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FINAL REPORT
PHASE IV MARKET TRIALS

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EXECUTIVE SUMMARY

On behalf of the Member Systems of the New York Power Pool (NYPP) and the New York ISO (NYISO), Navigant Consulting, Inc. (NCI) was retained to review the results of the Phase IV Market Trials recently conducted by the Staff of the NYPP. The Phase IV Market Trials were conducted on September 23 through the morning of October 1, and also included a set of reruns conducted on October 14 through October 16. The purpose of the Phase IV Market Trials was to complete testing of the software and processes that have been developed for operating the New York ISO under the market structure and pricing rules described in the NYISO OATT and NYISO Services Tariff

The Phase IV Market Trials allowed the NYPP and NYISO to test the security-constrained unit commitment (SCUC) and security constrained dispatch (SCD) software, and associated pricing modules, that will be used for the day-ahead and real-time electricity markets in New York. NCI's assignment has been to assess the economic consistency of the results produced by the SCUC and SCD software and associated pricing modules. NCI also assessed the economic consistency of the balancing market evaluation (BME) software. This report summarizes the results of our analyses.

The ISO software systems are designed to make optimal commitment and dispatch decisions based on market participant bids, subject to physical equipment constraints and power system reliability considerations. NCI has taken advantage of this property in testing the software, as the prices and schedules developed by the software should satisfy a series of internal consistency and equilibrium conditions if the software is functioning properly both in calculating prices and developing schedules.

Based on the analyses performed, on both the original Phase IV Market Trials data and on data developed in a series of reruns of the market trials using corrected software, NCI has not observed problems that would prevent the ISO software systems from producing prices consistent with the LBMP pricing methodology and committing and dispatching load and generation based on least bid cost.

I. INTRODUCTION

On behalf of the NYPP and the NYISO, NCI was retained to review the results of the Phase IV Market Trials recently conducted by the Staff of the NYPP. The Phase IV Market Trials began on September 23 and continued through the morning of October 1. In addition, Phase IV testing included a set of market trail reruns that took place on October 14 through October 16, based on the bids submitted by market participants in the Phase IV Market Trials run on September 29 through October 1. SCUC was rerun on each day from October 14 to October 16. SCD was rerun on October 14 and October 15 only. The purpose of the Phase IV Market Trials was to complete the testing of the software and processes that have been developed for operating the New York ISO under the market structure and pricing rules described in the NYISO OATT and NYISO Services Tariff.

The Phase IV Market Trials were intended to provide a test of the actual operation of the day-ahead and real-time markets for energy and transmission under the NYISO tariff approved by FERC. The Phase IV Market Trials allowed the NYPP and NYISO to test the changes made following the Phase III Market Trials to the SCUC and SCD software, and associated pricing modules, that will be used for scheduling, dispatch and settlements in these markets. NCI's assignment has been to assess the economic consistency of the results produced by the SCUC and SCD software and associated pricing modules. NCI also assessed the economic consistency of the BME software. This report summarizes the results of our analyses.

The ISO software systems are designed to make optimal commitment and dispatch decisions based on market participant bids, subject to physical equipment constraints and power system reliability considerations. NCI has taken advantage of this property in testing the software, as the prices and schedules developed by the software should satisfy a series of internal consistency and equilibrium conditions if the software is functioning properly both in calculating prices and developing schedules.

In performing its tasks, NCI frequently requested intermediate results from certain software modules or the rerunning of cases either to test certain hypotheses or to perform further analyses once specific software corrections had been made by NYPP Staff and/or ABB. In validating the SCD and SCUC software NCI had access to the underlying bids,[1] and intermediate, as well as final, model results.

Based on the analyses performed, on both the original Phase IV Market Trials data and on data developed in a series of reruns of the market trials using corrected software, NCI has not observed problems that would prevent the ISO software systems from producing prices consistent with the LBMP pricing methodology and committing and dispatching load and generation based on least bid cost.

The second section of this report describes the SCUC, BME and SCD tests that NCI performed on the Phase IV Market Trials data. The third section describes the results of the tests NCI

[1] NCI has agreed to maintain the confidentiality of the bid and related data.

applied, the problems that we identified, the corrections that were made and the verifications that were applied in the course of the Phase IV tests. This section also provides explanations of some Phase IV results that NCI concluded were not caused by flaws in the SCUC, BME or SCD software and updates the status of the resolution of problems identified during the Phase III Market Trials. The final section summarizes our conclusions.

II. TESTS OF SCUC, BME AND SCD

NCI performed a series of tests on the Phase IV SCUC, BME and SCD data in order to validate the price calculations, unit commitment and dispatch solutions and identify potential economic inconsistencies in the prices and schedules produced by the software. As described below, our tests of SCUC included a review of the energy and ancillary services prices and schedules. We also tested the energy prices and schedules produced by SCD. In addition, we have examined the external transaction and ancillary service schedules and prices in BME.

A. TESTS

NCI's tests of the economic consistency of the SCUC, BME and SCD results looked for patterns between and among generator and load schedules and energy and ancillary services prices that should be observed if the software is performing as expected. If the tests detected anomalies, NCI worked with NYPP Staff and/or ABB to identify the reason for the anomaly. As a general matter, the tests were designed to find flaws in the software logic, not to systematically test the data read by the software. As a practical matter, however, the tests also identified other types of flaws, such as problems in data handling between the software modules.

1. Replicate LBMP Prices

For SCUC, BME and SCD, NCI verified that we could independently replicate the calculation of the LBMP prices from the components. For each generator bus and load zone, we verified that we could calculate the LBMP from the price at the reference bus, the penalty factor, shift factors and constraint shadow prices.[2] This validation was based on the reference bus price, penalty factors, shift factors and constraint shadow prices calculated by the SCUC, BME and SCD models, and the underlying grid model.

2. Validate LBMP Prices Based on Marginal Generators

NCI verified that we could identify the marginal generators that determined the LBMPs in each hour (for SCUC and BME) or SCD interval. In an hour or SCD interval with no constraints, at least one generator should be on the margin (i.e., partially dispatched and not at a ramping limit) and the LBMP at this generator's bus should be equal to the generator's energy bid at its dispatch point. Similarly, in an hour or SCD interval with one constraint, at least two generators should

[2] See ISO OATT Attachment J.

be on the margin and the LBMP at each such generator's bus should be equal to its energy bid at its dispatch point; and so on, as there are additional binding constraints.[3] In order to identify the marginal generators for each SCUC or BME hour and SCD interval, NCI used data from the "ideal" dispatch used to calculate prices, in which GTs are modeled as if they are dispatchable. The results of this step show what the dispatch would look like without the discontinuities introduced by the block loading of GTs in the final step of the SCUC, BME or SCD.

3. Examine Energy Schedules for Consistency with LBMP Prices

For SCUC, BME and SCD, NCI examined the schedules for generating units to verify that they were consistent with the LBMP prices. For the purposes of this test, generating units were divided into three categories based on their schedules: (1) units on the margin; (2) units that were scheduled to provide as much energy as possible given their ancillary services schedules and ramp rate constraints (i.e., fully dispatched); and (3) units that were scheduled to provide as little energy as possible given their ancillary services schedules, minimum loads and ramp rate constraints. The next step was to verify that (1) the LBMP for each marginal unit was equal to the unit's energy bid at its dispatch point (same as Test 2); (2) the LBMP for each unit scheduled at maximum was greater than or equal to the unit's energy bid at its dispatch point; and (3) the LBMP for each unit scheduled at minimum was less than or equal to the unit's energy bid at its dispatch point.[4] Equivalent tests were to be applied to dispatchable loads in SCUC; however, there were too few dispatchable load bids in the relevant price ranges to allow NCI to verify that dispatchable loads were being treated correctly.[5]

4. Validate Ancillary Service Prices Based on Marginal Generators

NCI identified the marginal generators determining the market-clearing prices for spinning reserves, 10-minute reserves, 30-minute reserves and regulation in each hour (for SCUC) and validated the calculation of the availability component of the market-clearing prices. The availability component of the market-clearing price for each class of reserves and regulation should be the marginal availability bid for that class of service.

5. Examine Ancillary Service Schedules for Consistency with Prices

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[3] This rule may be more complicated in hours in which the simultaneous SCUC or BME optimization includes tradeoffs on the margin between the scheduling of energy, reserve and regulation products. For example, there are instances in which the marginal cost of serving an increment of load (LBMP) in SENY may be based, in part, on the marginal cost of replacing an increment of reserves. See additional explanation in Section IIIA2.

[4] This rule is also more complicated in hours in which the simultaneous SCUC or BME optimization includes tradeoffs between the scheduling of energy, reserve and regulation products. See additional explanation in Section IIIA2.

[5] NYPP Staff will verify the implementation of internal dispatchable load.

NCI verified that the ancillary services schedules for generating units were consistent with the market-clearing prices for energy, spinning reserves, 10-minute reserves, 30-minute reserves and regulation in each hour (for SCUC).

6. Examine Unit Commitment for Consistency with LBMP Prices

NCI validated the SCUC results by applying two tests to generating unit schedules. First, NCI determined whether there were units that were not committed that could have profitably operated at the day-ahead LBMPs. Second, units receiving uplift (i.e., units that receive Supplemental Payments because their day-ahead energy and ancillary services revenue is less than their as bid costs) were identified. NCI's general approach was to work backwards through the unit commitment process (using special reruns and intermediate outputs), to identify the steps in the SCUC process giving rise to material amounts of uplift. The sources of uplift in these steps were then scrutinized to assess the reasonableness of the uplift and to assess whether the uplift reflected any flaws in the SCUC logic or structure.

7. Examine BME Ancillary Service and External Schedules for Consistency with LBMP Prices

NCI verified that the BME schedules for ancillary services and external transactions were consistent with the prices calculated in the BME. NCI also validated the BME ancillary services prices and, when possible, replicated the calculation of the BME LBMPs.

8. Validate Unusual Price Patterns

In addition to applying the formal tests described above on a consistent basis, NCI also examined the factors determining price levels in hours in which SCUC or SCD prices in general, or at particular locations, were atypically high or low.

B. Data

NCI analyzed the SCUC data for each day of the Phase IV Market Trials from September 24 to October 2, and for each rerun day from October 14 to October 16. We also assessed additional forecast load SCUC sensitivity runs for September 27 and 28 and one GT block bidding sensitivity run for September 28.

NCI analyzed 122 SCD intervals on September 24; 110 SCD intervals on September 25; 29 on September 26; 57 on September 27; 84 on September 28; 29 on September 29; 47 on September 30; and 0 on October 1. NCI analyzed 31 intervals for additional testing done on October 6 and 71 intervals for additional testing done on October 7. NCI also analyzed all of the posted SCD intervals from the October 14 (286 intervals) and October 15 (308 intervals) reruns.

NCI analyzed the BME results for hours starting 9:00 and 15:00, from September 28 to September 30, 1999. NCI also analyzed BME for 3 intervals on October 14 and three intervals on October 15. To validate the ancillary service prices in BME NCI obtained data from the MIS system where the prices are calculated. We received and analyzed this MIS data for September 30 and for October 14.

As the basis for the economic tests, NYPP Staff provided NCI with a number of different data sets from the Phase IV Market Trials. For SCUC, data received included generating unit and load bid data, mitigated bids for generating units subject to market power mitigation, SCUC energy schedules for generating units, operating reserve and regulation schedules and market-clearing prices for energy (LBMPs), reserves and regulation. In some cases, information was received regarding the unit commitment and dispatch at interim steps in the SCUC process, e.g., for the ideal dispatch prior to the block loading of GTs. Data were also received on the components of the LBMPs including the reference bus LBMP, penalty factors, constraint shadow prices, shift factors and zonal weights.

For the SCD intervals that were evaluated, the data that were received included generating unit bid data, the ideal and final base points for generating units, generator limits in the SCD, the reference bus LBMP, penalty factors, shift factors, constraint shadow prices, zonal weights, posted LBMPs for generator locations and posted zonal LBMPs. The information on the posted LBMPs separately identified the marginal loss and congestion components of the LBMPs.

III. TEST RESULTS

Based on the analyses performed on the Phase IV Market Trials data and various reruns, it appears that the New York ISO SCUC and SCD software systems produce economically consistent LBMP prices and generator and load schedules based on the bids and other data that they are provided.

The first section below presents a summary of the results of each of the tests that NCI applied to the Phase IV Market Trials data. The second section contains a description of each of the problems that we identified in SCUC, SCD or BME, and its resolution. The third section contains additional explanations of the Phase IV Market Trials results developed in the course of our analyses and the final section updates the status of the resolution of problems identified during the Phase III Market Trials.

A. PHASE IV TEST RESULTS

1. REPLICATE LBMP PRICES

NCI has independently calculated the LBMP prices from the components for each SCUC hour, for each BME hour and for each SCD interval that we analyzed. For each generator bus, load zone and external proxy bus we have calculated the LBMP from the price at the reference bus, the penalty factor, shift factors and constraint shadow prices. All of the SCUC and BME calculations were replicated except for some external bus prices. This problem was corrected and verified during Phase IV Market Trials, as described in Section IIIB, Paragraphs 1d and 3a below.

The SCD calculations subsequent to September 29 were also replicated. The SCD price calculations could not be replicated for 14 of 402 SCD intervals evaluated prior to September 29 because of the data handling problems discussed in Section IIIC, Paragraph 2d. The errors described in Section IIIB, Paragraphs 2a, 2b, and 2f caused the reported reference bus prices and/or the reported constraint shadow prices to be incorrect, but the LBMPs were correctly replicated from the reported reference bus prices and reported constraint shadow prices.

2. Validate LBMP Prices Based on Marginal Generators

NCI has identified the marginal generators in every hour in SCUC in which the marginal energy was provided by units that were not fully scheduled for either energy or reserves. In these cases the LBMP at each marginal generator's bus was equal to the energy bid of the marginal unit evaluated at the point at which it was scheduled. However, in many hours throughout the Phase IV Market Trials, the actual incremental cost of supplying an increment of load, i.e., LBMP, involved a combination of energy and reserve costs. Due to the regularity with which regional reserve constraints were binding or violated, the number of these occurrences was too great for NCI to identify all of the marginal units within the available time.[6] However, NCI did validate the LBMPs for numerous hours in which the price was determined by a combination of the incremental energy and incremental reserve costs. Moreover, it was possible to consistently verify that there were no units in the ideal dispatch that were operating at points on their bid curve that were inconsistent with the LBMPs at their locations using the tests described in Section IIIA, Paragraph 3.

NCI has verified the marginal generators for the September 30 BME run for hours starting 9:00 and 15:00 and other BME data received for September 28, and 29.

NCI has also verified that marginal generators correctly determined LBMPs in SCD. Exceptions to this test that were resolved during the market trials are described in Section IIIB, Paragraphs 2a, 2b and 2f and Section IIIC, Paragraphs 2d and 2e.

3. Examine Energy Schedules for Consistency with LBMP Prices

For SCUC, BME and SCD, the schedules for generating units were consistent with the LBMP prices in the hours and intervals that NCI analyzed. NCI's analysis was based on the schedules

[6] The difficulty in validating the LBMPs by finding the marginal providers of energy and reserves was complicated by occasional inconsistencies in the simulated ideal dispatch data. It was also complicated by the fact that the opportunity cost of meeting a reserve constraint, while reflected in the energy clearing prices, is not always reflected in the day ahead portion of the reserve clearing prices. Finally, the large shadow prices on some constraints during some hours complicated the analysis by magnifying the typically small inconsistencies arising from the loss approximation in SCUC.

determined in the ideal dispatch used to set prices, in which GTs were treated as dispatchable. The final schedules may differ from the ideal schedules in hours in which GTs were block-loaded.

The application of this test to SCUC identified three problems that were corrected through software modifications during the Phase IV Market Trials and verified by NCI. These problems were the treatment of market power mitigated GTs, as described in Section IIIB, Paragraph 1e; a problem in the local reliability commitment, as described in Section IIIB, Paragraph 1a; and a suboptimal commitment on October 2, as described in Section IIIB, Paragraph 1f.

During the market trials NCI also observed several apparent scheduling anomalies that proved, instead, to be correct SCUC results. The first observation was of seeming inconsistencies in the scheduling of external generators. The second was comprised of numerous one hour anomalies that appeared throughout the market trials, typically when units were ramping up, ramping down or were near minimum load. These observations are described in Section IIIC, Paragraphs 1a and 1b, respectively.

NCI has verified the consistency between generator schedules and LBMPs in SCD. Exceptions to this test that were resolved during the market trials are described in Section IIIB, Paragraphs 2a, 2b and 2f and Section IIIC, Paragraphs 2d and 2e.

4. *Validate Ancillary Service Prices Based on Marginal Generators*

NCI has identified the marginal bids that determined the market-clearing prices for spinning reserves, 10-minute reserves, 30-minute reserves and regulation in each hour (for SCUC), and verified the calculation of the market-clearing prices.

5. *Examine Ancillary Service Schedules for Consistency with Prices*

NCI validated the posted schedules for ancillary services by confirming that the posted prices reflected the highest cleared availability bid in each of the ancillary services markets. NCI also performed the more complicated test of examining the consistency between the ancillary services schedules and energy prices. The day-ahead opportunity cost of meeting reserve constraints is reflected in the calculation of energy clearing prices, but may not be fully reflected in the calculation of the day-ahead market clearing prices for reserves. Hence, unless account is taken of the opportunity costs payable in real time, there were numerous occasions when units would have preferred to generate energy and receive the LBMP, rather than being held down to provide reserves and receive the market clearing (availability) price for that service. However, when NCI included the true energy-related opportunity cost in the price of reserves, the reserve schedules were consistent with the energy prices i.e., the as-bid margin for reserves, considering the true opportunity cost, was higher than the as-bid margin for providing energy.

Due to the complexities described in Section IIA, Paragraph 2, NCI was not able to evaluate the consistency of the schedule of every unit that appeared as if it might have preferred generating energy to providing reserves. However, NCI is satisfied that SCUC is making these scheduling decisions correctly and that the SCUC ancillary services schedules for generating units are consistent with the market-clearing prices for spinning reserves, 10-minute reserves, 30-minute reserves and regulation in each hour. It should be noted that, consistent with the tariff, when locational reserve constraints are binding, these constraints are not reflected in all reserve prices. In each case where these constraints bound, NCI confirmed that there was no reserve capacity available that could have met the regional reserve requirement more cheaply.

6. Examine Unit Commitment for Consistency with LBMP Prices

For SCUC, NCI verified that there were no generating units that were not committed that would have been profitable to operate at the day-ahead LBMPs. Second, we determined that the uplift attributable to the core SCUC, the reliability commitment and the commitment to meet local reliability rules appeared to be consistent with the intended market design.

				Core SCUC Uplift			
DAM	**Total Uplift**	**Local Reliability Uplift [1]**	**Remaining Uplift [2]**	**Ideal Dispatch**	**Block Dispatch**	**Comments**	**External Generator Uplift**
September 24	$ 368,232	$ 117,362	$ 250,870			Includes LRR problem before fix	$ -
September 25	$ 62,160	$ 62,160	$ -			Includes LRR problem before fix	$ -
September 26	$ 272,137	$ 74,084	$ 198,053			Includes LRR problem before fix	$ 5,786
September 27	$ 48,494	$ 3,279	$ 45,215	$ -	$ 6,340		$ 40,184
September 28	$ 342,105	$ 16,800	$ 325,305	$ -	$ 358		$ 239,151
September 29	$ 213,999	$ -	$ 213,999				$ 11
September 30	$ 141,076	$ 6,470	$ 134,606				$ -
October 1	$ 9,459	$ 11	$ 9,448				$ 94
October 2	$ 3,962	$ 566	$ 3,396				$ -
October 14 [3]	$ 200,617	$ 1	$ 200,617				$ -
October 15 [4]	$ 164,681	$ -	$ 164,681				$ -
October 16 [5]	$ 45,614	$ -	$ 45,614				$ -

1. Uplift associated with commitments made solely for local reliability rules.
2. Remaining uplift equals total uplift less LRR uplift.
3. This day was based of a re-run of September 29.
4. This day was based of a re-run of September 30.
5. This day was based of a re-run of October 1.

NCI was provided data permitting analysis of the uplift arising from the core SCUC unit commitment, i.e., prior to the effects of the reliability commitment to meet forecast load and the commitment to meet local reliability rules for two days. This uplift was $0 on September 27 and $0 on September 28. The total uplift, excluding uplift on units committed for local reliability and allocated to specific customers, but including the general effects of the reliability commitment and local reliability rules, was $45,215 on September 27; $325,305 on September 28; $213,999 on September 29; $134,606 on September 30; $9,448 on October 1; $3,396 on October 2; $200,617 on October 14; $164,681 on October 15 and $45,614 on October 16. October 14, 15 and 16 results were based on the bids and loads from the September 29, 30 and October 1 runs from earlier in the market trials. On many of the days of the Phase IV Market Trials the system was very short of energy and/or reserves, which lead at times to significant uplift.

Because of the magnitude of the uplift on some days, NCI analyzed the source of the uplift due to the reliability commitment and verified that it arose from the correct operation of SCUC given the bids and market conditions on September 27 through October 2. This analysis identified three problems that were corrected through software modifications during the Phase IV Market Trials and subsequently verified by NCI. First, on September 24, 25 and 26, large uplifts occurred on units committed in the local reliability pass of the SCUC, as discussed in Section IIIB, Paragraph 1a. Second, uplifts occurred on external units on September 26, as discussed in Section IIIB, Paragraph 1b. Third, uplift was paid to a unit that bid very high to reduce its schedule, but because of ramp rate constraints and reserve constraints was scheduled on at a very high cost, as discussed in Section IIIB, Paragraph 1g.

One additional investigation concluded that the remaining uplift resulted from SCUC performing correctly under unusual conditions. On September 27 and September 28 large uplift payments were made to external generators required to meet forecast load because of the large amount of generation neither bid into the day ahead market nor scheduled to support bilaterals. On September 29 and 30, the uplift arose from the proper operation of SCUC in circumstances in which not enough ancillary services were offered into the market to meet ISO requirements.

7. *Examine BME Ancillary Service and External Schedules for Consistency with LBMP Prices.*

NCI has verified that the BME ancillary service and external schedules are consistent with LBMP prices. NCI was able to confirm that the ancillary service schedules produced by BME were consistent with the data used in the optimization; no resources were scheduled inconsistently with their bids or the implied clearing price in the optimization.

While a problem was discovered with the ancillary service pricing module of BME, NCI has verified that it was corrected during Phase IV. This is described in Section IIIB, Paragraph 3b. The ancillary service prices have been validated for September 30 and October 14.

8. *Validate Unusual Price Patterns*

In addition to applying the formal tests described above to the SCUC and SCD solutions on a consistent basis, NCI also examined the factors determining price levels in hours in which prices in general, or at particular locations, were atypically high or low. This review identified a few software problems, as well as problems that resulted from data handling or simulator errors, but generally found that the remaining atypical prices could be accounted for by loads, bids and the grid configuration.

NCI examined periods in which the SCUC prices in some portions of New York City reached $10,000/MWh, while prices in other portions of the City were in the $30/MWh range. These outcomes were correct given the configuration of the grid, forecast and bid-in loads, and the available resources and bids. The high prices in portions of the City were caused by transmission line outages coupled with the failure of some market participants to participate fully in the market trials. As a result, the system was highly constrained and unable to meet bid-in load in some parts of the City. SCUC scheduled all available resources, including some resources not subject to market power mitigation that bid in incremental capacity at very high prices. However, at the same time that prices were very high in some portions of the City, line outages created transmission constraints that kept prices relatively low in other portions of the City.

As discussed in Paragraph 2c of Section IIIB, below, a portion of the SCD inter-interval price volatility observed in the early days of the Phase IV Market Trials was attributable to the modeling of the generation of off-dispatch units. After the implementation of SCD software changes, however, intra-hour price variations were somewhat damped but continued to occur through October 1. NCI sought to specifically identify the reason for these disturbances and verify that they resulted from the correct operation of SCD.

The role of the real-time simulator cannot be ignored in interpreting the SCD results in the market trials. The simulator at times caused units to depart from their base points and the SCD software properly responded to these departures. Some of these departures exacerbated congestion and caused prices to be lower at the affected location than they would have been had the units followed their base points. Moreover, it is apparent that inadvertent problems in the operation of the simulated test environment also contributed to the price fluctuations produced by SCD, as described in Section IIIC, Paragraph 2b below. The operation of the simulator at times produced congestion price patterns that are unlikely to prevail in actual operation.

Overall, the appearance of negative SCD prices at various locations in western New York and high prices in the East was the result of the correct application of the SCD and LBMP pricing, but at times reflected anomalies due to simulation problems.

B. PROBLEMS IDENTIFIED IN PHASE IV

Several problems were identified in the course of the Phase IV Market Trials that were not identified in Phase III. This occurred for a number of reasons. After the correction of a number of problems during and after Phase III, the Phase IV Market Trials ran more cleanly and produced a larger set of data for the NCI tests. The Phase IV Market Trials also reflect different market conditions than Phase III. Load was higher in Phase III, and in the first days of Phase IV a significant quantity of generation did not bid into the SCUC. SCD, in particular, was operated under a broader and more extreme set of conditions during Phase IV than during Phase III. One of the issues identified during the course of Phase IV Market Trials, SCD price spikes, was partially caused by the inadvertent simulation of relatively large and sudden changes in the SCD test environment.

All of the problems that NCI identified in Phase IV have been diagnosed, corrected and verified through subsequent testing.

1. SCUC: CORRECTED AND VERIFIED

a. Incorrect treatment of start-up and no load costs in the local reliability step. Early in the Phase IV Market Trials, NCI noticed that units were incurring uplift as a result of commitments made to resolve local reliability constraints, even though the units were distant from the local area constraints and had no effect on them. ABB and NYPP Staff traced this problem to an incorrect treatment of start-up and no load bids in the local reliability rule pass of the SCUC, resulting in the commitment of units with large and expensive minimum load blocks. The impact of this problem on SCUC results was twofold. These units received large uplift payments and also depressed LBMPs, which in some cases caused uplift to increase on other units. This software problem was identified in the September 24 SCUC run and appeared until September 26. A software correction was implemented before the SCUC run on September 26 for September 27. The problem did not reappear in Phase IV Market Trials or subsequent reruns.

b. Unintended result of modification of external generator bids in the forecast load and local reliability steps. In reviewing the results for September 26, NCI found that uplift payments were being made to external generating units committed during the forecast load or local reliability steps. A number of factors inadvertently produced this result. In the forecast load and local reliability steps of SCUC, generator bids are modified so that the commitment minimizes the capacity (start-up and no load) costs of any additional generation that is committed in these steps. Since external generators have no start-up or no load costs, the result was that they were often selected when generation was required in these steps. Moreover, because these external units are not ICAP resources, the software recognizes that they are not recallable. In order to maintain system security, since the ISO would not be able to recall the units in the event that they were not scheduled, SCUC blocks these units on in subsequent steps. This procedure inadvertently led to uplift for external generators.

   This problem was corrected by modifying the software so that the energy bids for external generators are not modified in the forecast load and local reliability steps of SCUC. This software change was implemented for September 27. NCI verified in the runs on September 28 through October 2 and October 14 through October 16 that any uplift on external units was due to the correct operation of SCUC.

c. Incorrect scheduling of IC units in the local reliability commitment step. In the September 24 SCUC run NCI noticed that many of the Barrett IC units were being scheduled inconsistently with the LBMPs at their locations. This problem occurred in the local reliability commitment stage of SCUC because the code did not correctly identify the hours in which units had been committed for local reliability. The problem was corrected and the software change was verified in later SCUC runs. It has not reappeared in the Phase IV Market Trials or subsequent reruns.

d. Incorrect external bus prices were posted for SCUC on several days. This problem was traced to an error in how the LBMP calculation software calculated prices for external buses. External buses have multiple generators and only one posted price. The error arose because the LBMP calculation included a congestion cost component for each of the generators at the external location, thereby adding the congestion cost into the bus price repeatedly. NYPP Staff verified that the prices NCI derived for these buses were the prices that the SCUC optimization was, in fact, seeing. This was a reporting error that did not affect the optimality or efficiency of the SCUC software. The problem was fixed and was verified in the October 14 through October 16 reruns.

e. Incorrect treatment of mitigated incremental energy bids for GT units subject to market power mitigation. NCI identified a number of anomalies in the scheduling of GTs subject to market power mitigation. Initially, the problem appeared to be that SCUC had difficulty scheduling units, particularly electrically equivalent GTs, whose energy and/or reserve bids were identical. However, after running several sensitivities with graduated energy and reserve bids, it became apparent that identical bids were not the cause of the apparent scheduling inconsistencies.

   ABB and NCI identified that the apparent problem arose because the SCUC software commits and schedules GTs subject to market power mitigation based on their full load average energy costs per MWh, rather than based on their mitigated incremental energy bids. The full load average energy cost per MWh is calculated by dividing the mitigated GT's minimum generation cost by the capacity of the unit. NCI has confirmed that the GT schedules and prices were entirely consistent with their full load average energy costs per MWh, rather than with their mitigated incremental energy bids.

   While finding that SCUC was operating properly in this instance, NCI identified an additional issue concerning the implementation of market power mitigation for the mitigated GTs. SCUC was using the minimum load cost (per MWh), rather than the mitigated incremental energy bids, to commit these GTs. However, the minimum load cost of these units is only subject to mitigation, through a substituted bid in SCUC, when the units are required for reserves. To address this issue, ABB modified the SCUC software to ensure that the mitigated GT bids are effectively substituted when energy market mitigation is triggered. No change has been made to the mitigation measures for the steam units. This change was verified in the October 14 through October 16 market trial reruns.

f. Suboptimal dispatch. A review of the October 2 SCUC run revealed numerous anomalies in the scheduling of GTs. In hours 20:00 and 21:00, when prices in NYC reached almost $10,000 in some locations and averaged around $5,000[7] a number of GTs that had bid in at much lower prices were not dispatched for energy or reserves. NCI passed this case to ABB, who confirmed that SCUC had not converged to an optimal dispatch. After modifying the optimization algorithm ABB reran the case for October 2 and found that the $10,000 prices no longer appeared. ABB also tested the altered software logic to ensure that the change to the code performed effectively. NCI verified the change in the October 2 rerun of SCUC and also in the October 14 through October 16 market trial reruns.

[7] The average price was around $5,000 because the binding constraint, Rainey-Vernon, splits New York City in half.

g. Uplift on September 29. Analysis of the sources of uplift highlighted an apparent anomaly in the treatment of a specific generating unit on September 29. This unit bid $9,999/MWh in the hour starting 20:00 to ensure that after running throughout the afternoon it would not be scheduled above minimum load in that hour. However, given the unit's ramp rate, in order for it to operate at minimum at 20:00 it needed to be scheduled at less than full capacity in hour 19:00 so that it could ramp down to its minimum load at 20:00. NCI observed that the unit was not scheduled at minimum at 20:00, although it ramped-down at its maximum rate across the previous hour. Because the unit was ramp constrained it did not set the LBMP at 20:00 but was eligible to receive uplift payments associated with its as-bid cost of $9,999/MWh in that hour. This result occurred because the region that the unit is located in was severely short of reserves in the hour starting 19:00. This triggered logic in the SCUC software that enables it to reach a feasible solution by relaxing the ramping constraints on units. This meant that in hour 19 the unit was scheduled as a level that did not enable it to reach its minimum load in hour 20, once it ramp rate was reapplied. ABB addressed this problem with a software change that was tested and verified in the market trail r-runs and other specific cases where this condition existed.

2. SCD: Corrected and Verified

a. Incorrect sign at reference bus. NCI and NYPP found that the sign of the price at the reference bus could be reversed in the SCD price calculation under some circumstances because of the point in the program at which the shadow price of constraints was calculated. This problem was detected in 6 of the 318 intervals tested through September 27 (8:20 on 9/24; 8:35 on 9/25; 5:00 and 7:12 on 9/26; and 6:17, 6:19 and 17:44 on 9/27). The SCD software was corrected beginning on September 28. The problem briefly re-emerged at 8:44 in the October 7 test case, when NYPP Staff inadvertently relaxed a tolerance setting, rather than tightening it, in the course of a software test. The tolerance setting was corrected at about 10:30 and the problem did not reappear in the remainder of the October 7 testing.

b. Redundant constraint shadow prices. NCI found that under certain circumstances, the same transmission constraint may be binding for two contingencies evaluated during the same dispatch. SCD was correctly redispatching the system in these instances, but the calculated LBMP prices included congestion components calculated for each of the constraints, even through only one was binding in the final dispatch. This problem occurred in intervals 8:04, 8:09 and 8:15 on September 24, and intervals 11:33, 11:43 and 11:53 on September 25. It was corrected on September 28, and the problem did not reemerge in the Phase IV Market Trials. NCI has been able to verify positively that in some intervals with the characteristics described above the problem has not reoccurred.

c. SCD treatment of off-dispatch unit schedules. In examining the periods in which LBMP prices changed significantly between SCD intervals, NCI found that the SCD basepoints for some off-dispatch units were markedly different from the actual output of the units.

These differences appeared to be contributing to, or even creating, some of the price swings. Diagnosing the problem further, NCI and NYPP Staff found that the SCD dispatch basepoints for these units were based upon their BME schedules and that, furthermore, the BME schedules could change abruptly from hour-to-hour. In instances in which the actual generation of off-dispatch units differed very materially from their BME schedules, this could cause SCD to dispatch the system based on the wrong data. For instance, on September 25, a unit's hour-ahead schedule changed from 0 MW in hour 10 to almost 500 MW in hour 11, but the DTS simulator used in SCD did not start the unit until the middle of hour 11. The result was that at the beginning of hour 11, SCD was instantly presented with 500 MW of additional generation, and was unable to ramp down on-dispatch generators fast enough to accommodate the schedule change. This caused a sharp drop in prices in the west at the same time that regulating units were being brought up to respond to the need to replace the 500 MW that the unit was not actually producing. NYPP eliminated this source of price disturbances by modifying the SCD software to set the basepoints for off-dispatch units based on their actual generation, rather than their BME schedules. This change was implemented on September 29 and tested during September 30 to ensure that SCD responded properly to changes in the schedules of off-dispatch units that were not reflected in changes in output. After examination of the September 30 results, a second software modification was made to apply this change in a second place in the software. This change was verified in the October 6 test case and has not reoccurred.

d. Incorrect block dispatch of GTs. NCI noticed that GTs at the same location appeared to be incorrectly dispatched as a block, forcing down the dispatch of lower-cost units. This result occurred because SCD requires monotonically increasing bid curves, so that a very slight slope is introduced to flat GT bids before they are provided to SCD. In instances in which GTs at the same location provided the same bid (this occurs for groups of GTs), this meant that the least cost dispatch was always to take the lower part of the bid curve of each GT. For instance, if the dispatch needed 10 MW and 5, 20 MW GTs at the same location bid in at the same price, SCD dispatched 2 MW of each of these GTs in the ideal step of the dispatch. Each of these GTs was then block-loaded in the final step of SCD. This anomaly was addressed through a software modification that will, effectively, mean that SCD will dispatch one GT at a time. This software change was verified in the results for the October 7 test case.

e. Incorrect basepoints for off-dispatch GTs. NCI found that SCD was not seeing the correct basepoints for some off-dispatch GTs. In instances in which the GTs were scheduled as a group, SCD was using a basepoint for the group that was equal to the actual basepoint divided by the number of GTs. Software modifications were made to address this problem and were verified in the October 6 and October 7 test cases.

f. Incorrect price at the reference bus. The posted LBMPs were inconsistent with generation schedules on September 24 at 11:04, 12:26 and 12:37; September 25 at 8:34; and September 28 at 11:00, 11:37 and 19:31. All of these intervals had a related problem, which occurred because a generator on margin in the SCD solution had an extremely steep bid curve at the solution point. This steeply sloped bid curve interacted with the methodology that SCD used to reach a solution given a non-linear representation of losses. NYPP Staff implemented a software change to address this problem. NCI and NYPP Staff conducted tests to verify that the problem was resolved and confirmed that it did not occur during the October 14 and October 15 market trial reruns. These tests reduced the Central-East limit well below normal and added steeply sloped bid curves from $1/MW to $9999/MW on units that were forced to be marginal.

3. BME: Corrected and Verified

a. Incorrect external bus prices were posted for BME on several days. This is the same problem that was identified in the SCUC software, as described in Section IIIB, Paragraph 1d above. NYPP Staff verified that the prices NCI derived for these buses were the prices that the BME optimization was, in fact, seeing. This was a reporting error that in no way affected the optimality or efficiency of the BME software. The problem was fixed and was verified in the October 14 through October 16 reruns.

b. Incorrect reserve prices posted on September 30. NYPP has identified and corrected the MIS software problem in the ancillary services pricing module. NCI has validated these changes based on a rerun of the reserve price calculation for September 30.

c. Incorrect treatments of external generator bid. NCI identified an anomaly in the schedule for an external generator on September 28 at 9:00. NYPP found that the problem occurred because the generator was classed as unavailable because its bid was so extreme. This problem was addressed through a software modification, which NCI has validated in a rerun of the September 30 data for this hour. The problem did not reappear in the October 14 and October 15 reruns.

C. Other Analysis of the Phase IV Market Trial Data

This section describes the results of NCI's investigations of a number of additional hours and intervals of the Phase IV Market Trials. It reports on a number of instances in which the prices appeared to be anomalous, but in which NCI has confirmed that SCUC, BME and SCD were functioning correctly. In addition, the section reports on hours and intervals in which the prices were anomalous because of data handling or simulator problems, but not because of incorrect operation of SCUC, BME or SCD.

1. SCUC

a. External generators committed in the forecast load step. NCI observed several cases in which external generators received substantial uplift and/or appeared to be uneconomic based on the SCUC prices calculated in the ideal dispatch to meet bid-in load. These cases occurred after the software modification described in Section IIIB, Paragraph 1b, which was designed to prevent external generation from being incorrectly selected in the forecast load step of SCUC. However, there continued to be instances when the prices in the forecast load step were high enough to clear high priced external generators. These generators were then blocked on and subsequently looked uneconomic in the ideal dispatch to meet bid-in load. NCI and NYPP Staff investigated each of these anomalies and in each case confirmed that the external generators were scheduled appropriately. High uplift occurred on September 28 ($239,000), while lower levels of uplift were observed on September 29 ($11) and October 1 ($94). In each of these cases, NCI determined that SCUC was correctly selecting external units as the cheapest way of meeting forecast load, given the unusual circumstances prevailing during the market trials in which not enough internal generation was bid into the day ahead market to meet forecast load.

b. Isolated anomalies. A number of anomalies occurred in the dispatch of specific generators during single hours. ABB identified that the source of this problem was inconsistencies between the simulated ideal dispatch received by NCI and the actual ideal dispatch used by the SCUC. The SCUC software is not currently written so that the actual ideal dispatch could be provided to NCI. Therefore, NCI's analysis was based on an ex post resimulation of this dispatch. Each of the isolated anomalies was tracked and analyzed by NYPP or ABB Staff to their satisfaction. NCI did not receive the data necessary to confirm the NYPP and ABB analyses.

2. *SCD*

a. SCD (and BME): Incorrect simulation when unit trips off-line. On September 30, NCI observed a number of anomalies in the BME and SCD schedules for a generator between the hours of 18:00 and 24:00. This appears to have occurred because the unit tripped off-line and then came back on-line in the DTS simulator during this period, causing BME to incorrectly schedule the unit off and on. However, BME appears to have performed correctly given the inputs given to it in each hour during the simulation. NYPP Staff has explained that the problem occurred because the simulation did not include the communications that would have occurred when a unit trips off-line during actual operation. In the actual operation of the system the dispatcher would take manual action to insure that the outage scheduler contains accurate information about whether or not a unit is coming back on line. This information would be provided to BME, preventing the problems experienced on September 30.

b. SCD (and BME): Abnormal and incorrect simulation of load. In examining the periods on September 30 in which LBMPs changed significantly between SCD intervals, NCI and NYPP Staff identified a number of problems due to the abnormal simulation of load. These problems all resulted from the implementation of the market trials simulation:

- Prices were negative in much of western New York from 19:00 to 22:00 on September 30. During this period, the BME was run with inaccurate load forecasts, which were much higher in Western New York than the actual SCD load. Moreover, starting at 19:00 and ending at 22:00, BME scheduled additional hour-ahead external transactions that increased net imports by almost 500 MW. At least one of these external transactions, 700 MW from an external source to an internal sink, had a significant effect on flows over the Central East Interface. Because SCD was running off much lower in Western New York, from 19:00 to 22:00, SCD was unable to solve the Central East Interface with the resources it had available to dispatch based on the BME schedule. It appears that the dispatcher did not curtail any external transactions over this period nor did the external sellers interrupt their sales in the simulation despite negative prices.
- Prices abruptly rose in the East and fell in the West between SCD intervals 11:55 and 12:01 on September 30. At 12:00, new load data was manually entered into the simulator following normal procedures used during the simulation. As a result, the simulator produced an actual load at 12:01 of 19,814 MW. However, because the load trending program that creates a five-minute forecast for SCD did not see the manually induced decrease in load, it did not produce an accurate forecast of load for 12:01. At 11:55, the load trending program forecasted load at 12:01 to be 20,338 MW. At 11:55, SCD sent base points to on-dispatch units to meet 20,338 MW of load at 12:01. This resulted in an unanticipated drop of almost 500 MW of load entirely in the western part of the state and at 12:01, SCD was suddenly presented with increased line flows across the Central East due to excess generation in the western part of the state. Because SCD had not started to move units at 11:55 to respond to the sudden change in load, it had to try to catch up at 12:01. As a result, SCD was unable to solve the Central East Interface for three intervals.
- Prices abruptly rose in the East and fell in the West from 11:10 to 11:22 on September 30. This price change resulted from a temporary line outage that reduced the transfer limit on Central East at a time when the constraint was binding. The high prices reflected the high cost of the constraint. The relatively negative prices at some locations in western New York reflected the adverse cost impact of injections at these locations at a time when the Central East constraint was binding. These negative prices also provide a measure of the high cost to the system and to market participants of inflexible generation bids in the West.
- NYPP Staff found that there were large differences in the distribution of load between BME and the DTS simulator as well as abrupt changes between hours in the DTS load. In hour 15 of September 30, BME placed 31.3 percent on the load in the Con Edison service territory, versus 38.7 percent in DTS. Both of these factors could have led BME to provide a generation schedule to SCD that would have made it difficult for SCD to solve transmission constraints when confronted with the actual level and distribution of load in the SCD simulator.

NYPP Staff created an October 7 test case to assess the source of the price volatility in the load simulation on September 30. This case was based on September 30 day-ahead schedules and September 30 bids, but with a different actual load. The DTS simulator was run on a higher level of load than on September 30, and without the large shifts in actual load between hours**.** In addition, BME was operated with more realistic hour-ahead forecasts so that the generation schedules provided to SCD should not have contained an unusual amount of forecasting error. The October 7 test case does not exhibit the level of price volatility observed on September 30, although there was congestion on Central East. In this test case, NCI noted anomalies in intervals 8:44, when the negative reference bus price error from Section IIIB Paragraph 2a occurred, and 9:09, when it appeared that the anomaly described in Section IIIB Paragraph 2f occurred.

c. Incorrect Simulation Data. On September 28 at 7:43 a single generator's schedule was inconsistent with its LBMP. This was a result of incorrect data supplied to SCD while reinitializing the simulation after a break in the testing.

d. Data handling problems. In hour 20 of September 24, there was a system failure that led to errors when SCD read the file containing generator bid data. A data handling error also occurred in interval 0:13 of September 28, resulting in a price spike. NYPP Staff is investigating the first problem and will take steps to ensure that it does not occur again. They have added error checking to SCD to address the second problem. Neither problem reoccurred in the intervals NCI tested during Phase IV Market Trials.

e. Problem with operation of load trending program. On September 30, there was an extreme price spike, with prices reaching over –$16,000 in western New York. Prices abruptly rose in the East, fell in the West and then returned to normal between 13:41 and 13:56. This anomaly occurred because the SCD for 13:51 solved based on incorrect demand due to problems with the operation of the load trending program.

f. Implementation of minimum run time constraints for GTs. NCI has observed that the SCD ideal dispatch does not block load GTs that have not met their minimum run time constraints. Given a two pass operation of SCD, NCI believes that this is consistent with the intention to have GTs set price when they are required to serve load. However, under certain circumstances, it could also lead to the inefficient dispatch of too many GTs. This problem is a Day 2 issue and has not been corrected in the Phase IV Market Trials.

D. PROBLEMS IDENTIFIED IN PHASE III

The following list summarizes the problems that NCI identified in its review of the Phase III Market Trials data and describes the current status of these corrections.

1. SCUC

a. Calculation of LBMPs from the components in SCUC. These data handling problems did not reappear in the September 23-24 Phase IV Market Trials.

b. Mistaken treatment in the final step of the SCUC of GTs turned on in the reliability commitment step. This problem did not reappear in the Phase IV Market Trials.

c. Non-optimal unit commitment due to the structure of the market power mitigation logic in the SCUC. This problem did not reappear in the Phase IV Market Trials.

d. The pricing module for ancillary services did not correctly reflect the simultaneous optimization of energy and ancillary services within the SCUC. This problem has been corrected through a software modification and did not reappear in the Phase IV Market Trials.

e. Incorrect (or missing) calculation of the LBMPs for external proxy buses in the SCUC price reporting. This problem has been addressed through a software modification. The modification was working correctly in the Phase IV Market Trials.

f. Incorrect scheduling of certain generating units in the reliability dispatch. A solution to this problem was developed by ABB and implemented in tests beginning on September 20. The problem has not reappeared in the Phase IV Market Trials.

g. Incorrect scheduling of external dispatchable loads. Price capped external loads initially were not scheduled correctly in the day-ahead market. This problem affected a single load bid in the Phase III Market Trials data for August 5. The source of the problem was identified and ABB developed a solution which has been implemented. This problem did not reappear in Phase IV Market Trials.

h. Units providing regulation were at times incorrectly scheduled in the SCUC to operate at their minimum load. This problem is a Day 2 issue and was not corrected in the Phase IV Market Trials.

i. Under certain conditions some of the LBMPs calculated in SCUC for some locations were inconsistent with the schedules of generators at those locations due to the modeling of the losses. A software modification was implemented in SCUC testing beginning on September 20 and has operated correctly in the Phase IV Market Trials. The maximum inconsistency between day-ahead schedules and prices due to the approximation of losses that has been detected in testing is 2 cents per MWh.

j. Inconsistency between ideal and final SCUC schedules due to incorrect resetting of reserve limits. This problem was corrected during NCI's Phase III validation process and did not reappear in the Phase IV Market Trials.

k. Spinning reserve bids for Con Edison units subject to market power mitigation were not initially set to zero. This problem has been corrected in the software and did not reappear in the Phase IV Market Trials.

2. SCD

a. Incorrect calculation of LBMPs in SCD causing spikes in the LBMP prices in certain intervals. This problem arose from a sign handling convention. This problem was corrected on September 17. The software correction was not perfect and a less severe version of this problem reappeared in the Phase IV Market Trials as noted above in III.B.2.a, and software corrections were completed during the Phase IV Market Trials.

b. Data handling problems in the treatment of bids for two individual units and shift factors for three others. These data handling problems affected a very limited set of units and had a miniscule effect on the overall results. The problems caused inconsistencies between the SCD dispatches, bids and LBMP prices for the affected units. These problems were corrected and did not reappear in the Phase IV Market Trials.

c. In addition to the sign handling convention problems, there was a problem in setting the dispatch limits on units on dispatch that was causing the SCD solution to diverge from the true least-cost dispatch. This problem has been corrected and did not reappear in the Phase IV Market Trials.

IV. CONCLUSIONS

Based on the analyses performed, on both the original Phase IV Market Trials data and on data developed in a series of reruns of the market trials using corrected software, NCI has not observed problems that would prevent the ISO software systems from producing prices consistent with the LBMP pricing methodology and committing and dispatching load and generation based on least bid cost.