Market Design Concepts to Prepare for Significant Renewable Generation:

Real-Time Performance Incentives with Negative LBMPs

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Agenda:

- Background
- Purpose
- Examples
- Potential Enhancements
- Stakeholders Feedback

Background

Background

- The NYISO conducted a preliminary review of the market design concepts proposed in the Market Assessment with 50% Renewables Report. (2017 Market Assessment)

- Concepts were evaluated according to the following criteria:
  - Whether the product or rule change would incentivize performance attributes such as availability, predictability, flexibility, and dispatchability.
  - Need demonstrated by the results of the NYISO's 2017 Market Assessment.
  - Anticipated future system need based on observations from other control areas or other NYISO studies.

Background

- The NYISO recommended that the following design concepts be further explored during 2018:
  1. Flexible ramping product to address forecast uncertainty
  2. Re-evaluate shortage pricing for Ancillary Services
  3. Real-Time payments and charges when LBMPs are low
  4. More frequent transaction scheduling
- Market Design Concept Proposals for these products or rule changes were considered for inclusion in the Master Plan.
  - Work on this effort was proposed for prioritization in 2019.

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2017 Market Assessment Findings

- Persistently negative LBMPs were observed in the Real-Time Market (RTM) study cases. [1]
  - Incremental renewables added for the Market Study cases were treated as price sensitive at -$47/MWh.
  - The point of price sensitivity is dependent on available incentives and may change in the future, but is not expected to be positive. [2]
- Increased penetration of renewables is expected to drive energy prices to settle at or below zero much more frequently in the future.
- When real-time (RT) Energy prices are zero or negative, it is still important that suppliers respond to NYISO dispatch instructions.
  - This effort seeks to determine whether payments and charges with negative LBMPs provide adequate incentives to do so.

1. 2017 Market Assessment with 50% Renewables, Page 77
2. $47/MWh is the sum of the Federal Production Baseline Tax Credit (PTC) available to qualifying renewable resources and the average value of RECs awarded by New York State in 2016.

Previous Presentations

- This topic was discussed previously at the April 10th, 2018 MIWG.
  - April 10th MIWG Meeting Materials
- NYISO staff planned at that time to return to stakeholders with examples of current payments and charges when LBMPs are negative.
- Project effort was identified as part of the 2019 project prioritization process and was included in the 2017 Master Plan.

Purpose

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- Identify if enhancements to the existing settlements are rational when LBMPs are negative :
- Payments and charges that were reviewed are:
  - Balancing Market Supplier Settlements
  - Bid Production Cost Guarantee (BPCG)
  - Day-Ahead Margin Assurance Payment (DAMAP)
  - Over/Under Generation Charges
  - Regulation Revenue Adjustments (RRAC/RRAP)
- Determine how these payments are impacted by Negative RT LBMPs.

Current Payment Impact with Negative LBMPs

Balancing Market Supplier Settlements

- When RT LBMPs are negative, Supplier payments are calculated based on the following formula:
  - RT Settlement = (Actual - DA Schedule)* RT LBMP
  - A positive value indicates a payment to the Supplier

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Balancing Energy: Positive RT LBMP

	Value	Units
UOL	100	MW
3% of UOL	3	MW
RT LBMP	10	$/MWh
DA Schedule	5	MW
RTD Base Point	12	MW
Actual Output	18	MW

Settlements calc:

When RT LBMP is positive, compensable generation is limited to the lesser of actual output or schedule plus tolerance for over generation

RT Settlement = [min(Actual, (RTD BP+3% UOL)) - DA Sch]* RT LBMP

=[min(18,(12+3)) - (5)]*$10

=[15-5]*$10

=$100

- When RT LBMP is positive, limiting compensable generation to the lesser of actual output or schedule +3% provides an incentive to not over-generate –Supplier will not be <u>paid</u> for excess generation.

Balancing Energy- Negative RT LBMP

	Value	Units
UOL	100	MW
3% of UOL	3	MW
RT LBMP	-5	$/MWh
DA Schedule	5	MW
RTD Base Point	12	MW
Actual Output	18	MW

Settlements calc:

When RT LBMP is negative, compensable generation is be based on Actual Output rather than min(Actual, (RTD BP+3% of UOL)

RT Settlement = [(Actual - DA Sch)* RT LBMP]

=(18-5)*-$5

=13*$-$5

=-$65

If the min(Actual, (RTD BP+3% of UOL) term was applied:

RT Settlement = [min(Actual, (RTD BP+3% UOL)) - DA Sch]* RT LBMP

=[min(18,(12+3)) - (5)]*-$5

=[15-5]*-$5

=-$50

Using lesser of actual output or schedule +3% would relieve the unit of the obligation to <u>pay</u> for their excess generation.

Day-Ahead Margin Assurance Payment

- DAMAP is available to provide incentives for resources to offer flexibly in the Real-Time Market by protecting their Day-Ahead Margin.
  - DAMAP is intended to reimburse a Supplier for any lost Day-Ahead Margin that may result from actions taken by the NYISO in real-time that reduce a Resource’s Day-Ahead Margin.
  - The purpose of such payments is to protect Suppliers’ Day-Ahead Margin associated with real-time reductions after accounting for any real-time profits associated with offsetting increases in real-time Energy, Regulation Service, or Operating Reserve schedules.

Existing DAMAP formula

- Currently, DAMAP for generators in any RTD interval is determined by:

$$CDMAP = CDMAPenergy + \sum CDMAP_{reserves} + CDMAPregulation$$

- Where,
  - CDMAPEnergy = Energy contribution of RTA interval to the DAMAP payment for supplier
  - CDMAPreserves = Operating Reserve contribution of RTD interval to the DAMAP payments determined separately for each reserve product for supplier
  - CDMAPregulation = Regulation service contribution of RTD interval to the DAMAP payments for supplier
- Hourly Netting: $DMAP_{hu} = max\left(0, \sum_{i \in h} CDMAP_{iu}\right)$
- If the Real-Time energy schedule is lower than its Day-Ahead Energy Schedule:

$$CDMAP_{energy} = ((DA_{schedule} - LL) * RT\ LBMP - \int_{LL}^{DA_{schedule}} DA\ Bid\ ) * seconds/3600$$

  - Where Lower Limit (LL) =
    - if RT schedule < EOP; LL=min(max(RT schedule, min (AEI, EOP)), DA Schedule) or
    - If RT schedule >= EOP; LL=min(RT schedule, max (AEI, EOP), DA schedule)
  - Where
    - [DA schedule –Lower Limit (LL)] term determines the MWs that will be protected through DAMAP payments
    - EOP = Economic Operating Point calculated without regards to ramp rate
    - AEI = Average Actual Energy injection but limited to RT schedule + compensable over generation

Existing DAMAP formula:

- If the Real-time Energy Schedule is greater than its Day-Ahead Energy schedule then:

$$CDMAPen_{iu} = min\left[\left((DASen_{hu} - UL_{iu}) * RTPen_{iu} + \int_{DASen_{hu}}^{UL_{iu}} RTBen_{iu}\right) * \frac{Seconds_i}{3600}, 0\right]$$

- Where Upper Limit (UL)=
  - If $RT_{schedule}$ >= EOP >=DA Schedule; UL = max(min(RT schedule, max (AEI, EOP)), DA schedule); or
  - UL=max(RT schedule, min (AEI,EOP), DA schedule)
- Where,
  - $DA_{schedule}$- Upper Limit(UL)- term that determines the MW's that will offset from DAMAP payments.

DAMAP example with Negative RT LBMP

	Value	Units
DA Schedule	50	\$/MW
DA Bid	20	\$/MW
RT LBMP	-10	\$/MW
RT Schedule	30	MW
Lower Limit (LL)	20	MW
EOP	0	MW
Actual Output	20	MW
Interval	300	Seconds

*When RT Scheduled is less than DA Schedule

$$=((DA_{Schedule}-LL)* \text{ RT LBMP}- \int_{LL}^{DA_{Schedule}} * \text{ DA Bid}) * (\frac{\text{seconds}}{3600})$$

$$=((50-20)*-10)- \int_{20}^{50} 20) * (300/3600)$$

(50-20)*(-10)-(30*20)*.0833

=\$-75

Real Time Bid Production Cost Guarantee (RT BPCG)

- A supplier may be eligible for a RT BPCG payment if it will not recover its offered costs for scheduled Ancillary Services, Minimum Generation, Start-Up, and Incremental Energy through market revenues, including energy and ancillary services payments over the course of the entire day.
  - The payment is based on a net daily calculation:

$$\sum_{g\in G} Max\left\{ \sum_{i=1}^{N} \left(\begin{array}{l} \left(\begin{array}{l} \int_{EI_{gi}^{DA}}^{EI_{gi}^{RT}} C_{gi}^{RT} + MGC_{gi}^{RT} \times \left(MGI_{gi}^{RT} - MGI_{gi}^{DA} \right) \\ + SUC_{gi}^{RT} \times \left(NSUI_{gi}^{RT} - NSUI_{gi}^{DA} \right) - LBMP_{gi}^{RT} \times \left(EI_{gi}^{RT} - EI_{gi}^{DA} \right) \end{array} \right) \times {}^{S_i}\!/_{3600} \\ \\ - \left(NASR_{gi}^{TOT} - NASR_{gi}^{DA} \right) - RRA_{gi} \end{array} \right), 0 \right\}$$

RT BPCG Example with Negative RT LBMP

Description	Value	Unit
Incremental Cost in RT	5	$/MWh
RT LBMP	-10	$/MWh
DA Energy Schedule	5	MW
RT Energy Schedule	15	MW
Time	300	Seconds

RT BPCG for RTD interval =

*Assume the resource has no ancillary services scheduled
*Assume Min Gen is 2 MW

$$\int_{\max(DA\ schedule, \text{min } gen)}^{\max(RT\ schedule, \text{min } gen)} Incremental\ cost - RT\ LBMP * (RT\ schedule - DA\ schedule)) * seconds/3600$$

$$= (\int_{5}^{15} 5 \ - {}^{-}10 * (15 - 5)) * (300/3600)$$

$$= (5*(15\text{-}5) - {}^{-}10*(15\text{-}5)\ *0.0833$$

$$= (50 - {}^{-}100)*0.0833 = 150*0.0833 \ = 12.50$$

- The incremental cost of $50 exceeds the LBMP revenue of -$100.
- The contribution of the RTD (5 minute) interval to the RT BPCG calculation is **$12.50.**

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Persistent Over Generation Charges

- Over Generation Charges take into account Regulation prices, therefore they are not impacted by negative RT LBMPs

$$\sum_{i=1}^{N}\{[max(\{[EI_{gi}^{RT} - RTD_{gi}^{RT}] - [UOL_{gi}^{RT} \times 3\%]\}, 0) \times Max(MPRC_{DAM}, MPRC_{RT})] \times [s_i^{RT} \div 3600\ seconds]\}$$

Where,

- $MPRC_{DAM}$: Regulation Capacity Market Price in the DAM
- $MPRC_{RT}$: Regulation Capacity Market Price in the RTM

Persistent Under Generation Charges

- Under Generation Charges take into account Regulation prices, therefore they are not impacted by negative RT LBMPs.

$$\sum_{i=1}^{N}\{[max(\{PLU_{gi}^{RT} - EI_{gi}^{RT}\},0) \times REGMCP_{gi}^{RT}] \times (s_i^{RT} \div 3600\ seconds)\}$$

Where,

$$PLU_{gi}^{RT} = max[min(\{AGC_{gi}^{RT} - CET_{gi}^{RT}\},\{[900 \times PLU_{g(i-1)}^{RT}] + [s_i^{RT} \times (AGC_{gi}^{RT} - CET_{gi}^{RT})]\} \div \{900 + s_i^{RT}\}),0]$$

Where,

CET_{gi}^{RT} = 3% of Upper Operating Limit of Generator for RTD interval

AGC_{gi}^{RT}: = AGC basepoint over RTD interval

$PLU_{g(i-1)}^{RT}$ = Penalty Limit for Under-Generation for RTD interval, or 0, if generator hasn't been running in the last 4 hours

Persistent Over and Under Generation Charges

Parameters:	
UOL:	100
Basepoint	50
3% Threshold	3

Actual MW's		Settlement MW's	
50-53	Acceptable	50+	Settled for Actual Output
53.1+	Over Generating	More than 53+	Compensated for Base Point plus 3% of the UOL above the unit's given basepoint
46.9-	Under Generating	Less than 47-	Compensated for the unit's actual output but subject to a charge for the amount below Base point minus 3% the unit's UOL is deficient

Regulation Revenue Adjustment

- Regulation Revenue Adjustments are designed to balance the Energy payments that Generators receive and the cost that Generators incur when providing Regulation Services.
  - For any interval in which a Generator that is providing Regulation Services receives an AGC basepoint that is different from its RTD basepoint, it may be eligible to receive Regulation Revenue Adjustments Payments (RRAP) or be required to pay a Regulation Revenue Adjustments Charge (RRAC).

- The RRAC and RRAP are designed to compensate Generators for following an AGC basepoint that differs from its RTD basepoint.

- Generators are eligible for RRAC/RRAP when:
  - Schedule by RTD to provide Regulation service and;
  - Regulating up or down from their RTD basepoint.

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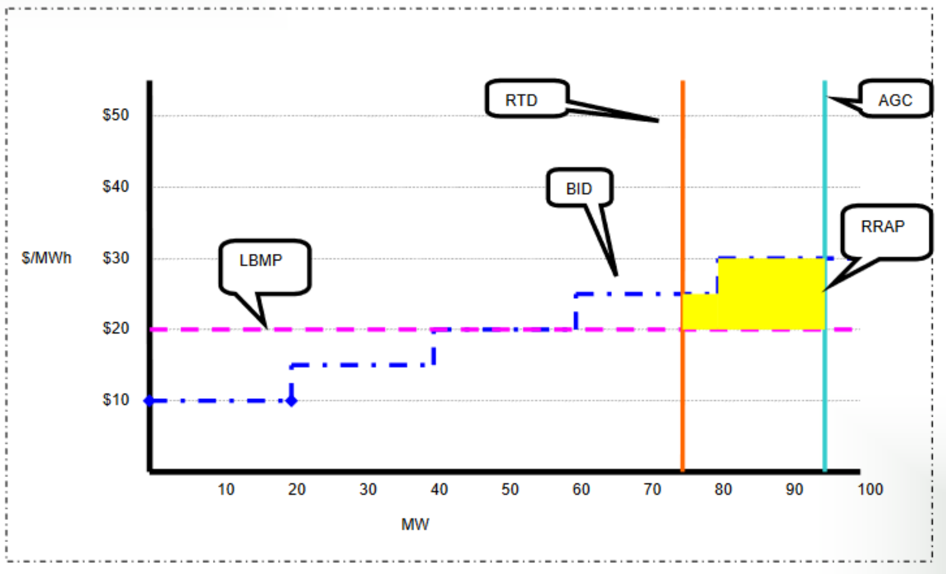
Regulation Revenue Adjustments

- When the AGC basepoint is greater than the RTD basepoint:
  - Calculated over an RTD interval (5 mins)
    - (((Bid cost from RTD to lower of (Actual, AGC))-(Gen LBMP * (lower of (Actual, AGC)-RTD))



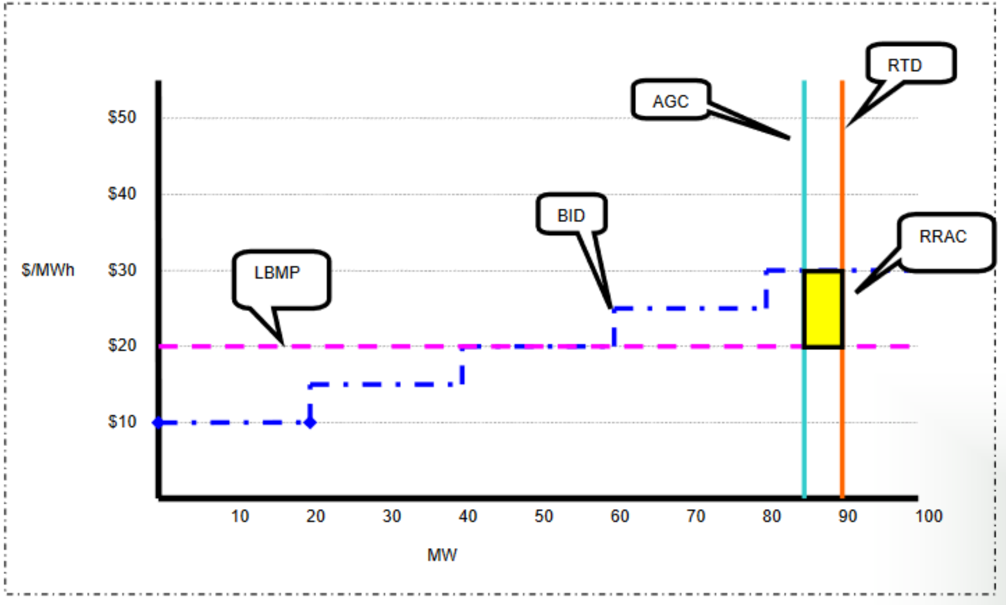
Results in:

RRAP: if Bid cost > Gen LBMP

RRAC: if Bid cost < Gen LBMP

Regulation Revenue Adjustments

- When the AGC basepoint is less than the RTD basepoint:
  - Calculated over an RTD interval (5 mins)
    - (((Bid cost from higher of (Actual, AGC) to RTD)-(Gen LBMP * (RTD – higher of(Actual, AGC)-RTD)) *-1)



Results in:

RRAP: if Bid cost < Gen LBMP

RRAC: if Bid cost > Gen LBMP

Current Payments and Charges when LBMPs are Negative

- Existing payments and charges provide incentives to Suppliers to follow NYISO dispatch instructions when LBMPs are negative.
- Payments and charges work as designed even when LBMPs are negative.

Potential Enhancements to Payments and Charges when LBMPs are Negative

Potential Enhancement: Hourly RT BPCG

- BPCG payments could be assessed on an hourly basis in the Real Time market.
  - Hourly settlements could more accurately compensate the marginal value of resources that can start multiple times per day.
    - Ability to cycle was recognized as a desirable attribute in the 2017 Market Assessment.
  - Would still incentivize generators to offer at marginal costs.
  - Hourly BPCG would net gains and losses within each hour.
    - Eligible Suppliers could recover most of their costs during intervals where they lose revenue while providing Energy and Ancillary Services because LBMPs are negative.
    - Could improve incentive to respond to NYISO dispatch instructions when LBMPs are negative.

Potential Enhancements

- Review 3% threshold for Persistent Over and Under Generation charges.
  - Current over/under generation charges do not apply if the energy difference is within a tolerance band equal to 3% of the unit's UOL_N.
    - Determine if the 3% threshold is an adequate tolerance, primarily when the system moves rapidly.

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Evaluate Symmetry of Performance Charges for Generators when Withdrawing

- Stakeholders have suggested that the NYISO consider enhancements to the persistent over-withdrawal charges that will be applied to Energy Storage Resources (ESRs).
  - Charges for over and under withdrawal for ESRs are designed symmetrically to persistent over and under-Generation charges for Suppliers while injecting.
    - Over-withdrawal charges will be assessed at 3% of Lower Operating Limit.
    - This may provide less of an incentive to follow NYISO dispatch than analogous under-generation charges assessed at 3% of Upper Operating Limit.
  - The NYISO could explore alternative persistent over and under withdrawal charges if future operating experience with ESRs suggests they are necessary.

Real-Time Performance Incentives with Negative LBMPs Review:

- Stakeholders did not prioritize the enhancement of existing settlements provisions or development of new settlements as a 2019 market design effort.
  - Enhancements discussed in this presentation may be revisited at a later date, depending on operational experience and future stakeholder interest.

Questions?

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- Planning the power system for the future
- Providing factual information to policy makers, stakeholders and investors in the power system

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