ATTACHMENT V

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

New York Independent System Operator, Inc.	)	**Docket No. ER00-1969-000**
Niagara Mohawk Power Corp. v. **New York Independent System Operator, Inc.**	)	**Docket No. EL00-57-000**
Orion Power New York GP, Inc. v. **New York Independent System Operator, Inc.**	)	**Docket No. EL00-60-000**
New York State Electric & Gas Corporation v. **New York Independent System Operator, Inc.**	)	**Docket No. EL00-63-000**
Rochester Gas and Electric Corporation v. **New York Independent System Operator, Inc.**	)	**Docket No. EL00-64-000**
Strategic Power Management, Inc. v. **New York Independent System Operator, Inc.**	)	**Docket No. EL00-67-000**
New York Independent System Operator, Inc.	)	**Docket No. ER00-2624-000**
New York Independent System Operator, Inc.	)	**Docket No. ER00-3038-000**
New York State Electric & Gas Corporation v. **New York Independent System Operator, Inc.**	)	**Docket Nos. EL00-70-000 and EL00-71-001**
Niagara Mohawk Energy Marketing, Inc. v. **New York Independent System Operator, Inc.**	)	**Docket No. EL00-82-000 (not consolidated)**

**AFFIDAVIT OF
JAMES H. SAVITT**

James H. Savitt, having been duly sworn under oath deposes and says:

1. My name is James H. Savitt. I am the Manager of Market Monitoring for the New York Independent System Operator, Inc. ("NYISO"). My business address is 3890 Carman Road, Schenectady, New York 12303. As Manager of Market Monitoring, I am responsible for the analysis of the market outcomes of the bidding and offering behavior of the participants in New York's wholesale electric markets, including its reserves markets. I was closely involved with the development of the March 27, 2000 *Request of New York Independent System Operator, Inc. for Suspension of Market-Based Pricing for 10-Minute Reserves and to Shorten Notice Period,* which described the problems that led to the imposition of reserves market mitigation measures. I also assisted in the development of, and have closely monitored, the NYISO's 10-Minute Spinning, 10-Minute Non-Synchronized Reserves, and 30-Minute Reserves markets. My position involves supervision of price reservation and correction procedures. I have also completed analyses of price volatility and price convergence in and between the NYISO-administered markets.

2. I will address three topics in my affidavit: 1) functioning of the various operating reserves markets, both with and without market mitigation measures; 2) NYISO compliance with Temporary Extraordinary Procedures in price corrections; and 3) market volatility and convergence.

Operating Reserves Markets

3. In connection with the September 1 compliance filing, the NYISO conducted an analysis of the performance of the operating reserves markets for the period 1 April 2000 to 18 August 2000. This analysis looked at the 30-minute operating reserves ("30 OR"), 10-minute non-synchronous operating reserves ("10 NSR"), and 10-minute spinning operating reserves ("10 SR") market components. The first two months of the period saw the 10-minute market portions operating under the NYISO-filed bid caps for the respective components. During June, July, and August to date, there was a cap on 10 NSR, but no cap on 10 SR.

<u>Prices</u>

4. Exhibit 5-A is a graph of the average Day-Ahead prices for the three categories of reserves for the period 1 April 2000 through 29 August 2000. During the period 1 April through 31 May, the ten-minute operating reserves markets were operating under bid caps and mandatory bidding requirements pursuant to the NYISO's 27 March 2000 filing. From 1 June forward, the 10 SR portion of the market operated without either a bid cap or a mandatory bidding requirement. The 10 NSR portion of the market has retained both strictures to date. The 30 OR portion has operated free of any caps or bidding requirements.

5. Over the four-and-a-half month period, the 30 OR prices have shown no discernible trend, largely staying in the region of $1. There have been four spikes in the average daily price. Each can be explained either by (planned) load levels prevailing for the day, or by other special circumstances. These would include the effects of certain locational requirements for operating reserves. As explained in the September 1 compliance filing, the NYISO is taking steps to lessen or remove the impact of these locational requirements on the markets for operating reserves. The 30 OR price spikes did not presage future upward movements. Exhibit

5-B is a chart containing the monthly means of the Day-Ahead prices for each category of reserve. The chart and the graph show no trend in the price of 30 OR. Exhibit 5-C takes the same information as the previous graph and focuses on the period 1 July 2000 to 18 August 2000. It represents a slightly more spread out view of the prices. It confirms that 30 OR prices show no discernible trend, and that the spikes did not lead to any significant change in patterns.

6. The graph in Exhibit 5-A shows two distinct regimes for 10 SR prices. April and May clearly represent performance under a bid cap. The price trend is quite flat, with only a few bumps during this period. The chart in Exhibit 5-B shows the monthly prices as quite flat for those two months, and rising a bit in June, July, and August. The graph shows a slight trend upward from the period of the capped regime, but still nothing to indicate a steep rise in the price of 10 SR. However, there is more day-to-day volatility in the post-cap period. During the period of the cap, prices remained well below the cap level. The cap on 10 SR was $6.68, but prices in April and May stayed around $3, rarely exceeding $4. Even in the post-cap period, prices for 10 SR averaged below $5. The graph in Exhibit 5-C provides a bit more spread-out picture and shows clearly that 10 SR prices largely remained in the $4 range.

7. The 10 NSR portion of the reserves market has been operating under a Day-Ahead cap of $2.52 and a requirement that eastern units capable of doing so offer all of their 10 NSR capacity. The two graphs show no trend in prices. There are four spikes – the same as mentioned above in the discussion of 30 OR – that push the Day-Ahead prices higher than the mean, and indeed, higher than the cap. On the days when 30 OR cleared at a price higher than that for 10 NSR, price cascading due to the 10 NSR constraint being slack and a high-priced 30-minute unit which was marginal for the total reserves requirement caused the price for 10 NSR to exceed the $2.52 cap.

8. Only once or twice, however, did the mean Day-Ahead price for 10 NSR exceed the cap (other than for the reasons cited above). The mean seems to be hovering around $2, except for a dip below $2 in the early to mid part of June. While the bid cap may have an impact on the level and trend of prices for 10 NSR, it does not fully explain why the price hovers well below the cap. Moreover, 10 SR is not currently under a cap, and 30 OR has never been capped.

Quantities

9. An important aspect of the robustness of a market is the relation between the quantities offered and those accepted (assuming the quantities are offered at prices not tantamount to economic withholding). A reasonable expectation for a competitive market is that such offers from a sufficient number of owners in excess of the quantity demanded should keep prices from rising to excessively high levels. There is no guarantee that prices will stay flat forever, or that there will never be any large fluctuations. Moreover, in the case of operating reserves, reserves and energy are different manifestations of the capacity of a facility, and the market models choose each according to the economics of both together.

10. Exhibits, 5-D, 5-E, and 5-F together show robust activity in offers and schedules for all three reserve categories, although the 10 NSR market is still under strictures. In each category of reserves, at least twice as much is offered as is taken in any hour. There appears to

be enough economically available reserves from which to choose that the market is not forced up an ever steeper offer curve to satisfy demand for the particular product. Moreover, the substitutability of one category for another – even though such substitution is only one way – means that competitiveness in the 10 SR portion of the market, for example, can work to mitigate anti-competitive actions in the 10 NSR or 30 OR portions of the market. However, removal of the cap from the 10 NSR portion of the market, without having in place any other mechanisms to counter market power, risks having prices in this potion of the market become non-competitive.

11. The existence of a good volume of offers in excess of demands may explain why the current biding patterns have resulted in prices in the markets that have remained fairly stable. The 10 NSR portion of the market must be considered in the context of vigorous competition in the 10 SR portion of the market. While the 10 NSR portion of the market is operating under a bid cap, it appears that the mandatory bidding requirement for 10 NSR, combined with the robustness of the 10 SR portion of the market, has helped to keep the 10 NSR prices below the $2.52 cap. Other factors that may be contributing to these results may include the facts that during summers months, most if not all steam units are on line and operating in merit to meet high seasonal demands, there are generally few if any natural gas curtailments, and few if any maintenance outages are scheduled.

12. Similarly, the availability of 10 SR and 30 OR at competitive prices well in excess of what is needed has apparently worked to keep those prices at levels consistent with expectations in a competitive market. Exhibit 5-D shows the hourly offer and acceptance patterns for the three reserves categories for 1 August 2000. The bottom chart in the exhibit shows that the NYISO took 1800 MW of reserves each hour to meet its requirements. Interestingly, the 10 minute categories accounted for about 1500 MW of the 1800 MW needed – an amount beyond the 1200 MW minimum requirement for 10-minute reserves. Since the top chart shows that there was more than enough 30 OR, the 10 minute reserves appear to have been able to satisfy an amount beyond the required minimum more economically than the 30 OR. It is also likely that much of the unaccepted 30 OR was accepted for energy. Thus, the systems in place appear to be resulting in an adequate supply of reserves, and current bidding patterns are resulting in reserves prices at levels consistent with competitive expectations. Exhibits 5-E and 5-F provide the same information over the period 5 July 2000 to 19 August 2000. The pattern is consistent over this time period. There continues to be enough of each reserve category offered to more than meet the demand. Moreover, the existence of enough potential substitutability among categories appears to help mitigate any emerging tightness in the next category down.

13. The substitutability of 10 SR for 10 NSR is especially important. The latter category has only three significant competitors in the East – where 10 NSR requirements are germane. Even the addition of a fourth competitor would not keep this portion of the market from being concentrated according to traditional measures. By contrast, there are sixteen organizations providing 10 SR in the East, eleven of which account for 96% of the 10 SR capability. Seven of the eleven account for just over 79% of the 10 SR capability. As noted above, however, during summer months the availability of 10 SR is likely to reflect the operating availability of steam units, and the relative absence of maintenance outages and natural gas

curtailments. In addition, the competitive impact of 10 SR is tempered by the start up and minimum generation costs required to bring spinning reserve units on line.

Conclusions

14. The picture that emerges is one that appears consistent with the outcomes that might be expected in a fairly vigorous market in reserves. Under current bidding patterns and requirements, prices, even without caps, seem not to be trending anywhere, and even when bids are or were capped, the clearing prices tended to stay below those caps. Quantities seem to be playing a major role in keeping prices consistent with competitive expectations. This latter finding is consistent with what the NYISO reported in its 27 March filing on reserves, in which the NYISO concluded that withholding of significant quantities of 10 NSR drove prices to non-competitive levels. Correspondingly, it appears that a mandatory bidding requirement for 10 NSR resources east of Central-East would be a significant factor in producing pricing consistent with competitive expectations in the 10 NSR market.

Compliance with Temporary Extraordinary Procedures

15. Addendum 1 contains the Emergency Corrective Actions ("ECA") in effect under the original Temporary Extraordinary Procedures ("TEP"), the first extension of the TEPs, and the current extension.

Price Corrections

16. Enclosed as Addendum2 are copies of the monthly reports detailing the nature of price corrections undertaken in the months of June, July, and August to date. These reports are posted on the NYISO's website in the Market Monitoring section. Each of the reports contains three sections. The first section describes the model conditions that caused a need for the price corrections; the second section describes the type of correction undertaken; and the third section lists the actual corrective action taken for each interval of each day for which corrections were necessary.

17. In its ten months of existence, the NYISO has recognized that the causes of corrections fall into certain well-defined categories. Each monthly report lists the categories germane to the situations prevailing for that month. Similarly, at this point there are only a few correction methods, and their application depends on the problem causing the need for the correction in the first place.

18. Although subject to some initial delays, the posting of these reports is now current. Since the price reservation and correction process can take up to six days, there is necessarily a comparable lag in the posting of price correction information. The NYISO has had in place for some months a procedure for receiving, verifying, and posting the corrected prices. By the time the September 1 compliance filing is submitted, that procedure should be modified to include the posting of the corresponding explanations for the corrections. While the NYISO expects the frequency of price corrections to drop, there will probably always be some amount of

correction taking place. For that reason, the NYISO plans to continue its correction and posting procedures.

Other Corrections

19. In addition to price corrections, the NYISO has taken action to delay the posting time past 11AM, and to populate the Market Information System ("MIS") with generator offers two weeks into the future. The latter has become almost a standard operating practice, used to ensure that the MIS is not empty at the time of market closing. The populating of the MIS in no way prevents market participants from deleting or changing their bids in any manner that they deem appropriate.

20. Other than the ECAs described above, the NYISO has invoked TEP authority on only two other occasions. Both instances were associated with the events of 8 and 9 May 2000. One of the two instances turned out not to need any corrective action, so no ECA was developed. These TEP instances, the ECA developed for the one situation requiring it, the detailed price corrections resulting therefrom, and a subsequent justification of that ECA are provided as Addendum 1, and described below.

21. *Bid production cost guarantees.* On 8 May 2000, a large bid production cost guarantee ("BPCG") was made to an external power supplier for the Day-Ahead Market ("DAM"). On 11 May 2000 the NYISO invoked its TEP authority to investigate the circumstances under which this occurred. The computation of the (external) price against which the BPCG was computed seemed high enough that there was the possibility of a design flaw in the LBMP calculation process as it related to the external proxy buses. Because of the possibility that certain market participants were not entitled to BPCG monies that they had received, invocation of the TEP was a way to put a "reservation" on those payments. A subsequent ECA would then provide the basis for articulating the design flaw and recovering monies which would not have been earned but for the flaw.

22. Analysis revealed that the situation had prevailed in the models for some time, and the decision was made not to try to recover the BPCG. Thereafter, an effort was undertaken to review the way in which external resources were evaluated. As a result, in late May and early June, NYISO staff incorporated changes in its Security Constrained Unit Commitment ("SCUC") software in the method of evaluation of external resources. SCUC is a computerized algorithm that calculates day-ahead market prices. Specifically, consideration of external resources was moved from pass one to pass five of SCUC. This had the effect of removing the flaw of computing BPCG against a strike price which had no relation to the LBMP.

23. The decision not to recover BPCG monies seemed to obviate the need for an ECA, and NYISO staff accordingly did not post an ECA for this issue.

24. *Energy limited resources.* On 12 May 2000 the NYISO invoked its TEP authority to investigate the circumstances under which an energy-limited resource ("ELR") was forced to bid in a way that it could manage its resources (*i.e.,* it would only be used as a last resort) that was inconsistent with part of its financial circumstances. The invocation of the TEP noted that

units chosen to provide energy at levels beyond their normal limitations end up setting a clearing price which is inconsistent with the normal costs of production – fuel, maintenance, emissions, and opportunity costs. The flaw lies in the strictures of the MIS, which provide no way other than prices to signal a unit's energy limitations. The consequences of this flaw became apparent in the prices experienced on 8 and 9 May 2000.

25. The resultant ECA was a procedure for calculating the LBMP in the intervals when an energy-limited resource was the last unit chosen. The ECA was posted within three days of the invocation of the TEP authority. The ECA is attached as part of Addendum 1. Under this ECA, a unit dispatched into the ELR region of its operating range will be considered out of merit and will not set the LBMP. The LBMP will instead be set at the level that would have prevailed but for the dispatch of the ELR unit into its ELR range.

26. The prices on 8 and 9 May were corrected, as appropriate, according to the usual procedures, described above, with the addition of the ELR ECA as an additional tool. A detailed explanation of those corrections is attached as part of Addendum 1. Subsequent concerns raised by market participants prompted a revisit of the application of this ECA, and near the end of July, the NYISO posted a further explanation of the application of this ECA. That explanation clarified the NYISO's use of an ELR under the circumstances prevailing on 8 and 9 May, and also articulated a going-forward procedure that would allow certain other kinds of units to be designated as ELR. This explanation is attached as Addendum 1.

Market Volatility and Convergence

Energy Price Fluctuations and Volatility

27. Set forth below are tables showing price information as a series of monthly numbers, illustrating how the market has moved from the beginning of January to 16 August. The tables show mean monthly prices and mean prices for January to date, standard deviations of those prices, and the respective coefficients of variation. Further explanations follow the tables.

Monthly Summaries of Price Information in the DAM, BME and RTM

Means

	DAMLBMP	BMELBMP	RTLBMP
January	$32.01	$24.03	$30.94
February	$30.49	$26.63	$24.14
March	$26.90	$22.56	$22.60
April	$27.84	$25.57	$24.48
May	$28.85	$22.44	$25.76
June	$33.57	$28.18	$19.30
July	$25.98	$22.11	$23.04
(to) August 16	$36.12	$40.33	$14.95
January to Date	$29.84	$25.58	$23.67

Standard Deviations

	DAMLBMP	BMELBMP	RTLBMP
January	$14.60	$15.44	$92.08
February	$10.56	$17.86	$15.41
March	$7.07	$6.85	$17.86
April	$9.51	$9.17	$12.50
May	$15.38	$61.21	$51.57
June	$22.35	$92.92	$50.28
July	$11.51	$14.78	$16.92
(to) August 16	$17.46	$69.34	$106.63
January to Date	$14.42	$46.14	$52.68

Coefficients of Variation

	DAMLBMP	BMELBMP	RTLBMP
January	0.46	0.64	2.98
February	0.35	0.67	0.64
March	0.26	0.30	0.79
April	0.34	0.36	0.51
May	0.53	2.73	2.00
June	0.67	3.30	2.61
July	0.44	0.67	0.73
(to) August 16	0.48	1.72	7.13
January to Date	0.48	1.80	2.23

28. The data analyzed are the 5500 hourly prices at the NYISO reference bus for each market, often referred to as the Marcy bus. The Marcy bus was selected in order to provide continuity with earlier analyses undertaken by the NYISO and reported on its website. In addition, use of the Marcy bus facilitates an analysis of marginal energy prices. Efforts are also being undertaken to analyze load-weighted LBMPs for the DAM, BME and SCD across the NYCA.

29. These prices represent only the marginal price of energy. They are the direct outcome of the optimizations that happen in each of the models. These prices are the "system lambdas," or shadow prices, inherent in the optimization of the NYCA's resources. The real-time market ("RTM") prices are the integrated hourly prices resulting from 12-15 dispatches by

the NYISO's Security Constrained Dispatch ("SCD") software in each hour. SCD is a computerized algorithm that calculates real-time market prices.

30. One set of adjustments has been made to this data. There are actually 5519 observations. Nineteen observations with prices predicted by the NYISO's Balancing Market Evaluation ("BME") that were so far beyond any of the other prices that they were not representative of (even extreme performance in the) BME were removed. A chart of the summaries, including all of the data, is incorporated below as an appendix. Removal of the 19 observations data does not change the conclusions supported by the tables, but rather allows a better focus on what is happening generally in the markets. A further explanation of the reasons for removal of the 19 observations is provided in a note to the appendix.

31. Accompanying the tables above is a set of three graphs, set forth below, showing the same data as time series. The tables and the graphs show that there is no obvious trend in any of the three sets of means. Although there is movement from month to month, the January-to-date numbers are well representative of the markets' performance.

32. The January-to-date means show a slight rise in the marginal price of energy as compared to the means previously reported – for the January through April period. The means then were $29.30, $24.57, and $24.55 for the DAM, BME, and RTM respectively. As the shown in the table above, the corresponding prices are $29.84, $25.58, and $23.67. Thus, DAM and BME prices have risen, while the RTM price has fallen. The BME rise of $1.01 seems to be countered by the RTM fall of $0.87. The numbers are coincidental. However, they do raise questions about price convergence (to be discussed in the next section) and hint at some volatility issues.

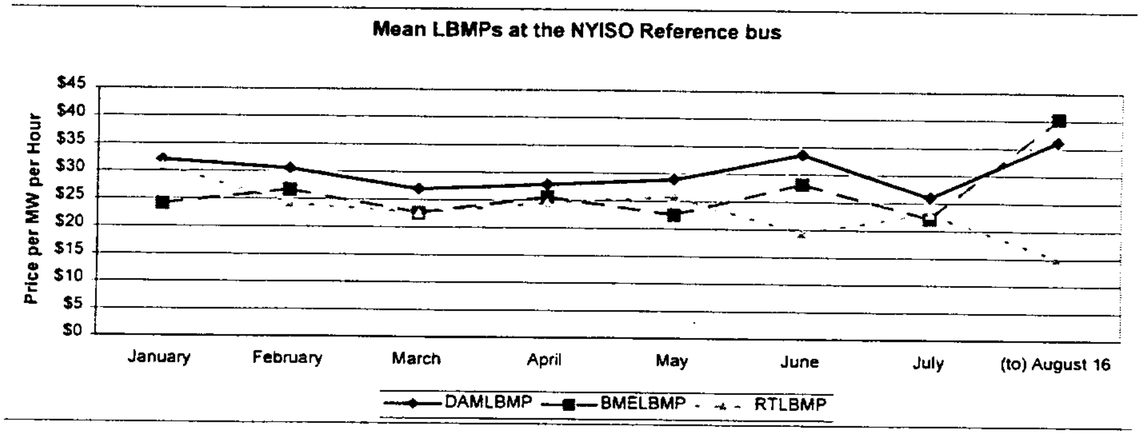
33. In May the NYISO reported on volatility by focusing on the standard deviation of prices. Here, the January-through-April numbers are extended through 16 August, and provide another perspective as well: relative volatility as measured by the coefficient of variation. The standard deviations of prices were $10.99, $12.27, and $27.68 for the DAM, BME, and RTM respectively. For the year-to-date, those standard deviations are $14.42, $46.14, and $52.68. Price volatility has increased in all three markets. As the middle part of the tables and the middle chart show, May, June, and August-to-date were the major contributors to the increase in volatility. July's volatility looked like that of February, March, and April (and January as well for DAM and BME).

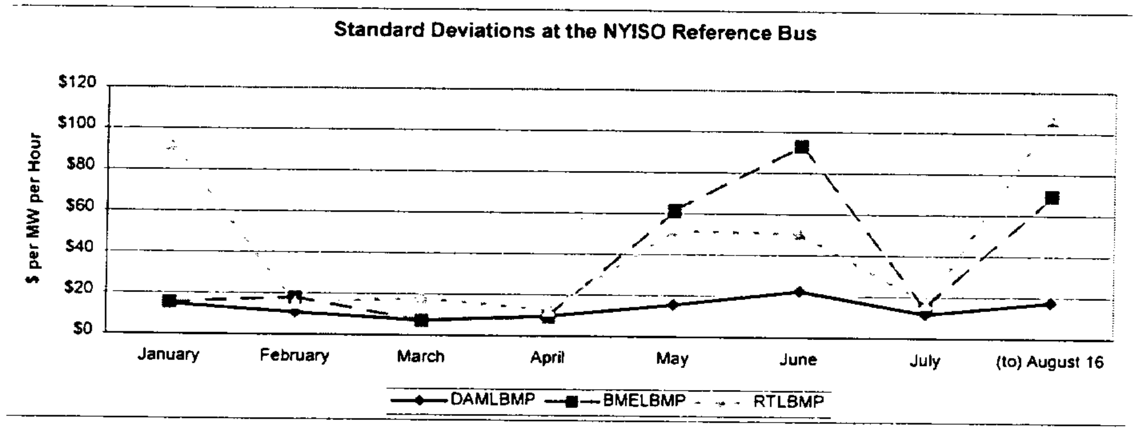
34. The coefficient of variation ("CV") is a measure of relative volatility. It is computed by dividing the standard deviation by the mean. This process puts volatility as measured by the standard deviation into context. For example, a series that has a mean values of 1,000 and a standard deviation of 100 is much less "noisy" than a series with a mean of 100 and a standard deviation of 100. Lower values for the coefficient indicate less relative volatility. A series with no variation at all would have a standard deviation of zero and therefore a CV of zero.

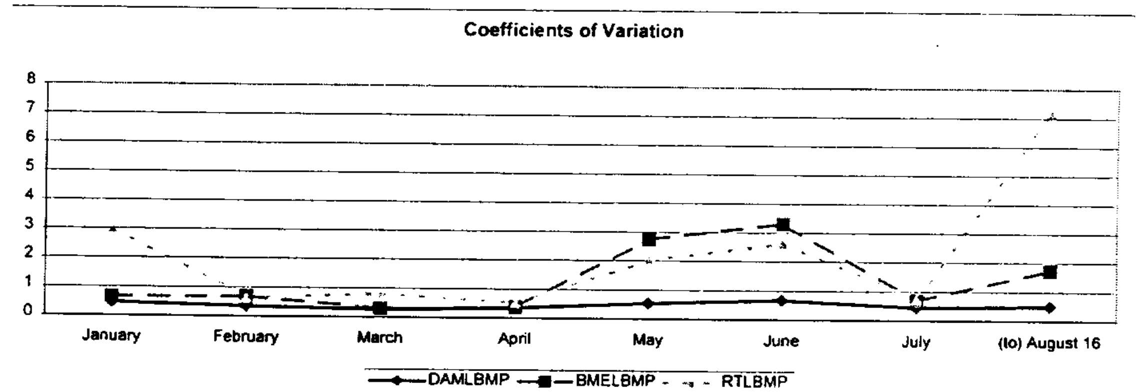
35. It is difficult to discern a trend in the CV of any of the three markets over the period examined. The CV for the DAM LBMP looks to be the most stable, while the CVs for the other two markets fluctuate. The CV for the DAM in any month is always less than its

counterparts, indicating that DAM prices do not exhibit much variation. On the other hand, BME and the RTM are both fairly volatile. Neither the BME nor the RTM show any strong tendency to be more volatile than the other. The data in tables and graphs show a marked increase in CV for BME and RTM in May, June, and August-to-date. Although prices for those markets moved a bit from their previous monthly paths, the variation in the prices increased even more; hence the increase in CV.

Graphs of the Monthly Performance of the Markets







36. There are some reasons for the increase in volatility during this time period. Two worth noting came about from requests by market participants.

37. Sometime in May, external transactions consummated in the DAM were given priority over those which came about in the BME. The reasoning was that with some of the purported problems of inappropriate transactions cuts in BME, the DAM was the right venue from which to signal that specific transactions should almost never be cut. The method of keeping transactions from being cut was to adjust export transactions by a large positive adder to the sink price, and to adjust import transactions by a large negative adder to the offer price. In both cases, the price signal to the market model was that the transactions should never be cut. This method of assigning a high priority had the effect of incorporating a bias into the prices considered by BME in its update of DAM information to the hour at hand. The NYISO believes that this bias has been manifested in increased volatility in BME. Moreover, since BME information is fed into SCD, the bias and resulting volatility is passed on to SCD.

38. A second change to the models that took place was an increase in the import transfer limit from Hydro-Quebec into the NYCA from 1,200 MW to 1,800 MW per hour (the limit was reduced in mid-August from 1,800 MW to 1,200 MW). The increase applied both to imports and to transactions wheeled through the NYCA. Regardless of the destination of the power from Hydro-Quebec, however, the flow in the NYCA aggravated congestion problems, particularly across the Central-East constraint. To the extent that energy from Hydro-Quebec was priced more cheaply than energy from NYCA sources (see the previous paragraph), the latter would effectively have had to find an alternate route within the NYCA, and would then have aggravated congestion elsewhere in the NYCA and at external proxy buses. The outcome of the flow patterns was an increase in price volatility as flow adjustments took place relative to the Marcy bus – the anchor point of the NYCA.

39. The descriptions above are possible explanations for increases in price volatility. The NYISO is committed to identifying the root causes of such volatility and working to eliminate that which can be eliminated by careful market redesign. The NYISO notes that these adjustments were made at the behest of market participants who were seeking to address some perceived problems in their operations (apparently unpredictable transactions cuts with severe financial consequences, and a seemingly arbitrary limit on imports) which would keep prices higher than necessary. Although those issues were addressed, there were consequences for other aspects of the NYCA's operations.

Price Convergence

40. Set forth below are calculations of the mean differences between markets pairs for the period from January 1, 2000 through August 16, 2000:

Monthly Mean Differences Between Pairs of Markets

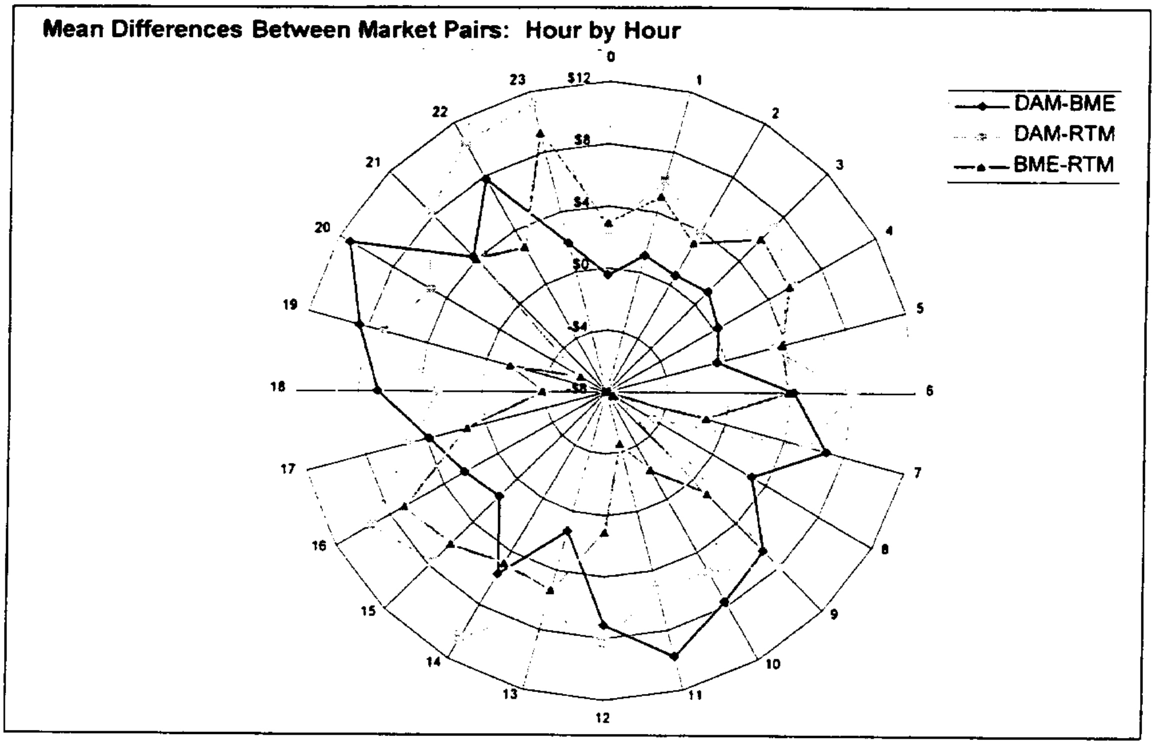
Means	DAM-BME	DAM-RTM	BME-RTM
January	$7.98	$1.07	-$6.91
February	$3.86	$6.35	$2.49
March	$4.34	$4.30	-$0.04
April	$2.26	$3.36	$1.09
May	$6.41	$3.09	-$3.32
June	$5.39	$14.27	$8.88
July	$3.86	$2.93	-$0.93
(to) August 16	-$4.21	$21.17	$25.38
January to Date	$4.26	$6.17	$1.91
Standard Error	$0.64	$0.71	$0.86

41. The last line of the foregoing table shows the standard errors of the means for the covered period. A test of significance would divide the mean by the standard error and then compare the calculation (of the computed statistic) against a benchmark "t" or "Z" value to test the null hypothesis that that the difference is zero. A quick way to arrive at the same result is to note that if the mean divided by the standard error exceeds 2, then the null hypothesis should be rejected. The calculation for BME-RTM shows that the computed statistic is indeed greater than 2: 2.22 to two decimal places. The comparable test number from the April data was –0.04. In April the NYISO concluded that the prices in the two markets were not different from each other, on average. The table above shows that the markets have diverged somewhat.

42. The divergence between the DAM and the RTM has increased somewhat as well. The mean differences between DAM and RTM, and between BME and RTM were $4.76 and $0.02 respectively. As shown in the table above, the comparable differences are $6.17 and $1.91.

43. Set forth below is a graph showing the differences between markets on an hour by hour basis across the entire time period. This "radar" display can be useful in understanding whether the aforementioned differences arise mainly during some specific part of the day.

Hour by Hour Differences in Market Price



44. The pattern of differences between markets across the day is intriguing. What shows most clearly is that the difference between BME and the RTM is consistently largest during the middle afternoon hours and during the late evening to early morning period. During the load pickup and load drop-off times – roughly 5 -12 noon and 5 -10 PM – the BME and RTM are quite similar to each other.

45. Set forth below is a table showing the hour by hour mean prices for the three markets, and the pairwise differences between the hour by hour prices. There does seem to be a bias in the prices, with BME prices higher than RTM prices in 17 of the 24 hours. The September 1 compliance filing explains some of the changes that have been made or that will be made to the BME and RTM models. Those changes address some of the reasons for the differences in the models' price outcomes. In addition, since BME secures for a number of constraints that are not faced by SCD, it should be expected that a BME model solution will show higher (shadow) prices. Generally, increasing the constraint set in any model does not lead to a better solution.

46. In summary, several perspectives on the potential convergence between BME and SCD indicate that over the time period studied, the two models looking at commitment and dispatch during the hour do not converge. Reasons for this lack of convergence include different constraint sets faced by each of the models, changes in information from the close of BME to the running of SCD, changes in the assumed amounts of generation available to each model, and changes in the amount of load for which each model must solve.

Hour by Hour Means and Mean Differences Between Pairs of Markets

	Means		
Hour Beginning	DAMLBMP	BMELBMP	RTLBMP
0	$22.75	$23.21	$20.31
1	$19.36	$18.24	$13.23
2	$17.95	$17.26	$14.21
3	$17.32	$16.18	$10.24
4	$17.49	$17.22	$11.65
5	$20.28	$20.89	$17.19
6	$26.92	$22.79	$19.01
7	$31.85	$25.02	$26.30
8	$30.63	$27.70	$35.17
9	$34.05	$27.55	$26.25
10	$34.63	$26.97	$29.19
11	$34.93	$25.18	$29.71
12	$34.45	$27.29	$26.16
13	$34.08	$32.75	$27.41
14	$33.44	$27.77	$22.90
15	$33.80	$32.18	$26.16
16	$35.82	$33.39	$26.46
17	$38.14	$34.36	$33.10
18	$36.59	$29.84	$33.74
19	$35.38	$26.87	$28.45
20	$34.16	$22.96	$29.03
21	$32.78	$28.53	$24.51
22	$30.56	$22.79	$20.07
23	$29.06	$27.14	$17.90

Hour Beginning	DAM-BME	DAM-RTM	BME-RTM
0	-$0.46	$2.44	$2.90
1	$1.12	$6.13	$5.02
2	$0.69	$3.74	$3.04
3	$1.14	$7.07	$5.93
4	$0.27	$5.84	$5.57
5	-$0.61	$3.10	$3.71
6	$4.12	$7.90	$3.78
7	$6.83	$5.55	-$1.28
8	$2.93	-$4.54	-$7.47
9	$6.50	$7.80	$1.30
10	$7.66	$5.44	-$2.22
11	$9.75	$5.22	-$4.53
12	$7.16	$8.29	$1.13
13	$1.33	$6.68	$5.35
14	$5.67	$10.54	$4.87
15	$1.62	$7.64	$6.02
16	$2.44	$9.36	$6.93
17	$3.78	$5.03	$1.26
18	$6.74	$2.84	-$3.90
19	$8.51	$6.92	-$1.58
20	$11.20	$5.13	-$6.08
21	$4.24	$8.26	$4.02
22	$7.76	$10.48	$2.72
23	$1.92	$11.15	$9.24

This concludes my affidavit.

Appendix

Monthly Summaries of Price Information in the DAM, BME, and RTM

(All observations)

	Means		
Month	DAMLBMP	BMELBMP	RTLBMP
January	$32.01	$37.63	$31.80
February	$30.49	$26.63	$24.14
March	$26.90	$22.56	$22.60
April	$27.84	$25.57	$24.48
May	$29.07	$5.17	$27.62
June	$33.71	$49.54	$19.47
July	$25.98	$22.12	$23.04
(to) August 16	$36.09	$32.06	$14.96
January to Date	$29.89	$27.39	$24.06

	Standard Deviations		
Month	DAMLBMP	BMELBMP	RTLBMP
January	$14.59	$371.37	$94.95
February	$10.56	$17.86	$15.41
March	$7.07	$6.85	$17.86
April	$9.51	$9.17	$12.50
May	$15.45	$4,987.06	$55.36
June	$22.52	$297.34	$50.08
July	$11.51	$14.78	$16.92
(to) August 16	$17.45	$176.21	$106.49
January to Date	$14.48	$1,838.95	$53.87

	Coefficients of Variation		
Month	DAMLBMP	BMELBMP	RTLBMP
January	0.46	9.87	2.99
February	0.35	0.67	0.64
March	0.26	0.30	0.79
April	0.34	0.36	0.51
May	0.53	964.27	2.00
June	0.67	6.00	2.57
July	0.44	0.67	0.73
(to) August 16	0.48	5.50	7.12
January to Date	0.48	67.14	2.24

Note: As noted in paragraph 30 of this affidavit, 19 observations were deleted from the dataset. Generally, analysis of a dataset should include all observations. However, there are valid reasons to exclude certain observations. Criteria for exclusion usually focus on particular observations being tainted and potentially invalid, or being the result of incorrect entry procedures, or being so far out of line that they will skew any analysis beyond usefulness.

The dataset under consideration contains data that falls into the latter category. The criterion used to exclude observations was that the difference between the DAM and BME price had to exceed $1,000 in absolute value. This criterion does not automatically exclude data with high prices.

The situations meeting the criterion were generally those with BME prices beyond $1,000, either positive or negative. Fifteen of the observations had BME prices beyond $2,000 in absolute value. Of those fifteen cases, seven were situations in which the BME price was beyond $10,000 in absolute value. These results reflect circumstances in which BME was attempting to solve reserve constraints that are not enforced in real time.

The list of excluded observations follows:
18 January: hour 9
8 May: hours 13, 14, 16-22
29 May: hour 5
5 June: hours 10-12
6 June: hours 11, 12, and 14
27 June: hour 18
6 August: hour 22

The descriptive statistics in this appendix can be compared with those in the table following paragraph 27 to discern the difference in means, standard deviation and CV for January, May, June, and August. Conclusions as to volatility and convergence do not change. Removing these observations does not make the series converge. The pattern of volatility described in the affidavit remains as well.

James H. Savitt
Manager of Market Power Monitoring

Subscribed and sworn to before me
this 30th day of August, 2000.

DIANE L. EGAN
Notary Public, State of New York
Qualified in Schenectady County
No. 4924890
Commission Expires March 21, 20 02

Diane L. Egan
Notary Public

In and for the County of Schenectady
State of New York

My Commission expires March 21, 2002

EXHIBIT V-A

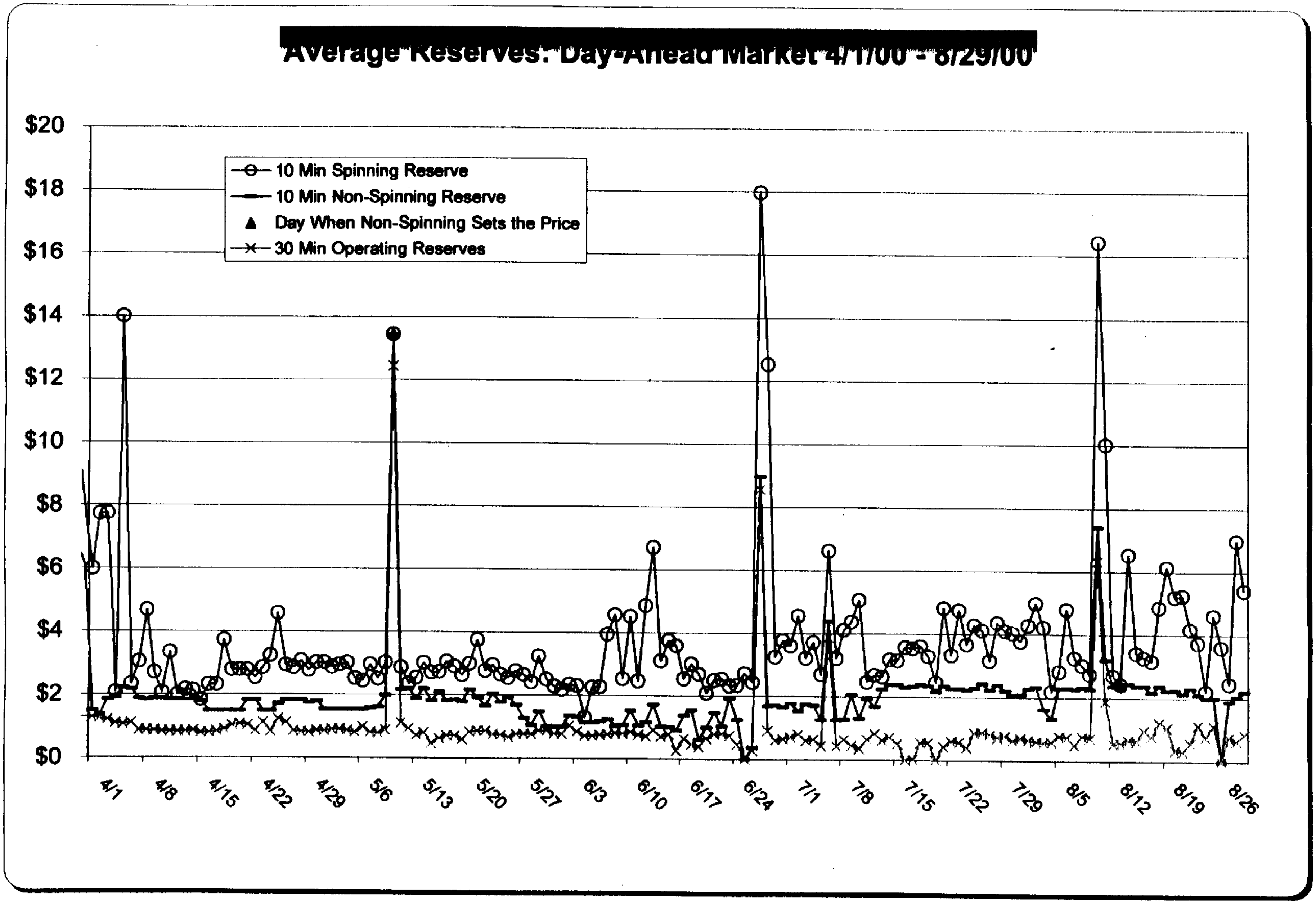

Average Reserves: Day-Ahead Market 4/1/00 - 8/29/00
$20
$18
$16
$14
$12
$10
$8
$6
$4
$2
$0
10 Min Spinning Reserve
10 Min Non-Spinning Reserve
Day When Non-Spinning Sets the Price
30 Min Operating Reserves
4/1
4/8
4/15
4/22
4/29
5/6
5/13
5/20
5/27
6/3
6/10
6/17
6/24
7/1
7/8
7/15
7/22
7/29
8/5
8/12
8/19
8/26

EXHIBIT V-B

Mean Day-Ahead Prices for Reserves

Category\Month	April	May	June	July	To August 29
10 SP	$3.51	$3.10	$3.89	$3.76	$4.58
10 NSR	$1.75	$2.07	$1.47	$2.12	$2.31
30 OR	$0.94	$1.17	$0.93	$0.66	$0.92

EXHIBIT V-C

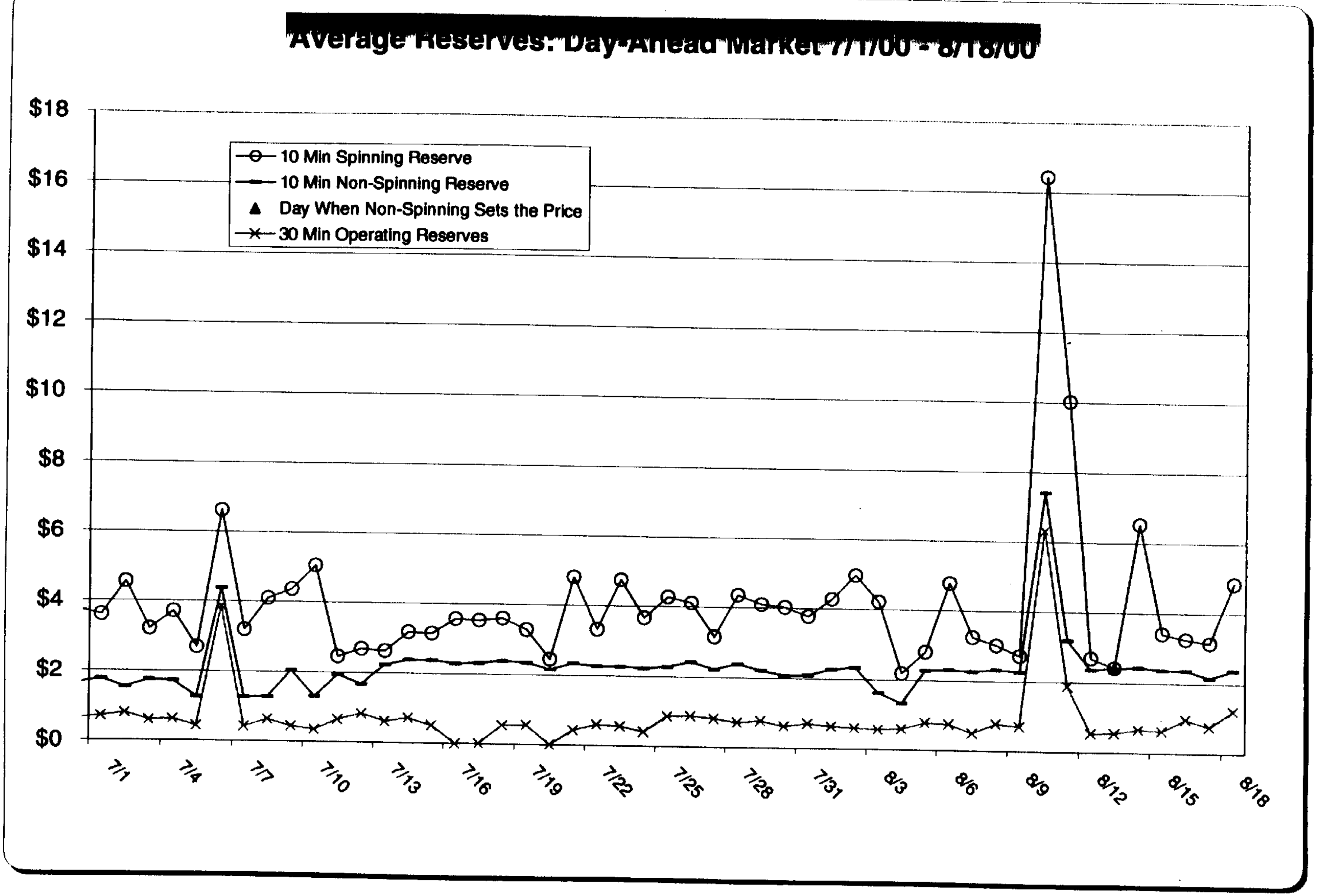
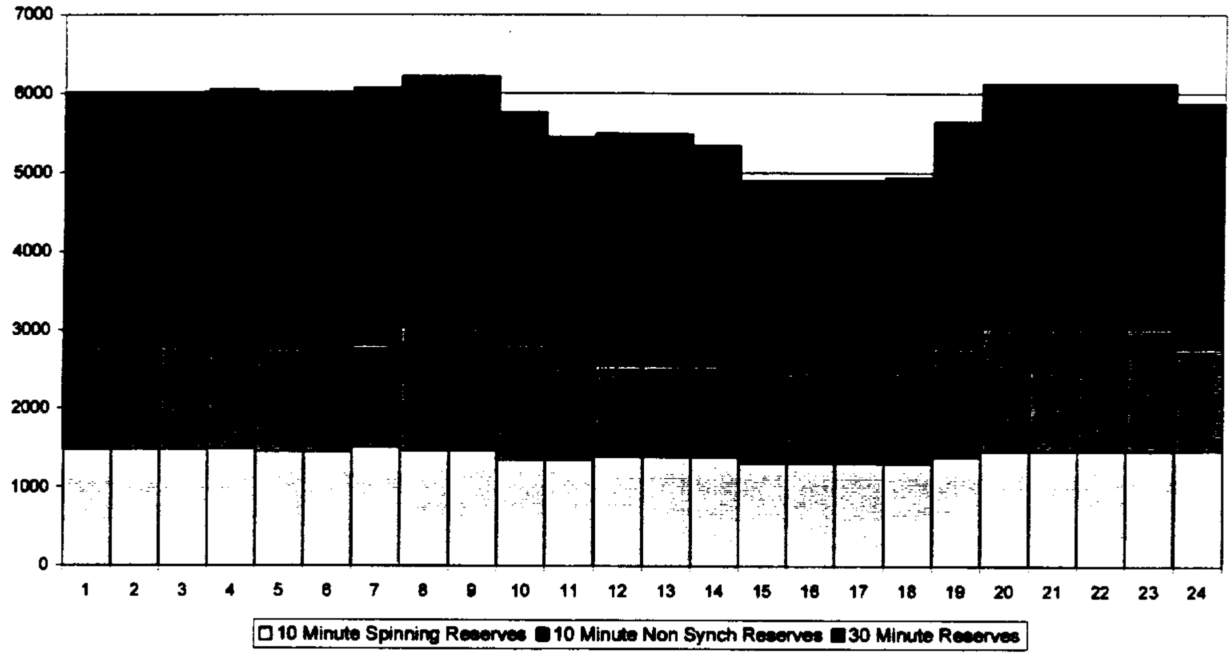

Average Reserves: Day-Ahead Market 7/1/00 - 8/18/00
$18
$16
$14
$12
$10
$8
$6
$4
$2
$0
10 Min Spinning Reserve
10 Min Non-Spinning Reserve
Day When Non-Spinning Sets the Price
30 Min Operating Reserves
7/1
7/4
7/7
7/10
7/13
7/16
7/19
7/22
7/25
7/28
7/31
8/3
8/6
8/9
8/12
8/15
8/18

EXHIBIT V-D

August 1, 2000 Day Ahead Market
Offered Reserve MW



August 1, 2000 Day Ahead Market
Accepted Reserve MW

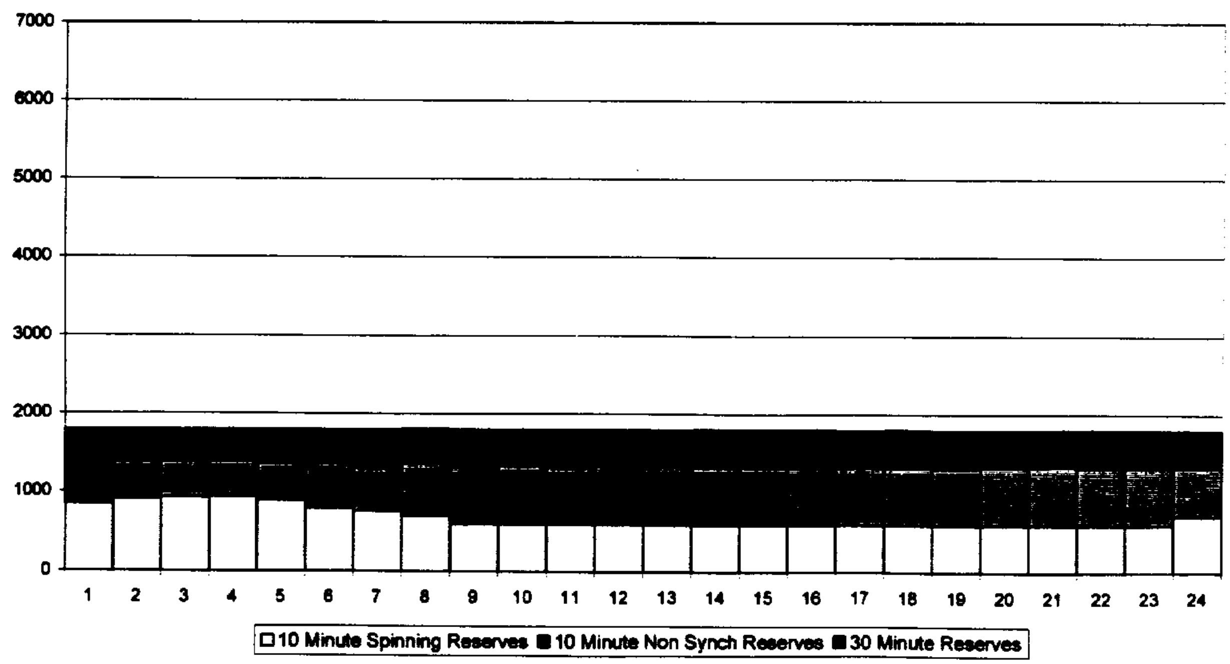


EXHIBIT V-E

Day Ahead Market Hourly Reserve Offers
July 5- August 19th, 2000

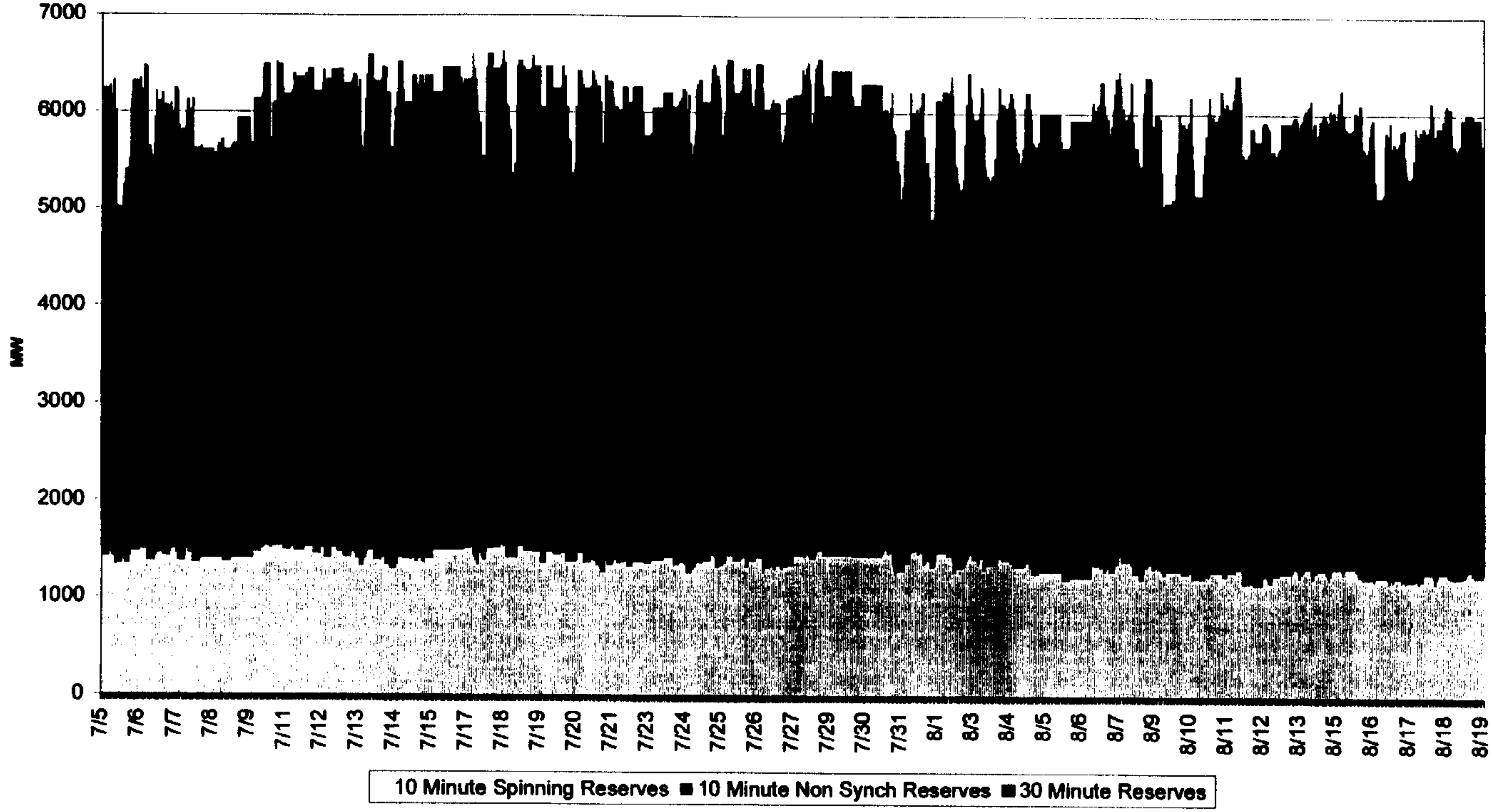
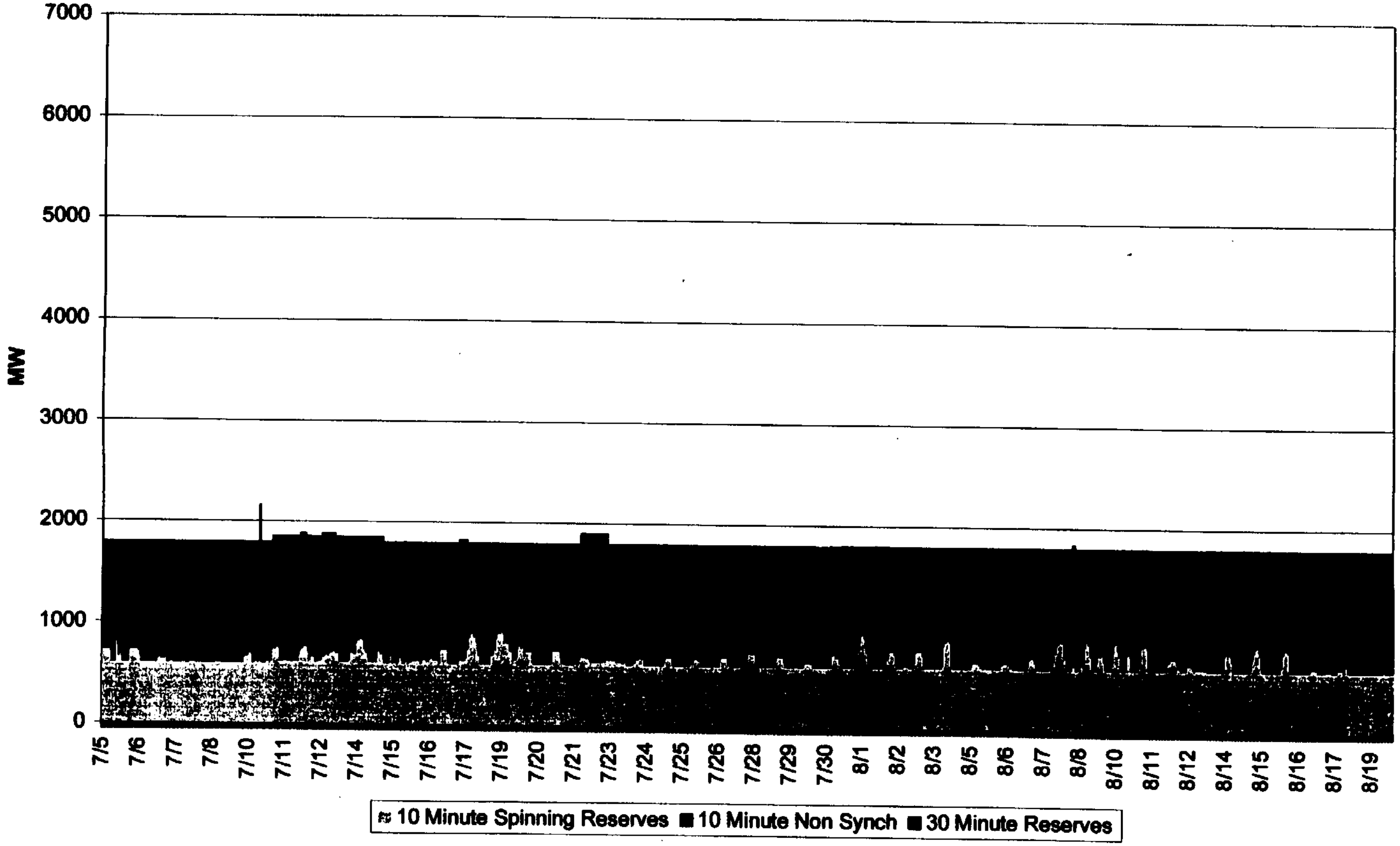


EXHIBIT V-F

Day Ahead Market Hourly Accepted Reserves
July 5-August 19th, 2000



Extraordinary Corrective Actions

1. The MIS does not produce a viable input file for the SCUC program (DAM bid data), or possibly for the BME/SCD programs (HAM bid data), but the bid data is retrievable.

If the data is accessible despite the inability of MIS to generate an appropriate SCUC input file, then NYISO staff will use the information at hand to undertake a manual commitment of units which recognizes the scheduling of firm external transactions. Right now there is no way to initialize the SCUC-Dispatch from any form of manual commitment/schedule. Currently, a manual commitment would be incremental in the sense that units already on would remain on, and additional units would be turned on to meet the NYISO's load forecast for the coming day. Since day-ahead prices cannot be determined, there would be no forward contracts; all transactions and TCCs would be settled in the RTM.

If this situation should arise for the BME, there is currently a methodology for initializing SCD for the coming hour from day-ahead and hour-ahead information. Assuming the SCD is operational, this commitment can then be used together with the bid information by SCD to conduct the dispatch and produce real time prices. If the SCD is not operational, the NYISO will invoke the procedures listed in #6, below.

2. The MIS does not produce a viable input file for the SCUC program (DAM bid data), or possibly for the BME/SCD programs (HAM bid data), and the data is not retrievable.

In this case, there is no current bid information on which to form a basis for commitment, let alone a schedule or prices. In both of these situations, it is reasonable to assume that the most recent previous input file is still available, either the previous day for the SCUC program or the previous hour for the BME/SCD process.

For day-ahead purposes, the NYISO will create a commitment for the next day utilizing ICAP generation commitments (derived the previous day) for the current day together with the most recent previous comparable day's generator bids, adjusted for known outages. In order to accommodate firm external transactions, the NYISO will notify market participants of the MIS failure as soon as possible and request that information on firm external transactions for both hour-ahead and day-ahead scheduling be sent via alternative means (e.g., fax or phone). The commitment will set ICAP at minimum generation, all market transactions will take place in the RTM, and TCCs will be settled at real time prices.

For the BME, this contingency will cause the NYISO to begin with the information from the previous hour's schedules and bids (i.e., which units are on, which are off and how long they have been off, and which ones are on a forced or maintenance outage). Based on this information and the most recent bid data, the NYISO would develop a commitment to be input into BME to develop a schedule for the next hour. SCD would then have a viable commitment set along with current information to dispatch over the coming hour and produce real-time LBMPs. However, if SCD is not operational, the procedures listed in #6, below will be invoked.

3. Something interferes with the ability of the NYISO to post DAM results by 11AM.

While the tariff and a GIRT resolution do treat the 11AM posting time as fixed, prudence requires that we articulate ECAs for the above situation and others in which the NYISO cannot meet that deadline.

The ECA is designed to give the NYISO the flexibility to address systems problems which might delay posting. At the same time, it is designed both to preserve the integrity of the two settlement system, and provide Market participants with the certainty necessary for them to conduct their businesses. For the first two weeks of operations the NYISO will post DAM results no later than 3PM. If the NYISO cannot meet the 3PM posting deadline, then it will forego the DAM, and all transactions will take place in the RTM. For the second two weeks the NYISO will tighten the posting deadline to 1PM. The NYISO will make every effort to post DAM results by 11AM, but in any event no later than 3PM (1PM after two weeks). Starting with week five, the NYISO will forego that day's DAM if it cannot post by 11AM. The NYISO states in the strongest terms that it remains committed to the goal of posting DAM results by 11AM. To execute this ECA, the NYISO will either post the DAM results by 11AM, or it will announce that posting may be as late as 3PM (in the first two weeks) or 1PM (in the second two weeks). Units scheduled to be on are required to be on, just as if they were committed through SRE.

4. Dispatchers make modifications to a nominally correctly solved dispatch set.

The original commitment information set should still be applicable, and settlement would take place at DAM and SCD prices as appropriate. Additional generation should get the market-clearing price, and through uplift receive the difference between the clearing price and its bid. Adjustments would also be made to recognize that there may be discrepancies between the original basepoints and those assigned by the dispatcher to bring about the modifications. The units selected (either via SRE or dispatcher initiative) will not set the LBMP since they are being dispatched out of merit order.

5. Incorrectly Calculated Prices are Posted

This contingency is more likely to fall into the category of a transitional abnormality in the process of gaining experience with the system. The ISO will have a procedure to validate posted prices, and will investigate potential anomalies that could be resulting from dispatcher error or programming problems. From 17 November through 7 December the NYISO will identify potentially incorrectly calculated prices within seventy-two hours, and correct them within a period of seven days from identification. From 8 December through 31 December 1999 the NYISO will identify such prices within forty-eight hours and correct them within a period of seven days from identification. Before the end of 1999 the NYISO will re-evaluate its seven-day window, with the objective of narrowing it.

After 31 December 1999, the NYISO will reduce to twenty-four hours the period within which it will identify the potentially invalid prices. Posted prices emerging from the process of identification and correction will be final and not subject to further revision.

6. **The general failure of the NYISO's control area functions necessitates TO-directed dispatch.**

The backup dispatch system (BDS) procedures for billing provide an ECA for the development of LBMPs in this circumstance. The BDS uses the most recent bidding information provided by the NYISO to the Transmission Owners for emergency purposes. This information, along with current DNI, allows dispatch to take place on a zonal basis. During the contingency, the Transmission Owners can dispatch economically within their own zones and meet DNI. This dispatch pattern probably will not be a NYCA optimum, but it will utilize the most recent generator bid curves that are available.

Billing reconciliation can take place when the contingency has passed. The NYISO needs the actual bid curves used, information on the output of the generators in the control areas, and the hourly integrated inter-zone tie line flows. The ECA in this circumstance focuses on achieving LBMPs that are as close as possible to a market solution, given that there was a major contingency. The NYISO would use the bid curves and other supporting information to create an optimal dispatch and associated LBMPs. Generators would receive the resulting LBMPs for their actual generation during the contingency. Since the actual dispatch was different from the optimal, reconstructed dispatch, and since some generators might have been dispatched when they exceeded the zonal LBMP, recovery for the contingency-driven actions will have to come from uplift charges. The LBMPs are associated with an optimal dispatch set, although the actual dispatch was different from optimal.

7. **ICAP Units fail to bid**

7a. ICAP units are required to bid into the DAM to satisfy the reliability requirements of the NYCA. Failure of an ICAP unit to bid into the DAM is a serious default on that unit's obligation to be available. This ECA is intended to provide Market Participants with the flexibility that they need in order to be aggressive competitors in various electricity markets, and at the same time provide the NYISO with the certainty that it needs to maintain system reliability.

The NYISO asks that ICAP units provide bids for at least seven, and up to fifteen days into the future. The NYISO would check the MIS database for bids that are eight, nine, ten, or eleven days into the future. If an ICAP unit has no such DAM bid, then the NYISO will replicate the last day's bid found for that unit through day fifteen. Market participants may populate the MIS with bids for the twelfth through the fifteenth day so that no actions would be undertaken by the NYISO. Participants may overwrite their bids at any time. They have full control over their bids up until the 5AM closing for the DAM. The first seven days allow for the lead time wherein only Market Participants can change bids since Market Services will populate only days eight through fifteen.

Should a unit need to make itself unavailable during any of days beyond the most recently closed DAM, it needs to take the action of deleting its bid. The NYISO will understand a deleted bid to mean that a unit is out of service.

7b. ICAP units not selected in the DAM are free to offer their resources to other areas, subject to the ICAP recall provisions. ICAP units not selected for the DAM and not operating in other markets will remain available for the SRE process. The intent and effect is to have ICAP units continually available for reliability, especially during the startup period of the market.

MEMO

To: James H. Savitt

From: William J. Museler

Date: May 12, 2000

Extraordinary Corrective Action ("ECA"):
Implementation Flaw re: Hydro Limited Resources

You have advised me of the emergence of a market design flaw, specifically an implementation flaw affecting the way Hydro Limited Resources ("HLRs") manage their bids within the confines of the NYISO's market models. HLRs must limit their electric production due to limitations driven by resource restrictions, maintenance, environmental, or other factors. The only method for limiting such production within the current software system is for these units to either delete their bids or to submit bids with extraordinarily high upper segments so that the likelihood of being chosen to operate is extremely low. When HLRs are scheduled at these upper segments, they may set clearing prices that reflect extraordinarily high bids submitted solely to limit their operation. Such bids do not reflect rational or verifiable elements of bid offers for example, fuel, maintenance, emissions credit, opportunity, or other costs. This result is not an outcome that would occur in a workably competitive market.

Under the NYISO's Temporary Extraordinary Procedures for Correcting Market Design Flaws and Addressing Transitional Abnormalities ("TEPs") the NYISO is empowered to correct this kind of implementation flaw since it would cause artificially high clearing prices and have a significant impact upon the New York markets. Accordingly, I request that you that you implement emergency corrective action to that will prevent HLRs bidding as described above from setting the marginal clearing price. The recalculated clearing prices should reflect a level that would be expected under the prevailing market conditions in the absence of this implementation flaw.

Please develop the text of the ECA and post it on the OASIS for immediate implementation.

Extraordinary Corrective Actions

(Updated and Renumbered)

1. Something interferes with the ability of the NYISO to post DAM results by 11AM.

While the tariff treats the 11AM posting time as fixed, prudence requires that the NYISO have limited flexibility to maintain a day ahead market even in the face of a slight delay in the posting of the DAM results.

The ECA is designed to give the NYISO the flexibility to address systems problems which might delay posting. At the same time, it is designed both to preserve the integrity of the two settlement system, and provide Market participants with the certainty necessary for them to conduct their businesses. The NYISO will post DAM results no later than 3PM. If the NYISO cannot meet the 3PM posting deadline, then it will forego the DAM, and all transactions will take place in the RTM. The NYISO will make every effort to post DAM results by 11AM, but in any event no later than 3PM. The NYISO remains committed to the goal of posting DAM results by 11AM. To execute this ECA, the NYISO will either post the DAM results by 11AM, or it will announce that posting may be as late as 3PM. Units scheduled to be on are required to be on, just as if they were committed through SRE.

2. Incorrectly Calculated Prices are Posted

This contingency is more likely to fall into the category of a transitional abnormality or a market design flaw which must be corrected manually until a software change can be made to the system. The NYISO has a procedure to validate posted prices, and will investigate potential anomalies that could result from dispatcher errors, incorrect data or programming problems. The NYISO will identify such prices no later than 5PM on the following calendar day and correct them within a period of five calendar days from the date of identification. Posted prices emerging from the process of identification and correction will be final and not subject to further revision.

ICAP Units fail to bid

3a. ICAP units are required to bid into the DAM to satisfy the reliability requirements of the NYCA. Failure of an ICAP unit to bid into the DAM is a serious default on that unit's obligation to be available. This ECA is intended to provide Market Participants with the flexibility that they need in order to be aggressive competitors in various electricity markets, and at the same time provide the NYISO with the certainty that it needs to maintain system reliability.

The NYISO asks that ICAP units provide bids for at least seven, and up to fifteen days into the future. The NYISO would check the MIS database for bids that are eleven days into the future. If an ICAP unit has no such DAM bid, then the NYISO will replicate the last day's bid found for that unit through day eleven. Market participants may populate the MIS with bids for the twelfth through the fifteenth day so that no actions would be undertaken by the NYISO. Participants may overwrite their bids at any time. They have full control over their bids up until the 5AM closing for the DAM. The first seven days allow for the lead time wherein only Market Participants can change bids since Market Services will populate only days eight through fifteen.

Should a unit need to make itself unavailable during any of days beyond the most recently closed DAM, it needs to take the action of deleting its bid. The NYISO will understand a deleted bid to mean that a unit is out of service.

3b. ICAP units not selected in the DAM are free to offer their resources to other areas, subject to the ICAP recall provisions. ICAP units not selected for the DAM and not operating in other markets will remain available for the SRE process. The intent and effect is to have ICAP units continually available for reliability.

Path: DOCSOPEN\WASHINGT\00876\55430\000001\2%ZM01!.DOC
Doc #: 133474; V. 1
Doc Name: latest TEP document
Author: Quint, Arnold, 00876

New York Independent System Operator

Extraordinary Corrective Action for Hydro Limited Resources

Implementation Policy

For units identified as Hydro Limited Resources (HLRs), the NYISO will recognize the appropriate megawatt range as an out-of-merit, resource-limited-block of their bid curve. Should such units be dispatched into that range, they will be designated as "out-of-merit: Hydro Limited Resource." That dispatch level will not set the LBMP, but will receive the LBMP that would have prevailed had the HLR not been dispatched into the resource-limited-block.

JULY 28, 2000

Energy Limited Resources (ELR) Emergency Corrective Action (ECA)

This memorandum is a follow-up to the NYISO staff's announcement at the July 20, 2000 BIC meeting that, after considering the views expressed by certain Market Participants and after discussing the issue with the NYISO Board of Directors, the May 12, 2000 ECA implemented in connection with certain ELRs would remain in effect and the May 8th and 9th price corrections would not be modified. This memorandum attempts to answer, within the bounds of the NYISO's confidentiality obligations, some of the questions raised about this issue.

1. The Events of May 8th and 9th

On May 8th and 9th the New York Control Area ("NYCA") experienced an unexpected combination of high temperatures, curtailed imports and generator outages that resulted in both unanticipated stress on the NYCA and bidding patterns and consequences that had not previously been seen.

The NYISO, consistent with its market monitoring practices, contacted several Market Participants concerning their bidding behavior on these dates. These communications revealed a flaw arising from the existing market design and bidding rules and dispatch software limitations. As a consequence of this flaw, an affected Market Participant, submitted bids intended to manage its ELR units' physical operation and output that bore no relationship to the units' production cost or opportunity cost. Because there presently is no other mechanism to convey a more precise message about the Market Participant's desired mode of physical operation and because all ICAP resources must be bid into the DAM, the Market Participant used artificially high bids to attempt to manage its units' dispatch by the NYISO.

These artificially high bids set clearing prices that would not have occurred but for the bidding and software limitations that presently exist. The NYISO did not unilaterally "interpret" the meaning of any Market Participant's bids and acted to correct prices only after having been made aware of the consequences of one bidder's inability to convey a more complex message about its operational limits under the current bidding rules and dispatch system.

2. The Nature of the Problem

The generating units in question historically have served as tools to manage the physical operation of the NYCA and, at certain times, to ensure system reliability. It is the owner's intent to operate the units in the current market in a manner consistent with their historic operation. Because of either unique design and/or non-economic restrictions, the units are limited in output or hours during a multi-day period. In particular, the units are physically incapable of, legally precluded from, or unable to sustain certain high levels of output beyond a prescribed period. The owner's intended mode of operation was not to limit the ELR units' output to some operating limit unless the clearing price reached a pre-determined dollar amount. Likewise, the owner did not intend to set an absolute limit on the short-term output of the unit by derating the unit. Rather, the owner's intent was to limit the units' operation except where, among other conditions, system reliability required the units to be dispatched at their highest levels. Simply bidding a high price to manage or conserve output does not accurately convey this complex message. Moreover, the units' owner acknowledged that its bids bore no rational relationship to any actual operating or opportunity cost. That is, had the units' owner been able to convey more accurately their availability and desired mode of physical operation, the bids would not have been set at artificially high levels.

3. The Nature of the Price Corrections

As discussed above, the ELR owner used a high bid price to attempt to manage the physical operation of its units in a more sophisticated manner than the current software and bidding rules will allow (while at the same time meeting the ICAP bidding requirements). Because the units in question were on the margin for a number of hours during May 8th and 9th, the resulting clearing prices did not reflect prices that would have occurred in an efficient operating market.

The NYISO corrected clearing prices by setting them at the highest non-ELR bid, i.e., the marginal bid cost that would have resulted absent the flaw. The ELRs were treated as infra-marginal and paid the corrected clearing price.

Several Market Participants commented that the appropriate remedy, if the ELRs did not want to run, would have been not to dispatch them and to call on the next unit in the bid stack. This approach was not possible because the ELRs were required to run to maintain the system's reliability i.e., there was no additional internal generation to dispatch in lieu of the ELR units.

Further, the problem encountered was not that the ELR units were refusing to run, under any circumstances, at their highest operating ranges. The ELRs were willing to run at their upper ranges for limited periods, as they had historically, when most needed to maintain system reliability. The problem was that they were forced, under the current bidding rules and software limitations, to use artificially high bids to convey a message that was more complex than (i) "dispatch the unit," (ii) "do not dispatch the unit" or (iii) "only dispatch the unit if the prices are at or above its bid."

Finally, the ELR units did, in fact, run on May 8th and 9th and the ECA price revision occurred after the actual dispatch. Thus, the NYISO could not, after the fact, devise a correction that would have required it to assume that the ELR units did not run and re-set clearing prices at a level that would have been set by resources that never actually were dispatched.

4. The NYISO's Proposal to Remedy the Problem

Prospectively, the NYISO will not "interpret" the meaning of any Market Participant's bid. Rather it is attempting to address the problem which was revealed on May 8th and 9th by developing a method for ELRs to both comply with ICAP bidding requirements and to convey their desired mode of physical operation in a more precise way than simply by submitting artificially high bids. The approach being developed by the NYISO would permit ELRs to submit bids that designate two ranges for operation. First, an ELR unit could bid an initial range with an operating upper limit at which the unit would under any circumstances be dispatched so long as it is in economic merit order. Second, an ELR unit could bid an upper operating range, available for a limited duration, designed to be used only when triggered by certain system requirements.

The NYISO staff believes that this approach, which requires further definition, may be useful for gas turbines with environmental restrictions, pumped storage units, and hydro units with water restrictions. The general approach outlined above would provide a more precise way than submitting artificially high bids for ELRs to manage their operation at certain upper operating ranges. This approach should avoid the phenomenon, experienced on May 8th and 9th, of clearing prices that bear absolutely no relationship to any actual long or short-term operating cost or opportunity cost. The NYISO intends to pursue this proposal in greater detail with the Scheduling and Pricing Working Group.

JULY 28, 2000

Energy Limited Resources (ELR) Emergency Corrective Action (ECA)

This memorandum is a follow-up to the NYISO staff's announcement at the July 20, 2000 BIC meeting that, after considering the views expressed by certain Market Participants and after discussing the issue with the NYISO Board of Directors, the May 12, 2000 ECA implemented in connection with certain ELRs would remain in effect and the May 8th and 9th price corrections would not be modified. This memorandum attempts to answer, within the bounds of the NYISO's confidentiality obligations, some of the questions raised about this issue.

1. The Events of May 8th and 9th

On May 8th and 9th the New York Control Area ("NYCA") experienced an unexpected combination of high temperatures, curtailed imports and generator outages that resulted in both unanticipated stress on the NYCA and bidding patterns and consequences that had not previously been seen.

The NYISO, consistent with its market monitoring practices, contacted several Market Participants concerning their bidding behavior on these dates. These communications revealed a flaw arising from the existing market design and bidding rules and dispatch software limitations. As a consequence of this flaw, an affected Market Participant, submitted bids intended to manage its ELR units' physical operation and output that bore no relationship to the units' production cost or opportunity cost. Because there presently is no other mechanism to convey a more precise message about the Market Participant's desired mode of physical operation and because all ICAP resources must be bid into the DAM, the Market Participant used artificially high bids to attempt to manage its units' dispatch by the NYISO.

These artificially high bids set clearing prices that would not have occurred but for the bidding and software limitations that presently exist. The NYISO did not unilaterally "interpret" the meaning of any Market Participant's bids and acted to correct prices only after having been made aware of the consequences of one bidder's inability to convey a more complex message about its operational limits under the current bidding rules and dispatch system.

2. The Nature of the Problem

The generating units in question historically have served as tools to manage the physical operation of the NYCA and, at certain times, to ensure system reliability. It is the owner's intent to operate the units in the current market in a manner consistent with their historic operation. Because of either unique design and/or non-economic restrictions, the units are limited in output or hours during a multi-day period. In particular, the units are physically incapable of, legally precluded from, or unable to sustain certain high levels of output beyond a prescribed period. The owner's intended mode of operation was not to limit the ELR units' output to some operating limit unless the clearing price reached a pre-determined dollar amount. Likewise, the owner did not intend to set an absolute limit on the short-term output of the unit by derating the unit. Rather, the owner's intent was to limit the units' operation except where, among other conditions, system reliability required the units to be dispatched at their highest levels. Simply bidding a high price to manage or conserve output does not accurately convey this complex message. Moreover, the units' owner acknowledged that its bids bore no rational relationship to any actual operating or opportunity cost. That is, had the units' owner been able to convey more accurately their availability and desired mode of physical operation, the bids would not have been set at artificially high levels.

3. The Nature of the Price Corrections

As discussed above, the ELR owner used a high bid price to attempt to manage the physical operation of its units in a more sophisticated manner than the current software and bidding rules will allow (while at the same time meeting the ICAP bidding requirements). Because the units in question were on the margin for a number of hours during May 8^{th} and 9^{th}, the resulting clearing prices did not reflect prices that would have occurred in an efficient operating market.

The NYISO corrected clearing prices by setting them at the highest non-ELR bid, i.e., the marginal bid cost that would have resulted absent the flaw. The ELRs were treated as infra-marginal and paid the corrected clearing price.

Several Market Participants commented that the appropriate remedy, if the ELRs did not want to run, would have been not to dispatch them and to call on the next unit in the bid stack. This approach was not possible because the ELRs were required to run to maintain the system's reliability i.e., there was no additional internal generation to dispatch in lieu of the ELR units.

Further, the problem encountered was not that the ELR units were refusing to run, under any circumstances, at their highest operating ranges. The ELRs were willing to run at their upper ranges for limited periods, as they had historically, when most needed to maintain system reliability. The problem was that they were forced, under the current bidding rules and software limitations, to use artificially high bids to convey a message that was more complex than (i) "dispatch the unit," (ii) "do not dispatch the unit" or (iii) "only dispatch the unit if the prices are at or above its bid."

Finally, the ELR units did, in fact, run on May 8th and 9th and the ECA price revision occurred after the actual dispatch. Thus, the NYISO could not, after the fact, devise a correction that would have required it to assume that the ELR units did not run and re-set clearing prices at a level that would have been set by resources that never actually were dispatched.

4. The NYISO's Proposal to Remedy the Problem

Prospectively, the NYISO will not "interpret" the meaning of any Market Participant's bid. Rather it is attempting to address the problem which was revealed on May 8th and 9th by developing a method for ELRs to both comply with ICAP bidding requirements and to convey their desired mode of physical operation in a more precise way than simply by submitting artificially high bids. The approach being developed by the NYISO would permit ELRs to submit bids that designate two ranges for operation. First, an ELR unit could bid an initial range with an operating upper limit at which the unit would under any circumstances be dispatched so long as it is in economic merit order. Second, an ELR unit could bid an upper operating range, available for a limited duration, designed to be used only when triggered by certain system requirements.

The NYISO staff believes that this approach, which requires further definition, may be useful for gas turbines with environmental restrictions, pumped storage units, and hydro units with water restrictions. The general approach outlined above would provide a more precise way than submitting artificially high bids for ELRs to manage their operation at certain upper operating ranges. This approach should avoid the phenomenon, experienced on May 8th and 9th, of clearing prices that bear absolutely no relationship to any actual long or short-term operating cost or opportunity cost. The NYISO intends to pursue this proposal in greater detail with the Scheduling and Pricing Working Group.

Introduction

There were a number of price corrections made in the real time price data for the month of June. There were five issues that caused the need for the price corrections.

1. Incorrect setting of SCD upper limits on steam units in the price calculation step in intervals in which gas turbines (GTs) are uneconomic.
2. Load data not consistent with actual loads.
3. The posted prices are inconsistent with the bids of marginal units and units at their SCD limits.
4. SCD timing problems
5. Incorrect on the hour prices

Each of these issues is described in detail and each interval during June for which a price correction was necessary is listed with a description of which issues resulted in the correction.

Description of Corrections

1. Incorrect setting of upper limits on steam units

The SCD upper limits of steam units are set using a cumulative basepointing methodology that sets the limit based on the higher of the actual output of the unit and the prior intervals final basepoint.

At times where there are large amounts of uneconomic GTs in the pricing dispatch that are basepointed in the final dispatch to their full capacity, the large differences between the actual and price calculation dispatch can cause SCD to use incorrect unit limits in the price calculation dispatch

A software fix has been designed that will allow the SCD upper limits in the pricing dispatch to be defined off the prior interval’s pricing dispatch rather than the final dispatch. This will allow SCD to see all of the available economic capacity on the flexible resources subject to ramping constraints. This fix is under development.

Prices were corrected by determining the level at which the steam units would have operated in the pricing dispatch had the SCD upper limits been set correctly.

2. Load data problem caused SCD to stop

A failure to read the NYSEG load data led to a bad NYCA load calculation that caused SCD to stop. Prices were corrected using the average of the interval before and after the data problem occurred.

3. Prices inconsistent with the bids of marginal units and units at their SCD limits

These price corrections are required due to various algorithm and communication problems that result in the prices posted for particular intervals being inconsistent with the bids and schedules produced by SCD. Sometimes this is due to multiple runs of SCD in very short time frame, other times an inability of SCD to correctly solve particular inequalities that result in the reference bus price being calculated incorrectly.

Prices were corrected using the average of the prices in the interval before and the interval after to the extent that these prices were also valid.

4. SCD timing problems.

SCD executions are performed close together causing incorrect data to be passed to the LBMP calculation module. In these instances the prices were inconsistent with the schedules. Prices are corrected based on either the interval before, or the interval after, depending on which one is consistent with the schedules.

5. Incorrect on the hour prices

Prices did not equal those in the last SCD interval of the prior hour.

Intervals Corrected

June 1 Price Adjustments:

11:32, 11:33 and 11:43 - (3) Prices inconsistent with the bids of marginal units and units at their SCD limits
12:00, 12:18, 12:28 through 13:00 - (1) Incorrect setting of upper limits on steam units
13:00, 13:06, 13:11, 13:23, 13:24, 13:32 and 13:45 through 13:55 - (1) Incorrect setting of upper limits on steam units
14:00 through 14:18, 14:23, 14:24, 14:27 and 14:37 through 15:00 - (1) Incorrect setting of upper limits on steam units
15:11 through 15:29 - (1) Incorrect setting of upper limits on steam units
19:23 through 19:46, 19:51 and 19:55 - (1) Incorrect setting of upper limits on steam units
20:05 and 20:23 through 20:41 - (1) Incorrect setting of upper limits on steam units
22:10 through 22:44 and 22:54 through 23:21 - (1) Incorrect setting of upper limits on steam units

June 2 Price Adjustments:

11:12, 11:17, 11:28, 11:33 through 11:51 and 11:55 - (1) Incorrect setting of upper limits on steam units
12:00, 12:29, 12:47 and 12:55 - (1) Incorrect setting of upper limits on steam units
13:06 - (1) Incorrect setting of upper limits on steam units
16:48 – (4) SCD timing problems
18:43 - (3) Prices inconsistent with the bids of marginal units and units at their SCD limits

June 3 Price Adjustments:

No price corrections required.

June 4 Price Adjustments:

No price corrections required.

June 5 Price Adjustments:

13:50 and 13:51 - (2) Load data problems

June 6 Price Adjustments:

No price corrections required.

June 7 Price Adjustments:

No price corrections required.

June 8 Price Adjustments:

No price corrections required.

June 9 Price Adjustments:

11:16, 11:18, 11:32 and 11:35 - (1) Incorrect setting of upper limits on steam units
12:15 through 12:19, 12:34 through 12:44 and 12:55 through 13:20 - (1) Incorrect setting of upper limits on steam units
13:24 - (3) Prices inconsistent with the bids of marginal units and units at their SCD limits
13:29 through 14:00 - (1) Incorrect setting of upper limits on steam units
14:05, 14:11, 14:13, 14:16, 14:21, 14:26, 14:29, 14:34 through 15:31, 15:56, 16:01, 16:22 and 16:23 - (1) Incorrect setting of upper limits on steam units

June 10 Price Adjustments:

No price corrections required.

June 11 Price Adjustments:

20:37 - (3) Prices inconsistent with the bids of marginal units and units at their SCD limits
21:41 through 21:49 - (1) Incorrect setting of upper limits on steam units
22:16 - (1) Incorrect setting of upper limits on steam units
23:05 through 23:24 and 23:54 - (1) Incorrect setting of upper limits on steam units

June 12 Price Adjustments:

0:01 - (1) Incorrect setting of upper limits on steam units
11:05 - (1) Incorrect setting of upper limits on steam units
17:55, 18:05, 18:18 and 18:27 - (3) Prices inconsistent with the bids of marginal units and units at their SCD limits

June 13 Price Adjustments:

No price corrections required.

June 14 Price Adjustments:

No price corrections required.

June 15 Price Adjustments:

8:14 – (4) SCD timing problems

June 16 Price Adjustments:

8:18 - (3) Prices inconsistent with the bids of marginal units and units at their SCD limits
10:00:00 – (5) Incorrect on the hour prices

June 17 Price Adjustments:

No price corrections required.

June 18 Price Adjustments:

No price corrections required.

June 19 Price Adjustments:

7:17 - (3) Prices inconsistent with the bids of marginal units and units at their SCD limits

June 20 Price Adjustments:

11:20 – (4) SCD timing problems
14:05 - (3) Prices inconsistent with the bids of marginal units and units at their SCD limits

June 21 Price Adjustments:

No price corrections required.

June 22 Price Adjustments:

11:44, 11:49, 13:01 and 13:06 - (1) Incorrect setting of upper limits on steam units
17:26, 17:36, 18:19, 18:27, 18:43 and 18:50 - (3) Prices inconsistent with the bids of marginal units and units at their SCD limits

June 23 Price Adjustments:

19:43 - (3) Prices inconsistent with the bids of marginal units and units at their SCD limits

June 24 Price Adjustments:

No price corrections required.

June 25 Price Adjustments:

9:05 and 18:36 - (3) Prices inconsistent with the bids of marginal units and units at their SCD limits

June 26 Price Adjustments:

7:26 - (1) Incorrect setting of upper limits on steam units
8:39 through 8:55 - (1) Incorrect setting of upper limits on steam units

9:00, 9:01 through 9:24, 9:34, 9:39 through 10:22, 10:32 and 10:33 - (1) Incorrect setting of upper limits on steam units
12:25 – (4) SCD timing problems
13:37, 13:38 - (1) Incorrect setting of upper limits on steam units
18:25, 19:17 through 19:24, 19:26 - (1) Incorrect setting of upper limits on steam units
21:48 - (3) Prices inconsistent with the bids of marginal units and units at their SCD limits
22:12, 23:01, 23:04, 23:06 and 23:07 - (1) Incorrect setting of upper limits on steam units

June 27 Price Adjustments:

12:33, 12:41, 12:56, 13:01, 13:06, 13:07 - (1) Incorrect setting of upper limits on steam units
13:46 - (3) Prices inconsistent with the bids of marginal units and units at their SCD limits
14:05, 14:10 and 14:18 - (3) Prices inconsistent with the bids of marginal units and units at their SCD limits
15:02, 15:32 through 15:57, 16:06 and 16:54 - (3) Prices inconsistent with the bids of marginal units and units at their SCD limits
18:14, 18:17, 18:38, 21:53, 21:56 and 22:01 - (1) Incorrect setting of upper limits on steam units

June 28 Price Adjustments:

0:53 - (3) Prices inconsistent with the bids of marginal units and units at their SCD limits
13:00 through 13:51 - (1) Incorrect setting of upper limits on steam units
14:50, 14:55 through 15:50 - (1) Incorrect setting of upper limits on steam units
16:08, 16:17, 16:22, 16:27, 16:28, 16:33, 16:44 through 16:56, 17:01 - (1) Incorrect setting of upper limits on steam units

June 29 Price Adjustments:

19:02 through 19:15 - (3) Prices inconsistent with the bids of marginal units and units at their SCD limits

June 30 Price Adjustments:

7:05 - (3) Prices inconsistent with the bids of marginal units and units at their SCD limits
8:16 through 8:23, 8:38 through 8:41 and 8:52 through 9:00 - (1) Incorrect setting of upper limits on steam units
10:11 - (3) Prices inconsistent with the bids of marginal units and units at their SCD limits
11:18, 12:27, 12:31, 12:41 through 12:52 - (1) Incorrect setting of upper limits on steam units
13:05, 13:06, 13:11 through 13:23 and 13:48 through 14:23 - (1) Incorrect setting of upper limits on steam units

Introduction

There were three issues that caused the need for the price corrections in the month of July.

1. Incorrect setting of SCD upper limits on steam units in the price calculation step in intervals in which gas turbines (GTs) are uneconomic.
2. The posted prices are inconsistent with the bids of marginal units and units at their SCD limits.
3. Incorrect on the hour prices

Each of these issues is described in detail, and each interval during these days for which a price correction was necessary is listed with a description of which issue resulted in the correction.

Description of Corrections

1. Incorrect setting of upper limits on steam units

The SCD upper limits of steam units are set using a cumulative basepointing methodology that sets the limit based on the higher of the actual output of the unit and the prior intervals final basepoint.

At times where there are large amounts of uneconomic GTs in the pricing dispatch that are basepointed in the final dispatch to their full capacity, the large differences between the actual and price calculation dispatch can cause SCD to use incorrect unit limits in the price calculation dispatch

A software fix has been designed that will allow the SCD upper limits in the pricing dispatch to be defined off the prior interval's pricing dispatch rather than the final dispatch. This will allow SCD to see all of the available economic capacity on the flexible resources subject to ramping constraints. This fix was implemented on July 25th and appears to be operating correctly.

Prices were corrected by determining the level at which the steam units would have operated in the pricing dispatch had the SCD upper limits been set correctly.

2. Prices inconsistent with the bids of marginal units and units at their SCD limits

These price corrections are required due to various algorithm and communication problems that result in the prices posted for particular intervals being inconsistent with the bids and schedules produced by SCD. Sometimes this is due to multiple runs of SCD in very short time frame, other times an inability of SCD to correctly solve particular inequalities that result in the reference bus price being calculated incorrectly.

Prices were corrected using the average of the prices in the interval before and the interval after to the extent that these prices were also valid.

3. Prices did not equal those in the last SCD interval of the prior hour.

Prices were corrected so the on the hour prices were equal to the prices posted for the last SCD interval of the prior hour.

Intervals Corrected

July 1 Price Adjustments:

No price corrections required.

July 2 Price Adjustments:

No price corrections required.

July 3 Price Adjustments:

12:37, 14:37, 15:00, 17:19, 17:25, and 17:32 – (2) Prices inconsistent with the bids of marginal units and units at their SCD limits.

July 4 Price Adjustments:

No price corrections required.

July 5 Price Adjustments:

13:01-18:05, 18:17-19:06, 19:16, 19:18, 19:29-21:11, 21:24-21:55 – (1) Incorrect setting of upper limits on steam units.

July 6 Price Adjustments:

No price corrections required.

July 7 Price Adjustments:

No price corrections required.

July 8 Price Adjustments:

No price corrections required.

July 9 Price Adjustments:

No price corrections required.

July 10 Price Adjustments:

15:48-16:03, 16:22, 16:42, 17:05-17:11, 18:00-18:31, 18:36-18:42, 18:52-18:55 - (1) Incorrect setting of upper limits on steam units.

July 11 Price Adjustments:

No price corrections required.

July 12 Price Adjustments:

No price corrections required.

July 13 Price Adjustments:

No price corrections required.

July 14 Price Adjustments:

12:47 - (2) Prices inconsistent with the bids of marginal units and units at their SCD limits.
17:00 and 17:05 - (1) Incorrect setting of upper limits on steam units.

July 15 Price Adjustments:

No price corrections required.

July 16 Price Adjustments:

16:25 - (2) Prices inconsistent with the bids of marginal units and units at their SCD limits

July 17 Price Adjustments:

No price corrections required.

July 18 Price Adjustments:

5:11 - (2) Prices inconsistent with the bids of marginal units and units at their SCD limits

July 19 Price Adjustments:

No price corrections required.

July 20 Price Adjustments:

2:00 – (3) Prices did not equal those in the last SCD interval of the prior hour.
9:47 - (2) Prices inconsistent with the bids of marginal units and units at their SCD limits

July 21 Price Adjustments:

18:19 and 18:26 - (2) Prices inconsistent with the bids of marginal units and units at their SCD limits

July 22 Price Adjustments:

No price corrections required.

July 23 Price Adjustments:

16:09 - (2) Prices inconsistent with the bids of marginal units and units at their SCD limits

July 24 Price Adjustments:

No price corrections required.

July 25 Price Adjustments:

No price corrections required.

July 26 Price Adjustments:

No price corrections required.

July 27 Price Adjustments:

22:56 - (2) Prices inconsistent with the bids of marginal units and units at their SCD limits

July 28 Price Adjustments:

No price corrections required.

July 29 Price Adjustments:

12:46, 12:48, 17:22 - (2) Prices inconsistent with the bids of marginal units and units at their SCD limits

July 30 Price Adjustments:

No price corrections required.

July 31 Price Adjustments:

15:02-15:45, 16:13 - (2) Prices inconsistent with the bids of marginal units and units at their SCD limits

Introduction

There were two issues that caused the need for the price corrections in the month of August.

1. The posted prices were inconsistent with the bids of marginal units and units at their SCD limits.
2. Incorrect on the hour prices.

Each of these issues is described in detail, and each interval during these days for which a price correction was necessary is listed with a description of which issue resulted in the correction.

Description of Corrections

1. Prices inconsistent with the bids of marginal units and units at their SCD limits

These price corrections are required due to various algorithm and communication problems that result in the prices posted for particular intervals being inconsistent with the bids and schedules produced by SCD. Sometimes this is due to multiple runs of SCD in very short time frame, other times an inability of SCD to correctly solve particular inequalities that result in the reference bus price being calculated incorrectly.

Prices were corrected using either the average of the prices in the interval before and the interval after to the extent that these prices were also valid, or by adjusting the reference bus price and shadow prices on the constraint that failed to solve. These adjustments create prices that are consistent with the congestion pattern implied by the binding constraints and the bids and schedules of marginal and ramp limited units.

2. Prices did not equal those in the last SCD interval of the prior hour.

Prices were corrected so the on the hour prices were equal to the prices posted for the last SCD interval of the prior hour.

Intervals Corrected

August 1 Price Adjustments:

12:23-12:46 – (1) Prices inconsistent with the bids of marginal units and units at their SCD limits.

August 2 Price Adjustments:

No price corrections required.

August 3 Price Adjustments:

12:44, 14:25, 15:27 – (1) Prices inconsistent with the bids of marginal units and units at their SCD limits.

August 4 Price Adjustments:

12:45 – (1) Prices inconsistent with the bids of marginal units and units at their SCD limits.

August 5 Price Adjustments:

6:20-6:45, 17:34, 22:33, 22:38, 23:00, 23:06 – (1) Prices inconsistent with the bids of marginal units and units at their SCD limits.

August 6 Price Adjustments:

3:18-3:38 – (1) Prices inconsistent with the bids of marginal units and units at their SCD limits.

August 7 Price Adjustments:

13:00, 15:28, 15:30, 15:47, 15:53 – (1) Prices inconsistent with the bids of marginal units and units at their SCD limits.

August 8 Price Adjustments:

18:38 – (1) Prices inconsistent with the bids of marginal units and units at their SCD limits.

August 9 Price Adjustments:

15:31 – (1) Prices inconsistent with the bids of marginal units and units at their SCD limits.

August 10 Price Adjustments:

No price corrections required.

August 11 Price Adjustments:

14:04 and 14:10 – (1) Prices inconsistent with the bids of marginal units and units at their SCD limits.

August 12 Price Adjustments:

7:24 – (1) Prices inconsistent with the bids of marginal units and units at their SCD limits.

August 13 Price Adjustments:

No price corrections required.

August 14 Price Adjustments:

9:00-9:06, 11:57-12:18, 15:30 – (1) Prices inconsistent with the bids of marginal units and units at their SCD limits.

August 15 Price Adjustments:

No price corrections required.

August 16 Price Adjustments:

10:33 – (1) Prices inconsistent with the bids of marginal units and units at their SCD limits.

August 17 Price Adjustments:

No price corrections required.

August 18 Price Adjustments:

No price corrections required.

August 19 Price Adjustments:

22:00 – (2) Prices did not equal those in the last SCD interval of the prior hour.

August 20 Price Adjustments:

17:00 – (1) Prices inconsistent with the bids of marginal units and units at their SCD limits.

August 21 Price Adjustments:

9:00 – (1) Prices inconsistent with the bids of marginal units and units at their SCD limits.

August 22 Price Adjustments:

No price corrections required.

August 23 Price Adjustments:

No price corrections required.

August 24 Price Adjustments:

13:00 – (2) Prices did not equal those in the last SCD interval of the prior hour.

August 25 Price Adjustments:

11:47 – (1) Prices inconsistent with the bids of marginal units and units at their SCD limits.

August 26 Price Adjustments:

No price corrections required.

August 27 Price Adjustments:

No price corrections required.

August 28 Price Adjustments:

6:17:24, 12:44-13:00, and 15:33 – (1) Prices inconsistent with the bids of marginal units and units at their SCD limits.

August 29 Price Adjustments:

No price corrections required.

August 30 Price Adjustments:

1:17 – (1) Prices inconsistent with the bids of marginal units and units at their SCD limits.
9:00 – (2) Prices did not equal those in the last SCD interval of the prior hour.

August 31 Price Adjustments:

No price corrections required.