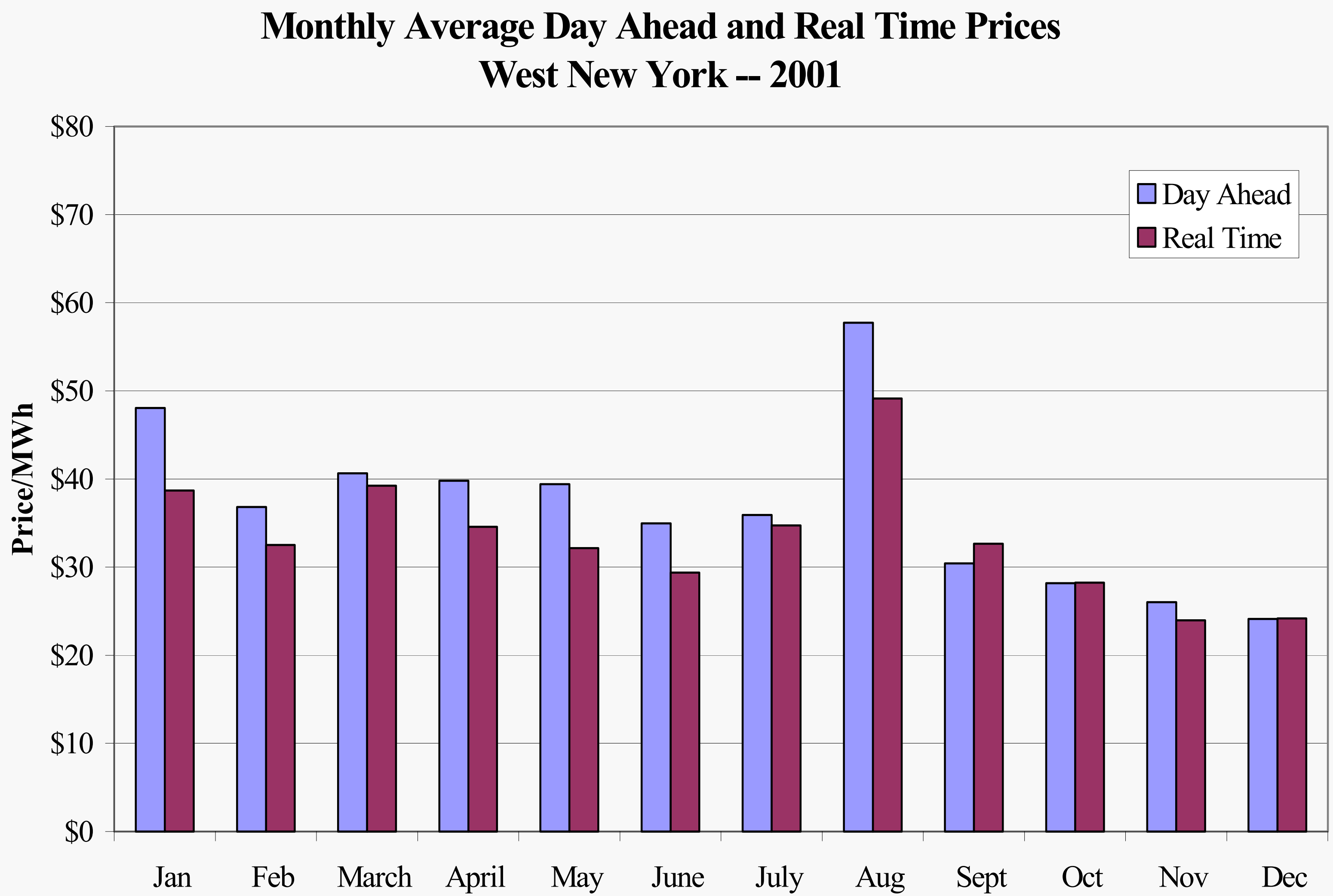
* Includes hours beginning from 1pm to 5pm, Monday through Friday.

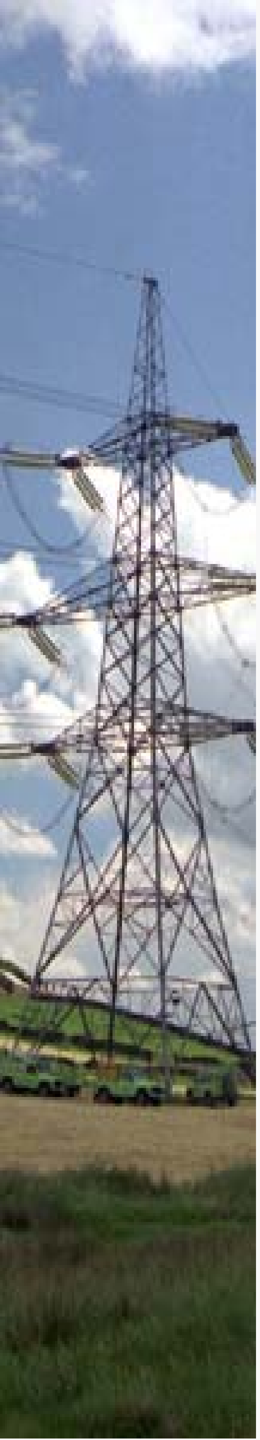


Day-Ahead and Real Time Energy Prices

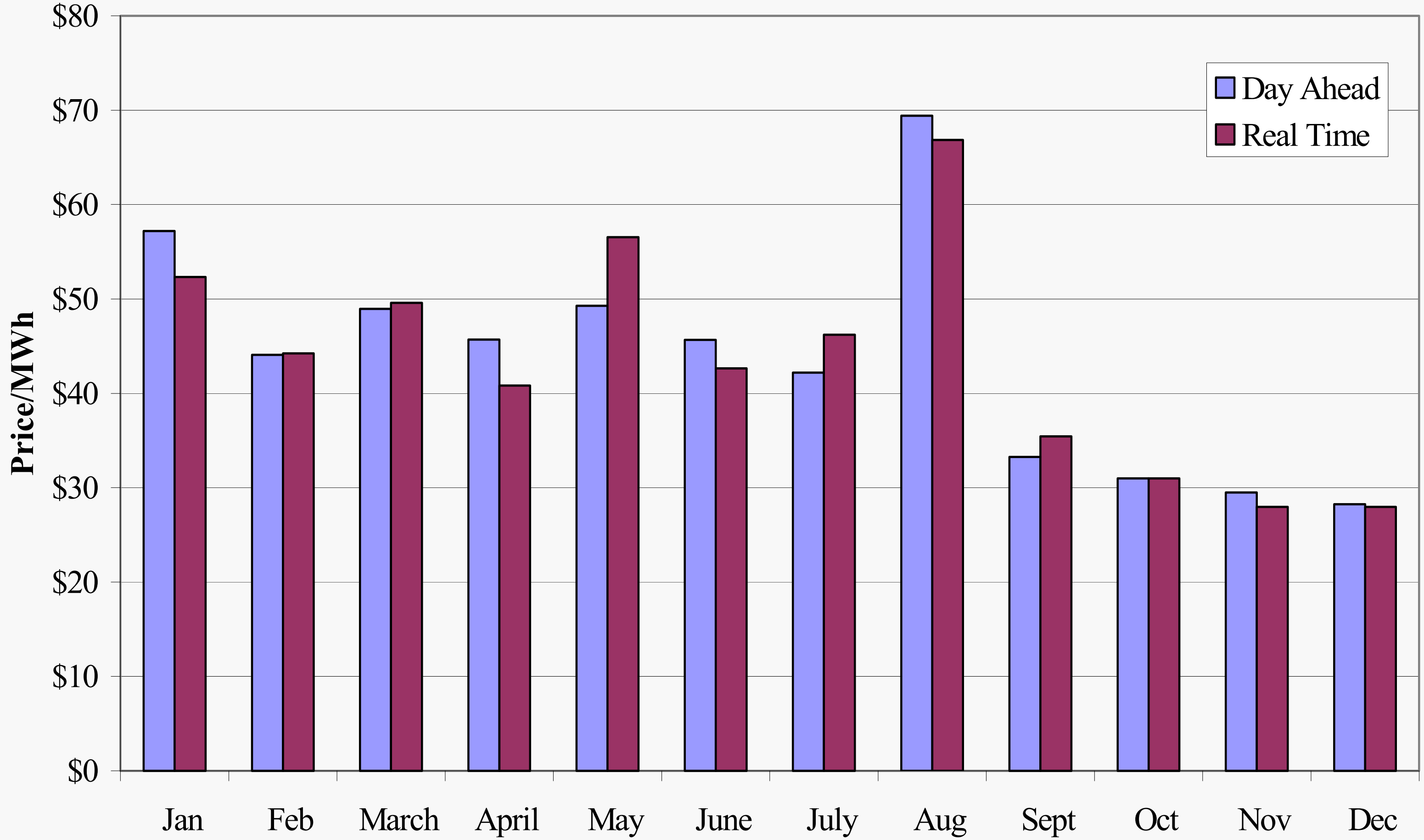
- The following three charts show monthly average day-ahead and real-time energy prices in West NY, East NY outside NYC, and NYC.
- The results show that a slight premium in the day-ahead market remains in in all three areas.
- Price convergence improved in 2001 compared to 2000, particularly in the fall of 2001. Contributing factors likely included:
  - ✓ Lower congestion in the State and overall price volatility.
  - ✓ The introduction of virtual bidding in November and increased activity in price capped load bidding.
  - ✓ Lower fuel prices in the fall of 2001.

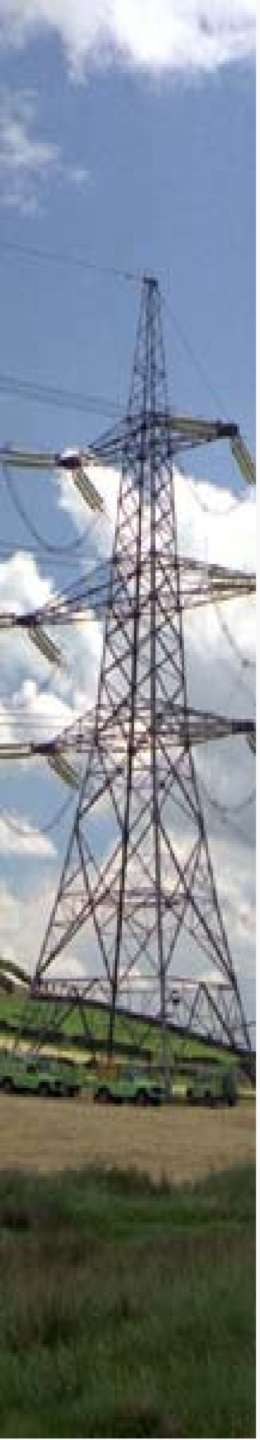



Monthly Average Day Ahead and Real Time Prices
West New York -- 2001
$80
$70
$60
$50
$40
$30
$20
$10
$0
Price/MWh
Day Ahead
Real Time
Jan
Feb
March
April
May
June
July
Aug
Sept
Oct
Nov
Dec

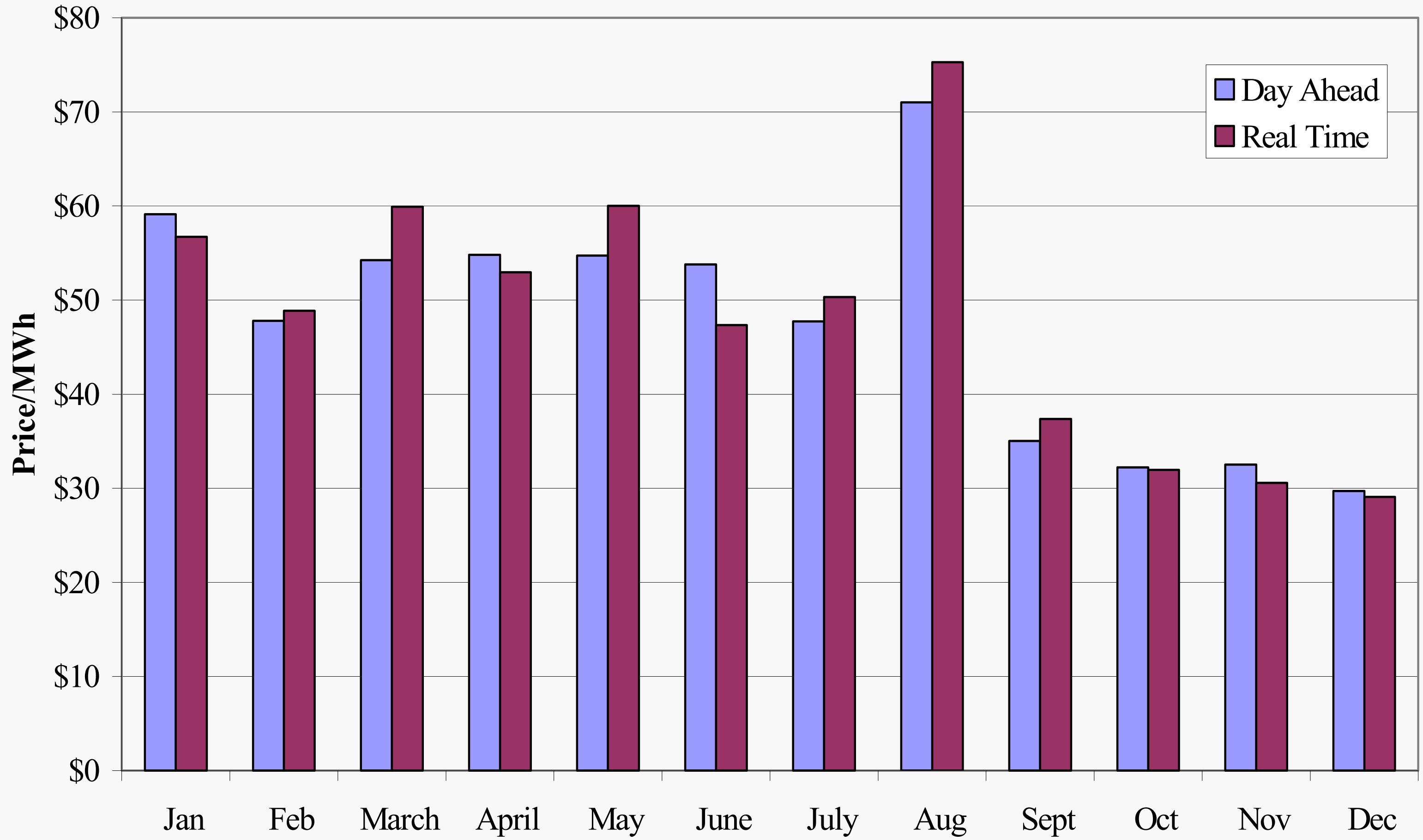


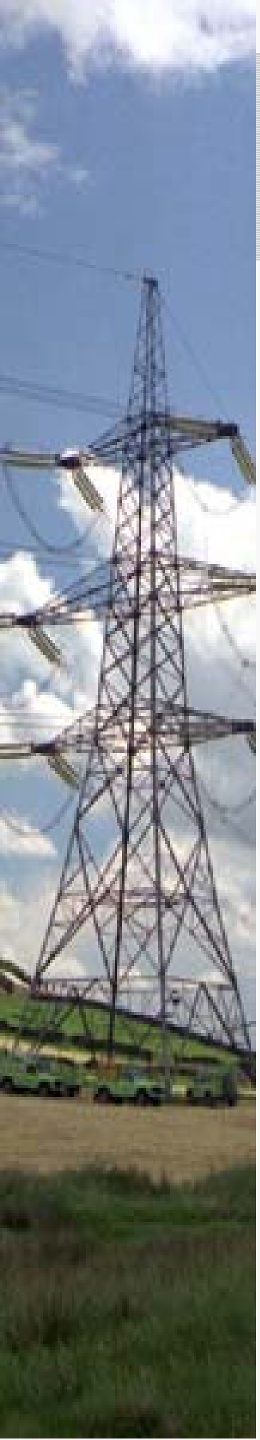
Monthly Average Day Ahead and Real Time Prices
East New York Above NYC -- 2001





Monthly Average Day Ahead and Real Time Prices
New York City -- 2001





Energy Price Statistics

- The following table shows annual price statistics for prices in the West, Capital and NYC zones for 2001.
- The results show a 10 percent premium in day-ahead prices versus real time prices in the West, while premiums exist in the other two zones of less than 1 percent.
  - ➳ These premiums likely reflect 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, as well as the outage risk of generators associated with day-ahead schedules.
- Convergence between day-ahead and real-time prices improved between 3 to 6 percent in the three zones (e.g., the price difference in the Capital zone fell a 7% premium in 2000 to less than 1% in 2001)
- The table also shows the standard deviations, which are the average of the monthly standard deviations for each hour of the day
  - ✓ The standard deviations have fallen from 2000 levels.
  - ✓ The volatility in the real-time prices remains roughly twice as high as day-ahead.

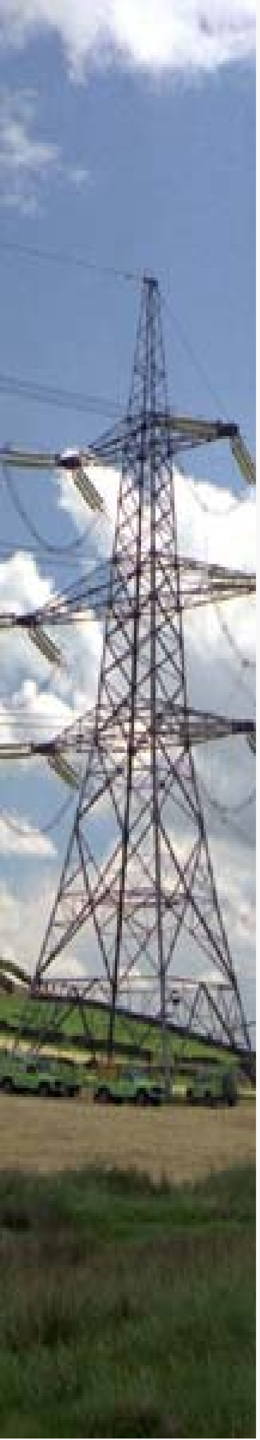
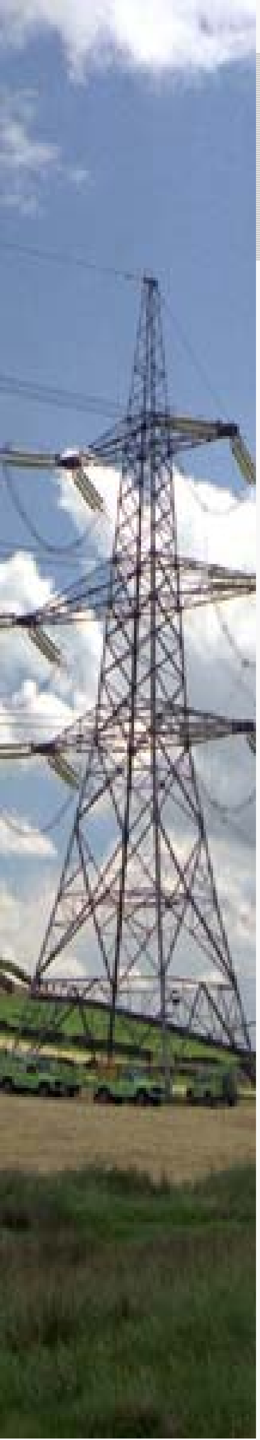


Table 1
Day-Ahead and Real-Time Pricing Statistics for Selected Zones
January to December 2001

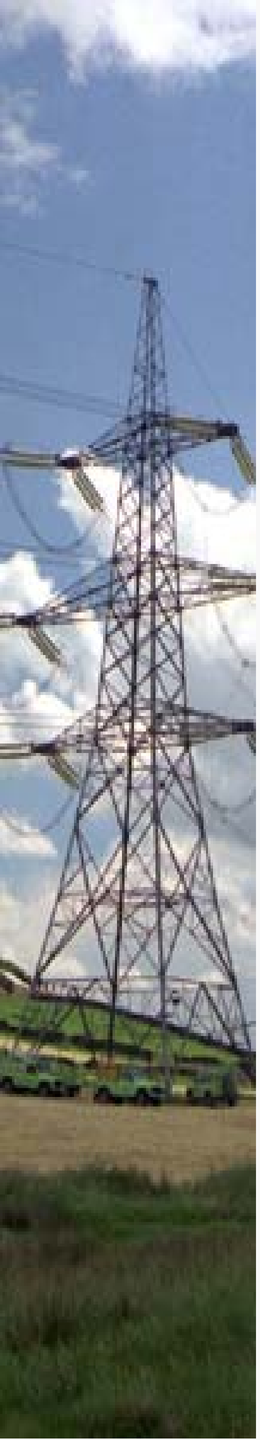
	New York City		Capital Zone		West Zone	
	Day-Ahead	Real-Time	Day-Ahead	Real-Time	Day-Ahead	Real-Time
Mean	$44.67	$44.49	$39.90	$39.69	$33.87	$30.76
Compared with 2000	*-$4.16*	*-$5.85*	*-$4.92*	*-$2.36*	*-$0.59*	*$0.88*
Avg. Std. Deviation*	$12.25	$30.68	$10.68	$24.64	$9.15	$15.82
Compared with 2000	*-$4.58*	*-$15.38*	*-$6.20*	*-$2.60*	*-$0.12*	*-$3.15*
Minimum	$0.11	-$169.37	$0.10	-$167.80	$0.10	-$152.35
Maximum	$1,024.91	$1,034.01	$976.15	$1,078.35	$912.28	$949.50

* Average of standard deviations calculated by month and hour of day.

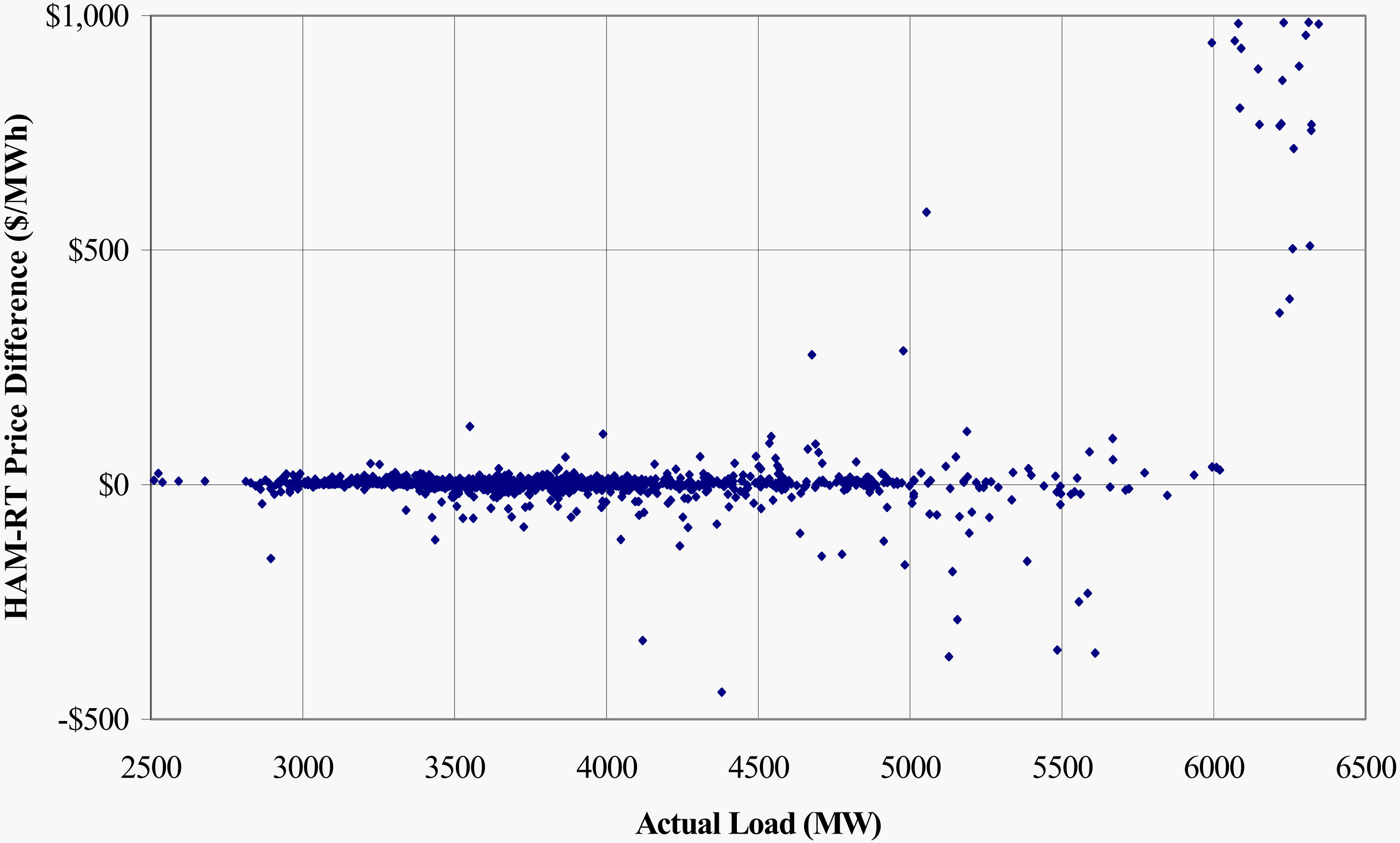


Hour-Ahead Prices and Uplift

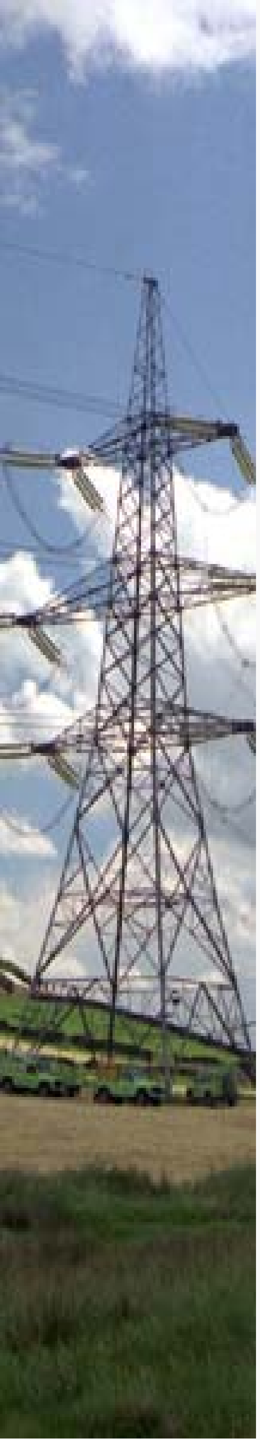
- These charts show the difference between hour-ahead and real-time prices at actual load levels during 2001.
- The difference in Hour-Ahead and Real-Time prices derive from the differences in the models:
  - ✓ SCD does not model all of the constraints in NYC that are modeled in the SCUC and BME models.
  - ✓ 30 minute reserves are treated differently in the BME and SCD models.
  - ✓ External transactions and other resources scheduled hourly can set prices in the BME, but not in the SCD.
- The east New York chart show that the largest differences occur under the highest load conditions.
- However, the NYC chart shows that substantial differences occur at mid-load levels. This likely reflected the out-of-merit dispatch that was used in SCD to manage constraints that are modeled in the BME (138 kv load pocket).



Relationship of Price Differences to Actual Load
Hour Ahead Prices Minus Real Time Prices
East New York Above NYC -- 2001, Peak Hours*



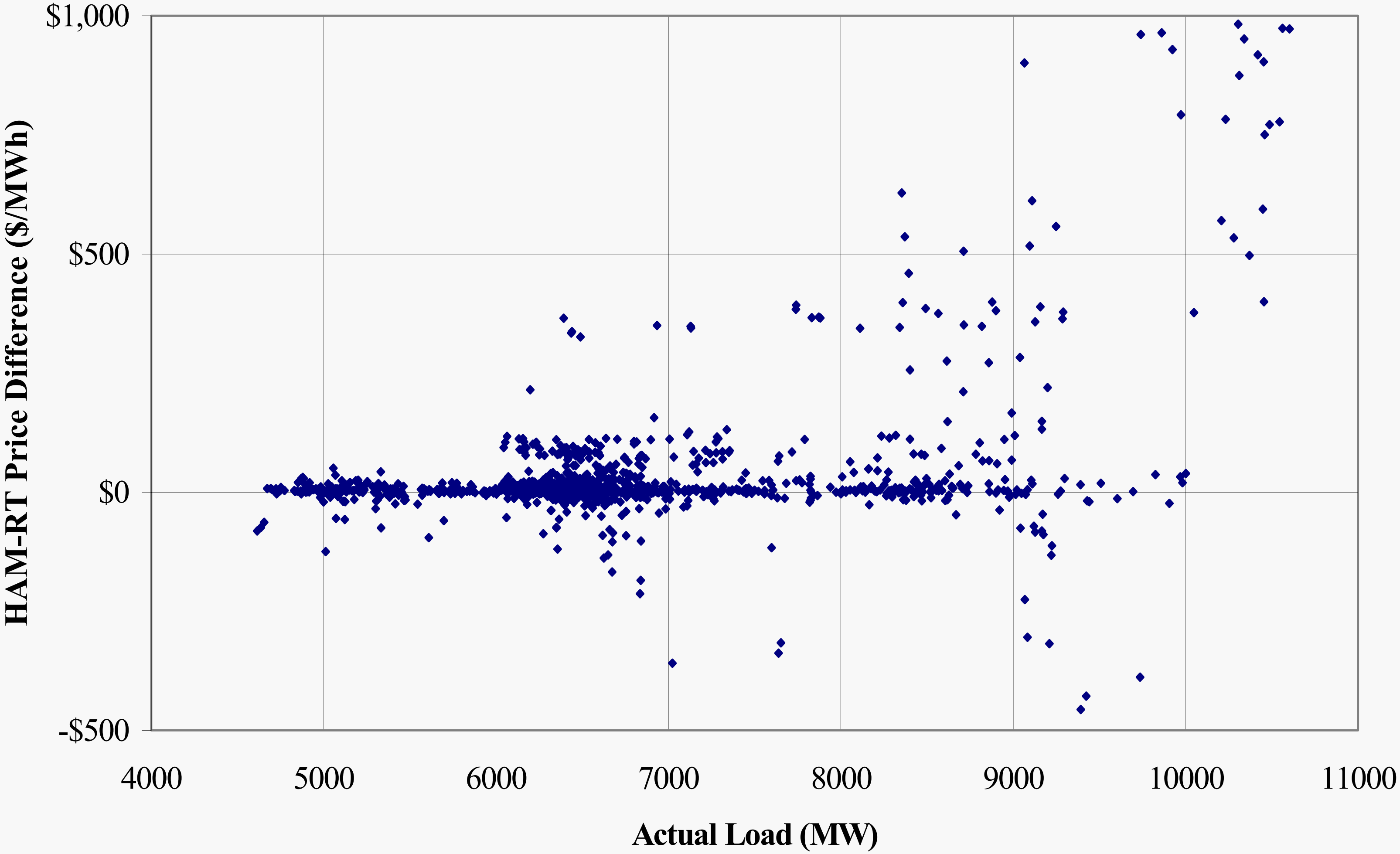
* Includes hours beginning at 1pm through 5pm, Monday through Friday.



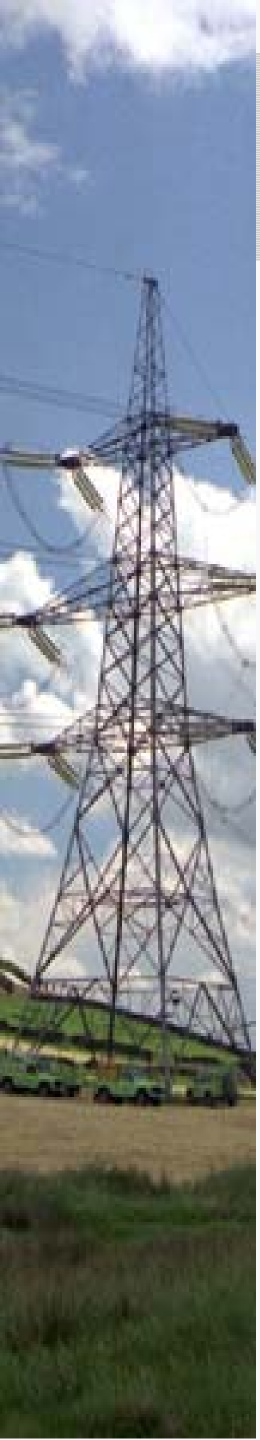
Relationship of Price Differences to Actual Load

Hour Ahead Prices Minus Real Time Prices

New York City -- 2001, Peak Hours*

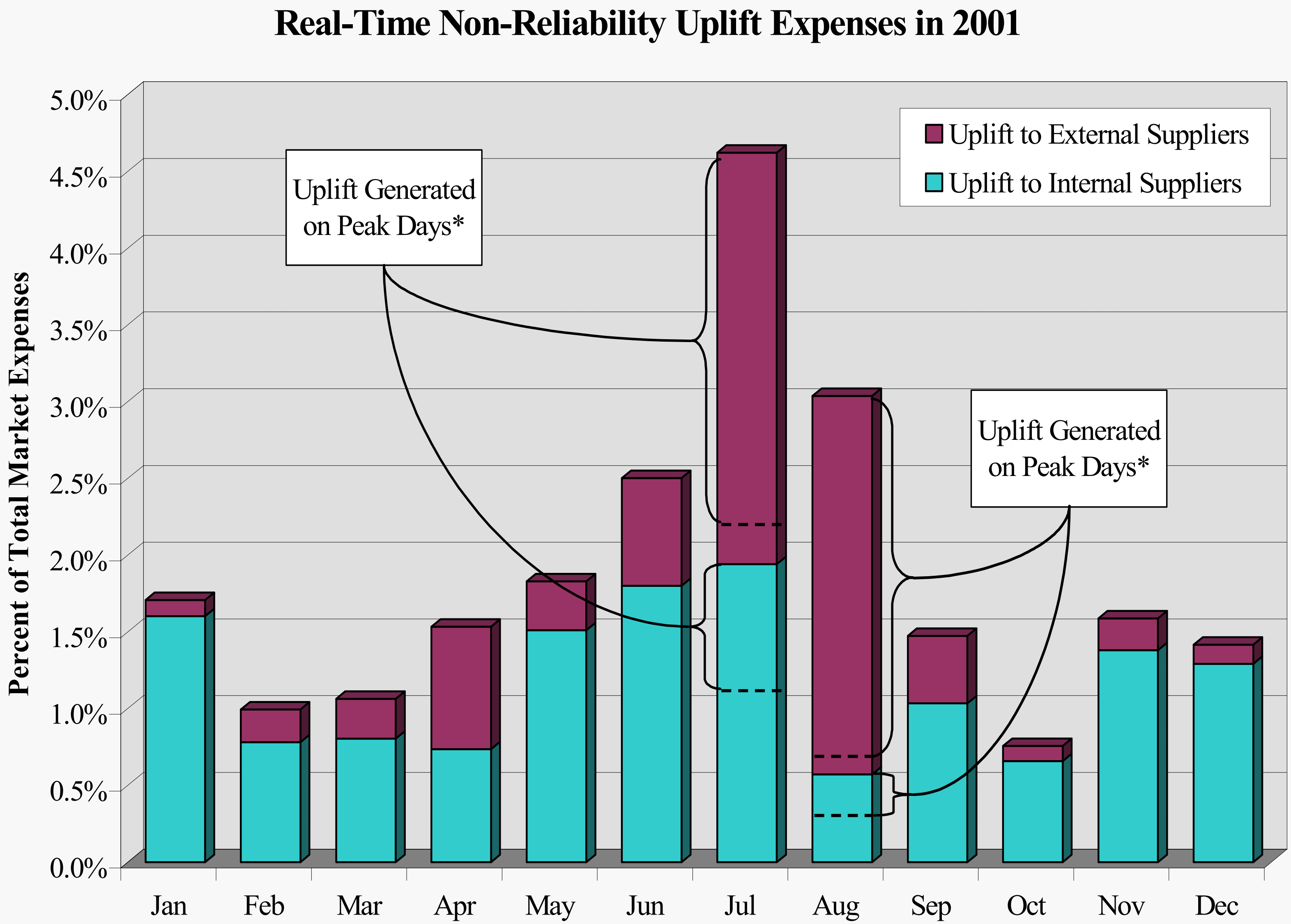


* Includes hours beginning at 1pm through 5pm, Monday through Friday.

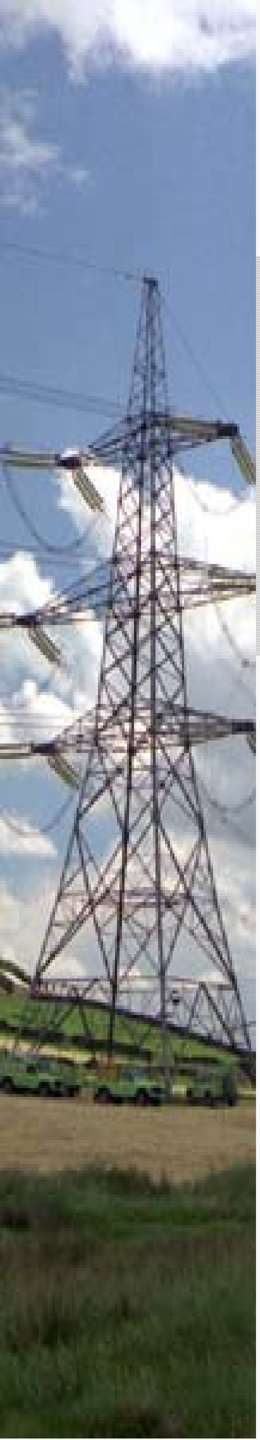


Price Divergence and Uplift

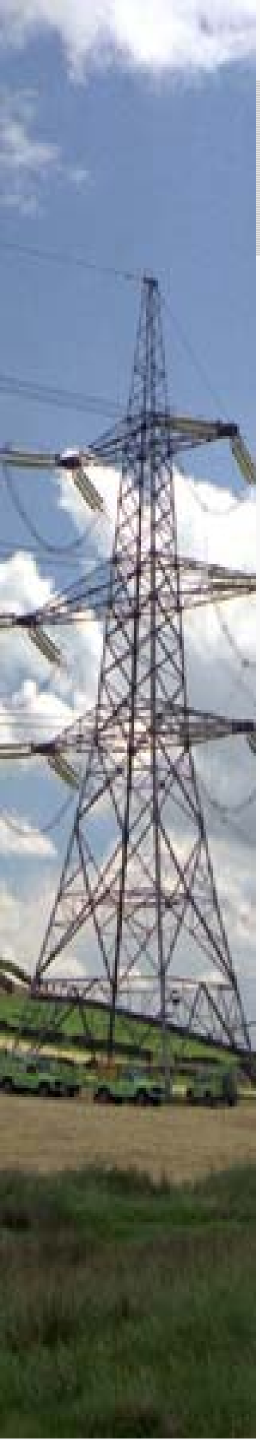
- Solutions to eliminate these differences are a high priority because they contribute to:
  - Higher uplift costs; and
  - Inefficiently low real-time energy prices in peak hours;
- The subsequent chart shows how the sizable uplift payments—especially for externals—coincide with periods when prices diverge significantly.
- The uplift costs related to externals occur when BME accepts expensive imports that are uneconomic relative to the real-time price.
- Similarly, uplift costs related to internals occur when BME commits high cost generation that is uneconomic relative to the real-time price.
- The modeling changes and reserve market changes to address this divergence are planned prior to Summer 2002.



* Days where the HAM price exceeded $1000/MWh for more than one hour in a zone other than Long Island.

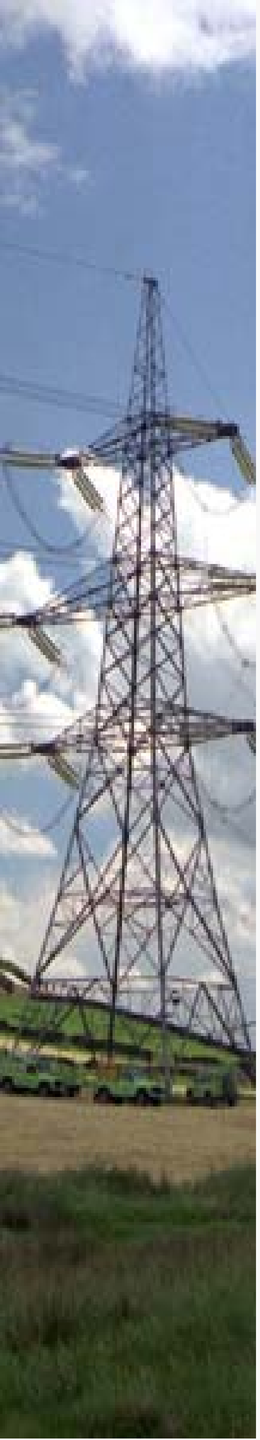


Analysis of Bidding Patterns

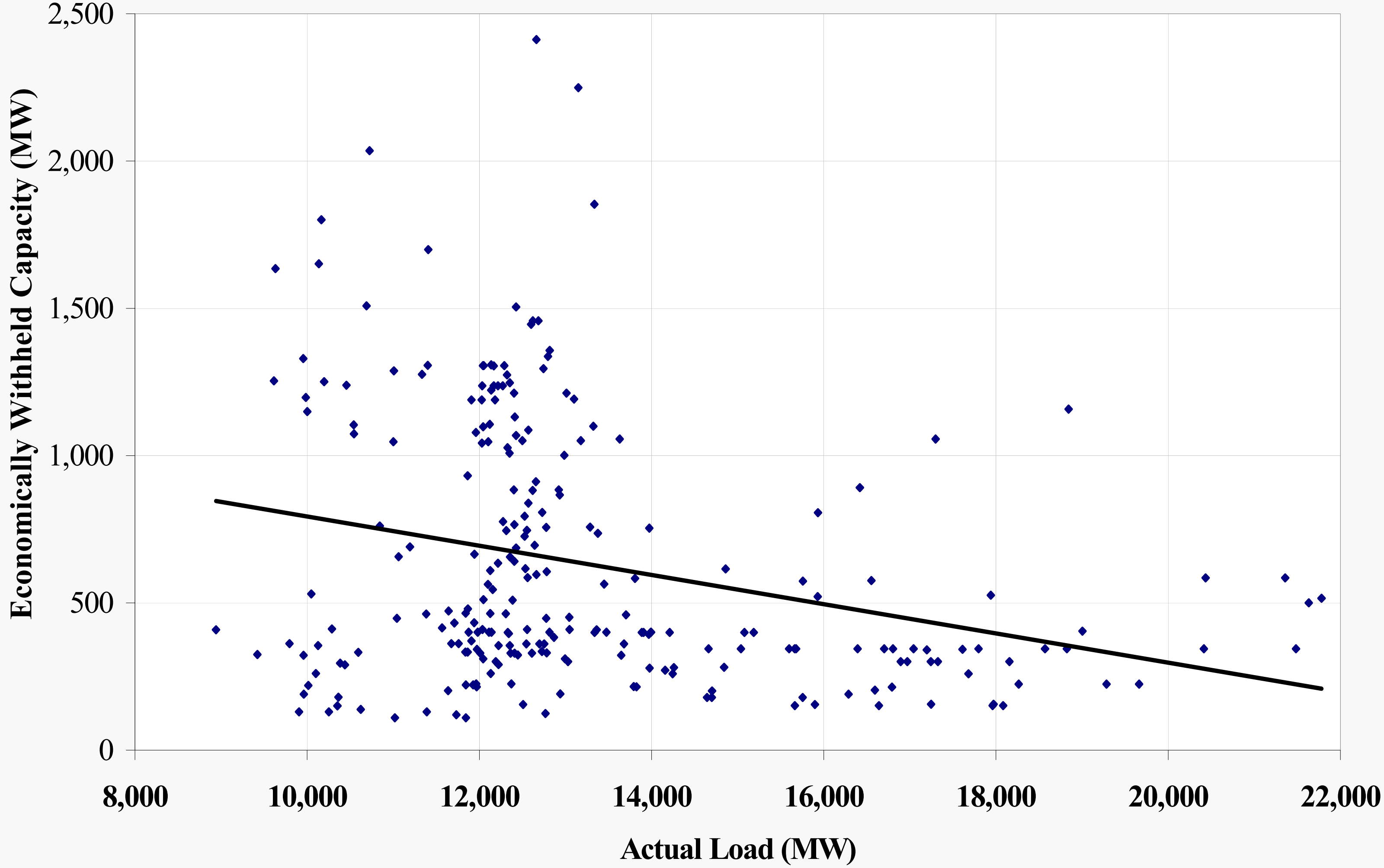


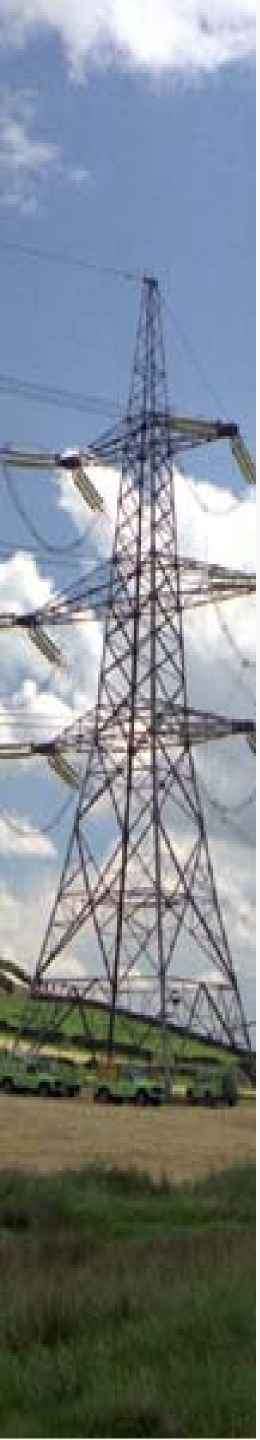
Analysis of Offer Patterns

- The analysis shown in the following charts assesses offer patterns in light of the following observations:
  - Suppliers in a competitive market should increase offer quantities during higher load periods to sell more power at the higher peak prices;
  - Suppliers with market power will have an incentive to offer less at peak load levels when the market impact is the largest.
- Therefore, the correlation of withholding (including both economic and physical withholding) to actual load levels have been assessed and are shown on the following charts.
- The trends shown in these charts are consistent with the hypothesis that the New York markets have been workably competitive during 2001.

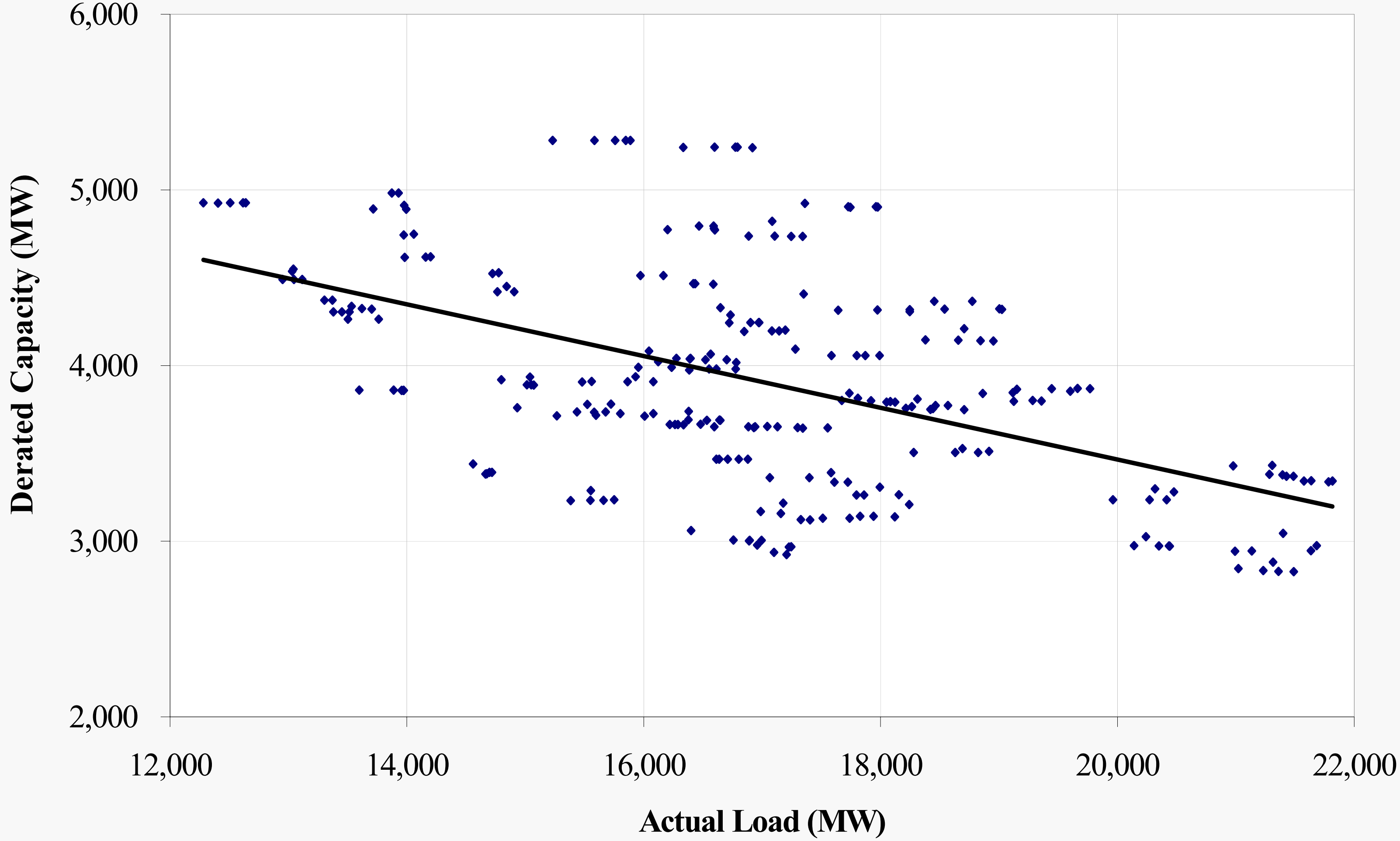


Relationship of Economic Withholding to Actual Load
Day-Ahead Market -- East New York
January 1 to December 31, 2001 -- 3pm Hour

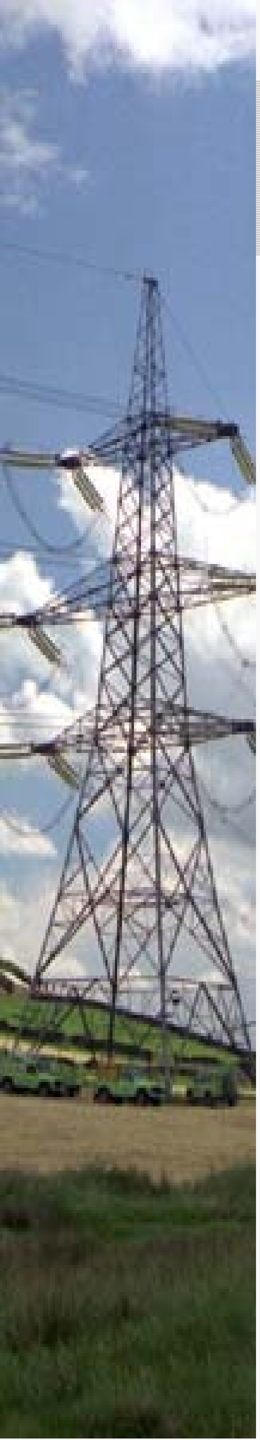




Relationship of Deratings to Actual Load
Day-Ahead Market -- East New York
Summer 2001 -- Peak Hours*



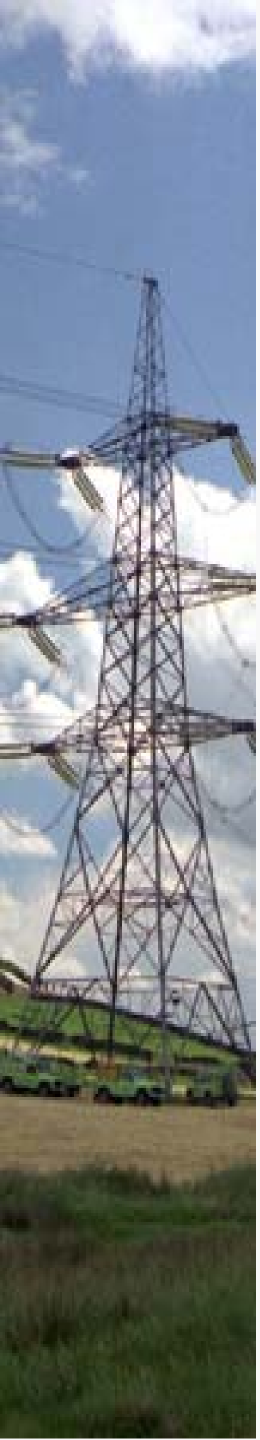
* Includes hours beginning at 1pm through 5pm, Monday through Friday.

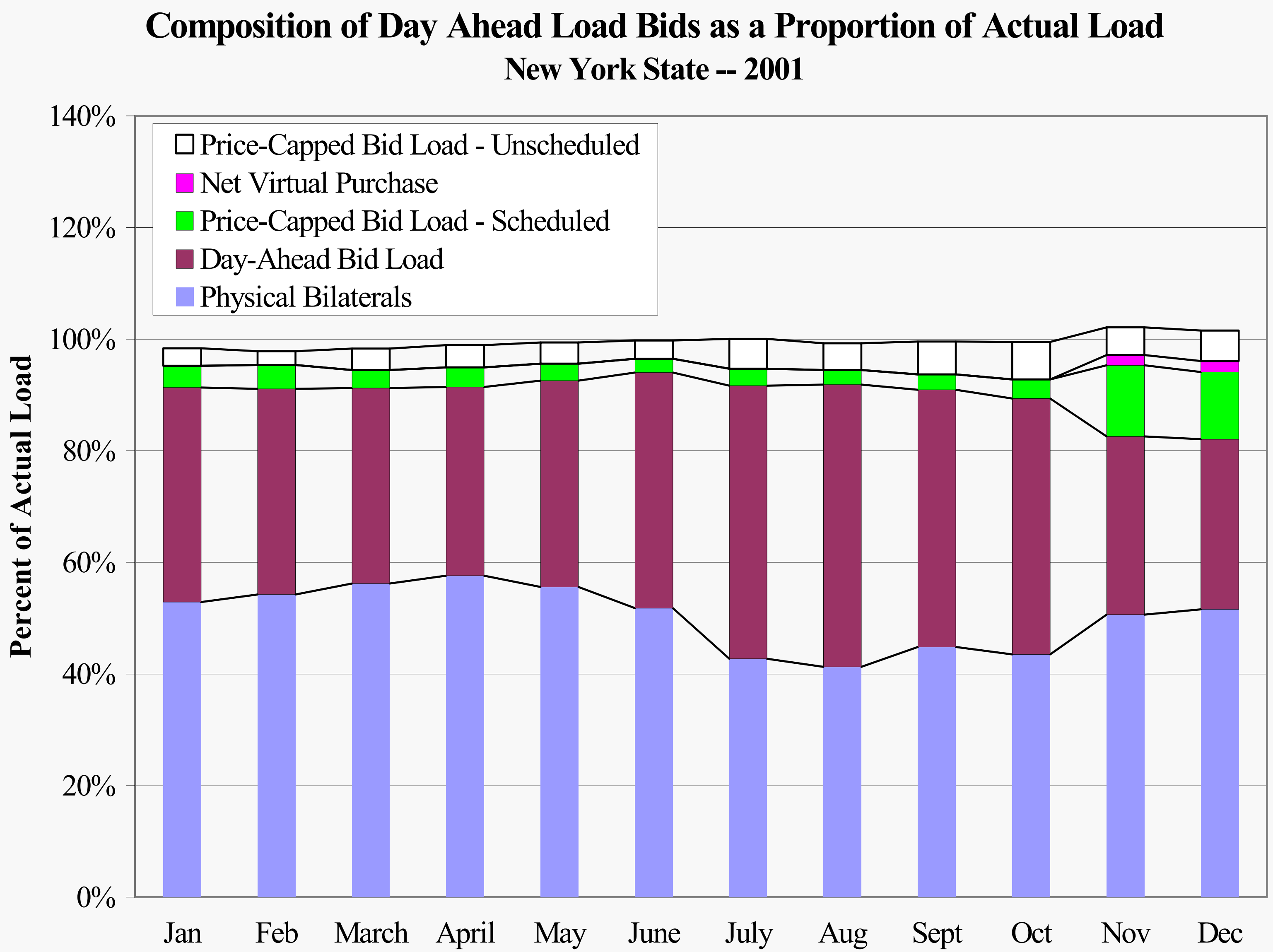


Analysis of Load Bidding Patterns

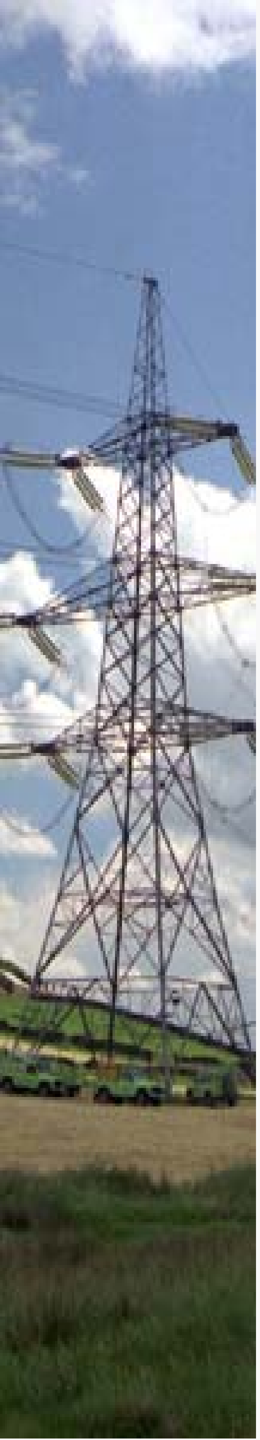
- The NYISO also monitors the bidding patterns of load-serving entities as specified in the mitigation plan.
- The following charts show the load bidding patterns during 2001 in the entire state and in New York City
- These charts show the following:
  - ✓ Price-capped load bidding was much more active than in 2000, particularly in November and December, coinciding with the implementation of virtual bidding.
  - ✓ The percent of the actual load supplied by physical bilaterals has been relatively constant.
  - ✓ Virtual loads scheduled in November and December substantially closed the gap between day-ahead load scheduling and actual load that had been present in prior months.

✓ A similar chart for East New York, and a chart comparing the 2001 bidding patterns to 2000 are contained in the Appendix.

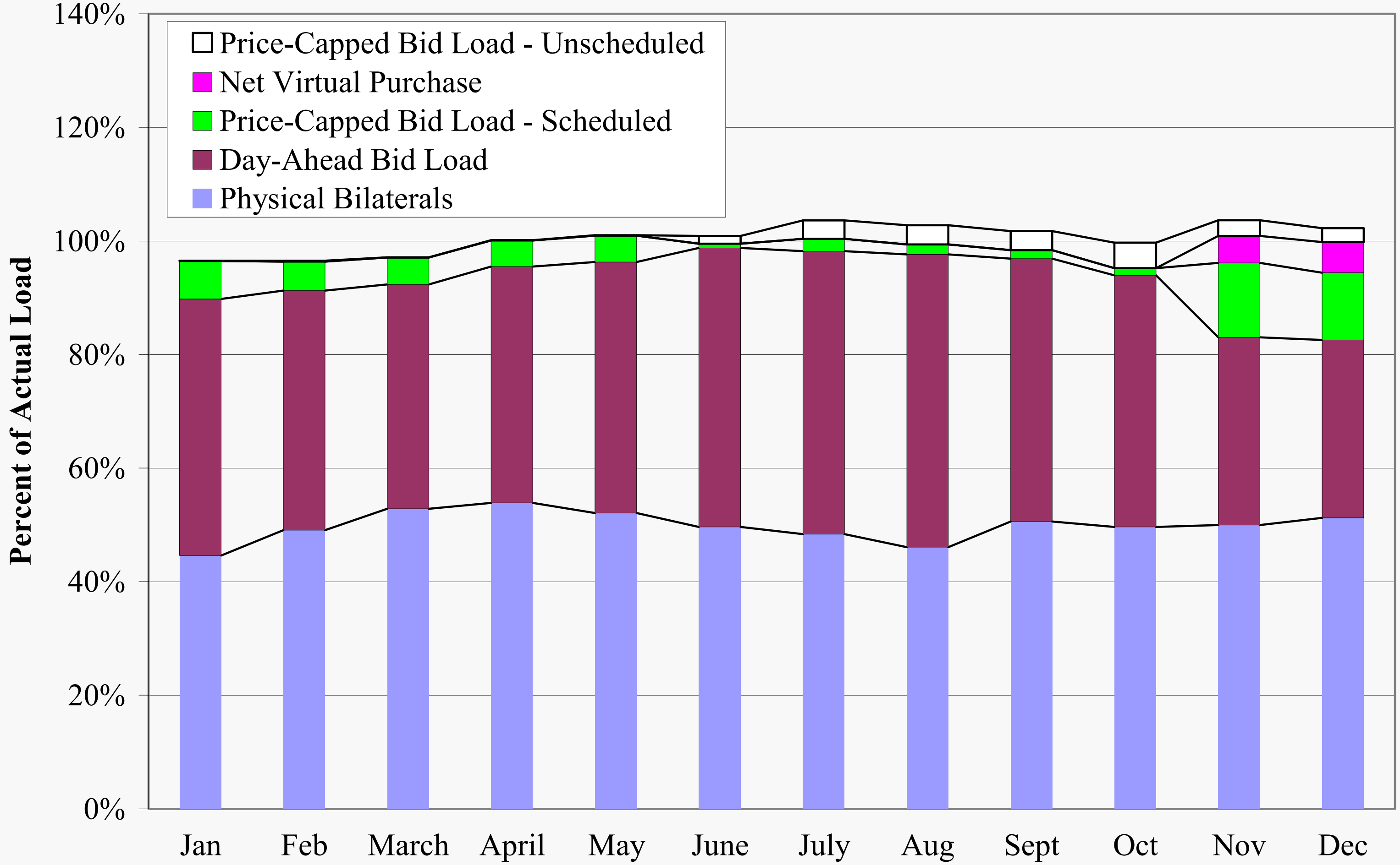


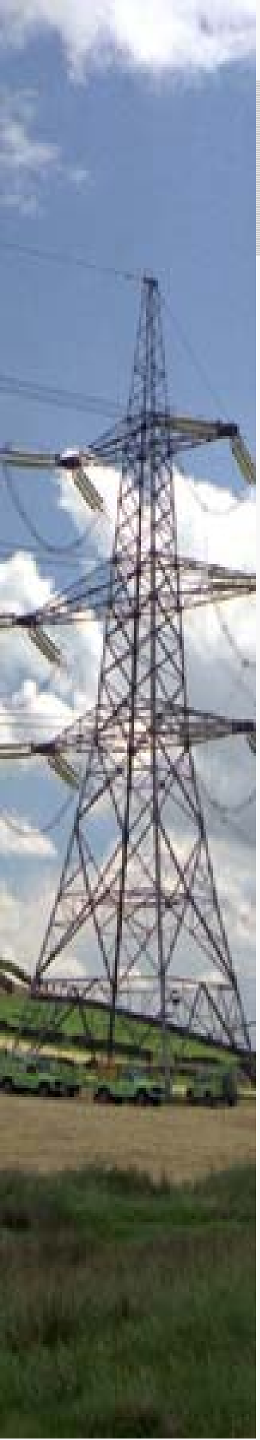


Composition of Day Ahead Load Bids as a Proportion of Actual Load
New York State -- 2001
Price-Capped Bid Load - Unscheduled
Net Virtual Purchase
Price-Capped Bid Load - Scheduled
Day-Ahead Bid Load
Physical Bilaterals
Percent of Actual Load
140%
120%
100%
80%
60%
40%
20%
0%
Jan
Feb
March
April
May
June
July
Aug
Sept
Oct
Nov
Dec



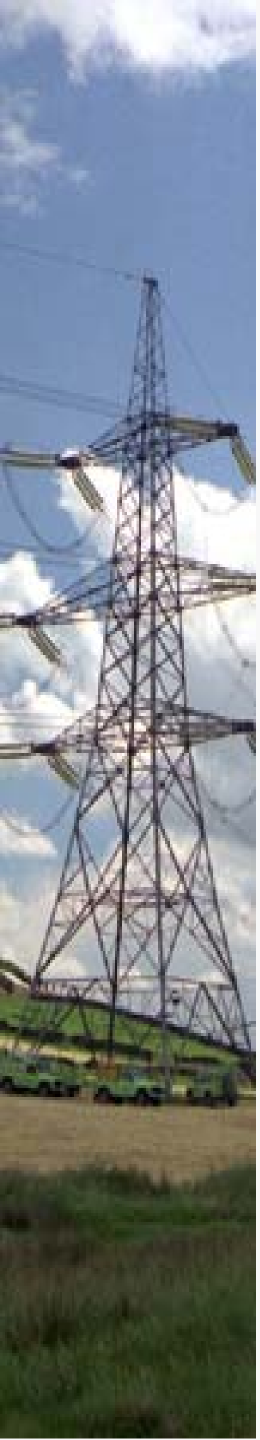
Composition of Day Ahead Load Bids as a Proportion of Actual Load
New York City and Long Island -- 2001



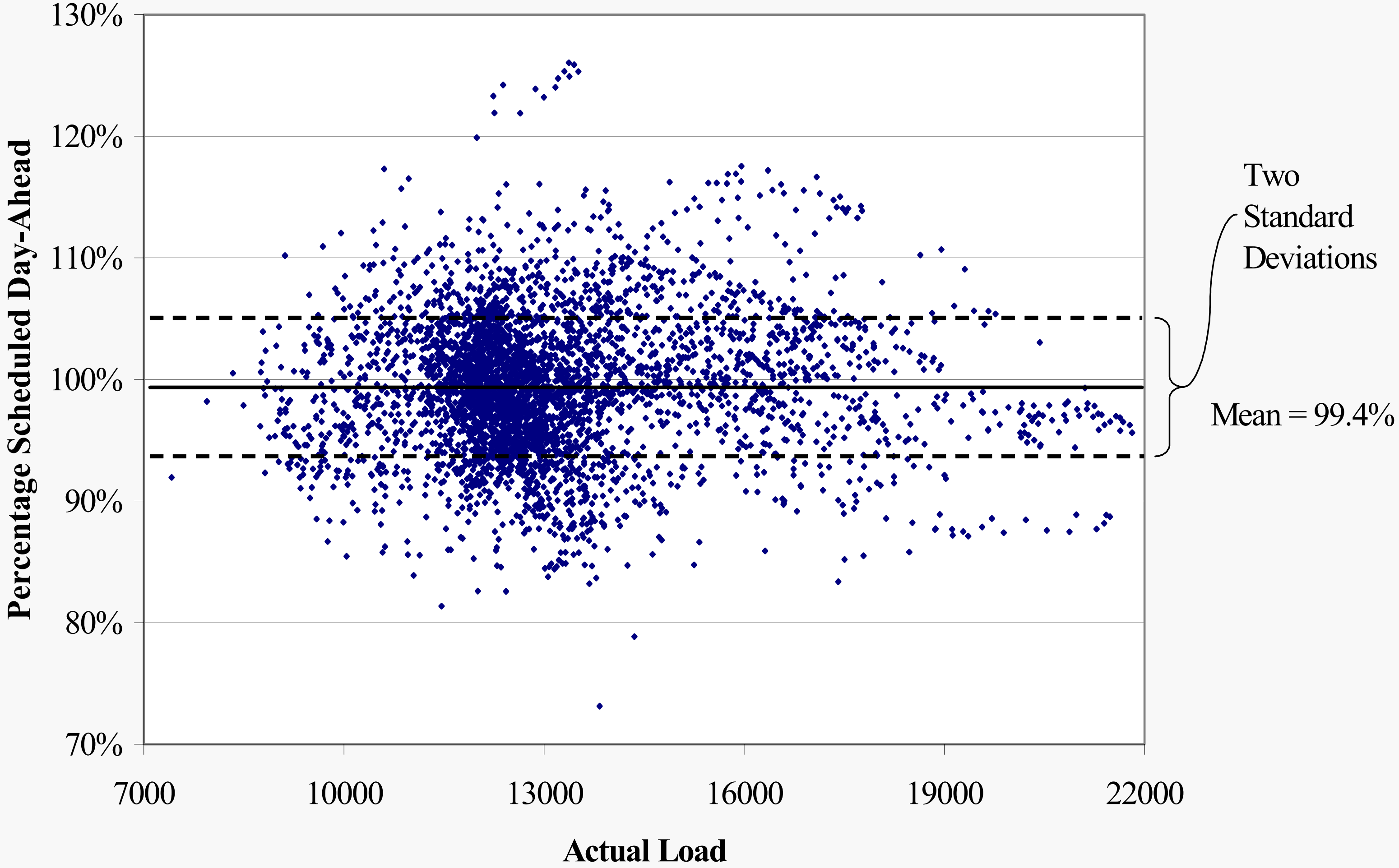


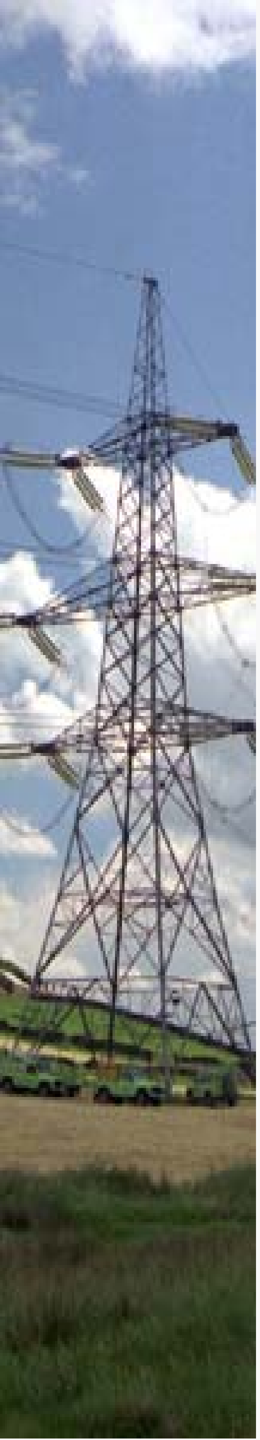
Analysis of Offer Patterns

- Some had raised concerns that load-serving entities may intentionally under-bid their loads to cause the day ahead market to clear at depressed prices.
- The following scatter diagram shows the load bidding patterns during 2001 in three areas.
- This chart shows the following:
  - ✓ Under-bidding by load is least pronounced as one moves from west to east with loads in NYC purchasing in excess of their actual load on average.
  - ✓ Under-bidding did not increase under peak load conditions.

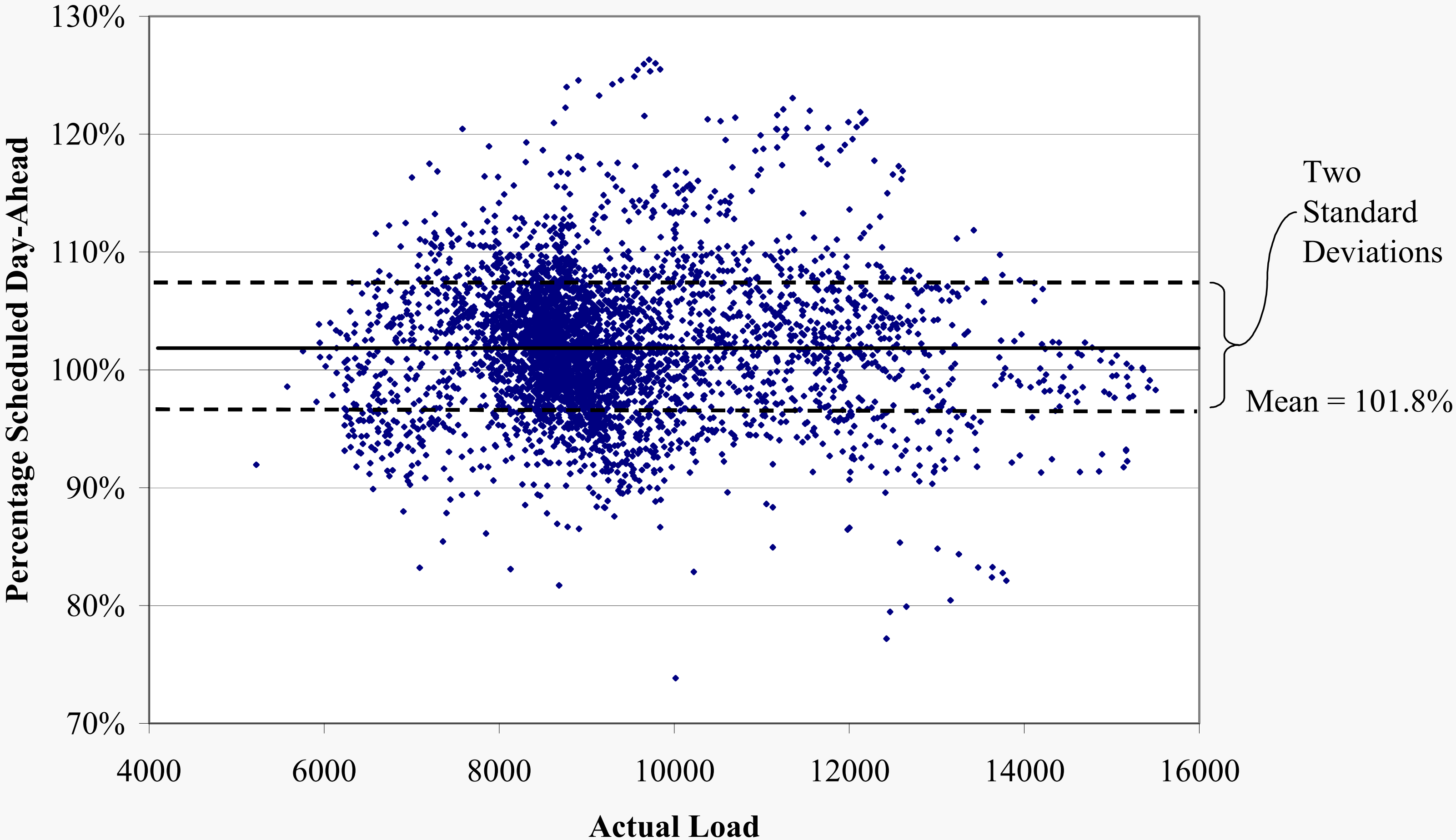


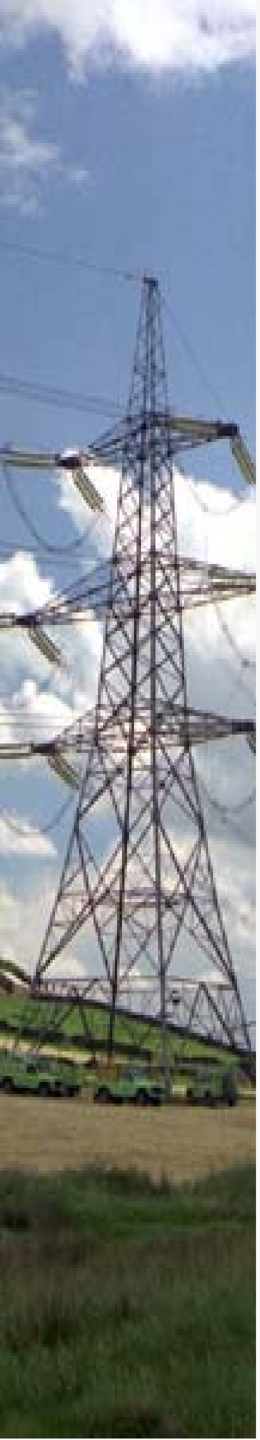
Percentage of Load Scheduled Day-Ahead versus Real-Time Load
East New York -- 2001, Peak Hours





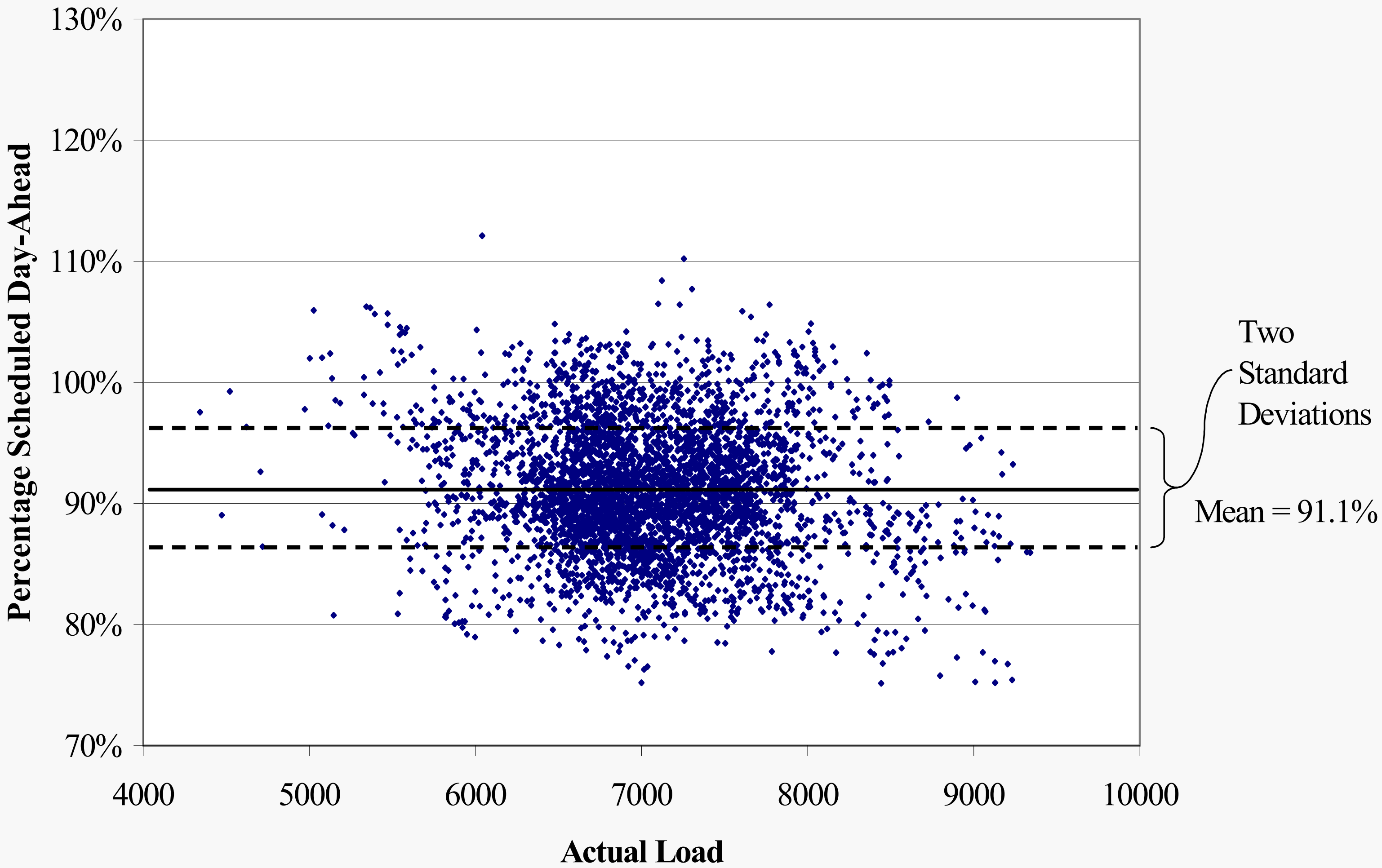
Percentage of Load Scheduled Day-Ahead versus Real-Time Load
New York City and Long Island -- 2001, Peak Hours

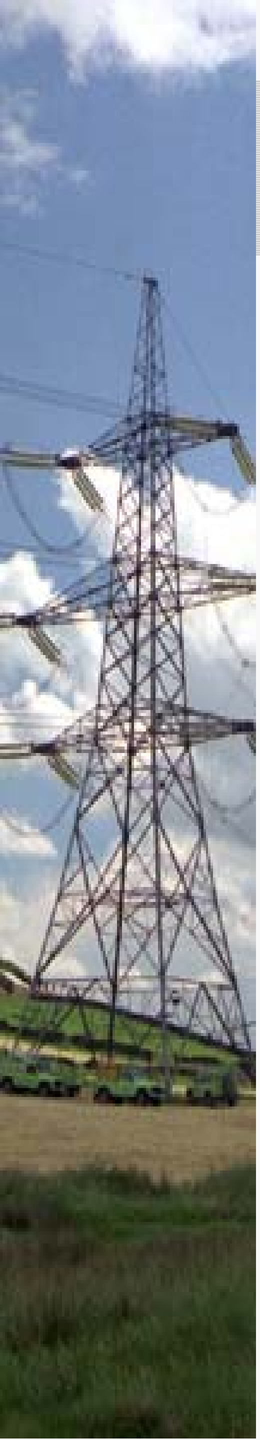




Percentage of Load Scheduled Day-Ahead versus Real-Time Load

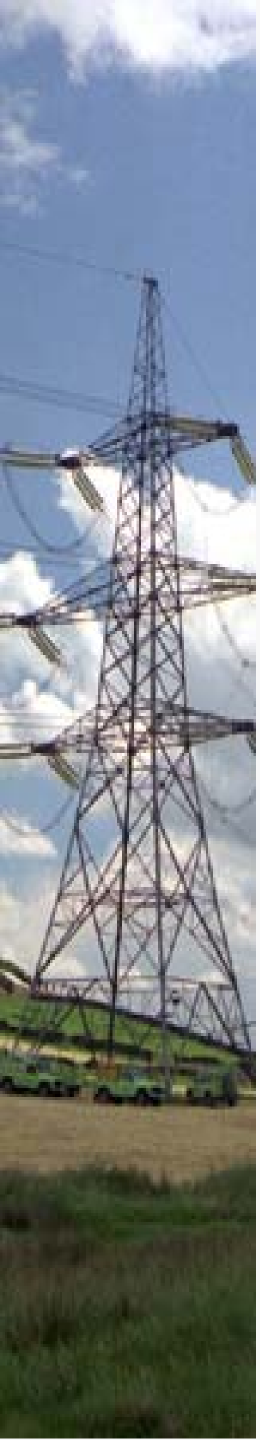
West New York -- 2001, Peak Hours

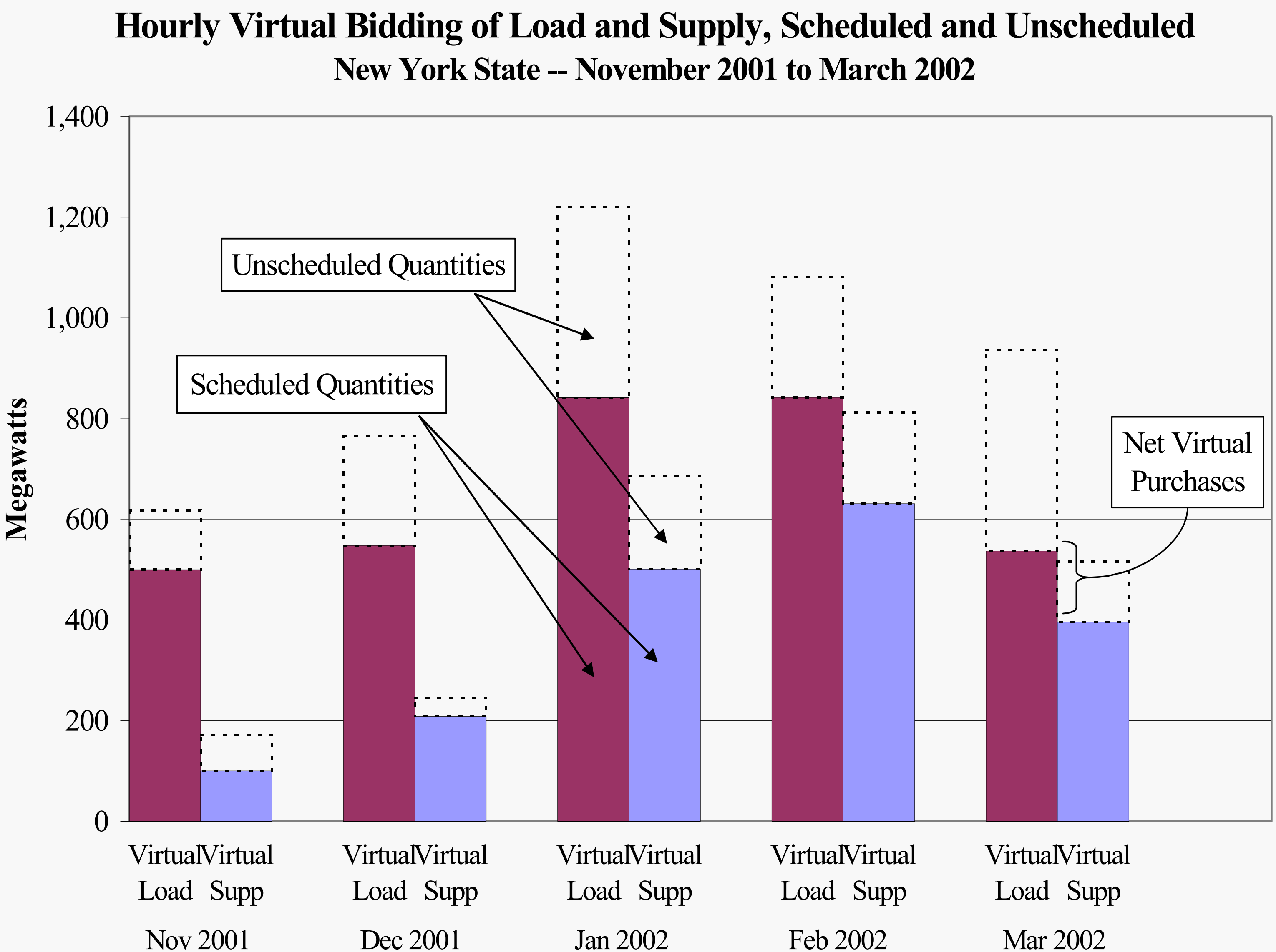


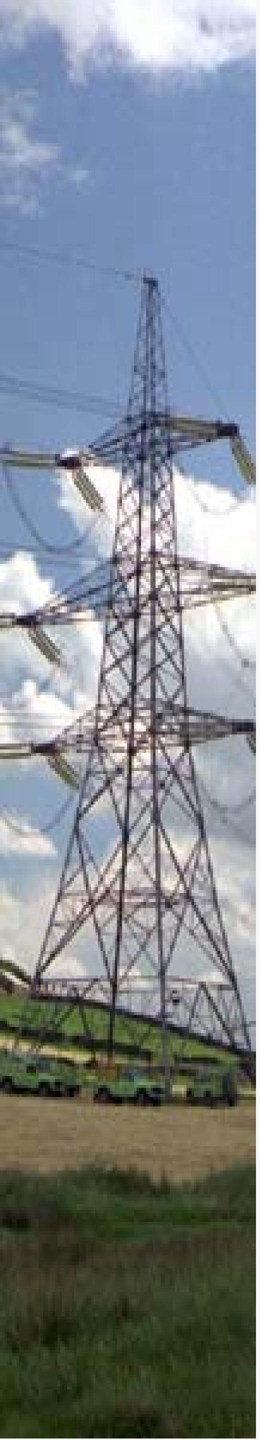


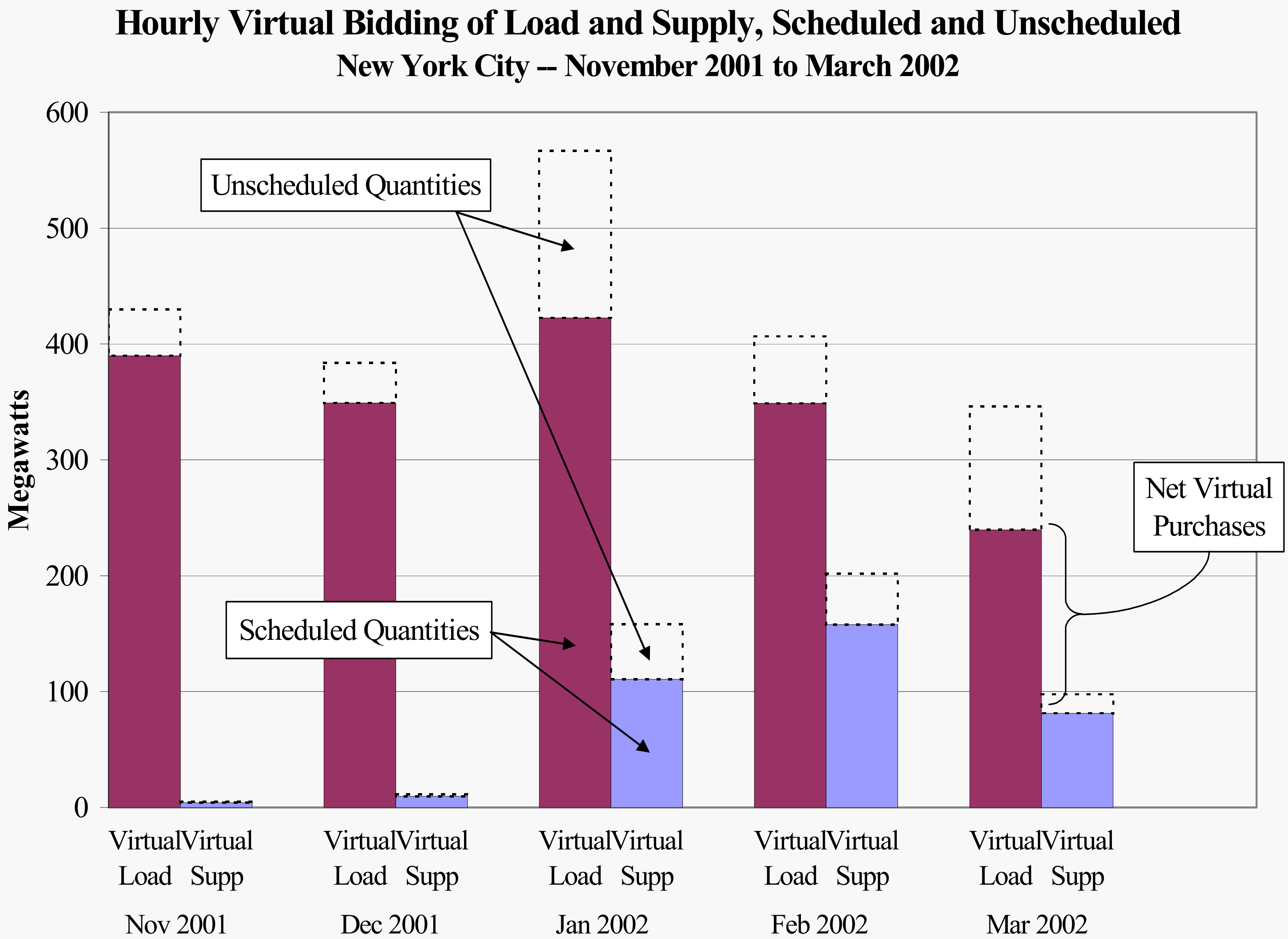
Virtual Bidding Patterns

- Virtual bidding was introduced in November to allow participation in the day-ahead market by entities other than LSE's and generators.
- The following figures show the quantities of virtual load and supply quantities that have been offered and scheduled on a monthly basis in the State and in NYC.
- This chart shows the following:
  - ✓ Virtual load bids rose initially in both areas and have leveled off in March.
  - ✓ Virtual suppliers have become much more active in the spring of 2002.
  - ✓ The vast majority of the virtual bids and offers have been price sensitive – i.e., most of the unaccepted quantities have been bid at prices close to market clearing levels.
  - ✓ Virtual loads have been larger than supply, raising the total day-ahead schedules as shown in the prior figures and, in part, displacing some of the price-capped load bids by the LSEs.

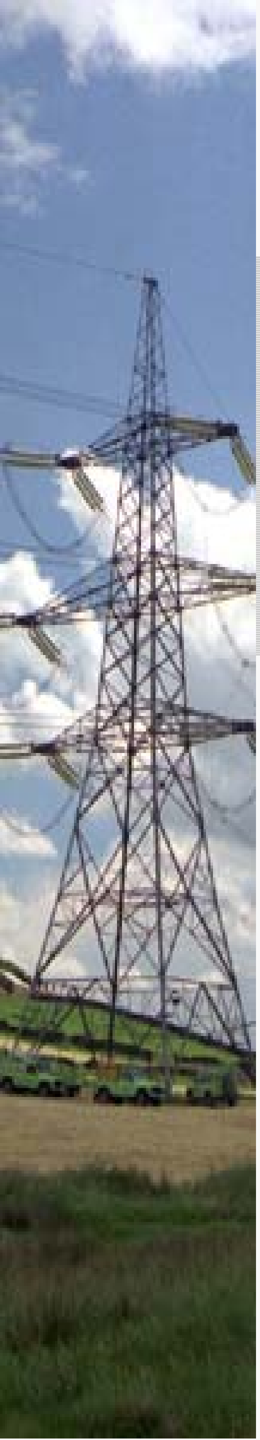



Hourly Virtual Bidding of Load and Supply, Scheduled and Unscheduled
New York State -- November 2001 to March 2002
Megawatts
1,400
1,200
1,000
800
600
400
200
0
Unscheduled Quantities
Scheduled Quantities
Net Virtual Purchases
Virtual Load
Virtual Supp
Nov 2001
Dec 2001
Jan 2002
Feb 2002
Mar 2002

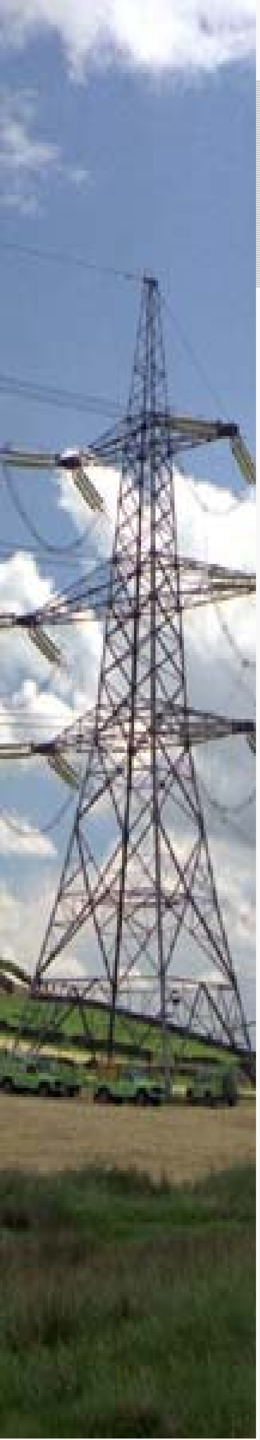




Hourly Virtual Bidding of Load and Supply, Scheduled and Unscheduled
New York City -- November 2001 to March 2002
Megawatts
0
100
200
300
400
500
600
Unscheduled Quantities
Scheduled Quantities
Net Virtual Purchases
Virtual Load
Virtual Supp
Nov 2001
Dec 2001
Jan 2002
Feb 2002
Mar 2002

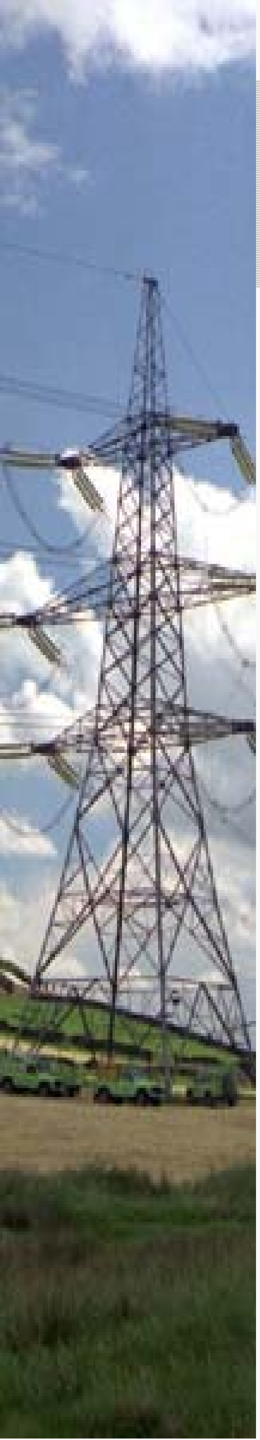


Imports and Exports



Assessment of Imports and Exports

- This section provides an update of the analysis for 2001 of external transactions provided in the Annual Assessment for 2000.
- The analysis in this section has two focuses:
  - ✓ First, it seeks to assess the extent to which the interfaces with the neighboring markets in the Northeast are rationally utilized; and
  - ✓ Second, it analyzes the results of the NYISO's import and export scheduling process to determine whether the NYISO market design has been an impediment to trading;

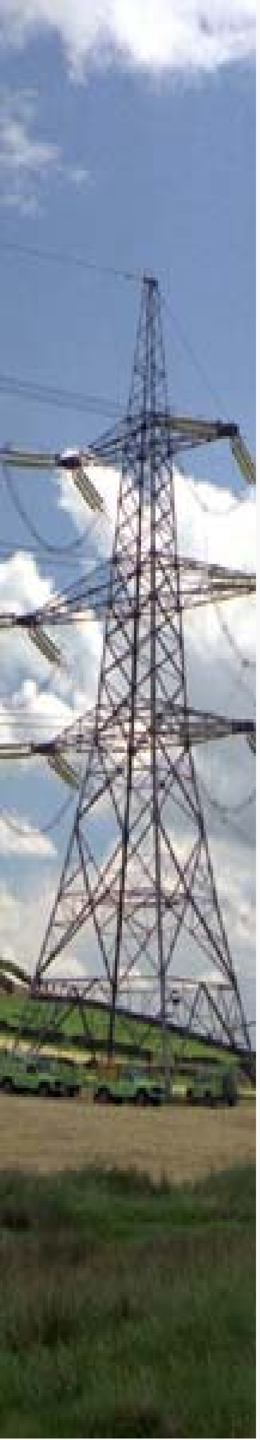


Utilization of the Interfaces

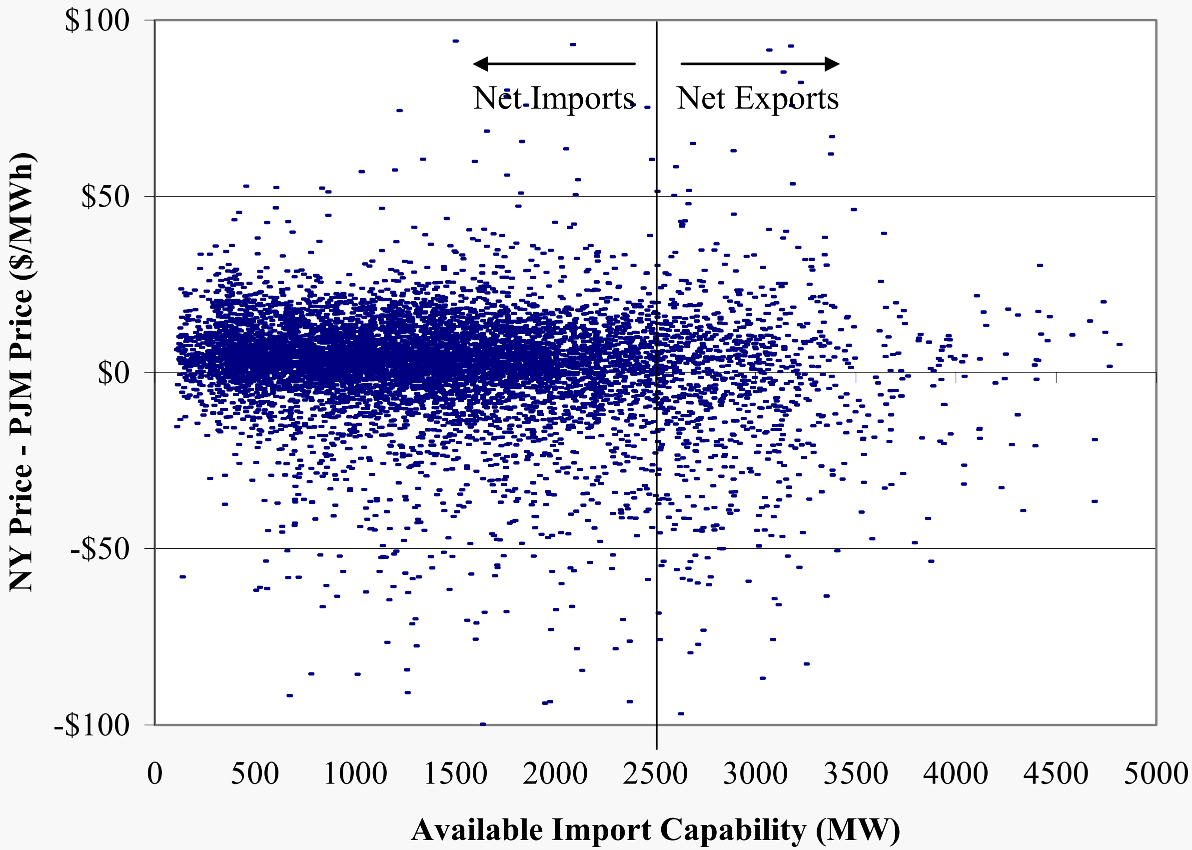
- The following three charts plot the hourly difference in prices between New York and neighboring markets against the available import capability during hours when transmission constraints are not binding.
- The price differences plotted against the left axis are always computed by subtracting the external price from the New York price (i.e., positive price differences mean prices are higher inside New York).
- The available import capability is computed in the following manner:

  Total Transfer Capability - Net Scheduled Import

  - ✓ Therefore, when the NYISO is exporting (net scheduled import is negative), the available import capability will exceed the total transfer capability;
  - ✓ The vertical dashed line is shown at the approximate TTC level for each interface -- so higher points (to the right) generally represent exports while lower points (to the left) generally represent imports.
- The counter-intuitive net schedules are a) net exports when NYISO prices exceed the adjacent market or b) net imports when NYISO prices are lower than adjacent prices.



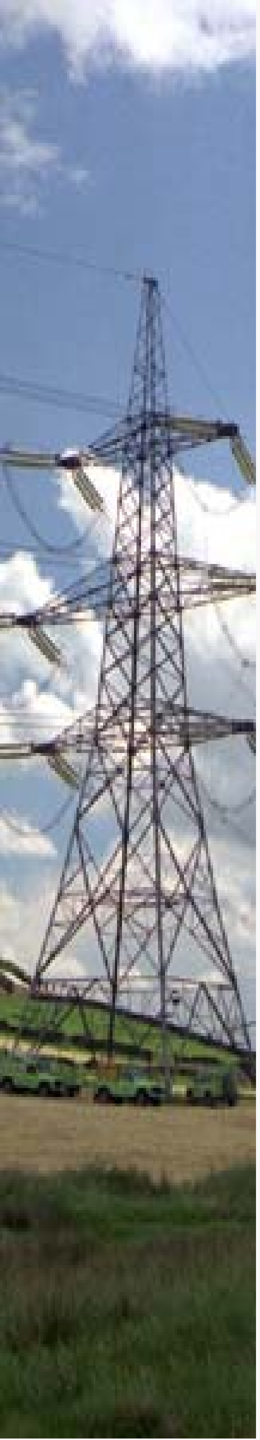
Difference Between West Zone and PJM Price* During Unconstrained Hours -
Real-Time Prices vs. Hour-Ahead Schedules -- January to December 2001



Monthly Price Statistics

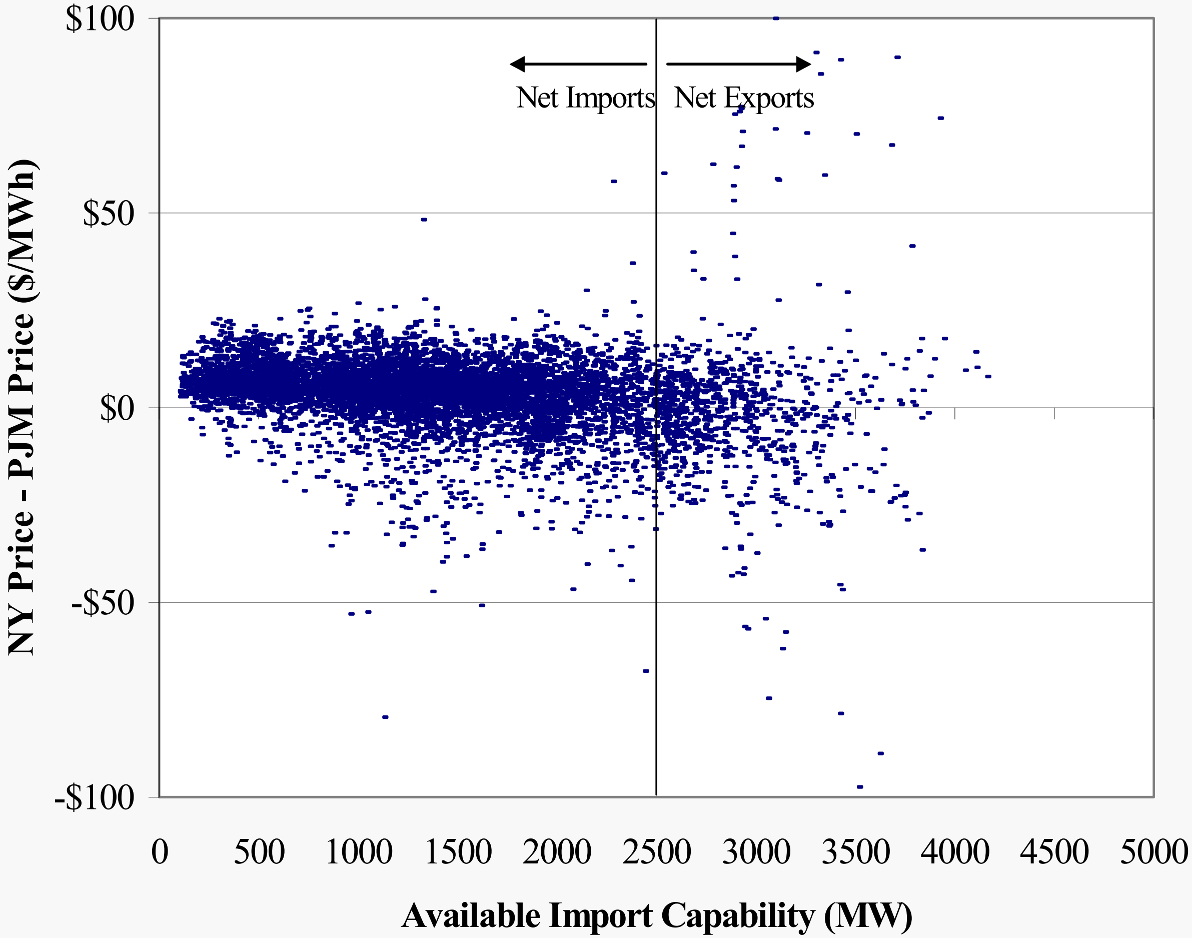
Month	Mean	Std Dev
Jan	$1.26	$21.95
Feb	$2.11	$22.46
Mar	$2.07	$28.95
Apr	-$2.67	$18.75
May	-$0.25	$16.90
Jun	$0.53	$22.30
Jul	$2.32	$31.59
Aug	-$3.65	$87.66
Sept	$7.47	$21.47
Oct	$4.60	$9.14
Nov	$2.31	$9.87
Dec	$3.13	$11.57

* PJM Western Hub Price



Difference Between West Zone and PJM Price* During Unconstrained Hours

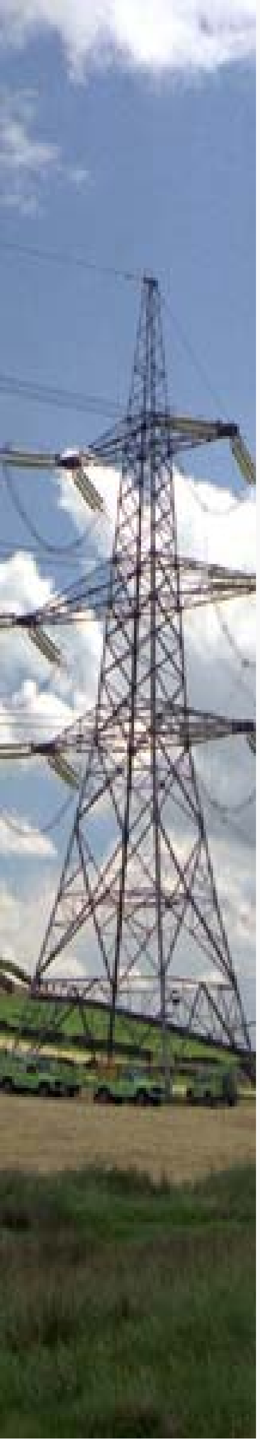
Day-Ahead Market -- January to December 2001



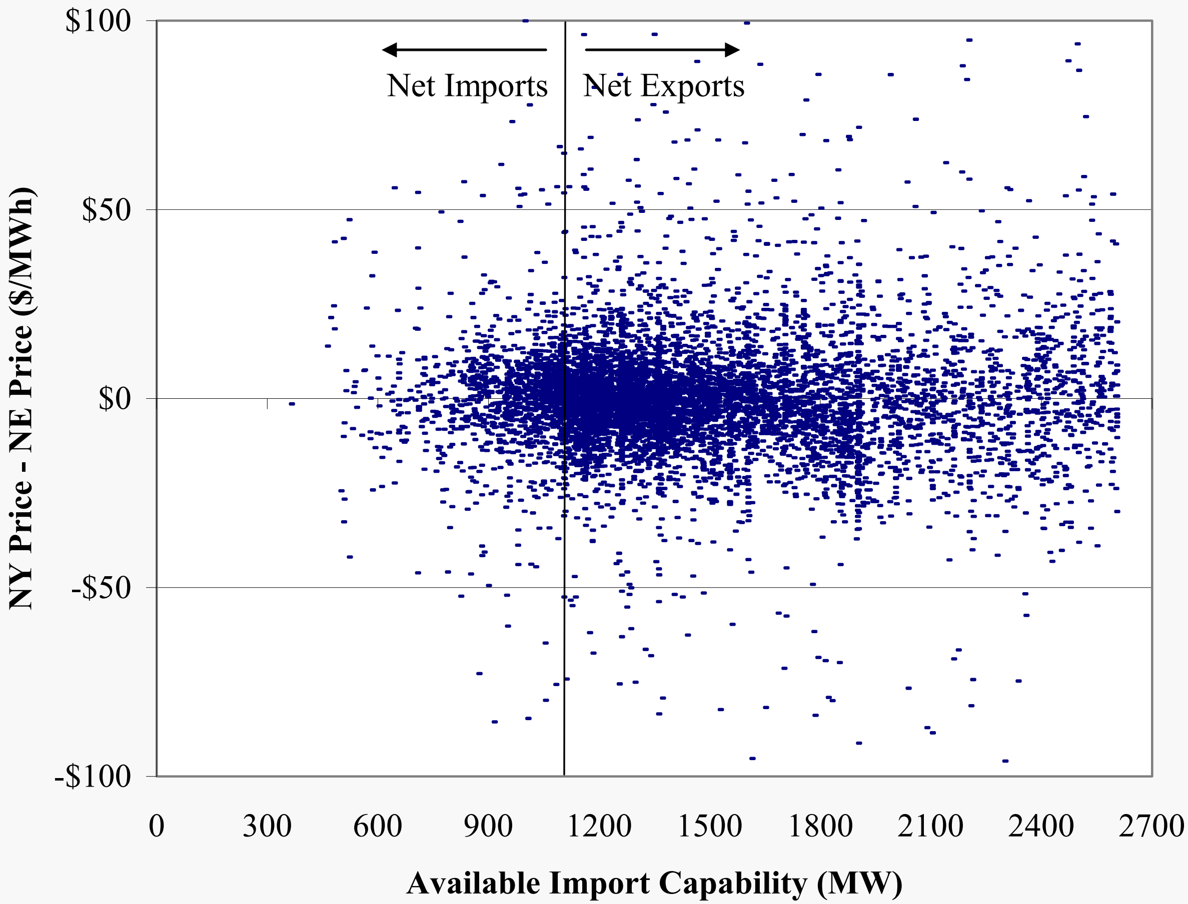
Monthly Price Statistics

Month	Mean	Std Dev
Jan	$6.16	$12.54
Feb	$4.33	$8.30
Mar	$0.25	$11.07
Apr	$1.32	$9.79
May	$5.39	$10.01
Jun	$2.27	$7.44
Jul	$4.13	$10.14
Aug	$0.72	$46.41
Sept	$5.62	$3.79
Oct	$3.31	$4.49
Nov	$3.46	$4.40
Dec	$1.72	$5.08

* Price at PJM Western Hub

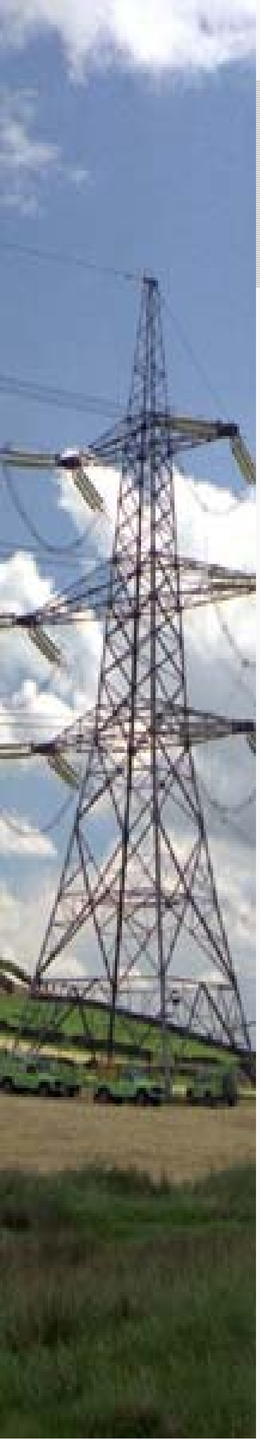


Difference Between Capital Zone and ISO-NE Price During Unconstrained Hours
Real-Time Prices vs. Hour-Ahead Schedules -- January to December 2001



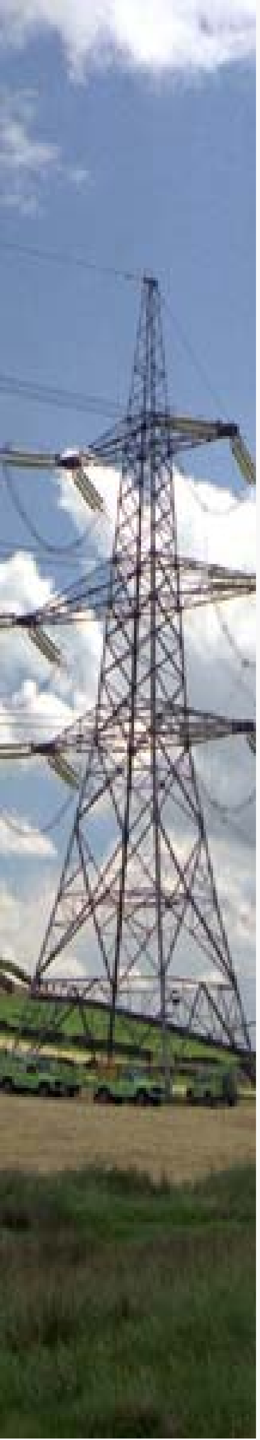
Monthly Price Statistics

Month	Mean	Std Dev
Jan	-$12.27	$29.61
Feb	$1.11	$35.01
Mar	-$1.21	$26.77
Apr	$0.92	$17.98
May	$11.84	$79.34
Jun	-$1.66	$27.82
Jul	-$12.37	$109.53
Aug	$11.24	$83.01
Sept	$1.32	$22.97
Oct	$0.24	$10.60
Nov	$0.57	$12.03
Dec	-$0.25	$13.41

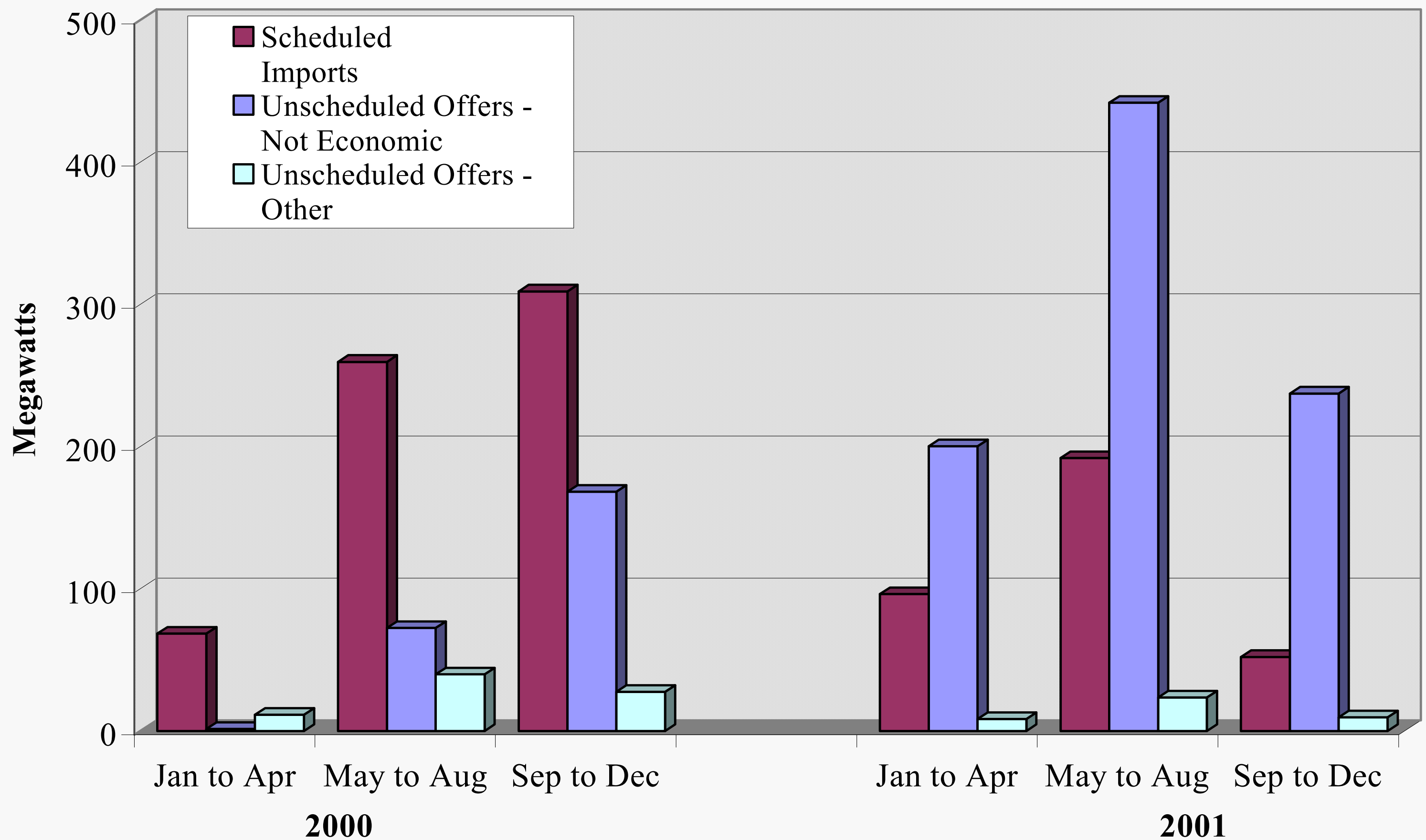


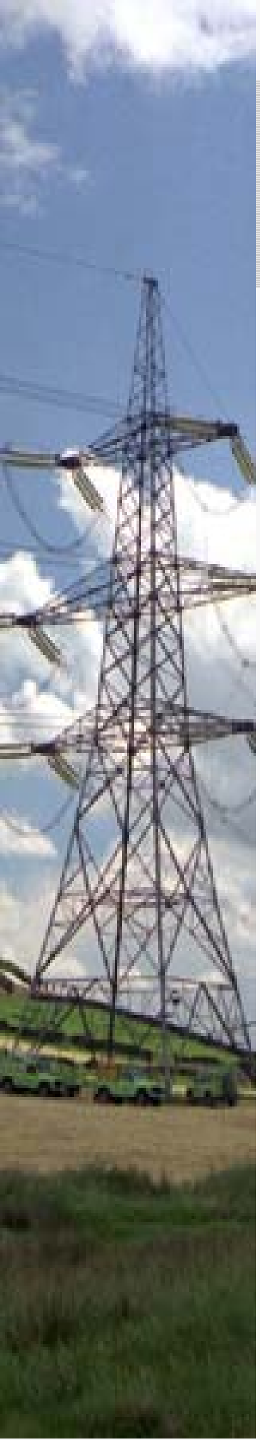
NYISO Scheduling of External Transactions

- The following bar charts show a comparison between the hourly average import transactions from New England that were scheduled or unscheduled in each month during 2000 and 2001.
- Those that are unscheduled are divided between those that are uneconomic versus those not scheduled for other reasons (e.g., failed checkout process).
- The chart shows that imports have fallen from the prior year.
- However, much larger quantities are being offered. This suggests an improvement in the attempt to arbitrage substantial price differences, which will benefit both New York and New England.
- Because the Central-East interface has been less congested, the prices in eastern New York have incented fewer imports.



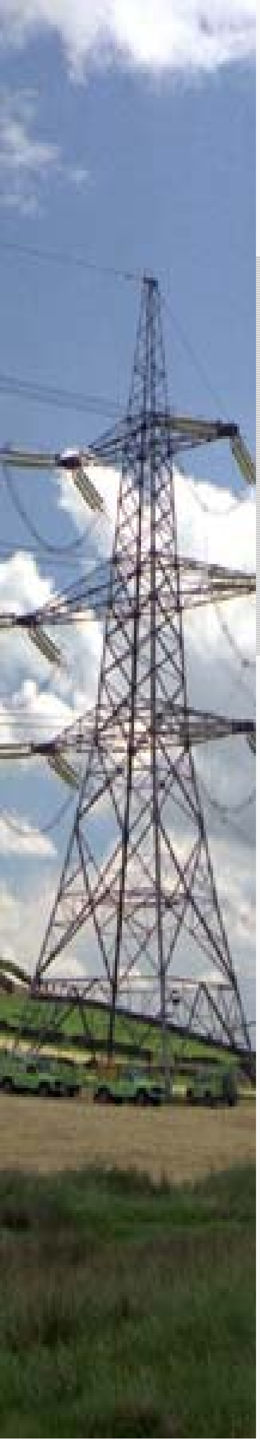
Imports from New England
Hour-Ahead Market, 2000 vs. 2001



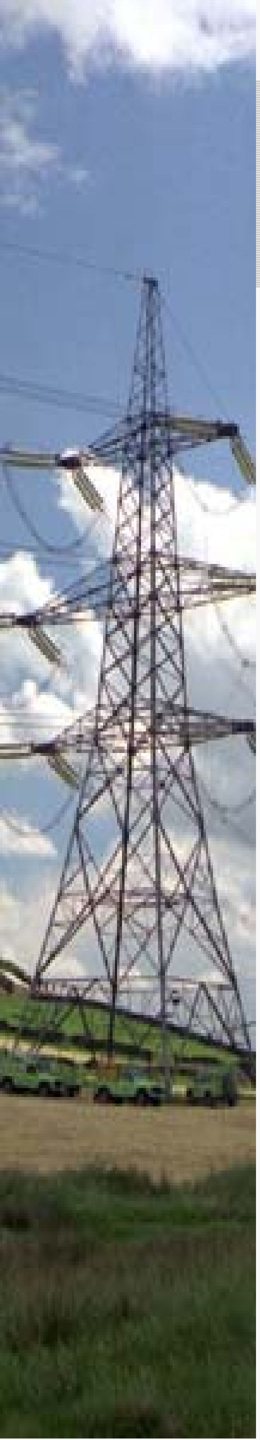


Assessment of Imports and Exports

- These results continue to suggest that impediments to efficient arbitrage remain with adjacent markets, particularly in real-time.
- Substantial changes are being made to improve scheduling with adjacent markets:
  - Changes in the short-notice transaction rules in New England;
  - Changes in BME that will improve export scheduling in peak hours;
  - Seams agreement with PJM;
  - Implementation of pre-scheduling provisions and multi-hour block transactions;
- The analysis of bidding and curtailments reveals the following:
  - ✓ The vast majority of the unscheduled transactions are unscheduled because they are not economic.
  - ✓ Virtually none of the unscheduled transactions in the DAM and a very small share in the HAM are not scheduled rejected for reasons other than economics and are often the result of transactions being withdrawn in one of the areas.



Installed Capacity Market



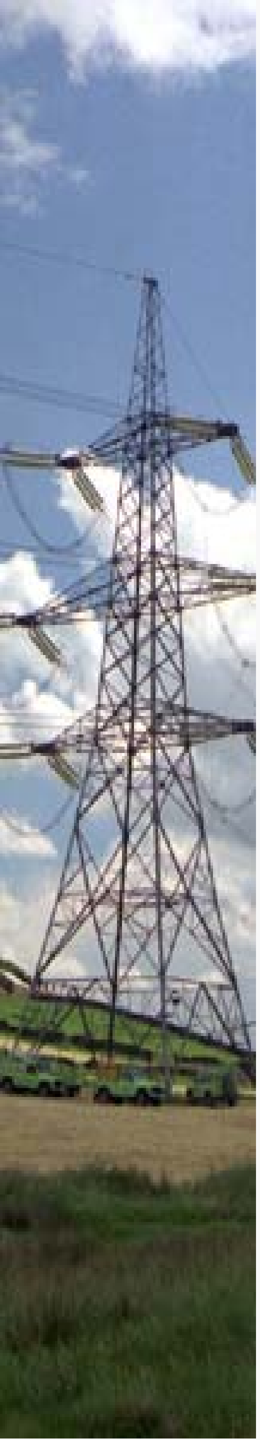
Installed Capacity Market

- The capacity market is intended to provide an economic signal to provide an efficient incentive for new investment and for capacity that is seldom utilized to remain in operation (e.g., peaking capacity).

- The following chart show the capacity amounts designated in New York (exclusive of capacity sold externally), as well as the “Rest of State” capacity prices.

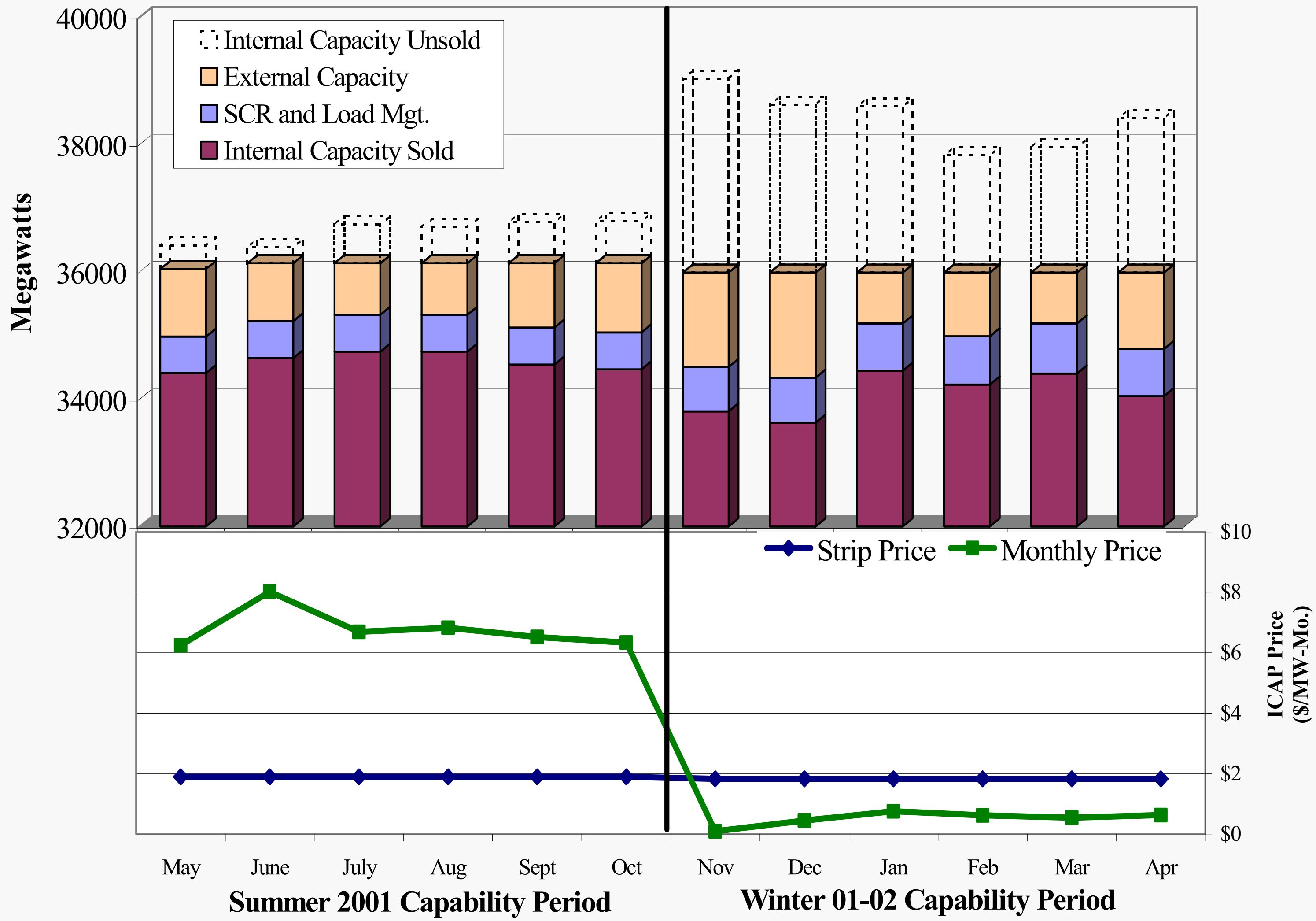
- The amounts shown as “unsold” were not sold within or outside of New York.

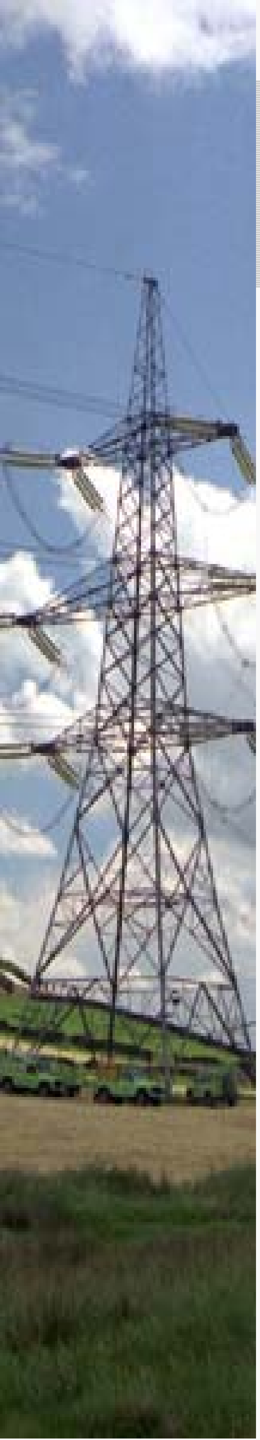
- This figure shows that when a capacity surplus existed statewide, capacity prices fell sharply as expected.



Installed Capability Market - New York State

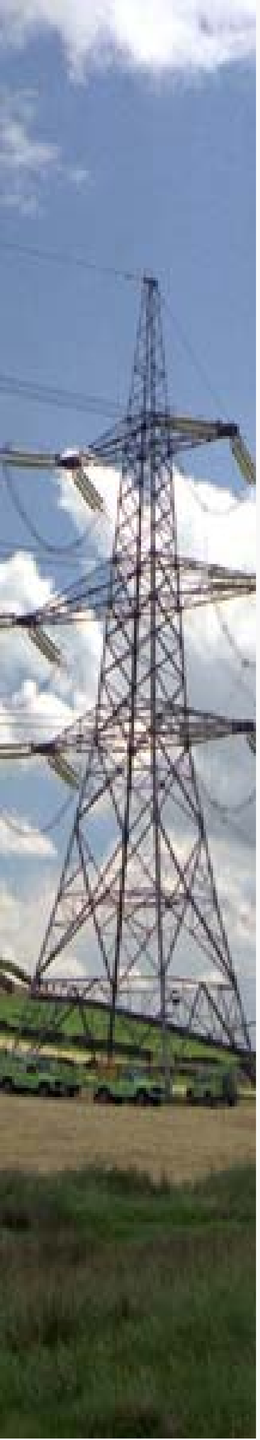
May 2001 to April 2002



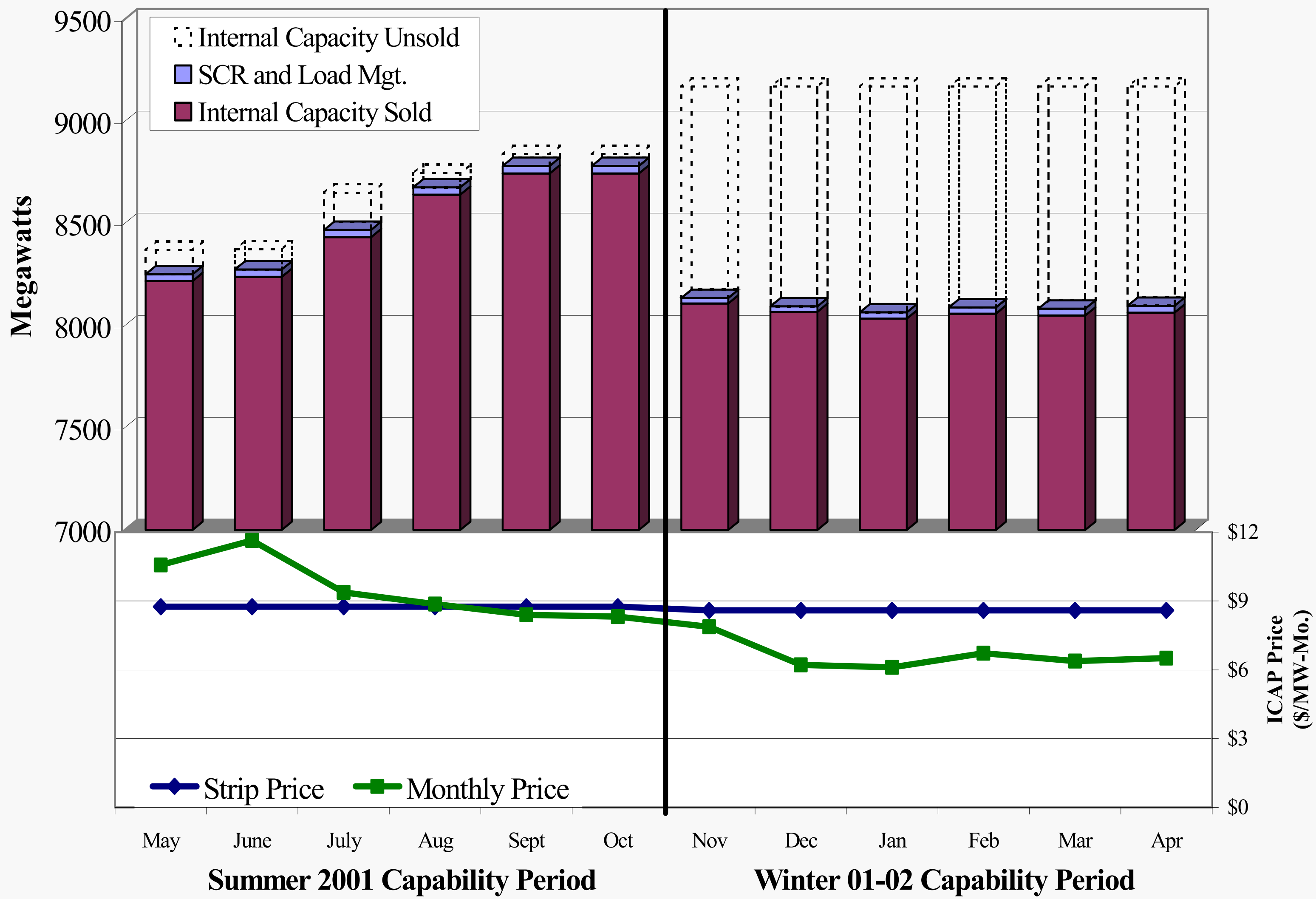


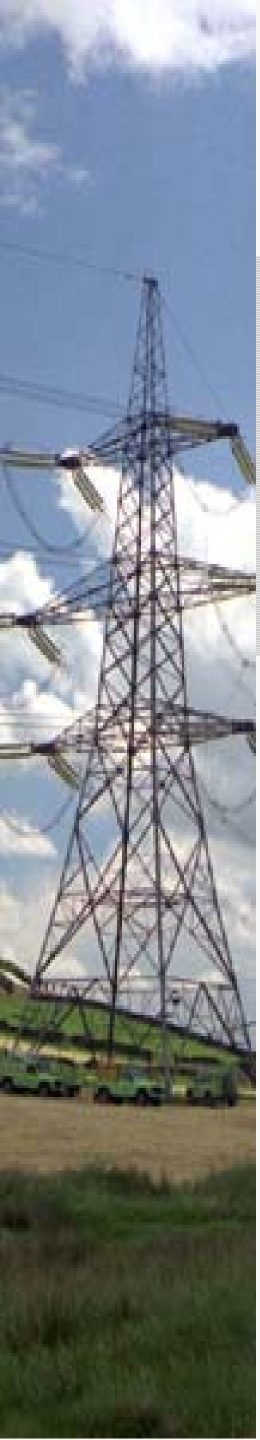
Installed Capacity Market

- The following chart show the capacity amounts designated in New York City (not limited to amounts sold to meet the NYC reqmt), as well as the NYC capacity prices.
- The increase in sales shown during Summer 01 corresponds to the new GTs that were installed in NYC.
- In contrast to the statewide results, this chart shows that when surpluses existed during the Winter 01-02 in NYC, capacity prices remained at levels substantially higher than the likely marginal cost of the capacity.
  - Marginal cost of providing capacity should not to be confused with the marginal cost of producing energy – it should generally equal the expected costs of the ICAP obligations accepted by the generator.
  - This result is not consistent with competitive expectations.
- New proposals should be considered regarding the structure of this market.
- For example, establishing a forward capacity requirement that can be met by existing capacity or new investment may improve the competitive performance of the market.

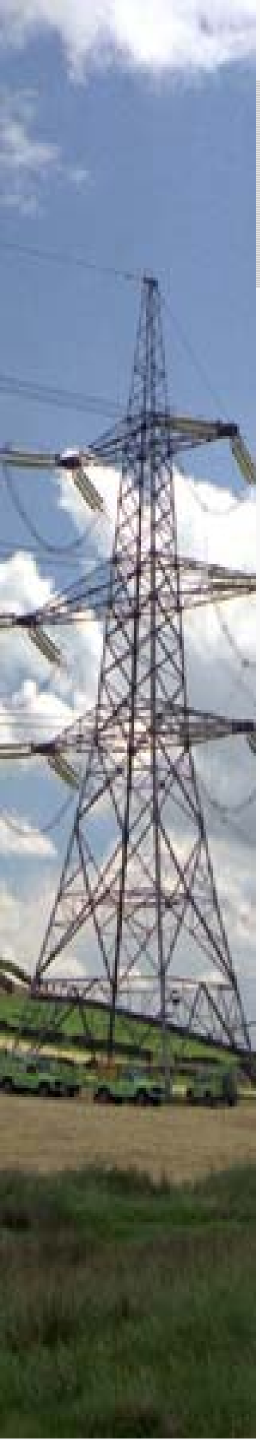


Installed Capability Market - New York City
May 2001 to April 2002



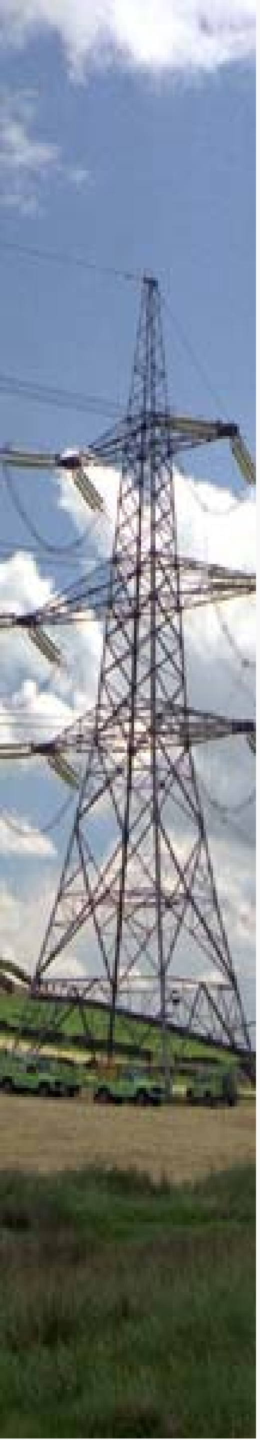


Ancillary Services Markets

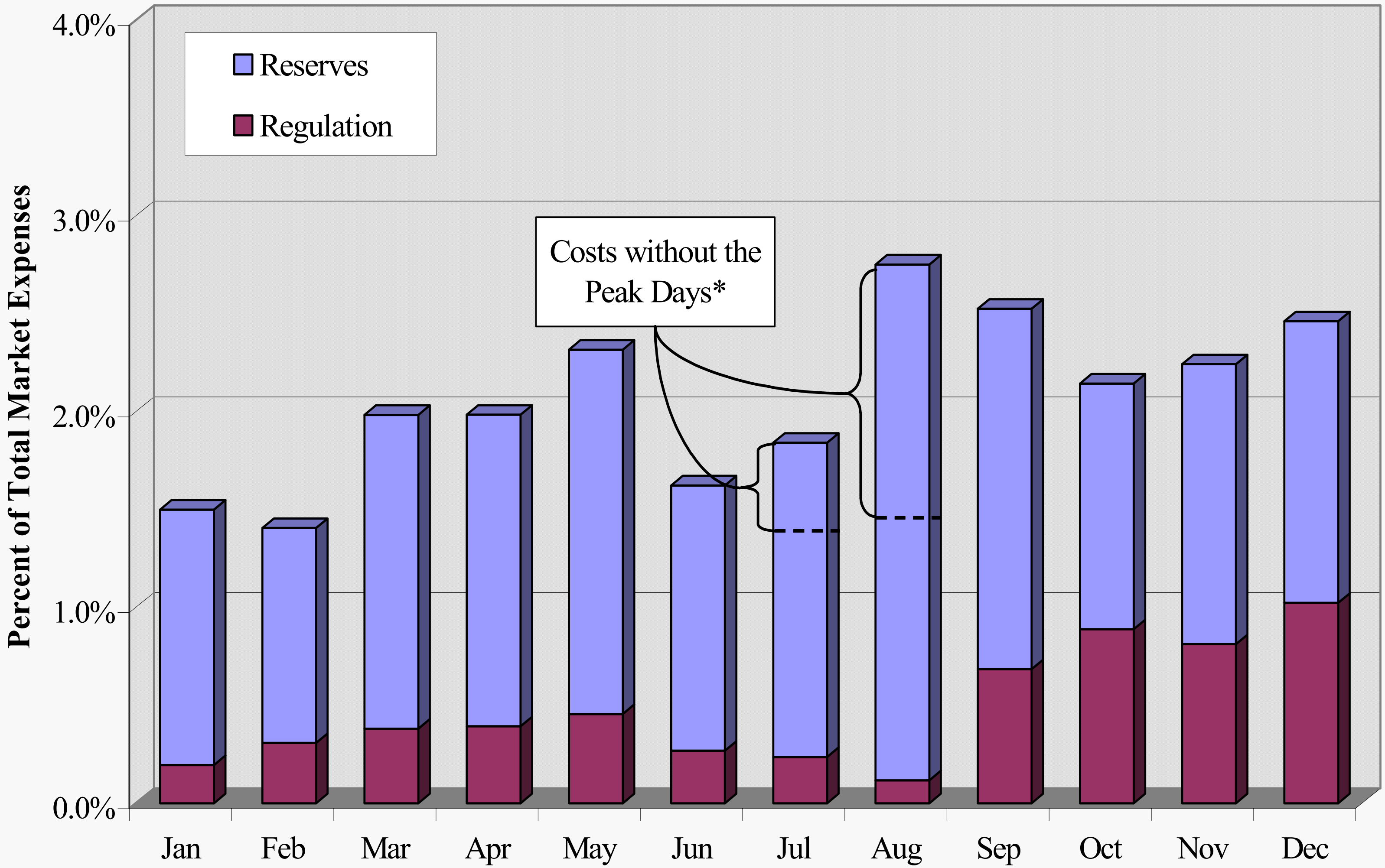


Ancillary Services

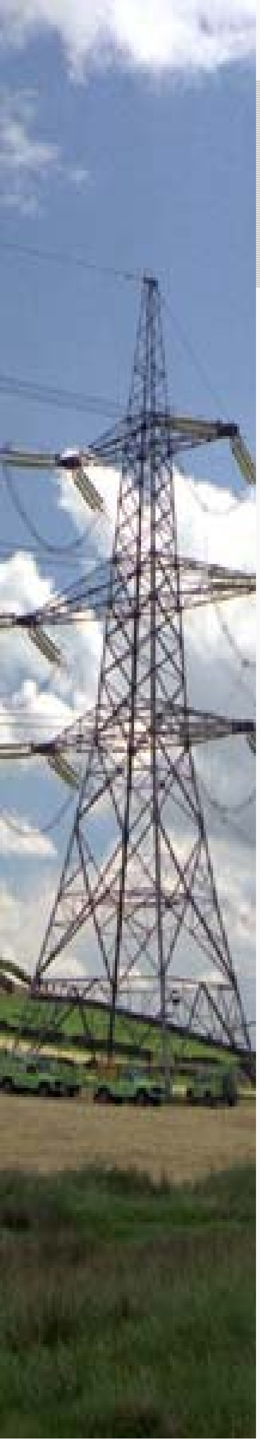
- The following chart shows that share of the total market expenses that are accounted for by ancillary services.
- These expenses are within expected levels based on experience in other markets.
- The increase in regulation costs as a share of market expenses is due in part to the fact that market expenses in total decreased sharply in the fall of 2001.
- The chart also shows the cost increases for ancillary services that occur associated with peak conditions as these markets must compete for resources with the energy market.



Reserves and Regulation Expenses in 2001

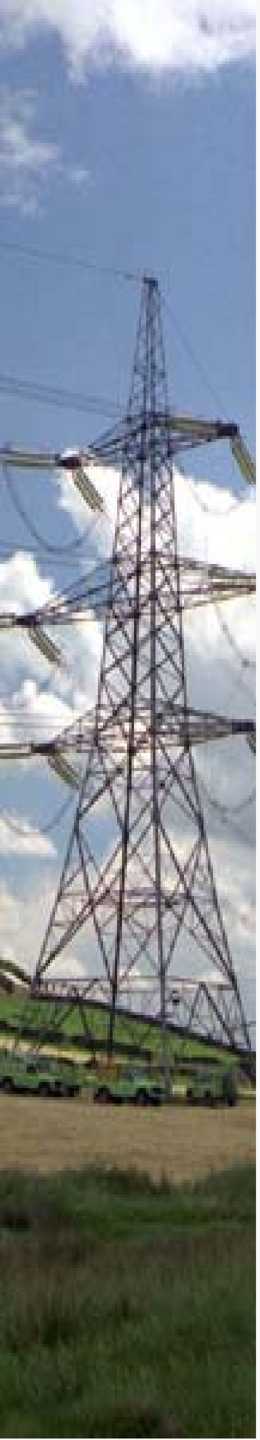


*Two days in July and four days in August where the HAM price exceeded $1000/MWh for more than one hour outside of Long Island.

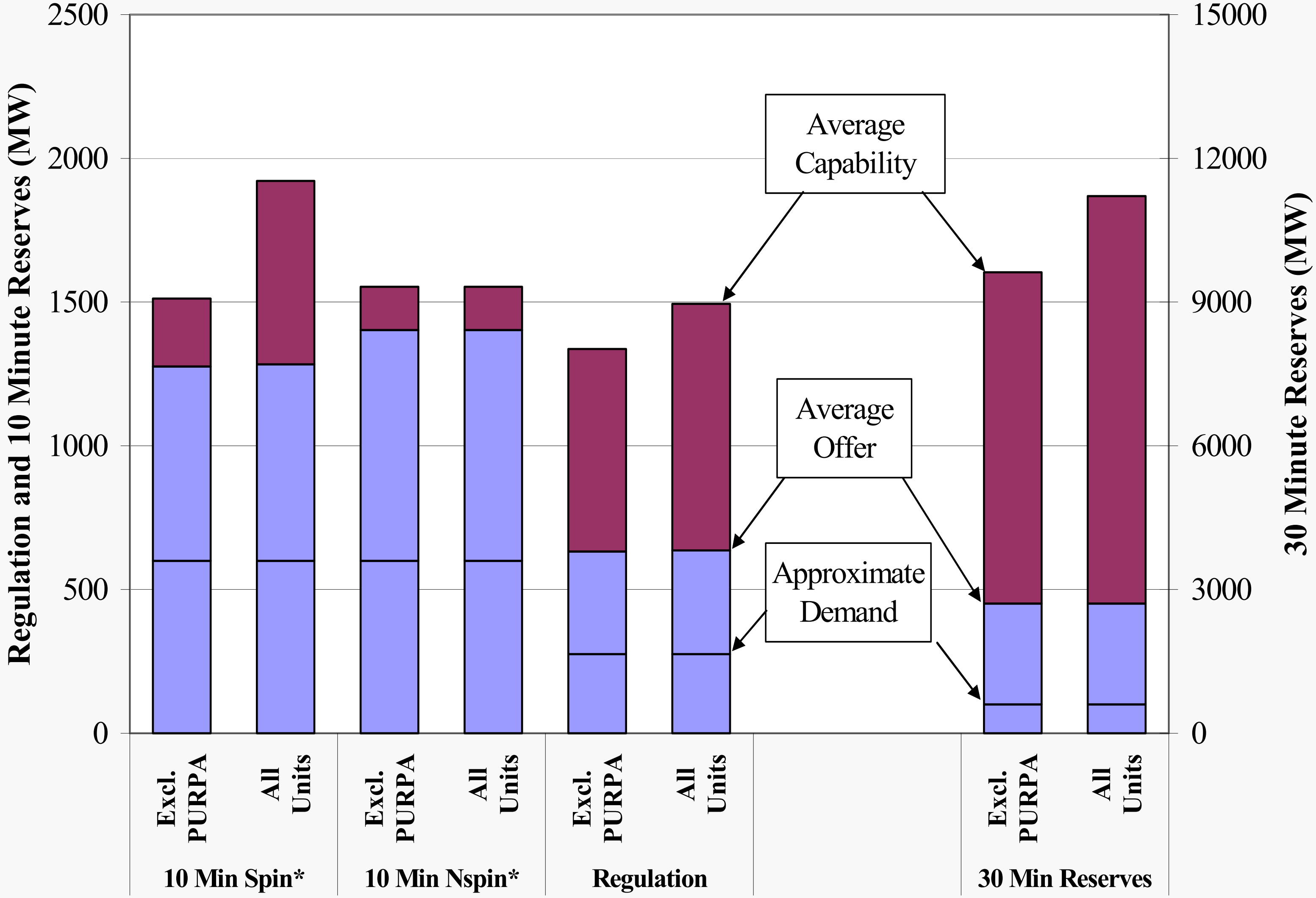


Ancillary Services

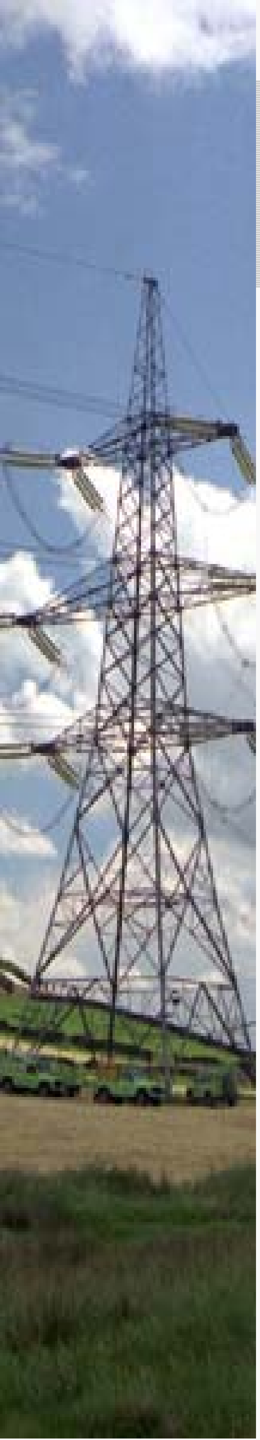
- Ancillary services markets are generally not tight because offers to supply typically exceed approximate demand:
  - ✓ For 30 minute reserves, offers typically exceed approximate demand by 380 percent (almost five times the demand);
  - ✓ For 10 minute NSR, offers typically exceed approximate demand by 160 percent -- although this market currently is subject to a requirement to sell and a bid cap;
  - ✓ For regulation and 10 minute spinning reserves, offers typically exceed approximate demand by 75 percent – but ignores the fact that some 10 minute spinning reserves can be purchased in the West;
- However, since these markets are jointly optimized and the same resources are offered in multiple markets, energy and other AS markets can bid resources away from a given service resulting in relatively tight conditions.



Ancillary Services Capability and Offers

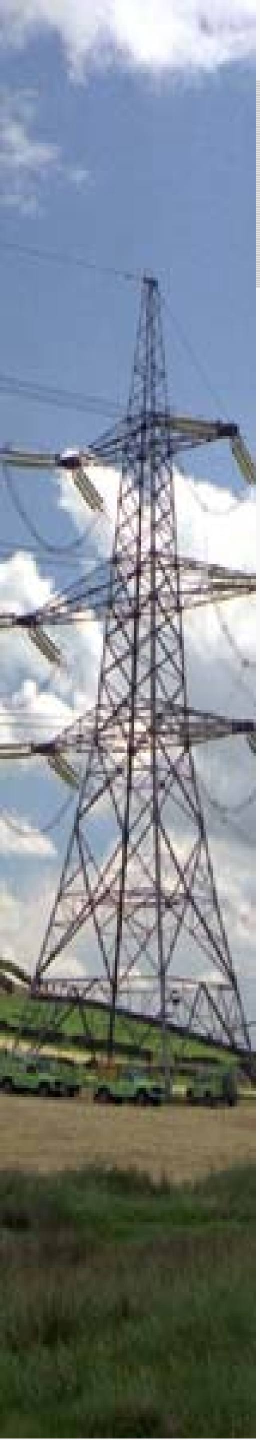


*10 minute reserves includes only capability in Eastern New York due to locational reserve requirements.

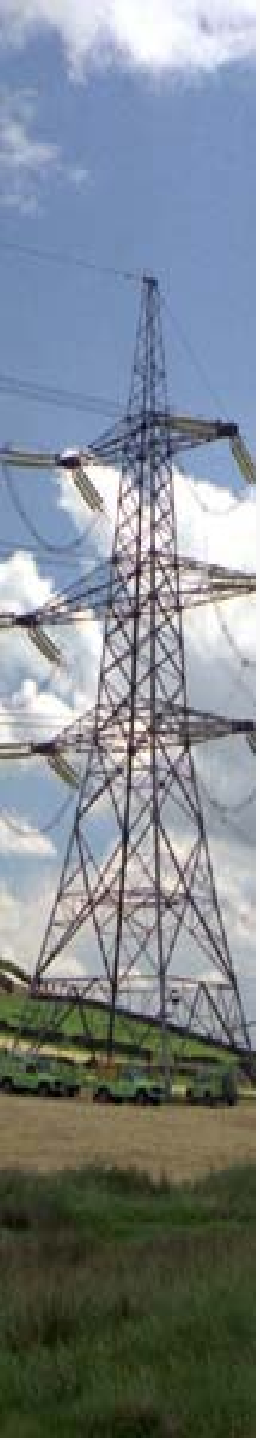


Ancillary Services Summary

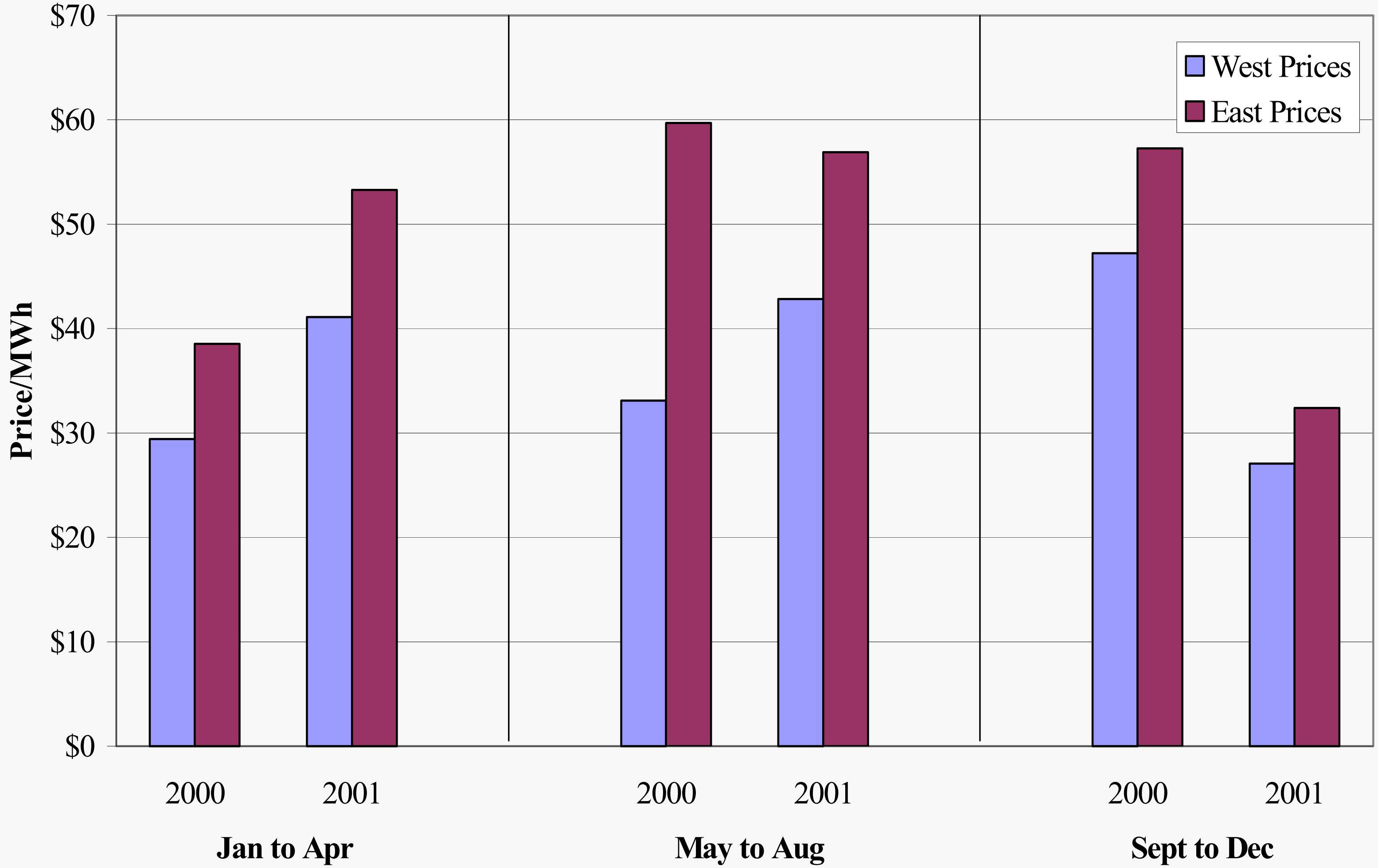
- A substantial amount of capability is routinely not being offered in the reserve markets.
- Conditions become tight in the ancillary services markets in peak hours as the energy market and reserve markets compete for the same resources. This can occur in off-peak hours when a large share of the capacity is offline.
- When this occurs, the shortage of reserves offers raises energy prices by causing relatively economic energy supplies to be diverted into the ancillary services markets.
- The sustained nature of the lackluster offers into the reserve markets indicates that the incentives to offer in these markets are inadequate.
- Therefore, I recommend that the NYISO modify the pricing rules for ancillary services to more completely account for potential opportunity costs of selling reserves.
  - This reform would ensure that a supplier selected for reserves or regulation is, at a minimum, not economically harmed by not being scheduled to provide energy.
  - In addition, this reform would improve the accuracy of the price signal for reserves.

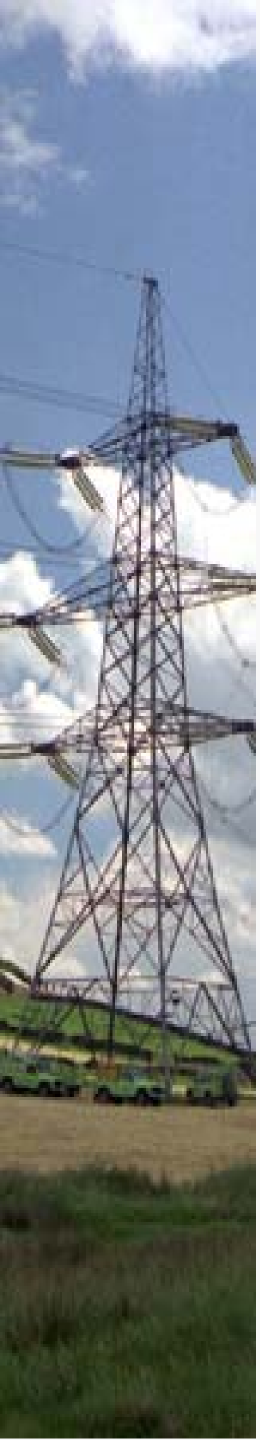


Appendix



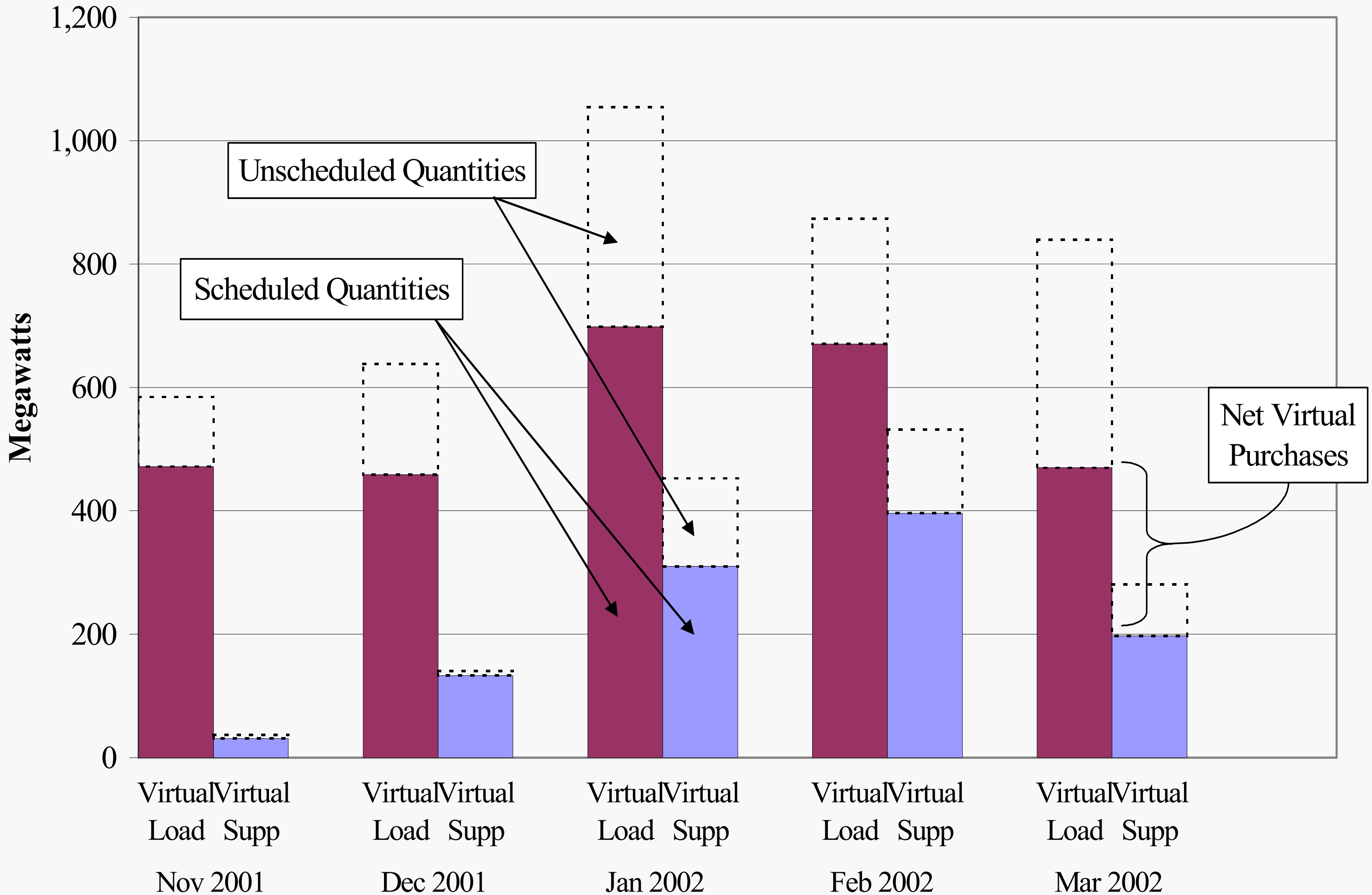
Seasonal Average Day Ahead Prices in New York
2000 vs. 2001

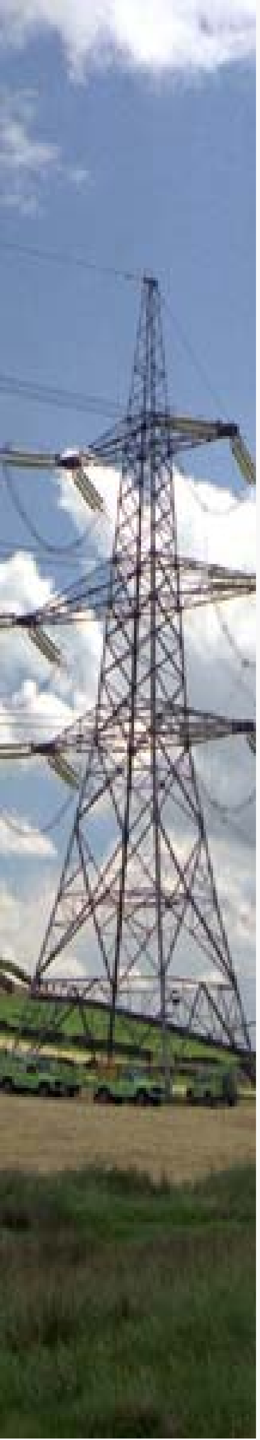




Hourly Virtual Bidding of Load and Supply, Scheduled and Unscheduled

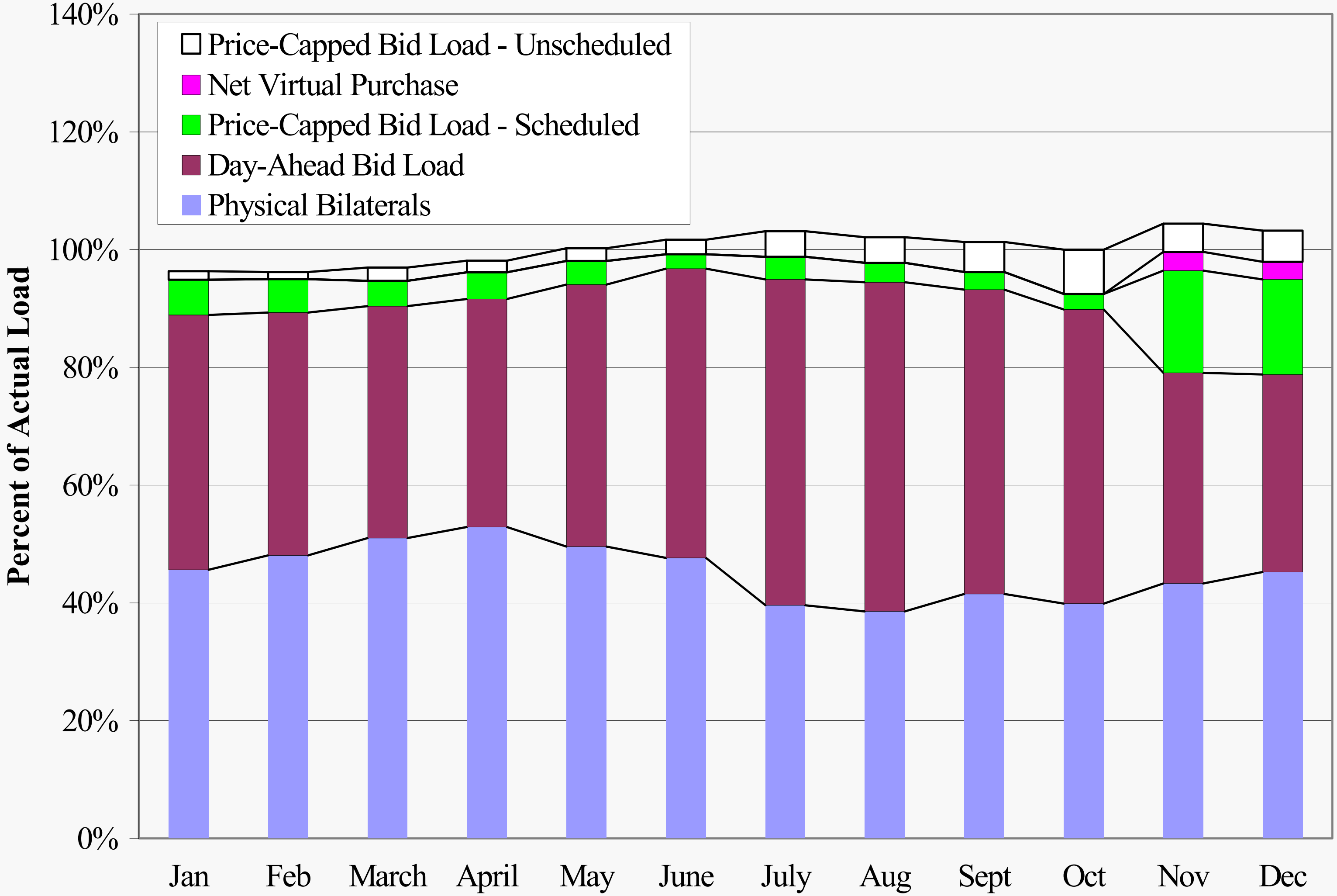
East New York -- November 2001 to March 2002

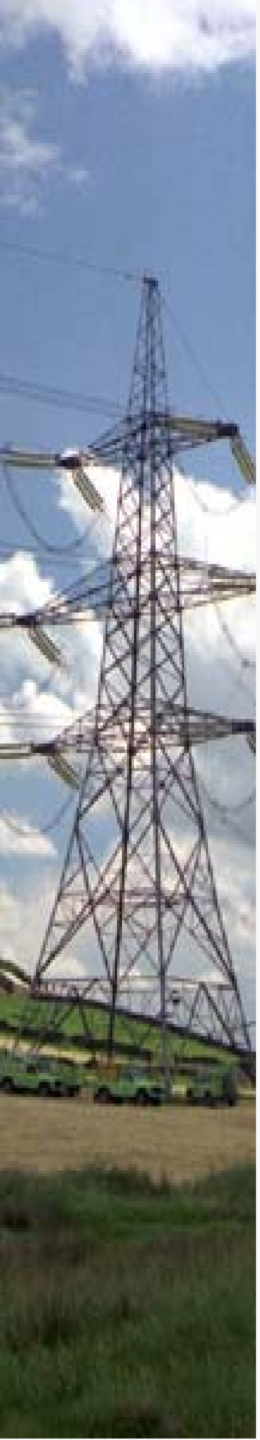


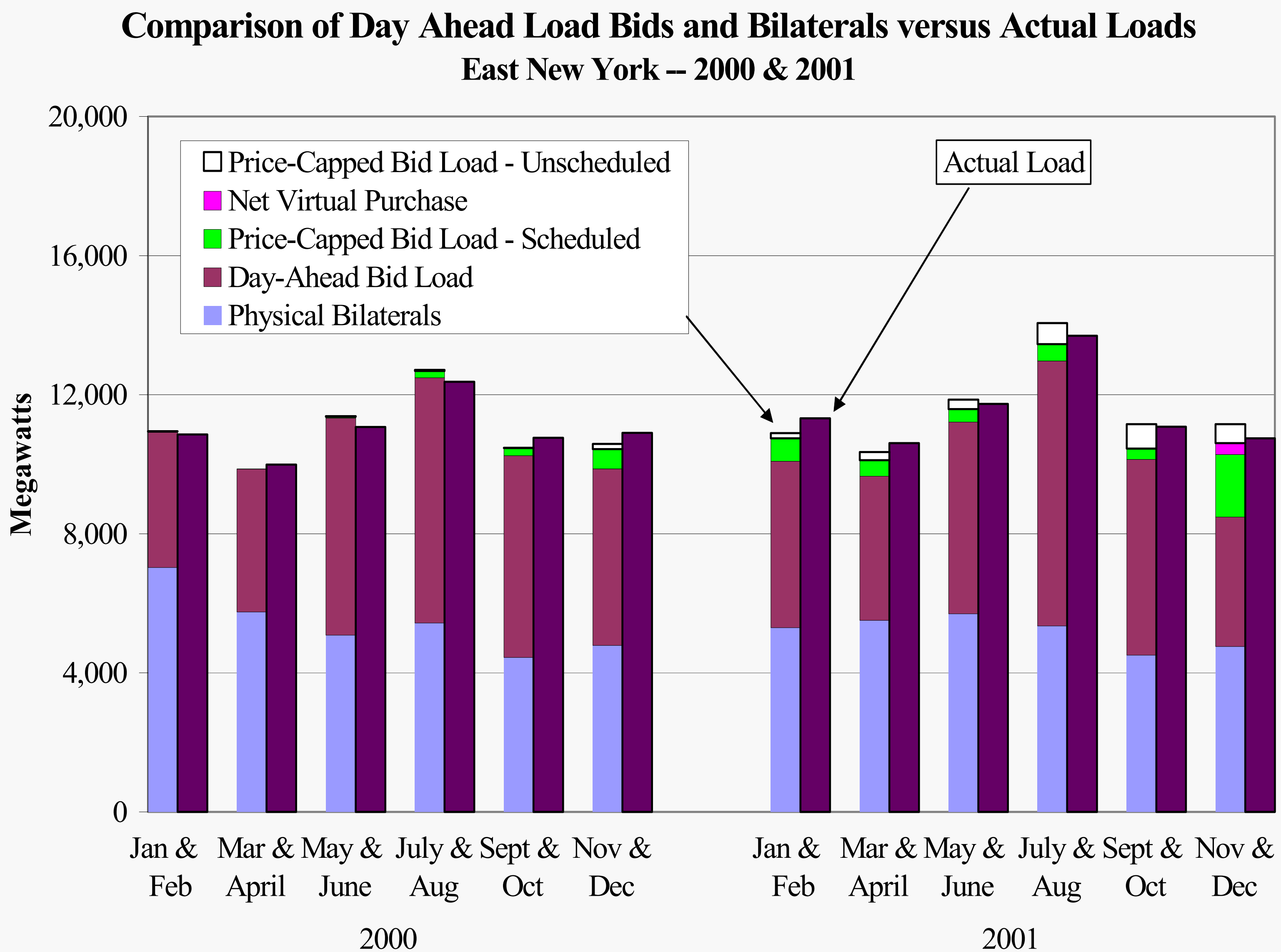


Composition of Day-Ahead Load Bids as a Proportion of Actual Load

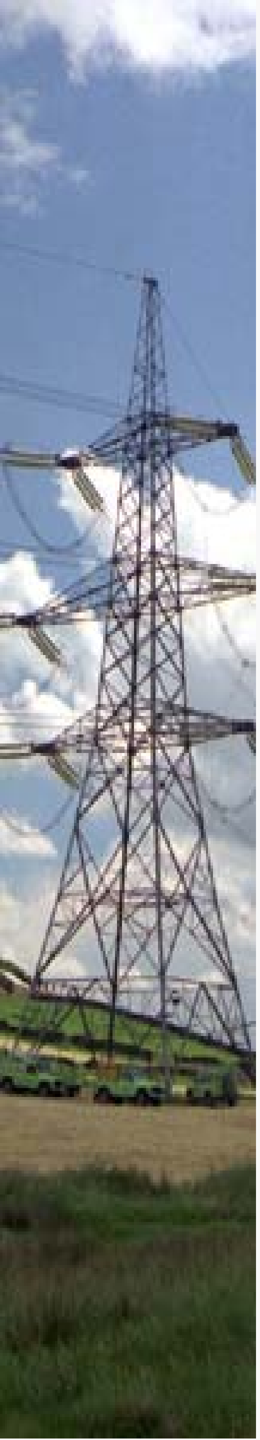
East New York -- 2001





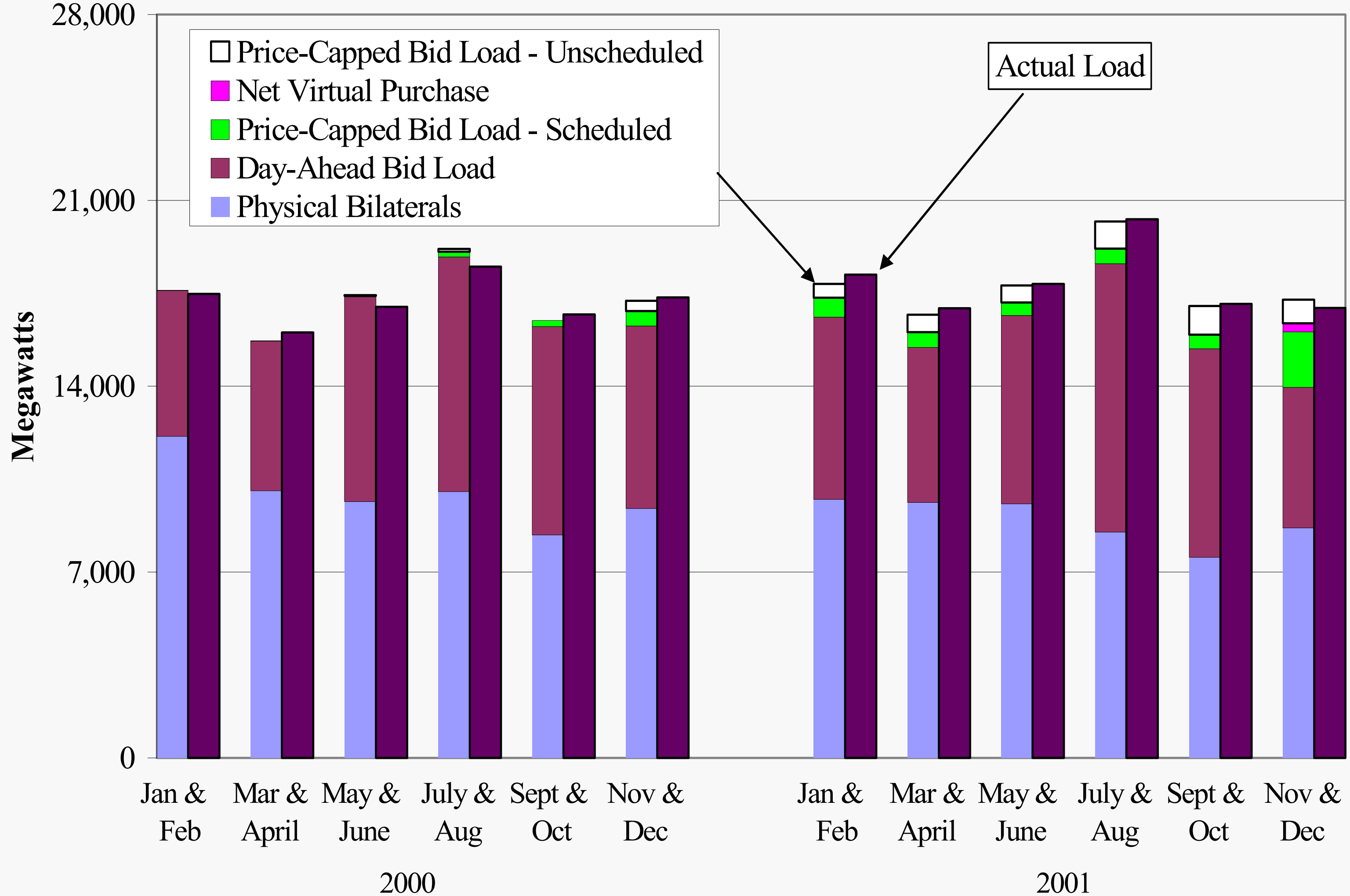


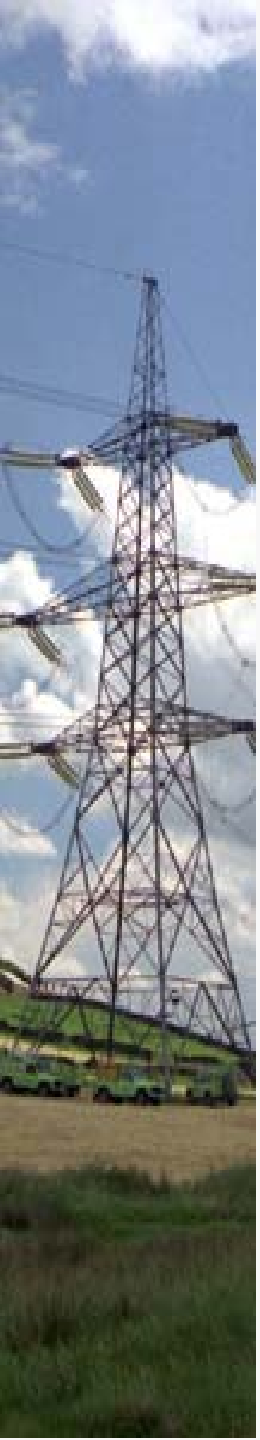
Comparison of Day Ahead Load Bids and Bilaterals versus Actual Loads
East New York -- 2000 & 2001
20,000
16,000
12,000
8,000
4,000
0
Megawatts
Price-Capped Bid Load - Unscheduled
Net Virtual Purchase
Price-Capped Bid Load - Scheduled
Day-Ahead Bid Load
Physical Bilaterals
Actual Load
Jan & Feb
Mar & April
May & June
July & Aug
Sept & Oct
Nov & Dec
2000
Jan & Feb
Mar & April
May & June
July & Aug
Sept & Oct
Nov & Dec
2001



Comparison of Day Ahead Load Bids and Bilaterals versus Actual Loads

New York State -- 2000 & 2001





Comparison of Day Ahead Load Bids and Bilaterals versus Actual Loads
New York City and Long Island -- 2000 & 2001