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NYISO 2025-2029 ICAP Demand Curve Reset (DCR)

LOE-AFs, VSS Revenue Adder, and Stakeholder Feedback

ICAP Working Group

July 23, 2024

BOSTON CHICAGO DALLAS DENVER LOS ANGELES MENLO PARK NEW YORK SAN FRANCISCO WASHINGTON, DC BEIJING BRUSSELS LONDON MONTREAL PARIS

Agenda

- Schedule
- Level of excess adjustment factors (LOE-AFs)
- Updated voltage support service (VSS) revenue adder
- Stakeholder feedback on the Draft Report

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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

LOE-AFs for 2025-2029 DCR

Level of Excess Adjustment Factors

Proposed Approach

- As discussed at the 2/29/2024 ICAPWG meeting, AG recommends setting the LOE-AFs for the 2025-2029 DCR using the years covered by the net Energy and Ancillary Services (EAS) revenue estimates throughout the reset period
  - As shown below, years 2021 through 2027 align with the years that will be used in determining the estimated net EAS revenues across the reset period

Capability Year	Historical Period Utilized in Net EAS Revenue Estimate
2025-2026	Sept 2021-Aug 2024
2026-2027	Sept 2022-Aug 2025
2027-2028	Sept 2023-Aug 2026
2028-2029	Sept 2024-Aug 2027

- When averaging Day-Ahead LBMPs from GE Multi-Area Production System (GE-MAPS) cases (i.e., base case/"as found" and "level of excess" or "LOE" case) to determine LOE-AF values, the LBMPs for each month, relevant Load Zone, and period (i.e., "on-peak," "high on-peak," and "off-peak," consistent with the groupings used in the 2021-2025 DCR) are weighted by how many times the given month and year combination are used as an input in the net EAS revenue estimates over the reset period (see next slide for weightings by month and modeled year)
- The GE-MAPS modeling uses recent data for the relevant model years consistent with other NYISO studies and previously reviewed by stakeholders
  - For model years 2021-2022, the 2021-2040 System and Resource Outlook Base Case is used; for model years 2023-2027, the 2023-2042 System and Resource Outlook Base Case is used

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Level of Excess Adjustment Factors

LBMP Weightings by Month and Modeled Year[1]

Month

Modeled Year

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2021	0%	0%	0%	0%	0%	0%	0%	0%	8%	8%	8%	8%
2022	8%	8%	8%	8%	8%	8%	8%	8%	17%	17%	17%	17%
2023	17%	17%	17%	17%	17%	17%	17%	17%	25%	25%	25%	25%
2024	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%
2025	25%	25%	25%	25%	25%	25%	25%	25%	17%	17%	17%	17%
2026	17%	17%	17%	17%	17%	17%	17%	17%	8%	8%	8%	8%
2027	8%	8%	8%	8%	8%	8%	8%	8%	0%	0%	0%	0%

[1]Over the reset period, the theoretical maximum number of times that LBMPs for a given month could be used is 12 (i.e., the rolling three-year historical periods used in the net EAS revenue estimates, multiplied by the four Capability Years covered by the DCR). The LBMP weightings reflect how many times LBMPs from each month and year combination are used as an LBMP input over the reset period divided by 12. For example, LBMPs from September 2021 will only be used in the net EAS revenue estimates for the 2025-2026 Capability Year ICAP Demand Curves. Thus, the LBMP weighting for September 2021 is 1/12 = 8%.

Level of Excess Adjustment Factors – 200 MW Peaking Plant

- LOE-AFs are generally similar in magnitude to the 2021-2025 DCR; LOE-AFs sometimes fall below 1 due to net load in the base case being higher than the scaled load in the LOE cases in certain zones.

Location	Period	January	February	March	April	May	June	July	August	September	October	November	December
Zone C - Central	HighOnPeak	0.933	0.947	-	-	-	0.972	0.939	0.954	-	-	-	0.905
	Off Peak	0.976	0.976	0.982	0.996	1.000	0.995	0.993	1.000	0.983	0.983	0.972	0.972
	On Peak	0.965	0.963	0.972	0.996	1.001	0.984	0.976	0.990	0.966	0.976	0.952	0.942
Zone F - Capital	HighOnPeak	1.040	1.029	-	-	-	1.006	0.952	0.978	-	-	-	0.998
	Off Peak	1.031	1.020	1.019	1.011	1.027	1.010	1.008	1.014	1.005	1.003	1.019	1.035
	On Peak	1.043	1.038	1.023	1.016	1.041	1.007	1.004	1.013	1.002	1.014	1.005	1.022
Zone G - Hudson Valley	HighOnPeak	1.147	1.099	-	-	-	1.082	1.278	1.126	-	-	-	1.150
	Off Peak	1.042	1.026	1.022	1.023	1.034	1.019	1.038	1.032	1.020	1.016	1.026	1.056
	On Peak	1.092	1.066	1.045	1.036	1.064	1.033	1.076	1.063	1.037	1.033	1.055	1.095
Zone J - New York City	HighOnPeak	1.061	1.049	-	-	-	1.046	1.180	1.050	-	-	-	1.058
	Off Peak	1.030	1.025	1.020	1.022	1.031	1.020	1.030	1.028	1.015	1.012	1.019	1.042
	On Peak	1.055	1.051	1.025	1.032	1.051	1.038	1.045	1.039	1.030	1.031	1.022	1.058
Zone K - Long Island	HighOnPeak	1.021	1.055	-	-	-	1.025	1.175	1.032	-	-	-	1.025
	Off Peak	1.018	1.044	1.026	1.007	1.017	1.017	1.018	1.013	1.014	1.015	1.015	1.027
	On Peak	1.015	1.056	1.022	1.006	1.031	1.030	1.032	1.019	1.022	1.025	1.015	1.041

[1] The “High On Peak” periods are defined consistent with the Summer and Winter Peak Load Windows for the 2024/2025 Capability Year (Summer: hour beginning (HB) 1 p.m. through HB 8 p.m.; Winter: HB 4 p.m. through HB 9 p.m.).

Level of Excess Adjustment Factors – 400 MW Peaking Plant

- LOE-AFs are generally similar in magnitude to the 2021-2025 DCR; LOE-AFs sometimes fall below 1 due to net load in the base case being higher than the scaled load in the LOE cases in certain zones.

Location	Period	January	February	March	April	May	June	July	August	September	October	November	December
Zone C - Central	HighOnPeak	0.991	0.993	-	-	-	1.016	0.988	1.008	-	-	-	0.971
	Off Peak	1.004	0.999	1.010	1.005	1.029	1.017	1.014	1.022	0.996	0.997	0.993	1.004
	On Peak	1.003	0.999	1.007	1.013	1.050	1.022	1.012	1.025	0.993	1.008	0.983	0.991
Zone F - Capital	HighOnPeak	1.043	1.050	-	-	-	1.024	0.994	1.017	-	-	-	1.011
	Off Peak	1.029	1.021	1.017	1.013	1.030	1.019	1.018	1.025	1.009	1.008	1.016	1.034
	On Peak	1.045	1.045	1.032	1.019	1.056	1.022	1.022	1.032	1.007	1.026	1.009	1.020
Zone G - Hudson Valley	HighOnPeak	1.130	1.109	-	-	-	1.085	1.220	1.120	-	-	-	1.111
	Off Peak	1.041	1.026	1.023	1.022	1.039	1.027	1.037	1.037	1.020	1.020	1.028	1.054
	On Peak	1.080	1.071	1.050	1.034	1.086	1.049	1.075	1.074	1.040	1.046	1.055	1.083
Zone J - New York City	HighOnPeak	1.056	1.049	-	-	-	1.039	1.132	1.048	-	-	-	1.046
	Off Peak	1.028	1.017	1.019	1.021	1.033	1.021	1.025	1.029	1.013	1.015	1.020	1.043
	On Peak	1.045	1.036	1.029	1.029	1.055	1.031	1.036	1.038	1.025	1.039	1.023	1.055
Zone K - Long Island	HighOnPeak	0.988	0.988	-	-	-	1.012	1.061	0.998	-	-	-	0.986
	Off Peak	0.999	0.985	0.975	1.004	1.020	1.012	1.003	1.001	1.021	1.031	0.993	1.000
	On Peak	0.988	0.984	0.971	1.001	1.033	1.013	1.010	1.001	1.037	1.056	0.982	0.997

[1] The High On Peak" periods are defined consistent with the Summer and Winter Peak Load Windows for the 2024/2025 Capability Year (Summer: HB 1 p.m. through HB 8 p.m.; Winter: HB 4 p.m. through HB 9 p.m.).

Updated VSS Revenue Adder

Updated VSS Revenue Adder

- Updated VSS revenue adder is based on the compensation structure set forth in Section 15.2.2.1 of Rate Schedule 2 to the Market Administration and Control Area Services Tariff:

  "… [T]he annual payment to Suppliers qualified and eligible to provide Voltage Support Service shall equal the product of the VSS Compensation Rate and the sum of the lagging and the absolute value of the leading MVAr capacity of the resource, as evidenced by tests conducted pursuant to ISO Procedures."

  "The VSS Compensation Rate of $2,592/MVAr, as determined in 2014, shall be adjusted annually by the annual average Consumer Price Index of the previous year."

- The 2024 VSS compensation rate determined by the NYISO and posted on the "Billing Rates" portion of its website (https://www.nyiso.com/billing-rates) is $3,307.31/MVAr

- VSS revenue adder value by technology option for the 2025-2026 Capability Year:

Frame Combustion Turbine: $3.97/kW-yr
- Nominal Capacity: 400 MW
- Reactive Capability: -180 MVARS to +300 MVARS
- Annual VSS Compensation: (300+180) * $3,307.31 = $1,587,509
- $1,587,509/(400*1,000)=$3.97

Lithium Ion Battery: $4.10/kW-yr
- Nominal Capacity: 200 MW
- Reactive Capability: -124 MVARS to +124 MVARS
- Annual VSS Compensation: (124+124) * $3,307.31 = $820,213
- $820,213/(200*1,000)=$4.10

- Analysis Group (AG) proposes to define the VSS revenue adder for the 2025-2029 DCR as a formula/methodology based on the compensation structure described above. As part of the annual updates for the reset period, the applicable adder value(s) will be updated to reflect the VSS compensation rate in effect at the time of the annual update.

Stakeholder Feedback on Draft Report

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Peaking Plant Technology

The draft report recommended that, based on the preliminary results, a 2-Hour battery energy storage system (BESS) be the appropriate peaking plant technology option in all locations

- Some stakeholders support the draft recommendation of a 2-Hour BESS in all locations. Others do not support the recommendation of 2-Hour BESS in any location, and generally support a simple cycle gas turbine (SCGT) or 4-Hour BESS.
- Based on the initial results developed to date, AG continues to recommend the 2-Hour BESS as the appropriate peaking plant technology for establishing each ICAP Demand Curve:
  - 2-hour BESS resources are eligible capacity suppliers under current NYISO market rules, and will contribute to maintaining resource adequacy in combination with all other resources
  - Capacity Accreditation Factors (CAFs) account for a resource's contribution to meeting resource adequacy requirements
  - AG's economic evaluation accounts for differences in CAFs among technologies by identifying the eligible technology capable of providing UCAP at lowest cost
  - There are no established minimum thresholds regarding the quantity or duration of energy a peaking plant must be capable of producing during peak periods to be considered a viable technology option for purposes of the DCR
- Some of the issues highlighted by stakeholders were considered when developing our recommendation and performing our analysis, including:
  - Future CAF uncertainty
  - Potential availability of state or other incentives for storage resources (such as the NYSPSC's recently approved index storage credit mechanism)
  - Future net EAS revenue uncertainty

Financial Parameters

The draft report recommended 15-Year Amortization and an after-tax weighted average cost of capital (ATWACC) of 9.02% and 8.76% (Load Zone J)

- Generators/suppliers generally argue that the recommended ATWACC assumptions are too low, and should not be set at the same level across technologies:
  - Stakeholders reference costs for certain alternative forms of debt (term loans), testimony regarding capital structure (from a 2018 PJM proceeding), various risks facing developers in New York
  - Stakeholders cite recent Brattle Group analyses recommending an increase in ATWACC from 8.85% in 2022 to 10.0% in 2024 in PJM, and 8.85% to 10.35% in ERCOT.
- Transmission owners note that amortization period should be 20 years rather than 15 years for the BESS options
- AG continues to evaluate financial parameters:
  - Data and information referenced by stakeholders includes information AG is considering in developing recommended values; however, in some cases the stakeholder comments include information that is unsupported, subjective or partial/incomplete (i.e., lacks complete information on financing structure), which impacts the applicability/veracity of such information
  - Our approach relies on an internally consistent set of parameters from publicly traded companies, with appropriate adjustments for project- and New York-specific considerations
  - AG is reconsidering all parameters, including ATWACC (and its components) and amortization period
- AG will update the financial parameters for current market information at same time as other parameters (e.g., net EAS revenues) are updated in early September

Feedback on Investment Tax Credit (ITC)

- 1898 & Co. have made adjustments to better capture the net value of the ITC to potential developers of BESS.
- Modified accelerated cost recovery system (MACRS) depreciation was previously calculated on the basis of pre-ITC capital costs. Per stakeholder feedback, IRS guidance requires that the depreciable tax basis must be reduced by 50% of the value of the credit.
- AG proposes subtracting 50% of the “gross” ITC value from the depreciable tax basis prior to calculating tax depreciation:

Depreciable Tax Basis=(Total Project Costs)-50%*(Total Project Costs)*(ITC Credit Percentage)*(Eligible Basis Allowance Percentage)

Feedback on Net EAS and Demand Curve Models

- Stakeholders raised concerns about the multi-day optimization step of the battery net EAS model for the Day-Ahead Market (DAM), in which the model calculates whether net revenues are maximized by emptying the battery each day or maintaining stored energy between cycle-days. This calculation relies on actual DAM prices more than 24 hours in advance.
  - AG proposes to remove the second step entirely, and instead require the model to achieve at least 200 MW of energy charge at the end of each day. This will ensure that the BESS operator is capable of earning overnight reserve revenues at nameplate capacity, but will not otherwise incur excessive charging costs.
- Consistent with current tariff rules, AG proposes to eliminate the application of transmission service charges (TSCs) to the BESS options for charging withdrawals because the BESS options are assumed to be qualified VSS suppliers
  - Sections 2.7.2.1.5 and 2.7.2.4.4 of the NYISO Open Access Transmission Tariff (OATT) exempt storage that is a qualified VSS supplier from TSCs for charging withdrawals
- AG also addressed several specific issues highlighted by stakeholders:
  - Allowance for funds used during construction (AFUDC) used in the demand curve model has been updated for consistency with data provided in Appendix A of the draft report.
  - Day-ahead battery net EAS model now defines a day as 12am to 12am, rather than 10pm to 10pm.
  - Corrected revenue calculation in the battery Real-Time Market (RTM) model for six hours impacted by Daylight Savings Time.
  - Corrected limited number of instances where battery charging exceeded physical capacity of the battery.

Feedback on Net EAS and Demand Curve Models (cont.)

- Stakeholders raised concerns about the 2% derating factor for BESS resources, recommending instead that AG apply a factor of 9.36% consistent with the EFORd for Pumped Storage in the most recent year.
  - AG continues to recommend the use of 2% based on the recommendation from 1898 & Co. that 2% is a more representative value for BESS
- Stakeholders raised concerns about the future uncertainty of reserve revenues for BESS as additional energy storage capacity comes online over time
  - The annual update process and rolling three-year lookback period already provide the mechanism for capturing changes in reserve market prices over time in the net EAS revenue estimates.
- Stakeholders raised concerns about battery buyouts from day-ahead schedule energy or reserve commitments during the NYISO-defined peak load window periods, suggesting that BESS may not have the energy to meet its hourly DAM schedule during such peak load window periods.
  - AG is evaluating this issue, but preliminarily does not believe this is a likely outcome that would materially affect BESS capacity availability or assumed EAS market participation as determined by the battery net EAS model.

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