NYISO 2019/2020 ICAP Demand Curve Reset: Draft Report Feedback

ICAP Working Group

July 22, 2020

Today:

- Review of ICAP Demand Curve Reset (DCR) Timeline
- Review of Feedback by Topic:
  - Peaking Plant Technology
  - Selective Catalytic Reduction (SCR) Emissions Control Technology
  - Capital Costs
  - Financial Parameters
  - Amortization Period
  - Gas Hub Selection
  - Net Energy and Ancillary Services (EAS) Revenue Model
  - Level of Excess Adjustment Factors (LOE-AFs)
- Appendix: Additional LOE-AF Information

Review of DCR Timeline

High-Level Schedule

- **Q4 2019 – Q1 2020**
  - Discuss DCR principles and framework
  - Evaluation of any potential tariff revisions
  - Review of net EAS revenue estimation method and data sources
  - Initial discussion of DCR assumptions
- **Q1 – Q2 2020**
  - Finalize net EAS modeling
  - Finalize DCR method and assumptions
  - Peaking unit technology assessment and cost estimates
  - Review LOE-AF methodology
  - Demand curve model development and discussion
- **Q2 – Q3 2020**
  - Finalize demand curve model
  - Final discussions and input
  - Draft report
  - NYISO staff draft recommendations
- **Q3 – Q4 2020**
  - Final report and NYISO staff final recommendations
  - NYISO Board review
  - FERC filing

Review of Draft Report Feedback

Draft Report Feedback

- Draft DCR Report was posted on June 5, 2020 and reviewed at the June 10, 2020 ICAPWG meeting
- Stakeholder comments were due by July 1, 2020
- Feedback was received from:
  - Suppliers/Generators: Independent Power Producers of New York, Cricket Valley Energy Center, Eastern Generation, Advanced Power North America, Ravenswood Generating, GenOn Energy Management, NRG Energy, and CPV Valley
  - New York Transmission Operators (NYTOs): Central Hudson Gas & Electric Corporation, Consolidated Edison Company of New York, New York Power Authority, New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation (National Grid), Orange and Rockland Utilities, Power Supply Long Island, and Rochester Gas and Electric Corporation
  - Load and Customer Stakeholders (Load Interests): New York State Department of Public Service Staff, City of New York, Multiple Interveners, and Consumer Power Advocates
  - Potomac Economics: Market Monitoring Unit (MMU)
- We thank all stakeholders for their participation and feedback in this process

Peaking Plant Technology

The draft report recommended that the GE 7HA.02 (H-class) unit be the peaking plant in all locations

- Parties generally expressed support for the recommendation:
  - No parties opposed the recommended use of the GE 7HA.02 frame turbine in all locations
  - Load Interests and the NYTOs noted their support for the use of the GE 7HA.02 turbine in all locations
- Analysis Group (AG) does not recommend any change to the selection of the GE 7HA.02 as the peaking plant technology in all locations

SCR Emissions Controls

The draft report recommended that units in Load Zones C, F, and G (Dutchess County) would not include SCR emissions controls, and that the units in Load Zones G (Rockland County), J, and K would include SCR emissions controls

- Multiple views were expressed in response to the draft recommendations:
  - Load Interests and the NYTOs supported the draft recommendation
  - Suppliers/Generators generally recommended that the plant design for Load Zone G (Dutchess County) be revised to include SCR emissions controls
  - The MMU noted that it may be appropriate to include SCR emissions controls in Load Zone G (Dutchess County) given concerns regarding the feasibility of permitting a unit without SCR emissions controls in the downstate region

SCR Emissions Controls (cont.)

- Upon further review, AG has updated its initial recommendation to include SCR emissions controls for fossil plants in Load Zone G (Dutchess County), while maintaining its prior recommendations for all other locations.
- This recommendation reflects several considerations:
  - Potential siting/permitting risk associated with permitting a dual-fuel unit without SCR emissions controls in the lower Hudson Valley
  - Recognition that the lower Hudson Valley also contains severe non-attainment areas and the peaking plant design should accommodate potential new plants throughout the region
  - Optionality to supply a larger quantity of energy by including SCR emissions controls compared to the emissions cap that would apply absent back-end controls, recognizing the limited scope of the net EAS revenue estimates (three year historic look back) and potential increases in demand for future peaker supply with increased renewables and potential peaker retirements downstate in the near future due to the NYSDEC “peaker rule”

Capital Costs

The draft report included detailed recommendations for total capital costs, by location, in Section II and Appendix B.

- Multiple views were expressed in response to the draft recommendations:
  - Load Interests opposed the inclusion of noise mitigation-related costs in Load Zones C, F, and G.
  - Suppliers/Generators generally expressed concerns that overall capital costs are underestimated, especially in the lower Hudson Valley and NYC. Particular focus was placed on site leasing costs in NYC; gas interconnection costs in the lower Hudson Valley and NYC; water and wastewater access costs; maintenance costs for the GE 7HA.02; staffing assumptions, and insurance costs.
  - The MMU noted that it is conservative to assume gas insulated switchgear (GIS) for plants in NYC, but did not recommend changing the assumption or estimate.

Capital Costs (cont.)

- Clarifications will be provided in the report text for certain EPC, Owner's Cost, and O&M estimate items
- Burns & McDonnell is considering whether the following items require any incremental adjustments to the estimated costs set forth in the draft report:
  - Site leasing costs in NYC
  - Gas interconnection costs in the lower Hudson Valley and New York City
  - Water and wastewater access costs
  - Development cost estimates
  - Major maintenance estimate for GE 7HA.02
  - Inclusion of sales tax for commodities
- To the extent changes are made for the final report, AG and Burns & McDonnell will identify any such changes at the time it reviews the final report with stakeholders
- No adjustments to noise mitigation costs are recommended. Burns & McDonnell's experience and comments by stakeholders shared in prior meetings indicates that noise mitigation costs are needed even on sites with substantially larger acreage

Key Financial Parameters

The draft report recommended a debt/equity (D/E) ratio of 55/45%, a cost of debt (COD) of 7.7%, and a return on equity (ROE) of 13%, for a weighted average cost of capital (WACC) of 10.09%. AG continues to monitor the impact of the COVID-19 pandemic on financial markets

- Multiple views were expressed in response to the draft recommendations:
  - Load Interests commented that the COD and ROE are too high, recommending a COD of 5.77% based on generic rates for a "BB" rated entity, and a ROE of 10.5% based on the national average for regulated electric utilities plus 100 basis points
  - Suppliers/Generators commented that the COD and ROE were too low given the risks associated development in NY and project financing, with one party recommending a COD of at least 8%, and parties recommending a ROE in the range of 14-17%. They also suggested the D/E debt leverage is too high, recommending 40/60 outside NYC and 50/50 in NYC
  - The NYTOs raised issues with analysis of PILOT agreements, recommending that the property tax rate outside NYC should be 0.5% instead of 0.9%
  - The MMU recommended a COD in the range of 6-6.5%
- A more detailed analysis of considerations is presented across the following slides

Key Financial Parameters (cont.)

Analysis of Factors Impacting the WACC

- AG's assessment recognizes that the financial parameters should reflect system conditions at a time of capacity need, which may be substantially different from current market conditions
- AG's initial recommendations reflect the inter-relation between the financial parameters, and different approaches to project development, including:
  - Cost of debt
  - Return on equity
  - Capital structure
  - Amortization period

Cost of Debt (COD)

Considerations

- Generic corporate bond indices
  - Long-term (pre-COVID-19 pandemic)
    - Pre-COVID-19, yield had been declining, at lower levels
    - Generic corporate bond yields over the past year (Feb. 2019 – Feb. 2020) ranged from: 3.5% to 5.1% (BB) and 5.0% to 7.1% (B)
    - Median yield for B rated bonds over this period was 6.1%
  - Near-term
    - After period of illiquidity with rates as high as 12.39% (3/23/2020), rates for below-investment grade debt have decreased substantially
    - More recently, average yield for B rated bonds is 6.78% (two weeks 6/22 – 7/3/2020) and 6.61% (four weeks 6/8 – 7/3/2020)
- Company-specific debt issues
  - Company-specific offers capture firm, sector risks, unique from indices

Final Recommendation (updated): 6.7%

Return on Equity (ROE)

Considerations

- Broad capital market effects
  - Lower risk-free rate prior to the COVID-19 pandemic likely to continue with Federal Reserve stimulus
  - Greater risk premium due to the COVID-19 pandemic, although the duration of this effect is uncertain
  - On net, lower cost of capital than in prior years (e.g., 2016 DCR)
- Current approach balances estimates of ROE from several perspectives, including publicly traded independent power producers (IPPs) (based on CAPM) and project finance – both perspectives provide useful information on cost of capital, even if capital structures associated with each perspective differ:
  - ROEs for publicly traded IPPs range from 6.6% to 10.5%, but represent a small sample (2 companies) with non-IPP business activities (e.g., competitive retail supply, renewables)
  - Project finance ROEs generally range from low- to upper-teens
- Our assessment also recognizes that the financial parameters should reflect system conditions at a time of capacity need, which may be substantially different from current market conditions

Return on Equity (ROE) (cont.)

Considerations

- New investment in a peaking plant in New York faces a mix of market and regulatory risks that can both *increase and decrease* market returns – *for example*:
  - Policy and regulatory changes that may affect market outcomes, including changes in loads and the mix of resources participating in the New York markets (e.g., CLCPA, environmental regulations, etc.)
  - NYISO market rule changes that may affect market outcomes (e.g., Master Plan and Grid in Transition initiatives, including potential ancillary service enhancements)
  - Our assessment accounts for these various considerations, along with the general risks facing new merchant investment

Final Recommendation (unchanged): 13.0%

Capital Structure (D/E Ratio)

Considerations

- AG's recommendation reflects a reasonable assumption about capital structure given the range of structures used by various entities developing projects
  - Our assumption reflects the inter-relation between the financial parameters, and different approaches to project development (e.g., balance sheet, project finance)
  - Accounts for various details of financing (e.g., financial hedges) implicitly, not explicitly
  - Reflects holistic assessment of financial parameters, including amortization period, and differences in market conditions between NY and neighboring RTO's
  - Preliminary recommendation is in line with capital structures from other recent similar studies in neighboring markets – 65/35 in PJM, 60/40 in ISO-NE – but reflects lower assumed debt leverage

Final Recommendation (unchanged): 55/45 D/E ratio

Weighted Average Cost of Capital

Final Recommendation

Financial Parameters Summary		
Inputs	**Recommended Value**	
Return on Equity	13.0%	
Cost of Debt	6.7%	
Debt to Equity Ratio	55/45	
WACC	9.54%	
	zone J	Other zones
Tax Rate	36.4%	27.5%
ATWACC	8.20%	8.52%

Amortization Period

The draft report recommended a 17-year amortization period for all fossil-powered units, and a 15-year amortization for all BESS units

- Multiple views were expressed in response to the draft recommendations:
  - Load Interests expressed that the amortization period for both fossil plants and storage should be 20 years, due in part to the residual value of assets
  - The NYTOs (1) raised concerns that the proposed amortization periods may be too short but recognized current factors that may support use of the recommended values and (2) indicated that recommendations for this DCR should not establish future precedent.
  - Suppliers/Generators commented that amortization period for fossil plants should not exceed 15 years
- AG does not recommends any changes to the recommended values of a 17-year amortization period for fossil-powered units and a 15-year amortization period for BESS units
  - The DCR consultant is required to evaluate all assumptions each reset and thus no precedent is created by any recommendations for this DCR, particularly if market conditions and circumstances change between resets

PILOT Rate

The draft report recommended use of a 0.9% PILOT rate for locations outside NYC

- NYTOs recommended a PILOT rate of 0.5%:
  - NYTOs argued that Brooklyn Navy Yard should be excluded on the basis that the PILOT rate should be based on units outside of NYC
  - NYTOs argued that PILOT rates should be calculated on the basis of the original project amounts, inflated to $2019 using the implicit GDP deflator
- Upon further review, AG has updated its initial recommendation, and recommends a PILOT rate of 0.8% for locations outside NYC
  - This rate reflects the exclusion of Brooklyn Navy Yard from the dataset
  - PILOT payments are negotiated with taxing authorities based on the nominal price of the project at the time of construction, which is consistent with the AG's methodology of calculating PILOT rates based on the original project price
  - PILOT rates did not show any discernable trend for changes over time across the dataset, thus adjustments for temporal effects do not appear warranted

Gas Hub Selection

The draft report recommended: (1) TGP Z4 (200L) for Load Zone C; (2) Iroquois Z2 for Load Zones F, G (Dutchess County), and K; (3) TETCO M3 for Load Zone G (Rockland County); and (4) Transco Z6 (NY) for Load Zone J. It also recommended a $0.27 per MMBtu gas transportation adder for Load Zones C, F, and G, $0.20 per MMBtu in Load Zone J, and $0.25 per MMBtu in Load Zone K.

- Multiple views were expressed in response to the draft recommendations:
  - Load Interests and the NYTOs supported the draft report gas hub recommendations
  - Suppliers/Generators generally oppose the recommendations for Load Zones C and G (Rockland County):
    - For Load Zone C, they recommend either TGP Zone 6 or Iroquois Zone 2. If TGP Z4 (200L) remains the recommendation, they recommend a transportation cost adder in the range of $1.00-$1.60/MMBtu
    - For Load Zone G (Rockland County), they recommend Algonquin City Gate or TGP Zone 6. If TETCO M3 remains the recommendation, they recommend a transportation cost adder of $0.65/MMBtu
  - The MMU supported the draft report gas hub and transportation adder recommendations

Gas Hub Selection (cont.)

- AG does not recommend changes to the recommended gas hubs or associated transportation adders
  - In both Load Zone C and Load Zone G (Rockland County), the selected hubs are reasonable selections, balancing geographic proximity, market dynamics, and liquidity
  - Geographic proximity is reasonable given liquidity concerns with other geographically appropriate gas hubs in each of these locations
  - Transportation adders are reasonable given considerations of pipeline tariff charges and market-based pricing for gas supply and pipeline transmission rights

Net EAS Revenues Logic

The draft report recommended no changes to the general net EAS model logic for fossil plants. It outlined a new approach for the estimation of battery storage net EAS revenues in Section IV.

- Multiple views were expressed in response to the recommendation:
  - Load Interests recommended that (1) due to the COVID-19 pandemic, a one-time adjustment to the historical data relied on to calculate net EAS revenues, should be pursued resulting in removal of data from September 2019-August 2020 from the calculation; (2) the proposed LOE-AF methodologies and preliminary values are reasonable
  - The NYTOs supported the net EAS model logic and LOE-AF methodology and preliminary values
  - Suppliers/Generators commented that (1) the current net EAS model overstates revenues for fossil plants due to gas price uncertainty, pipeline restrictions, gas market illiquidity, and the excessive foresight, particularly in real-time market participation; and (2) the CARIS base case used to determine the LOE-AF values should be updated to reflect resource assumptions consistent with the 2020 RNA base case
  - The MMU recommends that the net EAS model logic for dual fuel resources be updated to eliminate the assumed cost of obtaining fuel to provide reserves, as resources can operate on ULSD in response to reserve pick-up events

Net EAS Revenues Logic (cont.)

- AG does not recommend any changes to the current net EAS model logic for fossil plants
  - The model provides a reasonable estimation of the net EAS revenues that a peaking plant would be expected to earn in the NY markets
    - The model captures all costs to participating in DAM and RTM markets, including start-up and variable operating/production costs and need to buy-out of DAM position, and opportunities to earn net EAS revenues in both the DAM and RTM
      - Hourly LBMPs (less sensitive to transient price spikes)
      - Natural gas costs include 10-30% intraday premium for purchases and intraday discount for sales relative to day-ahead gas prices, which vary by Load Zone, reflecting potential operating costs, financial risks, or balancing costs to securing fuel in real-time (or securing fuel in advance but selling back such fuel)
      - Cost to a DAM reserve position will vary with natural gas markets conditions for dual fuel units, given relative costs of securing gas supply instead of relying on ULSD

Net EAS Revenues Logic (cont.)

- AG does not recommend any changes to the current net EAS model logic for fossil plants
  - One-time adjustments for particular historical market conditions, such as excluding market outcomes in certain periods, are not generally recommended
    - Market outcomes, such as those arising from the COVID-19 pandemic and past severe winter weather conditions, do occur and affect net EAS revenues; thus, they should be accounted for in estimating net cost of new entry (CONE)
    - AG does not recommend any restrictions or other adjustments to the use of market data from 2020 due to changes in market outcomes associated with the COVID-19 pandemic

Net EAS Revenues Logic (cont.)

The draft report recommended no changes to the general approach to accounting for the tariff prescribed level of excess (LOE) conditions and included preliminary LOE adjustment factor (LOE-AF) values based on the 2019 CARIS Phase 1 base case

- AG does not recommend any changes to the general approach to accounting for the tariff prescribed LOE conditions and methodology for determining the LOE-AF values used in the net EAS model

- AG recommends that the calculation of the LOE-AF values be updated to reflect more current information regarding supply and load (see the Appendix for additional information)
  - LOE-AFs have been updated based on certain changes to the 2019 CARIS Phase 1 base case to reflect more current information
    - Supply resource changes, including retirements and new resources, resulted in a net reduction of 992.5 MW of capacity
    - Updated load scaling given changes in resources and peak load forecasts

Net EAS Revenues Logic (cont.)

Changes Due to Updated LOE-AF Values

- The analysis below shows an estimate of the changes due to updating the LOE-AF values, holding all else in the model constant
- The version of the model used for this analysis reflects our current recommended assumptions

Net EAS Revenues ($/kW-Year)					
Zone C	**Zone F**	**Zone G (Dutchess)**	**Zone G (Rockland)**	**Zone J**	**Zone K**
($1.46)	($0.88)	($2.29)	($2.86)	($5.54)	($3.23)

Monthly Reference Point Price ($/kW-Month)					
Zone C	**Zone F**	**Zone G (Dutchess)**	**Zone G (Rockland)**	**Zone J**	**Zone K**
$0.16	$0.09	$0.29	$0.36	$0.77	$0.61

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Appendices

LOE-AF Calculation - Capacity Modifications

The following changes to the amount of capacity available in the 2019 CARIS Phase 1 base case have been made for the period at issue for this DCR (2021-2025)

Year	Unit	Zone	MW	Notes
2021	Somerset (aka Kintigh)	A	-687	Removal (Retired)
	Ball Hill Wind	A	-100	COD moved to 2023
	Cassadaga Wind	A	-126	COD moved to 2022
	Albany LFGE	F	-4.5	Removal (IIFO)
	Taylor Biomass	G	-19	Removal (previously included in the 2019 CARIS Phase 1 base case but did not meet the inclusion rules for the 2020 RNA base case)
	HTP	J	-660	Removal as capacity supply resource for the purposes of calculating the "prescribed level of excess", but the line is physically retained in the database for Energy and emergency assistance
	Hudson Ave GT 3	J	-16	Removal (IIFO)
	West Babylon IC	K	-49	Removal (Retired)
2022	Cassadaga Wind	A	126	Addition (Updated COD)
	Eight Point Wind	B	102	Addition
	Baron Winds	C	238	Addition
	Roaring Brook Wind	E	80	Addition
	Calverton Solar EC	K	23	Addition
2023	Ball Hill Wind	A	100	Addition (Updated COD)
2024	(No changes noted)			
2025	(No changes noted)			
	Net Impact:		-992.5	

LOE-AF Calculation – Load Scaling Impact

The table below shows the amount of load added to the as-found system in order to arrive at the prescribed level of excess

Load Scaling for Updated LOE-AFs (presented on July 22, 2020)

Year	Load Zones A-F	Load Zones G-J	Load Zone J	Load Zone K	NYCA
2021	658	711	104	468	1,837
2022	1,141	613	5	562	2,316
2023	1,252	667	41	691	2,610
2024	1,277	637	7	776	2,690
2025	1,301	655	12	861	2,817

Load Scaling for Preliminary LOE-AFs (presented on April 22, 2020)

Year	Load Zones A-F	Load Zones G-J	Load Zone J	Load Zone K	NYCA
2021	1,280	1,282	650	598	3,161
2022	1,357	1,275	641	619	3,251
2023	1,439	1,378	737	686	3,503
2024	1,517	1,393	747	760	3,670
2025	1,583	1,376	729	831	3,791

LOE-AF Calculation – Updated Values

Load Zone	Peak Period	January	February	March	April	May	June	July	August	September	October	November	December
Central (Zone C)	Off-Peak	1.088	1.114	1.085	1.025	1.037	1.050	1.037	1.044	1.033	1.035	1.030	1.050
	On-Peak	1.113	1.122	1.105	1.032	1.047	1.051	1.058	1.061	1.046	1.046	1.043	1.061
	High On-Pea	1.199	1.184	-	-	-	1.064	1.098	1.146	-	-	-	1.111
Capital (Zone F)	Off-Peak	1.015	1.011	1.005	1.016	1.014	1.024	1.027	1.033	1.025	1.027	1.014	1.025
	On-Peak	1.020	1.017	1.001	1.027	1.036	1.030	1.042	1.047	1.036	1.036	1.021	1.035
	High On-Pea	0.991	1.005	-	-	-	1.036	1.068	1.107	-	-	-	1.016
Hudson Valley (Zone G)	Off-Peak	1.029	1.026	1.018	1.017	1.016	1.026	1.026	1.034	1.024	1.029	1.017	1.026
	On-Peak	1.041	1.038	1.019	1.025	1.025	1.030	1.043	1.045	1.034	1.036	1.033	1.041
	High On-Pea	1.027	1.032	-	-	-	1.049	1.085	1.142	-	-	-	1.039
NYC (Zone J)	Off-Peak	1.027	1.023	1.016	1.016	1.015	1.022	1.022	1.028	1.020	1.026	1.014	1.024
	On-Peak	1.025	1.033	1.015	1.021	1.020	1.019	1.027	1.031	1.021	1.028	1.024	1.031
	High On-Pea	1.021	1.025	-	-	-	1.031	1.059	1.118	-	-	-	1.028
Long Island (Zone K)	Off-Peak	1.053	1.057	1.035	1.022	1.032	1.037	1.043	1.039	1.035	1.042	1.038	1.053
	On-Peak	1.083	1.073	1.033	1.025	1.021	1.035	1.070	1.073	1.038	1.045	1.048	1.065
	High On-Pea	1.071	1.066	-	-	-	1.049	1.164	1.268	-	-	-	1.063