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NYISO 2025-2029 ICAP Demand Curve Reset

Discussion of Level of Excess Adjustment Factors, Net EAS Models, and Financial Parameters

ICAP Working Group

January 25, 2024

Agenda

- Schedule
- Level of excess adjustment factors (LOE-AFs)
- Preliminary recommendations for net Energy and Ancillary Services (EAS) revenue models (i.e., thermal/fuel-fired, and storage)
- Review of financial parameters

Schedule

Timeline for 2025-2029 ICAP Demand Curve Reset (DCR) Process

- **Q4 2023 – Q1 2024**
  - Propose DCR principles and framework
  - Review of net EAS revenue estimation method and data sources
  - Initial technology screening assessment

- **Q1 – Q2 2024**
  - Finalize net EAS modeling enhancements
  - Finalize DCR methods and assumptions
  - Finalize initial technology assessment to identify technologies for further, detailed evaluation
  - Preliminary assessment of identified peaking unit technology options and cost estimates
  - Review LOE-AF methodology
  - Preliminary demand curve model results

- **Q2 – Q3 2024**
  - Finalize demand curve model
  - Final discussions and input
  - Draft report
  - NYISO staff draft recommendations

- **Q3 – Q4 2024**
  - Final report and NYISO final recommendations
  - NYISO Board review
  - FERC filing

Potential Process Changes

- Enhancements to support the determination of seasonal ICAP Demand Curves were approved by stakeholders in September 2023 and are currently pending before FERC (Docket No. ER24-701)
- AG has not identified any additional process changes that warrant consideration for the 2025-2029 DCR

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Level of Excess Adjustment Factors (LOE-AFs)

Level of Excess Adjustment Factors

Background

- Services Tariff, Section 5.14.1.2.2

  "The cost and revenues of the peaking plant used to set the reference point and maximum value for each ICAP Demand Curve shall be determined under conditions in which the available capacity is equal to the sum of **(a) the minimum Installed Capacity requirement and (b) the peaking plant's capacity equal to the number of MW specified in the periodic review and used to determine all costs and revenues** ([…] hereinafter referred to as the 'prescribed level of excess')." (emphasis added)

- LOE-AFs adjust historical LBMPs and reserve prices to account for the tariff-prescribed level of excess supply conditions (i.e., applicable minimum requirement plus the capacity of the applicable peaking plant)
  - For example, if actual LBMPs are based on system conditions with resource margins above the tariff-prescribed LOE conditions, net EAS revenues would likely be lower than the peaking plant would experience under the tariff-prescribed level of excess conditions. In this case, the adjustment factors would reflect a multiplier greater than one.
  - For the 2021-2025 DCR, average LOE-AFs were relatively modest, ranging from 1.02 in Load Zones F and J to 1.06 in Load Zone C across all months and periods

Level of Excess Adjustment Factors

Proposed Approach

- AG proposes to use the same general methodology from 2017-2021 and 2021-2025 DCRs to determine the LOE-AF values for this reset
  - Production cost model simulations conducted by GE Energy Consulting (GE), using GE's Multi-Area Production System (GE-MAPS)
    1. A base case represents current system conditions ("as found" conditions),
    2. "LOE" case represents system conditions at the tariff-prescribed LOE (i.e., minimum capacity requirement plus capacity of proposed peaking plant)
- LOE-AFs are developed as the ratio of average Day-Ahead LBMPs in the base case to average Day-Ahead LBMPs in the LOE case for each relevant Load Zone
- LBMPs are first averaged within each month and period (e.g., "on-peak," "high on-peak," and "off-peak" as used for the 2021-2025 DCR) across the modeled years
  - The time granularity of the LOE-AFs and the model years to use in the analysis are still under consideration
- LOE-AFs are calculated as part of the DCR and remain set for the duration of the reset period
- GE-MAPS modeling will use recent data for the relevant model years consistent with other NYISO studies and previously reviewed by stakeholders (e.g., 2023-2042 System and Resource Outlook)

Preliminary Recommendations for Net EAS Revenue Models

Review of Net EAS Revenue Models

Fuel-Fired Generators: 2021-2025 DCR Model

- Model estimates the net EAS revenues earned by the hypothetical peaking plant over a rolling three-year historical period, assuming dispatch of the plant and market offers set at the opportunity cost of producing energy or providing reserves
- Peaking plant can earn revenues through supplying in one of four markets:
  1. Day-Ahead Market (DAM) commitment for energy
  2. DAM commitment for reserves
  3. Real-Time Market (RTM) dispatch for energy
  4. RTM supply of reserves
- Hourly net revenues are calculated to ensure that fixed startup fuel and other costs are recovered, and dual-fuel capability (if applicable) is accounted for through the option to generate on available fuel options (e.g., natural gas or ultra-low sulfur diesel) based on a comparison of fuel prices

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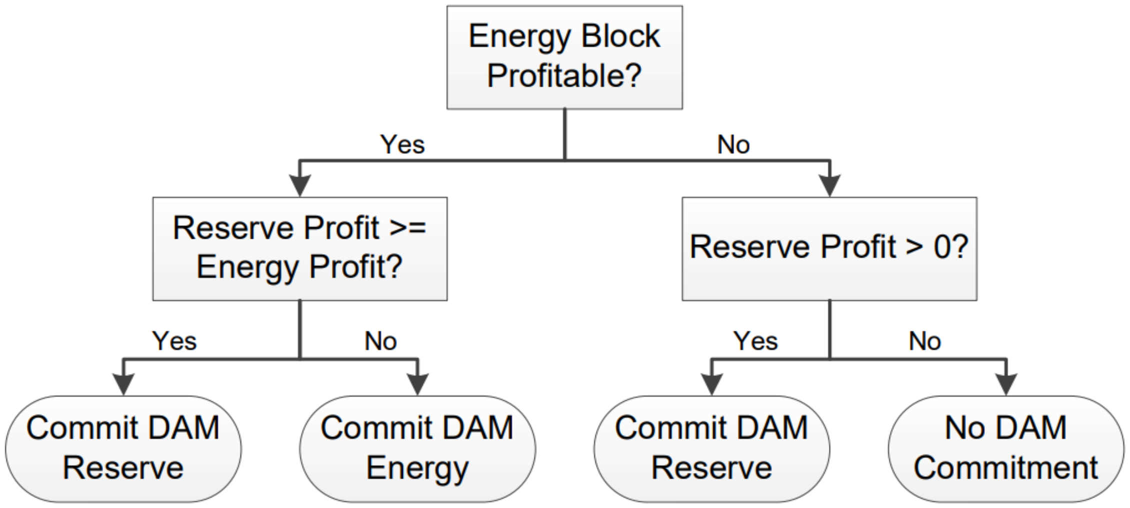
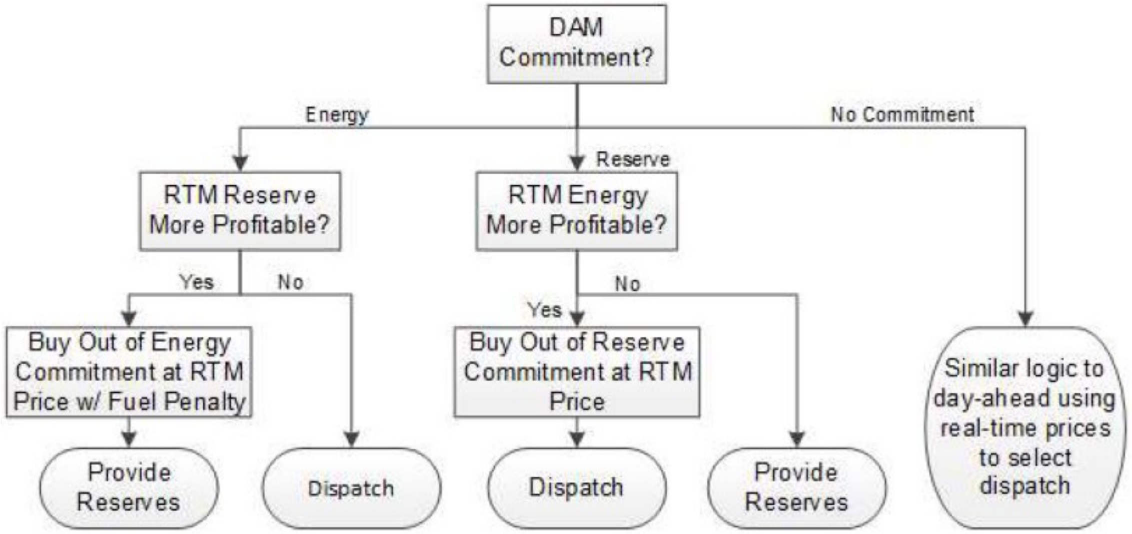
Review of Net EAS Revenue Models

Fuel-Fired Generators: 2021-2025 DCR Model

Day-Ahead Commitment Logic



Real-Time Commitment Logic



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Preliminary Recommendations for Net EAS Revenue Model

Fuel-Fired Generators: 2025-2029 DCR Model

- AG preliminarily recommends continued use of the same general structure and logic of the fuel-fired net EAS model developed as part of the 2021-2025 DCR.

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Review of Net EAS Revenue Models

Battery Storage Resources

- Although the battery storage model is conceptually similar to the fuel-fired generator model, the logic is modified to account for battery technology's unique technical properties, including:
  - Limited energy storage capacity
  - Need for a balancing of energy charges and discharges
  - Energy losses during charging
  - Operational practices that can reduce battery degradation
- Overall Modeling Framework (Consistent with 2021-2025 DCR approach):
  - Deterministic model using a three-year historical lookback period (i.e., same historical three-year period as the fossil-fired model)
  - One-hour granularity in pricing
  - 4/6/8 hour duration batteries modeled
  - Batteries participate in DAM and RTM energy and reserve markets
  - Batteries are assumed to be capable of providing spinning reserves when it has no DAM or RTM energy discharge position but has at least one hour capability of stored energy or is charging

Details of Battery Net EAS Revenue Model

Refinement of Modeling Approach Taken in 2021-2025 DCR

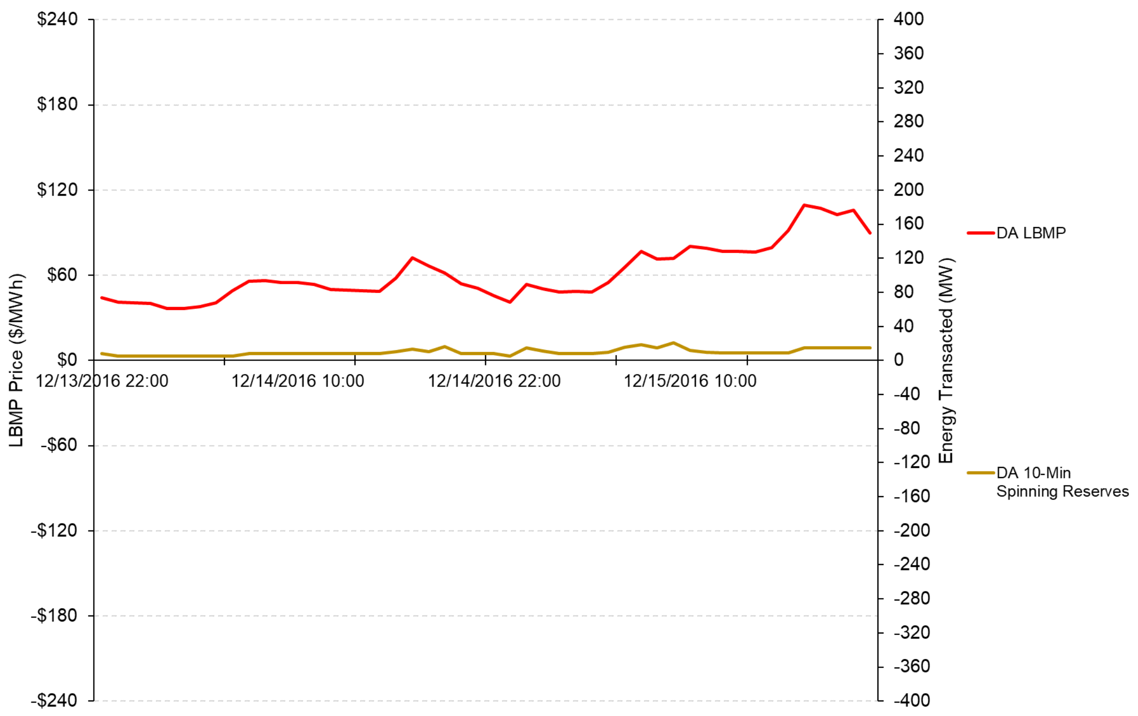
- Three steps:
  - 1. Determine optimal DAM schedule for energy and reserves using assumed perfect foresight in DAM prices (analogous to fuel-fired model)
    - Potential for zero or multiple cycles per day depending on prices
    - Optimal charge and discharge hours determined daily by unit/zone
  - 2. Optimize for multi-day DAM behavior (such as maintaining stored energy across days)
  - 3. Determine incremental RTM positions, including buyouts of DAM positions if RTM prices economically support such buyouts
    - RTM step is not perfect foresight; model goes hour-by-hour sequentially through each day and determines if there is a deviation between RTM and DAM prices that creates a profit opportunity greater than an assumed “hurdle rate”
    - Hurdle rate includes a risk premium and an opportunity cost adder (determined by modeling)
- Other factors
  - Model respects physical limitations of round-trip charge inefficiency, “prefers” to keep state of charge at 50% for periods when battery is not cycling in order to maintain battery health
  - Model takes into account variable operations and maintenance cost, applicable transmission service charges for battery charging, and Rate Schedule 1 charges (analogous to the fuel-fired model)

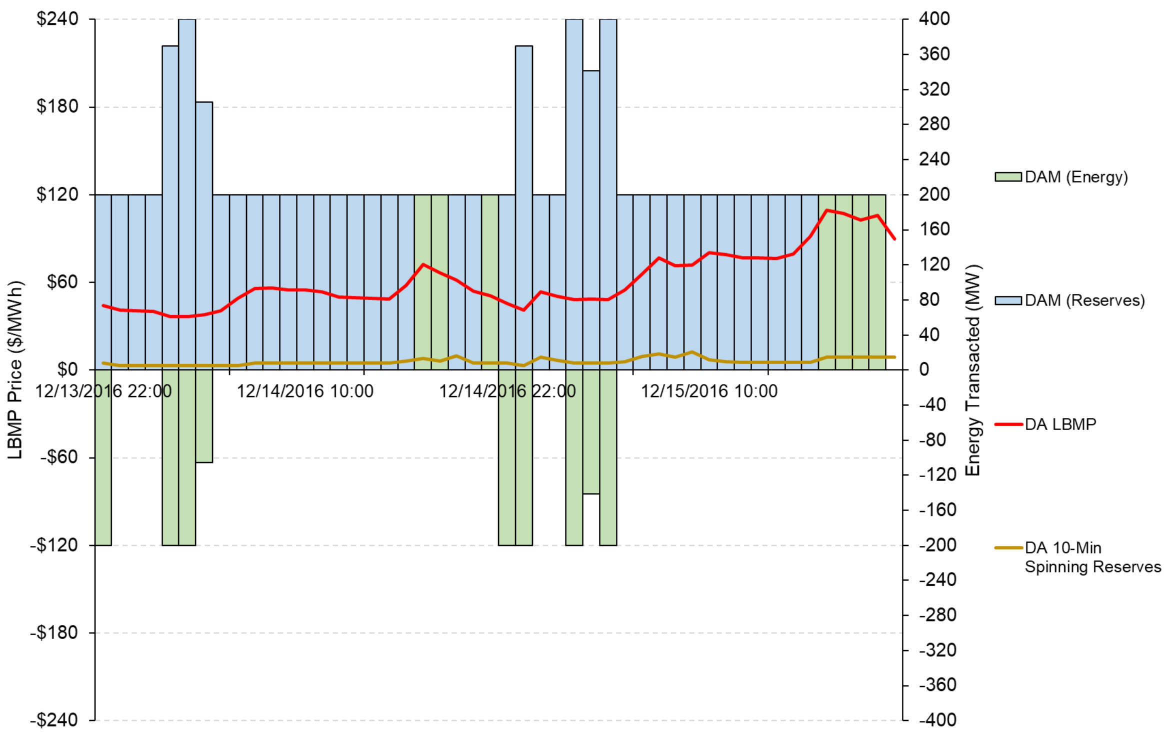
Introduction to Battery Net EAS Revenue Model

Step 1 & 2: Assignment of Day-Ahead Schedule

- Given historical day-ahead energy and reserve prices for a given zone on a given day(s)…

- Optimal day-ahead energy and reserves schedule is set to co-optimize energy and reserve revenues
- Accounts for charge inefficiency



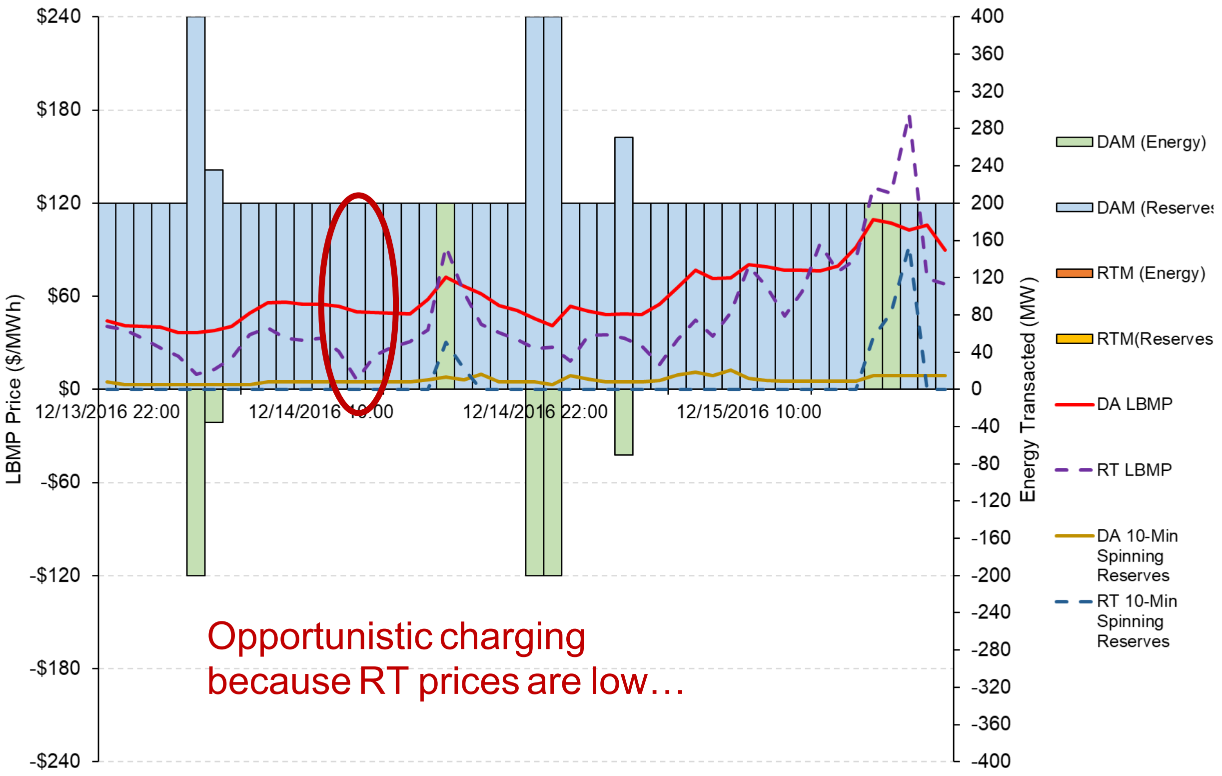


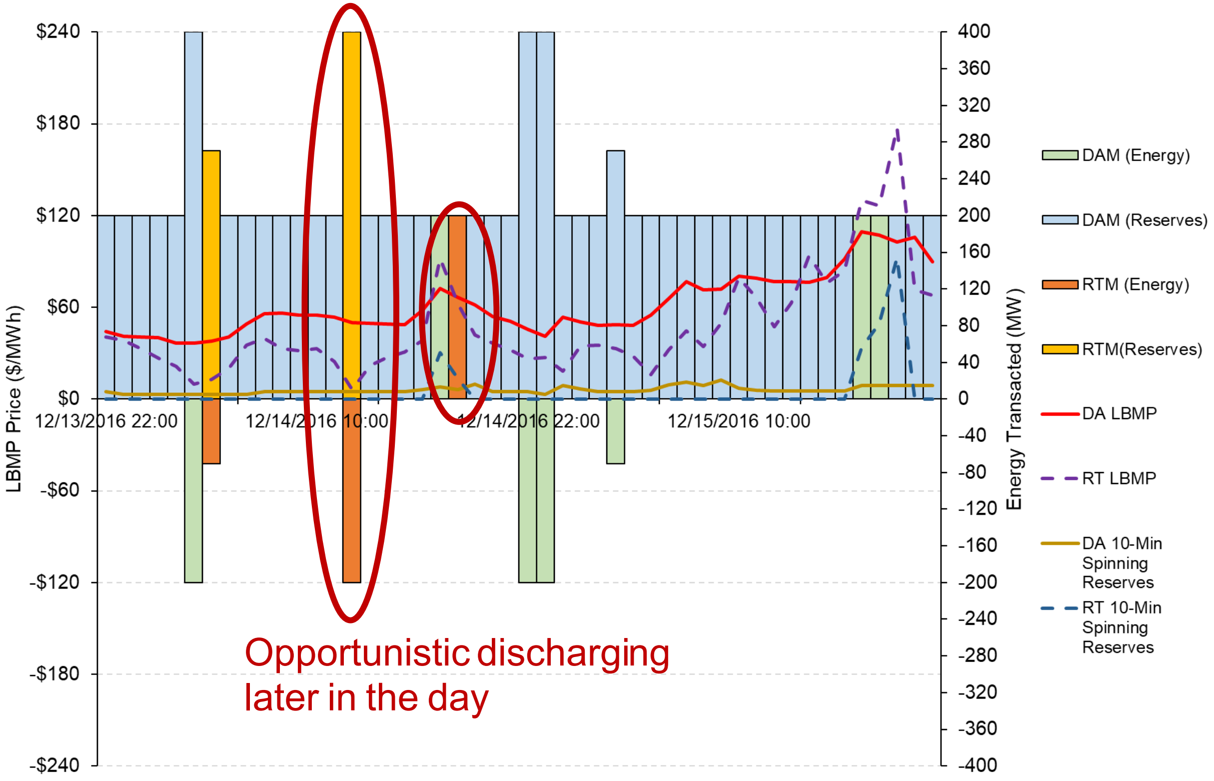
Introduction to Battery Net EAS Revenue Model

Step 3: Determination of Incremental RTM Positions

- Given historical real-time energy and reserve prices known hour by hour…

- Additional real-time cycles are added into the hourly schedule if profitable and feasible (limited to bounds of previously determined day-ahead energy and reserve schedule)
- Risk premium and opportunity cost adder determine hurdle rate for RTM decisions





Introduction to Battery Net EAS Revenue Model

Refinement of Modeling Approach Taken in 2021-2025 DCR

- Incremental refinements being considered for the 2025-2029 DCR:
  - Modeling changes to improve runtime by not analyzing potential battery cycles that are highly unlikely to be profitable
    - Preliminary analysis has identified a potential 90% decrease in required model runtime with minimal change in resulting net EAS revenue estimates (less than 1% difference in revenue estimates for majority of zones and battery duration options)
  - Modeling approach has been discussed with battery market participants and compared with (limited) battery operations data in NYISO-administered markets

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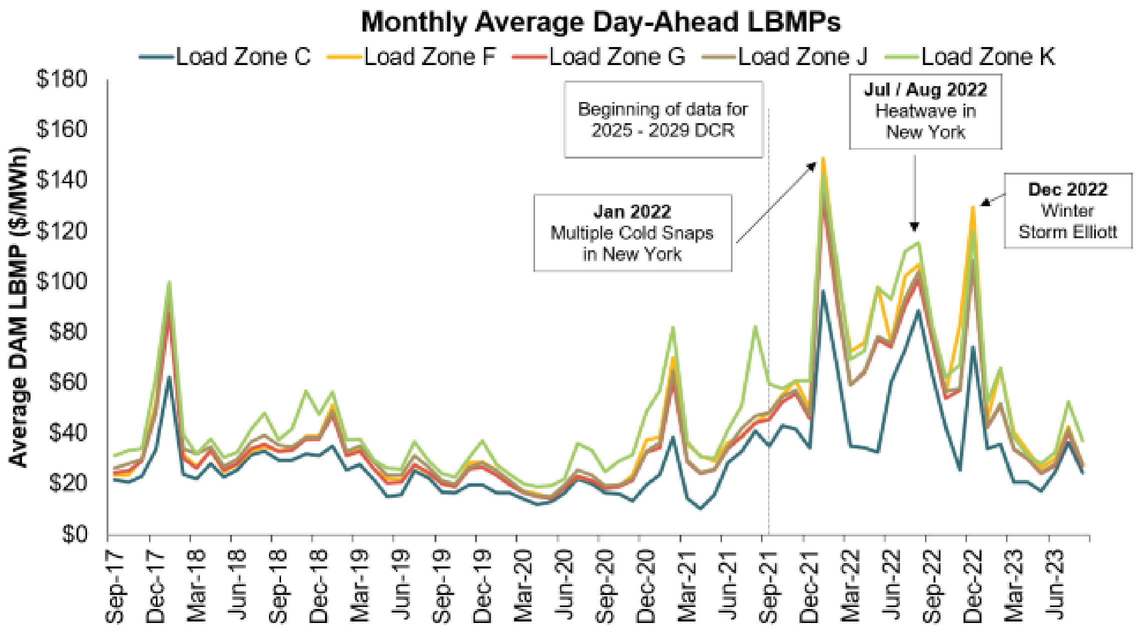
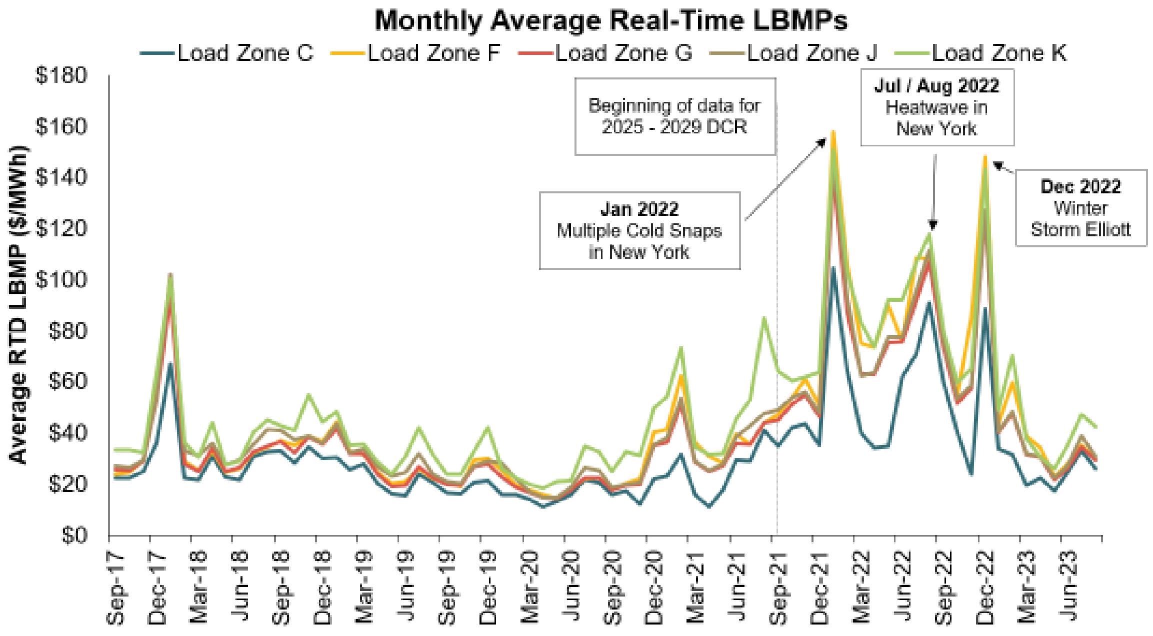
Summary of LBMPs, September 2017 – August 2023

Day-Ahead and Real-Time LBMPs by Capacity Zone



Source: NYISO Pricing Data.



Note: Underlying data are Time-Weighted/Integrated hourly Real-Time prices. **Source:** NYISO Pricing Data.

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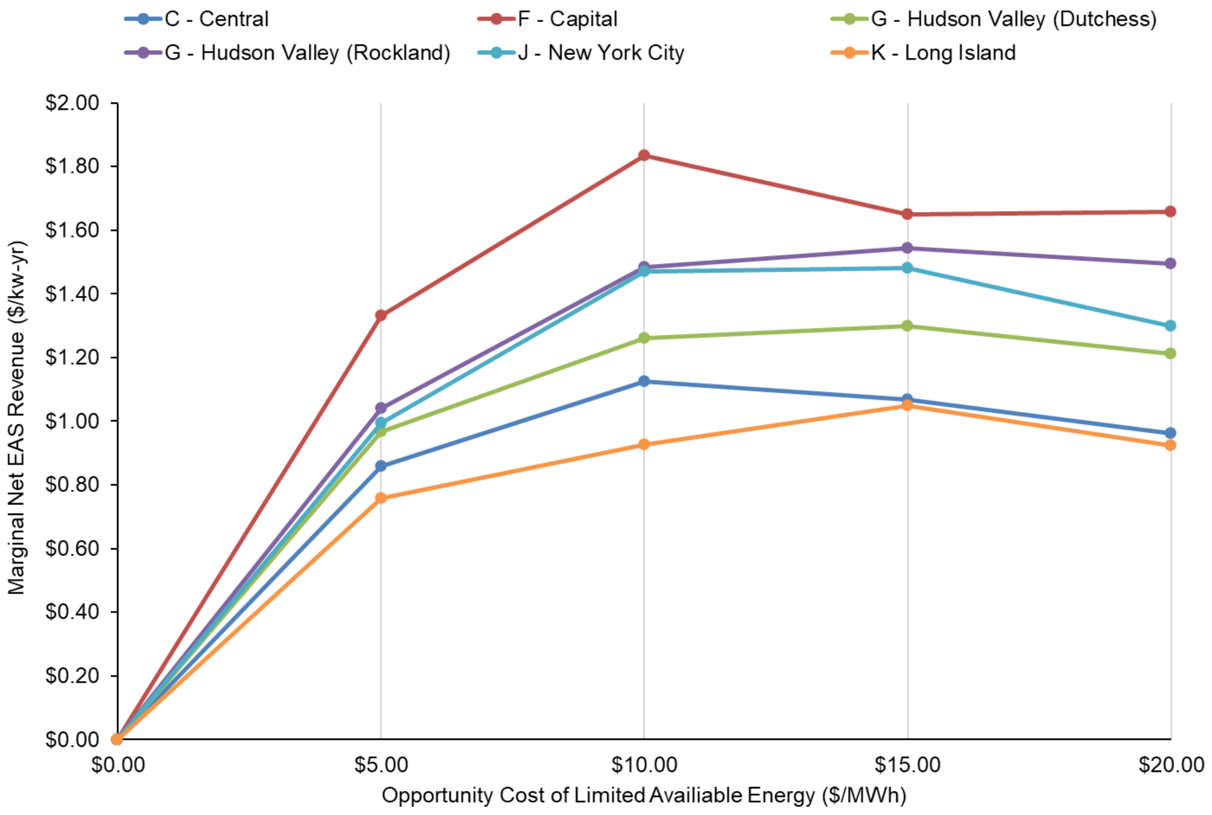
Real-Time Hurdle Rate

Summary of Approach

- Must exceed the applicable "hurdle rate" for expected profit before the model will dispatch the battery for a particular hour in the RTM
- The hurdle rate includes two components:
  - *Risk premium:* Set at $10/MWh, by assumption. Reflects risk aversion when participating in the Real-Time Market, in that volatility in prices could lead to losses relative to Day-Ahead positions
  - *Opportunity cost of limited available energy*: Estimated empirically using the model. Reflects that a battery may subsequently encounter an opportunity to earn higher revenues.
- The 2021-2025 DCR used the following hurdle rates:
  - Load Zones C and F: $20/MWh
  - Loads Zones G (Dutchess and Rockland), J, and K: $25/MWh

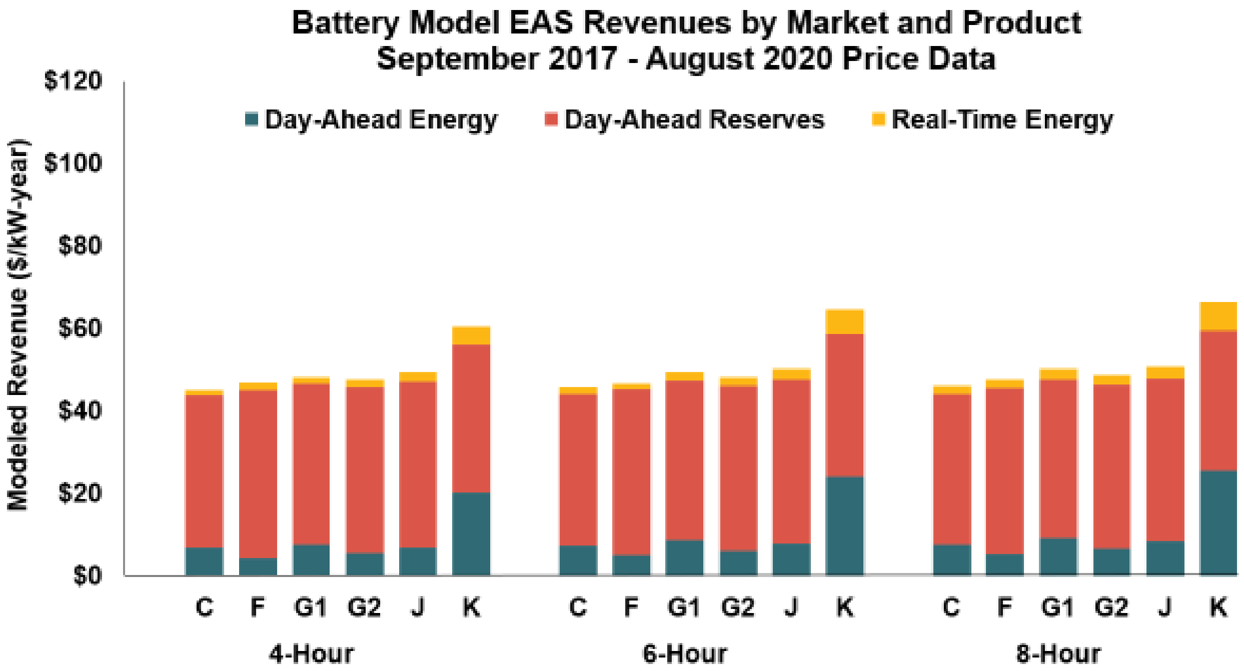
2021-2025 DCR Report, Figure 12
Change in RTM Net EAS Revenues for Alternative Bid Offer Hurdle Costs, 4-Hour Battery



Note: Marginal Net EAS revenue is the extra revenue gained compared to the $0 / MWh opportunity cost.

Observations of Net EAS Revenues for Batteries in Last Reset

- This slide summarizes patterns in results from last DCR (for the first year of the reset period [i.e., 2021/2022 Capability Year])
- Modeled batteries made a large proportion of revenues in reserve markets and DAM energy markets
- Load Zones with higher price volatility (J and K) had higher battery net EAS revenues
- Batteries cycle much less than once a day on average



Notes: Modeled revenue is based on price data from September 1, 2017 - August 31, 2020, and unit technical inputs from the 2021 - 2025 DCR. Modeled revenue is not derated to account for EFORd.

Preliminary Recommendations for Net EAS Revenue Model

Battery Storage Resources: 2025-2029 DCR Model

- We recommend using a refined version of the 2021-2025 Net EAS model for battery storage resources (i.e., incorporating refinements for improved model performance/reduced model runtime requirements).
  - 90% decrease in required model runtime with minimal change in resulting net EAS revenue estimates.
  - AG will continue to assess the appropriate hurdle rate for each zone.

Review of Financial Parameters

Conceptual Framework

Relevant Issues

- Financial parameters used to calculate the levelized gross cost of new entry (CONE) values should reflect project specific risk to future cash flows for a merchant developer based on investor expectations over the life of the project and the general conditions of investment in NY
- Financial parameters used to calculate the levelized gross CONE values include:
  - After Tax Weighted Average Cost of Capital (ATWACC), comprised of:
    - Cost of debt
    - Target return on equity
    - Debt-equity ratio
    - Tax rate (associated with interest deduction)
  - Tax rates/PILOT rates (vary by location)
  - Amortization period
- Financial parameters are interrelated, require internal consistency, and should be evaluated holistically

Conceptual Framework

Estimating the Cost of Capital for a Stand-Alone Peaking Plant

- The ATWACC will be estimated using the following formula:

$$ATWACC = \%Debt \times COD \times (1 - TaxRate) + \%Equity \times COE$$

where

$\% \, Debt$ = debt share of capital structure

COD = cost of debt (i.e., interest rate)

$TaxRate$ = tax rate associated with interest deduction

$\% \, Equity$ = equity share of capital structure

COE = cost of equity (i.e., required return)

- Recommended values for individual financial parameters will be developed via:
  - Observed costs of debt for independent power producer (IPP) companies with meaningful ownership of merchant generators
  - Observed yields for generic corporate debt with comparable credit quality
  - Estimated costs of equity using the Capital Asset Pricing Model (CAPM) for power companies with meaningful ownership of merchant generators
  - Additional considerations, including project-level risk and market and regulatory risks specific to New York

Conceptual Framework

Potential Market and Regulatory Risk Factors

- Developer must assess potential to earn expected net EAS revenues over the physical life of the plant given a host of possible market risks:
  - Load growth uncertainty (e.g., heating and transportation electrification)
  - State and national energy and environmental policy
    - Federal/state energy and environmental policies, such as the Climate Leadership and Community Protection Act (CLCPA)
    - Federal investment tax credit for stand-alone battery storage projects and federal/state tax abatements
    - Electrification
  - Prices (input and output)
  - Technological change (e.g., distributed energy resources (DER), new storage technologies, low/zero emission fuels such as hydrogen)
  - Transmission development
- Parameters may differ by unit type
- Other risks accounted for in financial parameters include project-specific risks, including those inherent to the development of new resources (e.g., development and siting risks)

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Financial Parameter Development

Property Taxes, Insurance, and Depreciation

- Property Tax/PILOT Payments
  - Generators are sometimes able to negotiate site specific, individual Payment in Lieu of Tax (PILOT) agreements with local authorities
  - Following the approach of the 2021-2025 DCR, we will review PILOT data from New York State Comptroller's Office
  - Tax abatements exist for storage through New York, and for the peaking unit technology underlying the NYC ICAP Demand Curve as it relates to New York City
- Insurance
  - Yearly cost will be calculated as a percentage of project capital costs, based on input from 1898 & Co.
- Depreciation
  - Peaking units will be depreciated using the 15 year Modified Accelerated Cost Recovery (MACR) schedule, consistent with IRS Publication 946

Preliminary Considerations for 2025-2029 DCR

Multiple Parameters: COD, COE, D/E ratio, Amortization Period

- Estimates of cost of debt, cost of equity and debt/equity ratio for IPP companies
- Amortization period
  - Technologies operating solely on fossil fuels will likely require an adjustment to account for the CLCPA's zero-emission energy requirement in 2040
    - For example, applying a similar approach as the 2021-2025 DCR would result in a **13-year amortization period** for fossil-fuel fired options (i.e., gas only and dual fuel with oil back-up)
  - Battery storage amortization period remains under consideration
    - 2021-2025 DCR assumed a 15-year amortization because, at the time of the last DCR, battery storage was more of an emerging technology
  - Amortization period for other emerging technology options (e.g., zero-emission fuels) should account for the current state of commercial/operational experience
- Market risk adder and/or other parameter adjustments to account for market risk remains under consideration

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