# A536: Real-Time Scheduling

# Real-Time Commitment (RTC) and Real-Time Dispatch (RTD)

## Concept of Operation

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# TABLE OF CONTENTS

# 1 INTRODUCTION

## 1.1 Goal Statement

Define the rules, bidding parameters, and constraints for the commitment and dispatch functions of the real-time scheduling system.

## 1.2 Definitions, Acronyms, and Abbreviations

| Term | Description |
|---|---|
| $10_{00}$ | 10-minute units started by $RTC_{00}$ |
| $10_{15}$ | 10-minute units started by $RTC_{15}$ |
| $10_{30}$ | 10-minute units started by $RTC_{30}$ |
| $10_{45}$ | 10-minute units started by $RTC_{45}$ |
| $30_{00}$ | 30-minute units started by $RTC_{00}$ |
| $30_{15}$ | 30-minute units started by $RTC_{15}$ |
| $30_{30}$ | 30-minute units started by $RTC_{30}$ |
| $30_{45}$ | 30-minute units started by $RTC_{45}$ |
| BME | Balancing Market Evaluation |
| EDRP | Emergency demand response program |
| RTC | Real-time commitment |
| $RTC_{00}$ | Real-time commitment that posts on the hour |
| $RTC_{15}$ | Real-time commitment that posts at 0:15 after the hour |
| $RTC_{30}$ | Real-time commitment that posts at 0:30 after the hour |
| $RTC_{45}$ | Real-time commitment that posts at 0:45 after the hour |
| RTD | Real-time dispatch |
| RTD-CAM | Real-time dispatch – corrective action mode |
| RTS | Real-time scheduling (RTC, RTD, and RTD-CAM) |
| SCUC | Security constrained unit commitment |
| SNET | Short notice external transaction |
| $SNET_{00}$ | Short notice external transactions scheduled by $RTC_{00}$ |
| $SNET_{15}$ | Short notice external transactions scheduled by $RTC_{15}$ |
| $SNET_{30}$ | Short notice external transactions scheduled by $RTC_{30}$ |
| $SNET_{45}$ | Short notice external transactions scheduled by $RTC_{45}$ |
| UOL | Upper operating limit |
| $UOL_E$ | Emergency upper operating limit |
| $UOL_N$ | Normal upper operating limit |
| | |
| | |

# 2 Real-Time Commitment (RTC)

As shown in Figure 1~~Figure 1~~, RTC is a multi-period security constrained unit commitment and dispatch model that co-optimizes to simultaneously solve load, reserves and regulation. Each RTC run optimizes over ten quarter hour periods for a total optimization horizon of 2 ½ hours. Each RTC run receives a label in terms of our description of the model that indicates the time at which the results of the run are posted. These results apply to the 2 ½ hour period that starts 15 minutes after the RTC results post , e.g., $RTC_{15}$ posts at time 15 and optimizes from time 30 through time 180. RTC will run every 15 minutes.

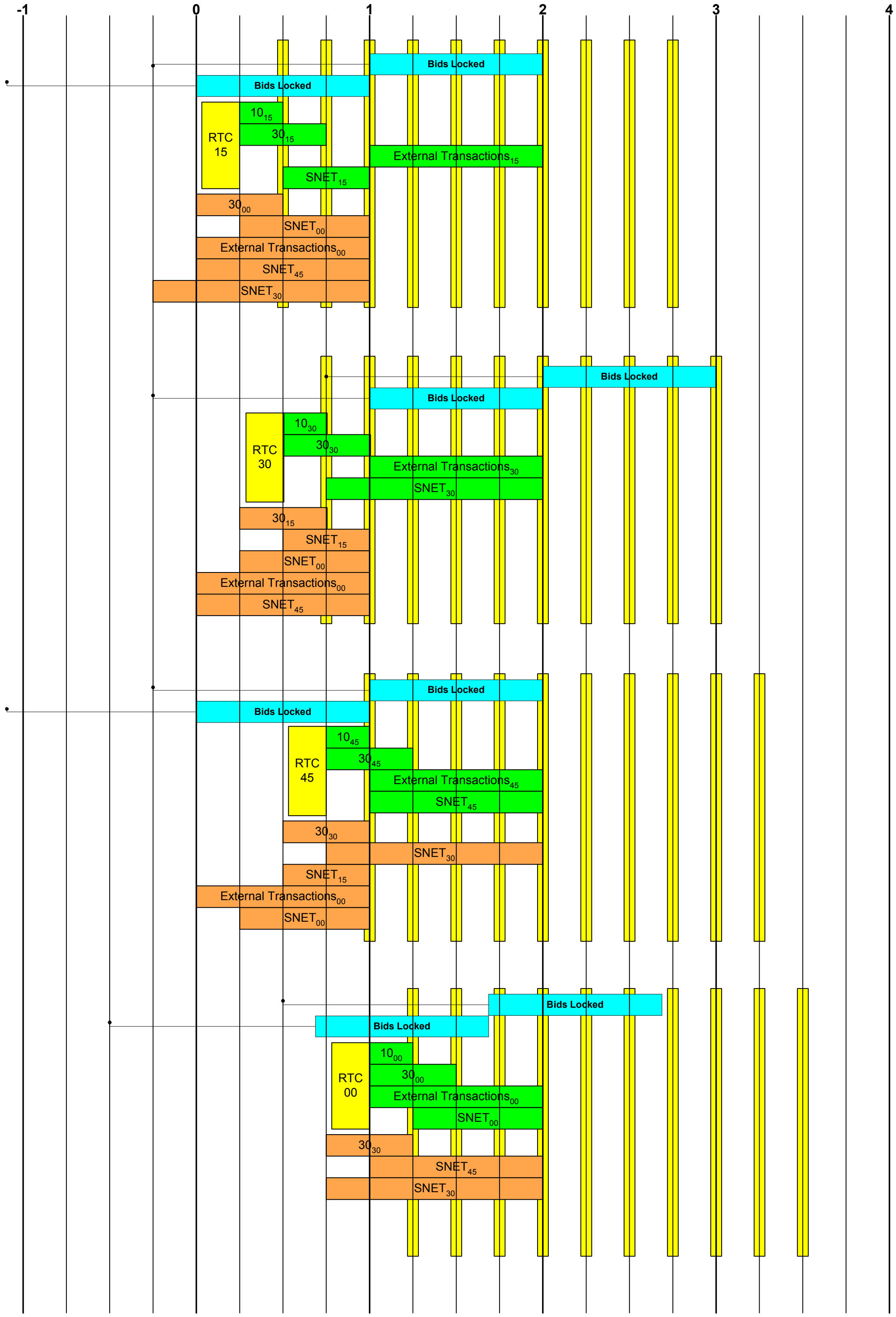


**Figure 1. Real Time Commitment Process**

### 2.1 Objective Function and Constraints

The most important element of any description of scheduling software is the objective function, the solution requirements and the constraint set. The overall objective is to minimize the total as-bid cost over the 2 ½ hour optimization timeframe. The solution requirements are:

- Commit, dispatch and schedule resources to meet forecast load plus losses
- Meet all reserve requirements by product type and location
- Meet the regulation requirement

The constraints modeled in RTC include but are not limited to:

- All transmission constraints (base case, contingency, thermal, voltage, stability)
- Generation bidding parameters (ramp rates, startup times, minimum down times, minimum generation levels, Upper Operating Limits, minimum run times)

The costs that are included in the optimization include but are not limited to:

- Generation startup costs
- Generation minimum generation costs
- Generation incremental energy costs
- Import generation costs
- Export schedule benefits
- Wheel through schedule benefits
- Dispatchable load schedule benefits
- Reserve schedule availability costs (Lost opportunity costs are implicitly captured through other costs)
- Regulation schedule availability costs (Lost opportunity costs are implicitly captured through other costs)

### 2.2 Generation

#### 2.2.1 Bid Representation

Generators will be able to bid in one of three general constructs:

- Dispatchable i.e. will follow a 5 minute (or 6 second) basepoint
- Self scheduled lower limit with a dispatchable range i.e. will follow a 5 minute (or 6 second) basepoint above a market participant specified lower limit. A physical lower limit must also be bid in for emergency re-dispatch situations.
- Self scheduled with no dispatchable range

Each generator will be able to specify a normal upper operating limit ($UOL_N$) and an emergency upper operating limit ($UOL_E$). These limits will be recognized both day-ahead and in real-time. Market Operations will determine if the normal or emergency ratings should be used for the day's unit commitment before running the day-ahead market model. The exact details of the rules that determine whether the day in question is normal or emergency are still to be finalized but operations staff will make this decision before initiating the SCUC run for a day. An "emergency" day allows the SCUC to use the entire units output up to its Emergency UOL for energy or reserves. On other days reserves and energy can only be scheduled up to the Normal UOL. Operators will be allowed to call for emergency UOLs after the day-ahead market if it becomes apparent that the real time conditions are predicted to be unexpectedly tight. The procedures for activating the Emergency UOLs are yet to be defined.

Inter-temporal constraints will be modeled in RTC. The parameters that define the maximum and minimum allowable values for each of the inter-temporal constraints in SCUC and RTC may be different:

- Minimum run time – maximum value allowed will be 1 hour
- Startup time – units can specify a 10 minute or 30 minute start time
- Minimum down time – maximum value allowed will be 168 hours
- Maximum stops

Bids for energy and ancillary services will be locked ~~one hour~~75 minutes before the beginning of the hour in which that bid would apply. Bidding restrictions currently in place on hour-ahead bids for segments of the generator's curve that were scheduled day-ahead would be maintained in a similar manner with the implementation of RTS.

#### 2.2.1.1 Energy Bid Representation

- Steam units will be bid in as they are in SCUC today with a startup cost, minimum generation cost and incremental energy bids that are blocks.
- Gas turbines may choose to submit bids with a minimum operating level plus a dispatchable range. They will be block loaded in day-ahead and RTS schedules only up to the specified minimum operating level. A gas turbine that chooses a minimum operating level equal to it maximum operating level will be treated as gas turbines are today. The Hybrid pricing logic will be continued in RTS.

##### 2.2.1.1.1 Startup Cost Bid Representation

- Startup costs bid as they are in SCUC today.
- The Market Participants can choose between a startup cost defined by:
  - Hour of the day
  - Time dependent increasing cost function (to model warm start steam).
  - Time dependent decreasing cost function (to model gas turbine willingness to restart quickly after it has shut down).
- Gas turbines will have a real time startup cost that will be used by RTC.
- RTD does not make commitment decisions and will not use startup cost in any scheduling or pricing decisions.
- RTD-CAM will be able to commit gas turbines and the startup cost will be built into the incremental energy cost considered by the RTD-CAM commit mode. The RTD dispatch schedules and prices will be based only on the incremental costs of the units.

##### 2.2.1.1.2 Minimum Generation Bid Representation

- Minimum generation cost bids will be submitted in the same form as they are in SCUC today.

- The minimum generation operating level is defined by a MW amount. This level may change hourly in SCUC and may change quarter-hourly in RTS.
- The minimum generation cost is defined by a total minimum generation cost in dollars ($) for one hour of operation at the minimum generation MW amount.

#### 2.2.1.1.3 Incremental Energy Bid Representation

- Incremental energy bids will be submitted in the same form as they are in SCUC today with a maximum of 12 incremental blocks. 12 $-MW pairs are proposed so that the allowable number of blocks is high enough to provide sufficient bidding flexibility but not so high as to adversely affect the software performance during SCUC or RTS.
- Each block is defined by a MW quantity and single incremental $ bid.
- Incremental energy blocks must have monotonically increasing bid prices.
- Must cover the full range of the unit being offered~~, at least from bid minimum generation level to emergency upper operating limit.~~ from zero MW to the DMNC.

### 2.2.1.2 Ancillary Service Bid Representation

Bidding constructs for ancillary services will apply in SCUC and all the RTS scheduling packages (RTC, RTD and RTD-CAM). Bids for reserves scheduled day-ahead may not be increased between the day-ahead and real-time markets. Figure 2~~Figure 2~~, below, summarizes the various types of ancillary services and bid parameters that each class of generator may provide in the day-ahead and real-time markets. Details for each class of reserve are outlined in the sections following Figure 2~~Figure 2~~.

| | 10-Minute Spinning | 10-Minute Non-Spin | 30-Minute Spinning | 30-Minute Non-Spin | Regulation |
|---|---|---|---|---|---|
| On-Dispatch | ✓ | | ✓ | | ✓ |
| Self-Schedule Flex | ✓ | | ✓ | | ✓ |
| Self-Schedule Fixed | | | | | |
| Fast-Start Units (10-Min Start) | ✓ | ✓ | ✓ | | ✓ |
| Slow-Start Units (30-Min Start) | ✓ | | ✓ | ✓ | ✓ |
| Availability Bids | | | | | |
| Real-Time | Must bid $0/MW | Must bid $0/MW~~Provided by the bidder. $0/MW assumed if no bid provided~~ | Must bid $0/MW | Must bid $0/MW~~Provided by the bidder. $0/MW assumed if no bid provided~~ | Provided by the Bidder |
| Day-Ahead | Provided by the bidder. $0/MW assumed if no bid provided | Provided by the bidder. $0/MW assumed if no bid provided | Provided by the bidder. $0/MW assumed if no bid provided | Provided by the bidder. $0/MW assumed if no bid provided | Provided by the Bidder |
| MW Quantity | Limited by ramp rate and capped at UOL | Limited by ramp rate and capped at UOL | Limited by ramp rate and capped at UOL | Limited by ramp rate and capped at UOL | Provided by the bidder. (MWs and MW/Min.) |

**Figure 2 - Generator Ancillary Service Bidding**

#### 2.2.1.2.1 10 Minute Spinning Reserve Bid Representation

- Units can only provide spinning reserves if they are on-dispatch or bid with a self-scheduled lower limit and a dispatchable range.
- Units do not explicitly define the quantity of reserve that they can provide. Reserve quantities will be defined by the unit's reserve ramp rate but may also be limited by the size of the dispatchable range on the unit as defined by the applicable Emergency or Normal Upper Operating Limit.
- In the real-time market, availability bids will be $0/MW by definition for all units capable of providing spinning reserve.
- In the day-ahead market, availability bids will be permitted. If no availability bid is submitted a bid of $0 will be assumed.

#### 2.2.1.2.2 10 Minute Non-Synchronized Reserves Bid Representation

- Units must be able to synchronize and generate within 10 minutes.
- A unit that has an energy bid curve will also be considered for scheduling as reserves.

- The reserve quantity will be defined by the applicable Emergency or Normal UOL.
- In the real-time market, availability bids will be $0/MW by definition for all units capable of providing reserve.
- In the day-ahead market, availability bids will be permitted. If no availability bid is submitted a bid of $0 will be assumed.

#### 2.2.1.2.3 30 Minute Synchronized Reserves Bid Representation

- Units can only provide spinning reserves if they are on-dispatch or bid with a self-scheduled lower limit and a dispatchable range.
- Units do not explicitly define the quantity of reserve that they can provide. Reserve quantities will be defined by the unit's reserve ramp rate but may also be limited by the size of the dispatchable range on the unit as defined by the applicable Emergency or Normal Upper Operating Limit.
- In the real-time market, availability bids will be $0 by definition for all units capable of providing spinning reserve.
- In the day-ahead market, availability bids will be permitted. If no availability bid is submitted a bid of $0 will be assumed.

#### 2.2.1.2.4 30 Minute Non-Synchronized Reserves Bid Representation

- Units must be able to synchronize and generate within 30 minutes.
- A unit that has an energy bid curve will also be considered for scheduling as reserves.
- The reserve quantity will be defined by the applicable Emergency or Normal UOL.
- In the real-time market, availability bids will be $0/MW by definition for all units capable of providing reserve.
- In the day-ahead market, availability bids will be permitted. If no availability bid is submitted a bid of $0 will be assumed.

#### 2.2.1.2.5 Regulation Bid Representation

- Availability bids will be allowed for regulation.
- Units will specify a regulating capability in MW and MW/min.

### 2.2.1.3 Inter-temporal Constraints

The RTC engine will have the same capabilities as today's SCUC to model inter-temporal constraints. The day-ahead schedules of all units capable of being started within 30 minutes will no longer be passed through into real time as must take capacity. Market participants must manage this risk for themselves.

#### 2.2.1.3.1 Startup Time

- Will be limited to a maximum of 30 minutes
- Units can specify a startup time of as little as ~~15~~ 10 minutes

#### 2.2.1.3.2 Minimum Run Time

- The maximum allowable minimum run time will be 1 hour.
- The minimum runtime can be as short as 15 minutes

#### 2.2.1.3.3 Minimum Down Time

- The maximum allowable minimum down time will be 168 hours.

#### 2.2.1.3.4 Maximum Number of Stops

Market Participants will be responsible for managing the number of stops per day through their bids. RTC will track the number of stops, but not enforce in its scheduling.

### 2.2.2 Commitment

Unit starts and stops will be controlled by RTC in most cases. The exception is the commitments made by RTD-CAM. The RTC runs that post at 15 minutes past each hour determine the economically evaluated external transactions scheduled for the following hour, i.e., $RTC_{15}$ determines the economically evaluated external transaction schedules for time 60 through 120.

The other 3 RTC runs in each hour must make some assumptions about all the transactions that were scheduled either as pre-scheduled, economically evaluated or SNETs. In any quarter hour period, in any RTC run that economic transaction decisions are made all external transactions will be evaluated consistent with their bids. RTC will treat all transactions as protected~~fixed injections or withdrawals~~ in quarter hour periods where economic evaluations are not being made. RTC may reduce specific transactions to maintain feasibility, but will not pass those curtailments to IS+. Instead, RTC will issue alarms to the operator indicating the amount of MWs of transactions that needed to be cut in order to maintain feasibility.~~This will require some form of pre-processing to ensure transaction feasibility. RTC will not select specific transactions to be cut but rather will indicate to the operator that some number of MWs of transactions need to be cut in order to maintain feasibility.~~ The operator will then use the IS+ tools to curtail the appropriate transactions if desired. RTS will have the capability of supporting both hourly and quarter-hourly transactions.

#### 2.2.2.1 Startup

All units in RTC will receive binding startup notifications consistent with startup time included in their real-time bids. Units that submit a 30-minute start-up time will receive a binding startup notification from the RTC that posts its results 30 minutes before the scheduled start of the unit. Units that submit a 10 to 15-minute start-up time will receive a binding startup notification from the RTC that posts its results 15 minutes before the scheduled start of the unit.

A unit that is scheduled to start at time 60 with a 30-minute startup time will be given a binding commitment by $RTC_{30}$. $RTC_{15}$ may have indicated that the unit was likely to start at time 60 but that commitment is only advisory. $RTC_{45}$ will not re-evaluate that commitment but rather will take the commitment of that unit as a given for time 60 and for the duration of the units minimum run time.

A unit that is scheduled to start at time 60 with a 15-minute or less startup time will be given a binding commitment by $RTC_{45}$. $RTC_{30}$ may have indicated that the unit was likely to start at time 60 but that commitment is only advisory.

On-dispatch units receive a real-time bid production cost-guarantee once they receive a binding commitment. If, in hindsight, the prices in RTD did not support the commitment made by RTC, the unit would receive a real-time bid production cost guarantee. Units that are self-scheduled fixed or self-scheduled with a dispatchable range receive no real-time bid production cost guarantees.

#### 2.2.2.2 Shut Down

Unit shut down decisions are not binding until the commitment immediately before the scheduled shutdown. $RTC_{15}$ may indicate that a unit will be shut down at time 45 but this is not binding until $RTC_{30}$ schedules that shutdown for time 45.

### 2.2.3 On-Dispatch Unit Schedules

The schedules produced by RTC for on-dispatch units are a binding commitment up to the minimum generation level of the on dispatch unit. The binding commitment includes a real-time bid production cost guarantee. The dispatch from RTC above minimum generation is only advisory. RTD and RTD-CAM are responsible for the 5-minute dispatch of the on-dispatch units above their minimum generation levels.

### 2.2.4 Self-Scheduled With Dispatchable Range Unit Schedules

The schedules produced by RTC for self-scheduled with dispatchable range units are binding up to the self-scheduled lower operating limit. These schedules are binding in the sense that the unit is expected to maintain its schedule within the parameters for following basepoints that apply to any other unit. Failure to maintain the schedule will be subject to applicable penalties and will be subject to the Market Monitoring Plan. These units receive no real-time bid production cost guarantee.

The dispatch from RTC above the self-scheduled minimum generation level is only advisory. RTD and RTD-CAM are responsible for the 5-minute dispatch of these units above their self-scheduled minimum generation levels.

### 2.2.5 Self-schedule Fixed Unit Schedules

The schedules produced by RTC for self-scheduled fixed units are binding up to the self-scheduled lower operating limit. These schedules are binding in the sense that the unit is expected to maintain its schedule within the parameters for following basepoints that apply to any other unit. Failure to maintain the schedule will be subject to applicable penalties and will be subject to the Market Monitoring Plan. These units receive no real-time bid production cost guarantee.

## 2.3 Demand Side Resources

### 2.3.1 Dispatchable Load

Load that meets all metering requirements and has demonstrated its ability to respond to dispatch instructions can bid into RTC. RTC will commit and dispatch the resource as if it were just another generator on the system. Loads that are able to respond on a shorter time frame than the 15 minute notice provided by RTC may treat the RTC schedules as advisory and wait for dispatch signals from RTD. The load forecast will reflect the actual response of the dispatchable loads.

### 2.3.2 Interruptible Load

~~Contractual i~~Interruptible loads will be ~~evaluated~~ treated like self-scheduled generators.~~dispatchable loads if there are prices associated with those contracts. If there are no prices associated with the~~ ~~i~~Interruptible loads not scheduled by the owner but available to~~they will be handled by~~ the operators in real time ~~and those decisions will~~ can be plugged into real-time scheduling processes as fixed injections as soon as the decision is made to interrupt that load. The load forecast will reflect the actual response of the interruptible loads.

### 2.3.3 Aggregators

Aggregators will be treated as zonal dispatchable loads to the extent that they are meterable and responding to NYISO dispatch signals. Aggregators that represent unmeterable loads will be recognized consistent with the EDRP program.

### 2.3.4 EDRP

Once EDRP warnings and alerts have been sent out to all the registered loads they will be treated the same way as interruptible loads. If the decision to actually curtail the EDRP loads is made this decision will be fed immediately into all the real-time scheduling processes. The load forecast will account for the expected and actual EDRP response.

## 2.4 Transactions

There are five classes of transactions listed below. A limited form of pre-scheduled transactions (PST), on an hourly basis is being implemented to accommodate external ICAP deliverability rules. Full pre-scheduling is being considered as a future enhancement to RTS but will not be included in the initial implementation. Further detail regarding future pre-scheduling capabilities can be found in the "Pre-Scheduling: Forward Ramp and Transmission Reservations" concept of operations document approved by the Management Committee in October 2001:

- Pre-scheduled before SCUC
- Economically scheduled by SCUC converted to pre-scheduled
- Pre-scheduled before RTC
- Economically scheduled by RTC

Within each of the classes of transactions there are three types of transactions

- Imports
- Exports
- Wheels

SCUC transactions can be bid hour-to-hour or as multi-hour block transactions. SCUC economic transactions are hourly only. ~~PSTs will have some ability to schedule ¼ hourly in the DAM.~~ RTC transactions are hourly or can be quarter hourly to the extent that the interface over which the transaction is being scheduled supports quarter hourly transactions, schedule changes and ramps directly through an OSS type tool. Interfaces that allow quarter hourly schedule changes will permit quarter hourly ~~defined~~ pre-~~schedules~~scheduled transactions in real time. Economic transactions will be scheduled only on an hourly basis and will provide one MW quantity and one price for the hour.

Every fourth RTC run does economic evaluations of external transactions. $RTC_{15}$ optimizes over a timeframe from time 30 through time 180. An economic evaluation is performed for time periods 60 through 120 for which binding external schedules are generated. The external schedules for time period 30 through 60 have already been established and will be treated as fixed injections and withdrawals. External transaction schedules for time period 120 through 180 are determined based on economics but the schedules generated for this period of time are not binding until $RTC_{15}$ of the next hour is run.

~~There is a fundamental question as to how quarter hour periods where economic transactions are not being evaluated should be treated. If interface capacities have not been reduced since scheduling the transactions there should be no problem. If they have been reduced however we need a mechanism to reflect those reduced schedules in the RTC solution. This will require some form of pre-processing to ensure transaction feasibility. RTC will not select~~ RTC may reduce specific transactions to maintain feasibility, but will not pass those curtailments to IS+. Instead, RTC will issue alarms ~~be cut but rather will indicate~~ to the operator indicating the amount ~~that some number~~ of MWs of transactions that needed to be cut in order to maintain feasibility. The operator will then use the IS+ tools to curtail the appropriate transactions if desired.

This approach will also be applied in RTD as the same external interface infeasibilities can result from real time transmission interface reductions.

### 2.4.1 Transaction Pre-scheduled Before SCUC

Pre-scheduled before SCUC transactions are bid in to SCUC with a bid price giving the transaction the highest possible economic priority. These transactions will maintain their highest economic priority bid price whenever economic evaluations are performed.

### 2.4.2 Transaction Economically Scheduled in SCUC and Converted to Pre-scheduled

These transactions will be bid into the day-ahead market. Maximum bids will be restricted to a level that ensures PSTs an economic priority. Following the receipt of a day-ahead schedule and an approved conversion of the transaction to a real-time pre-scheduled transaction the bids are passed to RTC with a price that assures it a priority over other economically scheduled transactions. If the conversion to pre-scheduled fails then the transaction is passed to RTC with its original day-ahead bids.

### 2.4.3 Transaction Pre-scheduled Before RTC

This is a transaction without a day-ahead schedule that is approved as a real-time pre-scheduled transaction. These transactions will be passed to RTC with a bid price assuring it an economic priority over economically scheduled transactions, but less than other day ahead PSTs.

### 2.4.4 Transaction Economically Scheduled in RTC

These transactions will be bid into RTC. Bids will be restricted to a level that ensures PSTs an economic priority. It is possible to allow day-ahead scheduled economic transactions an economic priority over real-time economic transactions by applying a lower priority bid limit; however there is no intent to give DAM economic transactions priority over RT economic transactions at this time. In addition, the MIS will continue to set scheduled DAM economic transactions to the bid limit after being scheduled by SCUC unless the transaction owner provides a different value.

## 2.5 Ancillary Services

### 2.5.1 Reserve Demand Curve

Reserve demand curves will be required for all categories and locations and will remain in place throughout all modes of operation. The definition of the demand curves will be table driven to allow modification per operational procedures. Up to 20 price/MW pairs can be specified for each curve.~~An identical demand curve for 30-minute total reserves will be included in both the RTD and RTC models. The reserve requirements for 10-minute spinning reserve requirements, 10-minute total reserve requirements and the locational elements of the 30-minute reserve requirements will be hard limits in the model.~~

#### 2.5.1.1 Normal Operation

The will be ~~no~~ a demand curve for 10-minute spinning reserve, ~~or~~ 10-minute total reserves, and 30-minute total reserves under ~~in~~ normal RTS operation. ~~There will be a 30-minute total~~ The reserve demand curves ~~that~~ will have ~~a~~ values up to~~of~~ $1,000 from some lower MW value up to the total MW requirement for each category of reserves.~~0 to 1000 MW and then have some lower valued curve between 1000 and 1800 MW of total 30-minute reserves.~~

If the cost of scheduling additional reserves exceeds the perceived value of those reserves as defined by the reserve demand curve then the reserves will not be scheduled and the reserve clearing price will be set consistent with the point on the demand curve that was reached.

~~In normal operation the 10-minute spinning reserve and 10-minute total reserve requirements will be hard constraints[1] and will be met at any cost by RTC or RTD~~

#### 2.5.1.2 Reserve Pickup

During a reserve pickup the ~~30 minute~~ demand curves remain~~s~~ unchanged. ~~The hard constraints on 10 minute spinning reserve and 10 minute total reserves are removed from the model.~~

#### 2.5.1.3 Reserve Recovery

At the conclusion of the reserve pickup we begin a period of reserve recovery.

During these intermediate RTC and RTD runs the ~~30-minute~~ demand curve again remains unchanged and will manage the restoration of reserve.

~~Demand curves for the 10-minute spinning reserve and 10-minute total reserve constraints are introduced such that a gradually increasing quantity of the reserves is valued at $1000 reflecting the desire to recover more and more reserves as the amount of time after the reserve pickup is terminated increases . The demand curve will recover more of the 10-minute spinning and total reserves if the cost of doing so is not more expensive than the rest of the defined demand curve.~~

~~For instance 10-minutes after the termination of the reserve pickup we may require that 200 MW of 10-minute spinning reserve and 400 MW of total 10-minute reserve be recovered. The spinning reserve demand curve will have $1000 for the first 200 MW and then have a significantly lower cost than that between 200 and 600 MW. The 10-minute total reserve demand curve will have 400 MW at $1000 and then significantly lower cost between 400 and 1000 MW.~~

~~As the time elapsed extends the quantity of $1000 valued reserves increases in the demand curves .~~

~~At the end of the recovery period the hard constraints are reinserted into the RTC and RTD models.~~

### 2.5.2 Regulation Demand Curve

A regulation demand curve will be required and will remain in place throughout all modes of operation in which regulation is scheduled. The definition of the demand curve will be table driven to allow modification per operational procedures. Up to 20 price/MW pairs can be specified for the curve.

# 3 Real-Time Dispatch (RTD)

RTD is a multi-period security constrained dispatch model that co-optimizes to simultaneously solve load, reserves and regulation. RTD makes no unit commitment decisions. It simply dispatches the resources available to it on a least-as-bid cost basis. RTD will run every 5 minutes.

Each RTD run optimizes over a nominal period of 1 hour with ~~a~~the number of periods in the hour of various duration, 5 minutes, 10 minutes or 15 minutes. The first period of each RTD run is always a 5-minute run. As much as possible RTD will attempt to line up with the 15-minute timeframes established in RTC.

~~[1] Where ever "hard constraints" are mentioned this can functionally be substituted by demand curve with very high costs.~~

Each RTD run receives a label in terms of our description of the model that indicates the time at which the results of the run are posted. These results apply to the 1 hour period that starts immediately the RTD results post, e.g., RTD-15 posts at time 15 and optimizes from time 15 through time 75.

Import, export and wheel through transactions are considered as fixed injections and withdrawals by RTD.

## 3.1 Objective Function and Constraints

The most important element of any description of scheduling software is the objective function, the solution requirements and the constraint set. The overall objective is to minimize the total as-bid cost over the nominal 1-hour optimization timeframe. The solution requirements are:

- Meet forecast load
- Meet all reserve requirements by product type and location
- Meet the regulation requirement

The constraints modeled in RTD include but are not limited to:

- All transmission constraints (base case, contingency, thermal~~, voltage, stability~~)
- Generation bidding parameters (ramp rates, minimum generation levels, Upper Operating Limits.)

The costs that are included in the optimization include but are not limited to:

- Generation incremental energy costs
- Dispatchable load scheduled benefits to the extent there are 5-minute dispatchable loads
- Reserve schedule availability costs (Lost opportunity costs are implicitly captured through other costs)
- Regulation schedule availability costs (Lost opportunity costs are implicitly captured through other costs)

Since the RTD optimization horizon is slightly longer than an hour, some short-term decisions made by RTD may appear to be inconsistent with incremental energy cost of dispatchable resources unless viewed in context of the entire optimization horizon. For example, in the short term a resource with a fast response rate may be backed down, regardless of incremental energy price in order to accommodate a significant load increase at some later time. Decisions made by RTD are always optimal when viewed over the entire scheduling horizon with all constraints taken into account.

## 3.2 Generation

### 3.2.1 On-Dispatch and Self-Scheduled Flexible Units

RTD and RTD-CAM are responsible for the 5-minute dispatch of the on-dispatch units above either their minimum generation levels or their self scheduled minimum generation level. These dispatches will honor ramp rates.

There are four sets of basepoints that are relevant

- Basepoints for pricing
- Basepoints for setting other units schedules
- Basepoints communicated to the units

- Basepoints used for billing and settlement

#### 3.2.1.1 Basepoints for Pricing

Basepoints and ex ante prices are determined in RTD using a pricing methodology that incorporates both the hybrid pricing and dual dispatch pricing elements of the existing SCD pricing constructs. ~~We are in the process of preparing a detailed functional description of both the hybrid dispatch and the dual dispatch including a description of pricing eligibility in the ex post pricing module.~~

##### 3.2.1.1.1 Dual Dispatch

~~The dual dispatch was implemented to fix the GT block loading problem in SCD that caused the NYISO to make many price corrections. Steam units were continually backed down due to GT block loading below their economic dispatch level and were unable to ramp up.~~The dual dispatch is a long-standing feature of the current real-time energy market that is being carried forward to the new RTS. The dual dispatch introduces an element of "anticipation" in the ex-ante pricing process. The dual dispatch remembers results of the previous dispatch and anticipates generating unit movement to better estimate the future performance of generating units. The need for price corrections is significantly reduced using the dual dispatch. Without the anticipatory elements of the dual dispatch, steam units tend to be unloaded, below their economic dispatch level, due to gas turbine block loading. Ramp rate limitations then tended to prevent steam generators from attaining their most economic output levels. The dual dispatch enables the economic steam capacity to be reflected in the pricing of energy.

##### 3.2.1.1.2 Hybrid Dispatch

~~The hybrid dispatch ensures that uneconomic minimum run-time constrained GTs are blocked on at their maximum output level for the pricing dispatch. The current hybrid pricing rules involve four passes.~~

~~A Commitment Pass that checks that there are enough GTs committed to meet load~~

~~A Scheduling Pass~~ The hybrid dispatch, and associated pricing, is a feature of the current real-time energy market that is being carried forward to the new RTS. The hybrid dispatch addresses the issue of establishing an energy-clearing price in the presence of inflexible resources (e.g. gas turbines), which have not yet met their minimum runtime, and are therefore constrained to operate, regardless of current economic merit. The hybrid dispatch methodology is a compromise between a pricing methodology that treats all such units as inflexible and unable to set price, and a methodology that treats all such units as flexible and able to set price.

The hybrid dispatch permits inflexible units to set price but ensures that uneconomic, minimum run-time constrained, inflexible resources are prohibited from setting price. These inflexible units are blocked on at their maximum output level for the pricing dispatch. The hybrid dispatch involves three dispatch calculations:

1. A scheduling pass that dispatches all units with all ~~GTs~~inflexible resources blocked on. Base points (desired generation levels) are determined in this pass and are sent to the generating units.

~~An Initial Ideal Dispatch that dispatches all units with committed GTs dispatched flexibly between 0 and their maximum output in oreder to identify the uneconomic minimum run time constrained GTs~~

2. ~~A Second Ideal Dispatch that dispatches all units with all GTs not dispatched in the Initial Ideal Dispatch that are within their minimum run time blocked on at their upper operating limits.~~A first ideal dispatch that dispatches all units as if they were flexible. That is, as if their output could be adjusted, subject to ramping constraints, anywhere between zero and their maximum output. The first ideal dispatch is used to identify the inflexible resources that are uneconomic yet are constrained to operate because of minimum run time considerations.

A second ideal dispatch. Inflexible units determined to be uneconomic in the previous step are blocked at their maximum output and prohibited from setting price. The remaining units are considered flexible and are permitted to set price. This dispatch sets the ex-ante energy prices

3. for the dispatch interval.

#### 3.2.1.1.3 Eligibility to set prices in the Ex ~~Post~~ Ante pricing

All flexible resources, including ~~Only~~ GTs dispatched in both ideal dispatches of the hybrid pricing module are eligible to set price in the Ex Ante~~Post~~ pricing module~~. Performance of steam units for the purposes of price setting will be evaluated against the final basepoints that were sent to the units~~.

Ex-ante pricing determines an estimate of prices made before the time period being priced. Ex-ante prices assume that projected conditions (load, system configuration, etc.) materialize, and that providers perfectly follow schedules determined by the optimization processes.

#### 3.2.1.1.4 Performance Tracking / Billing

Because there is no price chasing the performance tracking becomes a lot simpler. The actual generation can be compared directly to the basepoints produced by the Scheduling Pass of the dispatch. ~~For b~~Billing ~~we should~~will use the Market B~~b~~asepoint communicated to the units which in some instances can differ from the ~~FBT~~ Physical B~~b~~asepoint determined in the dispatch.

The 15 minute 3% tolerance on undergeneration and the 3% tolerance on overgeneration payment can be implemented as they are today.

### 3.2.1.2 Basepoints for Scheduling Flexible Generation

We schedule all units while ensuring that no units are considered to be at output levels inconsistent with either their last basepoints or the actual generation on the unit at the time that the RTD run was initialized. Basepoints are determined using a least-cost security constrained dispatch.

### 3.2.1.3 Basepoints Communicated to the Units

Basepoints communicated to the units differ from the Basepoints for Scheduling Flexible Generation when units are operating inconsistent with their bid information. These circumstances include when the actual output of self-scheduled units is inconsistent with the ramped self-schedule output and when actual output of on-dispatch units is outside the bid-in operating limits of the unit. In these cases, the Basepoint communicated to the Unit will be constrained to be consistent with the bid information. Additionally, basepoints communicated to the unit will differ for fast start units to communicate a start notification.~~The only instances where the basepoints communicated to units differ from the Basepoints for scheduling flexible generation is when the actual output of self-scheduled units is inconsistent with the ramped self-schedule or ramped self-scheduled lower limit. In all other cases these are identical.~~

### 3.2.1.4 Basepoints for Billing and Settlement

Basepoints for billing and settlement will be identical to those communicated to the units.

Payments will continue to be based on the lesser of the actual generation and the basepoint plus applicable overgeneration tolerance.

### 3.2.2 Self-Scheduled Fixed Units

RTD and RTD-CAM will take self-scheduled fixed level schedules as fixed injections. The market basepoints will satisfy the input schedule at the start of every 15 minute period. They will follow the ramp rate (if possible) going backwards in time until they meet the input schedule for that 15-minute period; they will then stay constant at the input schedule for the remainder of the 15-minute period. If the unit cannot ramp to the input schedule by the start of the 15-minute period, then the market basepoints will lie on the straight line connecting the input schedule at the start of this 15-minute period with the input schedule at the start of the next 15-minute period.

The physical basepoint will be calculated by starting at the initial condition moving forward in time, one time point at a time, and move as quickly as possible toward the market basepoint trajectory while satisfying the unit's ramp rate. Self-scheduled fixed units will be identified by having 'S' as the mode flag.

## 3.3 Demand Side Resources

### 3.3.1 Dispatchable Load

Load that has demonstrated that it meets all metering and deliverability requirements to respond to a 5-minute dispatch signal may be scheduled by RTD. Loads that require ~~longer~~ startup notification~~s~~ times will be scheduled by RTC. Consistent with its treatment of other sources of supply, RTC will permit startup notification times of 10 or 30 minutes for these loads. Dispatchable loads can be flexible or modeled like GTs that are block loaded and hybrided. The load forecast will reflect the actual response of the dispatchable loads.

### 3.3.2 Interruptible Load

Load that has demonstrated that it meets all metering and deliverability requirements to respond to a 5-minute dispatch signal may be scheduled by RTD. Loads with bids that require longer notifications times will be scheduled by RTC. Interruptible loads will be treated like self-scheduled generators. Interruptible loads not scheduled by the owner but available to the operators in real time can be plugged into real-time scheduling processes as fixed injections as soon as the decision is made to interrupt that load. The load forecast will reflect the actual response of the interruptible loads.~~Contractual interruptible loads called by the operators will be treated as fixed injections by the RTD package and will be fed into the solution as soon as is practicable after the operators have made the decision to curtail the interruptible load. The load forecast will reflect the actual response of the interruptible loads.~~

~~Interruptible loads will be able to specify an activation time that will be considered the same as a startup time of a generator. The interruptible loads will be modeled as GTs with either 15 or 30 minute "start up" times. They will be block loaded as well and can be hybrided. The interruptible loads will be able to specify minimum run times up to 1 hour but may be as short as 15 minutes.~~

### 3.3.3 Aggregators

Aggregators will be treated as zonal dispatchable loads to the extent that they are meterable and responding to NYISO dispatch signals. Aggregators that represent unmeterable loads will be recognized consistent with the EDRP program.

### 3.3.4 EDRP

Once EDRP warnings and alerts have been sent out to all the registered loads they will be treated the same way as interruptible loads. If the decision to actually curtail the EDRP loads is made this decision will be fed immediately into all the real-time scheduling processes. The load forecast will account for the expected and actual EDRP response.

## 3.4 Transactions

To the extent that the interface limits do not change from $RTC_{15}$ to $RTC_{30}$, $RTC_{45}$, and $RTC_{00}$ there are no transaction cuts the transaction schedules determined in the economic evaluation, $RTC_{15}$, will be feasible and the other RTCs can be run without any problems. However if interface limits change or if transactions are cut that cause net flows on an interface to exceed the interface limits the transaction schedules need to be modified. ~~What RTC will do is to compare "scheduled" net transactions across interfaces against the interface limit using a preprocessor that will reduce the injections or withdrawals at the external proxy bus to regain feasibility. The pre-processor will not determine which transaction is to be cut.~~ RTC may reduce specific transactions to maintain feasibility, but will not pass those curtailments to IS+. Instead, RTC will issue alarms to the operator indicating the amount of MWs of transactions that needed to be cut in order to maintain feasibility. It will notify the operator of how many MW of transactions need to be curtailed at each interface and then the operator will use IS+ to determine the appropriate transactions to actually cut to achieve feasibility.

## 3.5 Ancillary Services

A full two-settlement system for ancillary services will be implemented for all operating reserves and regulation. Ancillary services providers selected day-ahead will be paid the applicable day-ahead regulation or locational reserve clearing prices

The key changes to the ancillary service market design will be the removal of availability bids for spinning reserves in the day-ahead and real-time markets, the implementation of a consistent ~~reserve~~ demand curve in both real time commitment and dispatch and locational reserve clearing prices calculated directly from the shadow prices of reserves.

### 3.5.1 Demand Curves

Demand curves will be required for all categories and locations of reserve and regulation and will remain in place throughout all modes of operation. The definition of the demand curves will be table driven to allow modification per operational procedures. Up to 20 price/MW pairs can be specified for each curve.~~A demand curve for 30-minute total reserves will be included in the RTD and RTC models. The reserve requirements for 10 minute reserves and the locational elements of the 30 minute reserve requirements will be hard limits in the model.~~

### 3.5.2 Schedules

Schedules will be posted each five minutes out of RTD. Prices and settlements will be made on a five-minute basis. Reserve schedules will also be generated by RTD-CAM dispatches that may not correspond to well defined five minute time periods.

### 3.5.3 Market Clearing Prices

Market clearing prices will be set using the shadow prices directly from the RTD or RTD-CAM model, whichever is applicable to the period of time being settled. Generally this will be the RTD that is run every 5 minutes. If, however an RTD-CAM run is performed its results will apply until a subsequent RTD-CAM is run or until a valid RTD run is used to determine unit schedules and energy prices.

#### 3.5.3.1 Locational Clearing Prices

Reserve requirements will be solved for the Control Area, East of Central East and for Long Island. There are locational requirements specified for 10-minute spinning reserve, 10-minute total reserve and 30-minute total reserve. These reserve requirements correspond to locational reserve prices for West, East of Central East excluding Long Island and Long Island.

Long Island reserve ~~prices will be mitigated~~pricing rules will be retained such that they never exceed the Eastern reserve price for the same level of reserve product.

Reserve prices are determined directly from the shadow prices of the reserve constraints extracted from the SCUC, RTC, RTD or RTD-CAM models. The first matrix is the shadow prices from the model. The Incremental value of the reserves is determined by adding up the shadow prices from the bottom left to the top right. The last step mitigates LI prices to not exceed Eastern prices.

| Shadow Prices | | | |
|---|---|---|---|
| | Control Area | East | LI |
| Spin | 0 | 3 | 1 |
| 10 Minute Total | 0 | 1.52 | 0 |
| 30 Minute Total | 1 | 0 | 0 |

| Incremental Value | | | |
|---|---|---|---|
| | West | East excl LI | LI |
| Spin | 1 | 5.52 | 6.52 |
| 10 Minute Total | 1 | 2.52 | 2.52 |
| 30 Minute Total | 1 | 1 | 1 |

| Final Prices | | | |
|---|---|---|---|
| | West | East excl LI | LI |
| Spin | 1 | 5.52 | 5.52 |
| 10 Minute Non-Synch | 1 | 2.52 | 2.52 |
| 30 Minute Reserve | 1 | 1 | 1 |

Day-ahead reserve prices are calculated using the shadow prices from SCUC. Real-time reserve prices will be calculated using shadow prices from either RTD or RTD-CAM. Prices could also be determined from RTC if a third settlement was ever implemented or if RTD and RTD-CAM both failed to operate for some period of time.

#### 3.5.3.2 10-Minute Spinning Reserve Prices

10-Minute Spinning Reserve providers will be paid the applicable locational 10-minute spinning reserve clearing price. There will no longer be any separate lost opportunity cost payments.

#### 3.5.3.3 10-Minute Non-Synchronous Reserve Prices

10-Minute Non-Synchronous Reserve providers will be paid the applicable locational 10-minute non-synchronous reserve clearing price. There will no longer be any separate lost opportunity cost payments.

#### 3.5.3.4 30-Minute Reserve Prices

30-Minute Reserve providers will be paid the applicable locational 30-minute reserve clearing price.

#### 3.5.3.5 Regulation Clearing Prices

Regulation prices in the day-ahead and real time markets will also be determined directly from the shadow prices extracted from the SCUC, RTC, RTD and RTD-CAM. There are currently no locational regulation requirements. To the extent that locational requirements are added in the future a locational pricing logic similar to that applied to reserves would be applied to regulation.

### 3.5.4 Second Settlement Protection for Day-Ahead Scheduled Reserve Providers

Non-synchronized reserve providers. RTD energy and reserve prices will be consistent with each other.

## 4 SCUC Changes

~~Transaction pre-scheduling at times other than top of the hour.~~

- Implementation of ~~a reserve~~ demand curves consistent with RTS.

- Hourly bidding of startup costs.