Quarterly Report on the New York ISO Electricity Markets First Quarter 2010

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Highlights and Market Summary

- This presentation summarizes the outcomes of the NYISO energy, ancillary services, and capacity markets during the first quarter of 2010.
- The markets performed competitively and variations in wholesale market costs were driven primarily by changes in fuel prices and installed capacity.
- Real-time energy prices averaged $52/MWh statewide, up 11 percent from the prior quarter and down 8 percent from the first quarter of 2009.
  - ✓ Natural gas prices increased 30 percent from the prior quarter, increasing the cost of generation, especially in eastern New York.
  - ✓ Increased supply from Quebec helped lower prices, especially in the west.
- Congestion increased considerably across the Central-East Interface and into Long Island in the first quarter of 2010.
  - ✓ Day-ahead congestion revenue totaled $126 million, up 83 percent from the prior quarter and 48 percent from the first quarter of 2009.
  - ✓ Average real-time energy prices fell to $38/MWh in western New York, down 19 percent from the first quarter of 2009.
  - ✓ Average real-time energy prices rose to $72/MWh in Long Island, up 8 percent from the first quarter of 2009.

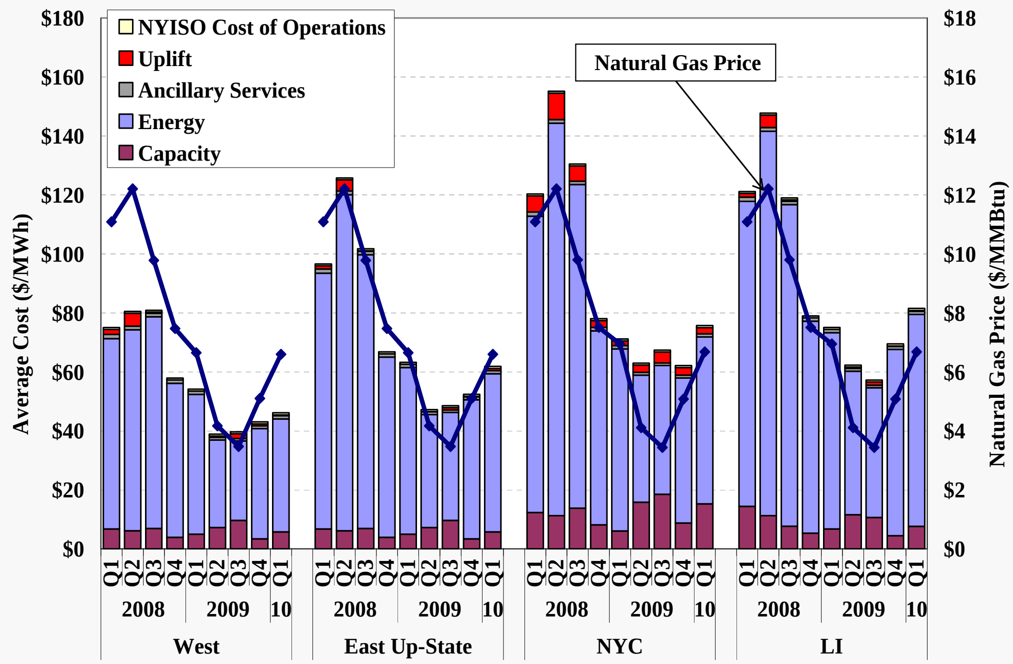
Highlights and Market Summary

- Capacity prices increased in the first quarter of 2010, primarily due to reduced supply following the retirement of the Poletti steam unit.
  - ✓ New York City prices averaged $5.85/kW-month, up from $1.82/kW-month in the same quarter of 2009 when the surplus capacity in the city caused the local requirement not to bind.
  - ✓ Rest-of-State prices (including Long Island) averaged $2.06/kW-month, up 13 percent from the same quarter of 2009.
- Uplift charges rose in the first quarter of 2010 from the first quarter of 2009 as reliability commitments in western New York increased.
  - ✓ Guarantee payments allocated locally totaled $37 million, down 14 percent from the prior quarter and up 19 percent from the first quarter of 2009.
  - ✓ Guarantee payments allocated state-wide totaled $22 million, up 24 percent from the prior quarter and 14 percent from the first quarter of 2009.
  - ✓ Balancing congestion revenue shortfalls remained low at $5 million.
  - ✓ Day-ahead congestion revenue shortfalls rose to $50 million, up 31 percent from the prior quarter and 195 percent from the first quarter of 2009. However, these are partly offset by the revenues from selling excess TCCs.

All-In Energy Price

- To summarize overall price trends in the New York markets, the following figure shows the “all-in” price metric, along with a natural gas price trend.
  - ✓ This includes energy, ancillary services, capacity, uplift, and NYISO costs.
  - ✓ The capacity component is based on spot capacity prices and load obligations in each area, allocated over energy consumption in the area.
  - ✓ The energy component is a load-weighted average real-time energy price.
  - ✓ The NYISO cost of operations and uplift from other Schedule 1 charges are averaged across all consumption in the area.
- All-in prices rose modestly (7 to 23 percent) from the previous quarter due to:
  - ✓ Increased fuel prices (e.g., natural gas prices up 30 percent).
  - ✓ Higher capacity prices from the reduction in New York City capacity.
- All-in prices rose in the east and fell in the west from the first quarter of 2009, reflecting higher capacity prices and more congestion. Congestion rose due to:
  - ✓ Clockwise circulation around Lake Erie rose to an average of 559 MW, up from 113 MW in the first quarter of 2009;
  - ✓ Imports from Hydro Quebec increased an average of 704 MW from the first quarter of 2009; and
  - ✓ The outage of a line into Long Island reduced import capability up to 600 MW.

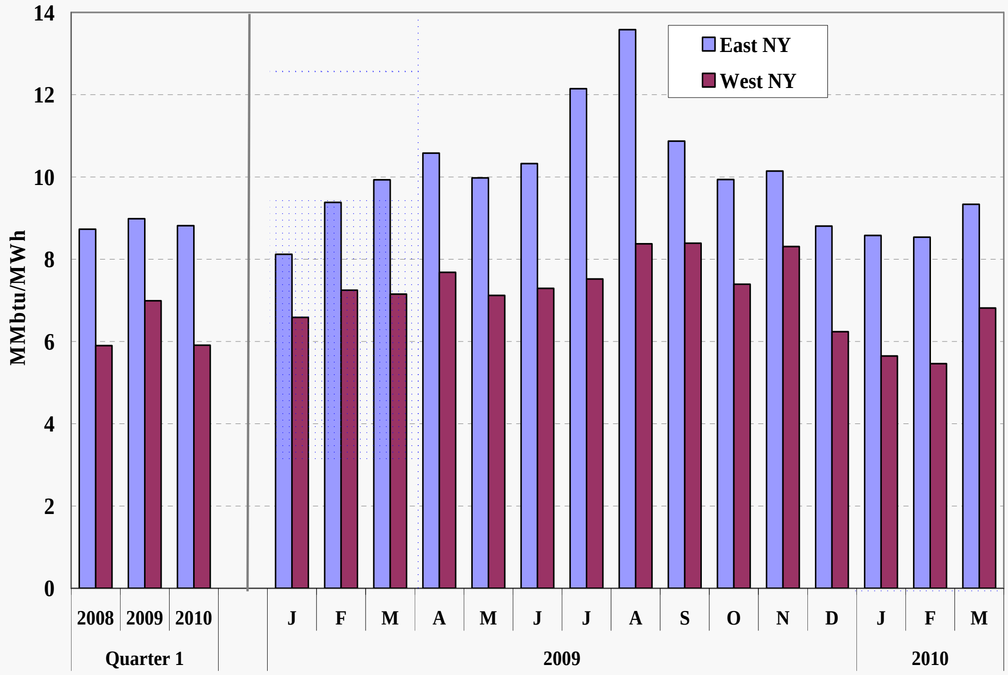
All-In Energy Price by Region



Implied Heat Rate

- To identify changes in electricity prices that are not driven by changes in natural gas prices, the following figure shows the marginal heat rate that would be implied if natural gas were always the marginal fuel.
  - ✓ Implied Gas Heat Rate = (Day-Ahead Electricity Price) ÷ (Natural Gas Price)
- Prices are higher in East New York than in West New York primarily due to transmission losses and congestion across the Central-East interface, into Southeast New York, into New York City load pockets, and into Long Island.
- The implied heat rate remained relatively constant in eastern New York from the first quarter of 2009 to the first quarter of 2010 where natural gas is generally the marginal source of fuel.
- The implied heat rate fell in western New York primarily caused by:
  - ✓ Imports from Hydro Quebec increased an average of 704 MW; and
  - ✓ Clockwise circulation around Lake Erie increased by an average of 446 MW, reducing the amount of transfer capability available to NYISO market participants.

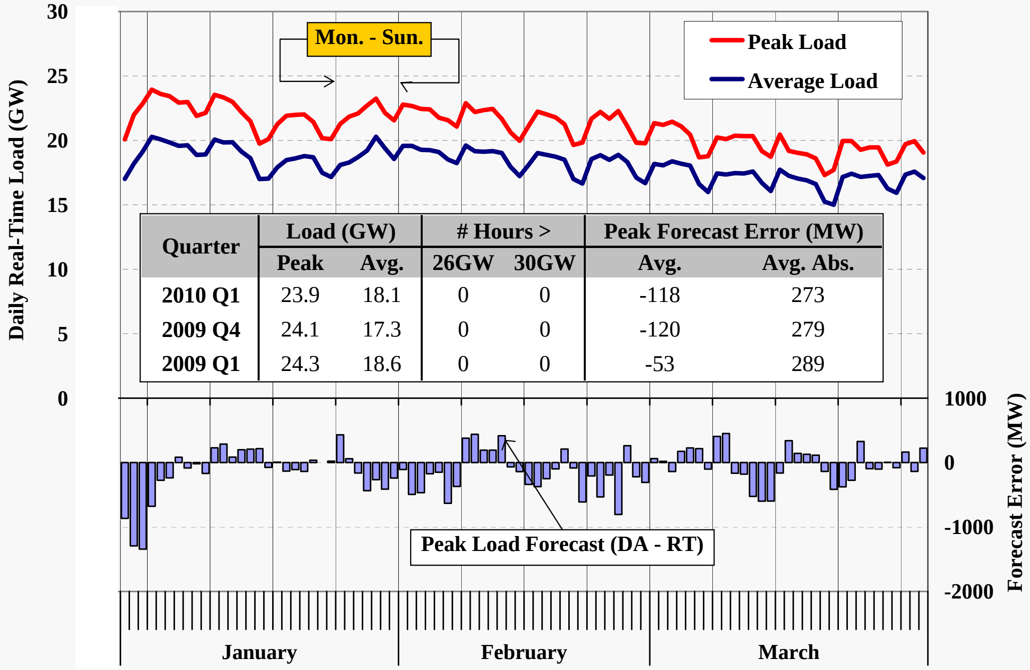
Implied Heat Rate by Region



Load Forecast and Actual Load

- The following figure shows the average load, the peak load, and the day-ahead peak load forecast error on each day of the first quarter.
  - ✓ The table compares key statistics for the first quarter of 2010 to the previous quarter and the first quarter of 2009.
- Load peaked at 23.9 GW on January 4th and then trended down throughout the first quarter.
  - ✓ Peak load was consistent with the previous quarter and the first quarter of 2009, but substantially lower than the winter 2009/10 peak load forecast of 25.0 GW.
  - ✓ The trend of year-over-year reductions in the average load continued with a decrease of 3 percent from the first quarter of 2009, although this was 5 percent higher than the previous quarter.
- The figure also shows that peak load forecasting was generally good, although sustained patterns of errors occurred on a number of days during the quarter.
  - ✓ Actual loads ran over the peak forecast on the first four days of January by an average of nearly 1 GW, contributing to tight real-time operating conditions on those days.

Load Forecast and Actual Load

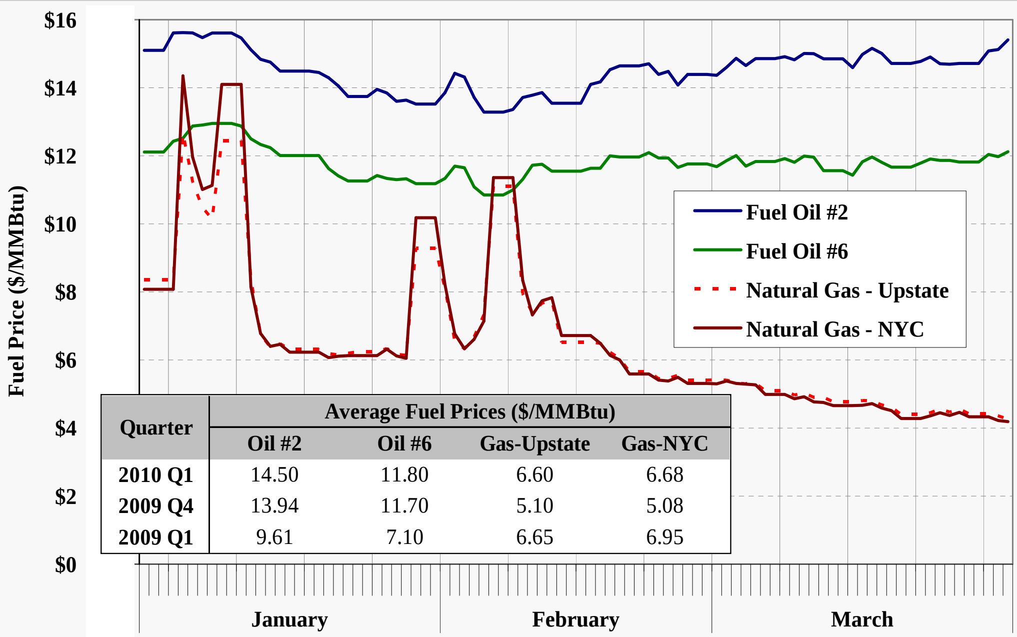


Quarter	Load (GW)		# Hours >		Peak Forecast Error (MW)	
	Peak	Avg.	26GW	30GW	Avg.	Avg. Abs.
2010 Q1	23.9	18.1	0	0	-118	273
2009 Q4	24.1	17.3	0	0	-120	279
2009 Q1	24.3	18.6	0	0	-53	289

Natural Gas and Oil Prices

- The following figure shows daily natural gas and fuel oil prices, which are key determinants of electricity prices.
- Natural gas prices ranged between $4 and $8/MMbtu during most of the first quarter, although prices spiked as high as $14/MMbtu on several days.
  - ✓ During these events, there was price separation of up to 12 percent between the Transco Zone 6 and Iroquois Zone 2.
- Average natural gas prices increased 30 percent from the previous quarter. In contrast, average fuel oil prices rose only slightly (4 percent for Oil #2 and 1 percent for Oil #6).
  - ✓ The increase in natural gas prices made many gas-fired generators less competitive with coal-fired generators, increasing the production of electricity from coal-fired units.
- Average natural gas prices were comparable to the first quarter of 2009, while fuel oil prices rose considerably over the same period (51 percent for Oil #2 and 66 percent for Oil #6).
  - ✓ The increased margin between fuel oil prices and natural gas prices has reduced oil-fired generation. However, some generators still burn fuel oil for reliability reasons or due to difficulties they face obtaining natural gas.

Natural Gas and Oil Prices



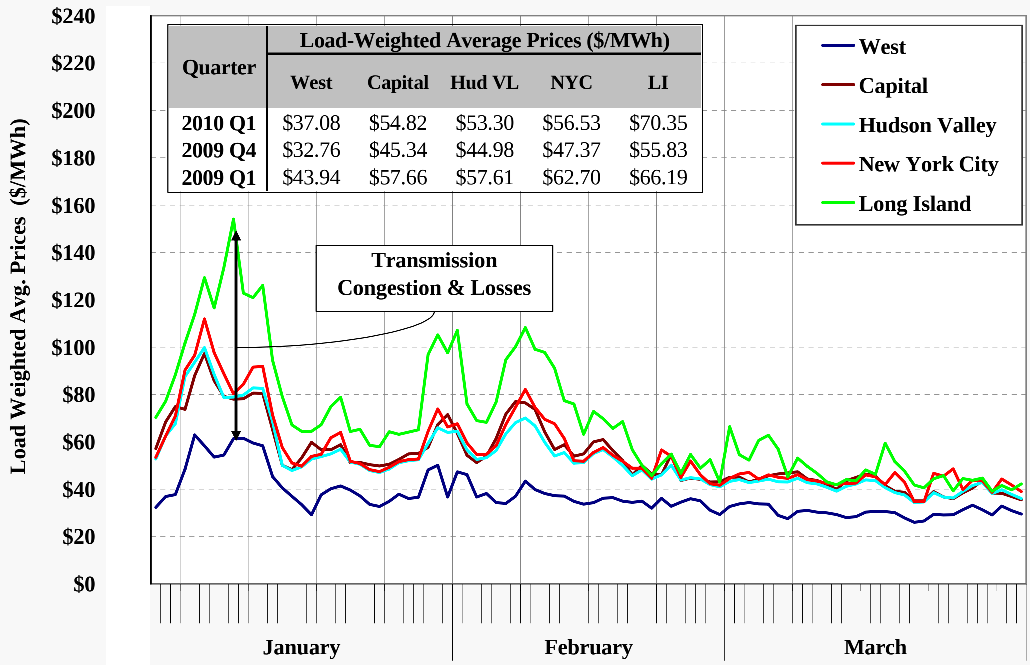
Quarter	Average Fuel Prices ($/MMBtu)			
	Oil #2	Oil #6	Gas-Upstate	Gas-NYC
2010 Q1	14.50	11.80	6.60	6.68
2009 Q4	13.94	11.70	5.10	5.08
2009 Q1	9.61	7.10	6.65	6.95

Note: Natural Gas Price for NYC is Transco zone 6 price and for upstate is Iroquois zone 2

Day-Ahead Electricity Prices by Zone

- The following figure shows load-weighted average day-ahead energy prices for five Zones on each day in the first quarter.
- Prices in the day-ahead market reflect probability-weighted expectations of real-time market conditions.
- Price differences between the West Zone and Capital Zone were driven by both expected congestion across the Central-East interface and expected transmission losses.
- Price differences between Long Island and the rest of New York were increased by the outage of the Sprainbrook-to-East Garden City line, one of the two lines connecting Long Island to up-state New York.
  - ✓ Congestion into Long Island was reduced after the line came back in service on February 20.
- Natural gas prices were volatile in January and early February, and then fell through the end of the quarter.
  - ✓ The largest congestion-related price differences occurred during periods of volatile natural gas prices.
  - ✓ The decline in natural gas prices led to smaller congestion-related price differences between the West Zone and Capital Zone.

Day-Ahead Electricity Prices by Zone

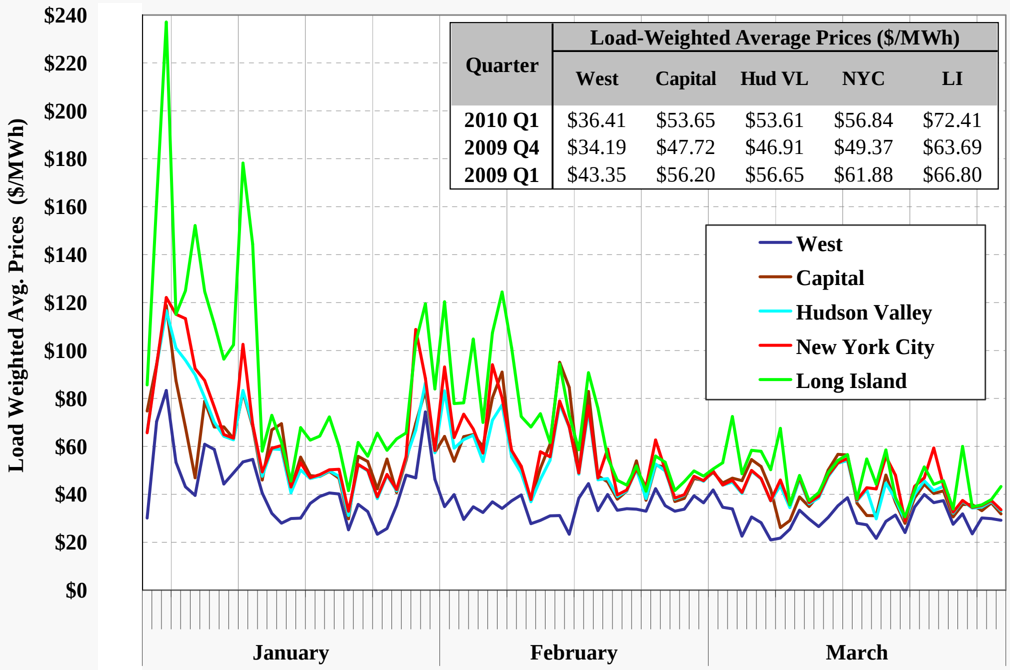


Quarter	Load-Weighted Average Prices ($/MWh)				
	West	Capital	Hud VL	NYC	LI
2010 Q1	$37.08	$54.82	$53.30	$56.53	$70.35
2009 Q4	$32.76	$45.34	$44.98	$47.37	$55.83
2009 Q1	$43.94	$57.66	$57.61	$62.70	$66.19

Real-Time Electricity Prices by Zone

- The following figure shows load-weighted average real-time energy prices for five zones on each day in the first quarter.
  - ✓ Prices are considerably more volatile in the real-time market than in the day-ahead market.
- Daily average real-time price differences between the West Zone and the Capital Zone spiked over $30/MWh on 12 days in the first half of January and the first half of February. These were driven by:
  - ✓ High natural gas prices, which affect generation costs in the east;
  - ✓ Clockwise circulation around Lake Erie, which averaged 614 MW on these days; and
  - ✓ Generation and transmission outages that reduced Central East transfer capability on several days.
- Daily average real-time prices in Long Island exceeded $120/MWh on 9 days before the return of the Sprainbrook-to-East Garden City line on February 20.
  - ✓ Long Island prices were increased partly due to unexpected events such as operational flow orders, natural gas price spikes, and reduced imports across the Neptune cable as a result of TLRs.

Real-Time Electricity Prices by Zone



Quarter	Load-Weighted Average Prices ($/MWh)				
	West	Capital	Hud VL	NYC	LI
2010 Q1	$36.41	$53.65	$53.61	$56.84	$72.41
2009 Q4	$34.19	$47.72	$46.91	$49.37	$63.69
2009 Q1	$43.35	$56.20	$56.65	$61.88	$66.80

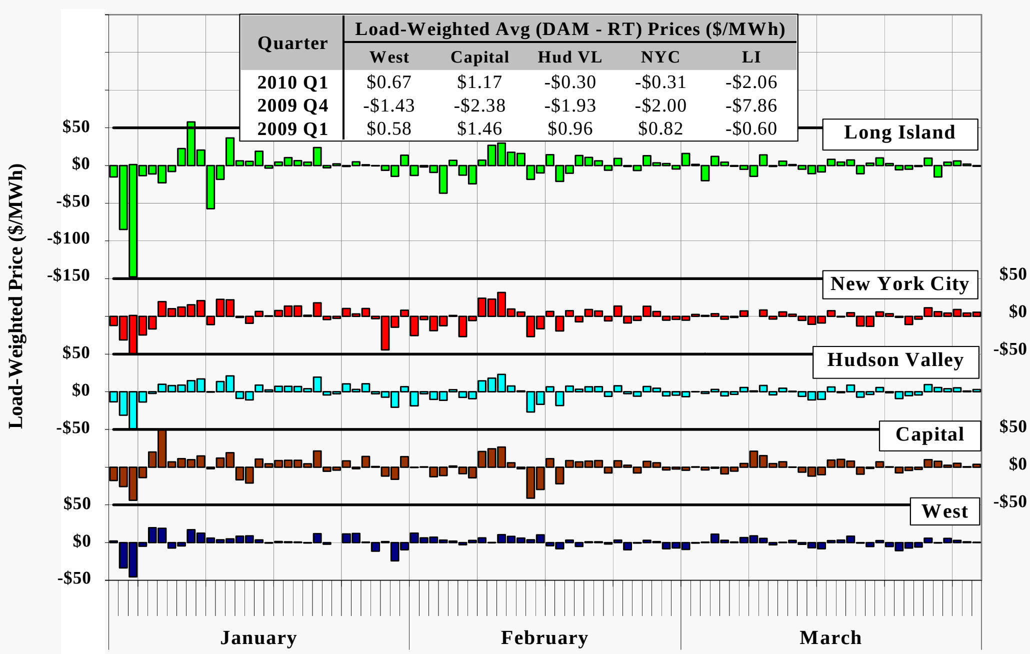
Convergence Between Day-Ahead and Real-Time Prices

- The next analysis evaluates day-ahead and real-time price convergence, which is important because the day-ahead market facilitates the daily commitment of generation, and most settlement occurs through the day-ahead market.
- The following figure shows the difference between average day-ahead prices and the average real-time prices on each day in the first quarter of 2010.
  - ✓ This is shown separately for five zones to account for changes in the pattern of congestion from the day-ahead to the real-time.
  - ✓ For example, convergence was good in the West Zone on February 13, but the eastern zones exhibited large real-time premiums due to congestion across Central-East that was not fully anticipated in the day-ahead market.
- Large differences between average day-ahead prices and average real-time prices occurred frequently on individual days due to unexpected factors.
  - ✓ Convergence should be measured over longer timeframes, since random factors can cause convergence on individual days to be poor. The table shows the average price convergence over the entire quarter.
  - ✓ Average day-ahead prices for the first quarter were generally consistent with real-time prices, as the differences between average day-ahead prices and average real-time prices were 3 percent or less at each location.

Convergence Between Day-Ahead and Real-Time Prices

- January 2 & 3 exhibited the largest differences between day-ahead prices and real-time prices due to unexpected conditions, including:
  - ✓ Reduced imports to Long Island because the Cross Sound Cable tripped offline on January 2 and remained out-of-service the next day;
  - ✓ An operational flow order on the New York City gas system limited the availability of some generators on January 3; and
  - ✓ High winter loads that exceeded the peak load forecast by up to 1.3 GW.
- Convergence between day-ahead and real-time prices improved for all locations from the fourth quarter of 2009 to the first quarter of 2010.
  - ✓ This was most evident in Long Island where the difference declined from 12 percent in the fourth quarter of 2009 to 3 percent in the first quarter of 2010.
    - – The initial outage of the Sprainbrook-to-East Garden City line in December 2009 contributed to the poor convergence in the fourth quarter of 2009.
  - ✓ The differences in other areas declined from about 5 percent in the fourth quarter of 2009 to less than 2 percent in the first quarter of 2010.

Convergence Between Day-Ahead and Real-Time Prices



Quarter	Load-Weighted Avg (DAM - RT) Prices ($/MWh)				
	West	Capital	Hud VL	NYC	LI
2010 Q1	$0.67	$1.17	-$0.30	-$0.31	-$2.06
2009 Q4	-$1.43	-$2.38	-$1.93	-$2.00	-$7.86
2009 Q1	$0.58	$1.46	$0.96	$0.82	-$0.60

Day-Ahead and Real-Time Ancillary Services Prices

- The following two figures summarize average day-ahead and real-time clearing prices on a daily basis for four key ancillary services products:
  - ✓ 10-minute spinning reserves prices in eastern New York, which reflect the cost of requiring:
    - 300 MW of 10-minute spinning reserves in eastern New York;
    - 600 MW of 10-minute spinning reserves state-wide; and
    - 1,000 MW of 10-minute total reserves (spinning and non-spinning reserves) in eastern New York.
  - ✓ 10-minute non-spinning reserves prices in eastern New York, which reflect the cost of requiring 1,000 MW of 10-minute total reserves in eastern NY.
  - ✓ 10-minute spinning reserves prices in western New York, which reflect the cost of requiring 600 MW of 10-minute spinning reserves state-wide.
  - ✓ Regulation prices, which reflect the cost of requiring up to 275 MW of regulation, depending upon season and time of day.
- The table in each figure shows the number of intervals when the real-time reserve price of the product was affected by a shortage of reserves.
  - ✓ During shortages, the prices of products that can satisfy the given requirement will include the "demand curve" value of the requirement.

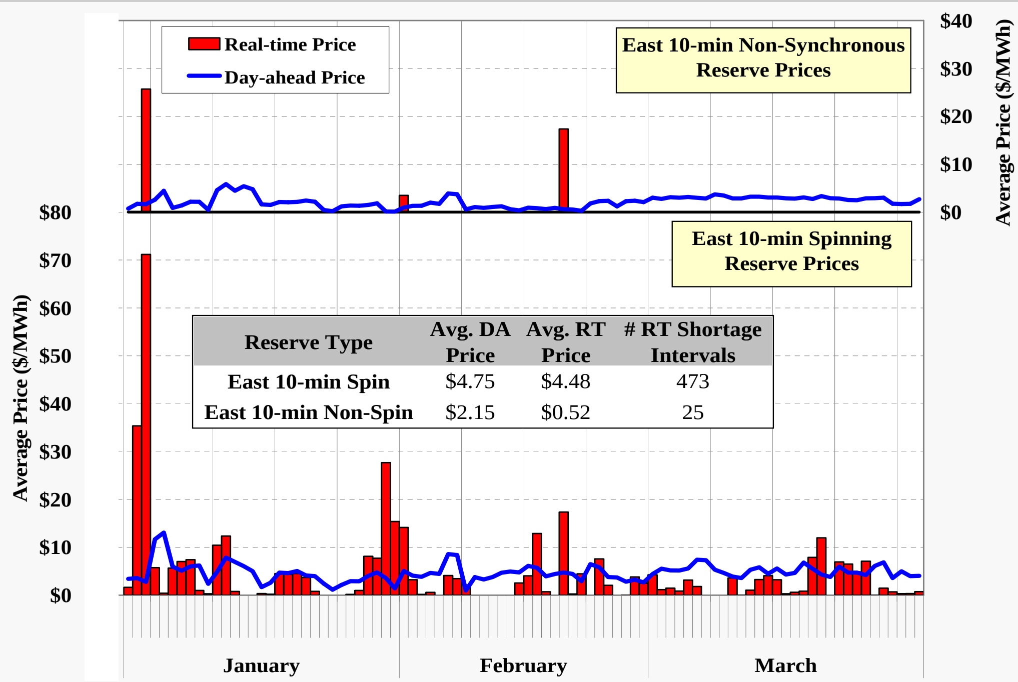
Day-Ahead and Real-Time Ancillary Services Prices

- Reserves prices are relatively consistent in the day-ahead, but are much more volatile in the real-time market.
  - ✓ Day-ahead reserves prices are based on suppliers' offers, which depend on expectations of real-time prices and the risks associated with selling reserves in the day-ahead market.
  - ✓ Real-time reserves prices are normally close to $0 due to the excess available reserves from online and quick-start units in most hours.
  - ✓ Real-time prices spike during periods of tight supply and high energy demand, which can be difficult for the day-ahead market to predict.
- Average day-ahead 10-minute non-spin reserves prices in Eastern New York were substantially higher than average real-time reserves prices in the first quarter of 2010.
  - ✓ However, average day-ahead reserve prices did not rise substantially on high load days when average real-time prices were high due to tight conditions.
- Average day-ahead regulation and 10-minute spin prices were relatively consistent with real-time prices.

Day-Ahead and Real-Time Ancillary Services Prices

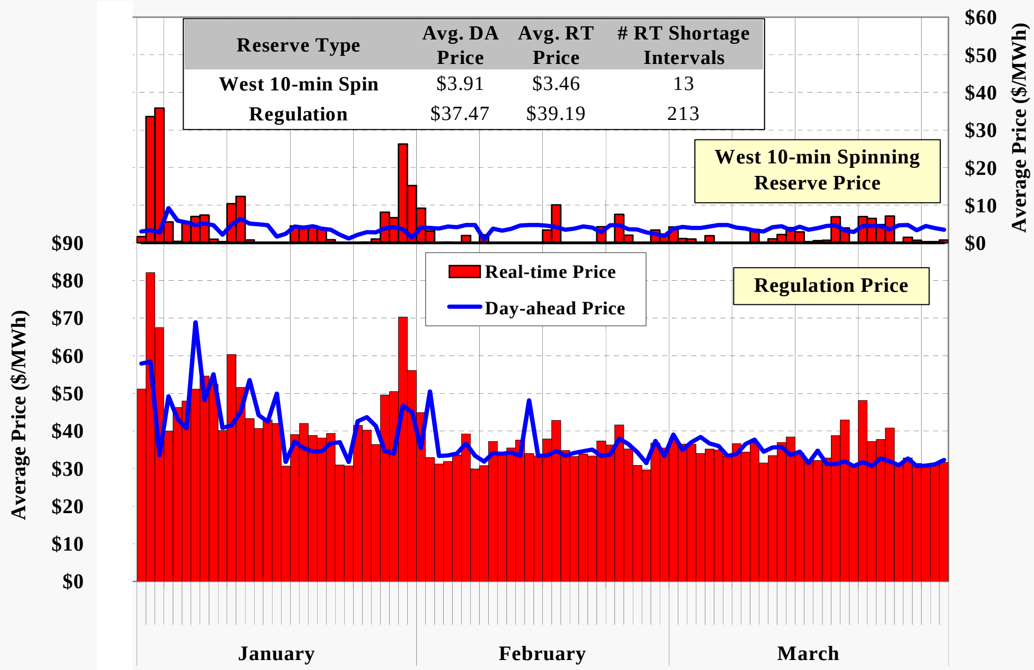
- A shortage occurs when a reserve requirement cannot be satisfied at a marginal cost less than its “demand curve”. Shortages occurred in RT for:
  - ✓ Eastern 10-minute spinning reserves in 435 intervals ($25 demand curve), 42 percent of which occurred during periods with Central-East congestion;
  - ✓ Eastern 10-minute total reserves in 25 intervals ($500 demand curve);
  - ✓ State-wide 10-min spinning reserves in 13 intervals ($500 demand curve); and
  - ✓ Regulation in 213 intervals ($250 to $300 demand curve).
- Prices for a product include the demand curve value for all requirements that the product can satisfy.
  - ✓ For example, the 10-minute spinning reserve prices in the east reflect 473 intervals of shortage pricing : (1) 435 of eastern 10-minute spin, (2) 25 of eastern 10-minute total reserves, and (3) 13 of state-wide 10-minute spin.
- The number of eastern 10-minute spinning reserve shortages rose from prior months partly due to increased Central-East congestion.
  - ✓ It is more important to secure Central East than to hold spin in eastern New York, so the real-time model frequently dispatches-up spinning reserve units.
  - ✓ The largest shortages occurred on January 2 & 3 for reasons discussed earlier.

Day-Ahead and Real-Time Ancillary Services Prices
Eastern 10-Minute Spinning and Non-Spinning Reserves



Day-Ahead and Real-Time Ancillary Services Prices

Western 10-Minute Spinning Reserves and Regulation



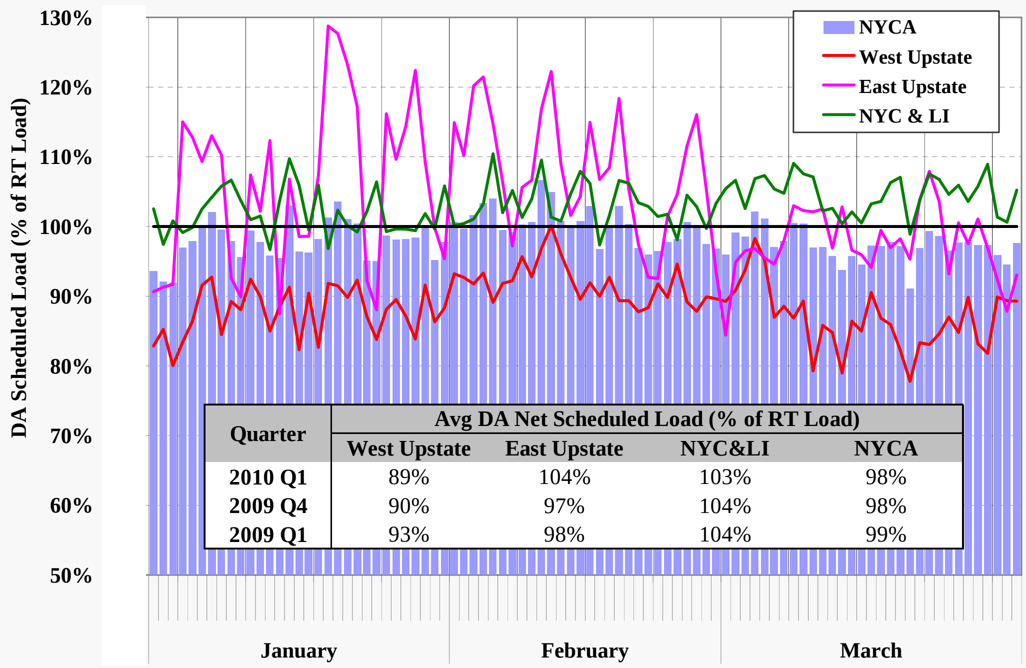
Reserve Type	Avg. DA Price	Avg. RT Price	# RT Shortage Intervals
West 10-min Spin	$3.91	$3.46	13
Regulation	$37.47	$39.19	213

Day-ahead Scheduled Load and Actual Load

- The following figure summarizes the quantity of day-ahead load scheduled as a percent of real-time load in each of three regions and state-wide.
  - ✓ Net scheduled load = Physical Bilaterals + Fixed Load + Price-Capped Load + Virtual Load – Virtual Supply
- The average amount of load scheduled state-wide in the day-ahead market is relatively consistent with the average amount of real-time load.
- Load was generally over-scheduled into New York City and Long Island, reflecting the anticipated congestion into those areas and across the Central-East Interface.
- Load was over-scheduled in eastern up-state New York, particularly on weekdays in January and February.
  - ✓ Load was over-scheduled by at least 10 percent on 23 days.
  - ✓ This was likely in response to increased congestion across the Central East Interface in the daily peak load hour.
- Load was consistently under-scheduled in western New York.
- The over- and under-scheduling patterns generally improve convergence between day-ahead and real-time prices in most areas.

Day-ahead Scheduled Load and Actual Load

Daily Peak Load Hour



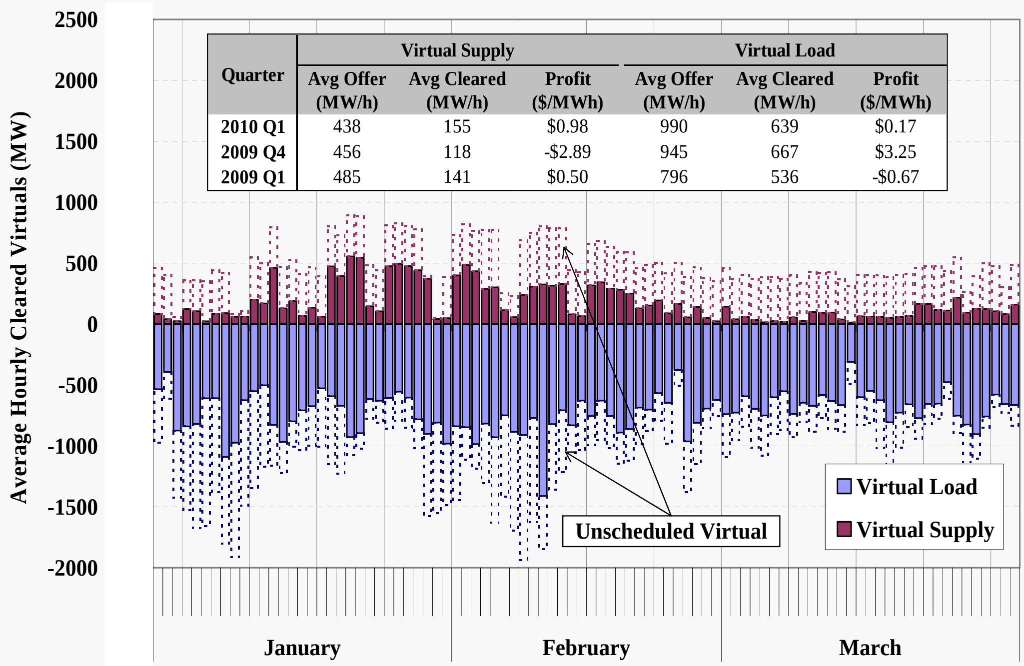
Quarter	Avg DA Net Scheduled Load (% of RT Load)			
	West Upstate	East Upstate	NYC&LI	NYCA
2010 Q1	89%	104%	103%	98%
2009 Q4	90%	97%	104%	98%
2009 Q1	93%	98%	104%	99%

Virtual Load and Supply

- The following two figures summarize virtual trading activity on a daily basis in downstate and upstate areas.
- There were substantial net virtual supply sales in upstate areas and net virtual load purchases in downstate areas.
  - ✓ This pattern has been persistent for years, although the average amount of net virtual load scheduled downstate increased to 483 MW in the first quarter of 2010 from 395 MW in the first quarter of 2009.
  - ✓ Likewise, the average amount of net virtual supply scheduled upstate increased to 846 MW in the first quarter of 2010 from 743 MW in the first quarter of 2009.
- Overall profitability from virtual trading was $2.2 million in the first quarter of 2010, up from $0.8 million in losses the previous quarter and $0.6 million in losses in the first quarter of 2009.
  - ✓ Most virtual trading profits in the first quarter of 2010 came from virtual supply scheduling in upstate New York.
  - ✓ [] The fact that virtual trades have generally been profitable indicates that they have improved price convergence in general.

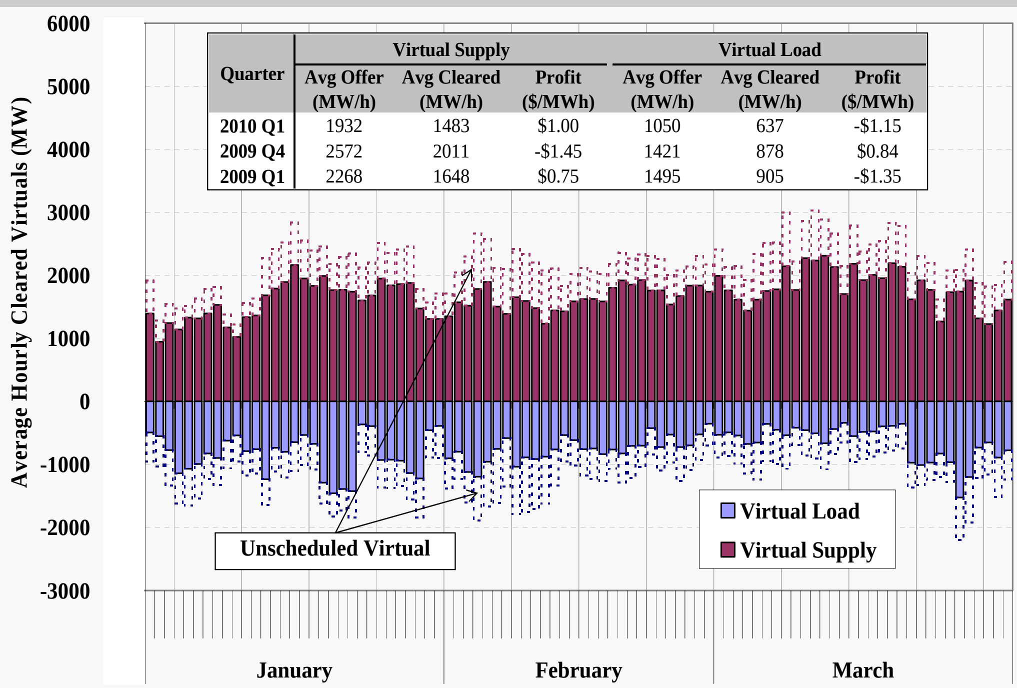
Virtual Load and Supply
New York City and Long Island

Quarter	Virtual Supply Avg Offer (MW/h)	Virtual Supply Avg Cleared (MW/h)	Virtual Supply Profit ($/MWh)	Virtual Load Avg Offer (MW/h)	Virtual Load Avg Cleared (MW/h)	Virtual Load Profit ($/MWh)
2010 Q1	438	155	$0.98	990	639	$0.17
2009 Q4	456	118	-$2.89	945	667	$3.25
2009 Q1	485	141	$0.50	796	536	-$0.67



Virtual Load and Supply
Upstate New York

Quarter	Virtual Supply Avg Offer (MW/h)	Virtual Supply Avg Cleared (MW/h)	Virtual Supply Profit ($/MWh)	Virtual Load Avg Offer (MW/h)	Virtual Load Avg Cleared (MW/h)	Virtual Load Profit ($/MWh)
2010 Q1	1932	1483	$1.00	1050	637	-$1.15
2009 Q4	2572	2011	-$1.45	1421	878	$0.84
2009 Q1	2268	1648	$0.75	1495	905	-$1.35

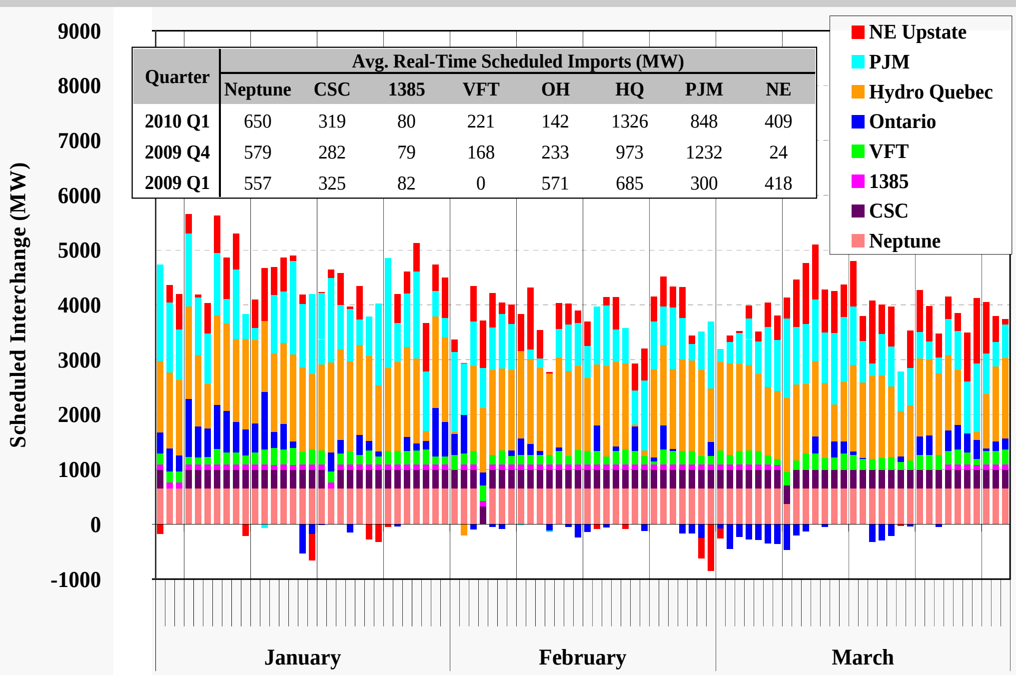


Net Imports Scheduled Across External Interfaces

- The following figure summarizes scheduled net imports to NYCA across eight external interfaces during the daily peak hour.
- Net imports to NYCA averaged 4.0 GW during daily peak hours in the first quarter of 2010, up 12 percent from the previous quarter and 36 percent from the same quarter of 2009.
  - ✓ Most of the increase in imports from the first quarter of 2009 was from HQ and PJM.
  - ✓ HQ revised down its projections of internal demand, allowing it to sell more energy to its neighbors.
- The Neptune Cable, the Cross Sound Cable, the 1385 Line, and the Linden VFT Line brought an average of 1,269 MW directly into downstate areas during daily peak hours in the first quarter of 2010. Imports increased across:
  - ✓ Neptune cable, which operated at its limit of 660 MW more frequently; and
  - ✓ Linden VFT Line, energized in November 2009 with a 300 MW limit.
- During the quarterly peak load hour on January 4, NYCA imported 5.7 GW, using imports to satisfy 24 percent of the peak load.

Net Imports Scheduled Across External Interfaces

Daily Peak Load Hour

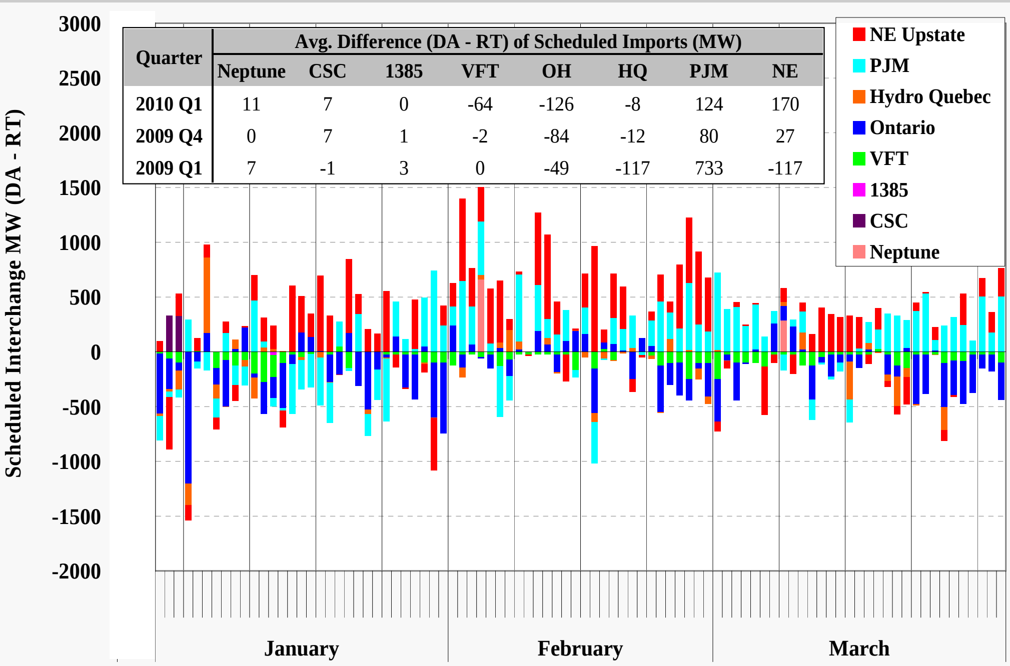


Quarter	Avg. Real-Time Scheduled Imports (MW)							
	Neptune	CSC	1385	VFT	OH	HQ	PJM	NE
2010 Q1	650	319	80	221	142	1326	848	409
2009 Q4	579	282	79	168	233	973	1232	24
2009 Q1	557	325	82	0	571	685	300	418

Change in Scheduled Imports from Day Ahead to Real Time

- The following figure summarizes the change in scheduled net imports between the day ahead market and the real time market in the daily peak load hour.
- From the day-ahead to the real-time, net scheduled imports:
  - ✓ Did not vary significantly across the three controllable lines into Long Island;
  - ✓ Frequently increased across the Linden VFT; and
  - ✓ Tended to decrease across the PJM and New England interfaces by a combined average of 294 MW, although they increased on many days.
- Generally, these changes in schedules improve consistency between day-ahead and real-time prices.
  - ✓ For example, from January 1 to 4, real-time prices were considerably higher than day-ahead prices throughout New York.
    - – Importers responded by increasing flows into NYCA by an average of 598 MW in the peak hours on these days.
    - – However, day-ahead scheduled imports across the Cross Sound Cable were curtailed on January 2 & 3 when it tripped offline, contributing to the severity of the price spike in Long Island on those days.

Change in Scheduled Imports from Day Ahead to Real Time
Daily Peak Load Hour



Quarter	Avg. Difference (DA - RT) of Scheduled Imports (MW)							
	Neptune	CSC	1385	VFT	OH	HQ	PJM	NE
2010 Q1	11	7	0	-64	-126	-8	124	170
2009 Q4	0	7	1	-2	-84	-12	80	27
2009 Q1	7	-1	3	0	-49	-117	733	-117

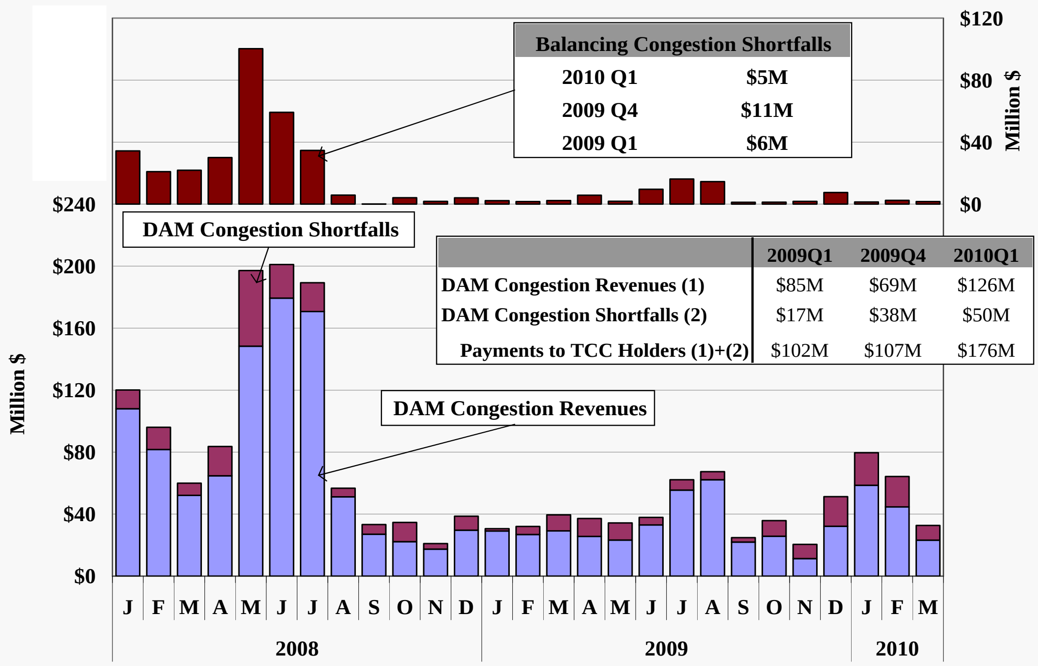
Congestion Revenue Collections and Shortfalls

- This section of the report summarizes and evaluates the congestion patterns in New York and quantifies the following categories of congestion costs:
  - ✓ *Day-Ahead Congestion Revenues* are collected by the NYISO when power is scheduled to flow across congested interfaces in the day-ahead market.
  - ✓ *Day-Ahead Congestion Shortfalls* occur when the day-ahead congestion revenues collected by the NYISO are less than the payments to TCC holders.
    - Shortfalls generally arise when the quantity of TCCs on a path exceeds the transfer capability of the path modeled in the day-ahead market during periods of congestion.
    - Payments to TCC holders are equal to the sum of day-ahead congestion revenues and day-ahead congestion shortfalls.
    - These shortfalls are partly offset by the revenues from selling excess TCCs.
  - ✓ *Balancing Congestion Shortfalls* arise when day-ahead scheduled flows over a constraint exceed what can flow over the constraint in the real-time market.
    - This requires the ISO to re-dispatch generation on each side of the constraint in the real-time market, buying additional energy in the high-priced area and selling back energy (that was purchased day-ahead) in the low-priced area.
    - This re-dispatch results in balancing congestion shortfalls which are recovered through uplift.

Congestion Revenue Collections and Shortfalls

- The following figure summarizes day-ahead congestion revenue, day-ahead congestion shortfalls, and balancing congestion shortfalls over the past two years.
- The figure shows that day-ahead congestion revenue rose 83 percent from the previous quarter and 48 percent from the first quarter of 2009.
  - ✓ Natural gas prices rose nearly 30 percent on average from the previous quarter.
  - ✓ Central East was congested more frequently than in prior periods.
- Day-ahead congestion shortfalls rose 32 percent from the previous quarter and 94 percent from the first quarter of 2009 primarily due to:
  - ✓ Increased value of day-ahead congestion; and
  - ✓ Changes in modeling assumptions between the TCC market and the day-ahead market.
- Balancing congestion shortfalls remained relatively low at $5 million in the first quarter of 2010. This was down from $11 million in the previous quarter and $6 million in the first quarter of 2009.

Congestion Revenue Collections and Shortfalls



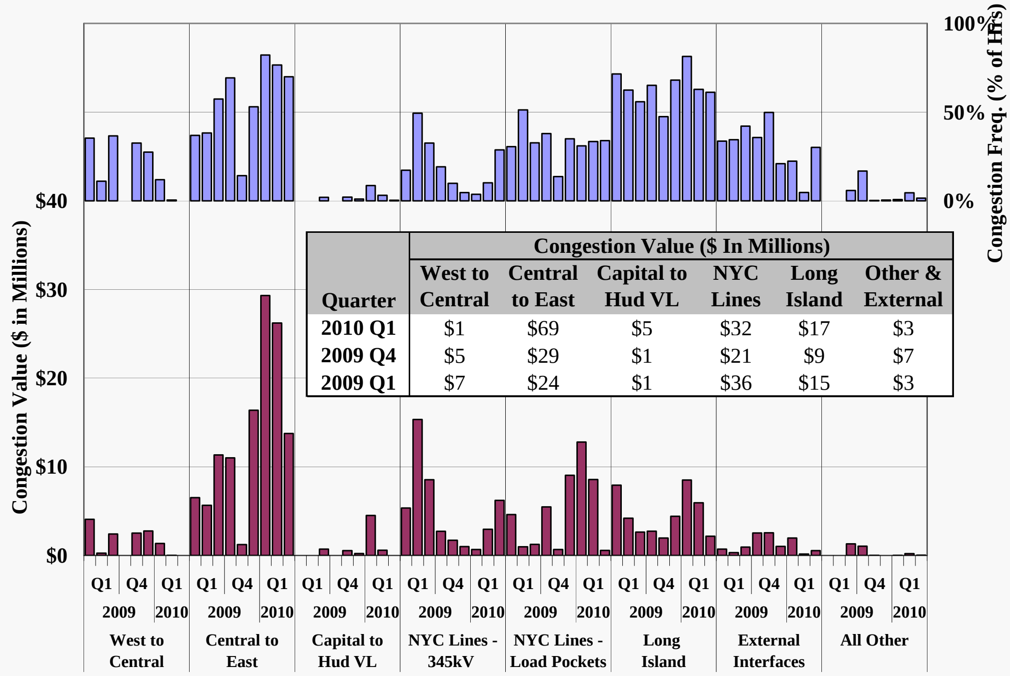
Congestion by Transmission Path

- The following two figures examine the value and frequency of congestion along major transmission paths in the day-ahead and real-time market.
  - ✓ The value of transfers is equal to the marginal cost of relieving the constraint (i.e., shadow price) multiplied by the scheduled flow across the interface.
  - ✓ In the day-ahead market, the value of congestion is equal to the congestion revenue collected by the NYISO, which is the primary funding source for TCC payments.
- The two figures group congestion into the following transmission paths:
  - ✓ West to Central: Primarily the Dysinger East interface.
  - ✓ Capital to Hudson Valley: Primarily the Leeds-to-Pleasant Valley line and the Leeds-to-New Scotland line.
  - ✓ Central to East: Primarily the Central-East interface.
  - ✓ Long Island: Lines leading into and within Long Island.
  - ✓ NYC Lines – 345kV: Lines leading into and within the NYC 345 kV system.
  - ✓ NYC Lines - Load Pockets: Lines leading into and within NYC load pockets.
  - ✓ NYC Simplified Interfaces: Groups of lines to NYC load pockets that are modeled as interface constraints
  - ✓ External Interfaces – Congestion related to the total transmission limits or ramp limits of the nine external interfaces.

Day-Ahead Congestion by Transmission Path

- The next figure summarizes the frequency of congestion and congestion revenue collected by transmission path in the day-ahead market.
- Day-ahead congestion patterns are determined by the market participants' bids and offers, which reflect their expectations of real-time congestion.
  - ✓ Congestion is more frequent in the day-ahead market than in real time, but shadow prices of constraints are generally lower in the day-ahead market.
- The majority of day-ahead congestion revenue in the first quarter of 2010 occurred over paths from Central to East (54 percent), lines into and within New York City (25 percent), and lines into Long Island (13 percent).
- The pattern of congestion changed from previous periods:
  - ✓ The Central to East path accounted for a larger share of congestion, while the lines into New York City accounted for a lower share.
  - ✓ Increased congestion on Central-East was partly due to increased imports from HQ and PJM, increased generating costs for gas-fired units in eastern New York, and clockwise circulation around Lake Erie.
- The patterns of congestion in the day-ahead and the real-time market were similar for most paths.

Day-Ahead Congestion by Transmission Path

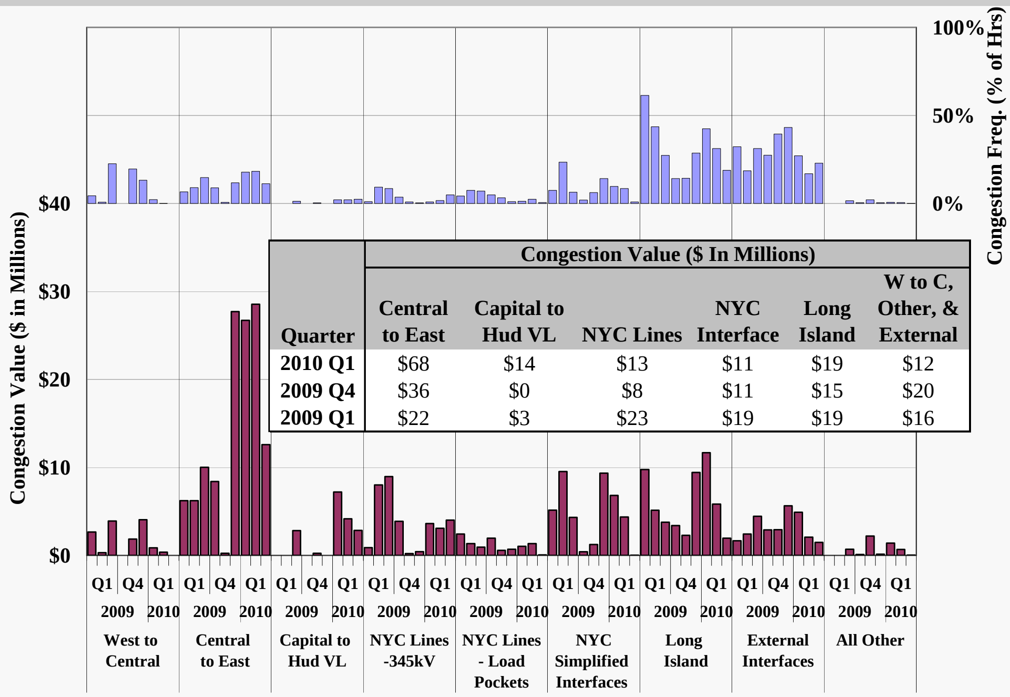


	Congestion Value ($ In Millions)					
Quarter	West to Central	Central to East	Capital to Hud VL	NYC Lines	Long Island	Other & External
2010 Q1	$1	$69	$5	$32	$17	$3
2009 Q4	$5	$29	$1	$21	$9	$7
2009 Q1	$7	$24	$1	$36	$15	$3

Real-Time Congestion by Transmission Path

- The following figure summarizes the value and frequency of congestion by transmission path in the real-time market.
- The value of real-time congestion increased 52 percent from the previous quarter primarily due to:
  - ✓ More frequent congestion across the Central East interface due to increased clockwise circulation around Lake Erie and imports from Hydro Quebec; and
  - ✓ The 30 percent increase in natural gas prices.
- Most (92 percent) real-time congestion occurred on four major transmission paths in the first quarter of 2010:
  - ✓ Central to East (49 percent):
  - ✓ NYC lines and simplified interface constraints (18 percent): Most of these were related to congestion into the Greenwood load pocket and congestion into the NYC 345 kV system.
  - ✓ Long Island (14 percent): This was elevated from December to February due to the outage of a major lines between up-state New York and Long Island.
  - ✓ Capital to Hudson Valley (10 percent): This was primarily due to congestion across the New Scotland-to-Leeds and Leeds-to-Pleasant Valley lines on January 5 & 6, February 1, and March 8.

Real-Time Congestion by Transmission Path

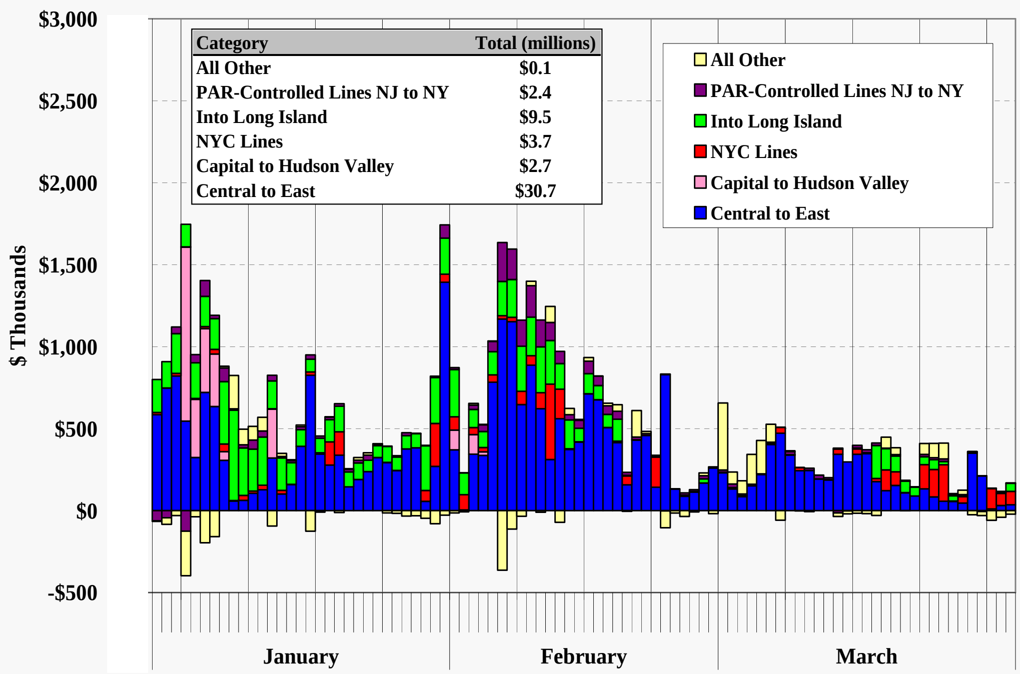


Quarter	Central to East	Capital to Hud VL	NYC Lines	NYC Interface	Long Island	W to C, Other, & External
	Congestion Value ($ In Millions)					
2010 Q1	$68	$14	$13	$11	$19	$12
2009 Q4	$36	$0	$8	$11	$15	$20
2009 Q1	$22	$3	$23	$19	$19	$16

Day-Ahead Congestion Revenue Shortfalls

- The following figure shows the daily congestion revenue shortfalls by transmission path or facility in the first quarter of 2010.
  - ✓ Negative values indicate congestion revenue surpluses.
- Day-ahead congestion revenue shortfalls can result from:
  - ✓ Modeling assumption differences between the TCC auction and the day-ahead market, including PAR schedules and unscheduled loop flows; and
  - ✓ Local TOs not incorporating their planned transmission outages in the assumptions of the TCC auctions.
    - – When outages are not reflected in the TCC auction assumptions, it leads to over-sale of TCCs, and ultimately congestion revenue shortfalls. The NYISO has a process for allocating shortfalls that are attributable to specific TOs.
- The Central to East and Into Long Island paths consistently generated revenue shortfalls and accounted for 80 percent of the total shortfall in the first quarter.
  - ✓ Day-ahead transfer capability along these paths is consistently lower than the amount of sold TCCs.
  - ✓ A major line from up-state to Long Island was out of service until February 20, reducing the transfer capability into Long Island by up to 600 MW.
  - ✓ Central East transfer capability is affected by assumptions regarding transmission facility outages and generator commitment patterns.

Day-Ahead Congestion Revenue Shortfalls



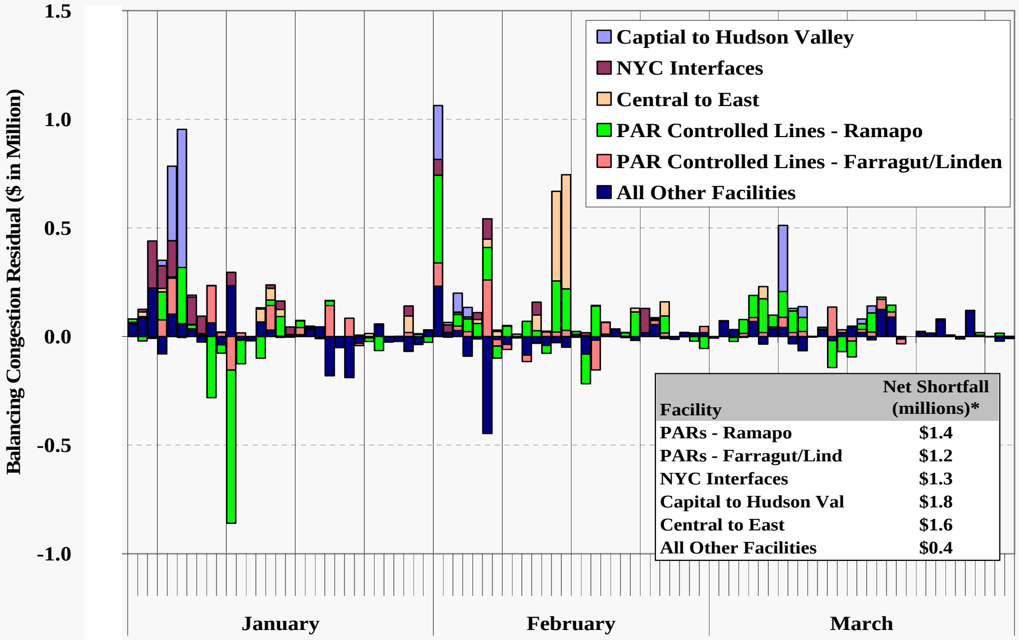
Balancing Congestion Shortfalls

- The following figure shows daily balancing congestion revenue shortfalls by transmission path or facility in the first quarter of 2010.
  - ✓ Negative values indicate balancing congestion surpluses.
- Balancing congestion revenue shortfalls can occur when the transfer capability of a particular interface changes between day-ahead and real-time due to:
  - ✓ Deratings and outages of the lines that make up the constrained interface;
  - ✓ Unexpected or forced outages of facilities that alter the distribution of flows across other constrained facilities; and
  - ✓ Unutilized transfer capability that can arise from Hybrid Pricing, which treats physically inflexible GTs as flexible in the pricing logic.
- Balancing congestion revenue shortfalls can also occur when assumptions used in the market models change from day-ahead to real-time. This includes the direction and magnitude of:
  - ✓ Unscheduled loop flows across constrained interfaces; and
  - ✓ Flows across PAR-controlled lines.
- Balancing congestion shortfalls were relatively low in the first quarter 2010.

Balancing Congestion Shortfalls

- Capital to Hudson Valley accounted for 23 percent of balancing congestion shortfalls in the first quarter.
  - ✓ Most occurred on four days (January 5 & 6, February 1, & March 8) as a result of outages of parallel transmission lines.
- Several PAR-controlled lines between New Jersey and New York (i.e., Waldwick, Ramapo, Farragut, and Linden) accounted for 29 percent of net balancing congestion shortfalls.
  - ✓ Shortfalls (and surpluses on some days) result from differences between the day-ahead scheduled flows and real-time flows on these PAR-controlled lines.
- Central to East accounted for 21 percent of balancing congestion shortfalls.
  - ✓ 58 percent of these shortfalls occurred on two days (February 13 & 14).
- Simplified interface constraints in New York City accounted for 17 percent of balancing congestion shortfalls in the first quarter.
  - ✓ Use of interface constraints in the real-time market (rather than the detailed model used in the day-ahead market) generally reduces transfer capability.
  - ✓ This category has been limited since July 2009 when the NYISO began assuming reduced transfer capability into NYC load pockets in the day-ahead market when real-time reductions in transfer capability were anticipated.

Balancing Congestion Shortfalls



Facility	Net Shortfall (millions)*
PARs - Ramapo	$1.4
PARs - Farragut/Lind	$1.2
NYC Interfaces	$1.3
Capital to Hudson Val	$1.8
Central to East	$1.6
All Other Facilities	$0.4

* These slightly over-estimate shortfalls since they are partly based on real-time schedules rather than metered values.

Uplift Costs from Guarantee Payments

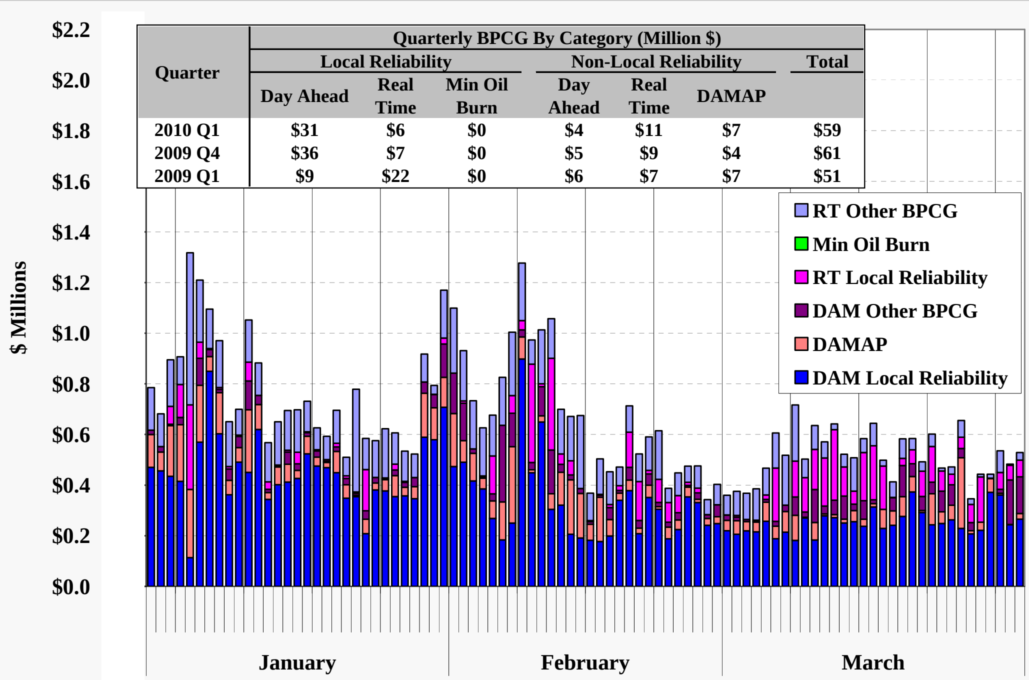
- The next figure summarizes uplift charges resulting from guarantee payments in the following six categories.
- Three categories of local reliability uplift are allocated to the local TO:
  - ✓ Day Ahead: From Local Reliability Requirements (“LRR”) and Day-Ahead Reliability Unit (“DARU”) commitments.
  - ✓ Real Time: From Supplemental Resource Evaluation (“SRE”) commitments and Out-of-Merit (“OOM”) dispatched units.
  - ✓ Minimum Oil Burn – Covers the spread between oil and gas prices when generators burn oil to satisfy NYC gas pipeline contingency reliability criteria.
- Three categories of non-local reliability uplift are allocated to all LSEs:
  - ✓ Day Ahead: Primarily for units committed economically that don’t recoup their as-offered start-up and min generation costs from LBMPs.
  - ✓ Real Time: Primarily for gas turbines committed economically that don’t recoup their as-offered costs from LBMPs, and also for SRE commitments and OOM dispatch that are done for bulk power system reliability.
  - ✓ Day Ahead Margin Assurance Payment (“DAMAP”) – For payments to cover losses for generators dispatched below their day-ahead schedule when the real-time LBMP is higher than the day-ahead LBMP.

Uplift Costs from Guarantee Payments

- Guarantee payment uplift fell to $59 million, down 3 percent from the previous quarter, partly due to less frequent reliability commitment. This was partly offset by increased production costs from higher natural gas prices.
- Guarantee payment uplift rose 16 percent from the first quarter of 2009 due to:
  - ✓ More frequent DARU and SRE commitments in western New York for bulk system reliability and local reliability; and
  - ✓ Increased oil prices, which led to increases in the offers of some generators committed for reliability.
- Guarantee payment uplift fell from January to March 2010, consistent with the decline in the amount of New York City capacity committed for reliability.
  - ✓ The average amount of capacity committed for local reliability fell 700 MW/day from January to March 2010.
- A large share of the uplift shifted from the real-time local category to the day-ahead local category since the first quarter of 2009.
  - ✓ This was due to changes that allow TOs to commit units for reliability in the day-ahead market (i.e., DARU commitment), which leads to more efficient overall commitment. TOs began using this at the end of February 2009.

Uplift Costs from Guarantee Payments
Local and Non-Local by Category

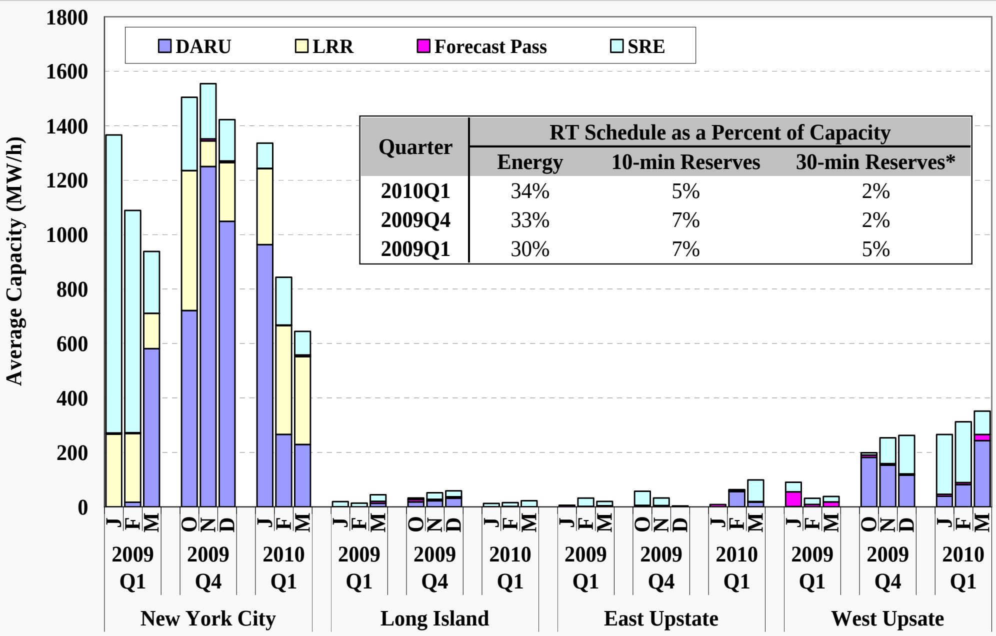
Quarter	Quarterly BPCG By Category (Million $)						
	Local Reliability			Non-Local Reliability			Total
	Day Ahead	Real Time	Min Oil Burn	Day Ahead	Real Time	DAMAP	
2010 Q1	$31	$6	$0	$4	$11	$7	$59
2009 Q4	$36	$7	$0	$5	$9	$4	$61
2009 Q1	$9	$22	$0	$6	$7	$7	$51



Supplemental Commitment for Reliability

- The following figure shows the monthly quantities of capacity committed for reliability by type of commitment and region.
  - ✓ The table shows the shares of capacity that are actually scheduled in the real-time market for energy and reserves.
- Local reliability commitment in New York City fell 37 percent from the fourth quarter of 2009 and 17 percent from the first quarter of 2009.
  - ✓ DARU commitment fell 700 MW from January to February 2010 after the retirement of the Poletti steam unit.
- Average reliability commitment in western New York increased 65 MW from the prior quarter and 270 MW from the first quarter of 2009.
  - ✓ The considerable increase from the first quarter of 2009 is primarily due to the emergence of SRE commitments for bulk power system reliability; and
  - ✓ More frequent commitment of several other units for local reliability due, in part, to transmission outages and changes in commitment patterns.
- Commitment for forecasted load fell 41 percent from the first quarter of 2009 primarily because local reliability commitment is now done in the day-ahead market (i.e., DARU and LRR) prior to the commitment for forecasted load.

Supplemental Commitment for Reliability
by Category and Region



Quarter	RT Schedule as a Percent of Capacity		
	Energy	10-min Reserves	30-min Reserves*
2010Q1	34%	5%	2%
2009Q4	33%	7%	2%
2009Q1	30%	7%	5%

* 10-minute reserves are excluded from this category. Units may have available capacity that can be ramped in 10 or 30 minutes that is not scheduled when excess reserves are available at $0/MWh in the real-time market.

Market Monitoring and Mitigation

- The following figure summarizes energy offer mitigation as well as the results of potential withholding screens.
- Energy offer mitigation is performed by automated mitigation procedures ("AMP") software in the day-ahead and real-time markets in New York City. The following figure reports:
  - ✓ The frequency of incremental energy offer mitigation; and
  - ✓ The average quantity of mitigated capacity, including capacity below the min gen level when the min gen offer is mitigated.
- The output gap is the amount of economic capacity that does not produce energy because a supplier submits an offer price above the unit's reference level by a substantial threshold. The following figure shows this using:
  - ✓ A high threshold (the lower of $100/MWh and 300 percent); and
  - ✓ A low threshold (the lower of $50/MWh and 100 percent).
- Generator deratings are reviewed to screen for potential physical withholding. The figure summarizes:
  - ✓ Total deratings, which are measured relative to the DMNC test value; and
  - ✓ Short-term deratings, which exclude deratings lasting more than 30 days.

Market Monitoring and Mitigation

Automated Mitigation in the Day-Ahead and Real-Time Markets:

- Most mitigation occurred day-ahead for DARU & LRR units (68 percent), Astoria West/Q/V congestion (10 percent), and Dunwoodie South congestion (14 percent).
- Mitigation decreased 60 percent from the previous quarter due to less DARU- and LRR-committed capacity, which is mitigated whenever its Start-up and MinGen offers exceed the reference.

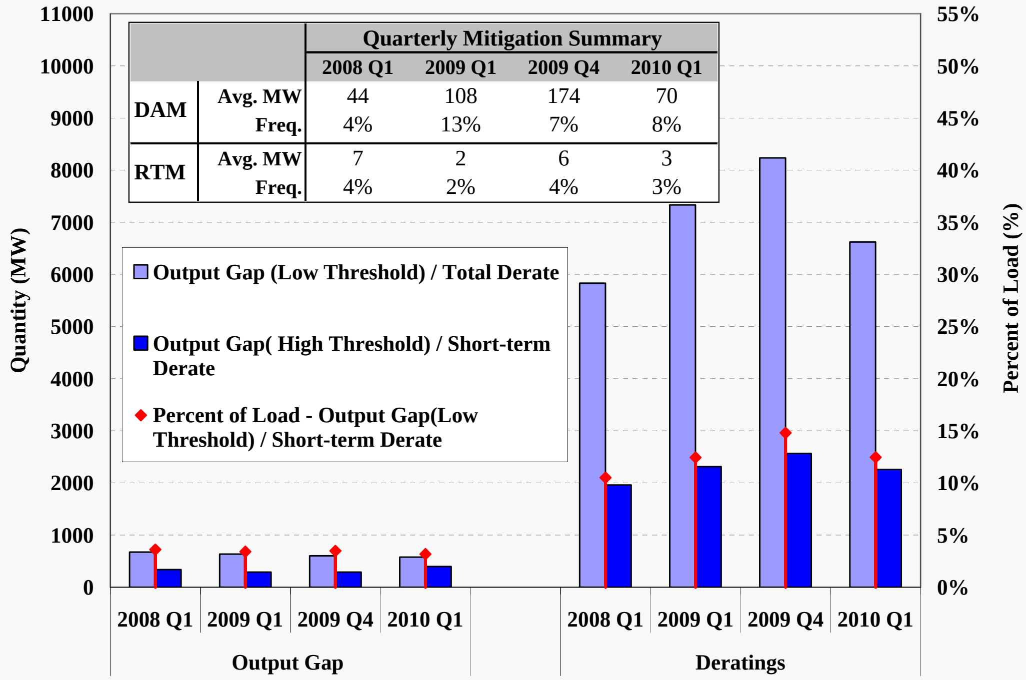
Output Gap at High and Low Thresholds:

- The output gap is low as a share of load (~ 3 percent), occurring primarily during periods when the prices would not be substantially affected.
- We review instances of significant output gap to identify potential competitive concerns.

Long-Term and Short-Term Deratings:

- Total deratings are sizable, but physical withholding concerns are limited because: (i) deratings are typically highest in the shoulder months when demand is lowest, and (ii) most deratings are long-term, which are less likely to reflect withholding.
- Deratings with significant market effects are reviewed by the NYISO and no significant concerns arose in the first quarter.

Market Monitoring Screens and Mitigation



		Quarterly Mitigation Summary			
		2008 Q1	2009 Q1	2009 Q4	2010 Q1
DAM	Avg. MW	44	108	174	70
	Freq.	4%	13%	7%	8%
RTM	Avg. MW	7	2	6	3
	Freq.	4%	2%	4%	3%

Capacity Market Results

- The following figure summarizes available and scheduled UCAP resources as well as the clearing prices in each capacity zone.
- UCAP spot prices increased from the first quarters of 2009 to 2010 by:
  - ✓ 221 percent to $5.85/kW-month in New York City; and
  - ✓ 13 percent to $2.06/kW-month in Rest-Of-State (and Long Island).
    - – The Long Island clearing price was equal to the Rest-Of-State clearing price, indicating the local capacity requirement was not binding. Long Island had substantial excess capacity, roughly 17 percent more than the requirement.
- New York City clearing prices rose considerably due to:
  - ✓ An increase in the peak load forecast, which raised the NYC requirement;
  - ✓ The scheduled escalation of the NYC capacity demand curve;
  - ✓ A reduction in UCAP supply due to higher equivalent forced outage rates ("EFORd"), although the price effect was mostly offset by a corresponding reduction in the UCAP requirement due to a higher derating factor; and
  - ✓ The retirement of the Poletti steam unit in February 2010 which reduced supply by nearly 900 MW, contributing to an average of $6/kW-month increase in the New York City price from January to February.

Capacity Market Results

- Rest-Of-State clearing prices increased due to:
  - ✓ An increase in the ICAP requirement from 115 percent to 116.5 percent of the forecasted peak load;
  - ✓ The reduction in internal supply due to retirement of Poletti in February 2010;
  - ✓ The lower available UCAP supply resulted from higher EFORd, although the price effect was mostly offset by a corresponding reduction in the UCAP requirement due to a higher derating factor; and
  - ✓ The reduction in net imports of UCAP.
    - – Net imports of UCAP decreased from approximately 420 MW in the first quarter of 2009 to 50 MW in the first quarter of 2010. This was partly driven by increased capacity prices in neighboring markets.
    - – However, imports of external capacity increased from an average of 360 MW in January and February to approximately 1,280 MW in March, contributing to a $2.64/kW-month decrease in the clearing price.
- The reduction in supply from the first quarter of 2009 to the first quarter of 2010 was partly offset by the additions of 600 MW in New York City and Long Island (the Linden VFT Line and the Caithness combined cycle unit).
- The spot price rose briefly in January 2009 when one firm inadvertently failed to offer some of its capacity in the auction.

Capacity Market Results