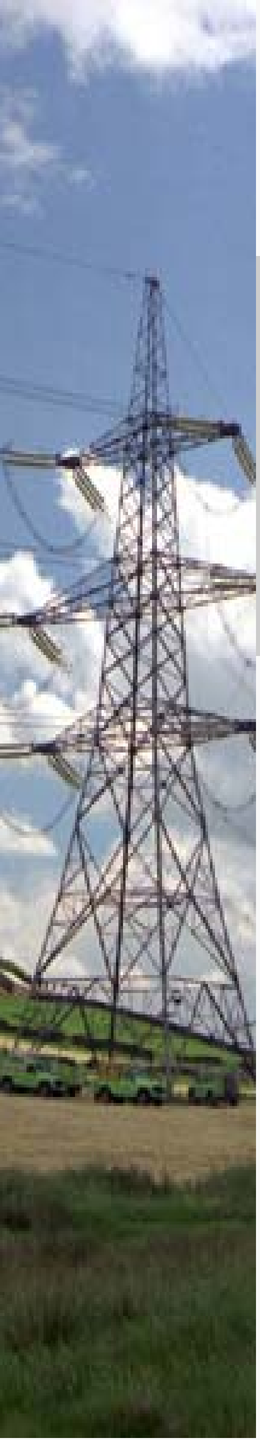


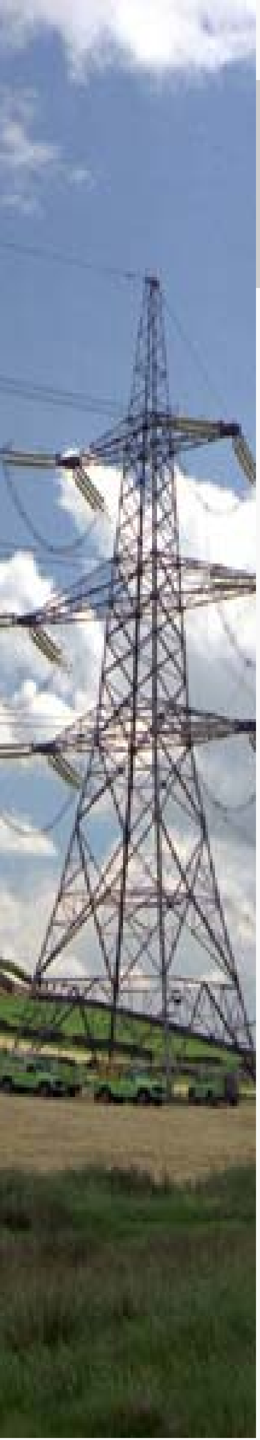
Summer 2002 Review of the New York Electricity Markets

Presented to:

New York ISO Board of Directors and
Management Committee

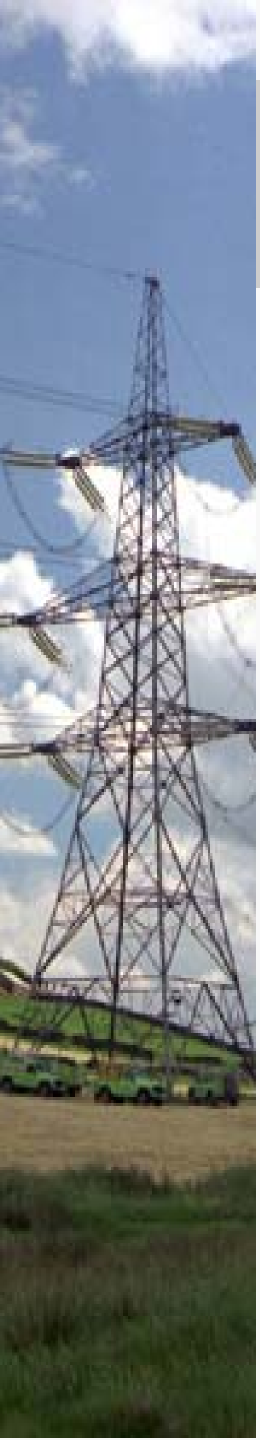
David B. Patton, Ph.D.
Independent Market Advisor

October 15, 2002



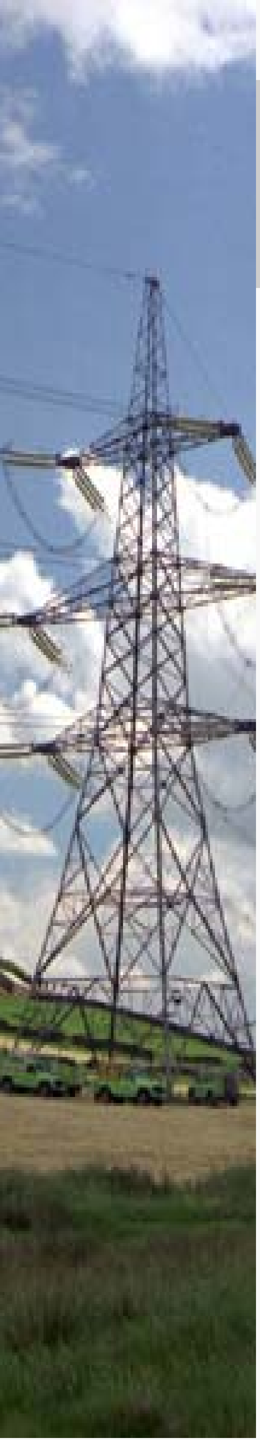
Summary and Conclusions

- Market performance improved in a number of areas this summer relative to 2001:
  - ✓ Substantially lower uplift;
  - ✓ Improved convergence of Hour-Ahead and Real-Time Prices;
  - ✓ Improved convergence of Day-Ahead and Real-Time Prices;
  - ✓ Increased utilization of virtual trading and price-capped load bid;
- Modeling of transmission constraints within NYC (load pockets) has resulted in more accurate locational prices.
  - ✓ The load pocket modeling has increased congestion costs in Eastern New York while reducing the uplift associated with the out-of-merit dispatch previously used to manage intra-City congestion.
  - ✓ However, price convergence between day-ahead and real-time prices could be improved in some of the load pockets.



Summary and Conclusions

- RTS will improve the long-term performance of the market and will provide a means to address most of the issues identified in this review.
- However, this review also identifies a number of market issues that should be addressed in the short-term.
  - ✓ The current pricing rules and operating procedures have hindered the market from setting efficient prices during shortage conditions. This problem is common to all of the operating wholesale energy markets.
  - ✓ External transactions have not responded efficiently to price signals under peak conditions.
- Finally, this review provides an assessment of the economic signals provided by the New York market to new investment in various locations.
  - ✓ Based on this analysis, the current market revenue would not likely support new investment in gas turbines ("GTs") outside NYC with significant uncertainty regarding GTs within NYC, although other investments may be economic.
  - ✓ This finding underscores the importance of the shortage pricing improvements, and ultimate design and role of the capacity market.



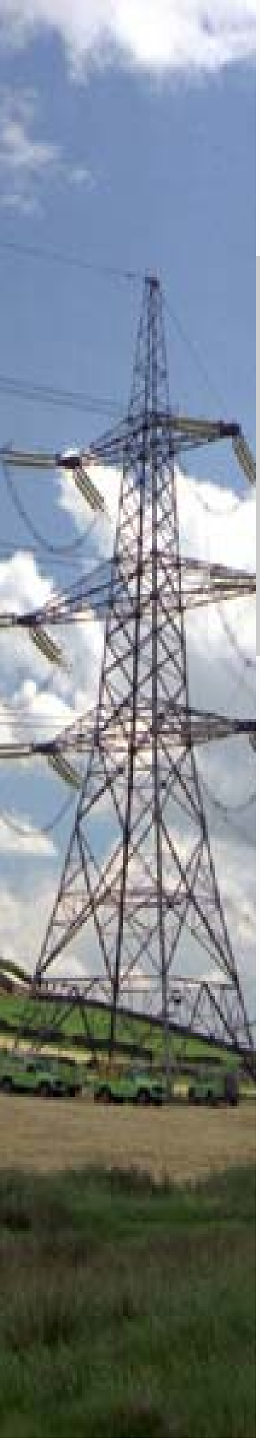
Recommendations

Peak Energy Pricing

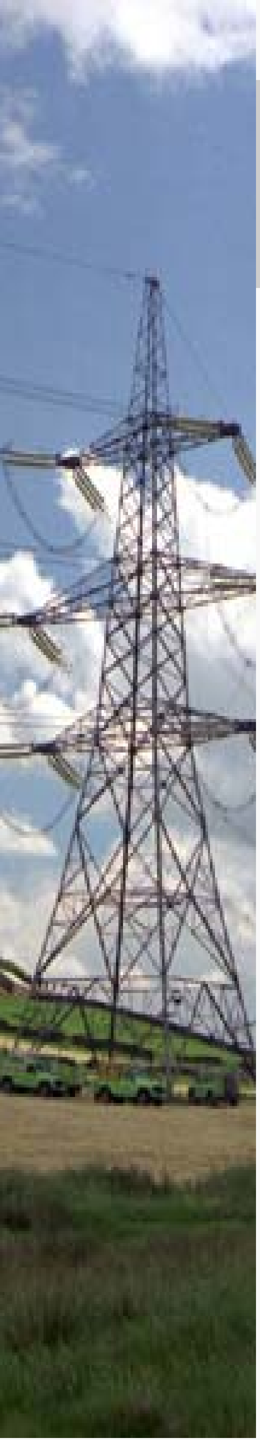
- Establish efficient energy prices during capacity shortages by increasing the shadow prices used to determine real time LMBPs:
  - (i) In all locations within State when the system is deficient in 10-minute spinning reserve or total 10-minute reserves, and
  - (ii) In locations in eastern New York when the system is deficient in 10-minute total reserves in the east.
- Allow EDRP and SCR resources to submit a wider array of curtailment bid prices and to set energy prices at the level of their payment for curtailing when they are economic.
- Improve procedures to allow 10-minute gas turbines committed manually to be eligible to set energy prices when they begin producing energy.
- Consider allowing virtual trading at the load pocket level within NYC or, alternatively, on the 345kv system separately from the 138 kv system.

External Transactions

- Modify the real-time scheduling process to adjust physical interchange with neighboring markets in response to real-time price differences (excluding capacity shortage conditions).
- Establish financial transmission rights for use of the external interfaces to hedge congestion at the interface.

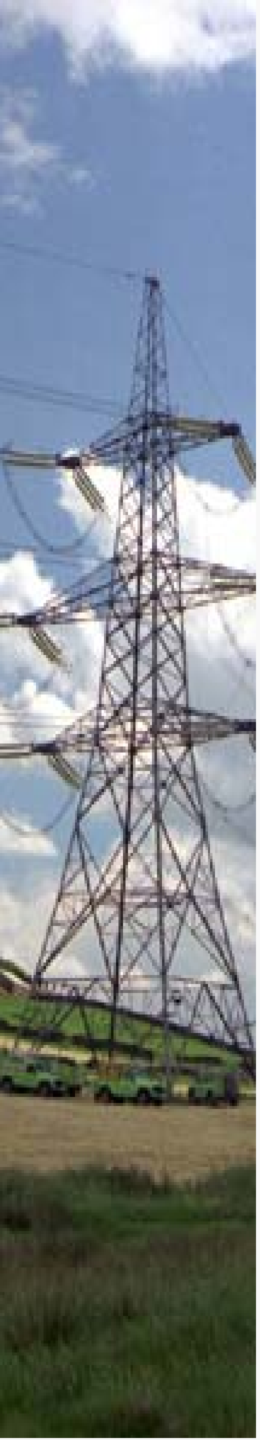


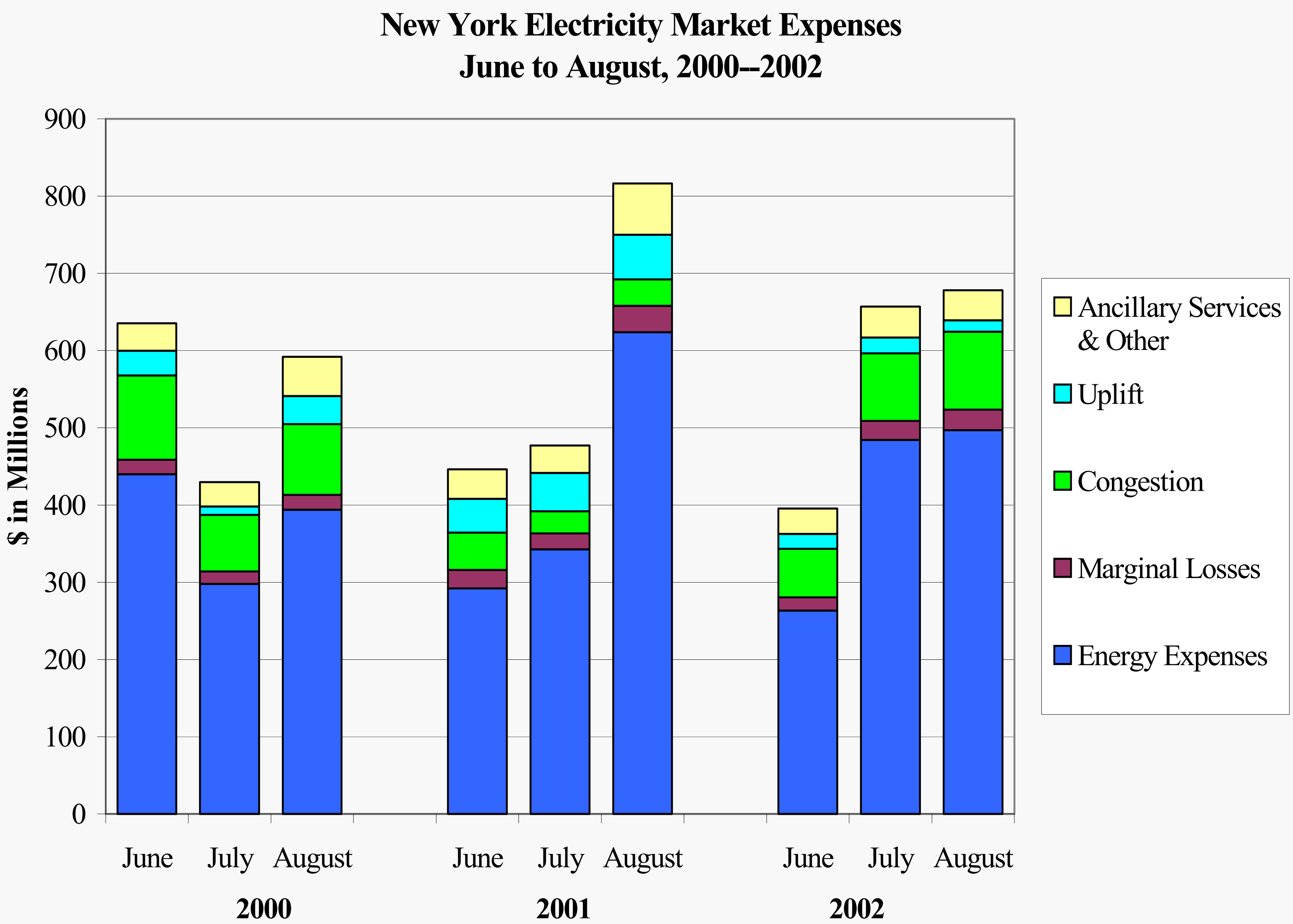
Market Prices and Outcomes

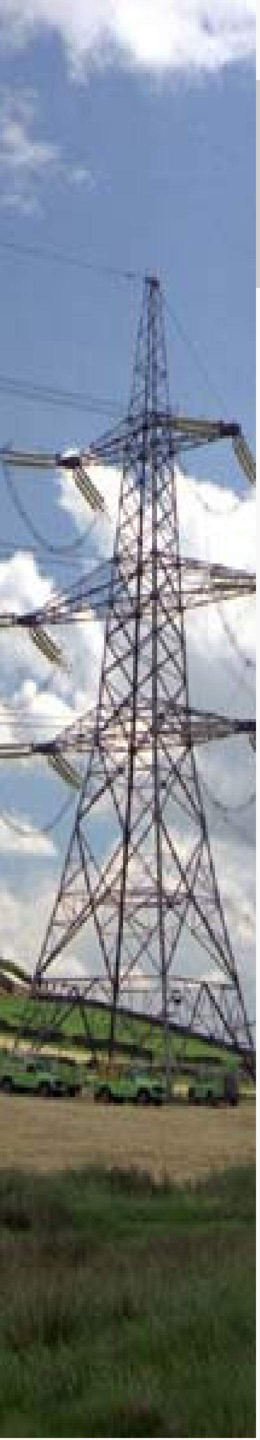


Total Electricity Costs in the New York Markets

- The following chart shows the total monthly expenses for market participants of the NYISO in the summers of 2000 to 2002.
- The total expenses for the summer of 2002 were approximately $1.7 billion – virtually the same as the expenses in 2001.
- Although the total expenses were the same, the chart shows that congestion expenses rose significantly and uplift costs fell sharply in the summer of 2002. These changes are described below.

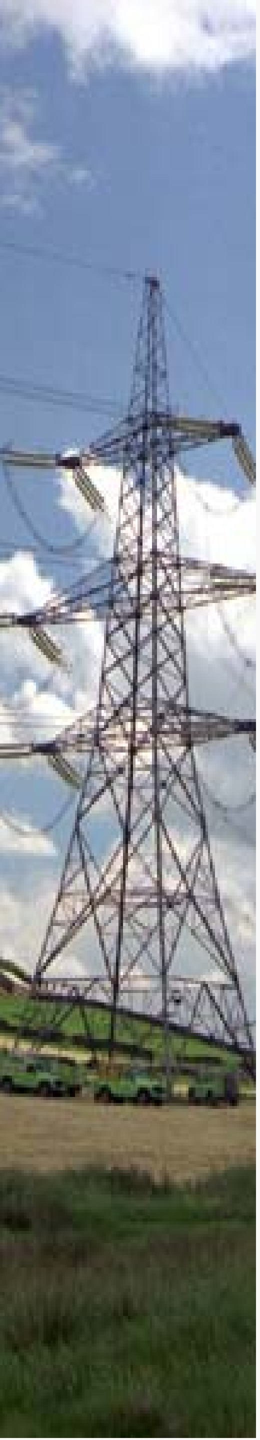


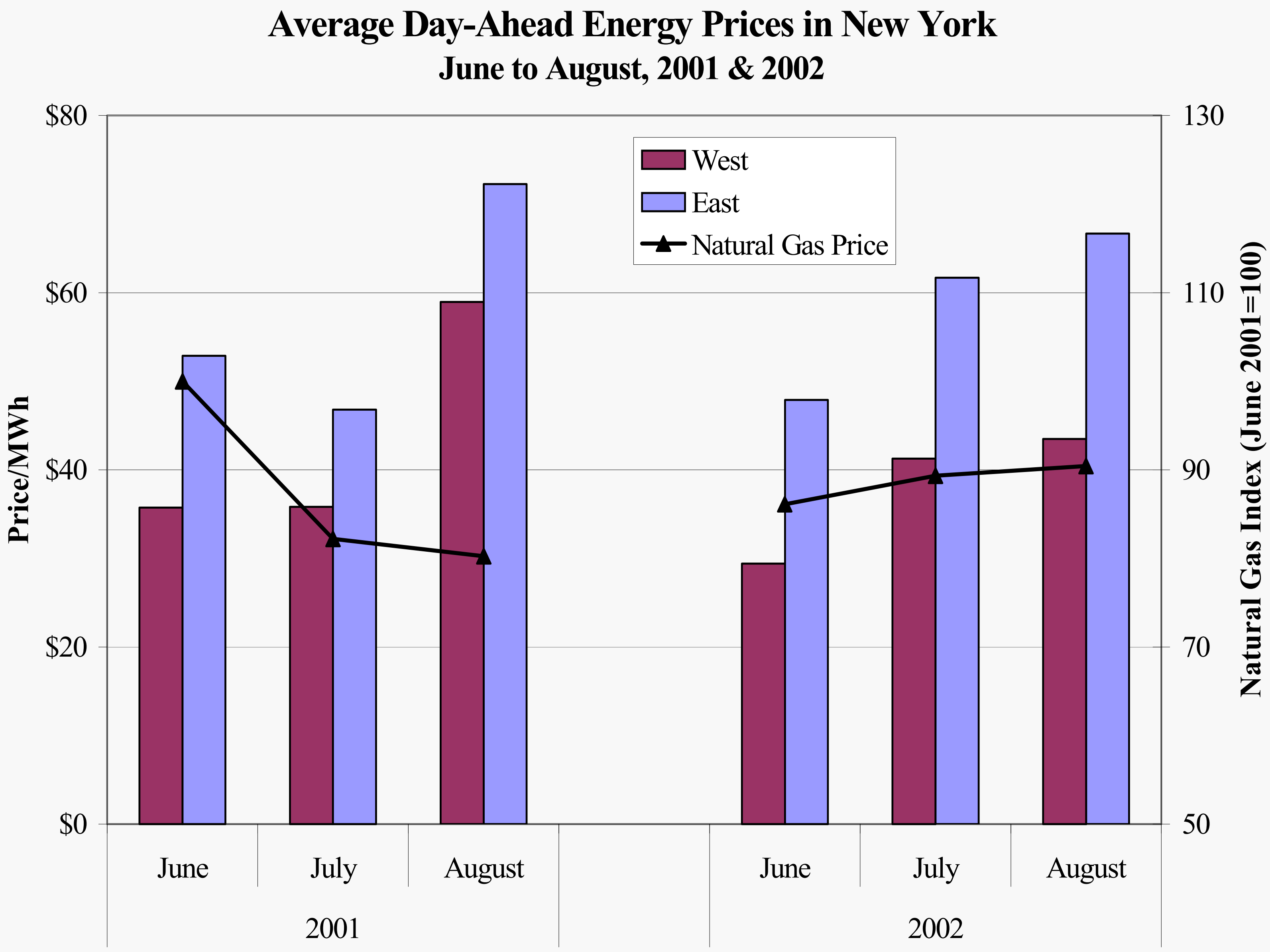

New York Electricity Market Expenses
June to August, 2000--2002
$ in Millions
900
800
700
600
500
400
300
200
100
0
June
July
August
June
July
August
June
July
August
2000
2001
2002
Ancillary Services & Other
Uplift
Congestion
Marginal Losses
Energy Expenses

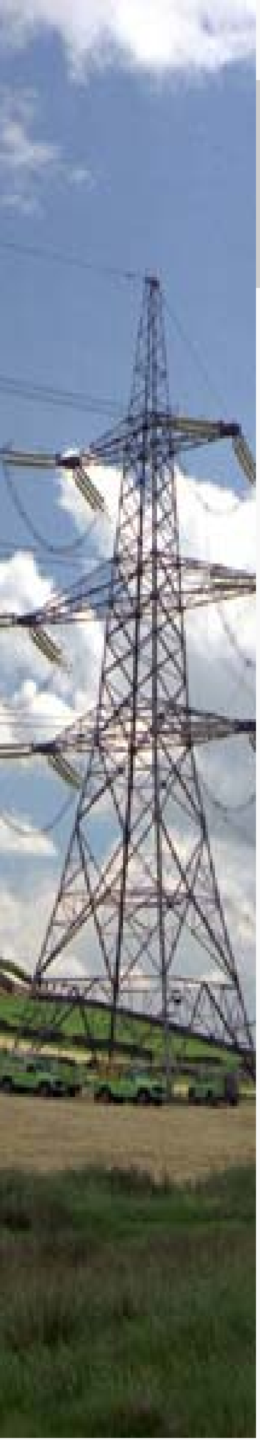


Energy Prices in the Day-Ahead Market

- The following chart shows average energy prices in east and west New York and natural gas prices during the summers of 2001 and 2002.
- This chart shows that energy prices have generally tracked changes in fuel prices, although high loads in August 2001, and July-August 2002 resulted in higher average prices in those months.
- The chart also shows that the difference between prices in eastern New York and western New York increased this summer, reflecting particularly the increase in congestion in the NYC.

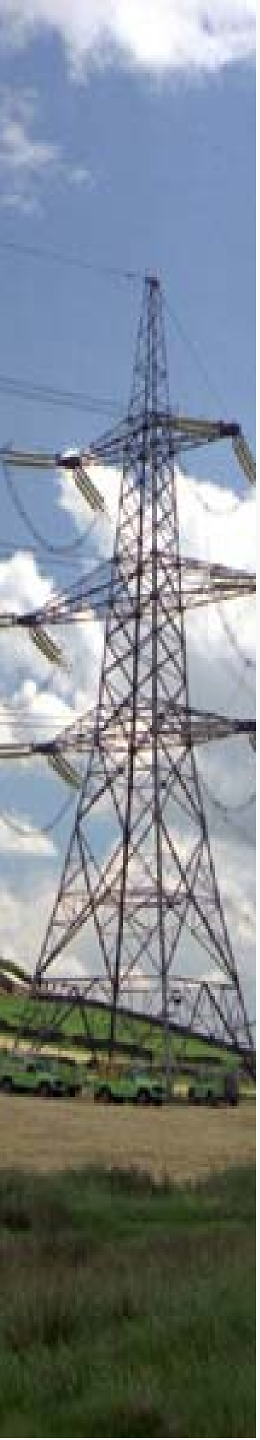



Average Day-Ahead Energy Prices in New York
June to August, 2001 & 2002
$80
$60
$40
$20
$0
Price/MWh
130
110
90
70
50
Natural Gas Index (June 2001=100)
West
East
Natural Gas Price
June
July
August
June
July
August
2001
2002

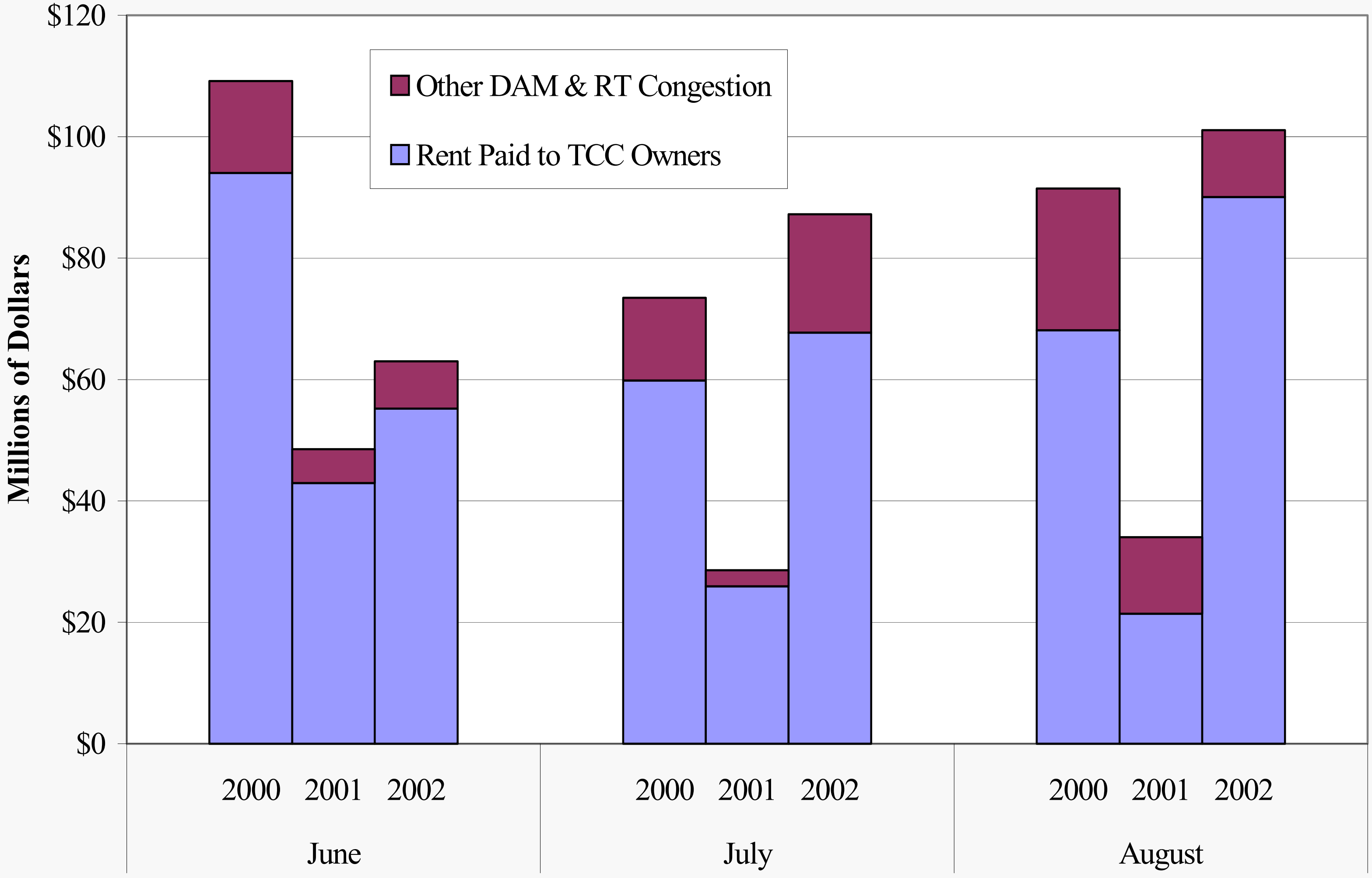


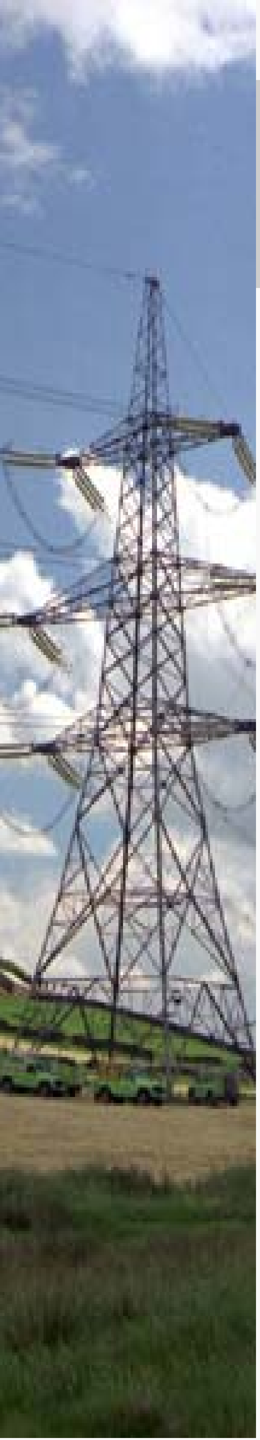
Congestion Costs

- The following chart shows how congestion costs have changed from 2000 to 2002.
- The reduction in congestion costs from 2000 to 2001 was largely due to a reduction in congestion on the central-east interface, 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.
- The subsequent increase in congestion costs from 2001 to 2002 is primarily due to the modeling if the load pockets within NYC.



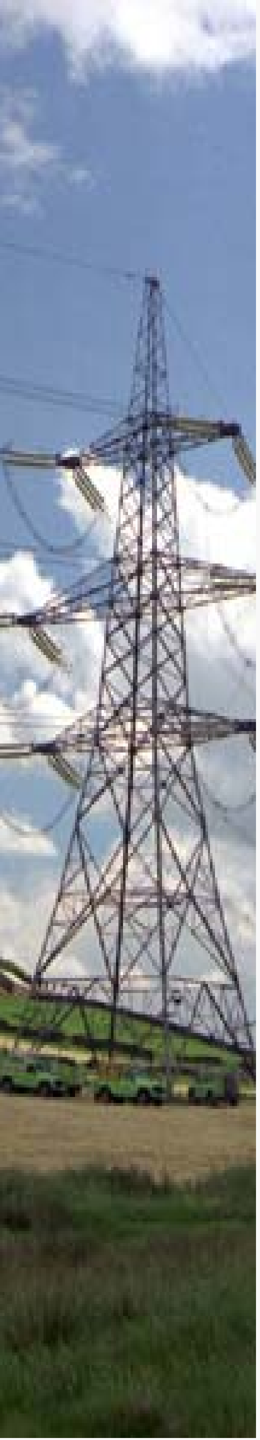
Total NYISO Congestion Costs
June to August, 2000--2002



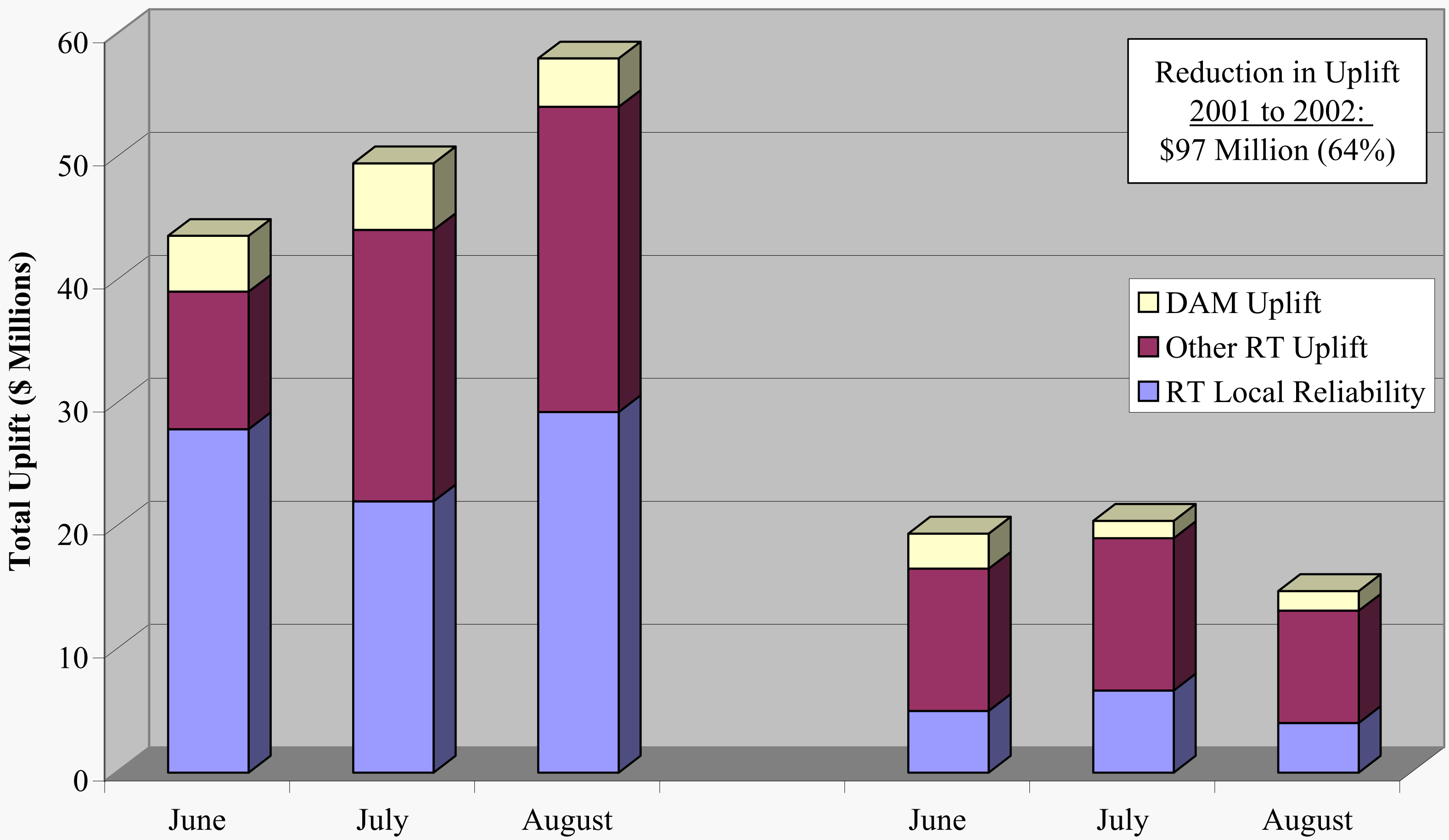


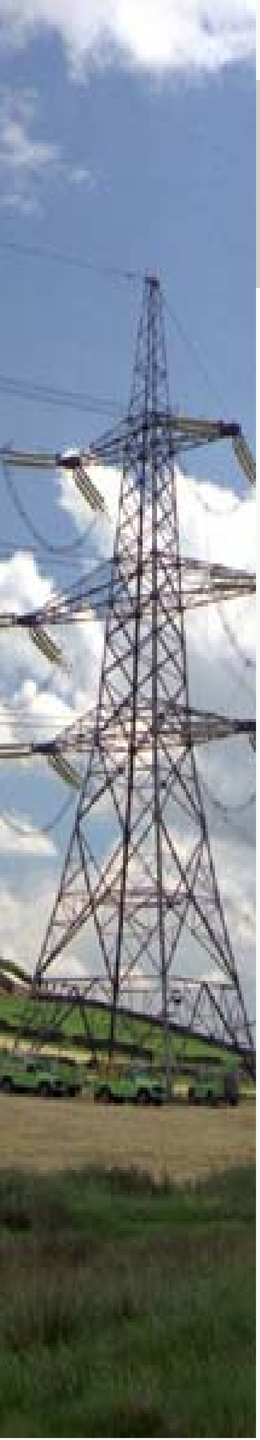
Uplift Expenses

- Uplift costs have fallen sharply as shown in the following chart.
  - ✓ Uplift costs were $97 million lower in June to August 2002 than the same time period in 2001.
  - ✓ This represents a reduction of almost two thirds.
- This reduction in costs was comprised of reductions in the following areas:
  - ✓ Real-time local reliability uplift: Reduction of 80 percent or $64 million resulting from implementing load pocket modeling.
  - ✓ Other real-time uplift: Reduction of 43% or $25 million resulting from improved BME performance.
  - ✓ Day-ahead uplift: Reduction of 58% or $8 million resulting, caused in part from the load pocket modeling in day-ahead .



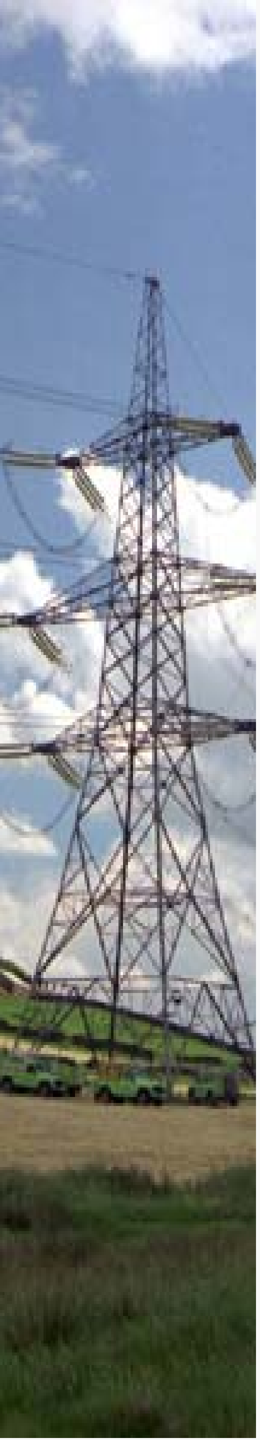
Monthly Uplift Expenses
Summer 2001 and 2002

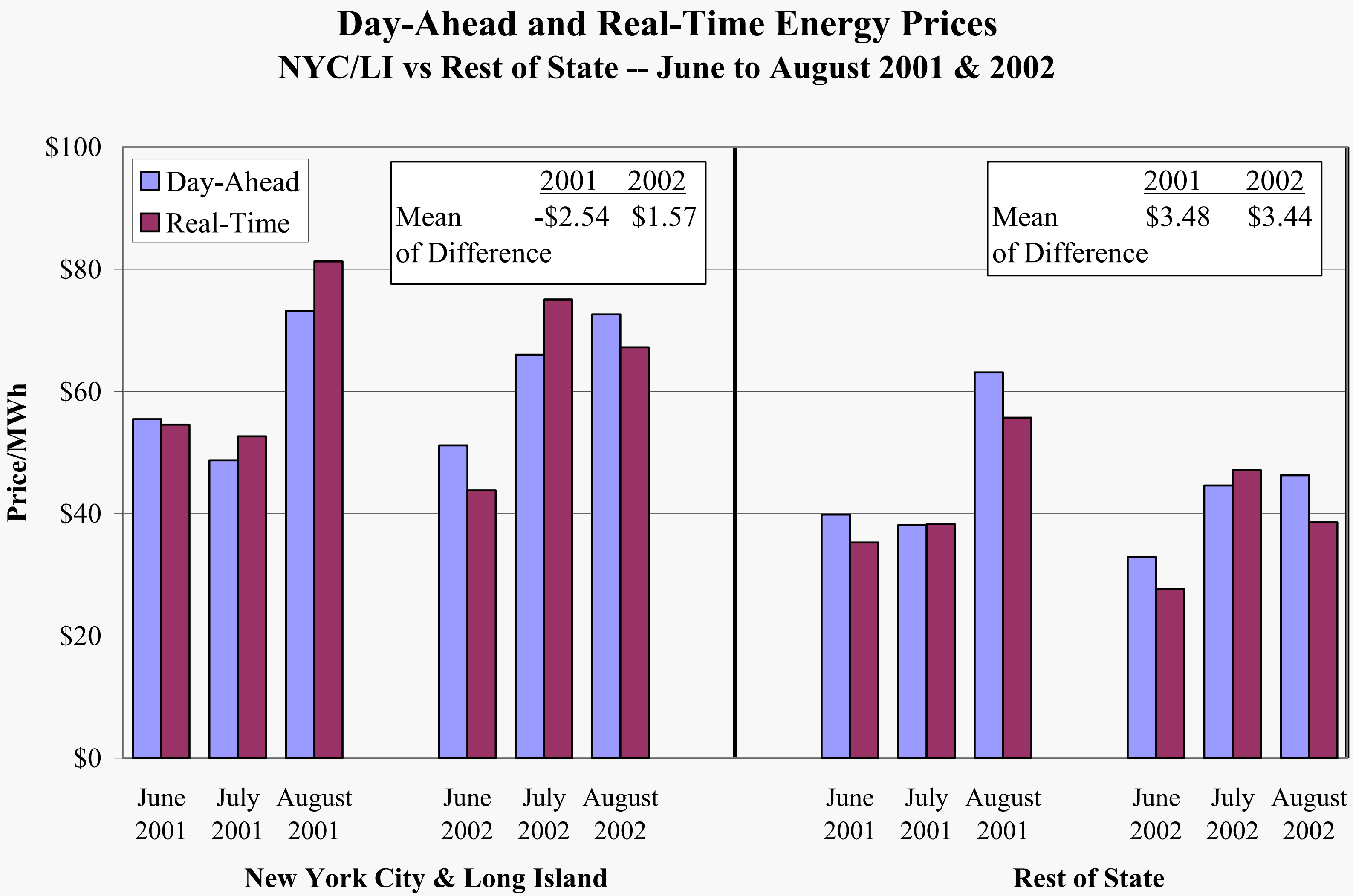




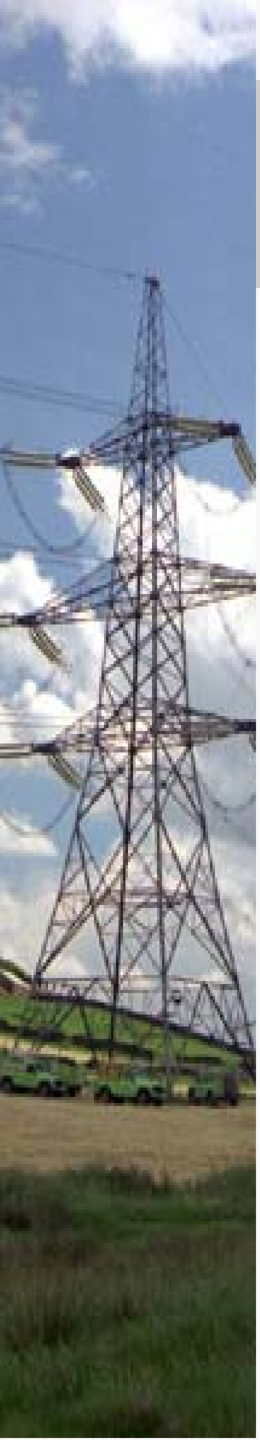
Day-Ahead to Real-Time Price Convergence

- The following chart shows a monthly comparison of the average day-ahead and real-time energy prices in NYC/Long Island and the Rest of State.
- The results generally show a slight premium associated day-ahead prices. This premium is consistent with participants' risks:
  - ✓ Loads should place a premium on the day-ahead due to the higher volatility in the real-time market while generators selling in the day-ahead market bear a risk associated with committing financially day-ahead;
  - ✓ If participants are risk-averse, these factors will generate a premium in the day-ahead prices.



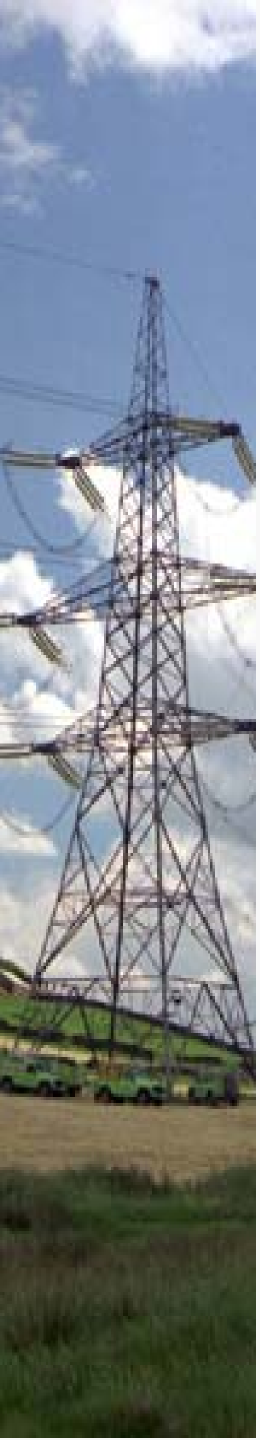


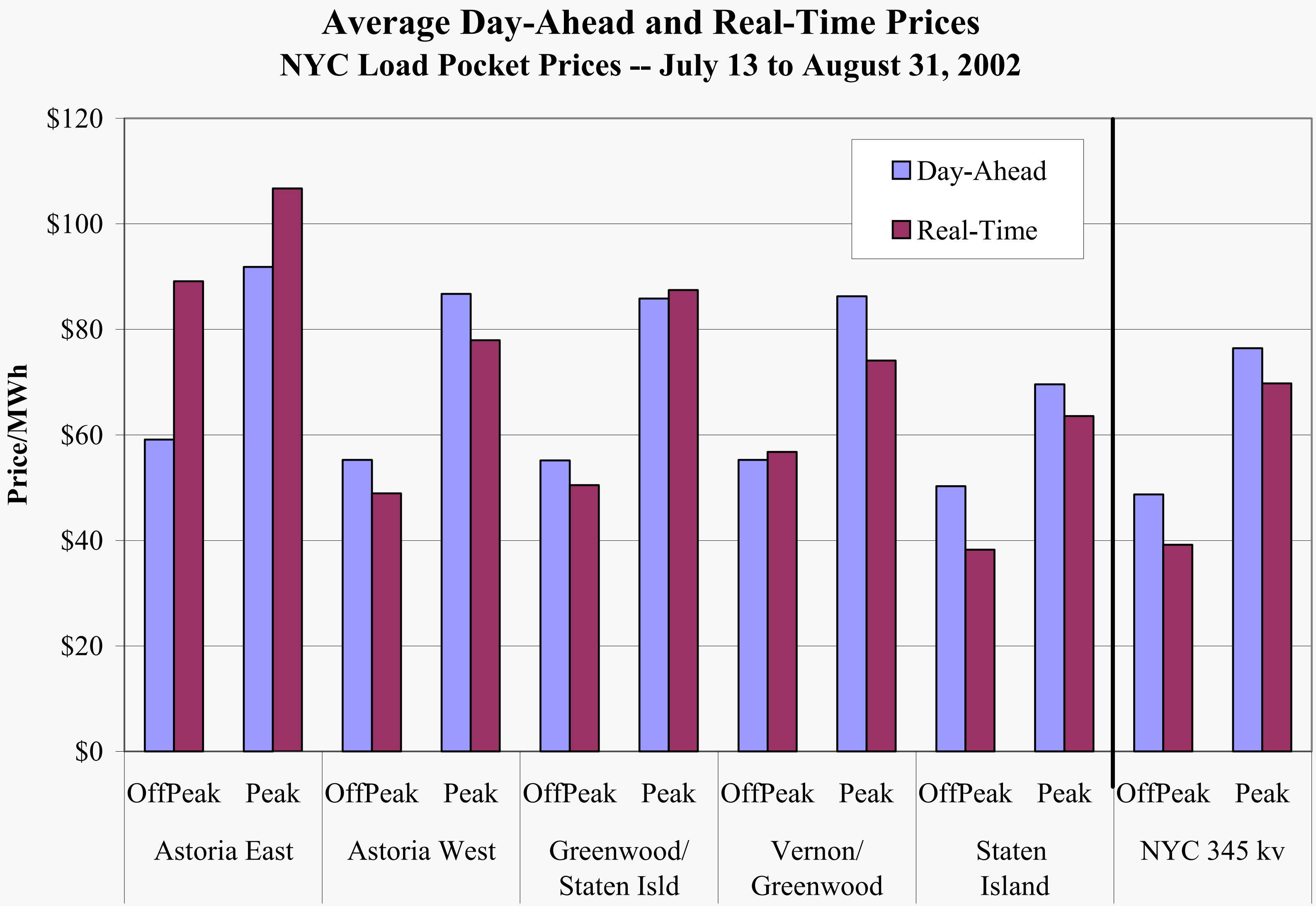
Day-Ahead and Real-Time Energy Prices
NYC/LI vs Rest of State -- June to August 2001 & 2002
Day-Ahead
Real-Time
2001 2002
Mean of Difference -$2.54 $1.57
2001 2002
Mean of Difference $3.48 $3.44
Price/MWh
$100
$80
$60
$40
$20
$0
June 2001
July 2001
August 2001
June 2002
July 2002
August 2002
June 2001
July 2001
August 2001
June 2002
July 2002
August 2002
New York City & Long Island
Rest of State

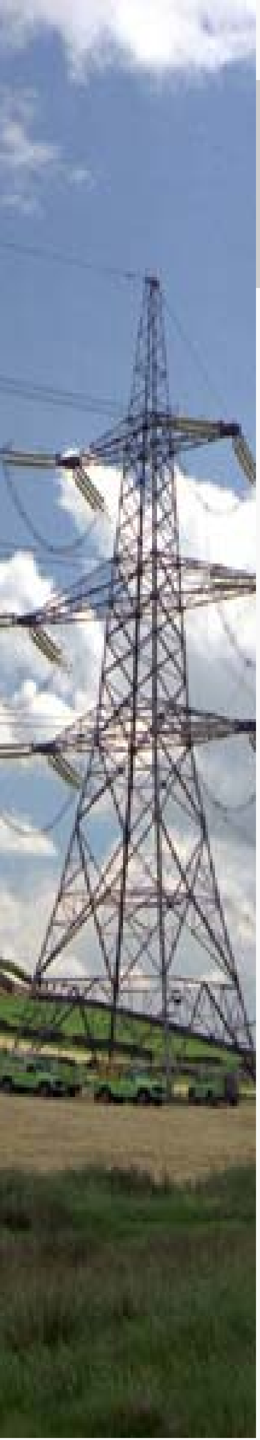


Price Convergence in the Load Pockets

- Modeling of the load pockets within NYC, which was implemented June 3 in real time and June 19 in day ahead, has resulted in more accurate locational prices.
- Due to limitations of the SCD, a simplified modeling representation of the intra-NYC constraints is used in real time while a more detailed representation is used in the day ahead model.
- The following chart shows that convergence has varied from pocket to pocket, with Astoria East showing a large premium in real time and the other pockets generally showing a modest premium in the day ahead market.
- For those load pockets showing the largest price differences, I recommend that the NYISO evaluate the load pocket modeling to ensure that any inconsistencies between the day-ahead and real-time modeling are minimized.
- In addition, virtual trading at the zonal level in NYC limits the ability of participants to arbitrage large price differences in individual pockets. Therefore, I recommend that the NYISO consider:
  - ✓ Allowing virtual trading at the load pocket level; or
  - ✓ Allowing virtual trading on the 345kv system separately from the 138 kv system, which would be a smaller departure from the current system.

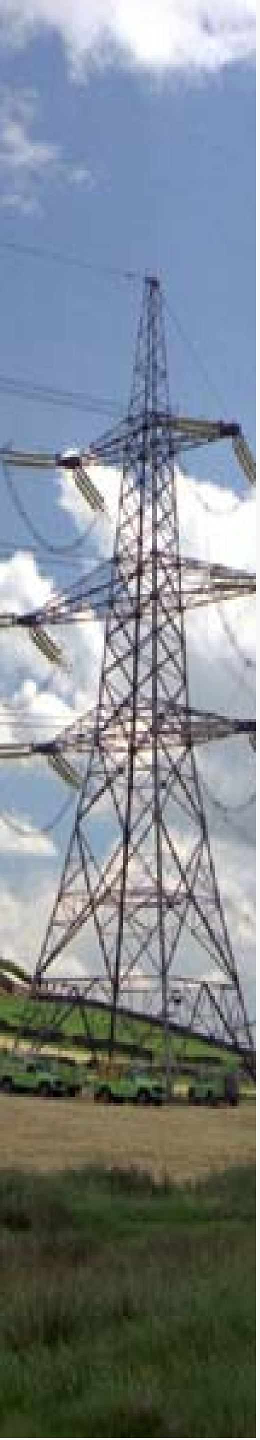



Average Day-Ahead and Real-Time Prices
NYC Load Pocket Prices -- July 13 to August 31, 2002
Day-Ahead
Real-Time
Price/MWh
$120
$100
$80
$60
$40
$20
$0
OffPeak
Peak
Astoria East
Astoria West
Greenwood/ Staten Isld
Vernon/ Greenwood
Staten Island
NYC 345 kv

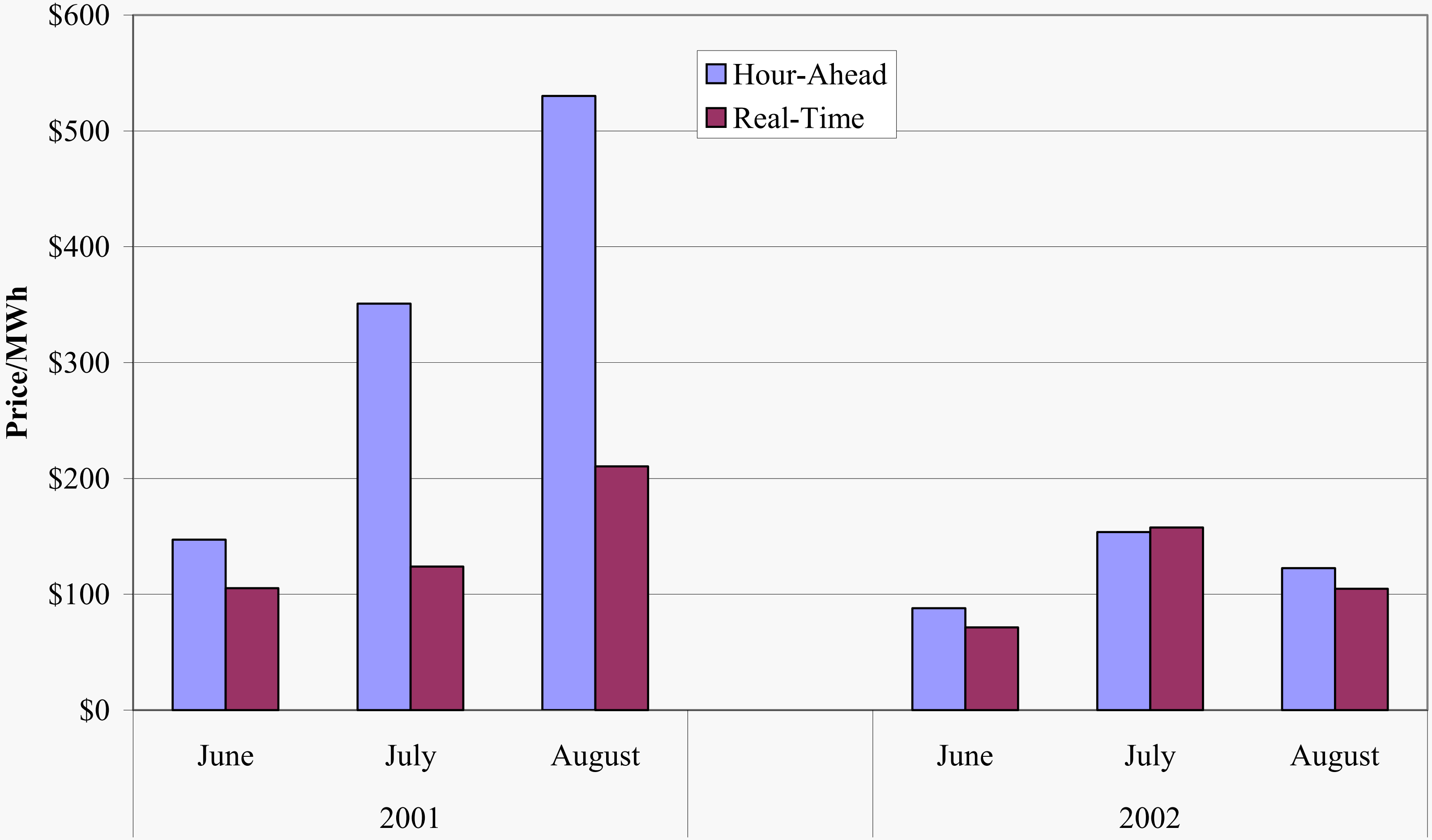


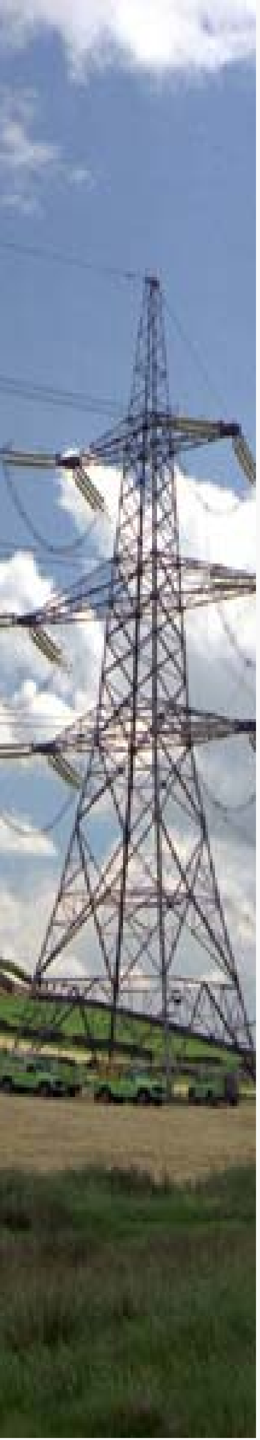
Hour-Ahead and Real-Time Prices

- 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 in real time.
- The following three charts shows remarkable improvement in the price convergence from 2001 to 2002 due to these changes.

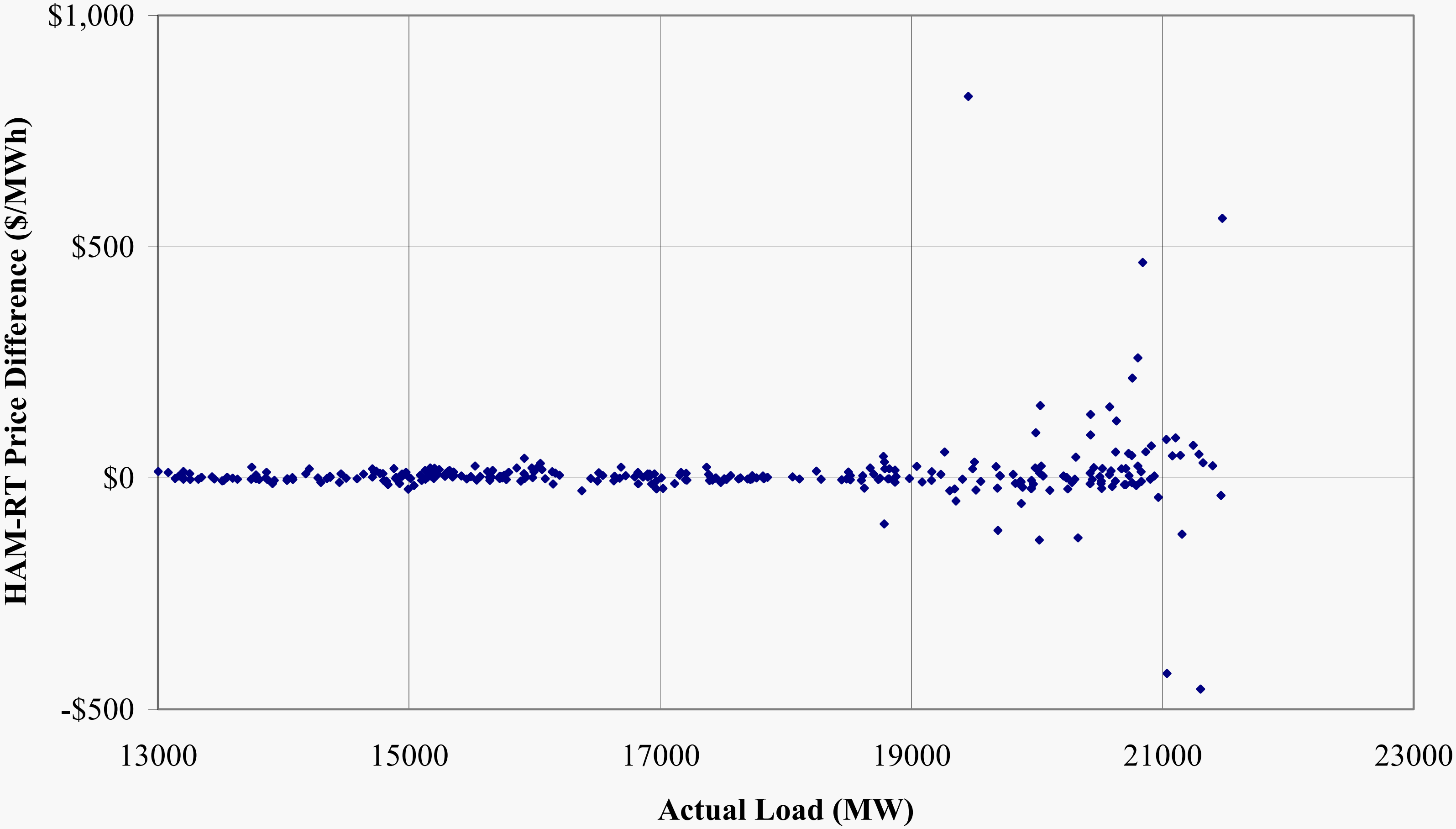


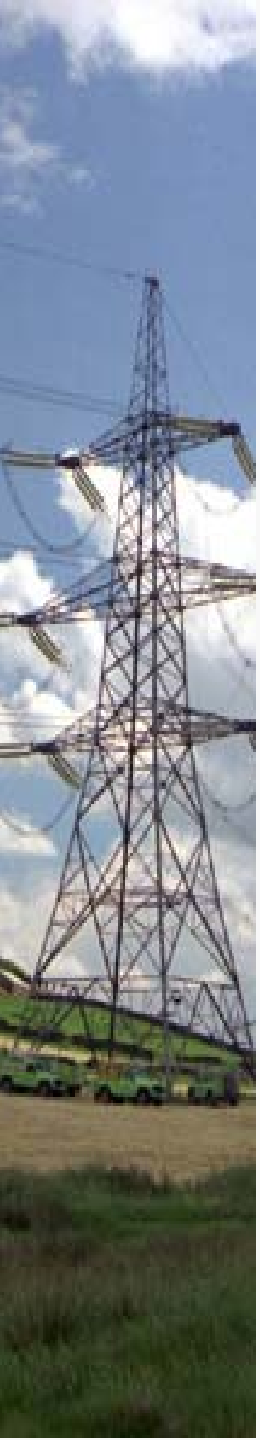
Average Hour-Ahead and Real-Time Energy Prices
East New York -- June to August, 2001 & 2002
Hours with Highest 10% of Real-Time Load

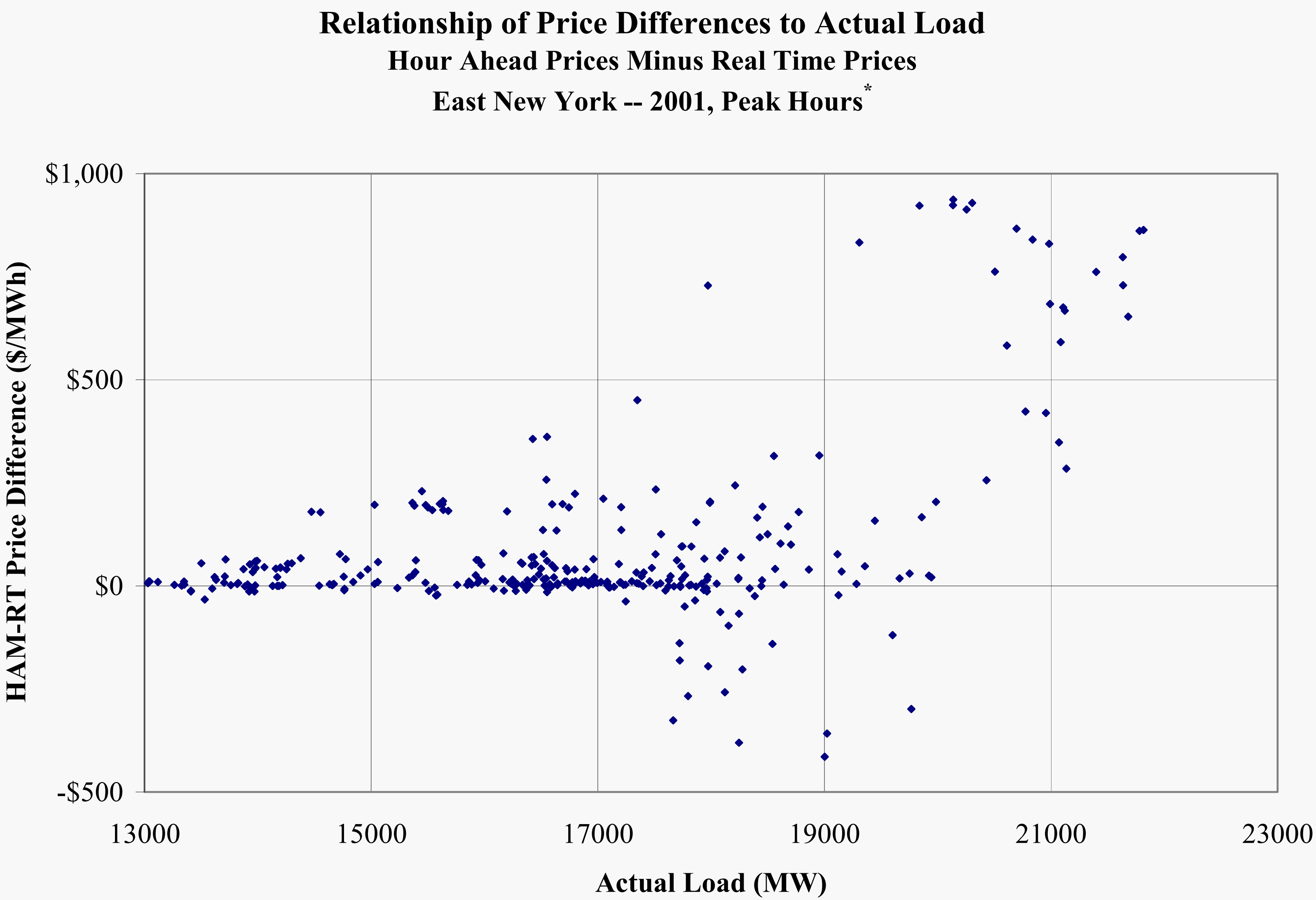




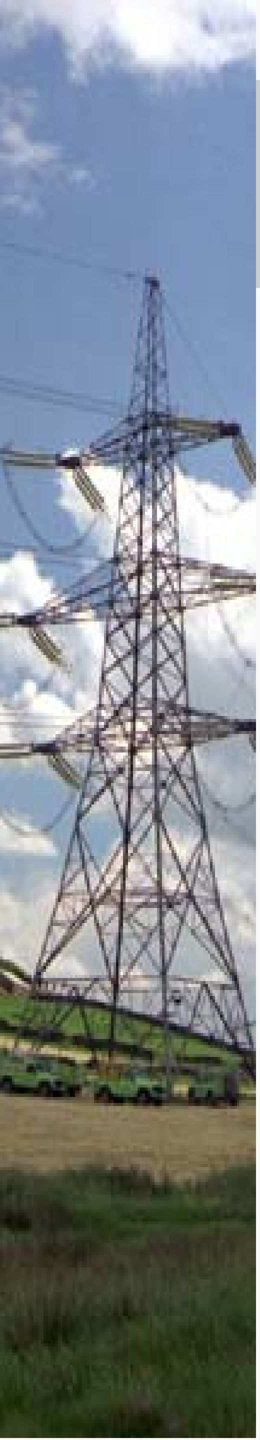
Relationship of Price Differences to Actual Load
Hour Ahead Prices Minus Real Time Prices
East New York -- 2002, Peak Hours*





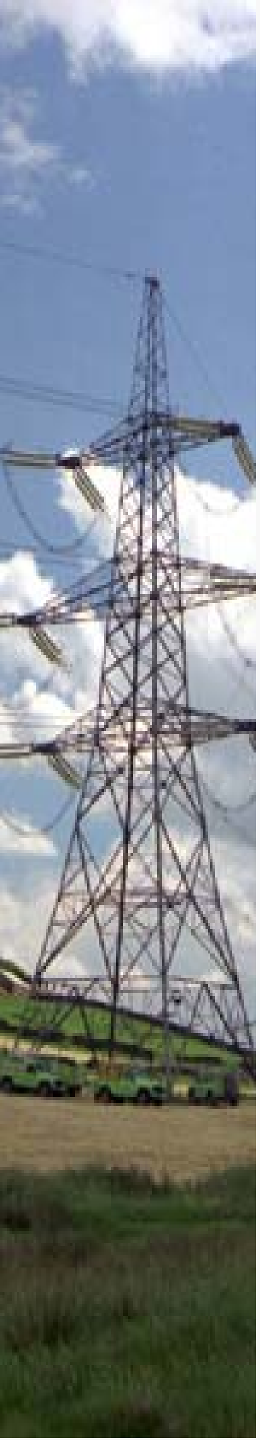


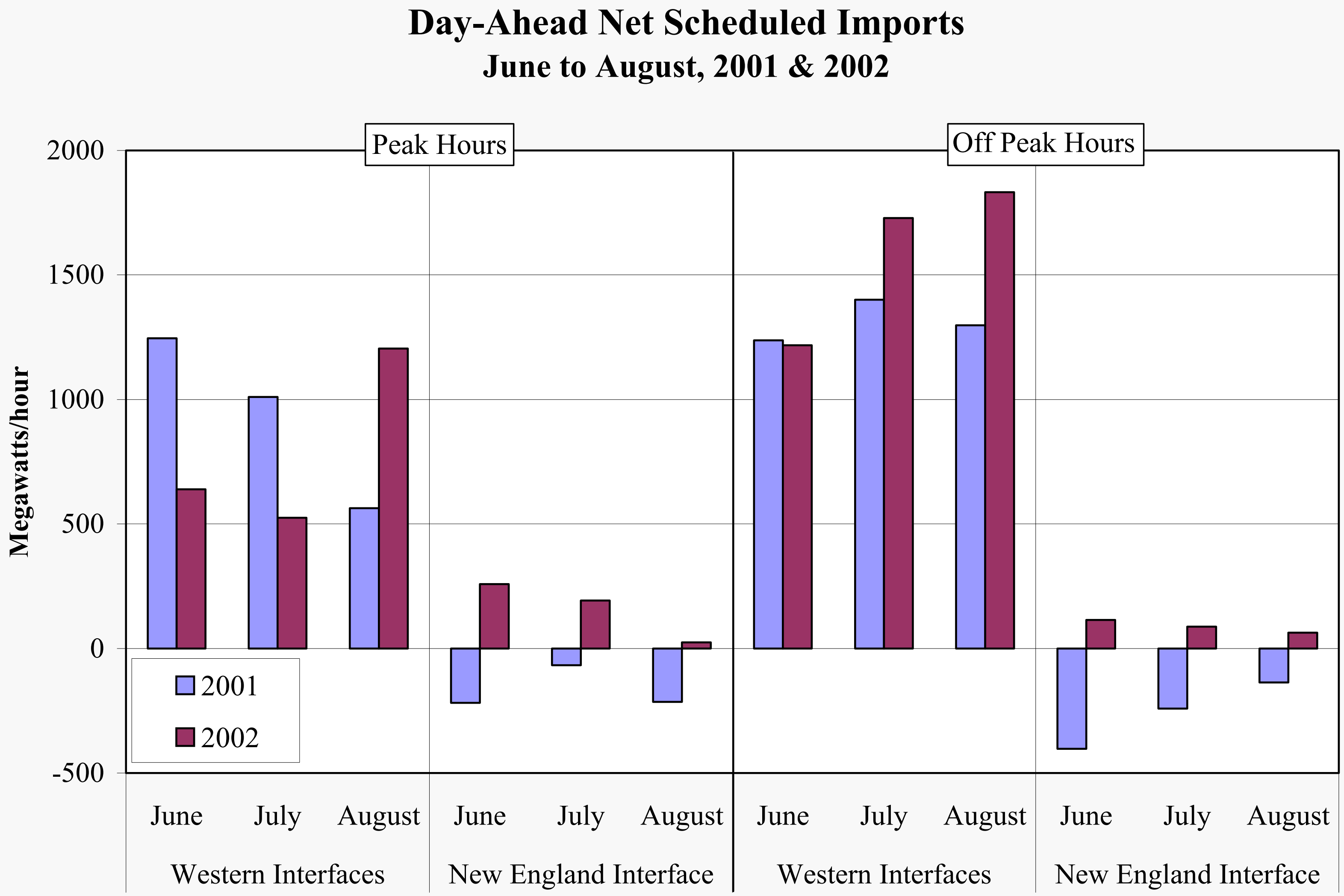
Relationship of Price Differences to Actual Load
Hour Ahead Prices Minus Real Time Prices
East New York -- 2001, Peak Hours*
$1,000
$500
$0
-$500
HAM-RT Price Difference ($/MWh)
13000
15000
17000
19000
21000
23000
Actual Load (MW)

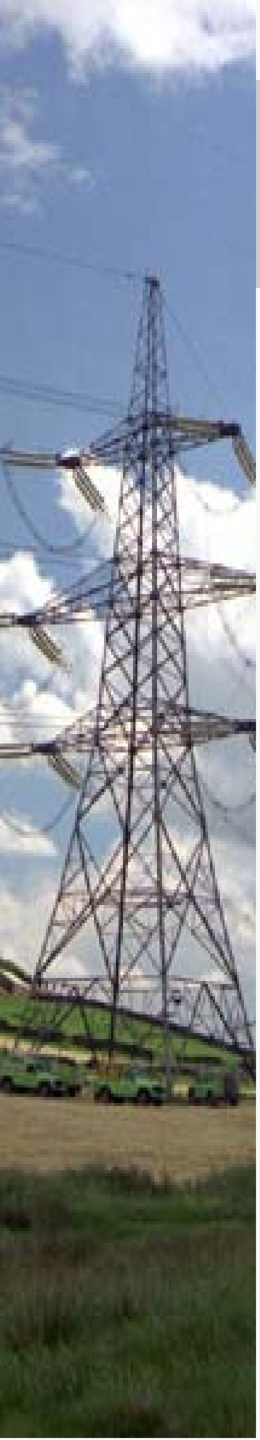


Interface Schedules

- The following chart shows how average day-ahead external schedules have changed in 2002 over the interfaces in eastern New York (New England interface) and western New York (PJM, HQ, and Ontario).
- On the western interfaces, New York's net imports generally decreased in peak hours and increased in off-peak hours.
- On the New England interface, the data shows that in both the peak and off-peak hours that New York became a net importer of day-ahead power in 2002 after being a net exporter in prior years.
- In the real time, net imports also increased from New England to New York. This changes reflect:
  - ✓ Changes in New England's market rules that I had recommended in 2001 and implemented prior to this summer.
  - ✓ Expansion of capacity that has occurred in New England over the past year and the high levels of resource availability.
- A more detailed analysis of external transactions is presented below.

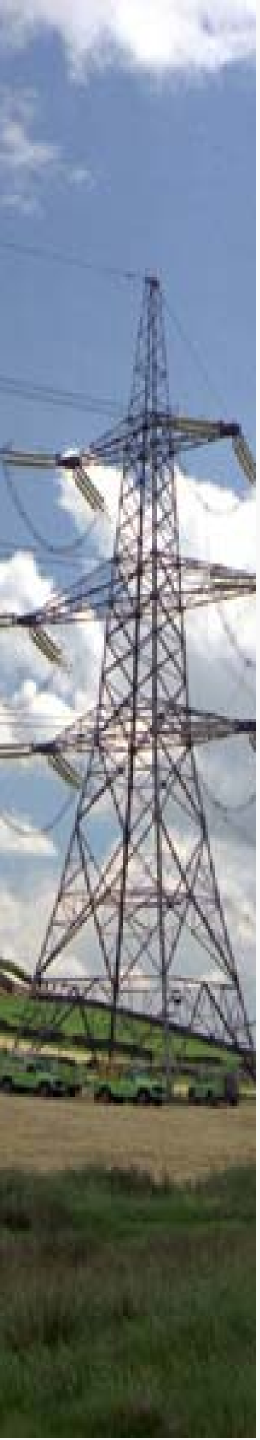



Day-Ahead Net Scheduled Imports
June to August, 2001 & 2002
Peak Hours
Off Peak Hours
Megawatts/hour
2000
1500
1000
500
0
-500
2001
2002
June
July
August
Western Interfaces
New England Interface

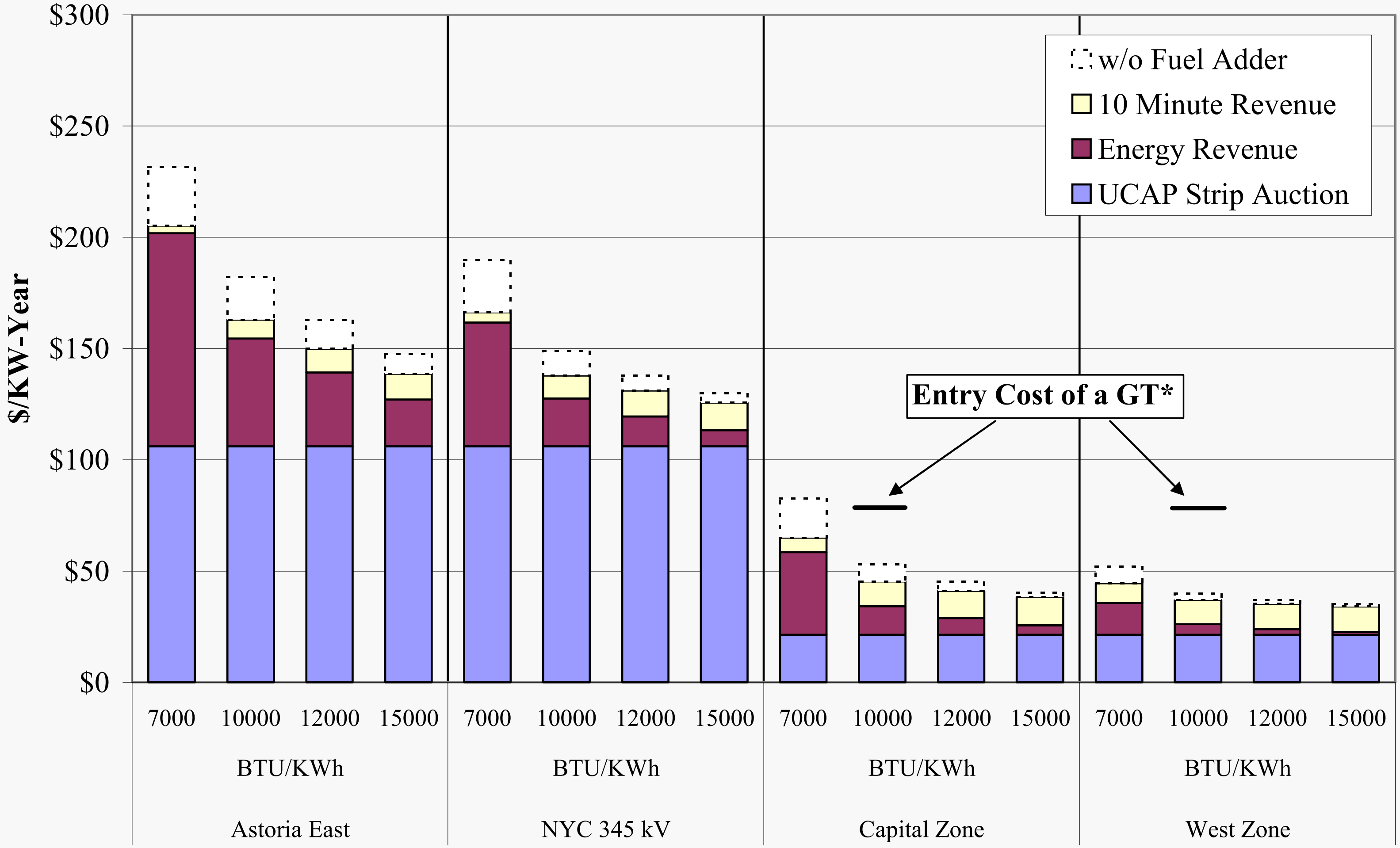


Economic Incentives for New Investment

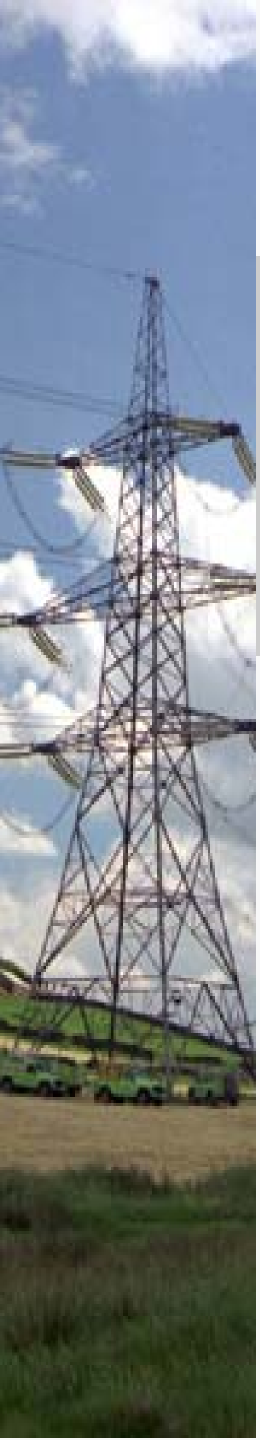
- The analysis above provides an assessment of the short-term performance of the New York markets. The following analysis addresses the long-term economic signals produced by the markets.
- In long-run equilibrium, the markets should support the entry of new generation (i.e., if the system is not over-built).
- This analysis shows the net revenue the markets would provide to various generators (with different heat rates) in different locations within the State.
- The chart also shows the estimated annual cost of a new gas turbine – $73/kw outside of NYC (based on a study of new investments in New England). Based on this analysis, the market revenue outside of NYC would not likely support new investment in GTs, although other investments may be economic.
- Costs of installing a new GT in NYC are likely significantly higher -- information from NYPA indicates annual costs of approximately $220/kw, although these costs may not be representative.
- Based on this analysis, the current market revenue would not likely support new investment in GTs outside NYC with significant uncertainty regarding GTs within NYC, although other investments may be economic.
- The peak pricing recommendations contained in this review should help address this issue.



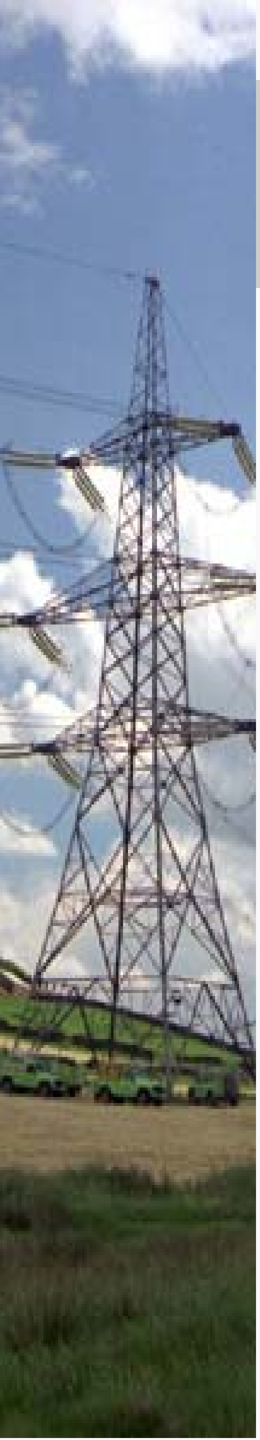
Estimated Net Revenue in the New York Markets
Sept. 2001 to Aug. 2002



Sources: * e Aumen Asset Valuation Study, October 2001.

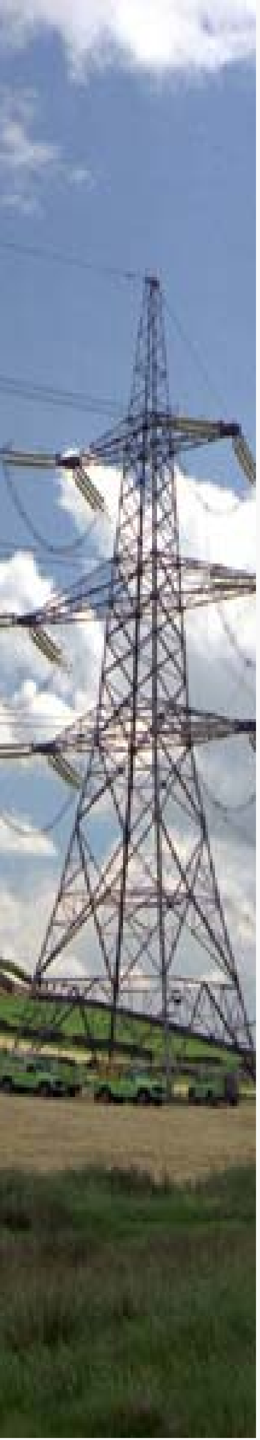


Analysis of Bidding Patterns



Analysis of Offer Patterns

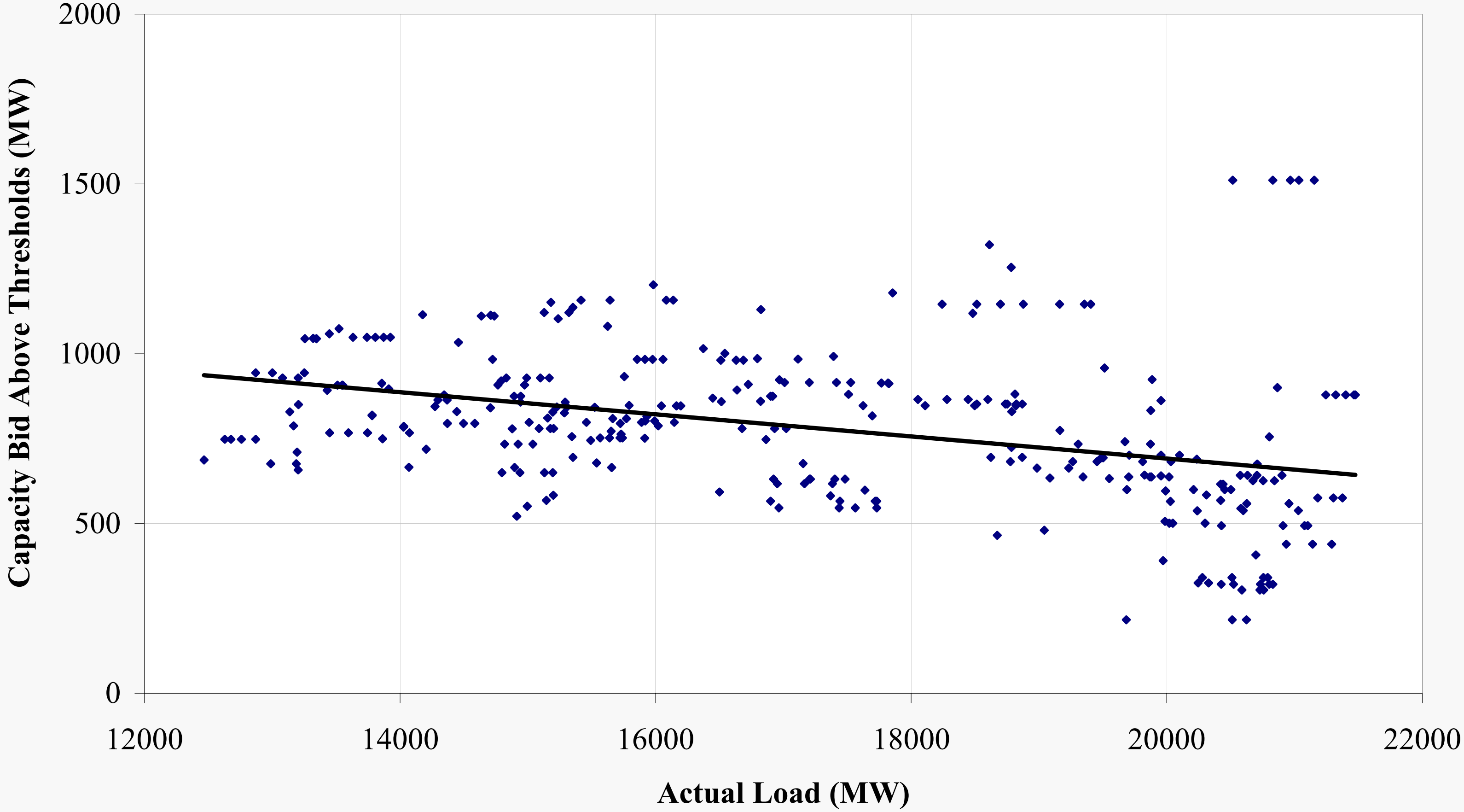
- Suppliers in a competitive market should increase bid quantities during higher load periods to sell more power at the higher peak prices;
- Suppliers in markets that are not workably competitive will have the greatest incentive to withhold at peak load levels when the market impact is the largest.
- Therefore, the correlation of withholding (including both economic and physical withholding) to actual load levels is generally consistent with competitive expectations.
  - ✓ Physical deratings are clearly negatively correlated with the loads during the summer period.
  - ✓ The quantities screened for economic withholding do not increase significantly during peak periods.



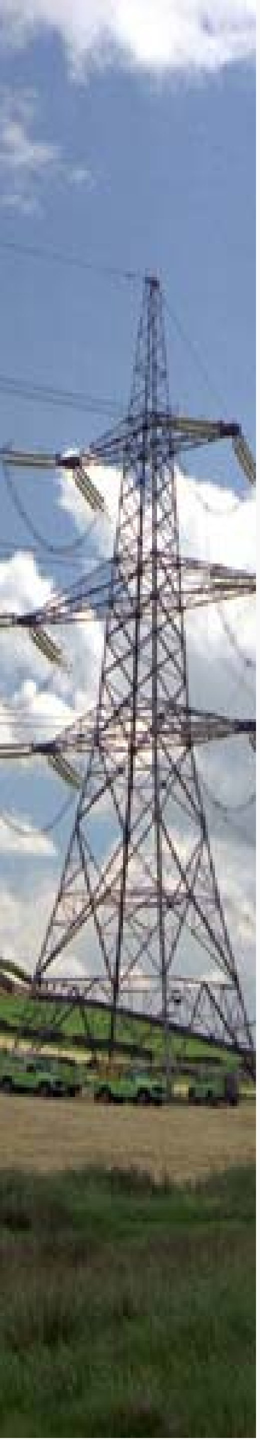
Relationship of Capacity Above Threshold to Actual Load

Day Ahead Market -- East New York

Summer 2002 -- Peak Hour*



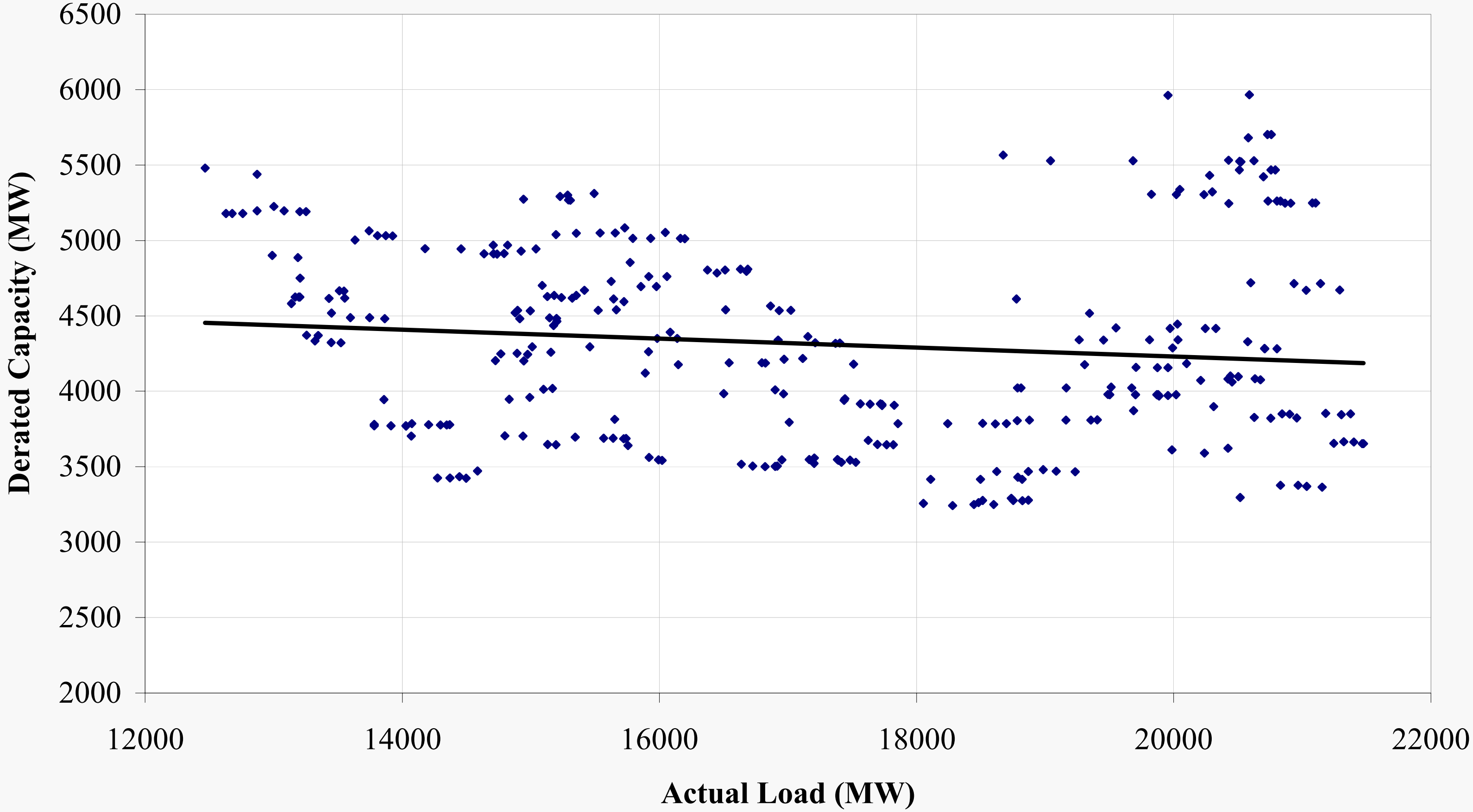
* Includes hours beginning from 1pm to 5pm, Monday through Friday.



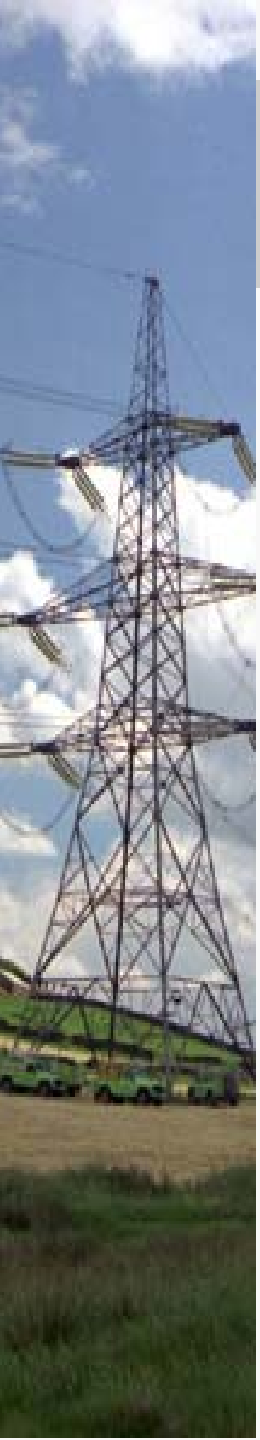
Relationship of Deratings to Actual Load

Day Ahead Market -- East New York

Summer 2002 -- Peak Hours*

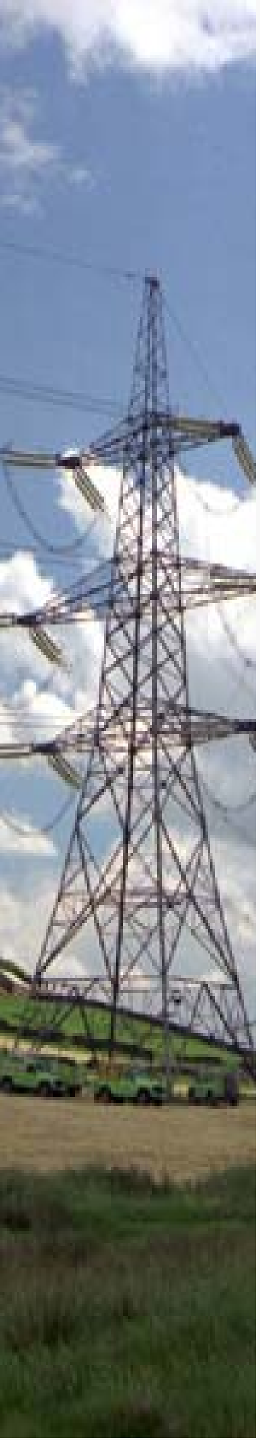


* Includes hours beginning from 1pm to 5pm, Monday through Friday.

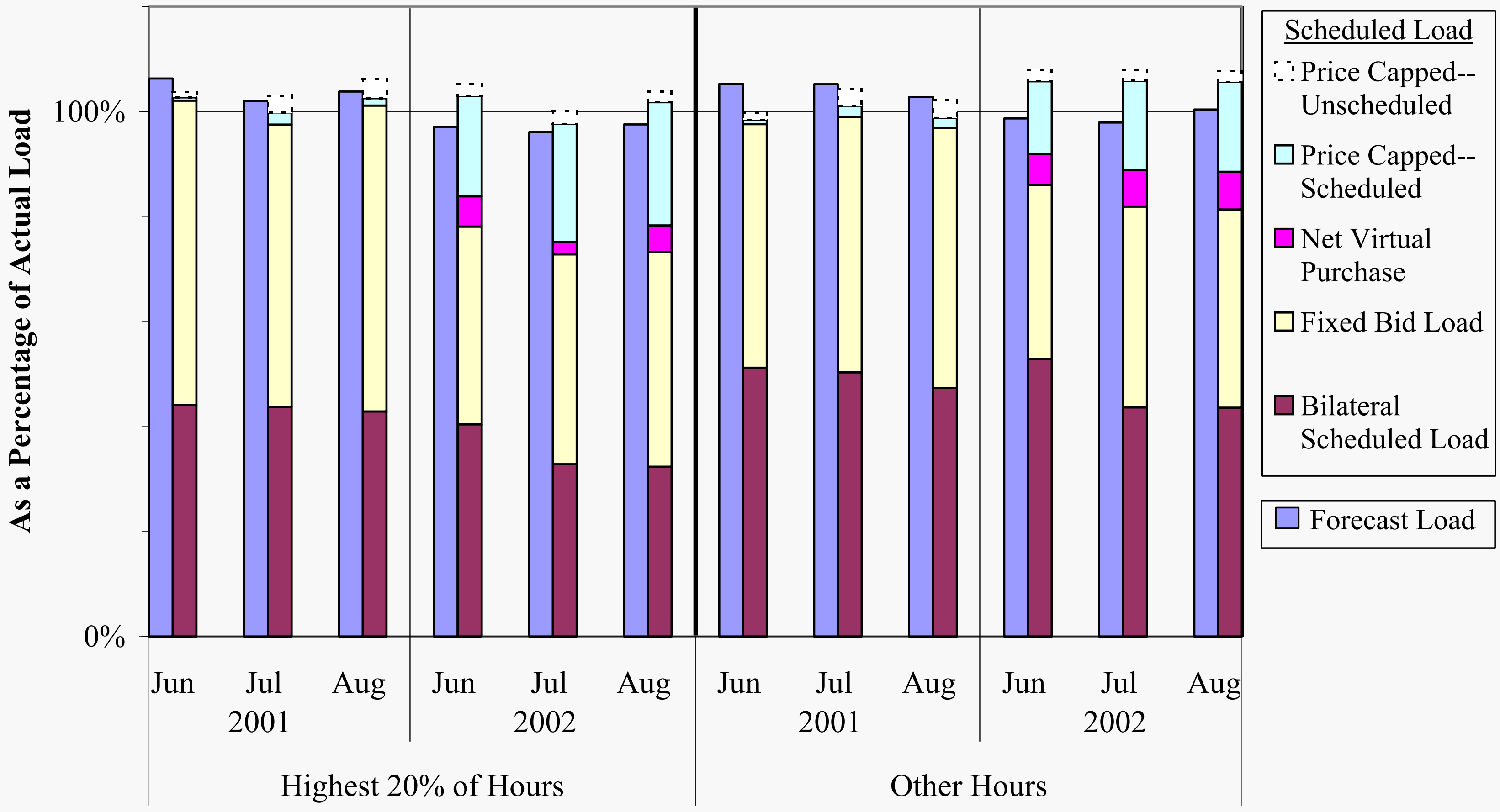


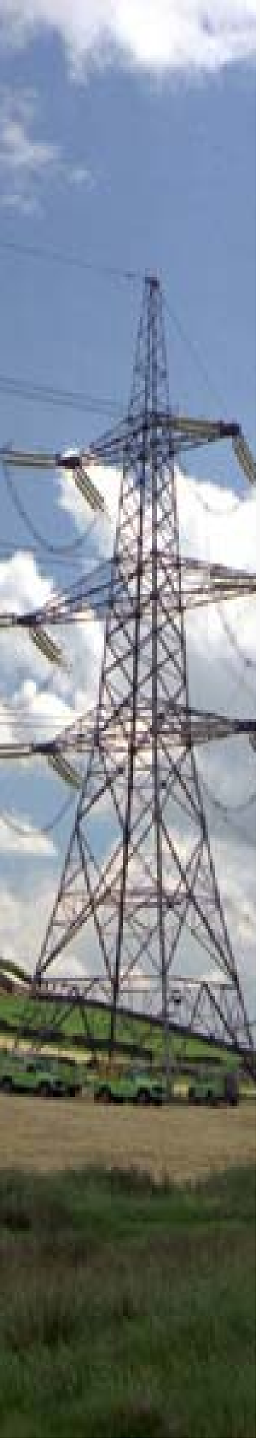
Analysis of Load-Bid Patterns

- The NYISO also monitors the bidding patterns of load-serving entities as specified in the mitigation plan.
- The accompanying charts show the load bidding patterns during the summer 2001 and 2002.
- Load bidding patterns have changed from last summer:
  - ✓ Price-capped load bidding is more widely used;
  - ✓ Scheduled load in NYC and Long Island in the day-ahead market was higher in average hours and in peak hours than the actual load;
  - ✓ Scheduled load in the Rest of State in the day-ahead market was lower in average hours and in peak hours than the actual load in all three months – this is consistent with the higher day-ahead prices in this area;
- No evidence of strategic under-scheduling by LSEs in the day-ahead.



Forecast Load and Composition of Day-Ahead Load Scheduling
Given as a Percentage of Real-Time Load -- NYC and Long Island
June to August, 2001 and 2002

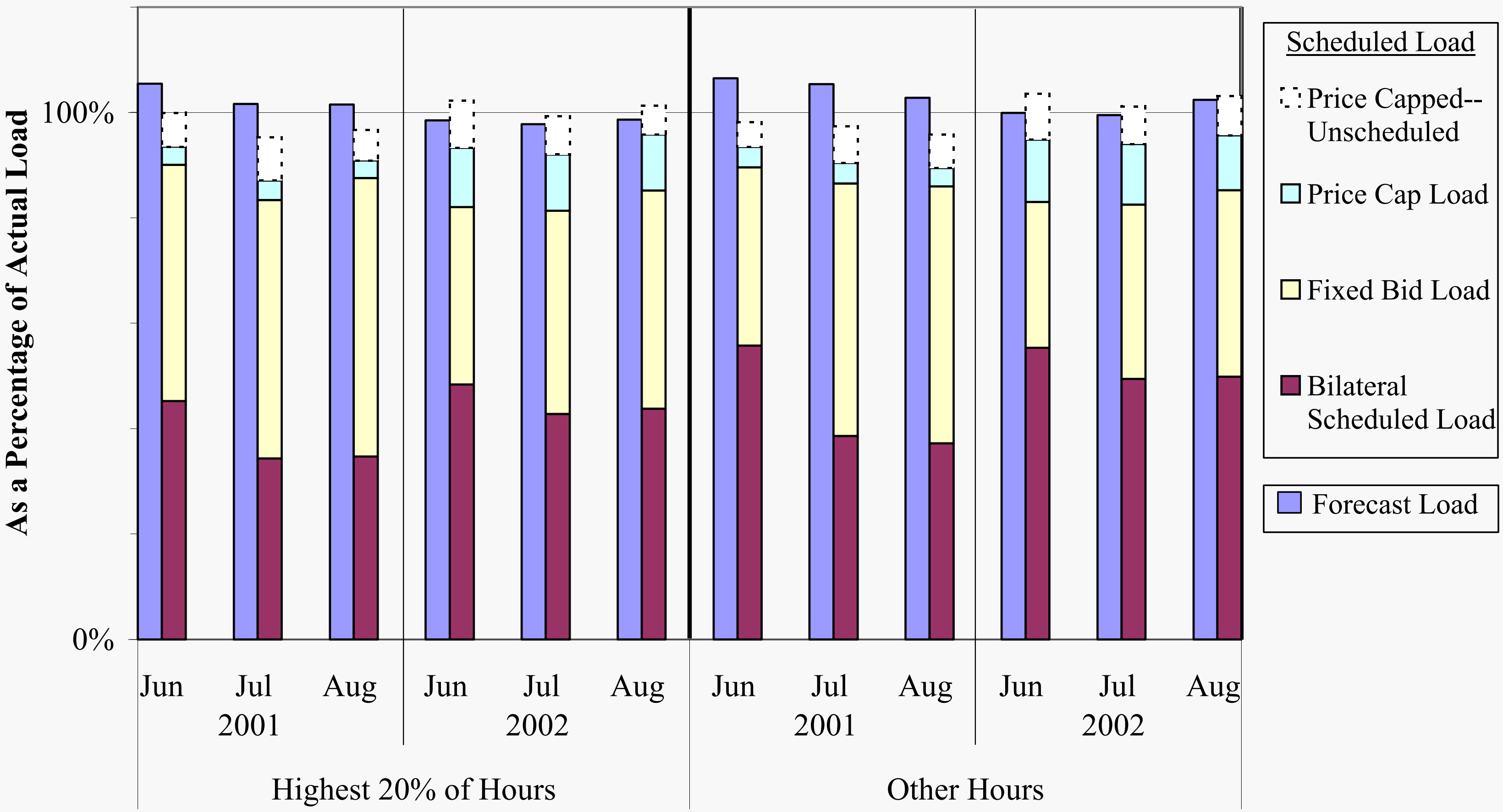


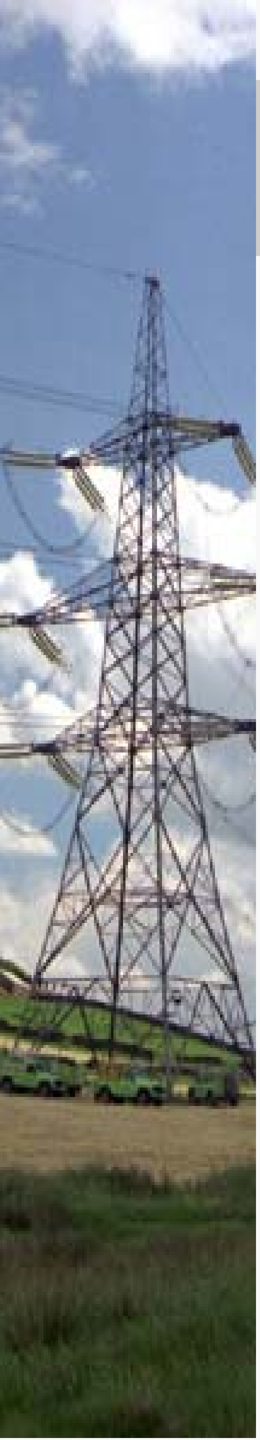


Forecast Load and Composition of Day-Ahead Load Scheduling

Given as a Percentage of Real-Time Load -- Outside NYC and Long Island

June to August, 2001 and 2002

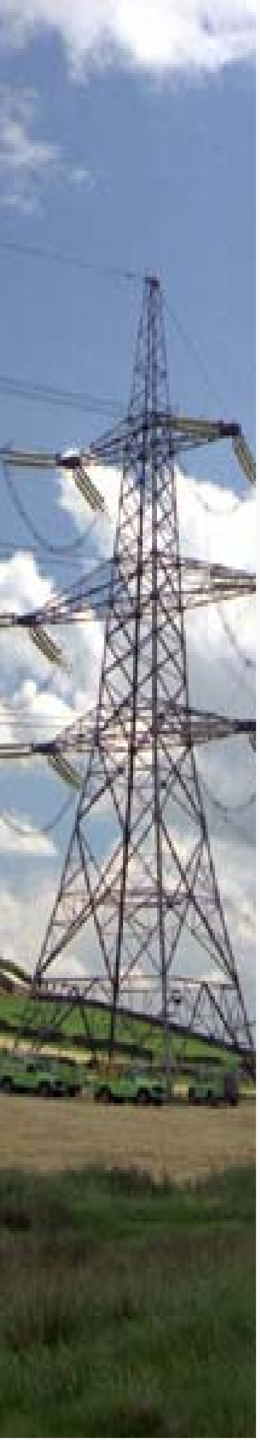


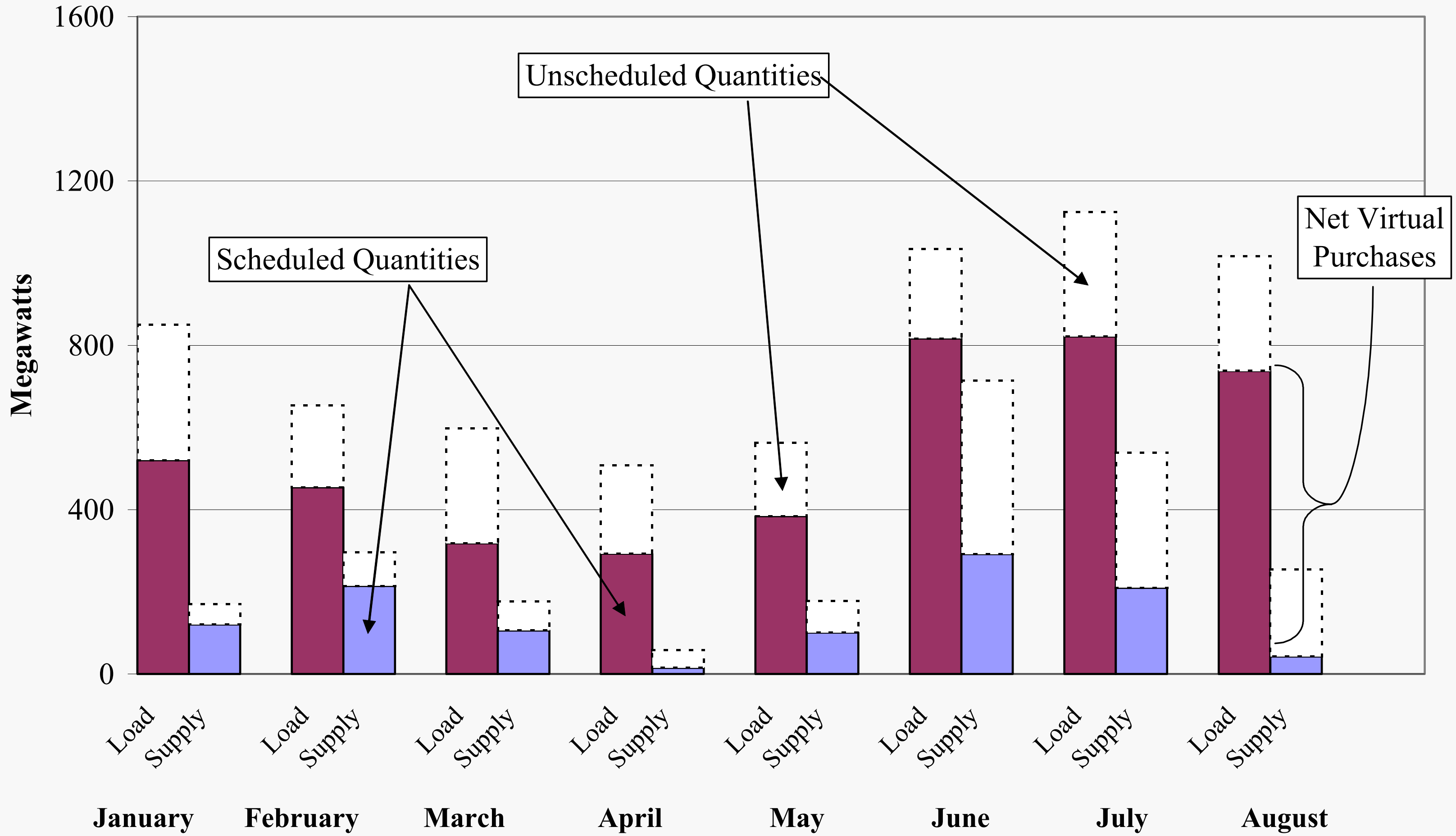


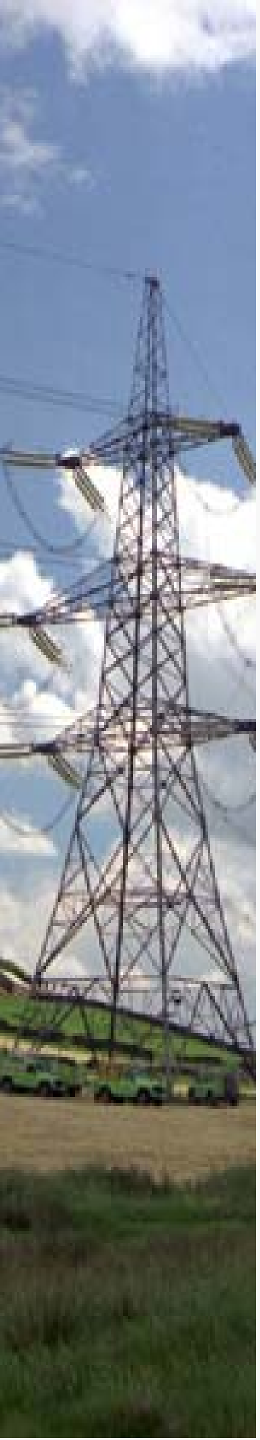
Virtual Trading Patterns

- 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:
  - ✓ The magnitude of the total virtual load offers and supply bids, as well as the quantities scheduled, increased significantly during the Summer 2002.
  - ✓ Net virtual purchases have been made in NYC and Long Island (virtual load schedules have exceed virtual supply schedules);
  - ✓ Net virtual sales have been made in outside NYC and Long Island (virtual supply schedules have exceed virtual load schedules);

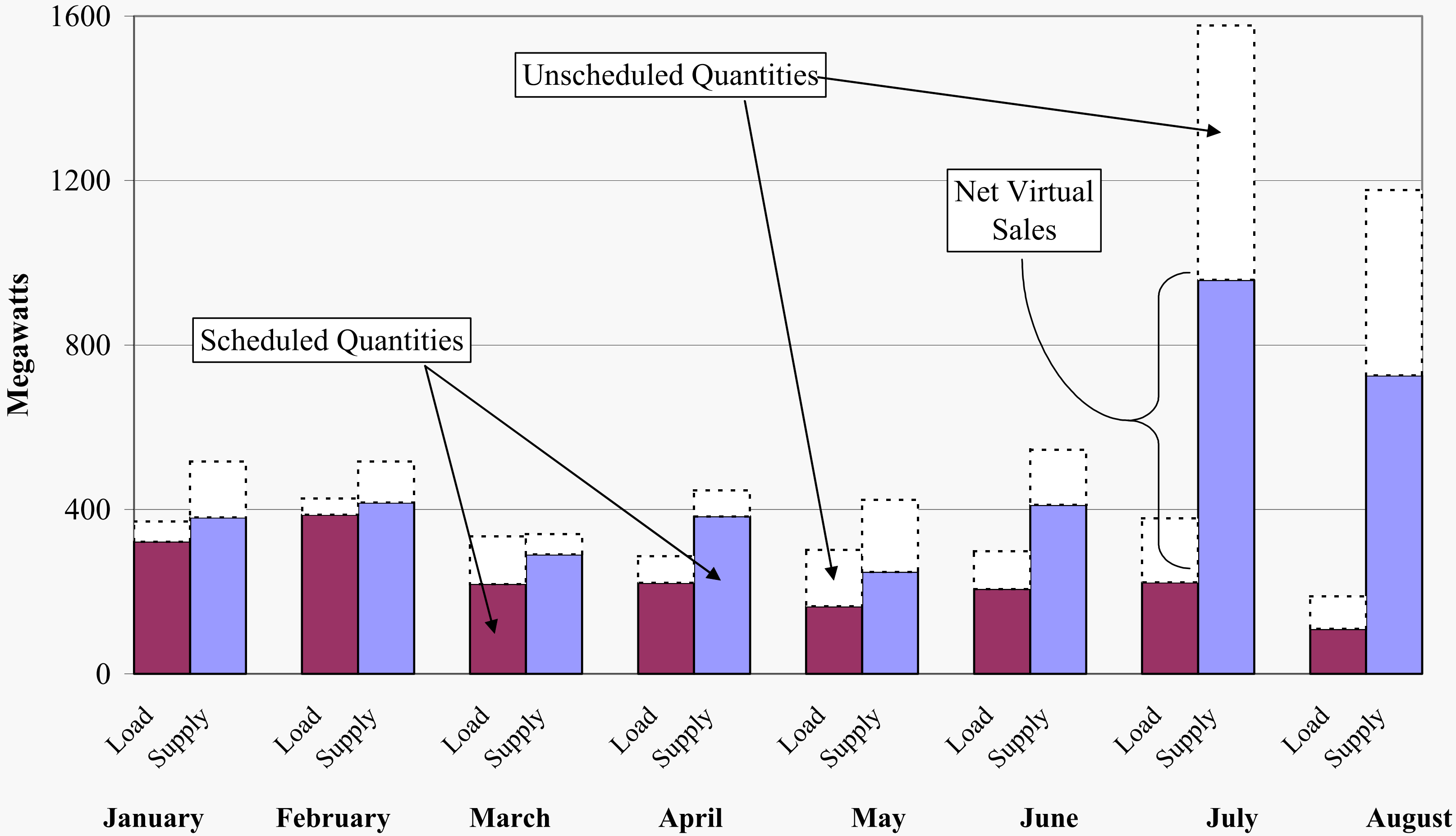
Hourly Virtual Bidding of Load and Supply, Scheduled and Unscheduled
NYC and Long Island -- January to August, 2002

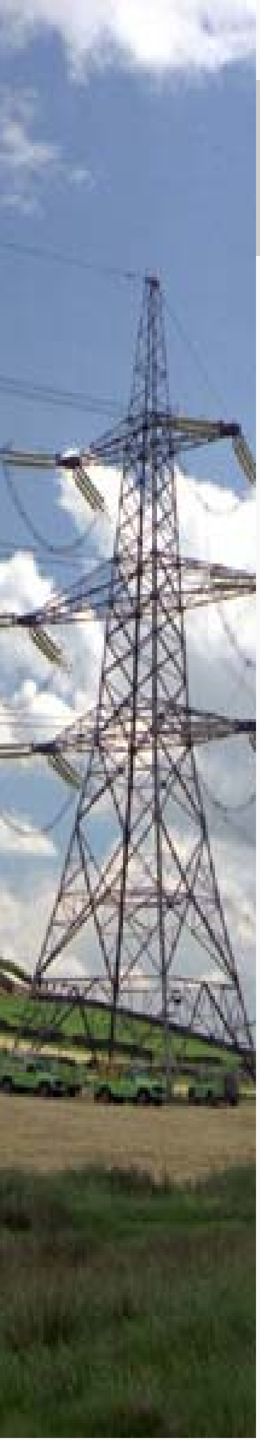






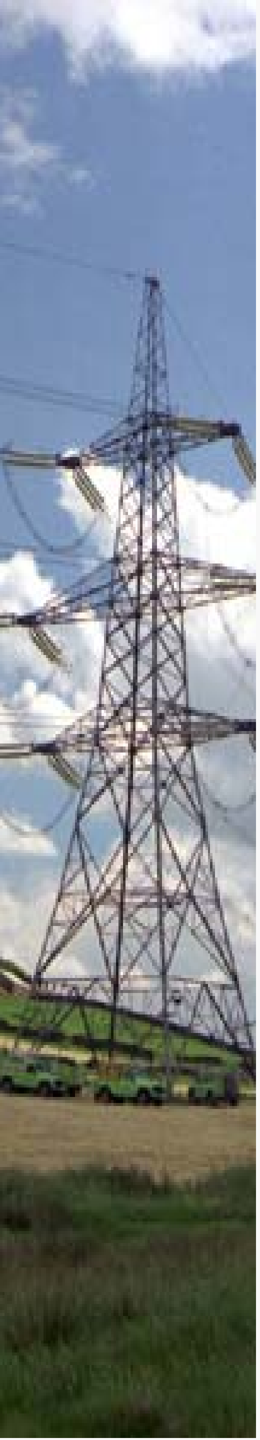
Hourly Virtual Bidding of Load and Supply, Scheduled and Unscheduled
Outside NYC and Long Island -- January to August, 2002

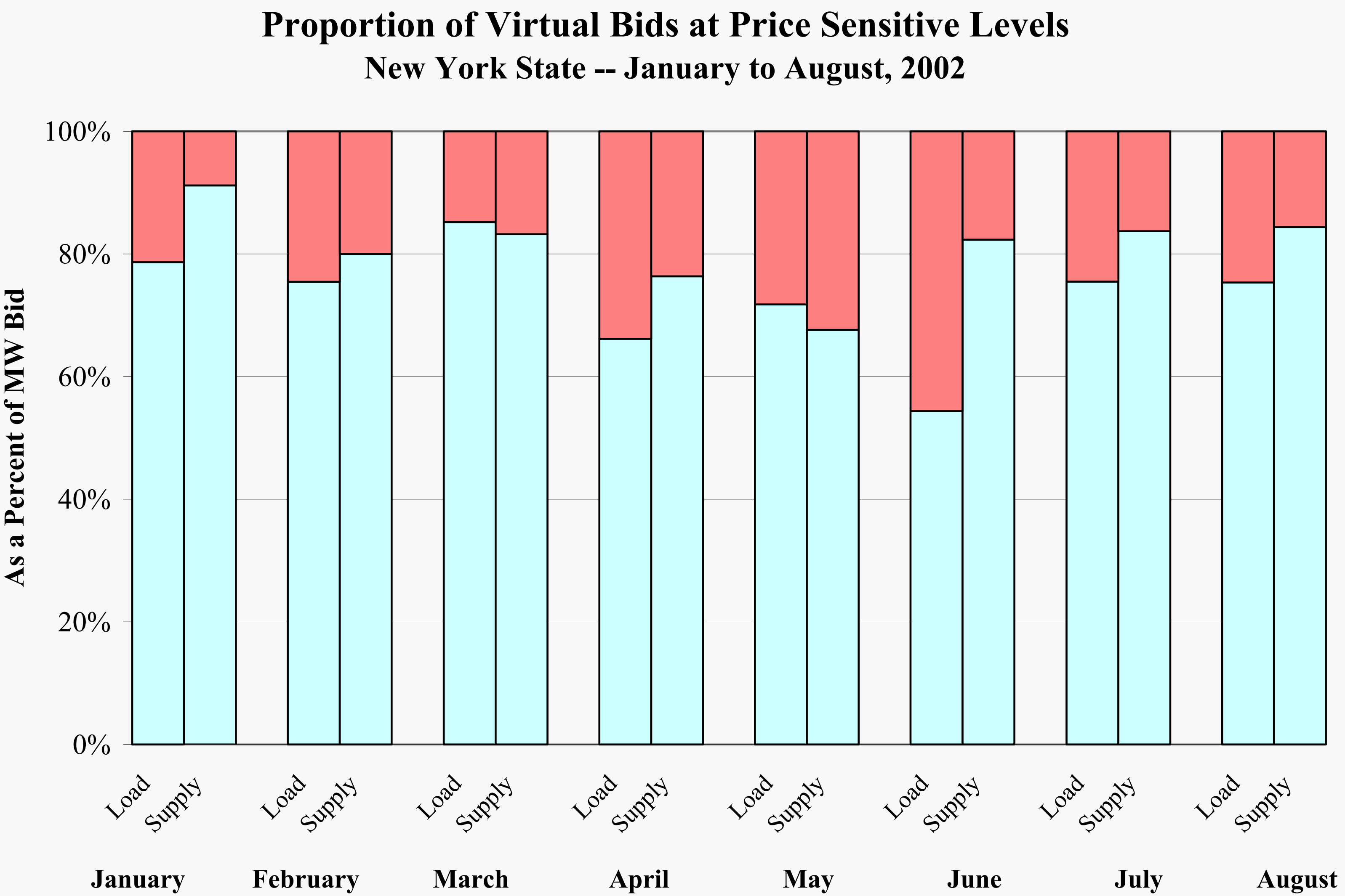


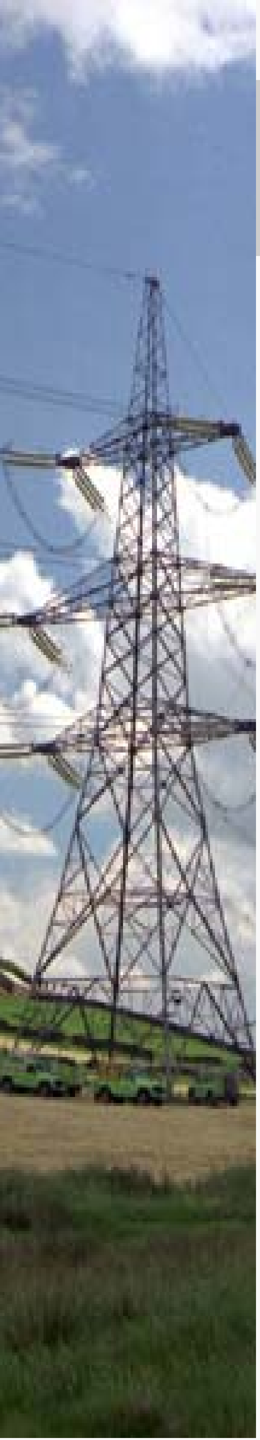


Virtual Trading Patterns

- The following chart shows the portion of the virtual bids and offers that is made price sensitively.
  - ✓ Virtual bids and offers that are not price-sensitive may indicate an attempt to inefficiently influence the day-ahead market.
  - ✓ Bids are considered price-sensitive for this analysis if they have a bid price between 33 percent and 300 percent of the actual day-ahead price.
  - ✓ With the exception of June, 70-90 percent of the virtual bids and offers were price-sensitive.
  - ✓ We have investigated the non price-sensitive bids and offers and have not found evidence that these bids have adversely affected day-ahead prices.

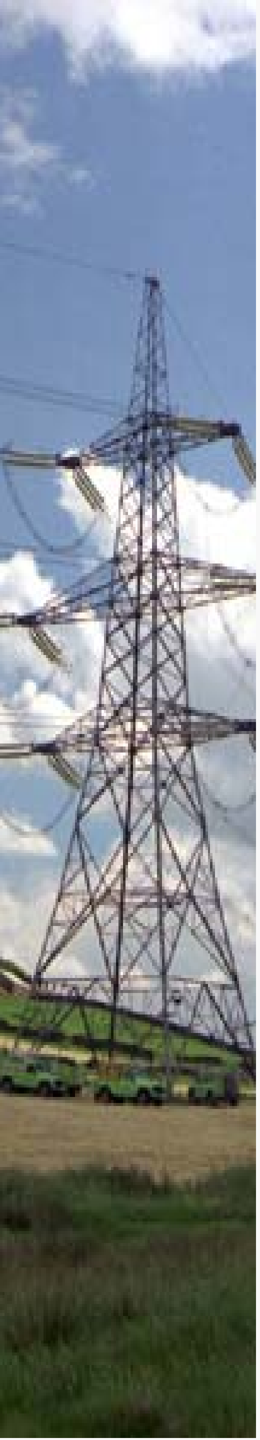



Proportion of Virtual Bids at Price Sensitive Levels
New York State -- January to August, 2002
As a Percent of MW Bid
100%
80%
60%
40%
20%
0%
Load
Supply
January
February
March
April
May
June
July
August



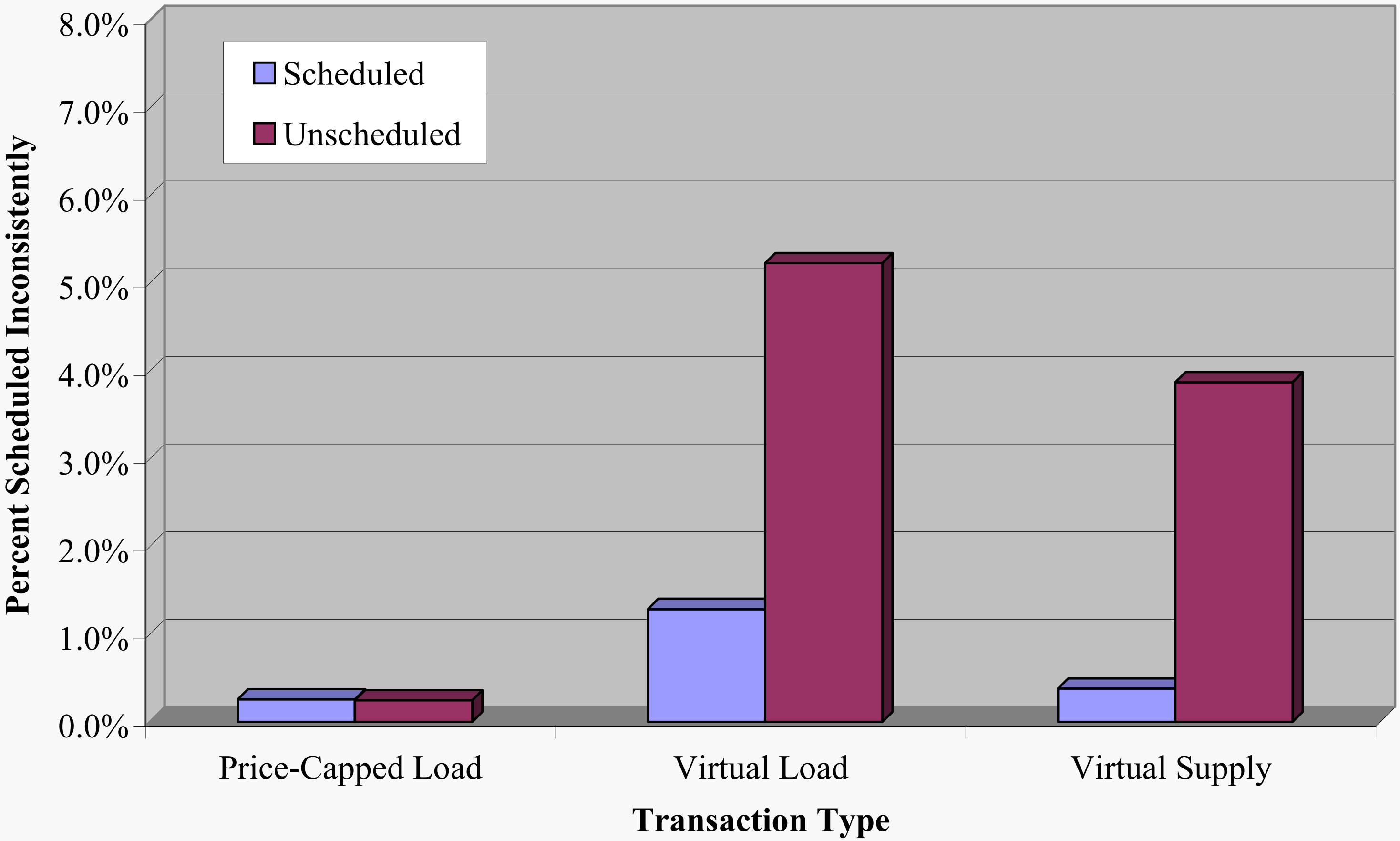
Virtual Trading Patterns

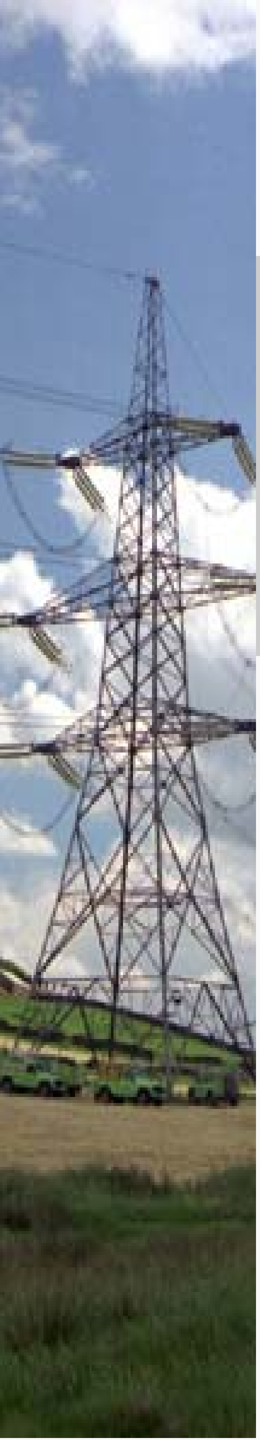
- A final issue related to virtual trading is that a portion of the virtual bids and offers has not been scheduled consistently with the market prices.
  - ✓ Inconsistent virtual load schedules occur when a virtual load is (i) accepted when the market price is *higher* than the bid price or (ii) not accepted when the market price is *lower* than the bid price.
  - ✓ Inconsistent virtual supply schedules occur when a virtual supply is (i) accepted when the market price is *lower* than the bid price or (ii) not accepted when the market price is *higher* than the bid price.
  - ✓ Inconsistent schedules are important because they will undermine the confidence of participants in virtual trading.
- The following chart shows the quantities of virtual trades and price-capped load bids that have been inconsistently scheduled.
- This has occurred because of an inconsistency between the pricing criteria used to schedule virtual trades and price-capped load bids and the determination of final prices for settlement (scheduling occurs with load-weighted prices while the final prices are generation weighted).
- Based on these results, I recommend that the NYISO eliminate this scheduling inconsistency by settling the market with load-weighted zonal prices rather than the current generation-weighted prices.



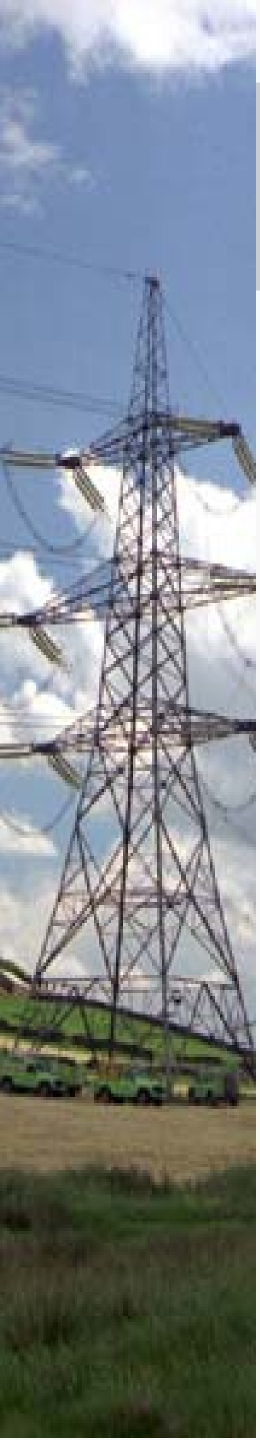
Percent of Virtual Trades and Price-Capped Load Bids Scheduled Inconsistently

June to August 2002



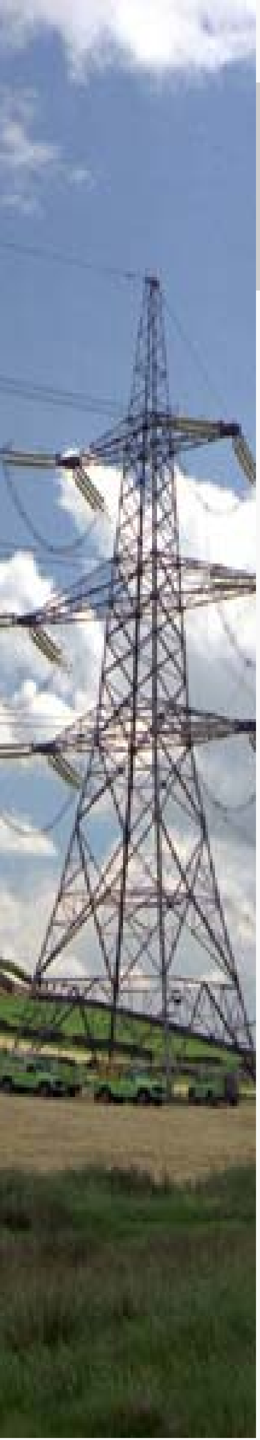


Pricing During Peak Demand Conditions



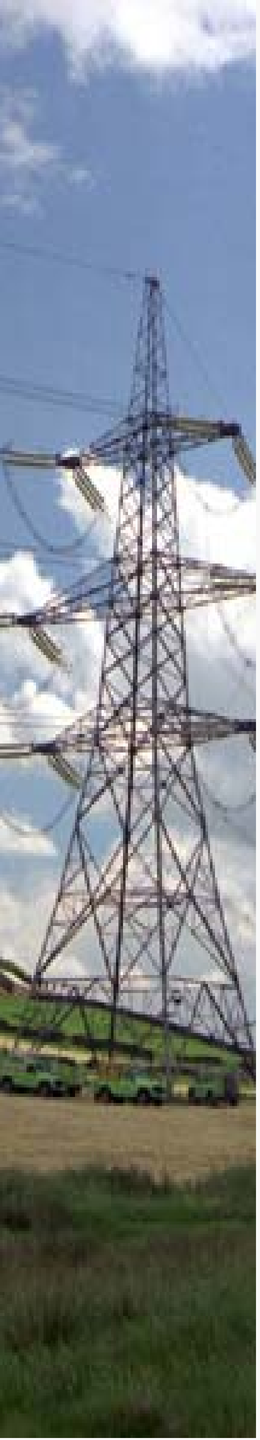
Introduction

- This section evaluates the price signals established under peak demand conditions, which play a critical role in:
  - ✓ Allowing existing high-cost units to recover their costs of remaining on the system; and
  - ✓ Establishing efficient incentives for new investment.
- Hence, this presentation focuses on 14 days with high demand conditions from late June to the middle of August, analyzing two essential areas:
  - ✓ The effect of market operations during these periods;
  - ✓ The efficiency of external transactions.



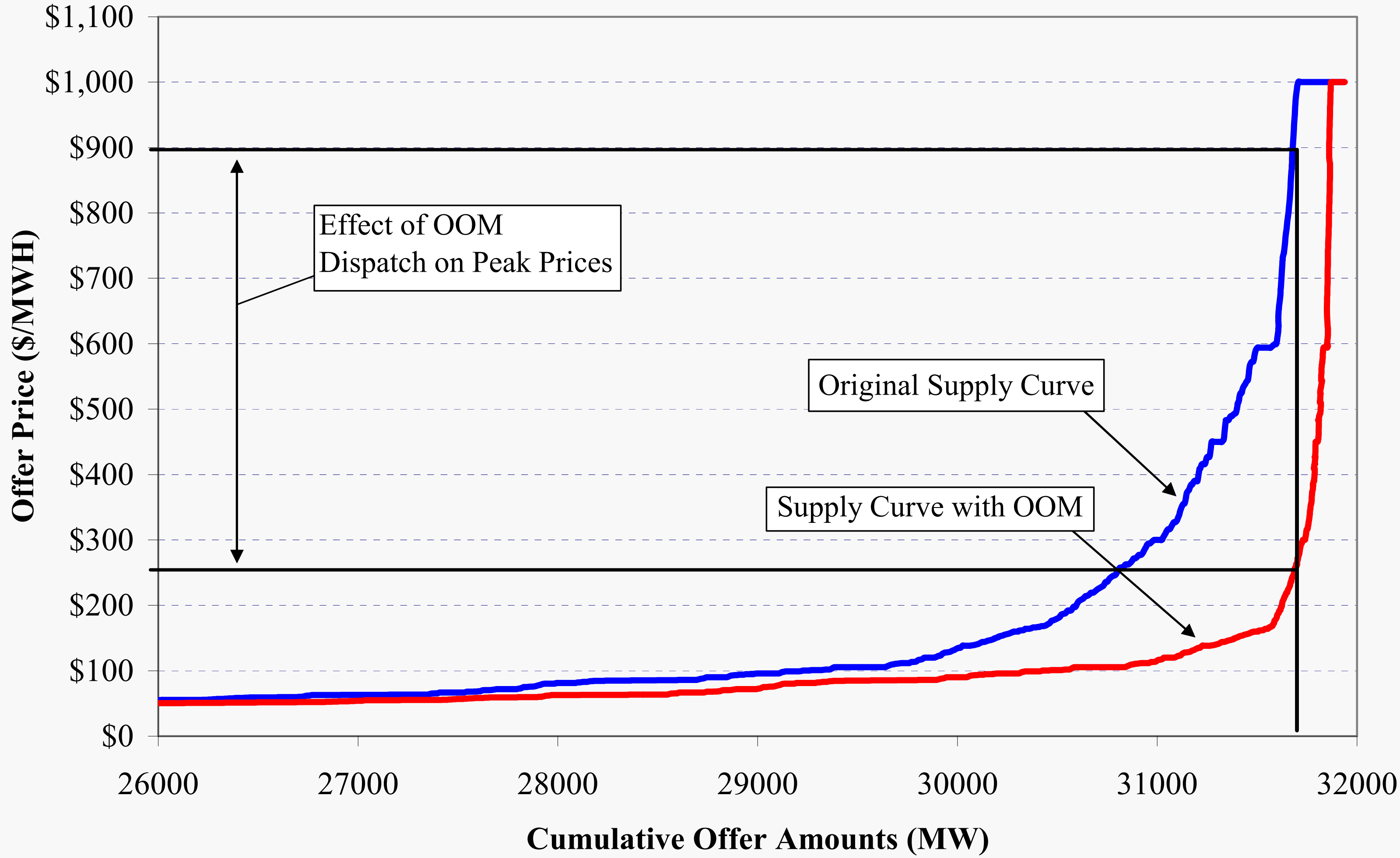
Peak Pricing

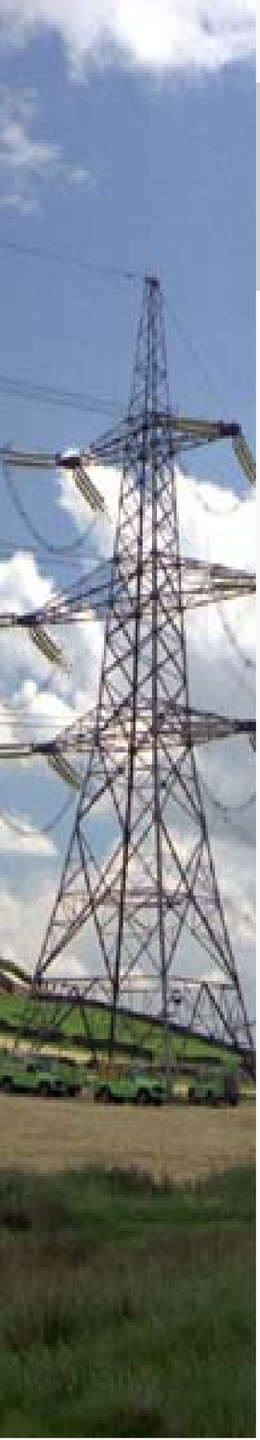
- The current market operations can affect peak pricing by altering the supply conditions through the following actions:
  - ✓ Dispatching generation “out-of-merit”;
  - ✓ Committing supplemental resources not selected by the day-ahead or hour-ahead models;
  - ✓ Dispatching reserves under peak load conditions;
  - ✓ Real-time load curtailment and emergency out-of-market purchases.
- Reliability requires that operators have the ability to take these actions, but they should be taken only when necessary and the pricing rules should minimize adverse effects on prices.
- Out-of-merit dispatch (“OOM”) occurs when a unit is dispatched whose energy bid exceeds the price at its location – this can be caused by the physical parameters of the unit (e.g., min. run-time) or by operator action.
- The following chart shows how out-of-merit dispatch can affect peak prices – the effects of the other three actions are very similar.



Effects of Out-of-Merit Dispatch on Peak Prices

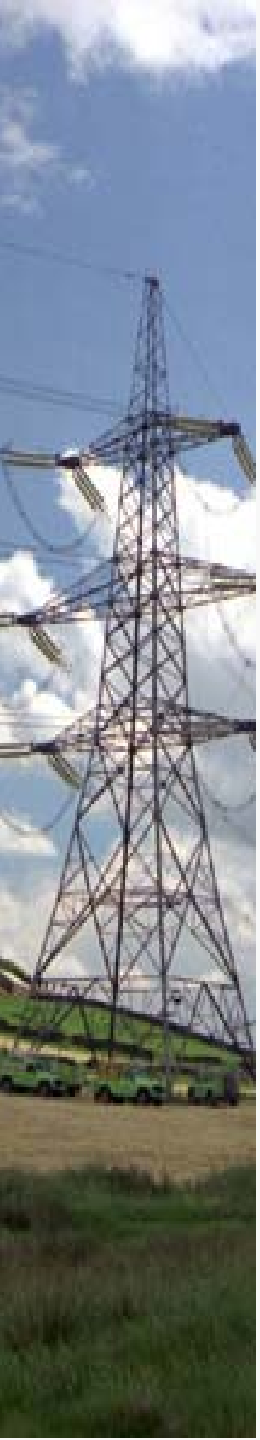
Peak Supply Curve Before and After OOM Dispatch



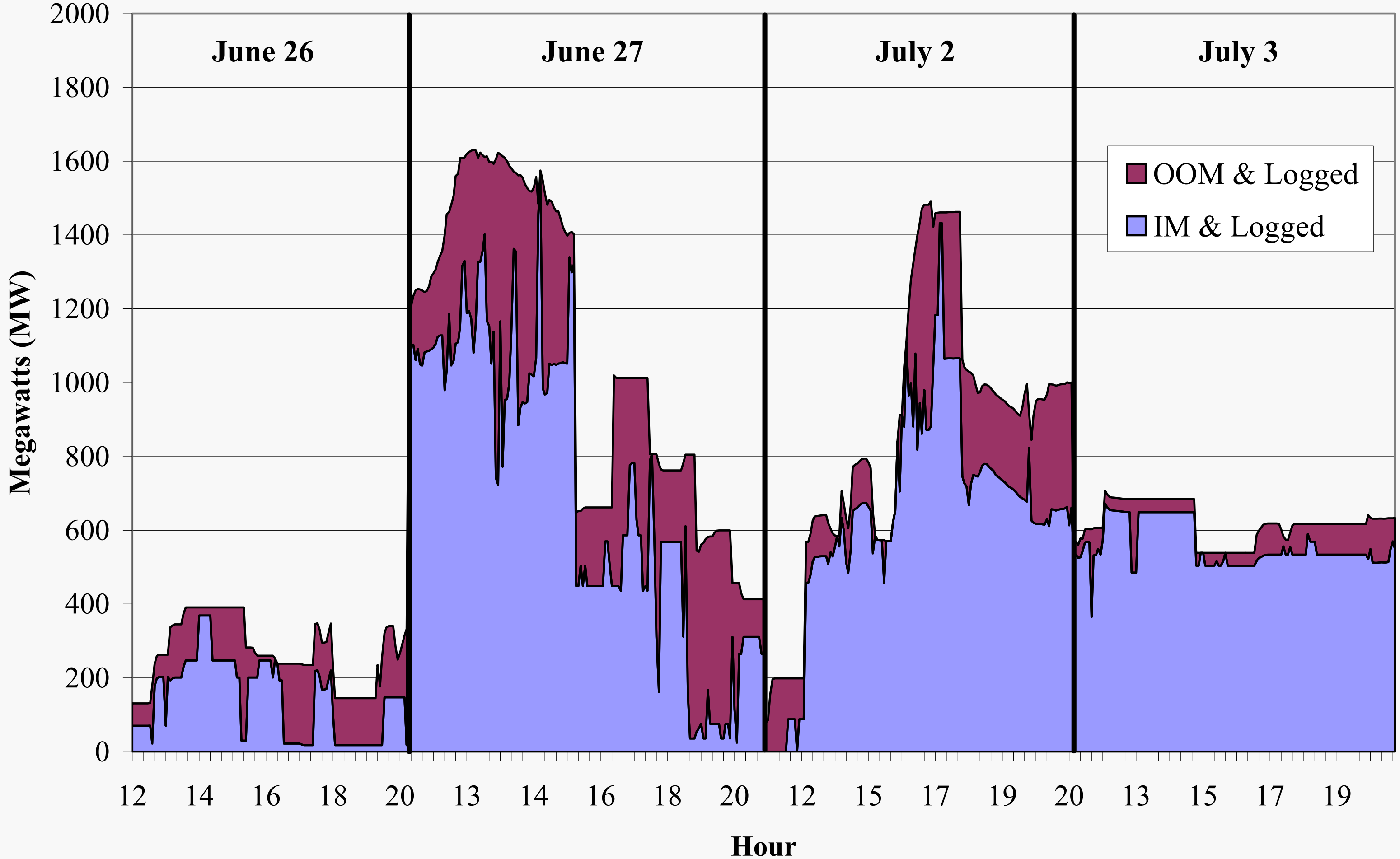


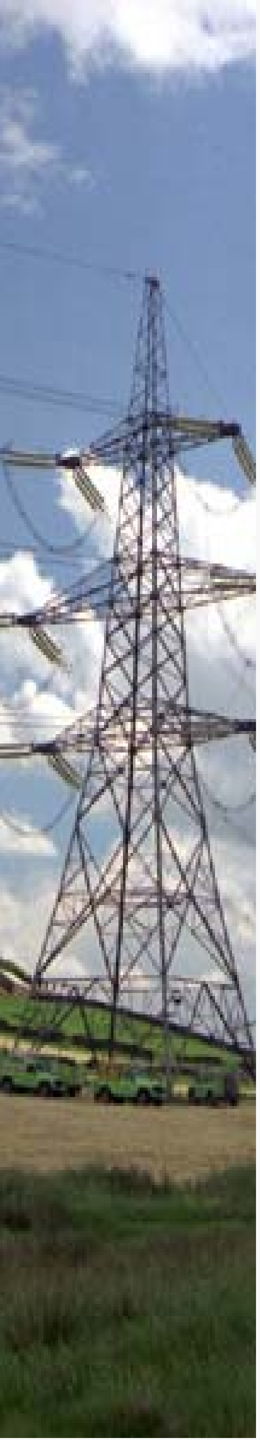
Out-of-Merit Analysis

- When OOM actions are taken by the operator, they are logged and reported on the NYISO website.
- When an operator dispatches a resource OOM, the resource loses its eligibility to set energy prices.
  - ✓ However, in many cases these resources turn out to be economic (i.e., in merit).
  - ✓ Only units that are "logged" and are economically OOM will affect prices.
- The following three charts show that most resources logged as OOM are actually economically in-merit on the peak days.

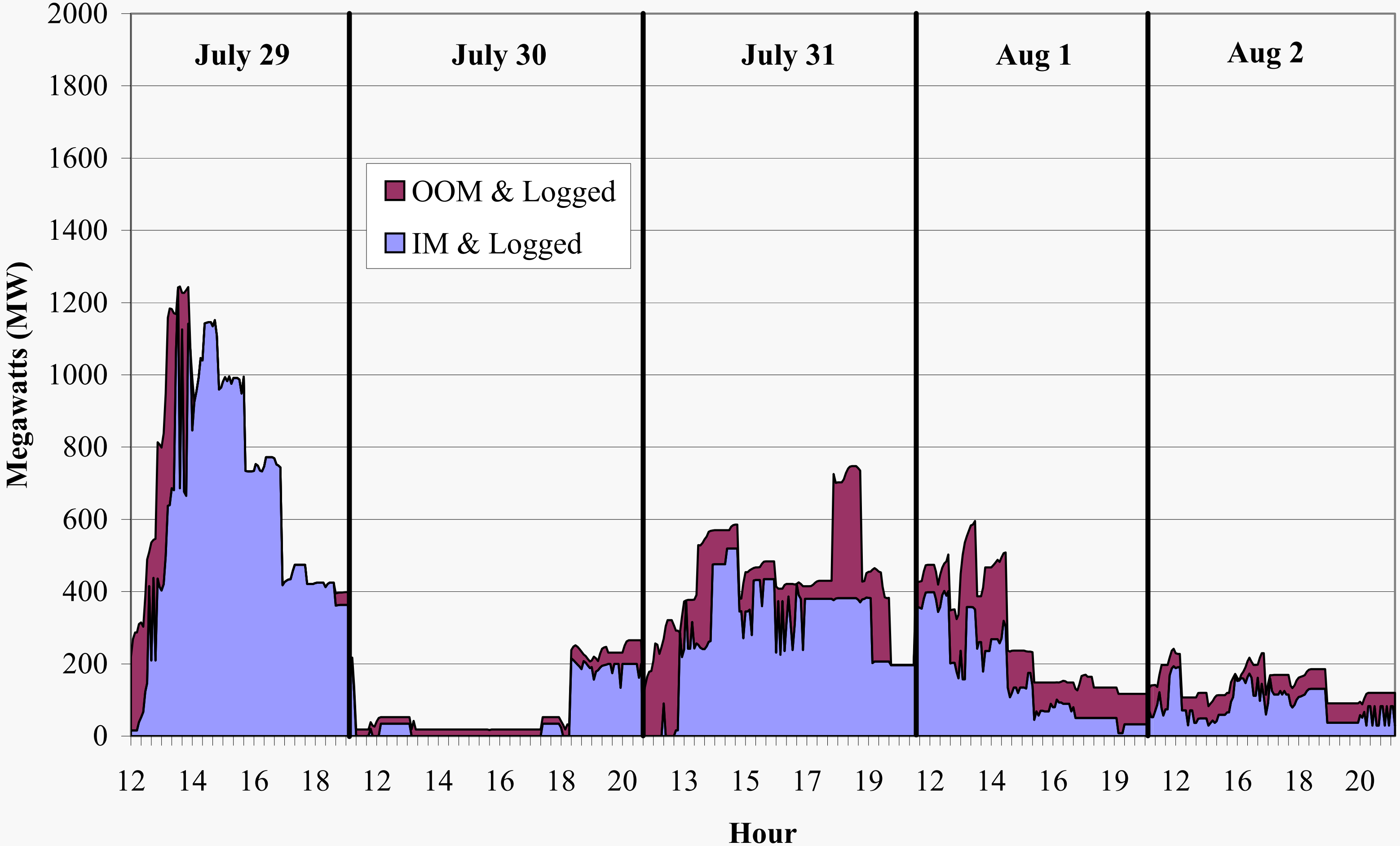


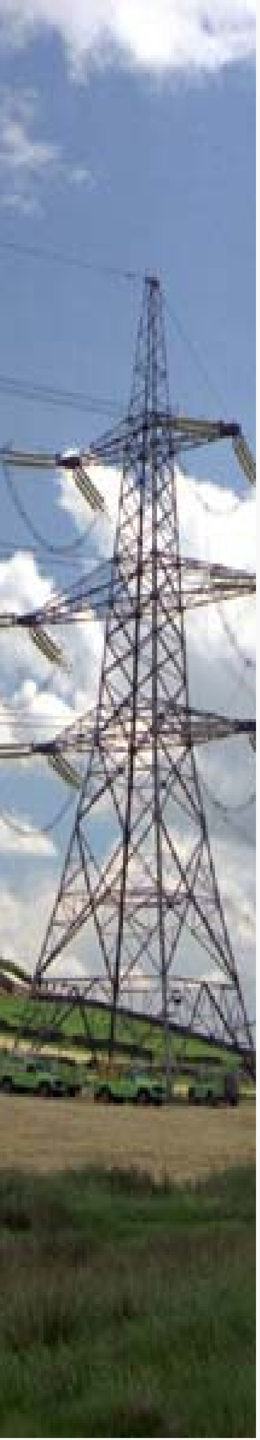
OOM Logging During Peak Hours
June 26, 27, July 2,3 -- 12 p.m. to 8 p.m.

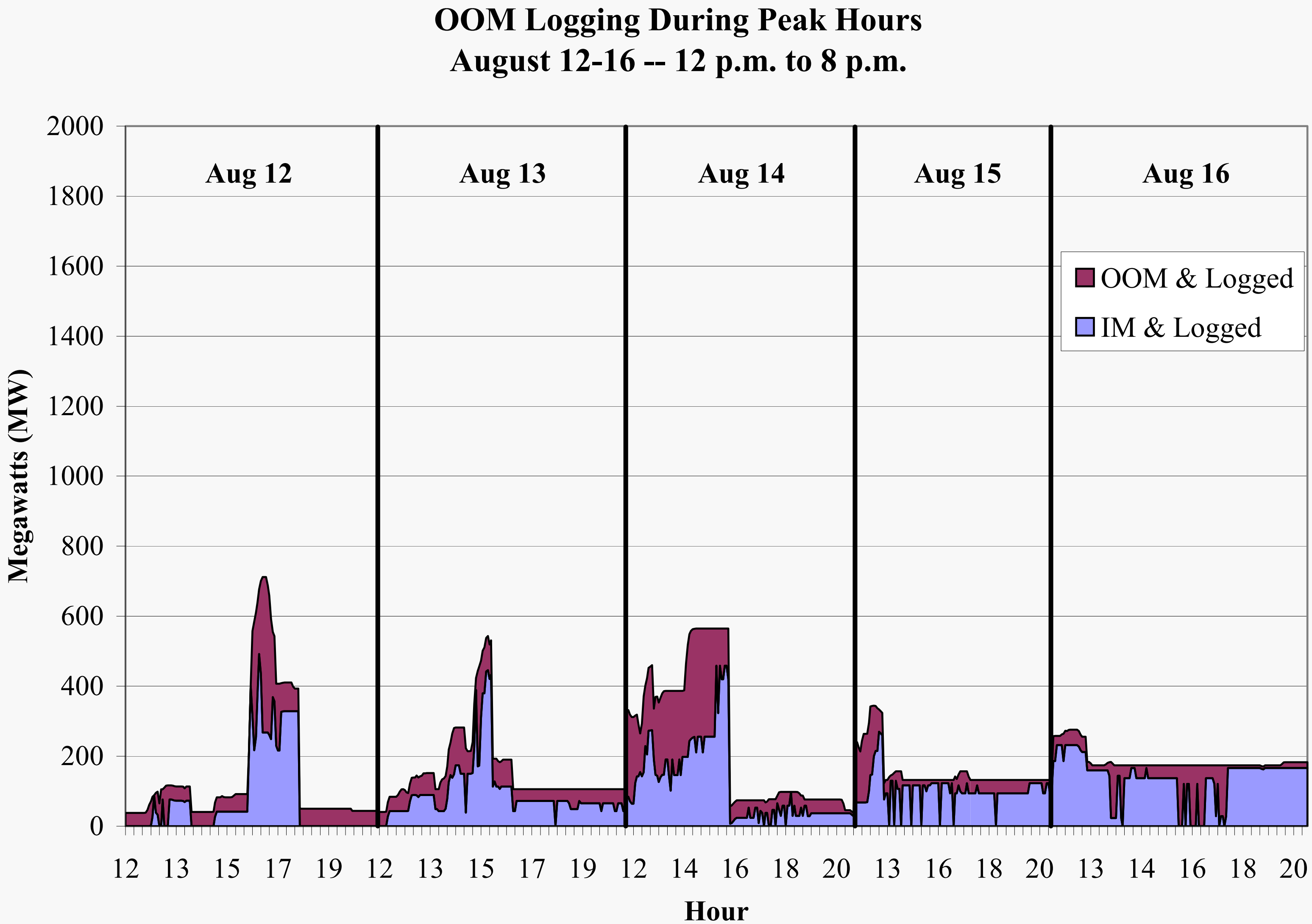




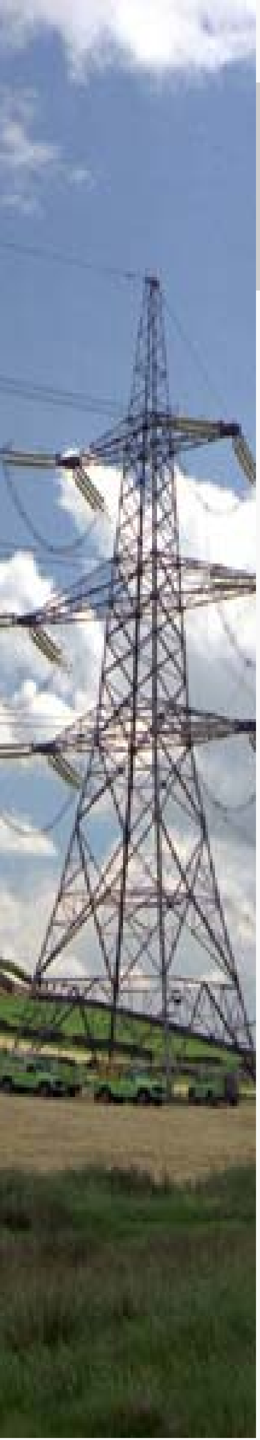
OOM Logging During Peak Hours
July 29, 30, 31, August 2, 3 -- 12 p.m. to 8 p.m.





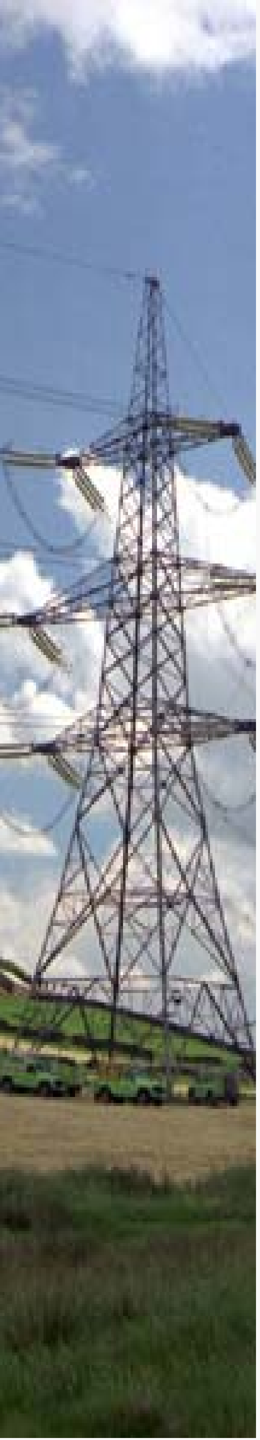


OOM Logging During Peak Hours
August 12-16 -- 12 p.m. to 8 p.m.
Aug 12
Aug 13
Aug 14
Aug 15
Aug 16
OOM & Logged
IM & Logged
Megawatts (MW)
0
200
400
600
800
1000
1200
1400
1600
1800
2000
12 13 15 17 19 12 13 15 17 19 12 14 16 18 20 13 16 18 20 13 14 16 18 20
Hour

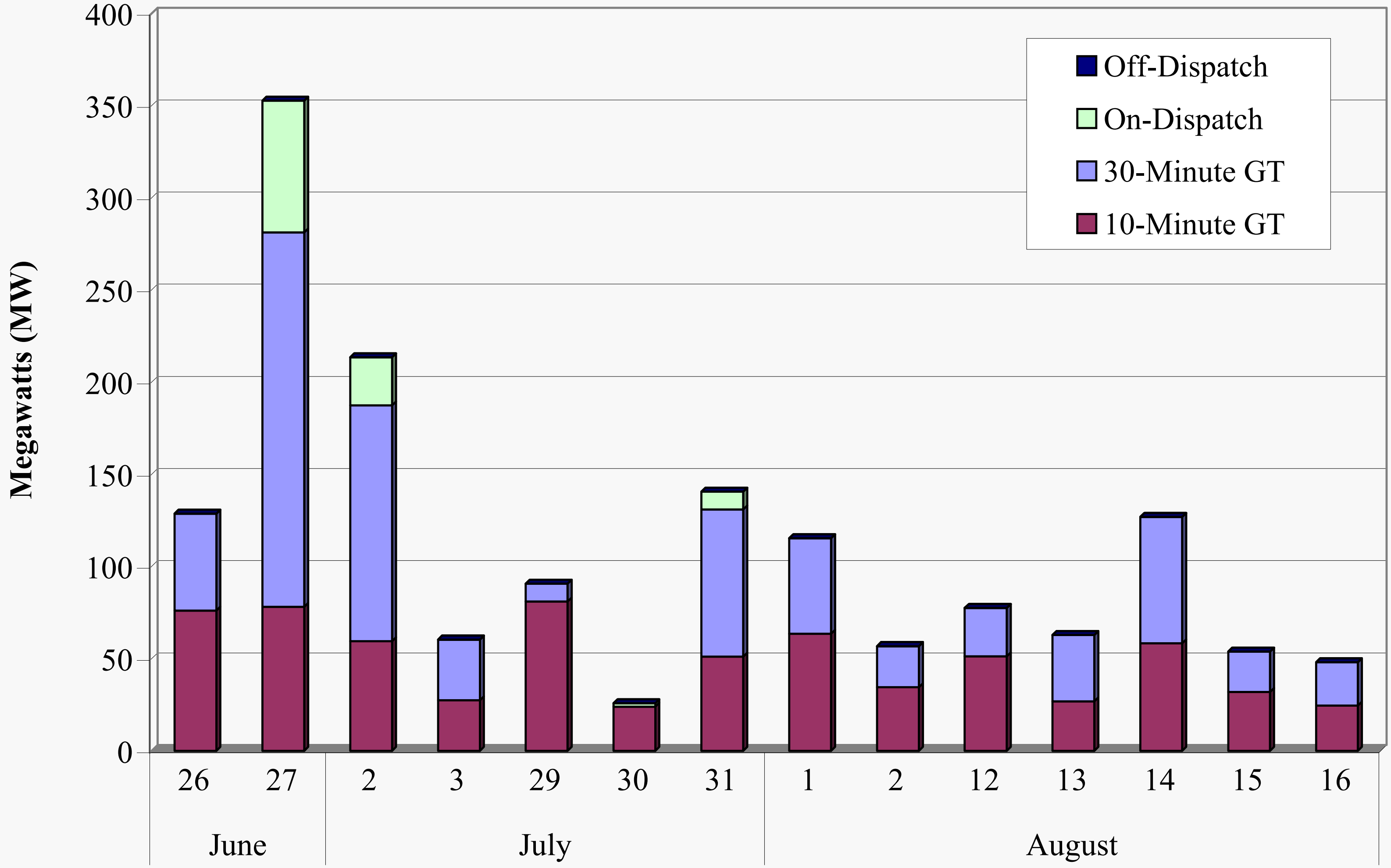


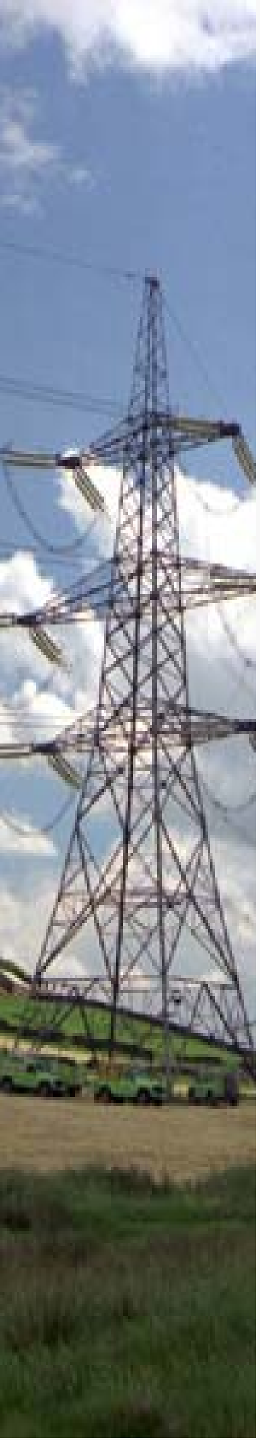
Out-of-Merit Analysis

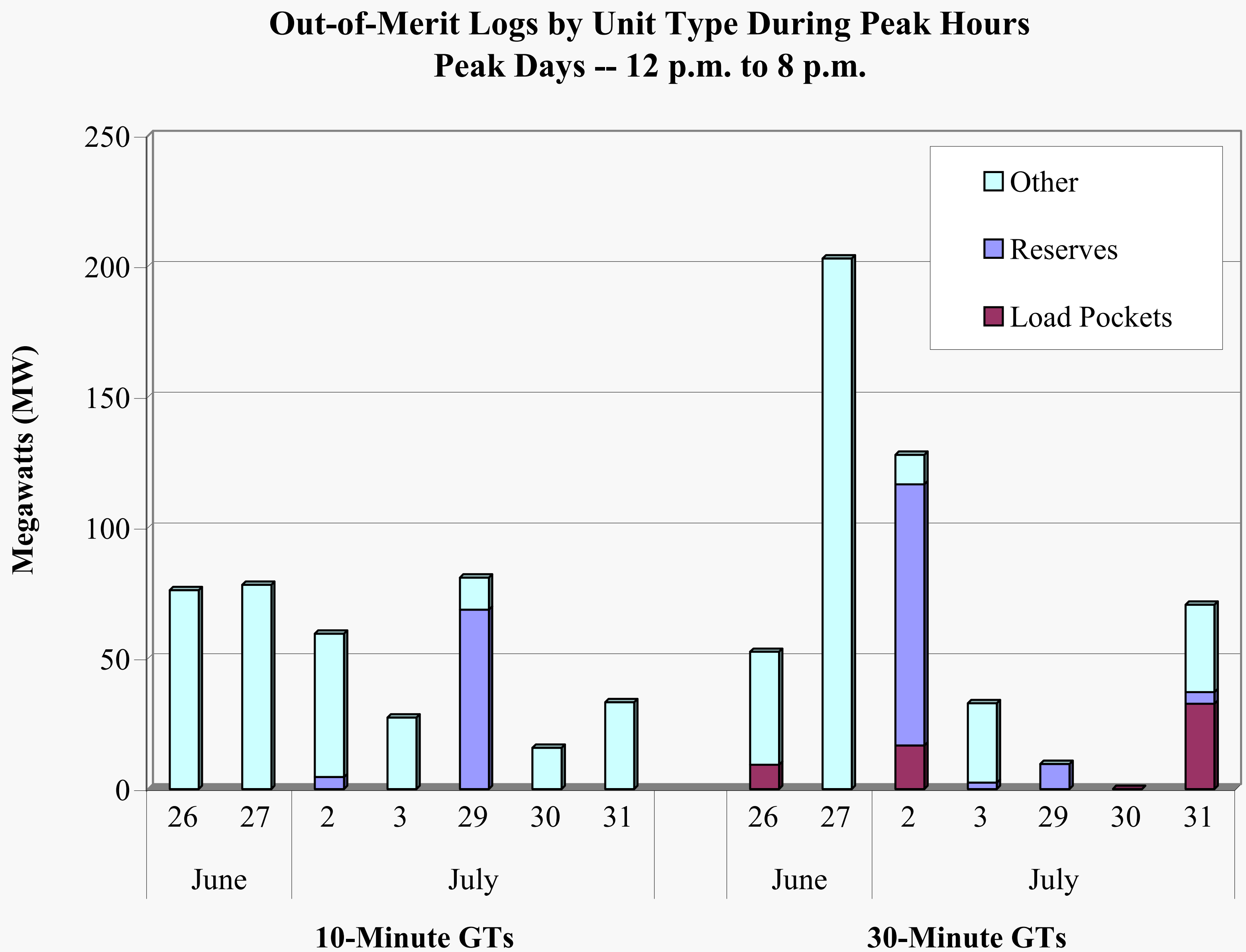
- The first chart below shows the types of units that are economically OOM and logged by the operators on the peak days.
  - ✓ These values show that the economically OOM resources are generally gas turbines – steam units are usually in-merit even when they are logged by the operators.
- The next two charts show the reasons logged by the operators when they are logging gas turbines out-of-merit.
  - ✓ Logically, units logged as OOM for “reserves” or “load pockets” should be able to set energy prices, while units logged for “other” should not.
  - ✓ The NYISO has already taken actions to allow 30-minute gas turbines to set prices that are OOM for reserves and load pockets.
  - ✓ These actions have resulted in substantial reductions in OOM quantities during th peak conditions in August versus the peak days in June and July.
- When 10-minute GTs are become eligible to set energy prices when they begin producing energy and operators unblock their lower limit. In some cases, delays in unblocking the GTs occurred that caused the GTs to operate OOM.

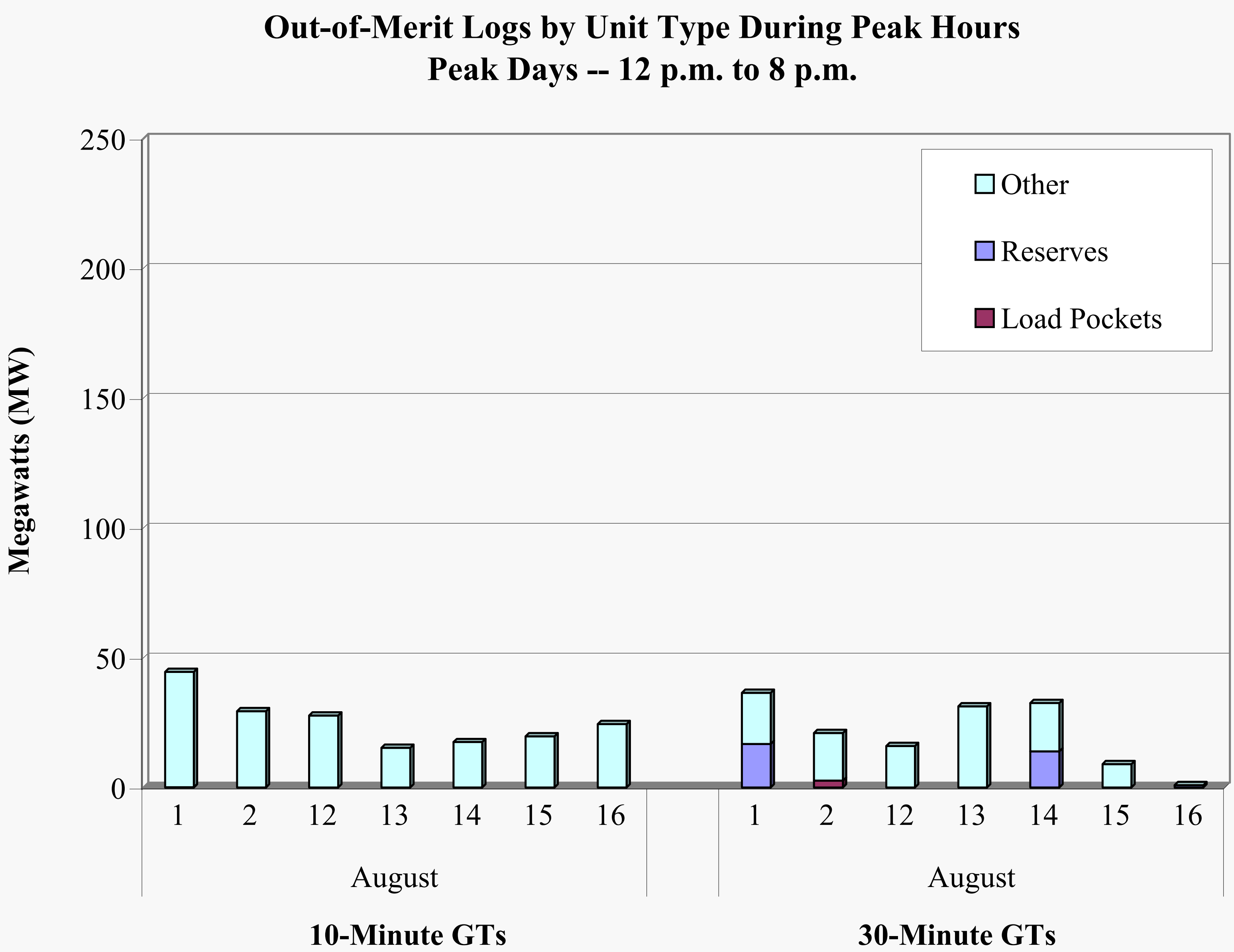


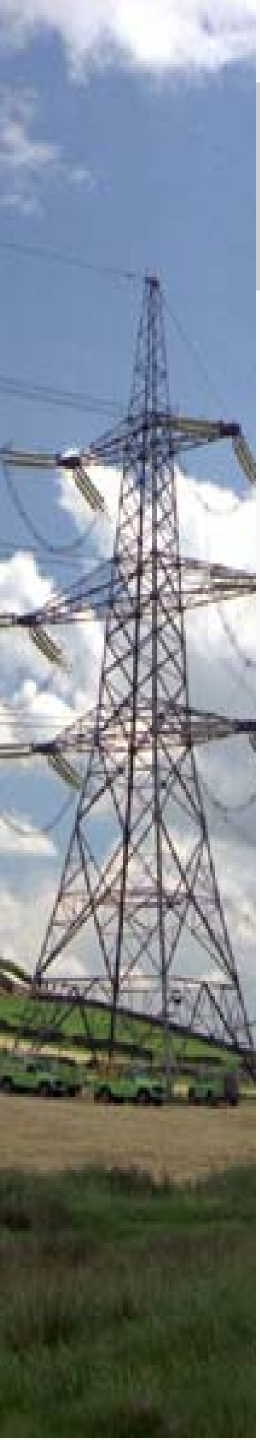
Average Economically Out-of-Merit Generation by Type
Peak Days -- 12 p.m. to 8 p.m.





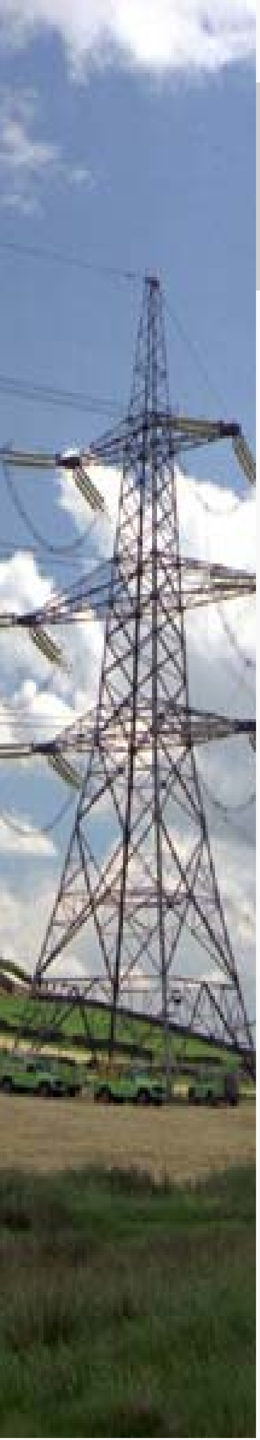

Out-of-Merit Logs by Unit Type During Peak Hours
Peak Days -- 12 p.m. to 8 p.m.
Megawatts (MW)
250
200
150
100
50
0
Other
Reserves
Load Pockets
26
27
2
3
29
30
31
June
July
10-Minute GTs
30-Minute GTs


Out-of-Merit Logs by Unit Type During Peak Hours
Peak Days -- 12 p.m. to 8 p.m.
Megawatts (MW)
250
200
150
100
50
0
Other
Reserves
Load Pockets
1
2
12
13
14
15
16
August
10-Minute GTs
1
2
12
13
14
15
16
August
30-Minute GTs



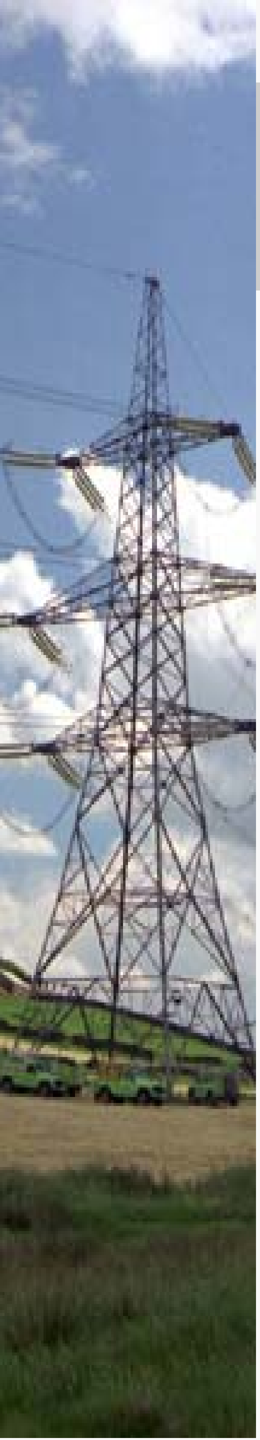
Out-of-Merit Analysis

- Finally, when 10-minute GTs are become eligible to set energy prices when they begin producing energy and operators unblock their lower limit.
- In some cases, delays in unblocking the GTs occurred that caused the GTs to operate OOM.
- Unfortunately, these delays are most likely under peak conditions when operators are the busiest maintaining the reliability of the system.
- To minimize such delays, I recommend that the NYISO improve the information available to the operators regarding when GTs with blocked limits begin producing energy, or improve other operating procedures that would allow the limits to be unblocked as soon as practicable.



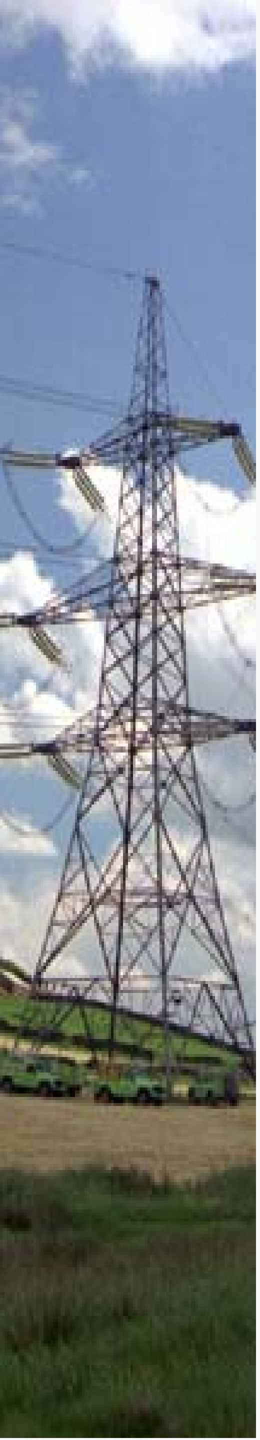
Supplemental Resource Evaluation

- When the operator commits resources outside of the SCUC and BME models, these are logged and reported on the NYISO website.
- This does not directly affect the day-ahead price, but makes additional resources available in real-time, and, therefore, may reduce real-time prices.
- Supplemental commitment should generally be necessary when the day-ahead market assumptions are modified after the market concludes – (e.g., operators expect loads higher than the SCUC forecast).
- When this occurs, the same economic criteria should be employed as is employed for supplemental commitments made by SCUC to meet the forecasted load (i.e., minimize start-up and min-gen costs).

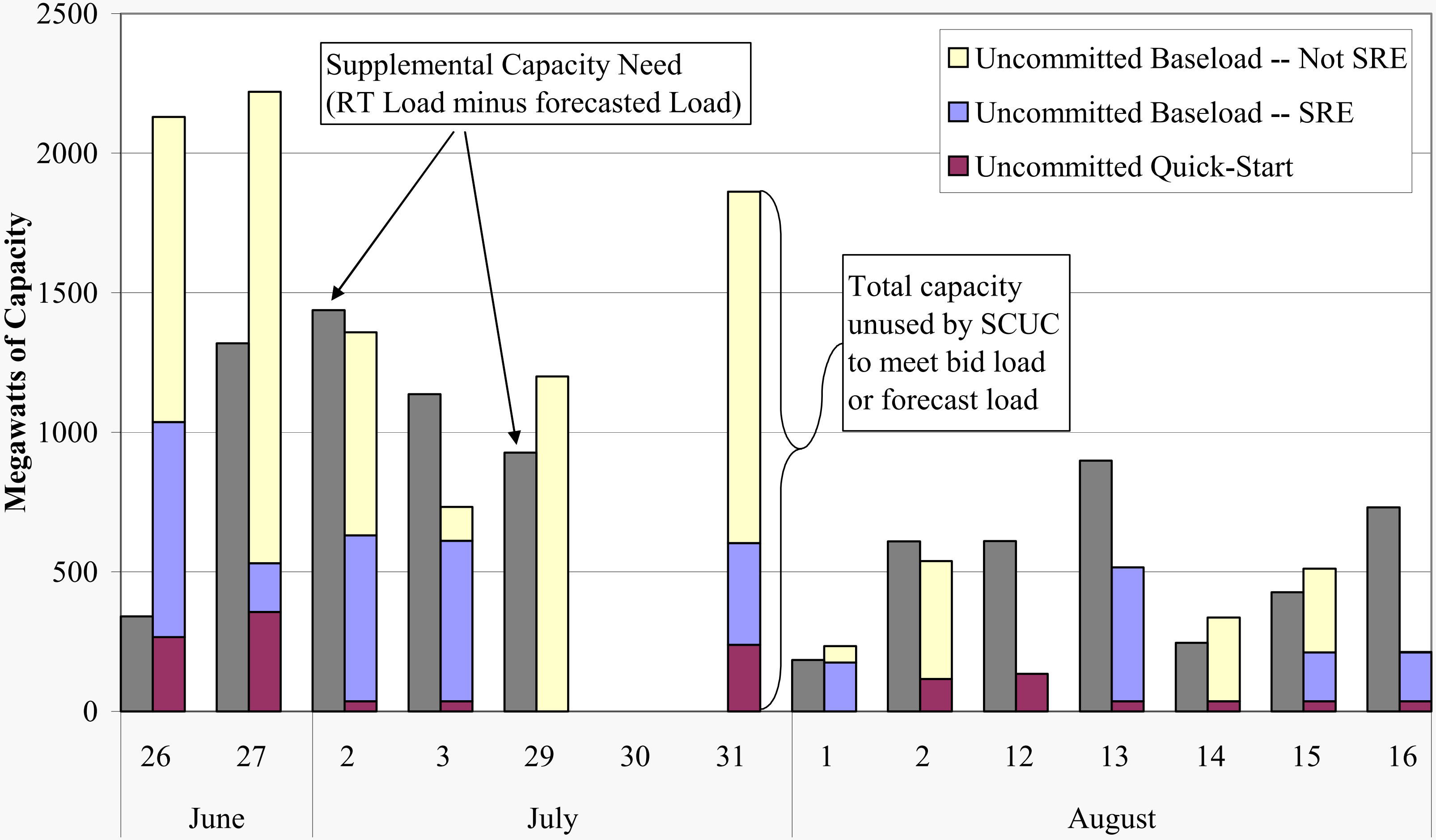


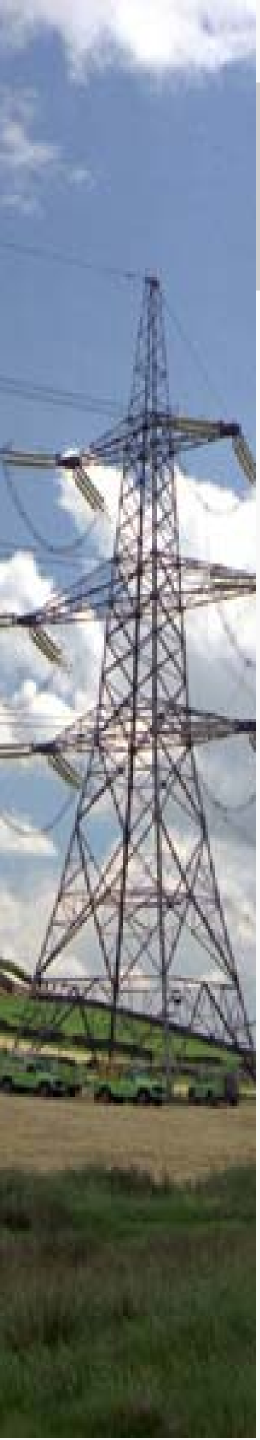
Supplemental Resource Evaluation

- The following chart shows the quantity of resources that were committed through the SRE process on the peak days.
- This analysis indicates that the SRE quantities were generally consistent with conditions in which:
  - ✓ The actual load exceeded the SCUC load forecast by a significant margin;
  - ✓ Substantial gas turbine capacity was not available to meet the increase in expected load;
  - ✓ These conclusions would not necessarily hold on other days that were not examined.
- Most of the SRE actions were called by the transmission owners to meet local reliability requirements, rather than by the ISO. To minimize potential price effects from these calls, the ISO should
  - ✓ Continue to adjust SCUC to meet local reliability requirments and minimize the need for TO SREs; and
  - ✓ Screen or audit the SREs called by the TOs to ensure that the units selected are needed and are the most efficient alternative.



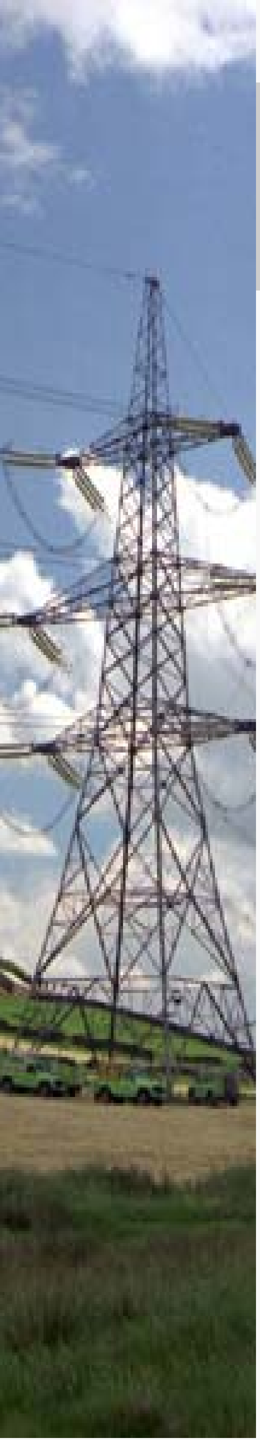
Supplemental Capacity Needs and Resources Not Used by SCUC
Eastern NY, Peak Hours on High Demand Days





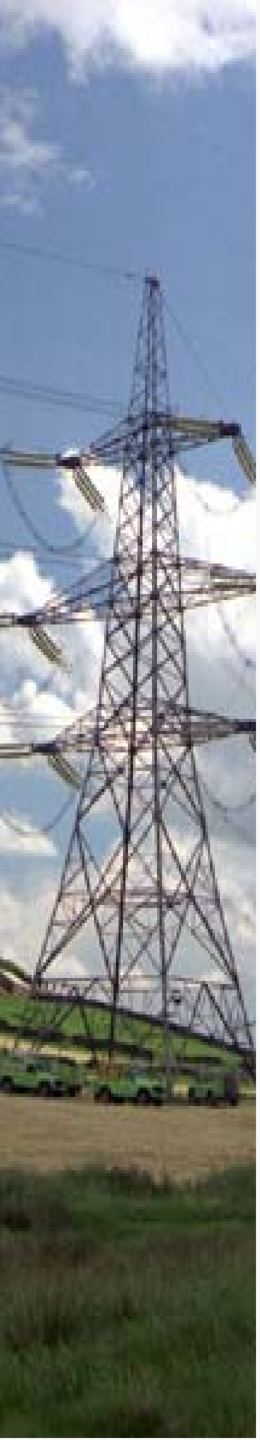
Reserve Shortages

- The final analysis of peak pricing relates to the dispatch of reserves in the energy market.
- When the system enters shortage conditions, trade-offs are sometimes necessary to ensure the requirements of the energy market are reliably met.
  - ✓ One of the trade-offs is to allow operating reserves to be dispatched to provide energy.
  - ✓ Provisions to allow this trade-off for 30-minute reserves was adopted prior to the summer by counting exports as 30-minute reserves at certain shadow price levels.
  - ✓ In some cases, trading 10-minute reserves for energy was necessary to meet the demand in the energy market.
- Like OOM dispatch, dispatching reserves for energy will increase the supply in real-time and can prevent prices from revealing shortages.
- In a sense, the reserve market has become the marginal supplier in this case and the prices in the energy market should reflect the value of the reserve that was sacrificed.

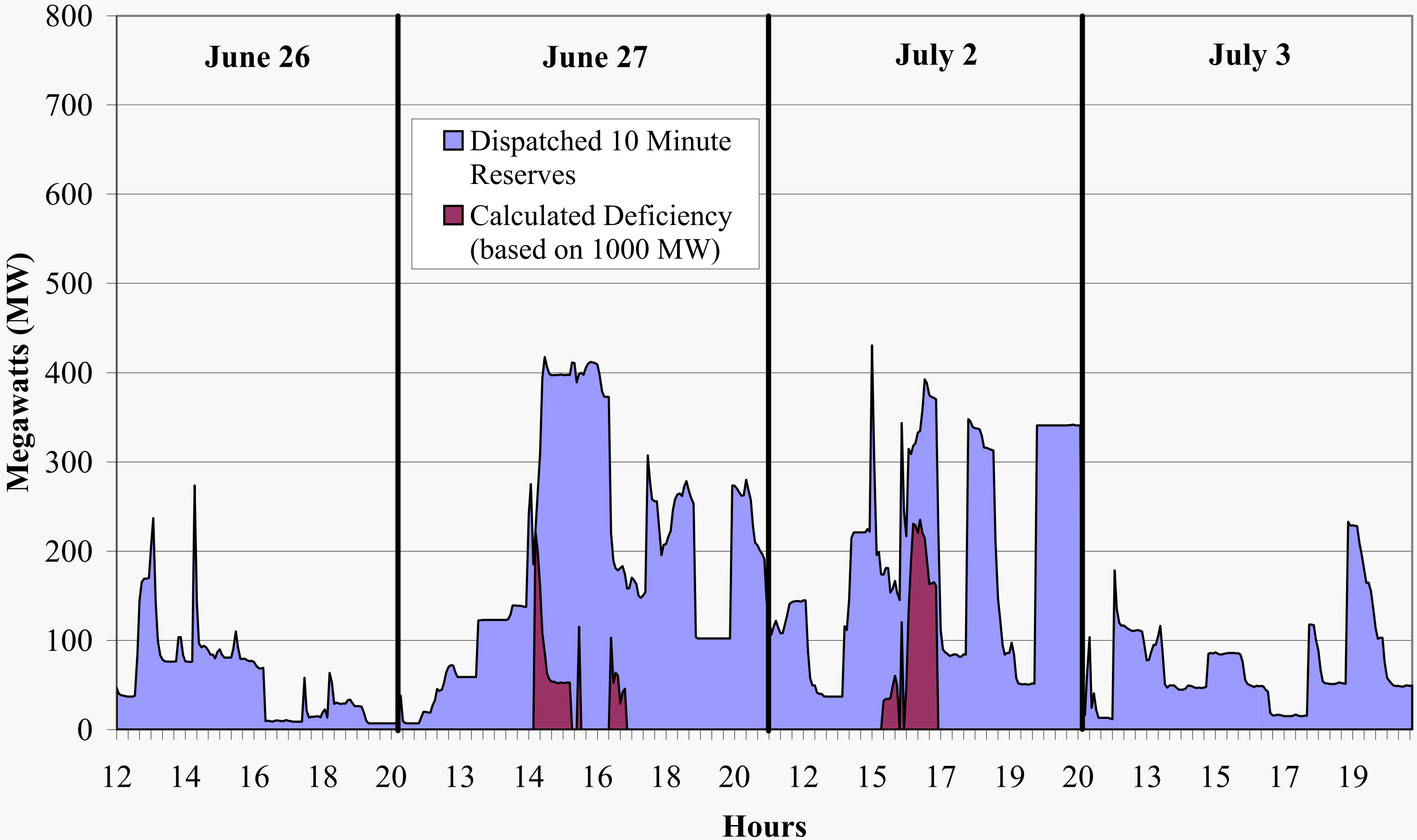


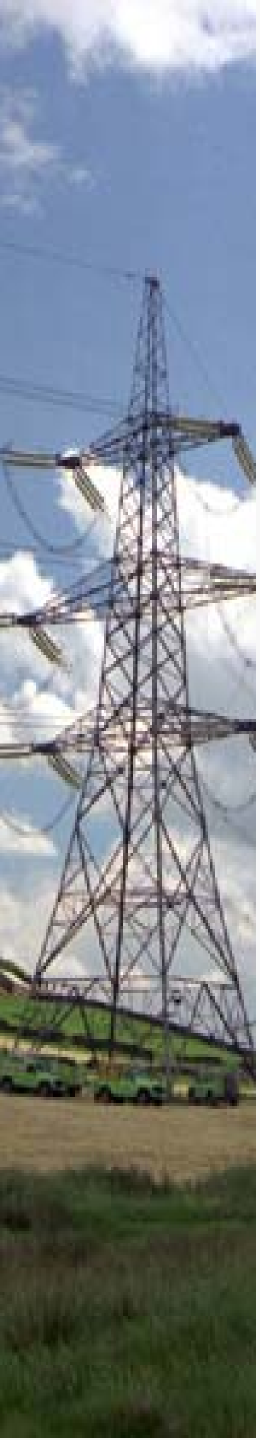
Reserve Shortages

- For each of the peak days, the following charts show:
  - ✓ The quantity of total 10-minute reserves designated by BME that are dispatched by the SCD in Eastern NY in each interval.
  - ✓ The deficiency, if any, of total 10-minute reserves in eastern New York (requirement = 1000 MW).
- Because other resources are often available in real-time that can provide 10-minute reserves, dispatching 10-minute reserves designated by BME does not always produce a reserve deficiency (the other resources effectively become the reserves).
  - ✓ However, the charts show that there were 151 of intervals (almost 13 hours) on these days when the NYISO was deficient in total 10-minute reserves.

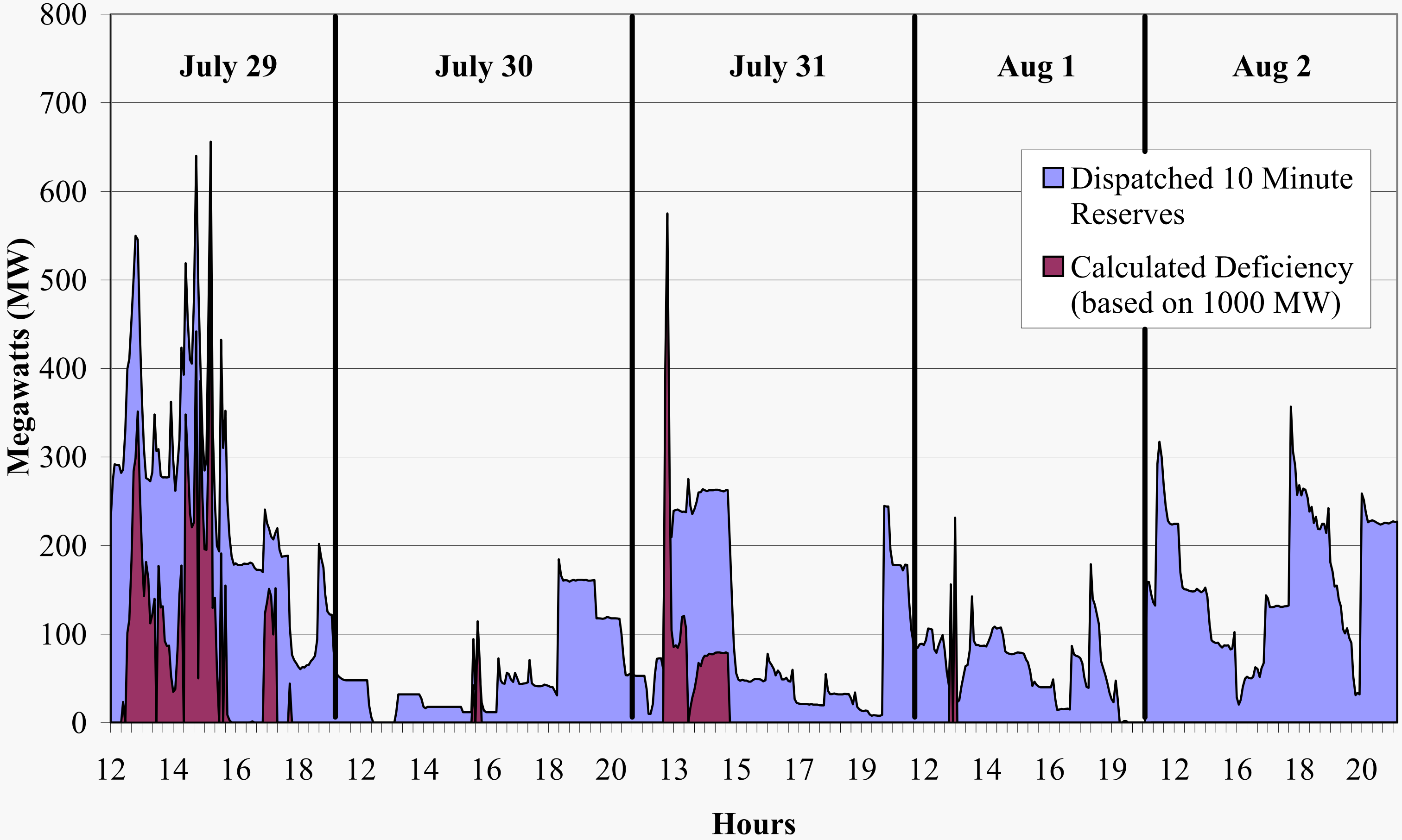


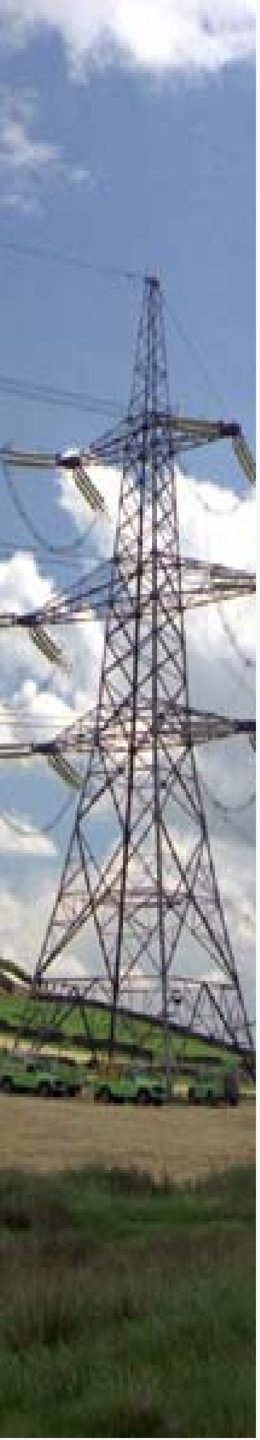
Dispatch of 10-Minute Total Reserves in Eastern New York
June 26, 27, July 2, 3 -- 12 p.m. to 8 p.m.



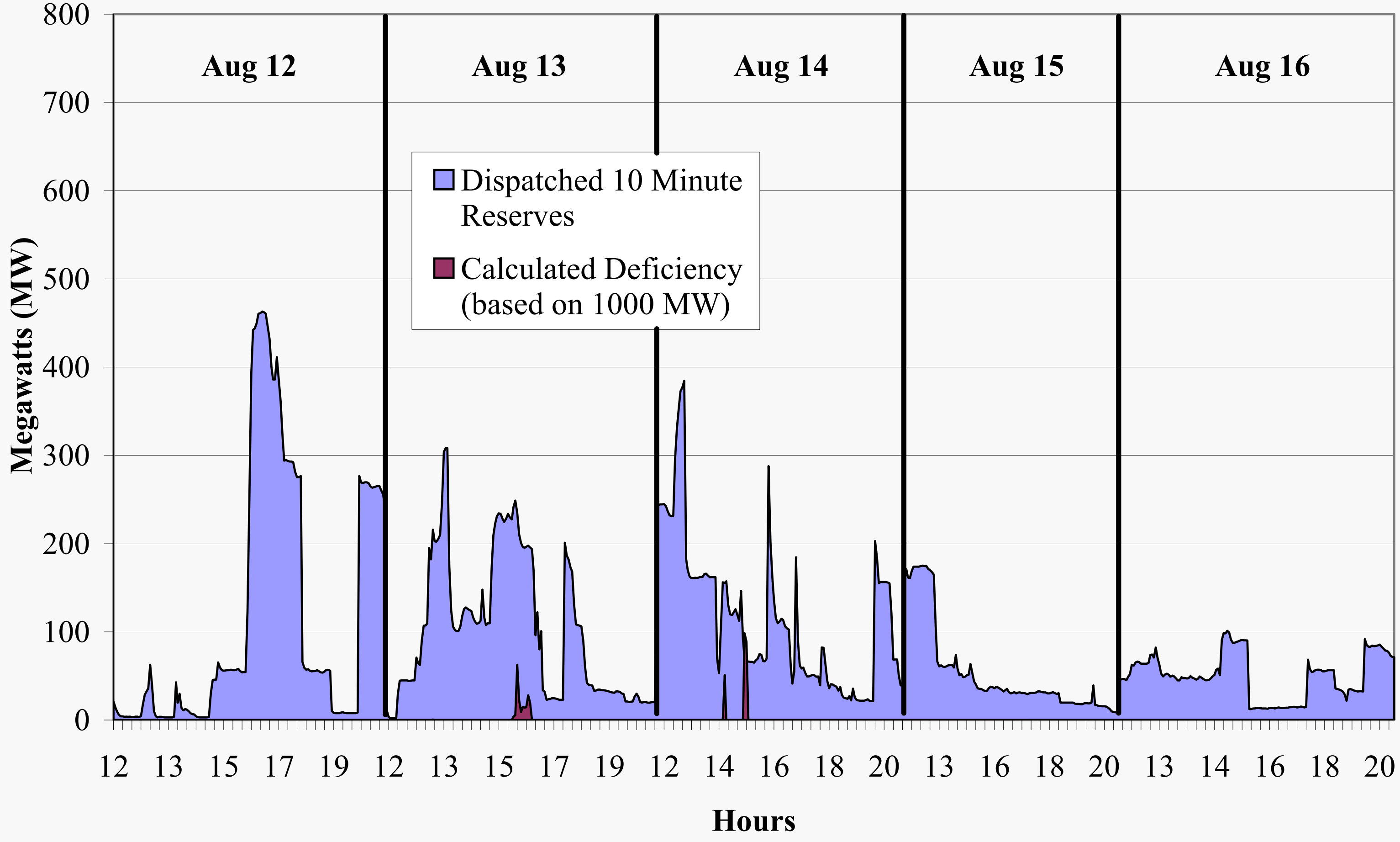


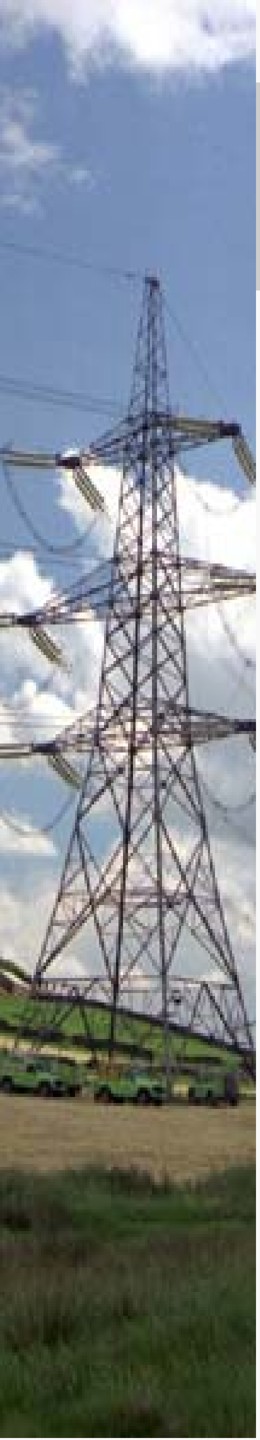
Dispatch of 10-Minute Total Reserves in Eastern New York
July 29, 30, 31, Aug 1, 2 -- 12 p.m. to 8 p.m.





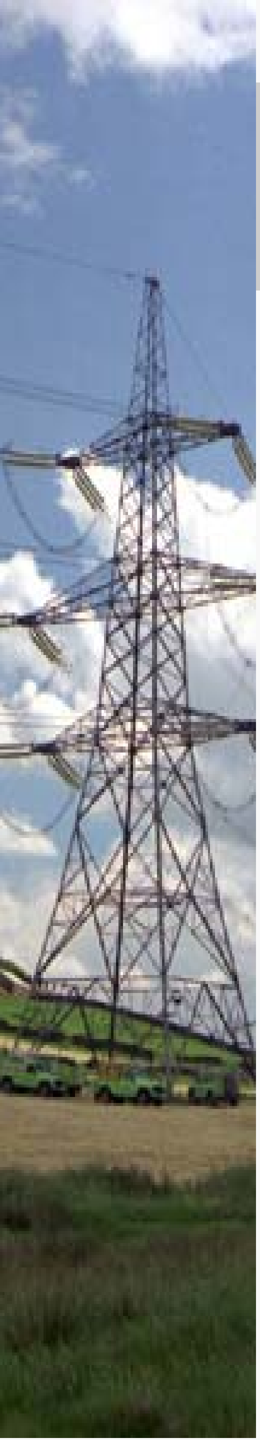
Dispatch of 10-Minute Total Reserves in Eastern New York
August 12-16 -- 12 p.m. to 8 p.m.





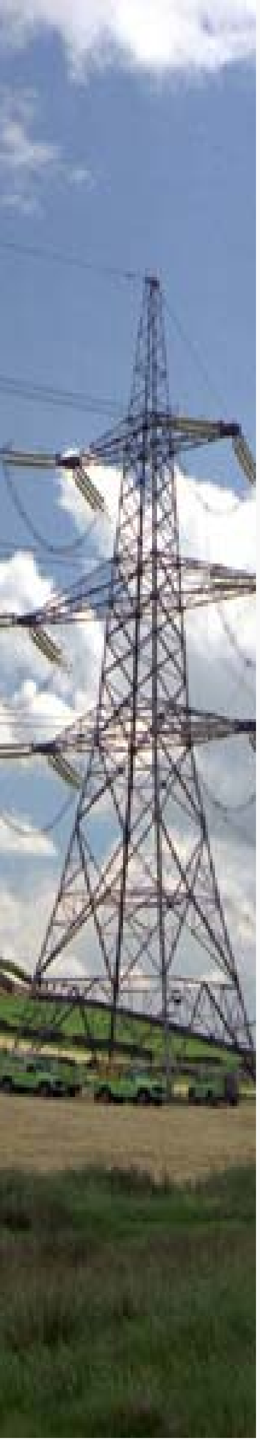
Load Curtailment and Emergency Power

- There are several other ways that the operators may curtail load or call on additional resources:
  - ✓ Calling upon Emergency Demand Response Program, which have the option to curtail load for the higher of $500/MWh or the real-time price.
  - ✓ Calling upon Special Case Resources which have the obligation to curtail load for the higher of $500/MWh or the real-time price. These resources are also eligible for ICAP payments.
  - ✓ Curtailing of exports from capacity resources.
  - ✓ Purchasing emergency power from neighboring control areas.
- Each of these actions can affect real time prices by altering the supplies available to the SCD.

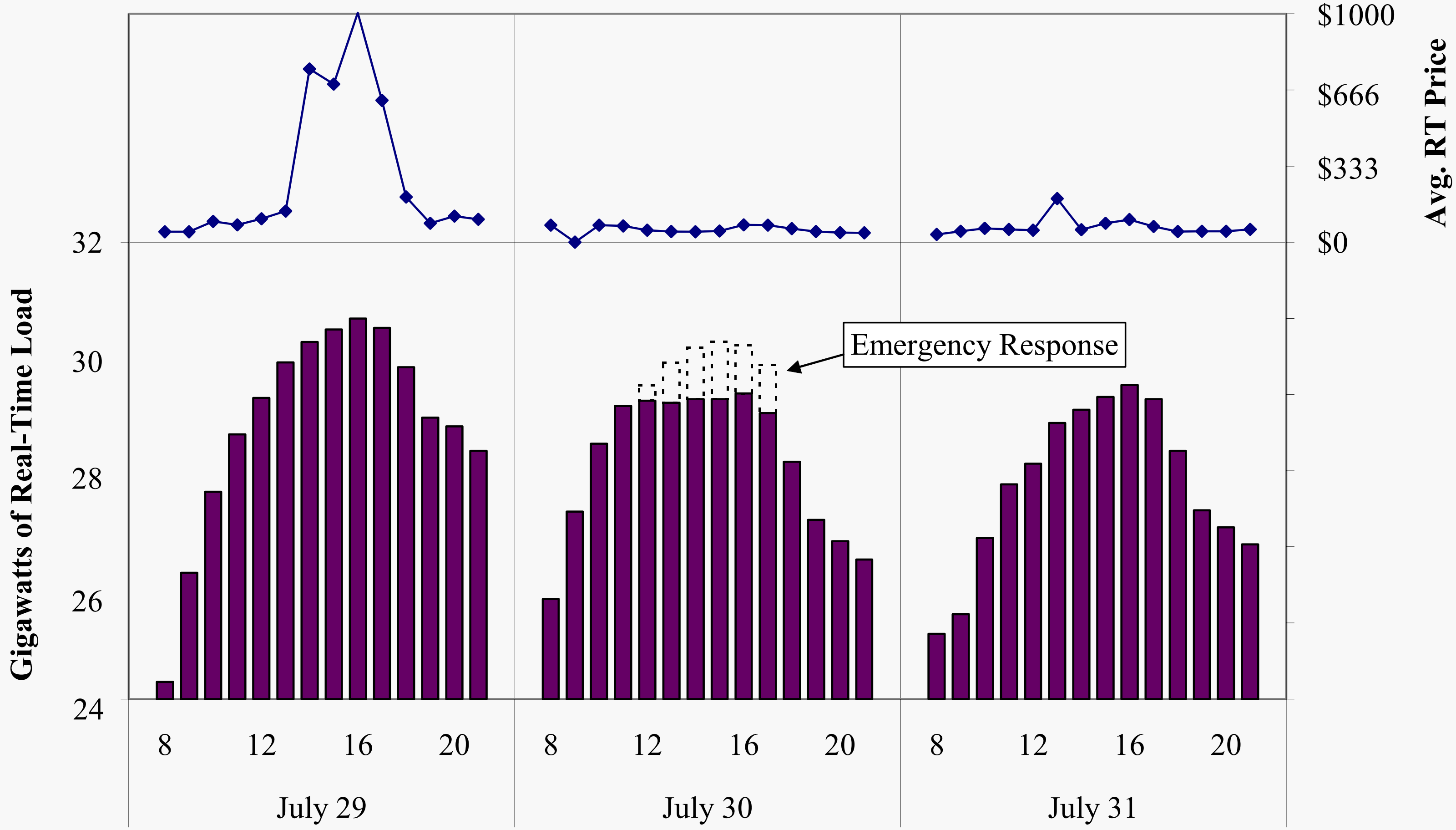


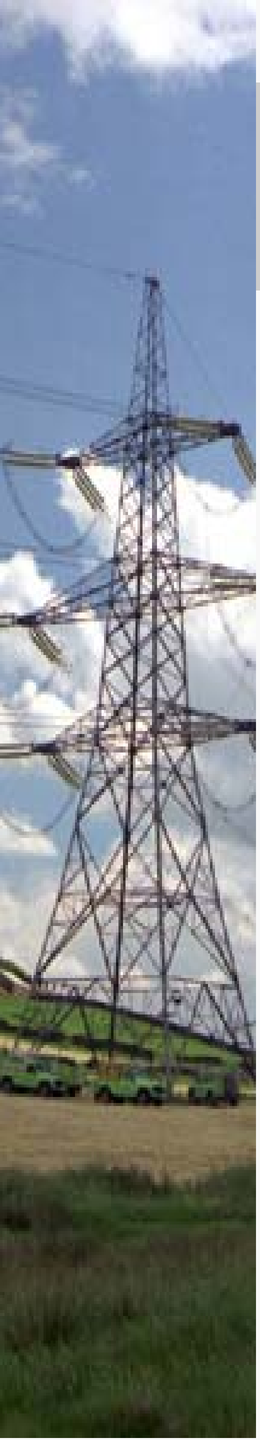
Load Curtailment and Emergency Power

- The following chart show actual loads and real-time prices on the July 30th when the Emergency Demand Response program was invoked.
- The chart also shows an estimate of the demand reduction that was achieved on July 30th – the actual reduction achieved is not yet known.
- Prices under peak conditions can be relatively sensitive to changes in supply or demand conditions, which is consistent with the change in prices from the 29th to the 30th when EDRP was called.
- In addition, EDRP capacity is relatively costly with the participants paid $500 per MWh for each MWh curtailed.



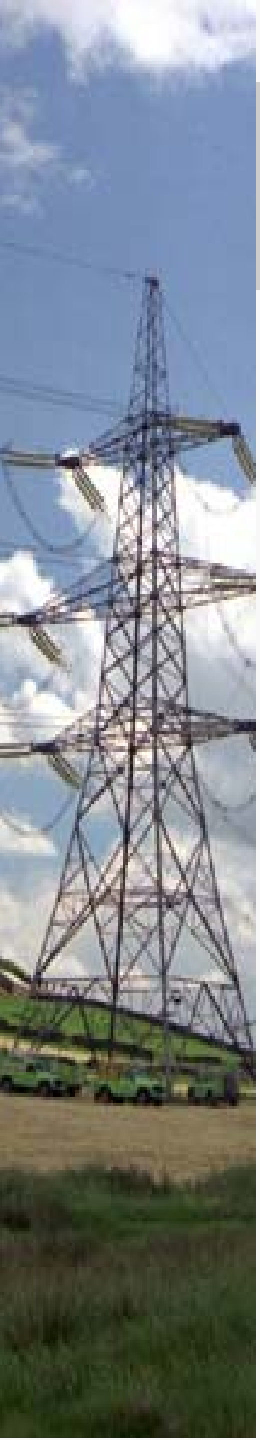
Real-Time Load, Prices, and Emergency Demand Response
New York State





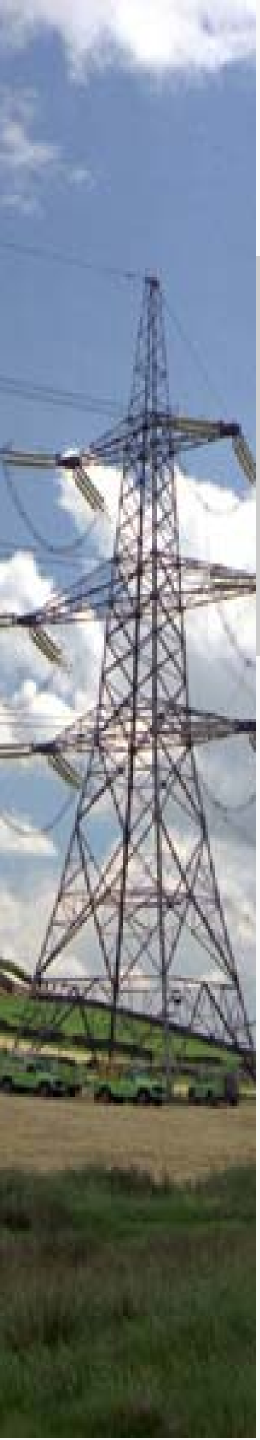
Peak Pricing Recommendations

- The analysis in this section shows that shortages occurred during a number of hours, and were avoided in other hours by calling on high cost demand response, yet the energy prices did not reveal the shortage value of power in many of these periods.
- This problem is inherent in each of the operating wholesale markets and is not addressed by FERC's proposed Standard Market Design ("SMD").
- The RTS provides the means to address this in the longer term through use of a reserve demand curve.
- However, implementing short-term solutions to addressing this issue should be a high priority prior to next summer.
- I recommend that the NYISO assess the feasibility of the following changes to the market rules:
- <u>Demand Response</u>
  - ✓ Allowing EDRP and SCR resources to set energy prices at the level of their payment for curtailing when they are economic.
  - ✓ Allowing EDRP and SCR participants to submit a wider array of curtailment bid prices.

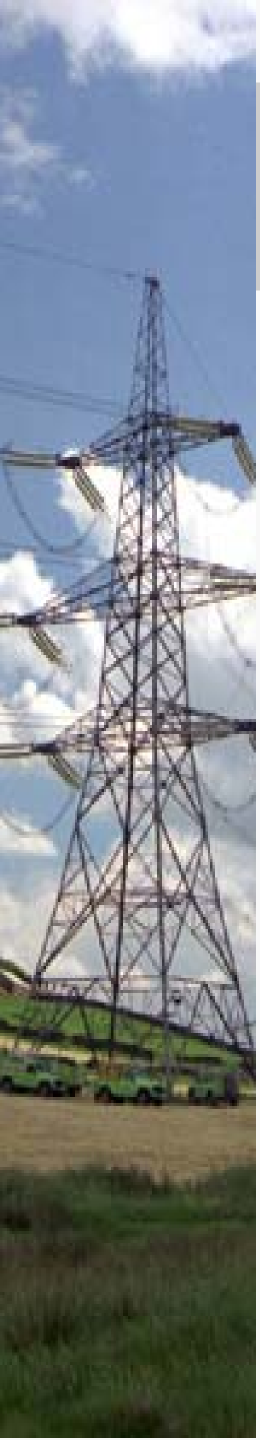


Peak Pricing Recommendations

- Shortage Pricing Provisions
  - ✓ The shadow price signal used to determine real time LMBPs could be increased by an adder amount (i) in all locations within State when the system is deficient in 10-minute spinning or 10-minute total reserves, and (ii) in locations eastern New York when the system is deficient in 10-minute total reserves in the east.
  - ✓ This adder would ensure that when these resources must be dispatched to meet energy requirements, the energy price will be set at an efficient level.
  - ✓ Alternatively, 10-minute reserve segments designated by BME (and generally blocked from dispatch by SCD) could receive an energy bid adder to reflect the cost of not meeting the reserve 10-minute reserve requirement.
  - ✓ The modified bids would only be used for dispatch and pricing purposes in the SCD and would not be used in computing a unit's bid production cost guarantees.
- Improved Operator Information
  - ✓ To ensure that 10-minute reserves committed manually are eligible to set energy prices, the operators should have information regarding when a manually committed unit begins producing energy.
  - ✓ Operators should receive information regarding quantity of GTs that were not relied on to meet forecasted load in the SCUC to ensure that steam units are only committed to meet increased expected load when GTs are not available (comparable to logic employed in the SCUC forecast load pass).

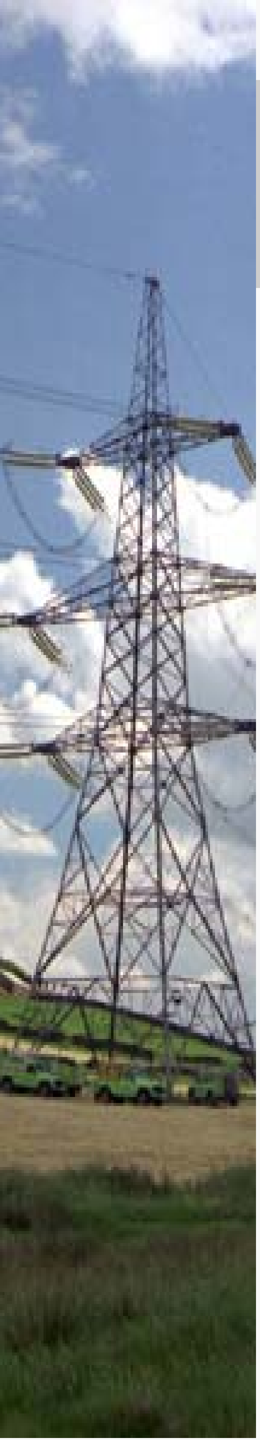


External Transactions During Peak Conditions



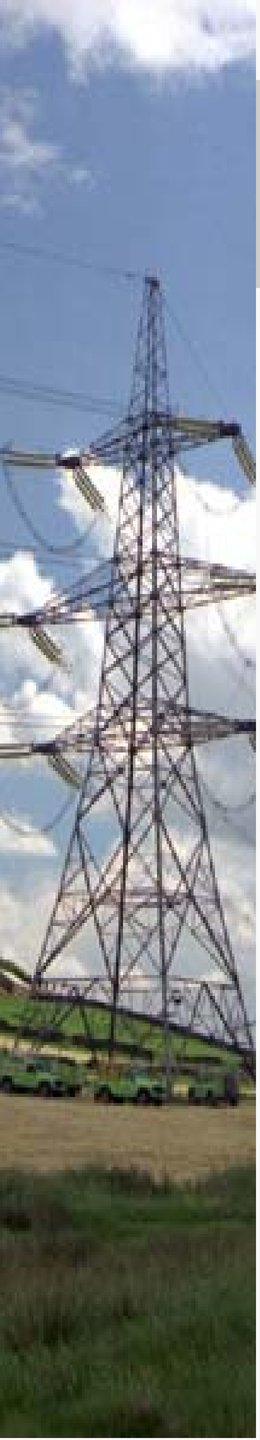
Introduction

- The 2001 Annual Report analyzed the utilization of interfaces between New York and the adjacent markets (ISO-NE and PJM).
  - ✓ Several changes in the transaction scheduling rules and procedures have been made that have improved the utilization of the interfaces.
  - ✓ The arbitrage of the prices between markets has improved through 2001 and early 2002.
  - ✓ However, substantial price differences between New York and adjacent markets have continued to occur under peak demand conditions.
- Efficient trading between the markets is most important under peak conditions when it has the largest effects on the energy prices in each market.
- Therefore, this presentation provides a preliminary analysis of the external transactions with adjacent markets (including Ontario that began market operations under the IMO in May 2002) during peak conditions this summer.



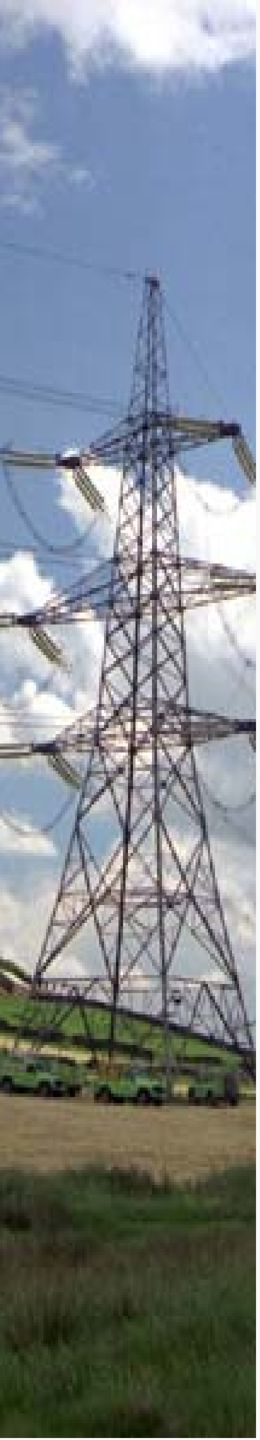
Analytic Methodology

- This analysis examines the scheduled transactions and price differences between New York and adjacent markets to determine the extent to which participants are efficiently arbitraging the market prices.
- This analysis is focused on eight peak days from late June to the end of July 2002.
- To exclude the effects of physical constraints, the analysis excludes hours where the interface constraints or DNI constraint were binding.
- The following would indicate that the interfaces have been scheduled efficiently:
  - ✓ When constraints are not binding, the difference in prices between neighboring control areas should be close to zero.
  - ✓ To the extent that price differences exist, electricity should generally flow from low-priced control areas to high-priced ones.
  - ✓ Market participants should act quickly to arbitrage large price differences.



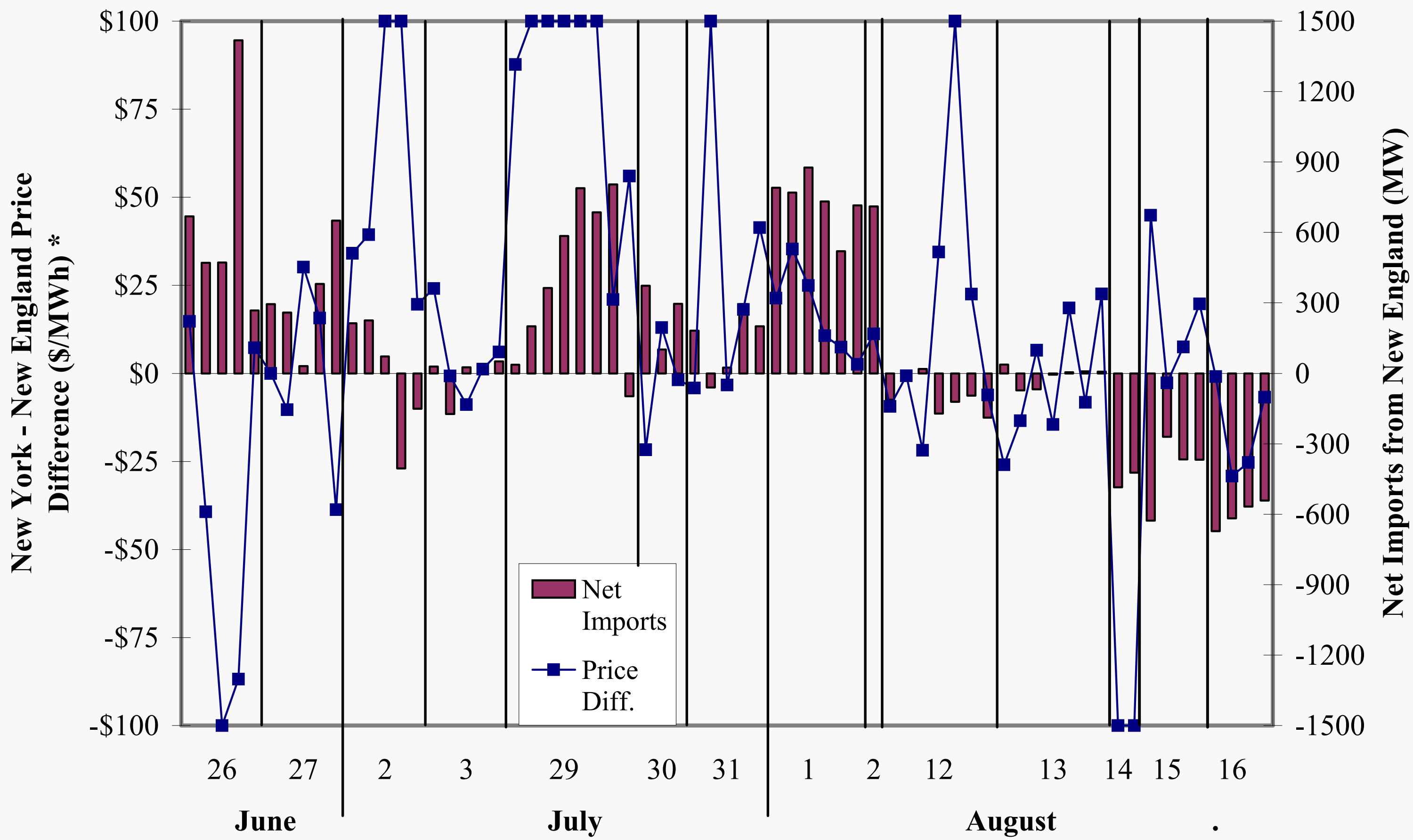
Analysis of Seams

- The following charts show the scheduled net interchange and price difference between New York and the adjacent markets during the peak hours.
- The price differences shown are bounded by $100 and -$100 in these charts to better show the smaller price differences. Additional charts focus particularly on the largest price differences on these days.
- The analysis of the New England interface shows:
  - ✓ There is little evidence that participants responded efficiently to the large price differences that existed on the peak demand days, however transmission outages did prevent exports from New England during some of these hours (e.g., July 2).
  - ✓ In 36% of the hours where constraints were not binding and the price difference exceeded $10, scheduled interchange moved power toward the low priced area.
  - ✓ On July 29th, participants responded to price signals by scheduling additional imports from New England, but not enough to effectively arbitrage the price substantial price differences that continued for six consecutive hours.
  - ✓ There is only a .20 correlation coefficient between the price difference and scheduled interchange.

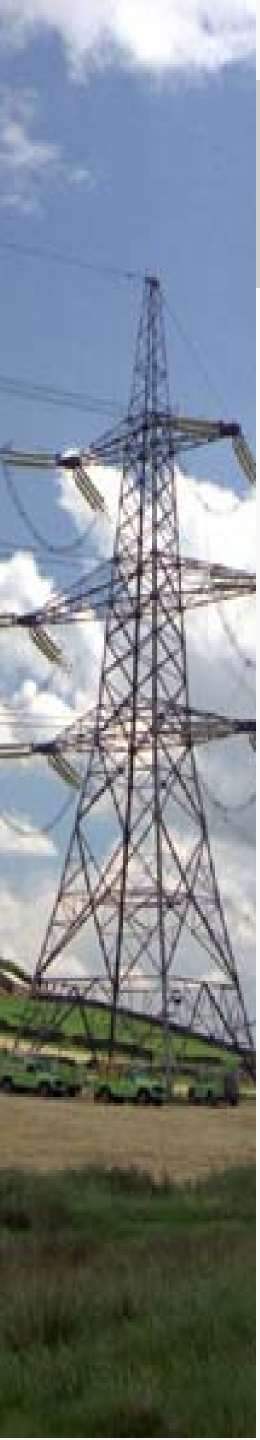


Relationship of Real-Time Prices to Net Imports from New England

Unconstrained Hours from 12 p.m. to 8 p.m. on Peak Days



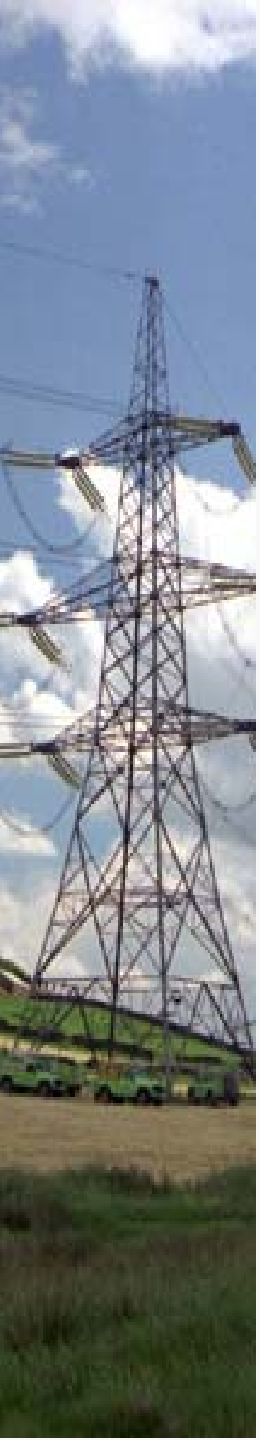
*Price differences are bounded at $100 and- $100. In certain hours, these were as high as $938 and as low as- $643.



Analysis of Seams

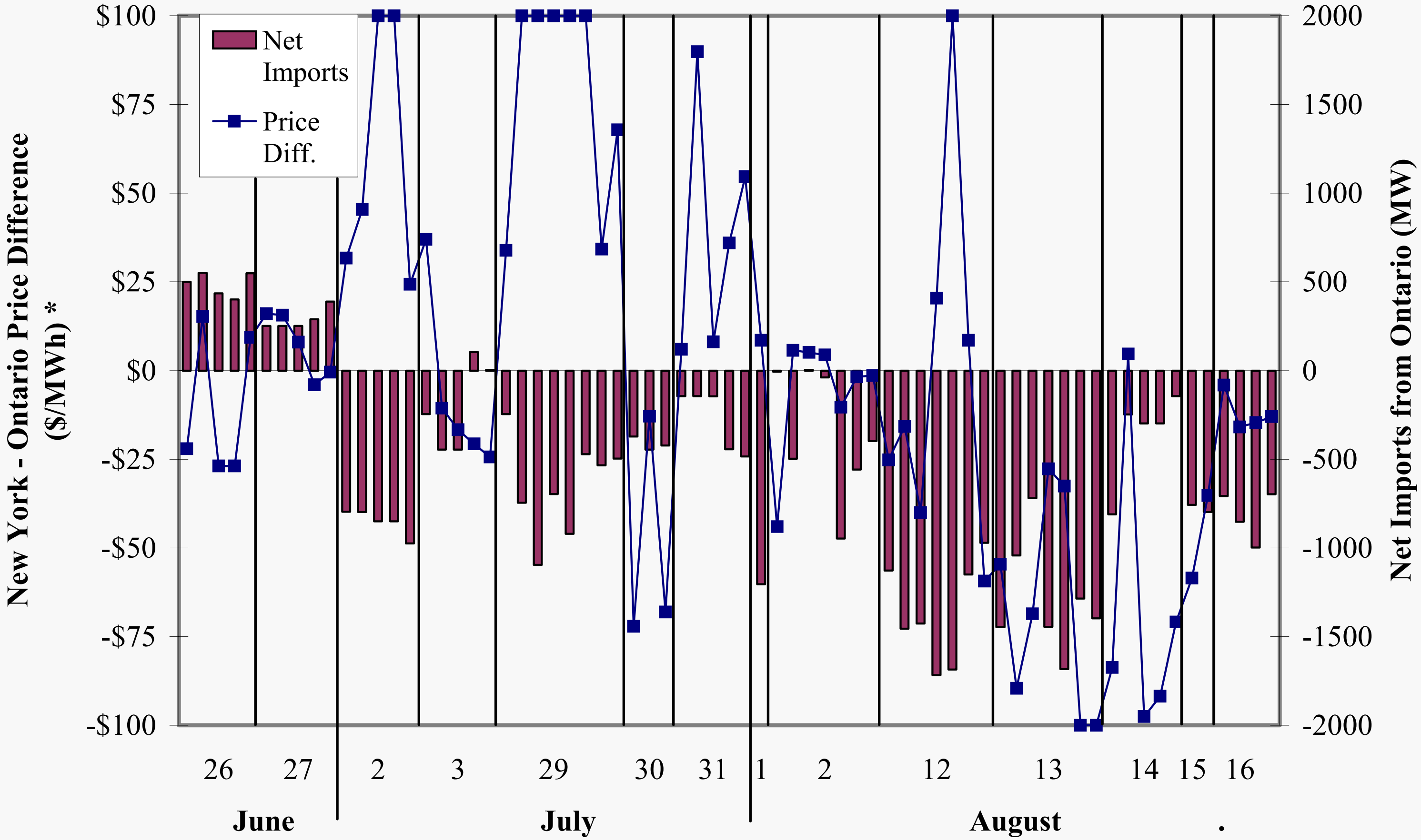
- The analysis of the Ontario interface shows:
  - ✓ There is little evidence that participants were able to schedule transactions to arbitrage significant price differences.
  - ✓ In 44% of the hours where constraints were not binding and the price difference exceeded $10, scheduled interchange moved power toward the low priced area.
  - ✓ There is a negative correlation between price differences and scheduled interchange on this interface.

- The results of the PJM interface show:
  - ✓ New York usually exported to PJM during the peak hours period, even when prices were substantially higher in New York.
  - ✓ There is a slight negative correlation between the price difference and scheduled interchange.

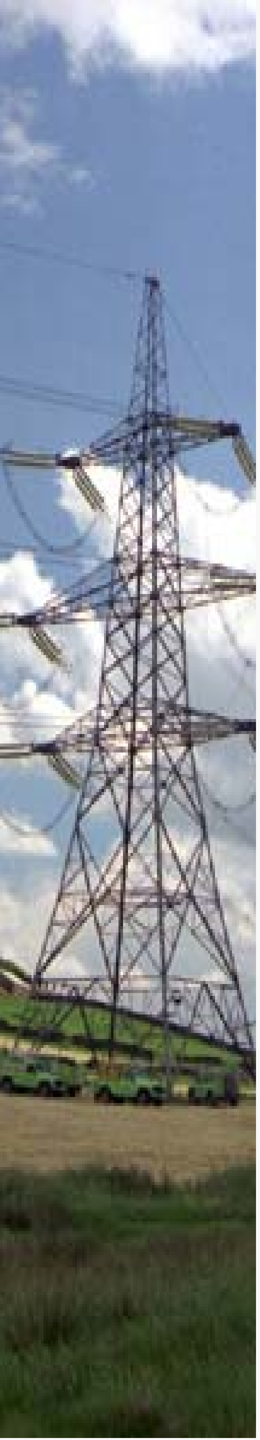


Relationship of Real-Time Prices to Net Imports from Ontario

Unconstrained Hours from 12 p.m. to 8 p.m. on Peak Days

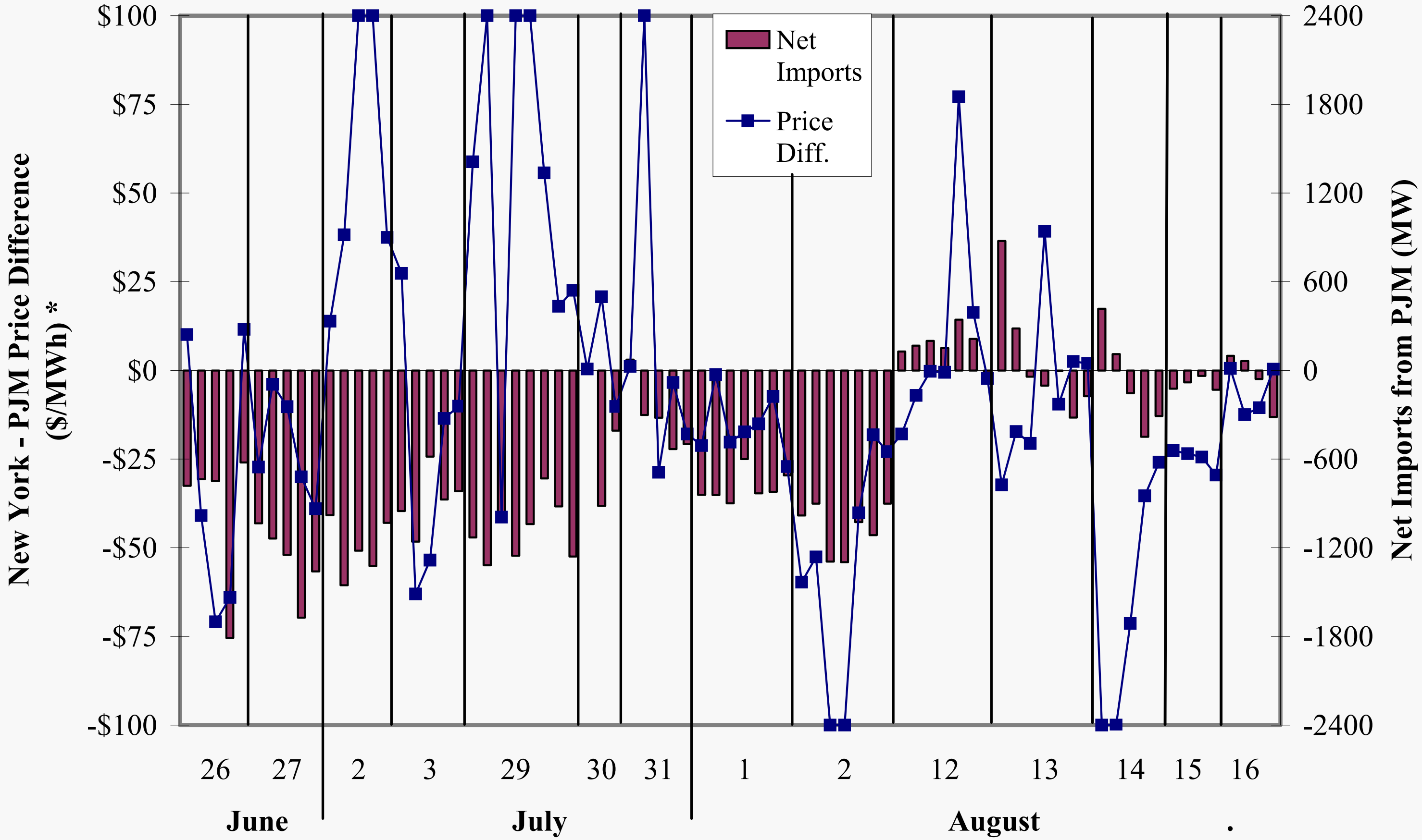


*Price differences are bounded at $100. In certain hours, these were as high as $944 and as low as- $530.

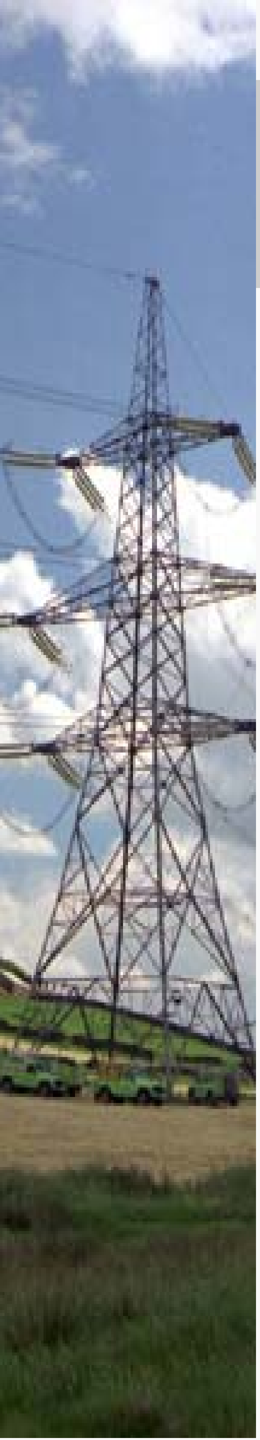


Relationship of Real-Time Prices to Net Imports from PJM

Unconstrained Hours from 12 p.m. to 8 p.m. on Peak Days

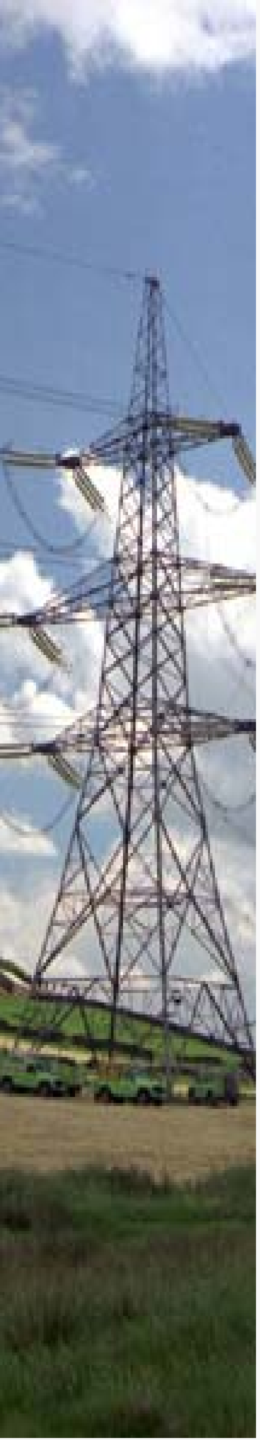


*Price differences are bounded at $100. In certain hours, these were as high as $695 and as low as- $256.



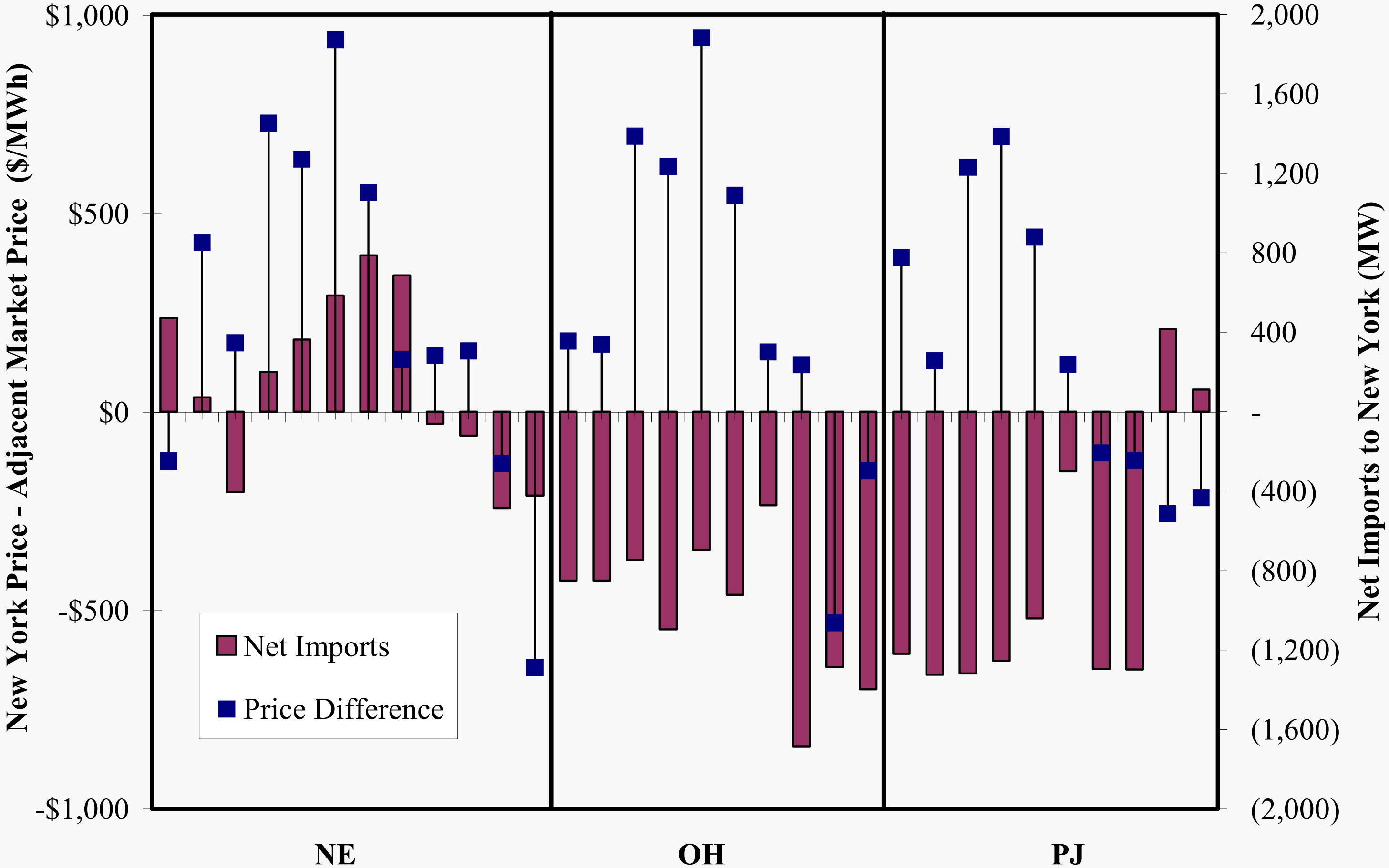
Analysis of the Largest Price Differences

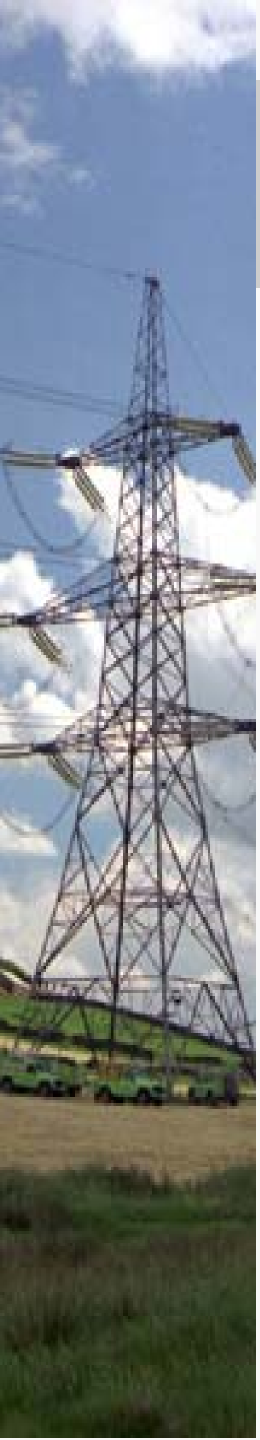
- The economic incentives provided by the markets, as well as the costs of scheduling transactions inefficiently, are the largest when the difference in prices between the markets is the highest.
  - ✓ Therefore, the following two charts focus on those hours when a price difference of more than $100 existing between New York and the adjacent markets.
- This analysis indicates that:
  - ✓ In more than 63 percent of these hours, the net interchange reflects power scheduled from the higher-priced market to the lower priced market;
  - ✓ Power was scheduled toward the low-priced market in nearly every hour on the PJM and Ontario interfaces, contributing to the large price differences.
  - ✓ Hence, the markets have not been efficiently arbitraged under the tightest market conditions, which affects the market in New York and in the adjacent areas.



Relationship of Real-Time Prices to Net Imports from Adjacent Areas

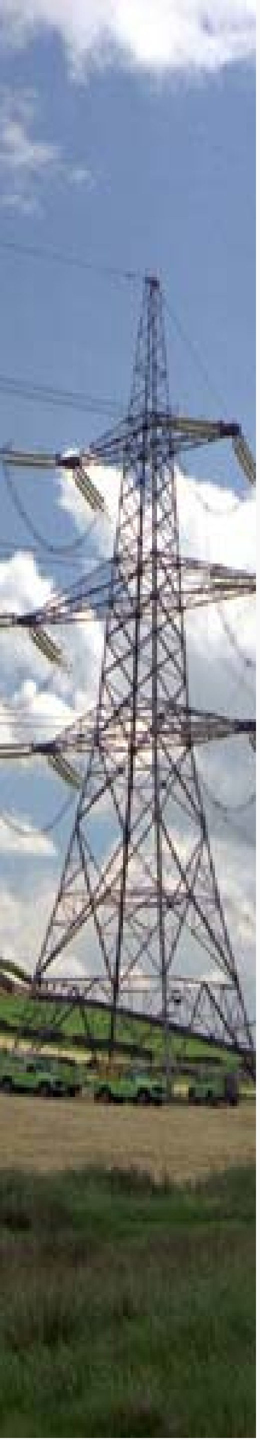
Unconstrained Hours with Price Differences > $100 per MWh



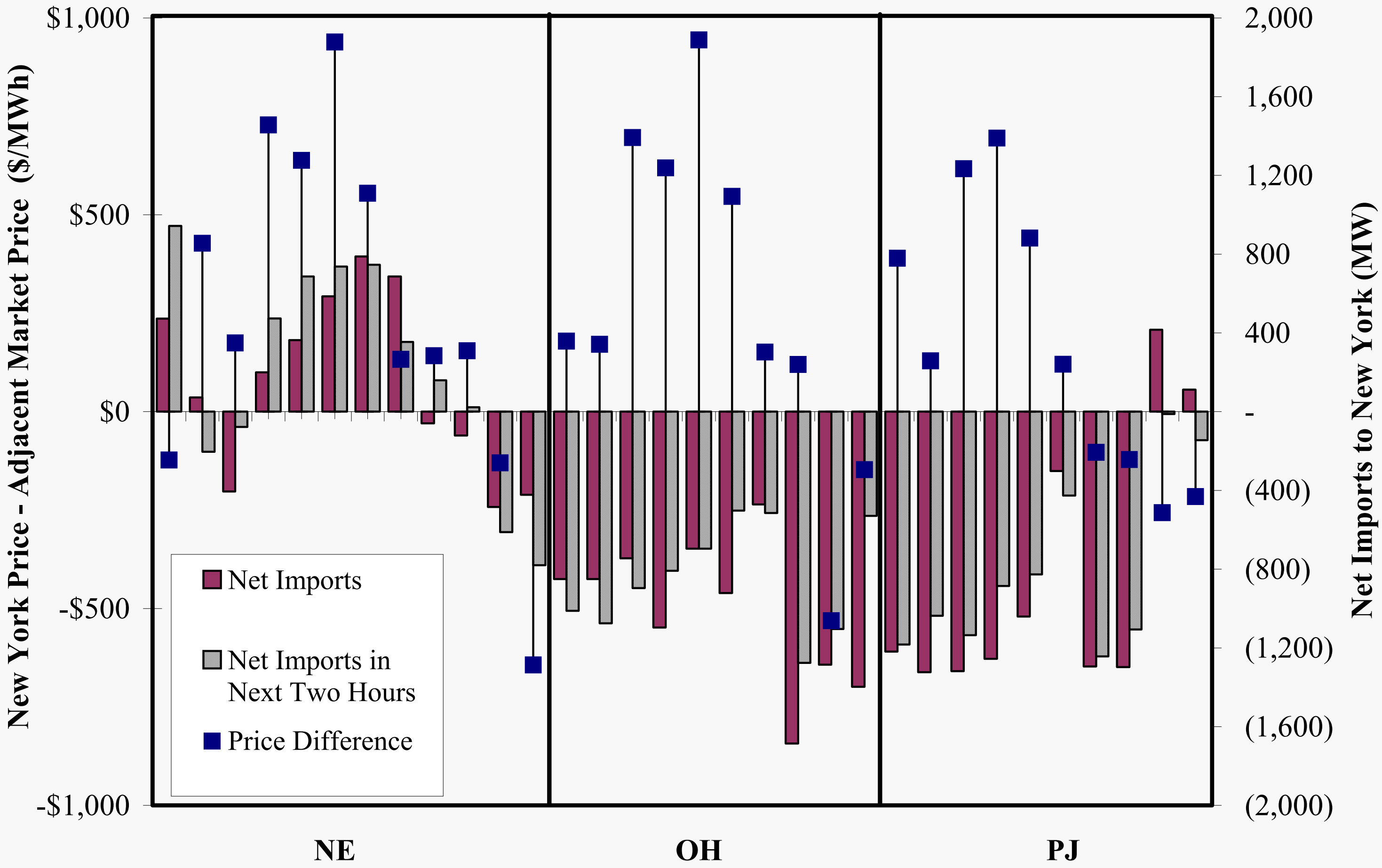


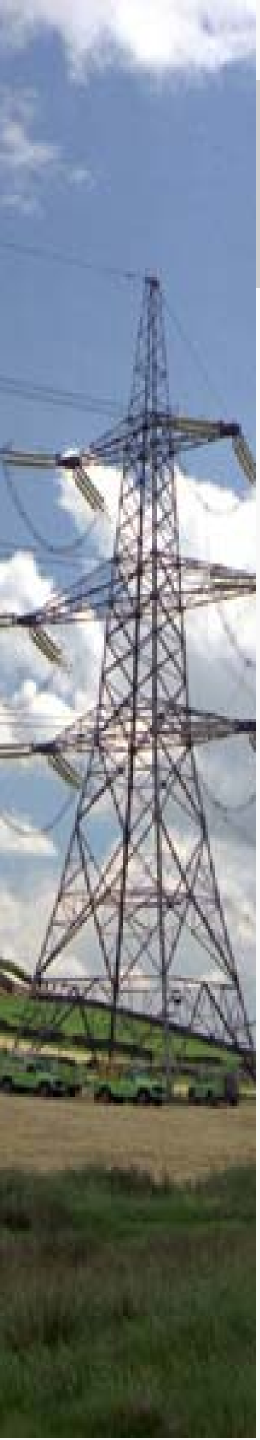
Analysis of the Largest Price Differences

- However, large price differences can arise quickly and their duration is uncertain – hence, they are difficult for participants to predict in advance when hourly transactions are scheduled.
- Therefore, to assess the responsiveness of the transactions to these price differences, we analyze the net interchange in the two hours following the large price differences.
- This analysis is presented in the following chart and shows that the interchange changed only slightly in response to the large price differences. Sometimes these changes were the wrong direction.



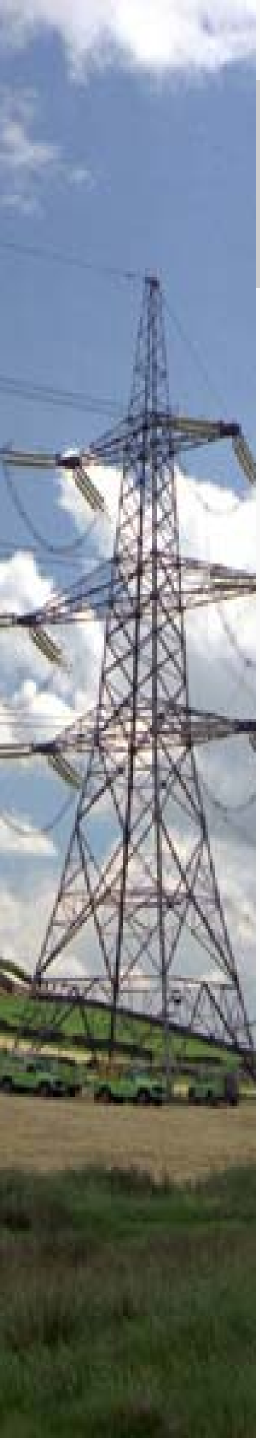
Relationship of Real-Time Prices to Net Imports from Adjacent Areas
Unconstrained Hours with Price Differences > $100 per MWh





Seams Conclusions

- The external transactions during recent peak periods have often resulted in inefficient scheduled flows between New York and adjacent markets. Some factors explaining these results likely include:
  - ✓ Participants must schedule with two separate ISOs more than an hour in advance of the real-time. Therefore, participants must anticipate the price differences.
  - ✓ These price differences can arise and dissipate quickly under peak conditions, creating substantial uncertainty and risk for participants scheduling transactions between control areas.
  - ✓ BME may not recognize the same relative economics between the markets when scheduling price-sensitive imports and exports.



Seams Recommendation

- Improvements have been made to address these factors, but further improvements are needed.
- Many of these improvements would be facilitated by the RTS, including.
  - ✓ Allowing schedule adjustments each 15 minutes;
  - ✓ Providing an ability to be more forward looking in the scheduling process;
  - ✓ Improving the efficiency of prices during capacity shortages;
- I am also recommending changes to the interchange scheduling procedures with the adjacent markets that would allow the physical interchange to be adjusted based on the real-time prices in each area.