ConOp

Real-Time Scheduling Concept of Operation[1]

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[1] This document is a working document designed to form the basis of ongoing and iterative discussions with the market place and NYISO staff.

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Purpose & Limitations of this Document

The Concept of Operations (COO) is the first document in the lifecycle of a software system implementation or enhancement. The COO generally describes the proposed functionality in plain terms (a.k.a. White Paper). It does not attempt to provide detailed explanations of requirements or implementation details, but rather explains the functionality in conceptual terms for discussion prior to detailed design.

Changes to the functionality or appearance of software that is described in the COO may be introduced in subsequent design, implementation, testing or maintenance phases. In addition, the software system or enhancement may evolve over time as other software systems and enhancements are introduced. The COO is not updated to reflect these changes. That is, the COO is not intended to document the software system or enhancement "as built." Other documents, specifically ***Technical Bulletins*** *and* ***Manuals****, describe the "as built" software system or enhancement. In short, the COO will become obsolete at some point during the lifecycle of a software system implementation or enhancement.*

Introduction

Background

On December 1, 1999, the New York Power Pool (NYPP) ceased to exist and the New York Independent System Operator (NYISO) took over control of the bulk power system of the New York State. The NYISO was formed as part of the restructuring of New York State's electric power industry. Its mission is to ensure the reliable, safe and efficient operation of the State's major transmission system and to administer an open, competitive and nondiscriminatory wholesale market for electricity in New York State. It utilizes a bid process for electricity and transmission usage, which enables the State's utilities, and other market participants, to offer electricity at competitive prices, rather than regulated rates. Being a two-settlement system, the NYISO utilizes a vendor (ABB) designed Day and Hour Ahead Commitment system and a retrofitted NYPP designed Security Constrained Dispatch (SCD) program package for use in the real time (spot) market. The replacement of the SCD package is what this document will address.

Business Need

Due to the short implementation time afforded to the transition of the NYPP to the NYISO, it was decided to modify the existing real time Security Constrained Dispatch (SCD) package to enable it to function as the real time dispatch mechanism for the NYISO. While this approach enabled the NYISO to meet the tight implementation schedule and has performed adequately, certain deficiencies in the real time market design were acknowledged from the outset. First and foremost were the price discrepancies that were caused by the process differences between the ABB designed Day ahead (SCUC) and hour ahead (BME) markets and the real time (SCD) market. These differences include the treatment of phase shifters, start-up costs, and fixed (off dispatch) generation. Additionally the ABB systems and SCD use different power system modeling techniques. These factors have contributed to the price discrepancies that have at times caused economic hardships to the Market Participants and are generally a major source of dissatisfaction.

Secondly, the current real-time dispatch package is essentially 20 years old. In addition to deficiencies in scalability that are now becoming acute, many technological advances have occurred which could be employed to greatly improve the NYISO real time dispatch performance and overall MP satisfaction.

System Impact

Replacement of the real time dispatch function will affect to varying degrees almost every sector of the NYISO business.

Impact on SCUC

Overview

SCUC will continue to be a 24-hour optimization with functionality that is largely unchanged.

Bidding

We may want to revisit the reserve and regulation bidding rules in light of a move to a full two-settlement system for reserves.

External Transactions

The scheduling of external transactions across interfaces will be changed to support quarter hour transaction schedules, i.e. those interfaces where the neighboring control areas are prepared to support quarter hourly schedule changes.

All interfaces will have ramp (hour to hour schedule change) and interface (total flow) constraints regardless of whether the neighboring control area will support quarter hourly schedule changes. The addition of individual interface ramp constraints has been proposed independent of this BME/SCD redesign project.

Quarter hourly scheduling will not be achieved by converting SCUC into a 96 period (24* 4) model. The optimization will just be run with increased region to region interface ramp limits across the quarter hourly schedulable reflecting the ability to ramp four times across the hour instead of once.

For those interfaces that will allow and support quarter hour schedule changes the hourly ramp limit will be changed to support additional off hour ramp that becomes available. We cannot support all the ramp for all quarter hours as it would create an energy balance problem for SCUC which will continue to be run on an hourly basis. An interface that supports 500 MW every 15 minutes will not be able to support 2000 MW of schedule change within an SCUC hour as the total energy delivered will only be 500 MWh (for the full hour), plus 375 MWh (500 MW for ¾ of an hour), plus 250 MWh (500 MW for ½ an hour) plus 125MWh (500 MW for ¼ of an hour), or a total of 1250 MWh.

Using a schedule change limit of 1250 MW is a significant improvement over today's capability that would only support 500 MW of schedule change for the same example. It is worth noting however that the use of a 1250 MW hourly ramp limit will result in only 1000 MWh of additional energy being delivered. It does not fully remove the energy imbalance created by the off-hour schedule changes it just reduces the impact of the energy vs. capacity modeling difference. 1250 MW results in 500 MWh from the 500 MW schedule change at the top of the hour, 375 MWh from the 500 MW schedule change at quarter past the hour, and 125 MWh from the remaining 250 MW schedule change at half past the hour.
Transactions that are prepared to be scheduled in the day-ahead market to begin or end their transactions at times other than on the top of the hour can indicate their willingness to do this by checking a box on the bid submittal.

Gas Turbines

Allow for the possibility of steam type GT bids and schedules? Min gen blocks, incremental ranges and multiple bid curve segments.
e.g. a min gen block, a normal incremental operating range (blocked up to this level) and an emergency operating range?

Reserves

The shadow prices of reserves will be used to set the market clearing prices for all reserve and regulation products. Shadow prices of reserves will also be used to set prices in real time allowing a two-settlement system for reserves to work.
Consistent demand curves for reserves will be implemented in SCUC and in the real time commitment and dispatch. These will avoid some of the issues associated with setting prices in times of capacity shortages.

Other

SCUC will support dispatchable loads as reserves and energy E-schedule type functionality for bilateral transactions. This would require that the billing link between bilaterals and physical units be removed.

Impact on the BAS

The necessary tariff changes will dictate significant changes to billing rules. These changes will not be addressed in this document.

Impact on the MIS

The required bidding changes will necessitate extensive MIS changes. These changes will not be addressed in this document.

Impacts on the MMU

These changes will not be addressed in this document.

Positions, Issues, and Resolutions

The overall objective is to create a real-time dispatch function that integrates the scheduling functions of BME with the actual real-time dispatch in order to eliminate the inherent mismatch between prices created by the dispatch software and schedules produced by a separate process (BME) that is conducted at a different time and assuming different conditions. The Real-Time Scheduling function should consist of two main sub-functions Real-Time Commitment (RTC) and Real-Time Dispatch (RTD) which working together will:

- Be scalable and fast enough to support the real-time (5 minute) security constrained economic dispatch of a Northeast Region made up of PJM, NY, and NE (Approximately 15000 LF busses).
- Insure that there is sufficient capacity available to meet load and reserve requirements including locational requirements
- Perform a dispatch that is consistent with the current NY tariff unless otherwise noted (objective function continues to be minimization of production cost)
- Incorporate functionality currently performed by BME including
    a) real-time ancillary service scheduling and management
    b) GT scheduling.
    c) Hourly real-time bidding.
    d) Hourly transaction scheduling and intra hour transaction scheduling that includes a market mechanism for acquiring external energy/capacity to meet in day needs.
- Eliminate a BME type scheduling process that establishes prices different from RT prices. In other words create a financially based scheduling process that is consistent with real time prices.
- Support full two segment (conduct and impact) real-time mitigation.
- Consider expanded demand response mechanisms including the future support of real-time dispatchable load
- Ability to handle 2 settlements for ancillary services (reserve and regulation)
- Ability to handle ¼ hour external transaction scheduling
- Ability to control real and reactive devices
  Real Power : Generators MW output, Dispatchable Load , Pars

  Reactive Power : Generator Var Output, SVCs, Cap banks, Inductors, Transformer Tap changes

Functional Outline of Real Time Scheduling (RTS)

RTS has three component parts – Real-Time Commitment, Real-Time Dispatch and Real-Time Dispatch – Corrective Action Mode. The following matrix shows which components are responsible for the major RTS tasks.

Real Time Scheduling tasks and component responsibility matrix

Component RTS Task	Real-Time Commitment (RTC)	Real-Time Dispatch (RTD)	RTD Corrective Action Mode (RTD-CAM)
External Transaction Scheduling and Posting	Yes	No	No
Gas Turbine Scheduling	Yes	No	Yes (Commit on only)
Non Gas Turbine Scheduling	No	Yes	Yes
Security Monitoring and Constraining	Yes	Yes	Yes
Reserve Pickup	No	No	Yes
Maximum Generation Pickup	No	No	Yes
Price Mitigation Process	Yes	Yes	No
Thunder Storm Alert Process	Yes	Yes	No
Phase Angle Regulator Scheduling	Yes	Yes	No
10 minute Reserve Constraining	Yes	Yes	No/RPU Yes/Security
10 minute Reserve Monitoring	Yes	Yes	Yes
30 Reserve Constraining	Yes	Yes?	No/Yes ?
30 Reserve Monitoring	Yes	Yes	Yes
Regulation Margin Constraining	Yes	Yes	No/RPU Yes/Security
Study Mode	Yes	Yes	Yes

Components

Real-Time Commitment (RTC)

Overview

The Real-Time Commitment (RTC) is a new function to support the Real-Time Scheduling (RTS) function and shall replace the existing Balancing Market Evaluation (BME) function. This tool shall perform up to a 2 ½-hour economic study constrained by network limitations to produce more accurate estimates of unit output. The RTC program will be a ten quarter-hour rolling commitment process that commits GTs, schedules all economic external transactions, and includes any short notice external transactions that might fit based on ramp and capacity limitations. It will ensure energy and reserve requirements are met at least as bid cost over the duration of the optimization. RTC will run every 15 minutes on the quarter hour.

The commitment of generating units in the Day-Ahead time frame was based on a load forecast and equipment outage schedule that is subject to change. Unforeseen events can cause loads to change. In addition, unplanned equipment outages may occur. Since the NYISO has the obligation to maintain reliability, a mechanism to augment and adapt the Day-Ahead schedules was created as the Real-Time Scheduling (RTS). The bidding for this market is

finalized 60 minutes prior to the beginning of the Operating Hour. The RTC tool shall balance an updated load forecast (performed by the NYISO) with generation commitment from the Day-Ahead Market plus energy bidding.

After the Day-Ahead schedule is published, and up to 60 minutes prior to each Operating Hour, Eligible Customers and Suppliers may:

1) Submit additional bids to the NYISO for Energy from:

   a) Generators or other resources that are dispatchable within five minutes and that can be included in and respond to the NYISO's RTD program

   b) Generators or other resources that are self scheduling into the real-time

2) Change their Bid Price for additional Energy from Generators that were committed by the NYISO in the Day-Ahead Market

3) Modify Bilateral Transactions that were accepted by the NYISO in the Day-Ahead schedule

4) Propose new Bilateral Transactions

5) Submit Bids to purchase Energy from the Real-Time Market.

The Bids submitted up to 60 minutes before the Operating Hour are referred to as Hour-Ahead-Bids. The NYISO uses the RTC before each Operating Hour to determine schedules for the LBMP Market and Bilateral Transactions including Exports, Imports and Wheels-Through. In developing these schedules, the RTC shall consider updated Load forecasts and evaluate the impact on reliability of the proposed schedules and commitments.

A generator which needs to remain on-line past the end of the Dispatch Day or Operating Hour to fulfill its minimum run time will have the responsibility to structure its bid in such a way as to continue to be economic as evaluated by SCUC or RTC, respectively, so it is scheduled to remain on-line.

Solution Process

The RTC function shall execute on a 15-minute periodic basis with a look-ahead horizon of up to 3-hours in 15-minute increments as illustrated in Figure 1.1.

Inputs **-** Market bid data, Market power mitigation constraints, network model, outage schedules, PAR schedules, zonal load forecast, contingency requirements, reserve requirements.

Outputs **-** Hour-ahead market schedules, LBMPs, posting data, congestion for NFTS, Interface limits and flows for TTC/AT.

External Transactions

External transactions shall be able to designate one of the following scheduling options:

1) Begin and end at the "top-of-hour" only or

2) Begin and end at 0, 15, 30, 45 minutes of the hour.

The RTC function shall respect the external interface up/down ramping constraints with respect to each external control area. External transactions shall be scheduled on the hour (preferred) or the ¼ hour intervals as appropriate for the external transactions and to satisfy the ramping constraints.

Real-Time Dispatch (RTD)

The RTD function shall normally execute with a 5-minute periodicity beginning at the top of the hour and following every 5 minutes after that.. RTD shall have an optimization look-ahead horizon of up to 60 minutes at 5-minute intervals. Optimization shall observe constraints, including: generation response rates, transmission security, reserve and gas turbine constraints, and external transaction ramp rates. The solution algorithms shall be identical to that incorporated in the RTC function and shall be subject to the same AC power system modeling conditions and constraints.

Solution Process

RTD shall calculate short-term generation schedules, referred to as a “base points”, for each of the generating unit.. The process that shall be used by RTD in performing this calculation can be described generally as follows (based on the existing SCD program). The RTD will be designed to with similar features while incorporating the new look-ahead aspect of the solution process:

1) NYISO databases. This information includes incremental bid cost curves of the generating units, telemetry data, and other data needed to model each of the constraints as previously described for SCUC and RTC.

2) RTD determines the initial conditions to begin the dispatch calculation. These initial conditions include:

   a) A snapshot of the telemetry values of generation output and power flows on the transmission system and load bus consumption, which represents the present state of the NYCA.

   b) Initial values of total system generation, load, actual net interchange, and transmission losses are computed based on the snapshot of telemetry data.

   c) Initial values of power flows associated with the transmission constraints are calculated.

d) Generation "penalty factors" (i.e.: "delivery factors", which are the reciprocal of penalty factors) are calculated, and are used to approximate the effects of changes in generation on system transmission losses. These penalty factors are updated throughout the RTD solution process.

e) The allowable dispatch range (maximum and minimum limits) of the dispatchable generating units for each five-minute period are determined, during the solution process, considering maximum and minimum limits specified by the Market Participants, regulation constraints, and the response rates of the steam units.

3) RTD sets up the dispatch problem in a manner similar to that of SCUC and RTC. The cost objective function and all constraints are also expressed in a similar manner.

When the RTD program has completed the solution process, the final base points are sent to the on-line ORACLE database for use by the LBMP Calculation module and sent out to the Transmission Owners and/or individual generating units. Data concerning the active security and reserve constraints, and a list of the units that were used to solve the security constraints are also audited for use by the billing program and archived.

When the RTD program is not able to solve all the constraints, alarm messages are issued to the NYISO Shift Supervisor, or his designee. The NYISO Shift Supervisor, or his designee, may elect to take alternative action, if necessary, to bring the constraints under control.

Real-Time Dispatch-Corrective Action Mode (RTD-CAM)

Real-Time Dispatch-Corrective Action Mode is a specialized version of RTD that will only be run under extraordinary circumstances at the request of the system operators. RTD-CAM will have the capability to commit Gas Turbines. RTD-CAM will be run on demand and have a requirement to produce schedules in under 30 seconds from kickoff and will look ahead 15 minutes. It will be able to be run in continuous cycling mode if deemed necessary by operations staff and have the following selectable operational modes:

- Reserve Pickup
- Maximum Generation Pickup
- Go to OPCAPS
- Use emergency Response Rates

Notable Implications of RTS Design

1) GT's will have either a 15 or 30 minute start notice
2) On a special case emergency basis some may be started with a 10 minute notice by the dispatch function.
3) All units will be on-dispatch (i.e. no more "off dispatch" generation
4) All units will be given 5 minute basepoints (via the web and where possible via TO direct communication) and 1 hours of 15 minute advisory look-ahead basepoints via the web.
5) Those that want to operate at a fixed point and not be moved should bid accordingly. In practice we will be providing a profile of currently expected future basepoints on the web for those units not equipped to receive control signals from a TO so all should be able to follow. In fact it should improve a unit's ability to follow economic signals since we will be providing a trail of expected 15-minute basepoints.
6) Self-commit and self-scheduling will be provided, subject to operator approval.
7) Ex-ante and ex-post pricing modules will be provided.
8) Pricing methods within the scheduling and dispatch components of SCUC and RTD will utilize the same logic as the ex-ante module.
9) Preliminary ex-ante prices will be calculated and posted as advisory prices.
10) Ex-post prices will be re-calculated prior to daily billing, will be considered final prices and posted early in the day following the dispatch. Substantial rules work is required in this area.
11) RT market will close for bid and external bid price based schedule changes 1 hour prior to the dispatch hour.
12) Advisory schedules for RT transactions (internal and external) will be posted 30 minute prior to the hour and external transactions will be confirmed when completing checkout..

The following Figures describes the timings of the RTC and RTD functions:

Figure 1.1 Real-Time Unit Commitment (RTC) – Time Line Sequence

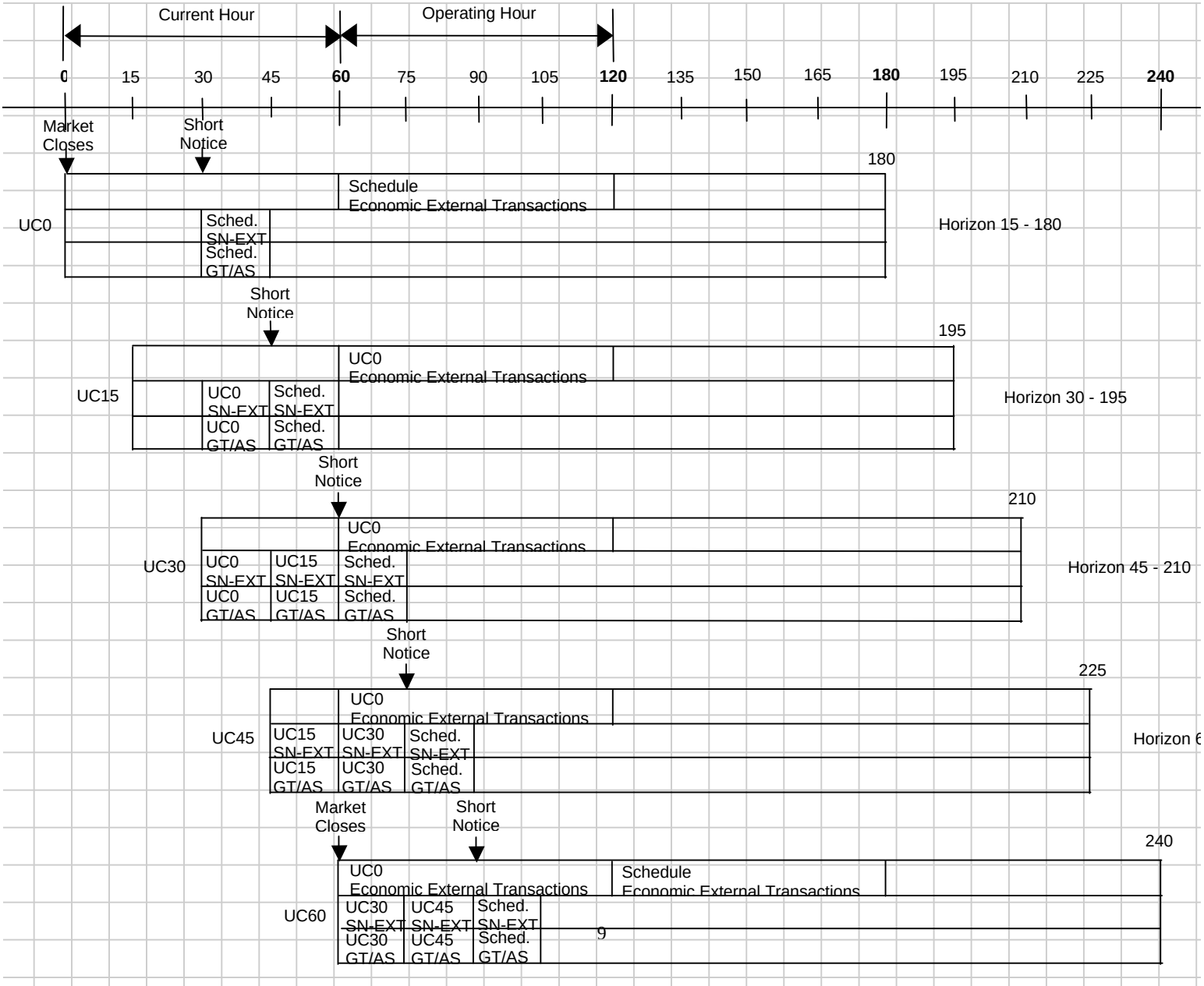
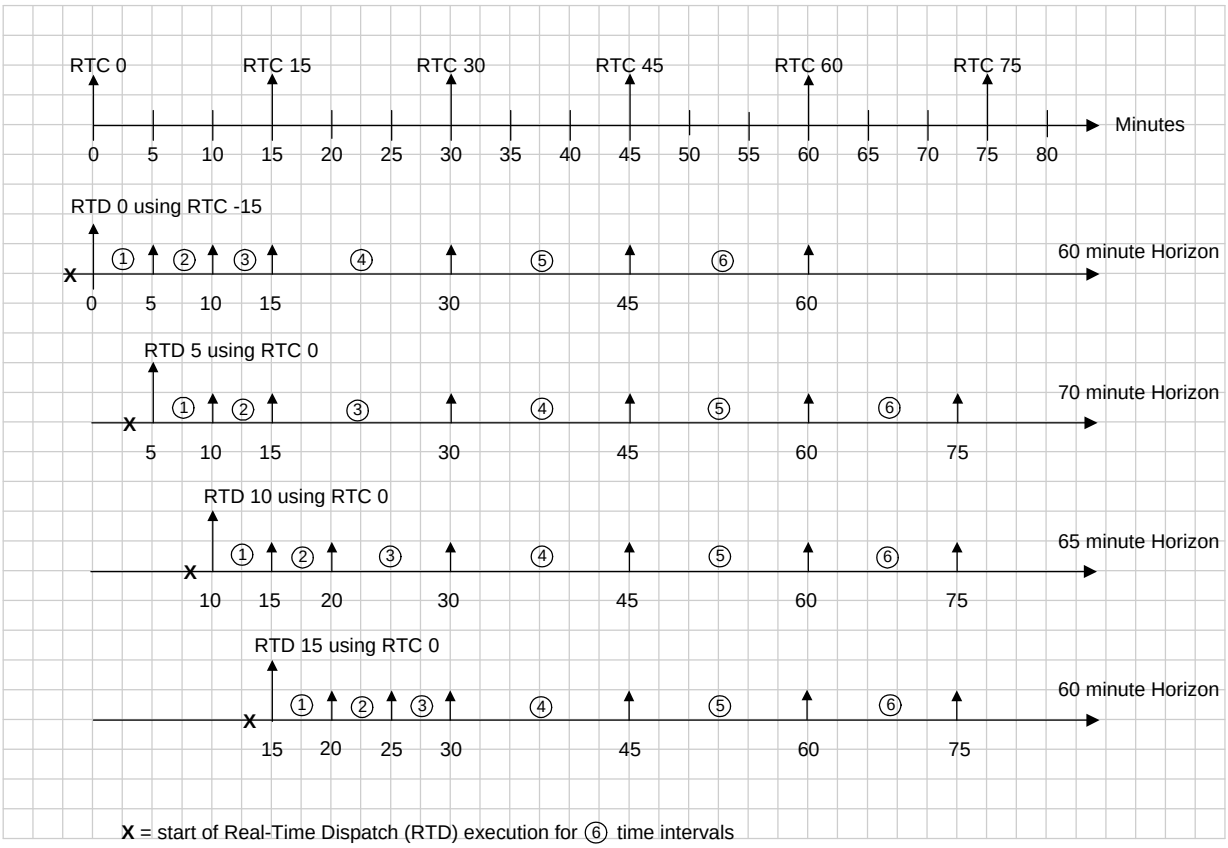


Figure 1.2: Real-Time Commitment and Real-Time Dispatch - Time Line Sequence



Bidding

1) All bids for energy and reserves will be submitted on an hourly basis. They may change between hours as they do today.
2) Bids for an hour will be locked 1 hour before the start of the operating hour. This to ensure that bids for the entire optimization timeframe being considered by the RTC software are locked in. Bids in the second and third hours of BME's optimization are not currently locked in this fashion.
3) Dispatchable load bidding for reserves and energy will be included in the model.

Tasks

External Transaction Scheduling in Real Time Commitment (RTC)

Please reference Figure1.1 for the following:

1) External transaction schedules will be generated by RTC every 4th run for the economically evaluated external transactions 60 minutes before every hour, i.e., UC0, UC60 etc. Economically evaluated transactions are scheduled out of this commitment for four quarter hour periods i.e. in UC0 the external transaction schedules are evaluated for t= 60 through t=120. These schedules would be posted a t=15 i.e. 45 minutes before the hour of operation. Both prescheduling and ramp management functionality would be maintained.
2) The subsequent commitments for t=60 through t=120 will take the economically evaluated external schedules from UC0 for t=60 through t=120 as fixed and include any short notice transactions that can be accommodated on a rolling basis as described in the next bullet
3) Short notice external transactions will be evaluated on a first come first served basis, as price takers, and honoring ramp and capacity constraints across the interfaces
    a) They will be accepted up to 30 minutes before the operating period e.g. for operating period beginning at t=60 and ending at t=75 these transactions are scheduled in UC30.
    b) These transactions will need to be checked out with some form of OSS or pre-scheduling package to ensure that the ramp and capacity constraints of both the importing and exporting control areas are not violated at either the beginning or end of any scheduled transaction. A 15 minute import looking to schedule at t=60 in UC30 would have to have not violate ramp or capacity limits in either the importing or exporting region at either end of the transaction for the transaction to be scheduled.
    c) The logic that has previously been described by LECG to honor accepted day-ahead and pre-scheduled hour ahead transactions for real-time pre-scheduling needs to be honored [These rules may need to be reviewed for consistency with a quarter hour construct];
    d) The acceptance of the transaction by the OSS or pre-scheduling software verifies the checkout of that transaction in both the sending and receiving control areas and these transactions are included in the RTC as fixed, price taking, injections and withdrawals.

External Transaction Scheduling in Real Time Dispatch (RTD) and RTD-CAM

External unit schedules are passed to RTD and RTD-CAM by RTC

Neither RTD or RTD-CAM requires any specific functionality to handle external transactions. IS+ will be used to manage transaction curtailments in RT and the RTD package must be able to accept DNI changes produced by the IS+ package.

Gas Turbine Scheduling in RTC

Please reference Figures1.1 and 1.2 for the following:

In normal operating mode all GTs will be scheduled in the RTC component. To Summarize:

1) Quick start GT commitments are made by the RTC that is run 30 minutes before the clock time and posted 15 minutes before the clock time and slow start GT commitment decisions are made by the RTC that is run 45 minutes before the clock time and posted 30 minutes before the clock time
2) There will be the capability of operator override of GT commitments made by RTC
3) Minimum runtime and minimum down time type conditions need to be enforced in RTC now that a one hour minimum runtime involves a four period schedule.

4) There will be the possibility of steam type GT bids and schedules (e.g. a min gen block, a normal incremental operating range (blocked up to this level) and an emergency operating range)

Gas Turbine Scheduling in RTD

1) Gas Turbines will not be scheduled on or off by RTD. RTD will receive the 15 or 30 minute GT schedules from RTC and will have the capability to calculate the appropriate transitional 5 minute basepoints for GTs based on this schedule and response rate versus output curves.

Gas Turbine Scheduling in RTD-CAM

RTD-CAM will be the mechanism to commit GTs in the short term. It will behave much like SCD does today in that it will be able to commit all available quick start (up to 15 minute start time) GTs. Once committed, these GTs schedules will be passed to the RTC and RTD components for the next execution.

Non Gas Turbine Scheduling in RTC

RTC will produce advisory schedules for all non-GT units. The RTC will produce a profile of expected generation by quarter hour periods for all the periods over which it optimizes based on unit bid curves and ramp rates. Units committed by RTC will be financially binding subject to operator confirmation.

Non Gas Turbine Scheduling in RTD

RTD will produce 5-minute basepoints for all units. There will no off-dispatch units or class B units. Units will indicate their willingness or ability to move based on their bid curve and ramp rates. The new RTD will produce a profile of expected generation for all the periods over which it optimizes which will provide units with an expected profile for the next hour.

The basepoints for later periods of the RTD are also communicated to the units (via the web) to indicate the likely direction of unit movement over a longer period of time. This information will provide similar insights to the information that was previously provided by accumulating basepoints when they existed. This will help both the unit owners to manage the operation of their plants and the dispatchers at the NYISO to manage the security of the system.

Non Gas Turbine Scheduling in RTD-CAM

RTD-CAM will produce 5-minute basepoints for all units in this mode. These units will be sent the next 2-5 minute schedules for all units to produce a profile of expected generation for the periods over which it optimizes.

Security Monitoring and Constraining

All three components (RTD-CAM included) will be required to monitor and if necessary adjust generations to accomplish the following:

1. Keep all pre-contingency real power flows within normal ratings for all monitored bulk power transmission facilities.
2. Keep all post-contingency real power flows within the appropriate emergency ratings for all monitored bulk power transmission facilities for any contingency defined under NYISO's operating criteria.
3. Keep all real power flows across the transfer interfaces within the appropriate transfer limits.

Both RTC and RTD will use a common Security Analysis (SA) function in which new contingency cases will be able to be created by operations staff in real time as conditions dictate. RTC and RTD will have separate but identical sets of displays to show both actual and predicted security constraint flows for all constraints that are within 90% of the appropriate limit for multiple look ahead periods. It would be desirable to be able to present both RTC and RTD time dependant sets of constraints such that known (or expected) system changes could be considered in the appropriate time frames. The SA for RTD-CAM, which would include the Security Monitoring function, will run on a 30 second cycle , evaluating all real and contingency flows and displaying the most critical facilities to the dispatchers. The NYISO shall operate the ISO Secured Transmission System during adverse conditions, including but not limited to thunderstorms, hurricanes, tornadoes, solar magnetic flares and threat of terrorist activities, in accordance with the Reliability Rules, inclusive of Local Reliability Rules and related PSC orders. Consistent with such Rules, the NYISO shall maintain reliability of the ISO Secured Transmission System by directing the adjustment of the Generator output levels in certain areas of the system to reduce power flows across transmission lines vulnerable to outages due to these adverse conditions, thereby reducing the likelihood of major power system disturbances. The NYISO shall have the sole authority to declare that adverse conditions are imminent or present and invoke the appropriate operating procedure(s) affecting the ISO Secured Transmission System in response to those conditions. Activation of a procedure in compliance with a Local Reliability Rule shall involve a two step process. The Transmission Owner, directly involved with such Local Reliability Rule, such as Storm Watch shall advise the NYISO that adverse conditions are imminent or present and recommend to the NYISO the activation of applicable procedures in support of that rule. Consistent with the Local Reliability Rule, the NYISO shall declare the activation of the appropriate procedures. The Transmission Owner and the NYISO shall coordinate the implementation of the applicable procedures to the extent that ISO Secured Transmission System facilities are impacted. Records pertaining to the activation of such procedures and the response in accordance with those procedures shall be maintained and made available upon request.

Thunderstorm alerts will cause a predetermined set of constraints to be added to the SA functions of both RTC and RTD to be evaluated by the next execution of each. If a thunder storm alert or any other unplanned event causes any type of overload there will be an option for the operators to run an the on-demand RTD-CAM which will produce new schedules in under 30 seconds to relieve the overload. Dispatchers will also have the capability to change limits at their discretion.

Reserve Pickup

A Reserve Pickup (RPU) run of RTD-CAM will be used to a major system event. The program runs through its normal solution process, only now the basepoints are constrained by emergency rather than normal response rates, and they may go to operating capability limits if necessary (for units not supplying 10 minute reserve the emergency RR will equal the normal RR and the OPCAP will equal the normal high limit). After zero ACE has been crossed the operators will run a RTD-CAM in a reserve restore mode which will attempt to reestablish reserves. Normal RTD runs would take over scheduling at the earliest possible time as all RTD runs are expected to maintain the 5, 10, 15… etc sequence. A flag will be sent to each unit along with the BP indicating the NYISO is in reserve pickup.

Max Gen Pickup

Maximum generation Pickup will be a sub function of RTD-CAM. The dispatcher will be able to select one or more of the following zones, or other combinations of subzones as deemed necessary. The program would move all of the generators in one or more of the selected area(s):

a. LI
b. SENY
c. East of Total East
d. Entire State

at their emergency response rates while attempting to balance load with the remaining units. Solving for Security and load would not be of primary importance, although the ability to do Max Gen pickup on a zonal basis will by definition incorporate some security considerations. Max Gen Pickups will also send an alarm flag with dispatch instructions similar to the reserve pickup flag. Basepoints will be issued for tracking purposes.

Price Mitigation Process

MMU will supply RTS with a watch list of units based on conduct tests. Preemptive price mitigation will be performed in RTC based on the watch list and impact tests conducted interior to the processes. Price mitigation process will be more fully discussed once the current real-time mitigation discussions have been completed.

Thunder Storm Alert

Thunderstorm alerts will cause a predetermined set of constraints to be added to the SA functions of both RTC and RTD to be evaluated by the next execution of each. If a thunder storm alert or any other unplanned event causes any type of overload there will be an option for the operators to run an the on-demand RTD Corrective Action Mode which will produce new schedules in under 30 seconds to relieve the overload. Dispatchers will also have the capability to change limits at their discretion**.**

Phase Angle Regulator Scheduling

Phase Angle Regulator optimization and/or scheduling will be a feature of RTS, but will initially be disabled due to current operating practices. When activated the following will apply:

a. The RTC program shall be initialized by the telemetered flows and settings of the phase angle regulators (PARs)
b. Software will be able to support individual selection of PARs to optimize
c. PAR scheduling would be used with limited movement (only ± 10 to 25 MWs range) per study period to represent actual tap movement
d. PAR scheduling would not be used in RTD-CAM

The user shall be able to select individual (or all) PARs to:

1) Hold the flow (block loaded) at the telemetered value, or

2) Adjust (optimize) the flow, or

3) Hold the PAR at the telemetered or user entered fixed tap setting.

GT Management Start/Stop

This feature will allow operations staff to start or stop, or delay the turning on or turning off of gas turbines. There will be a facility to allow the dispatchers to have the final say on whether a GT is actually started or turned off. This feature will apply in all RTS applications.

Information Posting

The following matrix details what information gets posted and where:

Real-Time Information Posting/Notification (NYISO Internal – Market Participant Private – Public)				
#	**Information**	**Real-Time Commitment (RTC)**	**Real-Time Dispatch (RTD)**	**RTD Corrective Action Mode (RTD-CAM)**
1	MW base points for generation and load resources: • All on-dispatch units • All self-commit/scheduled units • All dispatchable loads	• NYISO Internal. • 15-minute increments covering the RTC horizon.	• NYISO Internal. • Market Participant private via Internet or TO direct. • 5-min. increments followed by four 15-min. increments, covering the RTD horizon.	• NYISO Internal. • Market Participant private via Internet or TO direct. • Three 5-min. increments. • Notify TOs/Providers that Reserve Pickup mode is in effect.
2	Advisory ex-ante: • LBMP prices • Constraint shadow prices • Injection shift factors • Contingency distribution factors • Delivery factors	• NYISO Internal. • Proxy Prices for external buses via Public internet. • All RTC increments.	• NYISO Internal. • LBMP prices and constraint shadow prices (first increment only) – Public via the Internet. • All RTD increments.	• NYISO Internal. • LBMP prices and constraint shadow prices, depending on mode - Public via the Internet.
3	Final ex-post: • LBMP prices • Constraint shadow prices • Injection shift factors • Contingency distribution factors • Delivery factors	• NYISO Internal by Market Information System (MIS).	• NYISO Internal. • LBMP prices and constraint shadow prices (daily for 5-minute prices) - Public via the Internet. • First forecast increment (5-minutes ahead) of RTD solution.	• NYISO Internal. • LBMP prices and constraint shadow prices (daily) - Public via the Internet.

Real-Time Information Posting/Notification (NYISO Internal – Market Participant Private – Public)				
#	**Information**	**Real-Time Commitment (RTC)**	**Real-Time Dispatch (RTD)**	**RTD Corrective Action Mode (RTD-CAM)**
4	Economic schedules for real-time External transactions	• NYISO Internal. • Market Participant private via the Internet.	None	• NYISO Internal for Operator action and input to IS+, depending on mode.
5	Updated ATCs	• NYISO Internal. • Public via the Internet.	None	None
6	Commitment of short-start-time resources, including gas turbines	• NYISO Internal. • Notify TOs/Providers to start up resources.	• NYISO Internal.	• NYISO Internal. • Notify TOs/Providers to start up quick-start GTs, depending on mode.
7	Gas Turbine shut down	• NYISO Internal. • Notify TOs/Providers to shut down GTs.	• NYISO Internal advisory to Operator	• NYISO Internal. • Notify TOs/Providers to shut down GTs, depending on mode.
8	Phase Angle Regulators (PARs) Optimization • "Open-Circuit" model for real-time • "Fixed-Angle" model for contingencies	• NYISO Internal. • Notify TOs to make adjustments.	• NYISO Internal. • Notify TOs to make adjustments.	• NYISO Internal. • Optimization, depending on mode.

Real-Time Information Posting/Notification (NYISO Internal – Market Participant Private – Public)				
#	**Information**	**Real-Time Commitment (RTC)**	**Real-Time Dispatch (RTD)**	**RTD Corrective Action Mode (RTD-CAM)**
9	Volt/Var Resources: • Generator MVAR outputs • Static Var Compensators (SVCs) • Capacitor banks • Inductors • Transformer taps	• NYISO Internal. • Notify TOs to make adjustments.	• NYISO Internal. • Notify TOs to make adjustments.	• NYISO Internal. • Notify TOs to make adjustments, depending on mode.
10	Price Mitigation process: • Impact Tests • Watch list for mitigation provided by MMU	• NYISO Internal.	• NYISO Internal.	• NYISO Internal – after the fact impact test, depending on mode.
11	Study Mode – for each function (3 simultaneous users)	• NYISO Internal • One-hour look-ahead option.	• NYISO Internal.	• NYISO Internal.
12	External Interface Restrictions	• NYISO Internal • Operator interface to IS+ • Constraint shift factors to IS+		

Study Modes

RTC, RTD, and RTD-CAM will all have study modes. The RTC study mode will have a variable look ahead option feature which could be used if the normal 3 hour look ahead execution time is considered problematic. The following will apply :

a. Data is initialized from production data
b. RTD-CAM study mode would be single evaluation.
c. RTC & RTD study modes can be run as single evaluation or on timer (equivalent to production)
d. Timed evaluation should process similar to production mode with constant addition of dispatcher scenario
e. Dispatcher scenarios would include; transmission outages, generator outages, additional contingencies, different facility ratings, different load forecast (statewide or by zone)
f. Displays should clearly show operation in study mode (different background color)

Tasks External to the RTS

Shared Activation of Reserve

Program which calculates the amount of reserve to be picked up in 10 minutes by each Control Area in NPCC (ISO) when shared reserve pickup is required. Can be activated if any ISO experiences a unit loss greater than 500 MWs. Will observe transfer constraints in power system. Follows NPCC and NERC criteria. Input: MWs to be picked up and control area that lost unit.

RTC Load Forecast

The RTC load forecaster will support the 3-hour horizon of the RTC function and shall predict load at 15-minute intervals. The RTC load forecast shall be consistent with the SCUC load forecast and the RTD load predictor.

RTD Load Predictor

The RTD load predictor will support the 1-hour horizon of the RTD function and shall predict load at 5-minute intervals.

Location Based Marginal Price Calculator (LBMPC)

The Location Based Marginal Price Calculator (LBMPC) function calculates the bus and zonal energy prices for the New York Control Area (NYCA). The input data consists of system Lambda, penalty factors,

shadow Lambdas, and generation shift factors. The LBMPC function interfaces with SCUC, RTC, and RTD as described in the next subsections.

Facility which calculates LBMPs for all generator locations, and zonal locations based upon pre-defined weighted average of generator locations. Inputs: Cost output results from SCUC, RTC and RTD for system lambda, shadow costs, delivery factors and constraint shift factors. Generator weightings for zonal prices. Outputs: Generator and zonal LBMP broken down by Cost of Energy, Cost of Losses, and Cost of Congestion.