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NYISO 2025-2029 ICAP Demand Curve Reset (DCR)

Updated Natural Gas Hub Recommendations, Financial Parameters, 5-Minute Real-Time Battery Modeling, and Ongoing Analysis

ICAP Working Group

April 17, 2024

Agenda

- Updated Natural Gas Hub Recommendations
- Financial Parameter Considerations
- Continued Discussion of 5-Minute Real-Time Battery Modeling
- Ongoing Analysis

Updated Natural Gas Hub Recommendations

Decision Criteria for Fuel Hub Selection

1. **Market Dynamics**
   - Gas hub price index reflects historical relationship between gas hub pricing and LBMPs
   - Ideally, prices should reflect a long-term equilibrium rather than short run arbitrage opportunities (real or apparent), recognizing that other factors (e.g., congestion) influence LBMP price spikes
2. **Liquidity**
   - Gas hub price index with consistent historical data and trading activity
3. **Geography**
   - Pipelines with a geographic relationship that allows for gas delivery to potential peaking plant locations
   - Reported hub price indices (which reflect average prices over a broad geographic area) with a logical nexus to relevant delivery points
4. **Precedent/Continuity**
   - Gas hubs supported by information from multiple sources and used for similar purposes (e.g., 2021-2025 DCR, 2022 State of the Market report [2022 SOM], and 2021-2040 System and Resource Outlook [2021-2040 Outlook])

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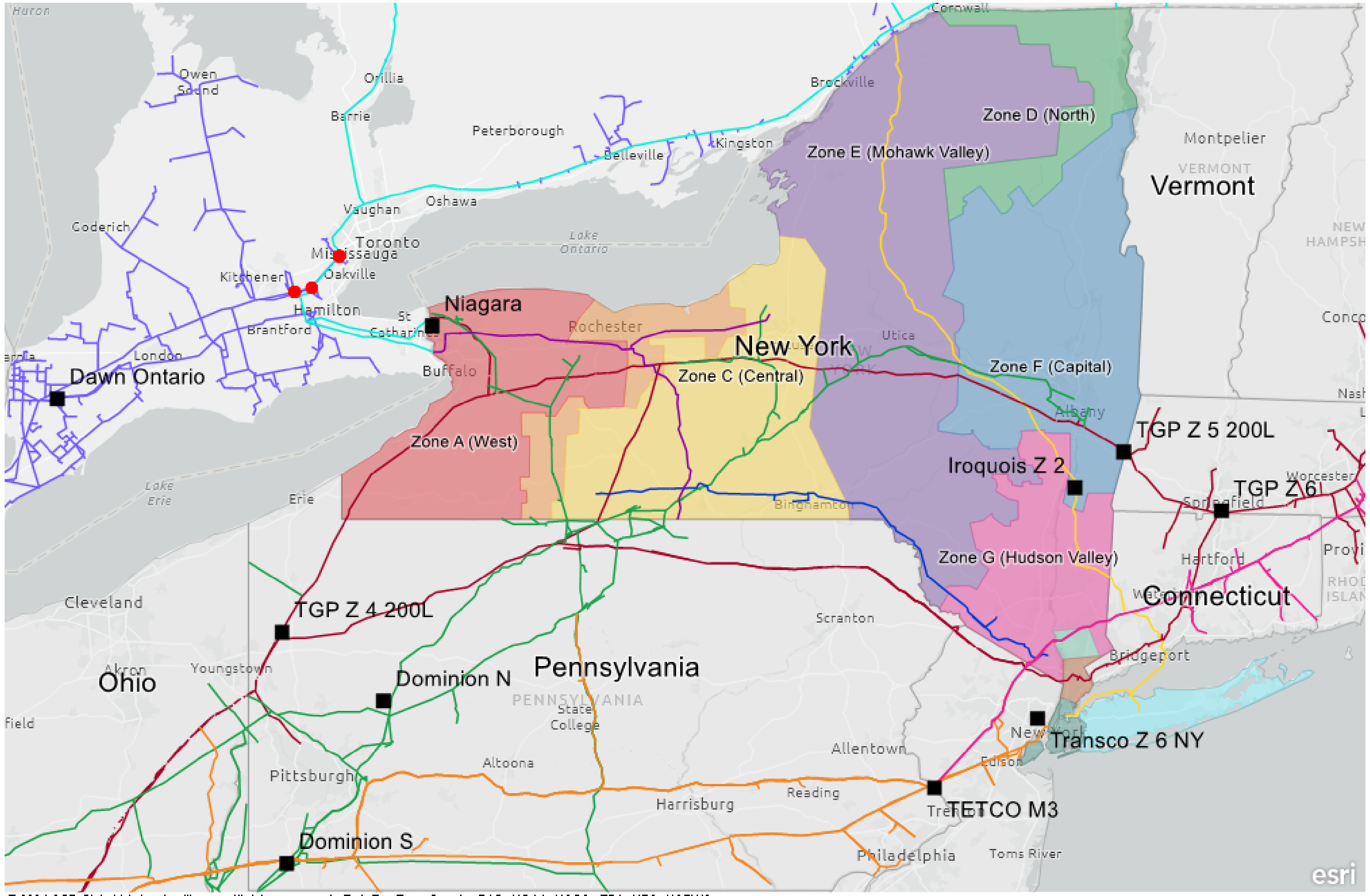
Geographic Locations of New York Natural Gas Hubs



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Kirkwall Delivery/Receipt

Receipt/Delivery

- Bi-Directional

Pipeline Operating

Company

- TransCanada PipeLines Limited

Pipeline Operating

Company

- Texas Eastern Transmission, LP
- Algonquin Gas Transmission, LLC
- Enbridge Gas Inc.

Pipeline Operating

Company

- Tennessee Gas Pipeline Company, L.L.C.
- Eastern Gas Transmission and Storage, Inc.
- Millennium Pipeline Company, LLC
- Empire Pipeline, Inc.
- Iroquois Gas Transmission System, L.P.

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Updated Draft Recommendations for 2025-2029 DCR

Summary of Updated Draft Recommendations

Location	2025-2029 DCR (Updated Recommendations)*	2025-2029 DCR (Preliminary Recommendations)	2021-2025 DCR
Load Zone C	Dawn Ontario (December - March) & Tennessee Zone 4 200L (April – November)	Dawn Ontario (December - March) & Tennessee Zone 4 200L (April – November)	Niagara (December - March) & Tennessee Zone 4 200L (April – November)
Load Zone F	Iroquois Zone 2	Iroquois Zone 2	Iroquois Zone 2
Load Zone G (Dutchess)	***Iroquois Zone 2***	Tennessee Zone 5 200L	Iroquois Zone 2
Load Zone G (Rockland)	***Tennessee Zone 6***	Tennessee Zone 5 200L	TETCO M3
Load Zone J	***Transco Zone 6 NY (February - November) & Iroquois Zone 2 (December – January)***	Transco Zone 6 NY	Transco Zone 6 NY
Load Zone K	Iroquois Zone 2	Iroquois Zone 2	Iroquois Zone 2

* ***Bold italicized*** font represents a proposed change to the preliminary recommendations presented at the 2/29/2024 ICAPWG meeting

Preliminary Recommendations for 2025 – 2029 DCR

Load Zone C

- Preliminary Recommendation: Tennessee Zone 4 200L (April to November) and Dawn Ontario (December to March); good historical precedent as a proxy gas hub in Load Zone C, sufficiently traded, and geographically well situated.
- Feedback on Preliminary Recommendation:
    - Dawn Ontario may not be optimal from the geographic location criteria
    - Request to further assess Dawn and Niagara prices to ensure that economic relationship between the prices supports the selection.

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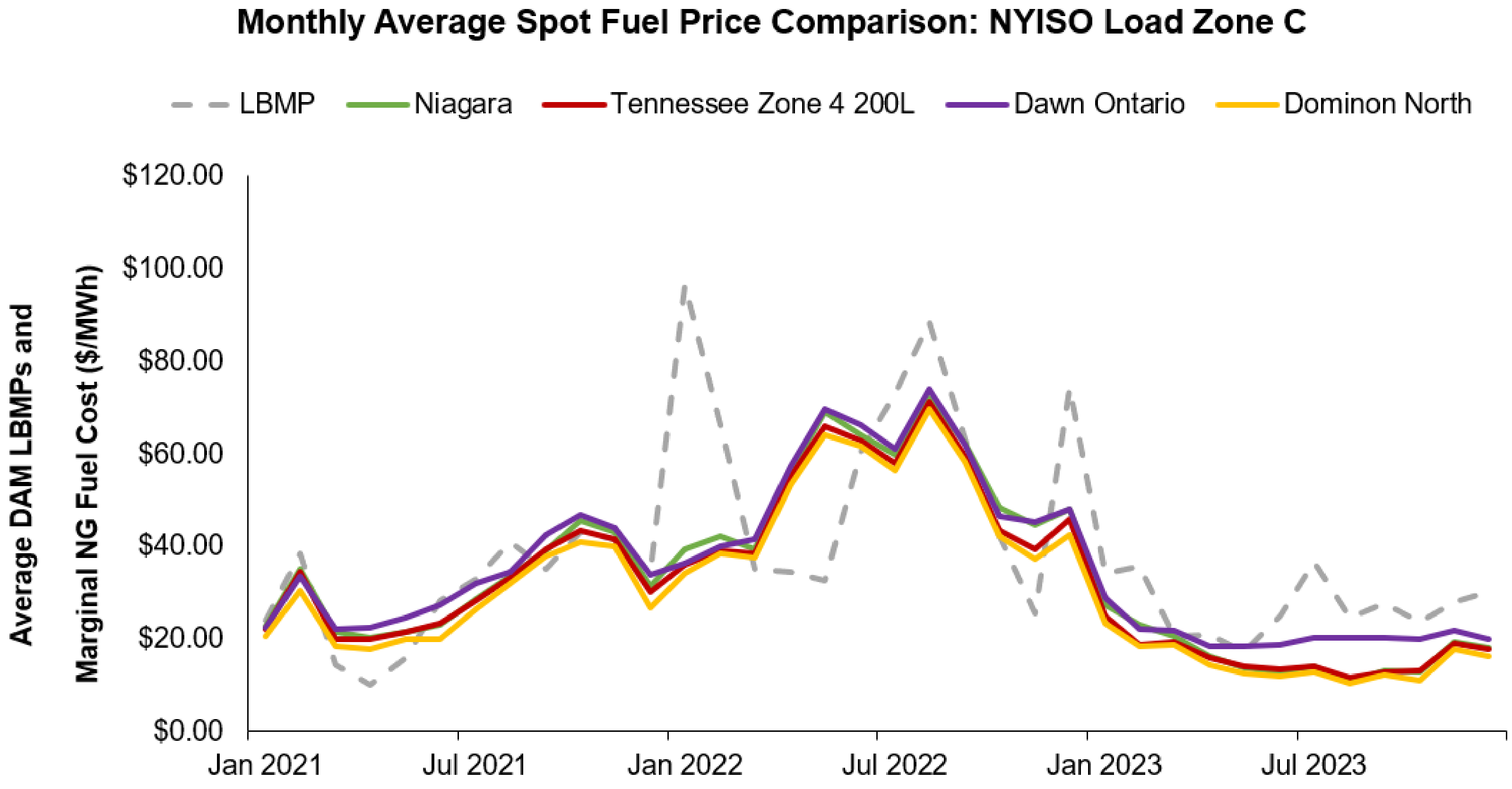
Load Zone C (LBMPs and Gas Prices)

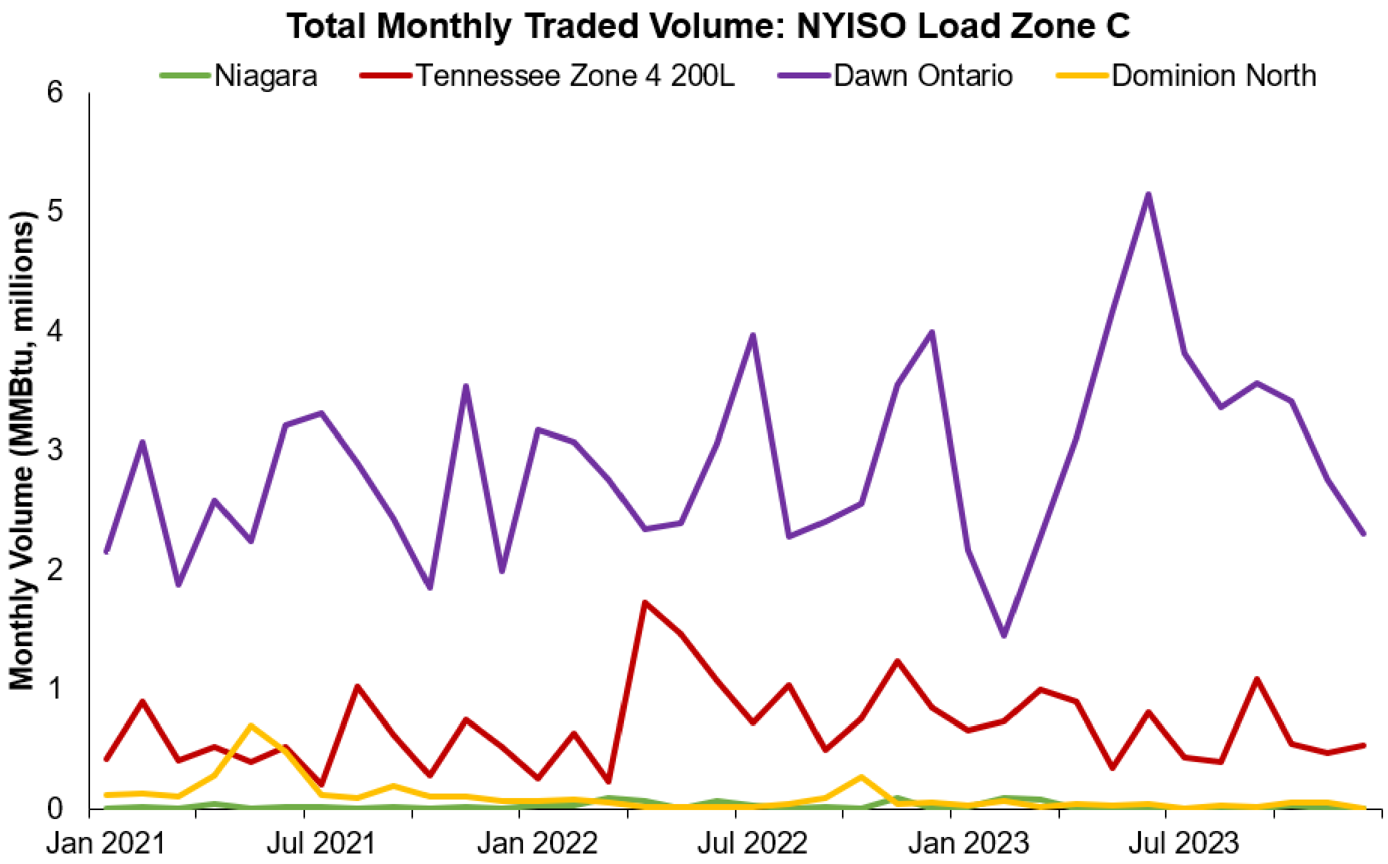
Review of natural gas pricing trends since 2021



Sources: [A] S&P CapIQ (Fuel Prices; obtained by AG).

Load Zone C (Trade Volume, MMBTU)

Review of natural gas trade volume since 2021



Source: S&P CapIQ (obtained by AG)

Updated Draft Recommendations for 2025 – 2029 DCR

Load Zone C

- Updated Draft Recommendation: Maintain Tennessee Zone 4 200L (April to November) and Dawn (December to March)
  - Tennessee Zone 4 200L and Dawn Ontario hubs have better liquidity than Niagara
  - Both hubs reflect gas sources that can be delivered to Load Zone C
  - Winter Dawn and Niagara prices track each other closely, with only a small difference in average prices over the historical three-year period

Decision Criteria		Dawn Ontario (December - March) & Tennessee Zone 4 200L (April – November)	Niagara (December - March) & Tennessee Zone 4 200L (April – November)	Dominion North	Dominion South (91%), Tetco M3 (7%), & Columbia (2%)
Market Dynamics		Low LBMP Correlation	Low LBMP Correlation	Low LBMP Correlation	Low LBMP Correlation
Liquidity		Medium/High	Low/Medium	Medium	Medium
Geography		Yes	Yes	Yes	No
Precedent	2021-2025 DCR	No	Yes	No	No
	2022 SOM	No	Yes	No	No
	2021-2040 Outlook	No	No	No	Yes
Updated Recommendation		✓			

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Preliminary Recommendations for 2025 – 2029 DCR

Load Zone G (Dutchess County) and Load Zone G (Rockland County)

- Preliminary Recommendation: Tennessee Zone 5 200L for both locations; has a good correlation with market prices, is sufficiently traded, and is geographically well situated.
- Feedback on Preliminary Recommendation:
    - The use of a single hub for both Dutchess and Rockland counties may not optimally represent geographic disparities and differences in gas pricing for locations on opposite sides of the Hudson River.

Updated Draft Recommendations for 2025 – 2029 DCR

Load Zone G (Dutchess County)

- Updated Draft Recommendation:
  - Iroquois Zone 2; good historical precedent as a proxy gas hub in Load Zone G (Dutchess County); good correlation with market prices, sufficiently traded, and geographically well situated.

Decision Criteria		Iroquois Zone 2	Tetco M3	Tennessee Zone 5 200L	Tennessee Zone 6 (62%), Iroquois Zone 2 (28%), Algonquin (7%), & Tetco M3 (3%)
Market Dynamics		High LBMP Correlation	High LBMP Correlation	Medium LBMP Correlation	Medium LBMP Correlation
Liquidity		Medium	High	Medium	Medium
Geography		Yes	No	Yes	Yes/No
Precedent	2021-2025 DCR	Yes	No	No	No
	2022 SOM	Part of Load Zone G Blend	Part of Load Zone G Blend	No	Yes
	2021-2040 Outlook	Part of Load Zones F-I Blend	Part of Load Zones F-I Blend	No	No
Updated Recommendation		✓			

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Updated Draft Recommendations for 2025 – 2029 DCR

Load Zone G (Rockland County)

- Updated Draft Recommendation:
  - Tennessee Zone 6; high correlation with market prices, sufficiently traded, and geographically more representative of region than Tetco M3.

Decision Criteria		Iroquois Zone 2	Tetco M3	Tennessee Zone 6	Tennessee Zone 5 200L	Tennessee Zone 6 (62%), Iroquois Zone 2 (28%), Algonquin (7%), & Tetco M3 (3%)
Market Dynamics		High LBMP Correlation	High LBMP Correlation	High LBMP Correlation	Medium LBMP Correlation	Medium LBMP Correlation
Liquidity		Medium	High	Medium	Medium	Medium
Geography		No	No	Yes/No	Yes	Yes/No
Precedent	2021-2025 DCR	No	Yes	No	No	No
	2022 SOM	Part of Load Zone G Blend	Part of Zone G Blend	No	No	Yes
	2021-2040 Outlook	Part of Load Zones F-I Blend	Part of Load Zones F-I Blend	Part of Load Zones F-I Blend	No	No
Updated Recommendation				✓		

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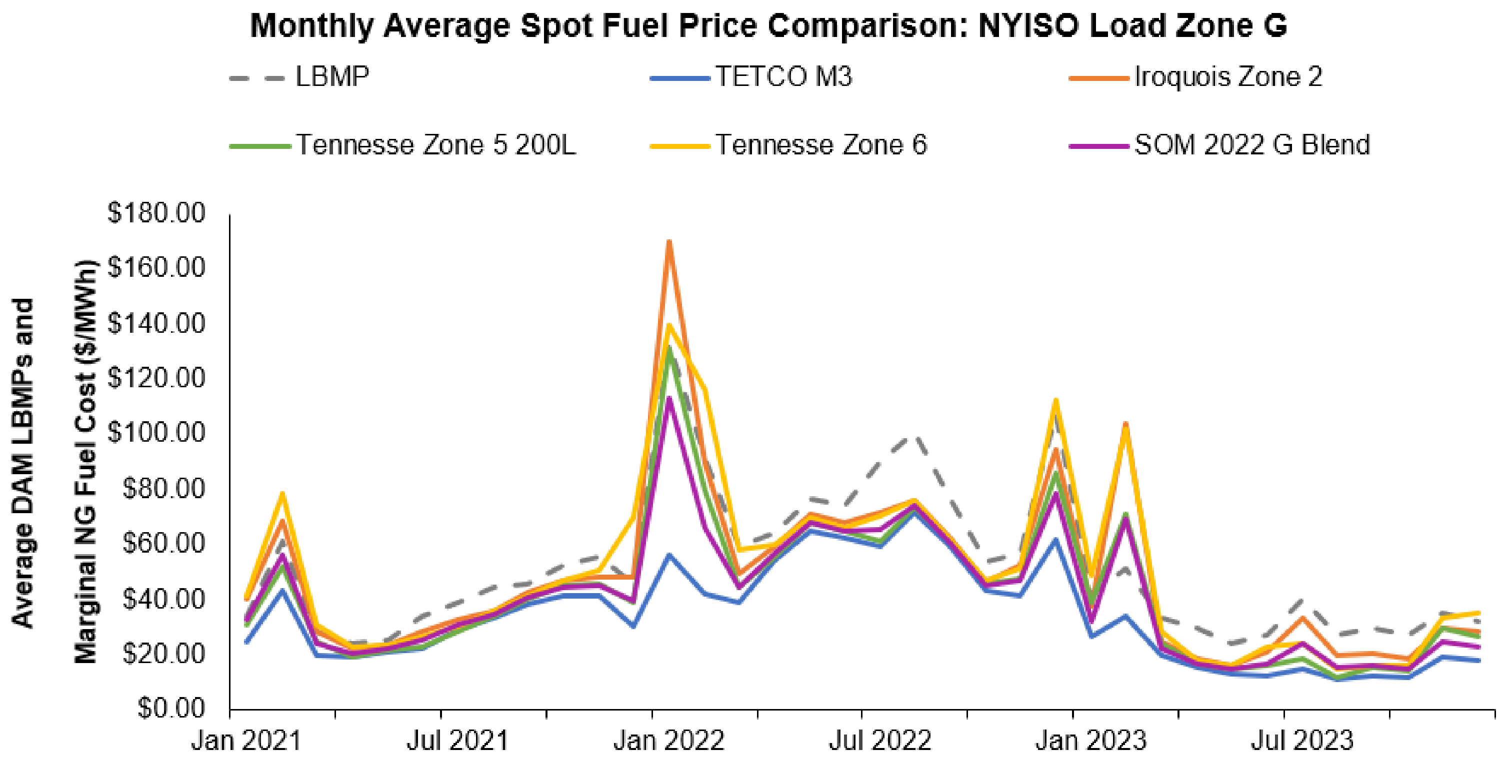
Load Zone G (LBMPs and Gas Prices)

Review of natural gas pricing trends since 2021



Notes: [1] "Marginal NG Fuel Cost" is calculated as the product of the natural gas price index and the heat rate of a GE 7HA.02 turbine, the 2021-2025 DCR reference peaking plant. The assumed heat rate is 8,890 Btu/kWh. [2] The 2022 SOM Index is comprised of a weighted average of Iroquois Zone 2 (50%) and Tetco M3 (50%). **Sources:** [A] S&P CapIQ (Fuel Prices; obtained by AG). [B] NYISO (DAM LBMPs).

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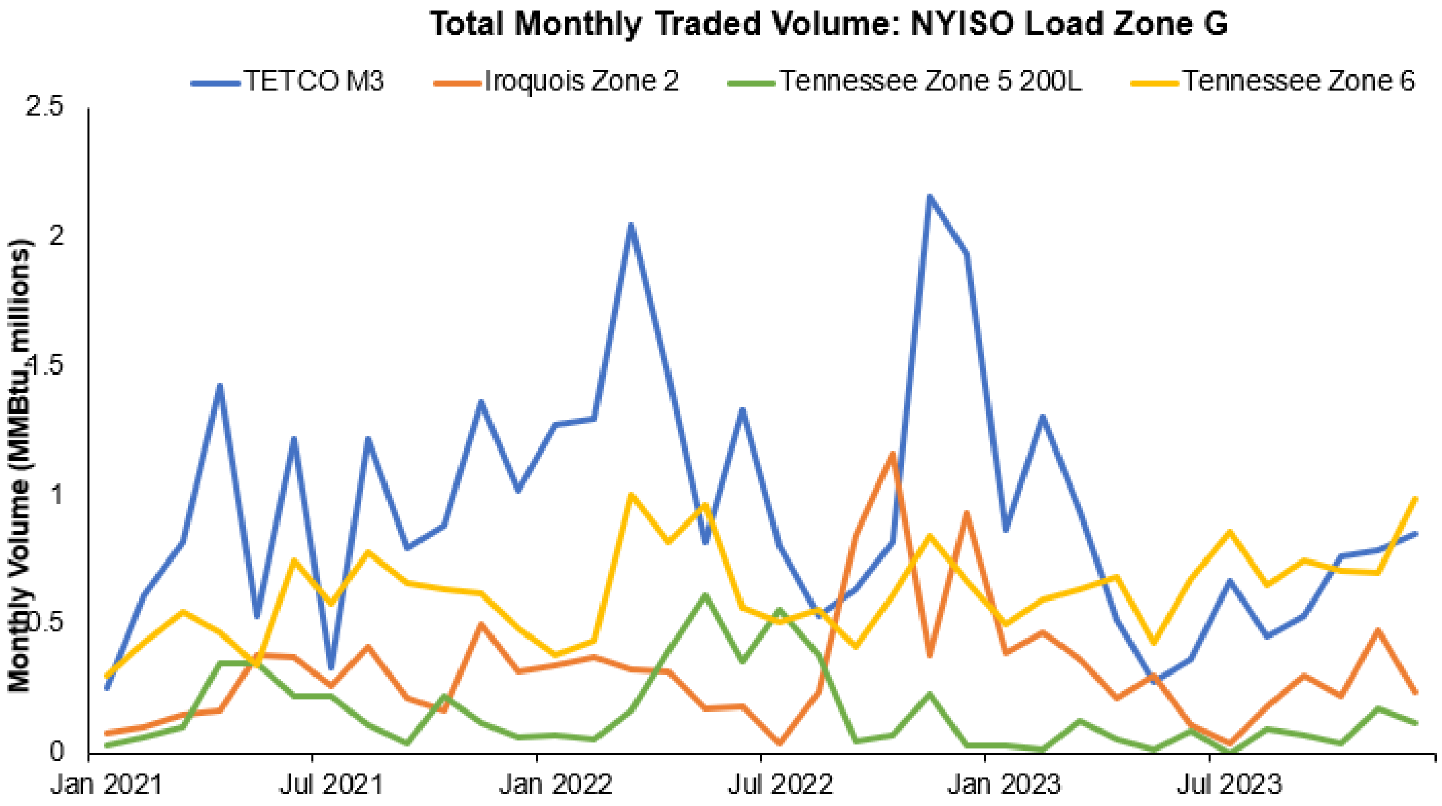
Load Zone G (Trade Volume, MMBTU)

Review of natural gas trade volume since 2021



Source: S&P CapIQ (obtained by AG)

Preliminary Recommendations for 2025 – 2029 DCR

Load Zone J

- Preliminary Recommendation: Transco Zone 6 NY; has a strong historical precedent as a trading hub in Load Zone J, has a strong correlation with market prices, is sufficiently traded, and is geographically well situated.
- Feedback on Preliminary Recommendation:
  - During winter months, prices available for interruptible/non-firm natural gas are more representative of pricing for Iroquois Zone 2 likely due to prioritization of firm gas use for retail gas demand using Transco Zone 6 NY capacity.
  - Request to further assess pricing during peak winter periods for gas generation that includes Iroquois Zone 2 pricing

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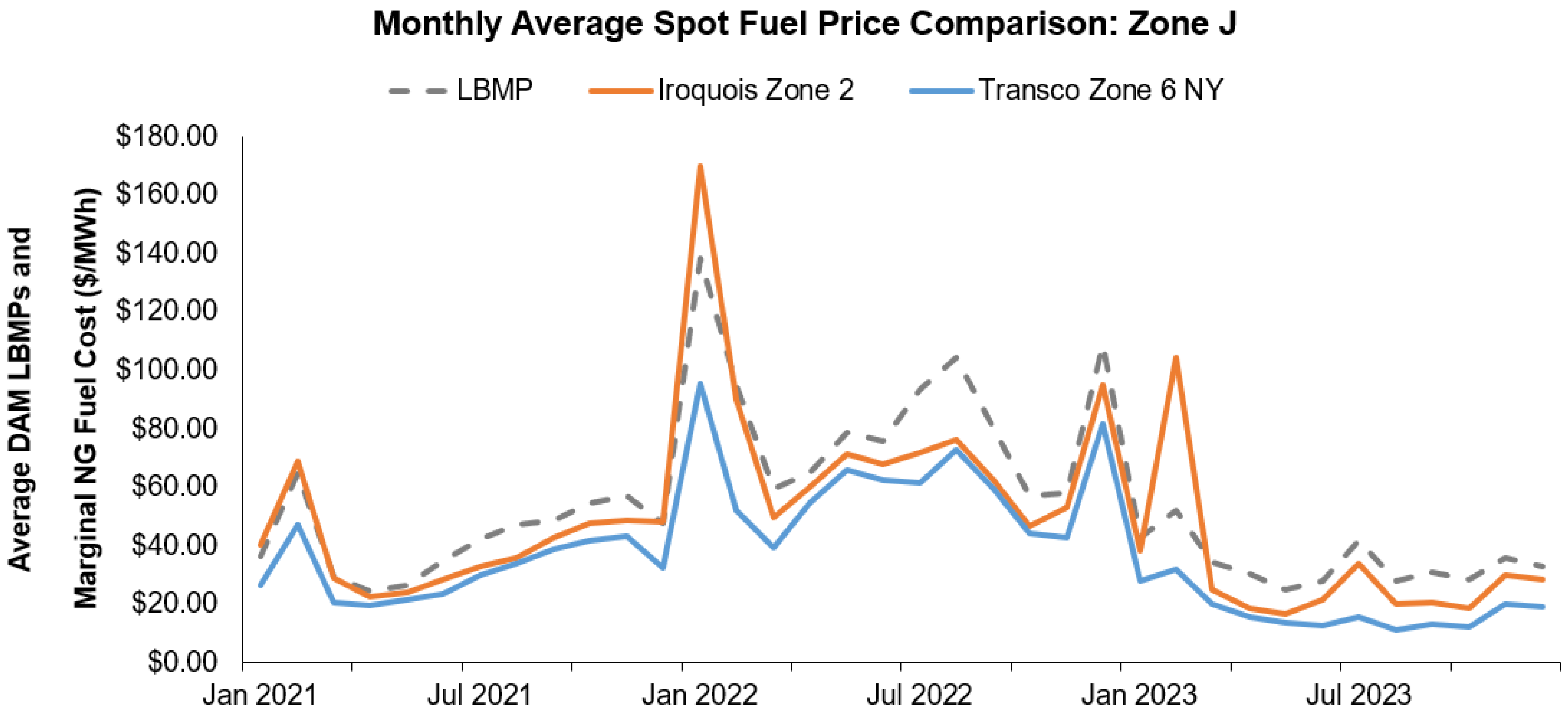
Load Zone J (LBMPs and Gas Prices)

Review of natural gas pricing trends since 2021



Notes: [1] "Marginal NG Fuel Cost" is calculated as the product of the natural gas price index and the heat rate of a GE 7HA.02 turbine, the 2021-2025 DCR reference peaking plant. The assumed heat rate is 8,890 Btu/kWh. **Sources:** [A] S&P CapIQ (Fuel Prices; obtained by AG). [B] NYISO (DAM LBMPs).

Load Zone J (LBMPs and Gas Prices)

Winter month gas hub and zonal LBMP correlations

Zone J Correlation: December - January and February

Month	*Gas Hub*	*Zonal LBMP Correlation*
December - January	Transco Zone 6 NY	0.8192
	Iroquois Zone 2	0.8949
February	Transco Zone 6 NY	0.7357
	Iroquois Zone 2	0.5199

Sources: [A] S&P CapIQ (Fuel Prices; obtained by AG). [B] NYISO (DAM LBMPs).

Note: Zonal LBMP correlations calculated from daily averages of hourly DAM zonal LBMPs

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Updated Draft Recommendations for 2025 – 2029 DCR

Load Zone J

- Updated Draft Recommendation:
  - Transco Zone 6 NY (February - November) & Iroquois Zone 2 (December – January); historical precedent as a trading hub in Load Zone J, improved correlation with market prices, sufficiently traded, and is geographically well situated.

Decision Criteria		Transco Zone 6 NY (February - November) & Iroquois Zone 2 (December – January)	Transco Zone 6 NY	Iroquois Zone 2
Market Dynamics		High LBMP Correlation	High LBMP Correlation	High LBMP Correlation
Liquidity		Medium	Medium	Medium
Geography		Yes	Yes	Yes/No (depending on season)
Precedent	2021-2025 DCR	Yes	Yes	No
	2022 SOM	Yes	Yes	No
	2021-2040 Outlook	Yes	Yes	No
Updated Recommendation		✓		

Financial Parameter Considerations

After-Tax Weighted Average Cost of Capital

Overview

- The cost of capital is estimated as the after-tax weighted average cost of capital ("ATWACC")
- The ATWACC weights the cost of the two types of capital—the cost of debt ("COD") and cost of equity ("COE")—based on the following formula:

$$ATWACC = \%\text{Debt} \times COD \times (1 - Tax\ Rate) + \%\text{Equity} \times COE$$

- %Debt and %Equity are the share of debt and equity capital of total capital (*i.e.*, the sum of debt and equity capital), respectively
- The cost of debt is adjusted by the tax rate, because interest on debt is generally tax deductible

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ATWACC (cont.)

Overview

- To estimate the ATWACC, we develop potential values for the COD, COE, tax rate and capital structure
- Potential values reflect consideration of multiple financial metrics including metrics for representative publicly-traded Independent Power Producers ("IPPs"):
  - AES Corporation ("AES")
  - NRG Energy, Inc. ("NRG")
  - Vistra Corp. ("Vistra")
  - Constellation Energy Corp. ("Constellation")[1]
- Potential values presented today for financial parameters reflect multiple considerations, including relationship between observable financial metrics and circumstances attendant to merchant project development in New York (including regulatory and market risks)

Note:

1. Used for COD and certain COE estimates, but not for capital structure analysis due to its origin (spinoff of an existing company) and the short history as a separate public entity.

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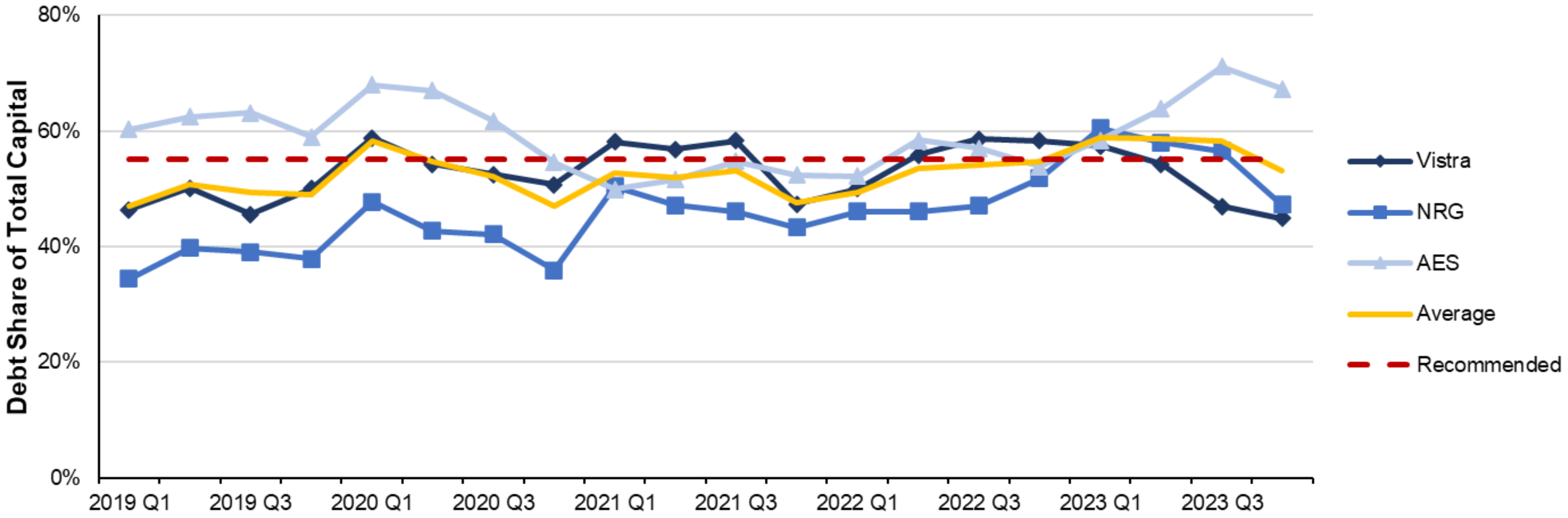
ATWACC (cont.)

Debt and Equity Shares of Capital

<u>Potential Debt and Equity Shares</u> = 55% Debt, 45% Equity

- Values based on:
  1. Balance of observed range of capital structures of new plants, which include more and less leverage
  2. Evolution of the capital structure of comparable IPPs (corporate, not project level)
- Also investigating whether public data is available on use of debt in merchant projects

Debt Share of Total Capital for Representative IPP Companies, Q12019 to Q42023



Note: Debt share of Total Capital is equal to net debt divided by the sum of net debt and the market value of equity
Source: S&P CapIQ (obtained by AG)

ATWACC (cont.)

Cost of Debt

Potential COD = 6.45%

- Potential value reflects two primary sources of relevant information
- First, yields to maturity of long-term bonds issued by comparable IPP companies
  - Potential differences for non-recourse, project debt
  - Observed yield to maturity range: 5.31% – 6.31%

Bond Yields of Representative IPP Companies, Dec. 16, 2023 – Mar. 15, 2024

Company	Credit Rating	Average Yield to Maturity
AES	BBB-	5.48
Constellation	BBB+	5.31
NRG	BB	6.31
Vistra	BB	5.67
Average	**n/a**	**5.69**
Median	**n/a**	**5.57**
Min	**BB**	**5.31**
Max	**BBB+**	**6.31**

Sources: S&P CapIQ; Bloomberg Data License (obtained by AG)

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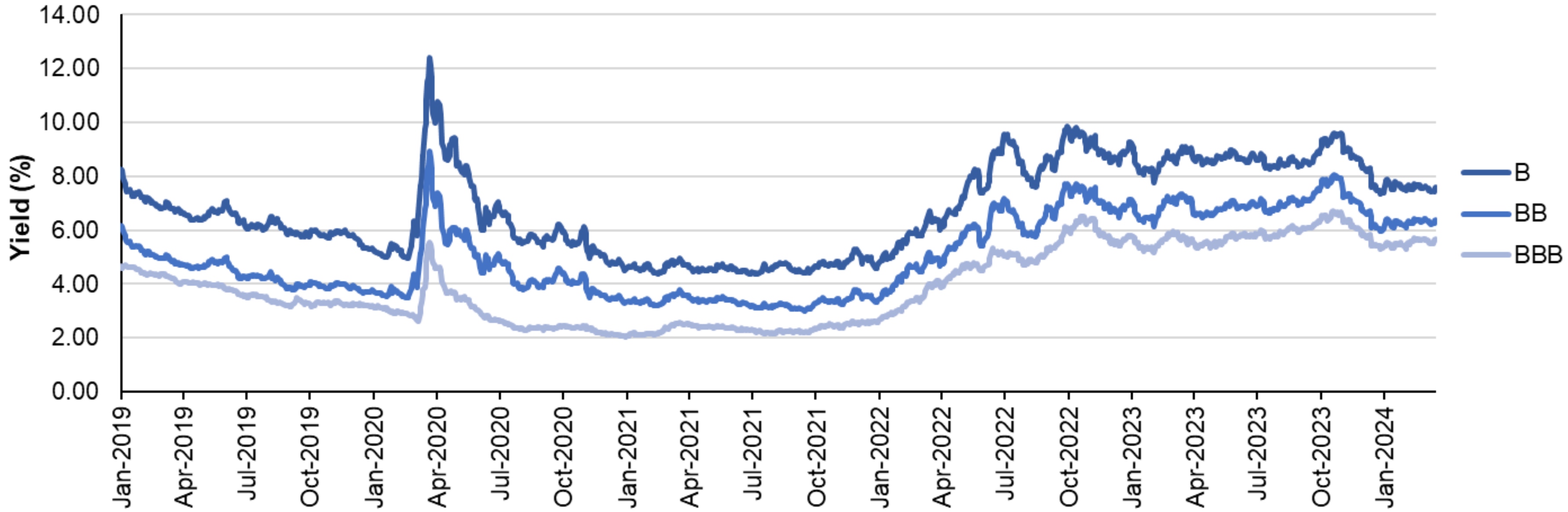
ATWACC (cont.)

Cost of Debt

- Second, bond yield of corporate debt for comparable credit rating:
  - 90-day Average for B credit rating: 7.59%
  - 90-day Average for BB credit rating: 6.26%
  - 90-day Average for BBB credit rating: 5.51%

Bond Yields for B, BB, and BBB Bonds, Dec. 1, 2019 to Mar. 15, 2024



Source: Federal Reserve Bank of St. Louis, FRED, ICE BofA US High Yield Index Effective Yield (series BAMLH0A2HYBEY, BAMLH0A1HYBBEY, and BAMLC0A4CBBBEY).

ATWACC (cont.)

Cost of Debt

- Yields from IPP bonds and generic B-BBB bonds reflect company-level (rather than project-level) risk
  - Unlikely to fully capture the risk profile of a specific project
- Potential value of 6.45% reflects:
  - Recent values of yield to maturity of IPPs and generic B-BBB bonds;
  - Differences between company- and project-level risks; and
  - Other market conditions related to the general economy (e.g. past volatility of yields and uncertainty about future rates)

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ATWACC (cont.)

Cost of Equity

<u>Potential COE</u> = 14.0%

- Project-level COE is unobservable and thus cannot be directly estimated
- To develop a project COE, a key source of information is the estimated company-level COE for publicly-traded IPP companies
  - We estimate COE using Capital Asset Pricing Model (“CAPM”)
  - Evaluate COE for multiple scenarios; each informs our potential value, with none reflecting a preferred scenario
  - In general, project-level COE ≠ company-level COE
    - In particular, we expect project COE > company COE, because of risk pooling (companies pool risks of many individual projects) and merchant risk for project development in New York likely exceeds risk of certain other assets held by IPPs in sample (e.g., regulated generation and transmission, merchant plants with PPAs or other long-term contracts)

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ATWACC (cont.)

Cost of Equity

- Estimation Method COE: CAPM
  - COE is assumed to be equal to the expected return for investors
  - Computed as:

$$COE = r_f + \beta_i \left[\underbrace{E(R_m) - r_f} \right]$$

Risk-free rate

Sensitivity of the stock security *i* to the market

Equity Risk Premium (“ERP”): Additional expected compensation required by equity investors in excess of the risk-free rate

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ATWACC (cont.)

Cost of Equity

- Estimation Method COE: CAPM
  - Assumed value for Scenario 1
  - Computed as:

$$COE = r_f + \beta_i \underbrace{\left[E(R_m) - r_f\right]}$$

Risk-free rate

90-day average 20-year treasury rate = **4.40%**.

Sensitivity of the stock security *i* to the market

Equity Risk Premium ("ERP"): Additional expected compensation required by equity investors in excess of the risk-free rate

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ATWACC (cont.)

Cost of Equity

- Estimation Method COE: CAPM
  - COE is assumed to be equal to the expected return for investors
  - Computed as:

$$COE = r_f + \beta_i \left[\underbrace{E(R_m) - r_f}\right]$$

Risk-free rate

Sensitivity of the stock security *i* to the market

Equity Risk Premium: Additional expected compensation required by equity investors in excess of the risk-free rate

Two estimates considered:

5.50%, based on Kroll estimate for the last 90 days

7.12%, a forward-looking estimate, using a discounted cash flow (DCF) model

ATWACC (cont.)

Cost of Equity

- Estimation Method COE: CAPM
  - COE is assumed to be equal to the expected return for investors
  - Computed as:

$$COE = r_f + \beta_i [E(R_m) - r_f]$$

Risk-free rate

Sensitivity of the stock security *i* to the market

Beta is computed using the following steps:

1. Estimate market beta for comparable IPPs
2. "Unlever" market betas and evaluate their range
3. "Relever" chosen beta using the target debt-to-equity ratio (D/E)

See Appendix for details

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ATWACC (cont.)

Cost of Equity: Scenario 1 using Historical ERP (scenarios further described on Slides 34-35)

Cost of Equity for Scenario 1 using historical ERP is calculated as follows:

$$COE = r_f + \beta_i \times \left[E(R_m) - r_f\right]$$

$$COE = 4.40\% + 1.11 \times [5.50\%]$$

$$COE = 10.51\%$$

ATWACC (cont.)

Cost of Equity: Scenarios

- We evaluate the COE under five scenarios and two alternative analytic approaches
  - Five scenarios are described on the following slide, with the difference between each scenario and Scenario 1 highlighted in blue
  - Two analytic approaches are considered
    - One in which we assume the IPP debt is risk-free (as assumed in calculations described above), and
    - One in which we assume the IPP debt is risky (using formulas described in the appendix)
  - Each scenario is computed using either the Kroll or forward-looking ERP
  - No particular scenario is preferred or intended as a “base” scenario in our evaluation; rather information from all scenarios is considered in the development of the potential COE

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ATWACC (cont.)

Cost of Equity: Scenarios

Scenario #	Beta	Sample IPPs	Risk-Free Rate
1	Computed using Bloomberg (5 years, monthly observations)	Vistra, NRG, AES	4.40%
2	Computed using ValueLine (5 years, weekly observations)	Vistra, NRG, AES	4.40%
3	Computed using Bloomberg (5 years, monthly observations)	Vistra, NRG (excluding AES)	4.40%
4	Computed using Bloomberg (2 years, weekly observations)	Vistra, NRG, AES, Constellation	4.40%
5	Computed using Bloomberg (2 years, weekly observations)	Vistra, NRG, AES	4.40%

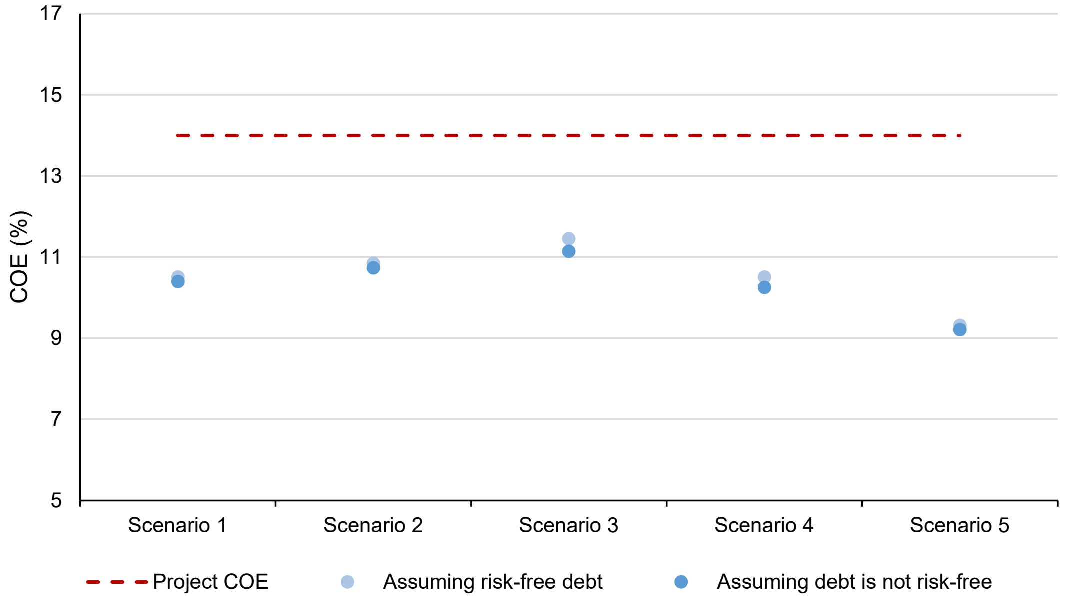
Note: Each Scenario (#1 through #5) is computed assuming: (i) debt is risk-free; (ii) debt is not risk-free.

ATWACC (cont.)

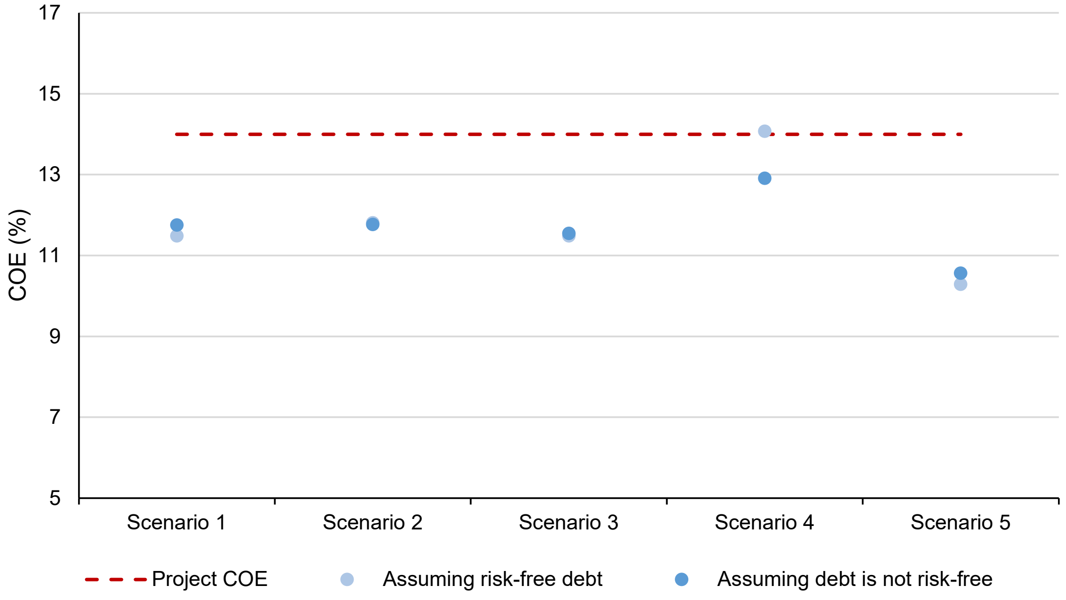
Cost of Equity: Kroll ERP (ERP = 5.5%)

- Using average representative IPP betas, COE range is 9.32% to 11.45% assuming risk-free debt and 9.21% to 11.14% assuming non-risk free debt
- Using upper-bound representative IPP betas, COE range is 10.29% to 14.08% assuming risk-free debt and 10.57% to 12.91% assuming non-risk free debt

Using Average of Representative IPP Betas



Using Upper Bound of Representative IPP Betas

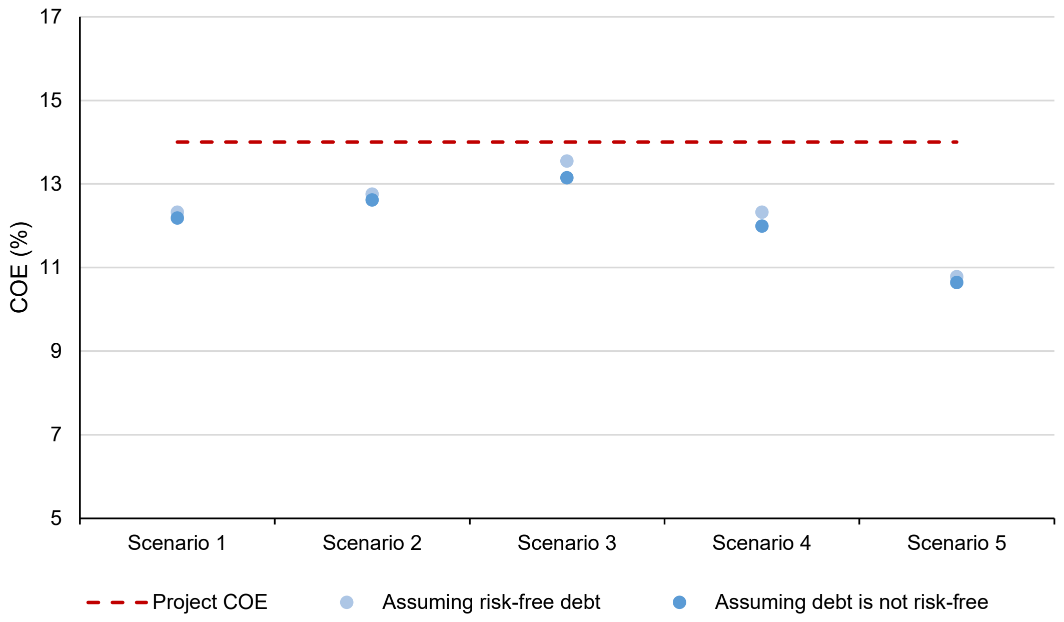


ATWACC (cont.)

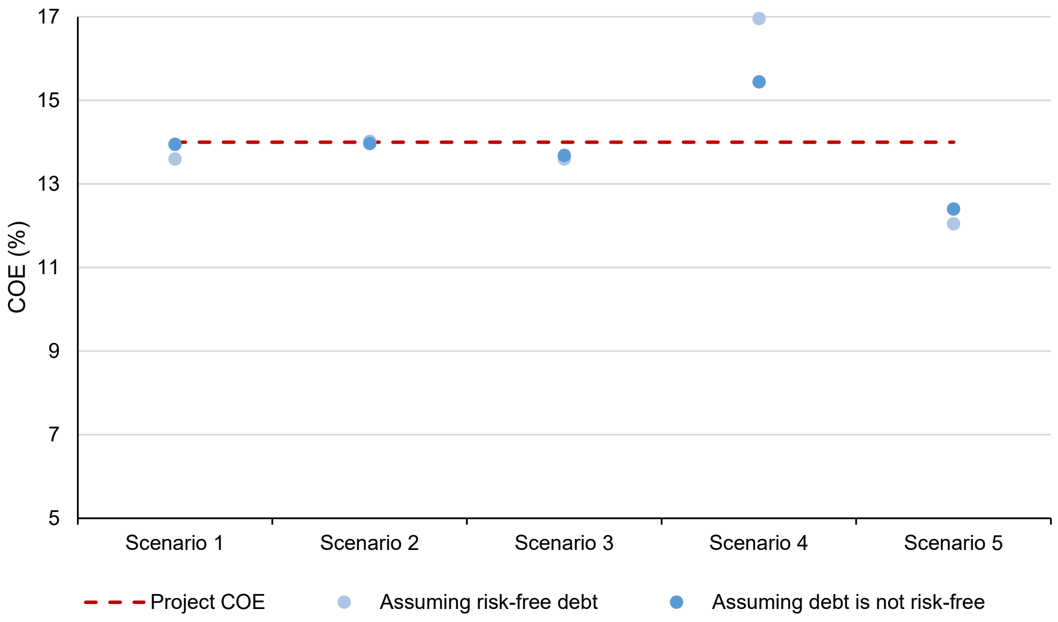
Cost of Equity: Computed Forward-Looking ERP (ERP = 7.14%)

- Using average representative IPP betas, COE range is 10.78% to 13.55% assuming risk-free debt and 10.64% to 13.15% assuming non-risk free debt
- Using upper-bound representative IPP betas, COE range is 12.05% to 16.96% assuming risk-free debt and 12.40% to 15.45% assuming non-risk free debt

Using Average of Representative IPP Betas



Using Upper Bound of Representative IPP Betas



ATWACC (cont.)

Cost of Equity: Scenarios

- Potential COE value of 14.0% reflects multiple considerations:
  - Evaluation of company-level COE
  - Evaluation of other financial metrics, sources, and relevant professional experience
  - Recognized differences between project-level COE and company-level COE (e.g., asset risk pooling, lower-risk assets and businesses held by IPP companies)
  - Accounting for merchant risks of project development in New York and the effect of recent changes in electricity and financial market conditions, including the effect of recent NYISO market rules (e.g., buyer-side mitigation/capacity accreditation changes) and effect of environmental regulations (e.g., Climate Leadership and Community Protection Act ["CLCPA"])

ATWACC (cont.)

Tax Rate

Preliminary Recommended Tax Rate (all locations, except Load Zone J) = 26.14%

- Preliminary recommended value assumes a federal tax rate of 21 percent, a state tax rate of 6.50 percent
- Combined, this yields a tax rate of 26.14%
  - 21% + 6.50% – (21% × 6.50%) = 26.14%

Preliminary Recommended Tax Rate (Load Zone J) = 33.13%

- Preliminary recommended value assumes a local tax rate of 8.85%, in addition to federal and state taxes.
- Combined, this yields a tax rate of 33.13%
  - 21% + (6.5% + 8.85%) – (21% × (6.5% + 8.85%))= 33.13%

Amortization Period

Amortization Periods for Technology Options

- Reminder of 2021-2025 DCR final recommendations:
  - Amortization Period: frame turbine (17 years) and energy storage (15 years)
- Choice of amortization period reflects a balance of considerations
  - Fossil plant physical life (before major overhauls) expected to be 20 years or more, but subject to environmental regulatory restrictions (e.g., 2040 zero emission energy requirement established by the CLCPA)
  - Experience with battery storage units is far greater than at the time of the last DCR
  - Many factors that create risks to cash flows, particularly over long-time horizons, including policy, market, technology and economic factors
  - As a result of differing risks, amortization period assumptions may differ by technology

Amortization Period (cont.)

Natural Gas Peaker

Potential Amortization Period for Natural Gas-Fired Frame Turbine: 13 years

- Option reflects accounting for the 2040 zero-emissions energy requirement of the CLCPA
- Consistent with methodology recommended for the last reset, recognizing that resolution of ongoing litigation is still pending
- Also considering the potential viability of alternative approaches that could provide for a longer amortization period in combination with other assumptions (e.g., net market revenues) addressing operations beyond 2040

Potential Amortization Period for Battery Storage: 20 years

- Option reflects the period of time over which developers may expect to recover initial fixed investments, particularly in light of major upgrades potentially required after 20 years
- Also considering the potential viability of longer amortization periods for battery storage, with appropriate capacity augmentation costs and potential adjustments to other assumptions

Property Taxes

Overview

- Where applicable law does not expressly provide a property tax exemption/abatement, it is assumed that peaking plant options outside Load Zone J will enter into a Payment in Lieu of Taxes (PILOT) agreement
  - Tax exemptions/abatements are applicable for energy storage options statewide,[1] as well as potentially for the fossil peaking plant options within Load Zone J.[2] Applicability of the Load Zone J specific tax abatement for the frame turbine option remains under review based on the current deadlines set forth in the applicable law
  - PILOT agreements are typically developed based on project-specific and regional economic conditions and are expected to vary based on the unique circumstances of each taxing jurisdiction and project at the time of negotiations.

Sources:
[1] New York Real Property Tax Law Section 487, available at https://www.nysenate.gov/legislation/laws/RPT/487.
[2] New York Real Property Tax Law Section 489-BBBBBB(3)(b-1), available at https://www.nysenate.gov/legislation/laws/RPT/489-BBBBBB.

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Property Tax Exemptions

NYC and Energy Storage Exemptions

- New York Real Property Tax Law Section 489-BBBBBB(3)(b-1) currently provides a 15-year tax abatement in New York City for the peaking plant underlying the NYC ICAP Demand Curve
  - The current tax abatement is set to expire on April 1, 2025. As such, we model results in Load Zone J both with and without extension of the 15-year property tax abatement and will continue to monitor the status of this abatement and any proposed extensions to the deadlines thereof
  - If applicable for the fossil-fired frame turbine option, based on the preliminary assumption of a 13-year amortization period for the fossil-fired frame turbine, the tax abatement would apply for the entire amortization period
  - If the abatement is not applicable for the fossil-fired frame for any period, the property tax rate would equal 4.77 percent, which is equal to the product of (1) the Class 4 Property rate (10.592 percent) and (2) the 45 percent assessment ratio[1]
- New York Real Property Law Section 487 provides a 15-year tax abatement statewide for energy storage facilities constructed after 1/1/2018 and before 1/1/2030, covering the entire 2025-2029 DCR period
  - A 15-year property tax exemption is assumed for all battery storage units in all locations. Based on the preliminary assumption of the 20-year amortization period for energy storage, energy storage would not be exempt from property taxes or PILOT payments for years 16-20.
    - For battery storage in Load Zone J, the 4.77 percent tax rate described above is used for all periods of the assumed amortization period not covered by the 15-year abatement (years 16-20 based on the preliminary recommendation of a 20-year amortization period)

Sources:
[1] New York City Department of Finance, "Property Tax Rates," https://www.nyc.gov/site/finance/property/property-tax-rates.page and New York City Department of Finance, "Determining Your Assessed Value," https://www.nyc.gov/site/finance/property/calculating-your-property-taxes.page.

PILOT Payments

Proposed Value and Analysis

- Outside of Load Zone J, **an effective PILOT rate of 0.6 percent is preliminarily proposed**
  - For locations other than Load Zone J, PILOT rate would apply for all years of the assumed amortization period for the fossil-fired frame turbine option and years 16-20 for energy storage (based on the preliminary assumption of the 20-year amortization period for energy storage)
  - The proposed 0.6 percent value is consistent with the range of current PILOTs for natural-gas fueled and battery storage units based on a review of data available through the New York State Comptroller's Office for 2021
  - Analysis calculated effective tax rate under publicly reported PILOT agreements for 10 natural gas-fueled generating stations in New York
    - Effective tax rates varied from 0.15% to 5.63% per year with median of 0.67%
  - Limited data is available for 4 existing battery storage projects
    - Effective tax rates ranged from 0.03% to 1.92% per year with median of 0.21%
- A 0.5% rate was used in the last reset, and 0.75% for the previous two resets

Property Taxes

Summary

- Preliminary recommended property tax rates are shown below:

	Load Zone J (NYC)		All Other Locations	
	Years 1-15	Years 16-20	Years 1-15	Years 16-20
Battery Storage	0%	4.77%	0%	0.6%

	Load Zone J with Extended Abatement	Load Zone J without Extended Abatement	All Other Locations
	Years 1-13	Years 1-13	Years 1-13
Fossil Fuel Units	0%	4.77%	0.6%

Continued Discussion of 5-Minute Real-Time Battery Modeling

5-Minute Battery Modeling

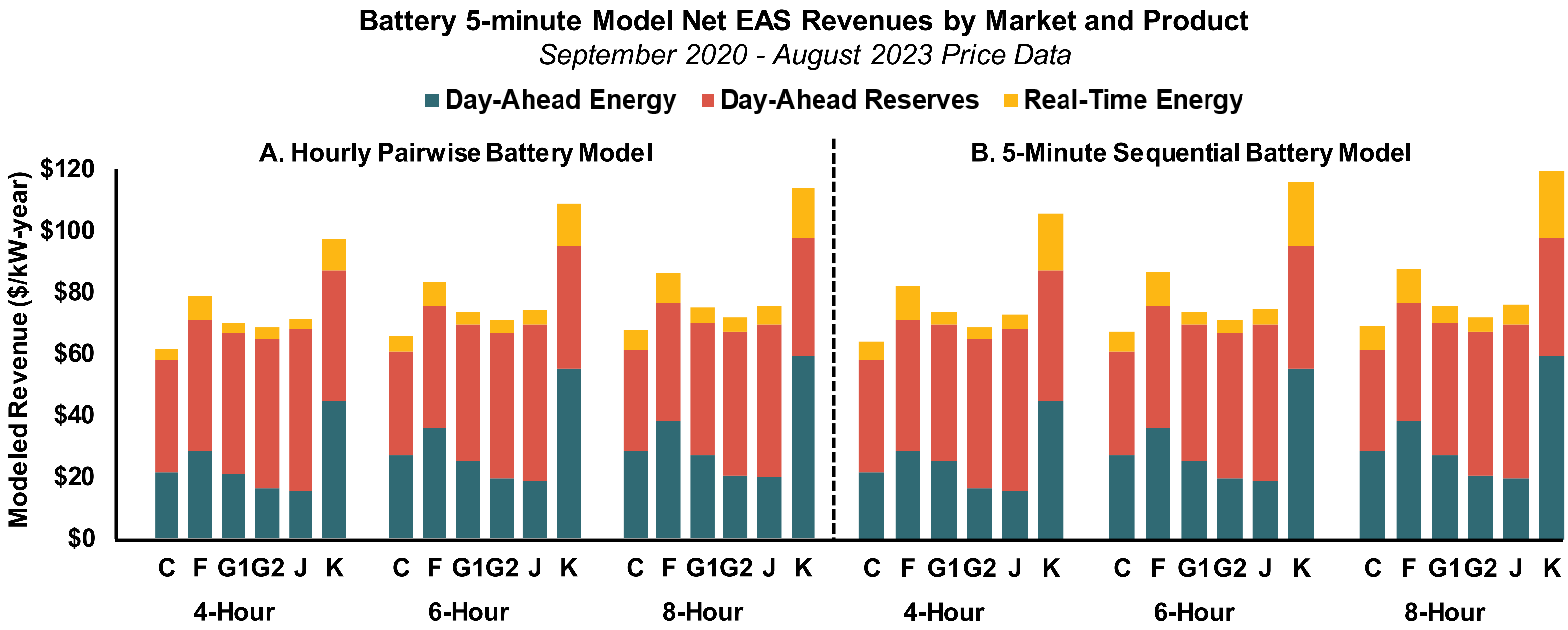
Reminder: Impact of 5-Minute Battery Modeling on Net EAS Revenues

- The impacts of switching from the previous hourly pair model to the 5-minute sequential model on net Energy and Ancillary Services ("EAS") revenues appear to be material and warrant the use of 5-minute real-time prices in the storage net EAS model
  - The net impact on net EAS revenues ranges from 0% to 8% for 4-hour batteries, depending on location, with the largest differences observed in Load Zone K
  - Results are similar, but smaller in magnitude, for 6-hour and 8-hour batteries
  - Day-ahead reserve and energy positions continue to provide a significant portion of net EAS revenues

Feedback about 5-Minute Battery Modeling from 3/25/2024 ICAPWG Meeting

1. Concern that AG's 5-minute battery model logic could not be operationalized by a real-world battery operator and may not reflect the expected capability of assets in the NYISO markets
2. Request for an example demonstrating the 5-minute battery model logic including DAM buyouts
3. Concern that AG's 5-minute battery model logic might result in excessively low net EAS revenues especially when DAM buyouts are required
4. Request for information about the frequency of cycling and overall discharge output relative to the assumed rated throughput of each battery technology

Reminder: Impact of 5-Minute Battery Modeling on Net EAS Revenues



Note: G1 corresponds to Load Zone G (Dutchess), and G2 corresponds to Load Zone G (Rockland).

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5-minute sequential model logic is feasible for real-world battery operators

- By 11 a.m. on the day prior to the Dispatch Day, NYISO posts the Day-Ahead schedule.
- Given this day-ahead schedule, the hypothetical battery operator could set its real-time *discharge* bids for each hour *h* of the subsequent day to operationalize the modeled strategy, defined as:

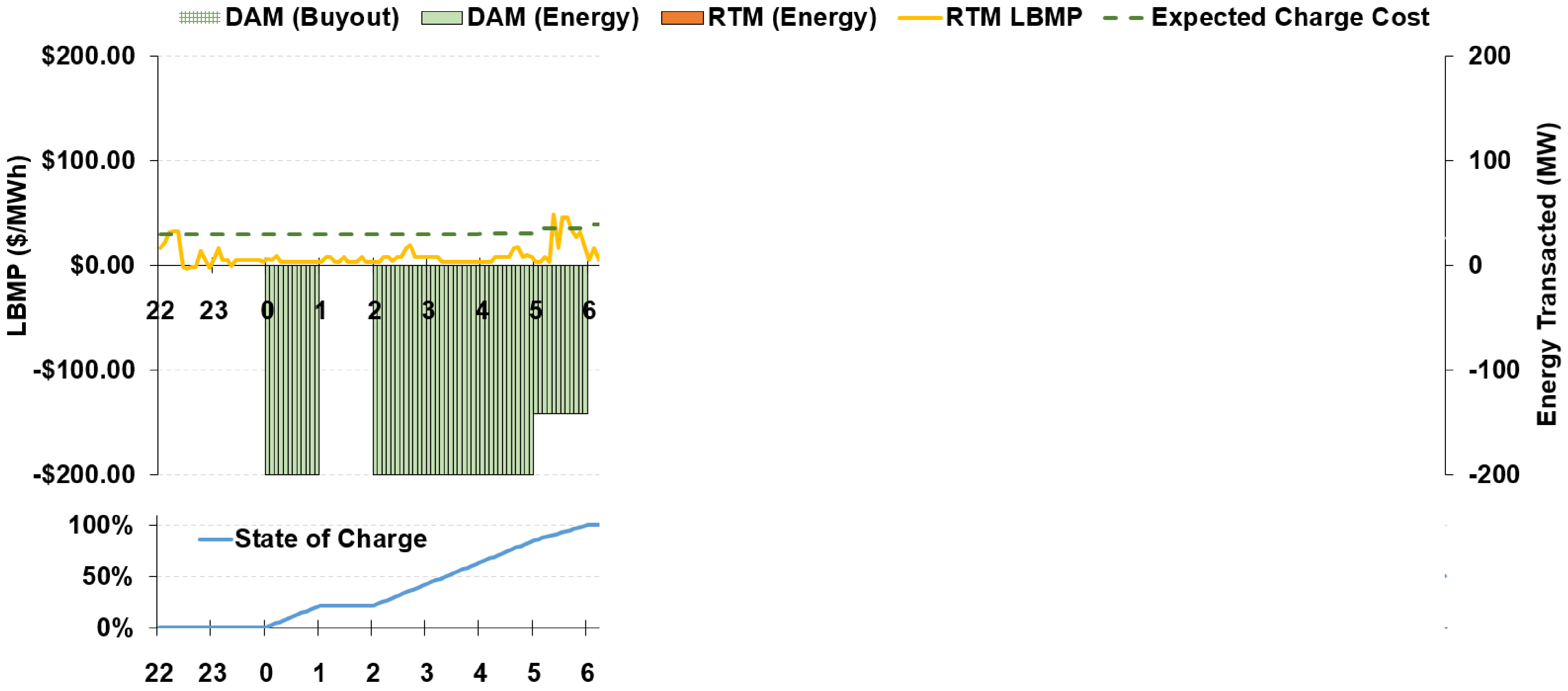
Expected Charge Cost + Hurdle Rate

where:

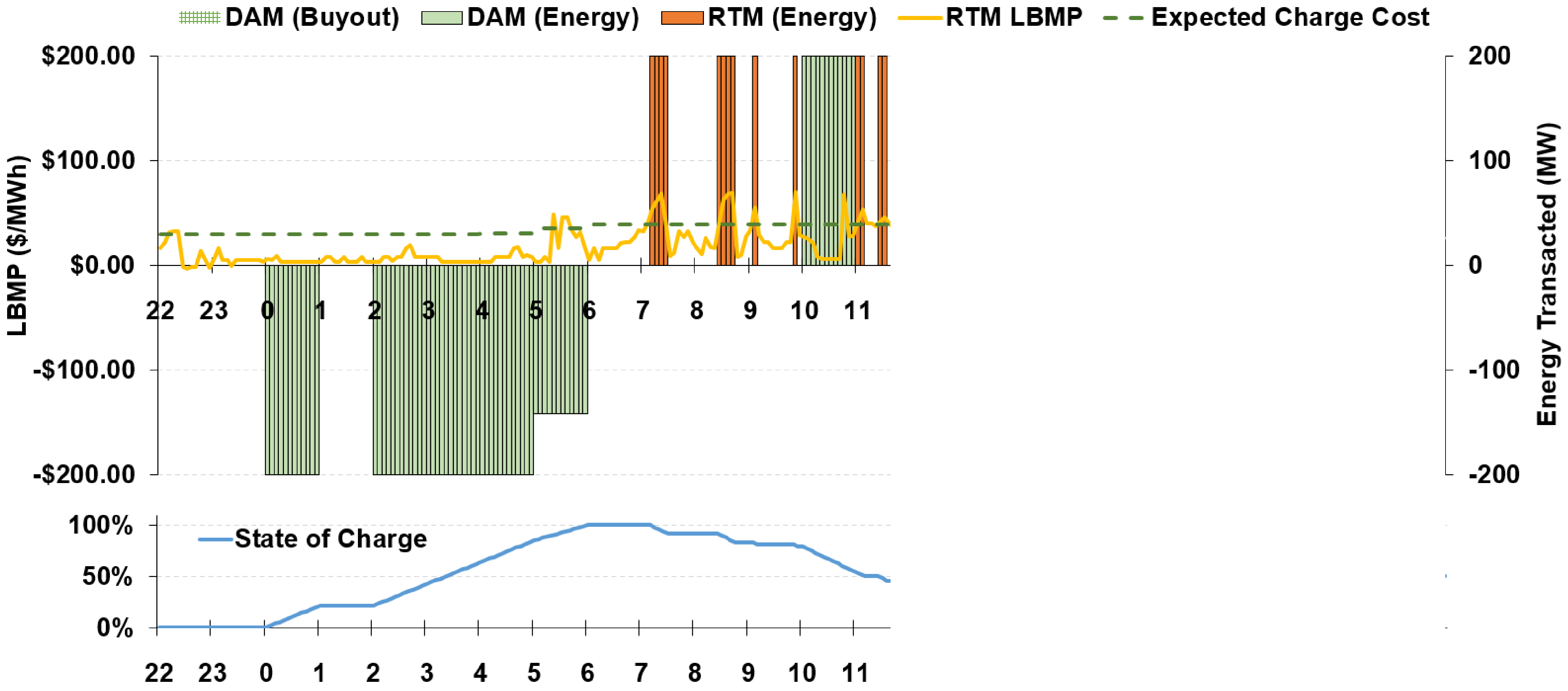
  - Expected Charge Cost equals -115% * (DAM LBMP + NYISO Rate Schedule 1 costs + transmission cost [for charging energy]), where DAM LBMP is set based on the lowest cost LBMP following hour *h,* NYISO Rate Schedule 1 costs reflects applicable administrative charges for recovery of NYISO cost of operations, and transmission cost reflects charges associated with use of the transmission system for charging energy.
  - Hurdle Rate is fixed *ex ante.*

- These bids/offers represent the minimum real-time LBMP required to deviate from the day-ahead schedule and could be submitted to NYISO well in advance of the real-time market deadline of 75 minutes before the start of the operating hour
- Analogous logic would allow operators to calculate bids for real-time *charging* whenever the real-time LBMP is sufficiently low

Example day for the 5-minute sequential battery model



Example day for the 5-minute sequential battery model



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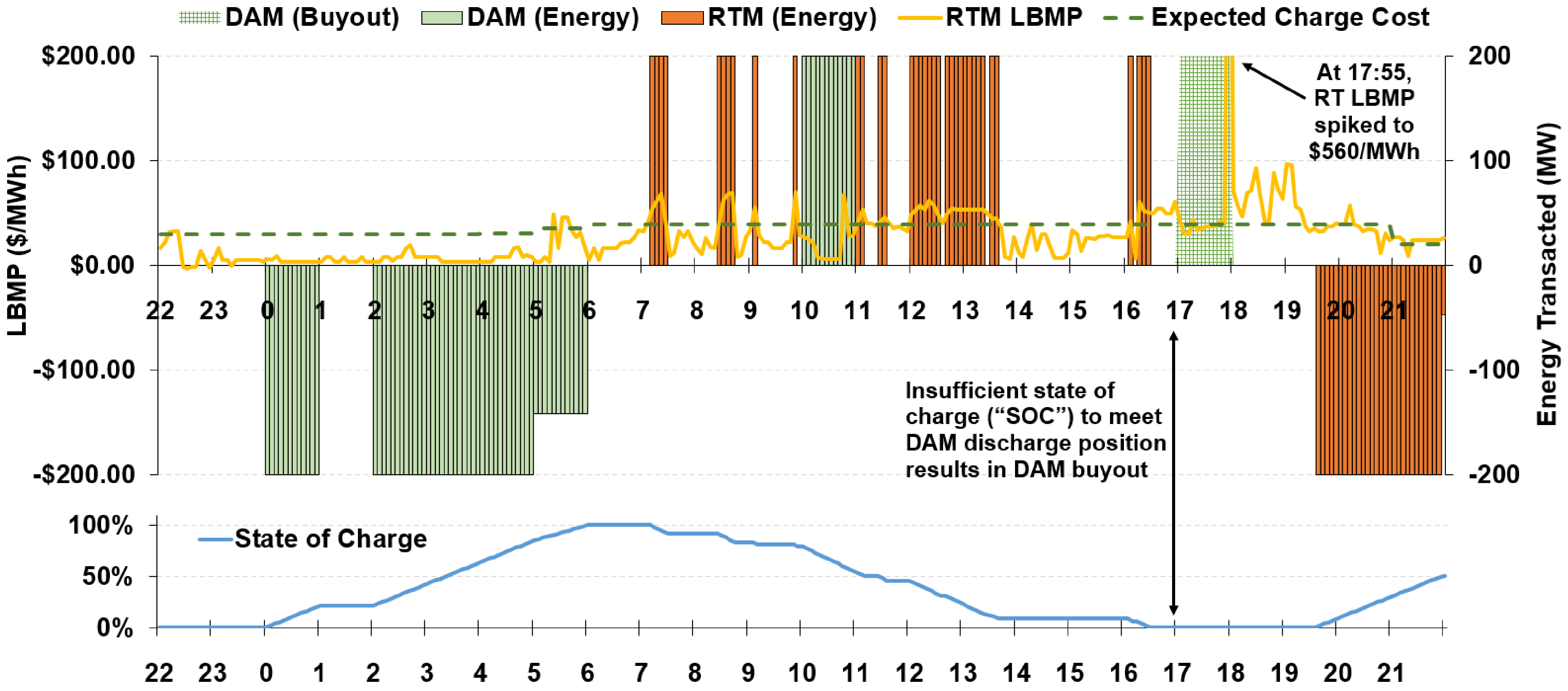
Example day for the 5-minute sequential battery model



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DAM energy buyouts have *de minimis* impact on overall net EAS revenues

- Under the 5-minute real-time battery model logic, DAM energy buyouts occur whenever satisfying the DAM energy schedule would violate the battery's physical operating limits.
- Currently, the model does not consider DAM energy buyout costs when choosing whether to dispatch in the real-time energy market.
- Certain stakeholders expressed concerns that the failure to consider DAM energy buyout costs could result in excessive DAM energy buyouts and artificially suppress overall net EAS revenues.
- However, assessment of the initial results for the 5-minute real-time model indicated that DAM energy buyouts have *de minimis* impact on overall net EAS revenues
  - We calculated total net EAS revenues for a version of the 5-minute battery model without any DAM buyouts. In effect, we assume batteries can meet their DAM energy positions regardless of violations of battery operating limits
  - The impact of DAM buyouts is less than one percent in all locations except Load Zone K (1.2%).

Zone	Hypothetical Impact of DAM Buyouts on Net EAS Revenues
C	0.35%
F	0.51%
G1	-0.51%
G2	-0.14%
J	0.84%
K	-1.23%

Note: Illustrative only – hypothetical 5-minute battery model without DAM buyouts ignores violations of the battery operating limits.

Across all locations/durations, batteries operate well below their maximum-rated throughput in the 5-minute battery model

- 1898 & Co.'s technical specifications assume sufficient capacity overbuild to ensure net battery energy capacity equal to (200 MW) * (nominal discharge duration), assuming at most one cycle per day on average.
  - One cycle corresponds to (nominal output) * (nominal discharge duration), e.g., 800 MWh for a 200 MW, 4-hour battery.
- As such, maximum-rated battery throughput is equal to (nominal output) * (nominal discharge duration) * (# of operating days).
- Assessment of preliminary results produced by the 5-minute real-time model indicate that batteries operate well below their maximum-rated throughput across all durations and locations.

Percentage of Total Discharged Energy Relative to Maximum-Rated Throughput by Duration and Zone
September 2020 - August 2023

	Zone					
Battery Duration	C	F	G1	G2	J	K
4-Hour	60%	47%	38%	28%	25%	70%
6-Hour	54%	53%	35%	28%	21%	61%
8-Hour	46%	43%	32%	25%	23%	55%

Ongoing Analysis

Work in Progress

Analysis Group

1. Additional review and consideration of amortization periods, NYISO-specific project risks, project financing experience, other financing parameter considerations
2. Economic evaluation of the current assumption that SCGT units have dual fuel and SCR emission controls in Load Zones C, F and G
3. 5-Minute Battery Model Enhancements
   a) Seasonal Hurdle Rates (Summer, Winter, and Shoulder Seasons)
   b) Ramping Constraints
   c) Sub 5-Minute Interval Pricing
4. Development of preliminary monthly reference point prices

Work in Progress

1898 & Co.

1. Provide publicly available information on land lease costs in Load Zone J and review Environmental Justice/Disadvantaged Communities areas to determine if these locations warrant any changes to land lease cost allowances or other factors (e.g., transmission/natural gas lateral assumptions)
2. Provide approximate acreage footprint for 96-hour of onsite hydrogen storage for informational purposes
3. Review NYISO site control requirements for site control for BESS to determine if changes are warranted to BESS acreage assumptions
4. Sales tax was excluded in preliminary estimates; continuing to evaluate stakeholder feedback related to sales tax applicability on materials and non-power-generating related (or storage related) equipment
5. Reviewing assumptions for property insurance to determine if any changes are warranted
6. Reviewing freeze protection requirements for gas turbines to determine if they warrant additional scope/cost
7. Providing updated plant performance information based on DMNC ambient conditions
8. Provide AG with breakout pricing for dual fuel to further evaluate SCGT technology design assumptions for Load Zones C, F, and G
9. Provide AG updated pricing for the 7HA.02 (with 15ppm NOx) without SCR emissions controls to further evaluate SCGT technology design assumptions for Load Zones C, F, and G

Work in Progress

1898 & Co.

10. Continue to assess stakeholder feedback about the potential need to account for the costs of a hedge on changes in the lithium carbonate raw material price (assumes that BESS price is indexed to raw material)
11. Continue to assess stakeholder feedback regarding the potential need to include an assumed annual expense related to right-of-way use for an underground transmission line interconnection
12. Continue to assess potential impacts of proposed NYSDEC rule for SF_6 on the assumed gas-insulated switchgear ("GIS") for Load Zone J switchyard.
13. Provide summary of the methodology to estimate BESS variable operating and maintenance ("VOM") costs; specific detailed information will not be provided because estimates include numerous confidential sources.
14. Preliminary allowance for funds used during construction ("AFUDC") costs are temporary placeholders and will be updated to align with AG's recommended ATWACC.

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Appendix - ATWACC

ATWACC

Cost of Equity: Beta

- "Unlevering" and "Relevering" of beta

Beta as reported by Bloomberg, obtained by estimating $R_{mkt} = \alpha + \beta_l R_i + \epsilon$, where R_{mkt} is the market return and R_i is the company return.

1. Step 1: Estimate beta for comparable IPPs ("Levered beta")
2. Step 2: "Unlever" the beta using the equation below:

Company debt over equity at the end of Q4 2023

$$\beta_u = \frac{\beta_l}{1+\frac{D}{E}}$$

Company	Levered beta (βl)	D/E Ratio	Unlevered beta (βu)
AES	1.05	2.05	0.35
NRG	1.10	0.89	0.58
Vistra	1.04	0.81	0.57
Average Unlevered Beta			0.50

3. Step 3: "Relever" the beta using the target D/E and the equation below:

$$\beta_l = \beta_u \times \left[1 + \frac{D}{E}\right]$$

Average Unlevered Beta	0.50
Target D/E	1.22
Relevered Beta (βl)	**1.11**

ATWACC

Cost of Equity: Beta

- “Unlevering” and “relevering” of beta assume representative IPPs to have negligible default risk (that is, risk-free debt)

- Assuming the debt of the representative IPPs is risky, the “unlevered” and “levered” betas are calculated as follows:

$$\beta_u = \frac{\beta_l + \frac{D}{E} \times \beta_d}{1 + \frac{D}{E}}$$

$$\beta_l = \beta_u + \frac{D}{E} \times (\beta_u - \beta_d)$$