RE: Case 19-E-0283; Comments on the Staff Whitepaper Regarding Marginal Cost of Service Studies

July 20th, 2023

Dear Secretary Phillips,

The Clean Energy Parties (CEP), a coalition of clean energy trade associations and member companies active in New York[1], submit the following comments in response to the Staff Whitepaper Regarding Marginal Cost of Service (MCOS) studies submitted on March 27th, 2023 in Case 19-E-0283.

I. Introduction and Summary

The New York Public Service Commission (Commission) Staff Whitepaper, released in March 2023, represents important progress towards the goal of arriving at transparent, consistent, and accurate Marginal Cost of Service (MCOS) studies to be used as the foundation for development of updated Demand Reduction Value (DRV) and Locational System Relief Value (LSRV) components of the Value of Distributed Energy Resources (VDER) Value Stack, as well as other tariffs and programs that compensate Distributed Energy Resources (DERs) for grid value.[2] The CEP appreciate the diligent work of Staff in reviewing an extensive evidentiary record compiled by the parties during the summer of 2019 through mid-2020. The Staff proposals in the Whitepaper are constructive and provide actionable steps that the Commission and the Joint Utilities can take to develop more consistent and transparent MCOS studies that accurately reflect the benefits of DERs.

The list below provides a summary of the conclusions and recommendations provided by the CEP in this comment letter:

[1] The CEP is a group of aligned commenters including the Solar Energy Industries Association, the New York Solar Energy Industries Association, New York Battery Energy Storage Technology Consortium, the Coalition for Community Solar Access, Vote Solar, the Alliance for Clean Energy New York, and Advanced Energy United. Our perspective is informed by on-the-ground experience developing clean energy projects including the expertise of the following participating companies (among others): Cypress Creek Renewables, Dimension Renewable Energy, Ecogy Energy, Finlo Solar, New Leaf Energy, Nexamp, NineDot, Pivot Energy, Sunnova, and US Light Energy

[2] The Distribution Load Management Program (DLM) is one example of a tariff or program whose pricing and structure is derived from MCOS studies.

- An accurate MCOS study requires high quality inputs of growth-related construction costs, inclusive of multi-value projects if applicable. For utilities that use ongoing and historical growth-related construction costs for their inputs, a robust dataset is needed.
- The "run" and planning horizon of the MCOS studies should be a minimum of 10 years to ensure that the analysis includes both short-term and medium-term capital investments that can be deferred through DER deployment, demand response and efficiency.
- Load forecasting methodologies must align with state energy policy goals including the Climate Leadership and Community Protection Act (CLCPA), specifically so that the forecasts adequately reflect expectations for load growth driven by beneficial electrification within buildings and transportation.
- Load forecasts should use probabilistic scenario analysis and counterfactual assumptions regarding DER capacity additions.
- The escalator used to estimate the inflation rate for investment annualization calculations should be comprised of a blended rate that considers current inflation that is presently pressuring industry supply chains as well as a publicly available forward looking inflation measure such as the 10-Year Breakeven Inflation Rate published by the Federal Reserve Bank of St. Louis.
- Including avoided non-jurisdictional transmission costs in MCOS studies is supported by Commission precedent in other areas and is needed to accurately reflect the benefits of DERs to the transmission system.
- In addition to producing accurate MCOS studies, it is critical that these study results be used to create clear, effective price signals for distributed generation projects to respond to. The CEP encourage the Commission to expeditiously initiate stakeholder discussions regarding how MCOS results translate into VDER value stack compensation so improvements can be implemented in parallel with MCOS improvements.

The CEP understand that the New York utilities have great diversity among their systems along with different planning methods. Despite these likely continued differences in planning methods, a critical objective of this proceeding is to arrive at a process that results in accurate, transparent, consistent, and comparable MCOS studies. Based on the record of evidence in this proceeding, differences in areas such as derivation of input capital costs or required reserve margins may continue to persist without jeopardizing MCOS study outputs. However, other items, such as load forecasting methods, time horizons, and others will require harmonization to ensure that results are comparable and consistent across utilities.

II. Review of the Staff Whitepaper

The CEP provide the following comments, organized by topic, in response to the Staff Proposals included in the Whitepaper. In instances where Staff has posed a question to stakeholders within the Whitepaper, the CEP provide responses within the relevant section.

I. Joint Utilities' Methodologies

Staff correctly identifies that a reasonable MCOS study methodology "should reflect the current likelihood that capacity relief projects would be required given recent expectations regarding load growth. (p. 7). Staff also notes that attaining consistent MCOS estimates that reasonably reflect the actual incurred capital costs of serving load growth requires some standardization in the study approach.

As discussed in previous comments of the CEP, a traditional MCOS is separate and distinct from a study of the costs that can be avoided by DERs which should instead be determined based on the specific transmission and distribution infrastructure costs that can be deferred or avoided via adoption of DERs.[3] Staff's proposal is correct in its identification of the advantages of the approach taken by Central Hudson and National Grid which "comprehensively evaluate the need for growth related projects over their entire service territories"(p. 7) with traditional utility solutions to address violations identified during load flow analyses. The objective to develop an MCOS value for use in determining the avoided distribution benefit of DERs requires an expansive approach that assesses the impact of DERs on the entire system. The CEP remain concerned that the MCOS study methodologies that don't involve a comprehensive systemwide study will struggle to overcome the inconsistencies and limitations discussed within the Whitepaper and therefore reiterates the need for system wide analysis of load growth.

The observation by Staff that the MCOS approach taken by Con Edison, O&R, NYSEG, and RG&E is highly driven by the investment projects that are selected for inclusion in the MCOS study is prescient. Given

[3] CEP Comments, 11/25/2019, pp. 23-24

the potentially lumpy nature of distribution system investment to handle load growth, there may be a limited number of planned or recently completed projects for inclusion in the study or projects that are unrepresentative of the norm. Unrepresentative or insufficient project data poses a risk of sending inaccurate price signals to DERs if not mitigated.

In response to this concern, Staff seeks input on the duration of the historic period that should be considered when identifying marginal investments for inclusion in MCOS studies. The CEP posits that if Con Edison, O&R, NYSEG, and RG&E are allowed to continue using their existing methodology, that they be required to demonstrate that they have assembled a robust and representative dataset of projects, including multi-value projects that have a system expansion component. Building this dataset may necessitate inclusion of projects occurring within the last several years if there are a small number of ongoing and future projects to accommodate load growth. This flexibility may be needed in smaller service territories such as Central Hudson and RG&E. If historical projects are included in the MCOS study dataset, it is critical that they be adjusted for inflation to the present to ensure that costs are accurate and representative of current price levels.

II. "Run" of the MCOS Studies

The purpose of the DRV in the Value Stack compensation formula is to provide a long-run price signal regarding the value of DERs, which are being compensated to supplant long-lived utility assets deployed via long-term planning and development processes, and depreciated over decades. The DRV price signal, in combination with the other elements of the Value Stack, will then spur entry of DERs to the marketplace commensurate with the ability of the price signal to support the construction and operation of these DERs. Staff cites long running Commission precedent on marginal cost studies that "the pricing relevance or use case for the MCOS study should influence the "run" of the cost estimate." (Whitepaper p. 10) Staff is right to apply a long-run view in this application given, that VDER is intended to compensate long-lived assets for their value in avoiding long-lived and long-lead-time utility investments.

VDER eligible technologies typically have useful lives of 20 years or more and often have financing terms of 10 years or more. As a result of the long-lived nature of DERs and the investments they supplant, the price signal must be derived over a time period that is aligned with the time horizons utilized by utilities for long term system planning and by infrastructure investors evaluating the viability of DER investments. The Staff proposal clearly recognizes this where it states “the pricing relevance or use case for the MCOS study should influence the “run” of the cost estimate.” (p. 10) Staff correctly notes that the use case for the MCOS study extends beyond the Value Stack to energy efficiency and demand response and that the MCOS time horizon must be aligned with those employed by private capital making investments that have benefits to the distribution system.

The discussion regarding the “blank slate approach” (p. 11) is somewhat of a red herring as no party has proffered the use of a fully hypothetical system wide long run approach with an indefinite timescale. Staff rightly observes that the National Grid and Central Hudson approaches do not use the blank slate approach, but instead model load growth scenarios on the existing system within a defined timespan. In this section, Staff reaches the right conclusion in that the run of the MCOS studies must be aligned with the decision-making criteria for investments that the price signal is intended to drive. This conclusion is consistent with the REV Track 2 Order and represents progress in aligning the MCOS studies with the principles enumerated by the Commission for the Value Stack.[4]

III. **Planning Horizon of the Joint Utilities’ MCOS Studies**

Staff’s recommendation to use a 10-year time horizon (p. 16) for MCOS studies is grounded in the record and is sufficient to fully consider the rapid changes in the distribution system that will arise out of implementation of the Climate Leadership and Community Protection Act (CLCPA). New York has aggressive public policy goals regarding electrification of transportation and heating and a 10-year time horizon is needed to incorporate the impact of electrification on distribution infrastructure investment needs. Staff is correct in its rejection of short run headroom analysis as a rationale for claiming zero marginal costs as such an approach is inconsistent with the needed “run” and time horizon given NY’s aggressive initiatives to speed electrification.

IV. **Reliability vs. Growth Related Investments**

For utilities other than National Grid and Central Hudson, Staff recommends that “to the extent that some of the replacement projects could also be considered as growth-related projects, utilities should incorporate these multi-value projects in the sample of construction projects used to calculate $/kW

[4] Case No. 14-M-0101, Order Adopting a Ratemaking and Utility Revenue Model Policy Framework, 5/19/2016. pp. 118-125, Appendix A

investment costs for a traditional NERA method MCOS study." (Whitepaper p. 18) The CEP support this approach and observe that it would be consistent with the analysis of multi-value projects conducted in other proceedings before the Commission as described below.

In the Coordinated Grid Planning Process (CGPP) proceeding, the New York Utilities submitted their updated CGPP proposal which includes a framework for conducting analysis of Bulk and Local Transmission and Distribution (LT&D) investment needed to support achievement of the objectives of the CLCPA, the Accelerated Renewable Energy Growth and Community Benefit Act, and the need to maintain reliability. The Commission initiated the CGPP proceeding to develop an integrated planning process to identify and construct LT&D infrastructure solutions, in coordination with any necessary bulk transmission infrastructure expansion, throughout NY to support the optimal deployment of these investments. The CGPP framework presently under review in Case 20-E-0197 has provisions for analysis of multi-value projects that serve renewable energy integration and reliability needs. The New York Utilities stated that "customers benefit when projects address multiple needs, and the Commission should encourage identification of projects with multiple benefit streams." [5]

In comments submitted by ConEd and O&R in the CGPP proceeding, they expressed support for the CGPP framework and elaborated on their experiences with multi-value projects that improve asset conditions, reliability, resilience, safety, and security. [6] While ConEd and O&R identified unresolved issues pertaining to the timescales of required investments, they reiterated the benefits of executing dual and triple purpose projects in a coordinated planning process.[7] ConEd and O&R also suggested further refinements to the CGPP proposal regarding analysis of multi-value projects which were supported by the CEP. The CEP's previous comments commended the utilities for recognizing "the enormous ratepayer benefit of dual or triple purpose projects and identified this gap in their revised proposal and requested directions to develop further process accounting for emerging needs."[8]

In its pending base distribution rate case, ConEd provided an extensive discussion of multi-value projects in its Energy Infrastructure and Operations Panel (EIOP). The testimony of the EIOP explains how ConEd evaluates projects in the following categories: Risk Reduction/Reliability; New Business & System Expansion; Replacement; Equipment Purchase; Safety & Security; Environmental; and Information

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[5] Case No. 20-E-0197, Coordinated Grid Planning Process Proposal, 12/27/2022, pp. 27-28
[6] Case No. 20-E-0197, Comments of ConEd and O&R, 2/28/2023, pp. 2, 7
[7] Id, p. 9
[8] Case No. 20-E-0197, Comments of Clean Energy Parties, 3/27/2023, p. 2

Technology. The EIOP testimony states that "the Company always seeks to develop multi-value projects that serve more than one goal, which increases the cost efficiency of our capital investments."[9] Given the fact that multi-value projects by definition serve more than one need, many of these projects should be included in the construction cost dataset if one of the value streams includes increased system capacity.

Staff's recommendation to include replacement projects that have a growth component in the sample of construction projects used to calculate $/kW investment costs would ensure consistency with other proceedings before the Commission. Multi-value projects that result in a material expansion of distribution capacity should be included in the construction cost dataset. The CEP recommend that projects exceeding a pre-defined growth or expansion threshold be included in the construction cost dataset. The CEP suggest that this benchmark be set at a capacity expansion threshold of 10%, but encourage stakeholder feedback on the methodology and thresholds used to identify multi-value projects with a growth component for inclusion in the construction cost dataset.

It is important that multi-value projects that result in tangible system capacity expansions be included in the construction cost datasets used to inform the MCOS to ensure that the datasets used by the utilities are robust and capture all relevant spending on growth related infrastructure.

V. Load Forecasting Methodology

The Staff proposal correctly recommends a robust 10-year load forecast in alignment with the planning horizons and "run" of the MCOS study. New York has aggressive electrification targets which are now translating to tangible policies, implementation pathways, and visible capital investment. The Scoping Plan released by the Climate Action Council counsel in December 2022 in accordance with the CLCPA, outlines recommendations for New York to realize economy-wide reductions in Greenhouse Gas (GHG) emissions of 40% by 2030 and 85% by 2050 from 1990 levels.[10] During the development of the record, the JU stated that "the extent to which EV and building electrification should be factored into future forecasts is unclear before the DEC adopts rules."[11] Given the developments in New York over the past three years, the JU's recommended approach is outdated and would result in underestimating load growth and therefore undervaluing efficiency, demand response, and DERs. The full weight of New

[9] Case No. 22-E-0064, Electric Infrastructure and Operations Panel, 1/28/2022, p.10
[10] New York's Scoping Plan, Available at https://climate.ny.gov/resources/scoping-plan/
[11] Joint Utilities Reply Comments, 12/13/2019, p. 2

York's political leadership, state agencies, and regulatory bodies are promoting the electrification of transportation and heating sectors and therefore, estimates regarding increases in electric loads attributable to these policies can and should be conducted at the present time.

a. Transportation Electrification

Between strong federal and state policies and programs, New York is poised to rapidly electrify vehicular transportation. Governor Hochul directed the State Department of Environmental Conservation (DEC) to issue regulations that require all new light duty passenger vehicles to be zero emissions by 2035.[12,13] In addition, New York has well-funded programs to support EV Make Ready infrastructure, highway corridor electrification (Evolve NY), rebates on new EV purchases (Drive Clean NY), and other programs that are existing or in development to spur EV adoption for light duty and Medium and Heavy-Duty vehicles.

In a recent Order regarding rate designs for EV use cases, the Commission discussed the "the necessity to help accelerate EV charging station deployment, and thus further reduce friction for greater EV adoption across the light-, medium- and heavy-duty market segments."[14] In an Order in the Make Ready proceeding, the Commission stated "In sum, electrification is key to decarbonizing the transportation sector, given the powerful progress and trajectory decarbonizing the power sector. Initially the focus is on light-duty vehicles, where the prospect for near term progress is greatest and where existing commitments provide clear direction."[15]

In the Climate Action Council's Integration Analysis Technical Supplement to the Scoping Plan, every scenario for transportation electrification results in material increases in electric consumption for EV charging that are multiples of present transportation sector electricity demand.[16]

b. Clean Heat Adoption

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[12] Press Release: Governor Hochul Drives Forward New York's Transition to Clean Transportation Available at https://www.governor.ny.gov/news/governor-hochul-drives-forward-new-yorks-transition-clean-transportation

[13] DEC Announces Adoption of Advanced Clean Cars II Rule for new Passenger Cars and Light-Duty Truck Sales, December 29, 2022 https://www.dec.ny.gov/press/126879.html

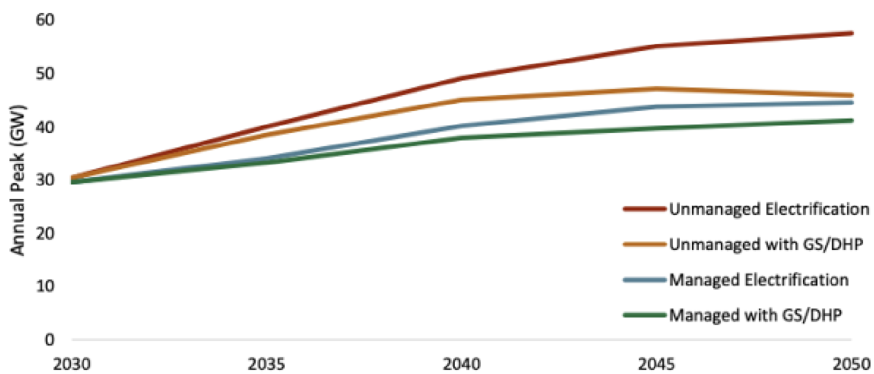
[14] Case 22-E-0236, Order, 1/19/2023, pp. 24-25

[15] Case 18-E-0138, Order 7/16/2020, p. 7

[16] w York State Climate Action Council Scoping Plan, Appendix G: Integration Analysis Technical Supplement, December 2022, Figure 26

Between strong federal, state and NYC policies/programs, New York is poised to rapidly electrify domestic heating. Key findings from the Climate Action Council's Integration Analysis state that approximately one to two million efficient homes are electrified by heat pumps by 2030 across compliant scenarios.[17] The Council also notes that without high investment in building efficiency and higher peak heat pump performance, electric peaks could rise to up to 58 GW by 2050.[18] The figure below compares annual peak load under different managed and unmanaged electrification scenarios.[19]

Figure 66. Building Sensitivities Annual Peak Load



In 2022, the NYS Clean Heat Program supported the installation of 22,293 heat pump projects, and the Long Island Power Authority (LIPA) supported 7,385 heat pumps, for a total of more than 29,500 heat pump projects installed across New York State.[20] This represents a significant increase in projects compared to the 21,500 heat pump projects installed in 2021.[21] Due to significant program growth, Con Edison petitioned the Commission for additional program funding in February 2022, which the Commission authorized on August 11, 2022.[22] On March 1, 2022, Orange & Rockland made incentive level adjustments for certain heat pump projects to manage its remaining authorized program budget, and in early 2023 Central Hudson petitioned for additional program funding.[23] National Grid, NYSEG and

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[17] Integration Analysis Technical Supplement New York State Climate Action Council Scoping Plan, December 2022, p. 9

[18] Integration Analysis Technical Supplement New York State Climate Action Council Scoping Plan, December 2022, p. 89

[19] Integration Analysis Technical Supplement New York State Climate Action Council Scoping Plan, December 2022, p. 90, Figure 66

[20] New York State Clean Heat Program 2022 Annual Report, 4/3/2023, p. 3

[21] New York State Clean Heat Program 2021 Annual Report, 4/1/2022, p. 4

[22] New York State Clean Heat Program 2022 Annual Report, 4/3/2023, p. 18

[23] Id. p. 16 & 20

RG&E also experienced significant increases in heat pump adoption, resulting in 115% and 50% increases in MMBtu savings from 2021, respectively.[24]

In addition to the uptick in heat pumps via the Clean Heat Program, recent legislation is also playing a key role in the widespread adoption of clean heat. Local Law 97 caps carbon emissions for New York City's large buildings and imposes fines on buildings that exceed their carbon budget starting in 2024.[25] NYC Local Law 154 sets strict carbon limits that effectively ban gas- and oil-fired appliances in new buildings and major renovations. New buildings up to seven stories must comply by 2024 and all other buildings need to comply by 2027.[26] The recent passage of the All Electric Buildings Act expands the ban on fossil-fuel systems in new construction projects statewide and will require that most new buildings be all-electric.[27] A NYSERDA Assessment of Energy Efficiency and Electrification Potential in New York State Residential and Commercial Buildings further explains that its baseline scenario assumes that new building energy codes will take effect for new construction, which require highly efficient, zero-emission new construction starting in 2025 for single-family buildings and 2028 for multifamily and commercial buildings.[28]

c. Aggregate New York Load Forecasts

The Integration Analysis Technical Supplement of the Scoping Plan observes that due to "electrification of end-uses where fossil fuels are consumed today, electricity demand is projected to double – with peak loads also nearly doubling – by 2050, even with aggressively managed loads."[29] The Scoping Plan Technical analysis estimates that overall load will begin to increase after 2025 with increases in demand appearing after 2030. Excerpts of the Scoping Plan analysis are shown below.

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[24] Id. p. 21 & 22
[25] NYC Building Energy Laws, LL94, Available at https://www.nyc.gov/assets/buildings/local_laws/ll97of2019.pdf
[26] NYC Building Energy Laws, LL154: All-Electric Buildings
https://accelerator.nyc/building-laws
[27] Senate Bill S 4006-C, State Budget, pp. 132-133, Available at
https://nyassembly.gov/leg/?default_fld=%0D%0A&leg_video=&bn=S4006A&term=2023&Summary=Y&Text=Y
[28] NYSERDA Assessment of Energy Efficiency and Electrification Potential in New York State Residential and Commercial Buildings, April 2023, p. 1-3
[29] Id, pp. 23-24

Figure 16. Statewide Annual Electric Load[11]

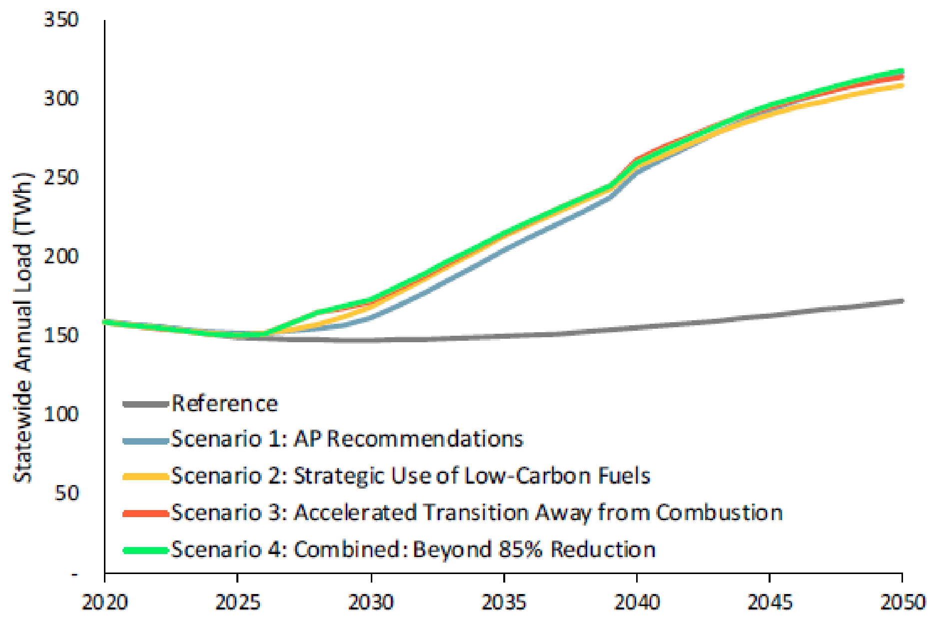
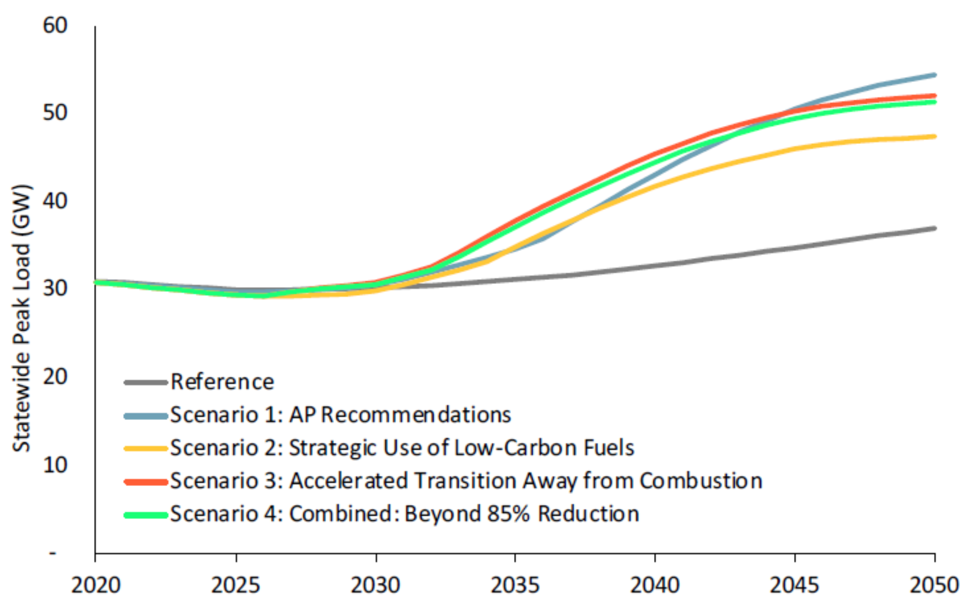
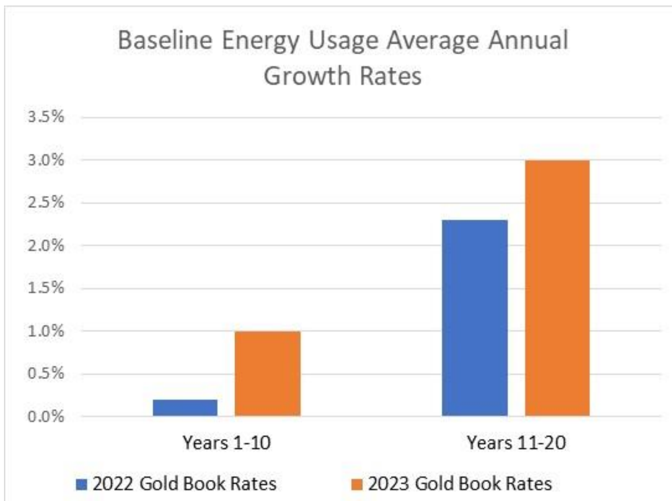


Figure 17. Statewide Peak Load Growth[12]



The NYISO Gold Book provides New York Control Area (NYCA) baseline net energy and summer and winter peak demand forecast growth rates over a 30-year horizon. The 2023 Gold Book identifies significant increases in baseline energy consumption and coincident peak demand throughout the forecast period and attributes this to growth from identified large load projects in the early forecast years, and electrification of space heating, non-weather sensitive appliances, and electric vehicle charging in the outer forecast years. Average annual growth rates included in the 2023 Gold Book have increased compared to 2022, largely due to an uptick in large load projects and EV charging impacts.[30] The figure below compares the average annual growth rates published in 2022 to those released in April 2023.



d. Load Forecast Recommendation

In the time that has elapsed since the development of the record in this proceeding, New York has made significant progress in the electrification of transportation and heating. Load forecasts must reflect the implementation of current policies and expected rates of consumer adoption. Electrification is a durable state policy that is gathering momentum in implementation and the results will be seen in distribution system loads in the coming years. As a result, any load forecasting methodology must be aligned with the state policy goals of New York.

e. Load Forecast Methodology

Staff rightly identifies the National Grid methodology using "integrated hierarchical bottom-up and top-down forecasting process" (p. 20) as superior due to its forecast level granularity down to the customer and/or circuit feeder level. Furthermore, the National Grid method relies on a 95/5 weather event

[30] NYISO Gold Book: 2023 Load & Capacity Data Report, April 2023, p. 2

calibration which accurately captures the risk of one in 20-year weather events.[31] As the impacts of climate change become more readily apparent, especially those related to extreme heat, evaluation of weather extremes in load forecast scenario modeling is not only prudent, but necessary. Although the Staff proposal recommends that the utilities "discuss how longer-term projections for electrification, rising temperatures, and extreme weather events are incorporated into their forecasts" (p. 20), the Commission should provide guidance regarding the methods to be used to assess the risk of weather extremes in load forecasts.

VI. Counterfactual Load Forecast

In the Whitepaper, Staff's position is that a "25 percent down payment for interconnection cost threshold is reasonable" (Whitepaper p. 23) for use in determining which DERs to include or exclude in load forecasts used to inform MCOS studies. While not all projects that make a 25% deposit ultimately get built, the CEP support Staff's position due to its alignment with CEPs' previous supplemental comments which proffered that "the utility's counterfactual load forecast should not include any DERs that have not made their 25 percent construction cost down payment, as construction of DERs beyond that level is speculative and, in part, dependent upon the level of compensation that the DER can expect to receive."[32] Staff correctly observes that "determining appropriate compensation for incremental DERs is the primary use case for the marginal costs in this proceeding." (p. 23)

The CEP agree with Staff's view that "the majority of the kW that actually affects the utility system and kW that planners must consider would be applicable to this threshold" (p. 23), but that future mass market residential and small commercial DERs would not be removed from the counterfactual load forecast. As a result, the CEP join Staff in reiterating the importance of clarifying the extent to which DERs have been removed from utility load forecasts (p. 23) and what business as usual assumptions underlie the expected growth rates of mass market DERs in load forecasts used in MCOS studies.

[31] National Grid, Case No. 16-M-0411, Information Request No: SEIA-1-24(Gahl) DG-1-24, Pg. 3, Response to Question 7, Filed November 2018.

[32] CEP memo to DPS Staff RE: Methodology for Calculating Avoided Transmission and Distribution Costs, 1/28/2020, filed in DMM on June 5, 2020, p. 1.

VII. Probabilistic vs. Deterministic Load Forecasts

The CEP reiterate that robust probabilistic forecasting methods are needed to determine the potential range of outcomes in utility load growth forecasts and the ability of DERs to avoid distribution and transmission infrastructure investments. Climate change is exacerbating weather extremes and the increasing volatility of our climate is best modeled through probabilistic scenario modeling. Use of probabilistic load forecasting methods would also be consistent with the DSIP proceeding and aligned with Commission guidance. The CEP also reiterate that transparency regarding modeling scenarios, assumptions, and sensitivities that drive different outcomes is needed to ensure that stakeholders have a good understanding of the process and sensitivities of outcomes to modeling variables.

VIII. Spare Capacity & Reserve Margin

The CEP support the following positions of Staff enumerated in the Whitepaper:

- Recommendation for the Commission to direct the Joint Utilities to consistently reflect necessary reserve capacity in their respective unit cost estimates. (p. 31)
- Recommendation that, in future filings, each of the utilities consistently explain how their respective reserve margins are reflected in their MCOS estimates.

Clear explanations of these items are necessary for stakeholders to fully understand the methodologies employed by each utility with regard to spare capacity and to advance the objective of ensuring that MCOS studies are done in such a way as to maximize transparency, consistency, and accuracy. The CEP understand that the utilities may have distinct planning processes based on their unique system needs and understand the Staff position as solely increasing the transparency around the underlying parameters regarding reserve margins.

IX. Input Costs

The CEP fully agree with the Staff positions that “a reasonable marginal cost study should rely upon accurate estimates of unit costs” and that investments driven by load growth included in the MCOS studies “are developed with the use of equipment prices and installation costs that appear to be reflective of those that the Joint Utilities are actually facing.” (Whitepaper p. 32). The CEP reiterate the importance of transparency and sufficient explanations as to the derivation of construction unit costs for the benefit of stakeholders.

X. Carrying Charge and Expense Factors

The Staff proposal notes that expense ratios for operations and maintenance (O&M) and depreciation expense have been relatively constant over time and that adjustments to expense ratios for depreciation or the cost of capital would only need to be adjusted if forward looking rates are expected to be materially different from recent historic factors. (p. 34) This approach is reasonable and the CEP recommends that any discounting to present of O&M costs include an escalation factor that is reflective of expectations for inflation.

Staff notes that they previously have argued that "MCOS study common costs allocations could be more economically efficient and forward looking if those allocations were reflective of relative demand elasticities" (p. 35) and requests comment on whether relative demand elasticities should be reflected in common cost allocations. CEP suggest that consideration of demand elasticities introduces unnecessary complexity into the calculation of expense factors with minimal benefits.

XI. Escalation Percentages

Inflation trends have changed dramatically since the record of evidence was developed in this proceeding. As a result, the calculation of inflation expectations requires a fresh review. Staff proposes the use of the Blue-Chip consensus forecast of the Gross Domestic Price (GDP) price deflator to estimate the inflation rate for investment annualization calculations. (p. 36) The Blue-Chip index is a subscription only product that is not transparent to stakeholders. In addition, inflation expectations involve a significant amount of psychology[33] and invariably will diverge from actual measured inflation in the economy. Once inflation accelerates, it takes months to years to wend its way through supply chains into prices for goods and services. For example, many projects are subject to union contracts that span several years. Vendor contracts also typically have multi-year durations and therefore, inflation from prior quarters may still be percolating through the energy industry.

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[33] Brookings Institution, What are inflation expectations? Why do they matter? D. Wessel, et. al., 6/27/2022, Available at https://www.brookings.edu/articles/what-are-inflation-expectations-why-do-they-matter/

As a result, the CEP recommend that Staff reconsider its proposal and instead utilize a blend of historical actual inflation from the prior 24 months and forward-looking inflation forecasts. For historical inflation, CEP recommend use of the GDP Price Index published by the Bureau of Economic Analysis within the US. Dept of Commerce.[34] In neighboring Massachusetts, the GDP Price Index is used as an input in the Performance Based Rate Mechanisms (PBRM) for electric and natural gas utilities to adjust utility revenues annually between base rate proceedings in line with estimated inflation.[35]

Recent actual inflation data should be blended with forecasted inflation rates to accurately capture the inflation that is currently moving through supply chains in addition to economist expectations for the future. In the current inflation environment, future inflation expectations have failed to capture the extent of actual inflation which is presently moving through the economy.[36] While Staff has proposed the Blue-Chip consensus forecast, there are other publicly available inflation indexes that can provide an accurate gauge of inflation expectations. The CEP recommend the use of the 10-Year Breakeven Inflation Rate published by the Federal Reserve Bank of St. Louis. This index is defined as "*The breakeven inflation rate represents a measure of expected inflation derived from 10-Year Treasury Constant Maturity Securities (BC_10YEAR) and 10-Year Treasury Inflation-Indexed Constant Maturity Securities (TC_10YEAR). The latest value implies what market participants expect inflation to be in the next 10 years, on average.*"[37] The 10-Year Breakeven Inflation Rate relies upon publicly available data and represents the consensus opinion of the financial markets. As a result, it is a sufficiently robust index.

The CEP recommend that the escalation percentage used in the MCOS studies consist of a 50/50 blend of recent historic inflation and the 10-Year Breakeven Inflation Rate. While the CEP presume that MCOS studies will be updated in cadences of five years or less, the inflation time horizon should align with the planning and load forecasting horizons of 10 years for consistency.

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[34] BEA GDP Price Index, Available at https://www.bea.gov/data/prices-inflation/gdp-price-index#:~:text=What%20is%20the%20GDP%20Price,t%20part%20of%20this%20index

[35] MA DPU 22-22, Order 11/30/2022 p. 57

[36] "What Markets Are Saying About the Fight Against Inflation" S. Goldfarb, Wall Street Journal, 7/16/2023, Inflation vs. Expectations Graphic. Available at https://www.wsj.com/articles/what-markets-are-saying-about-the-fight-against-inflation-3fc15306?st=12uorcjlkzei9td&reflink=desktopwebshare_permalink

[37] Federal Reserve Bank of St. Louis, 10-Year Breakeven Inflation Rate [T10YIE], retrieved from FRED, Federal Reserve Bank of St. Louis; https://fred.stlouisfed.org/series/T10YIE

At a minimum, the CEP urge that any inflation forecast not omit consideration of current business conditions regarding inflation which have challenged DER developers as well as the utilities as they work to manage costs.

XII. Avoidable Asset Types to be Included in MCOS Studies

Staff is correct in its recommendation that "the utilities be directed to include the cost of each portion of their T&D networks, including costs at the local distribution level" that are demand sensitive (p. 40) in their MCOS studies. A critical objective of this entire process is to obtain a consistent and transparent approach that includes all relevant aspects of the system. In a 10-year time horizon, local distribution projects for summer preparedness may be addressable by DERs. While Central Hudson cites load transfers as a low cost near term solution to accommodate load growth, the durability of this solution must be studied until a 10-year planning horizon with estimates for load growth that are aligned with New York electrification policies.

While the demand sensitive costs that are avoidable through DERs at lower voltage portions of the system may be small in some instances, they still must be studied to demonstrate this transparently. Staff is on the mark in its rejection of arguments against studying lower voltage portions of the system. A consistent and transparent approach to MCOS studies requires an end-to-end review of growth related costs from the transmission system to substations down to secondary network lines. This is especially true as battery storage technologies have proliferated over the last several years and are being increasingly deployed to provide dispatchable capabilities when deployed with renewable generation or on a standalone basis. The Value Stack is technology agnostic and its purpose is to send a price signal to the DER marketplace. As a result, the Commission should ensure that the ability of DERs to reduce system costs at the secondary voltage level are viewed broadly and consider the potential for deployment of storage.

A consistent approach to calculating the MCOS used to determine the DRV requires that all avoidable system costs, including transmission, be evaluated. Including avoided transmission capital costs attributable to DERs would also be consistent with Commission practice in other areas. Staff points out that the "Commission had already recognized the need for Demand Response program designs to reflect the value of the marginal cost of avoided transmission and distribution investments." (p. 40) Furthermore, each of the three cost effectiveness tests included in the Benefit Cost Analysis (BCA) framework: the Societal Cost Test (SCT); Utility Cost Test (UCT); and Rate Impact Measure (RIM) test all include assessment of avoidable transmission related costs.[38]

When assessing the benefits of potential DER, the BCA Framework requires that all three tests include components for avoided transmission losses and avoided transmission capacity infrastructure and related O&M.[39] The BCA framework guidance states that "Additional avoided costs pertaining to avoided transmission capacity infrastructure and O&M shall be calculated in the same manner as that employed for determining avoided distribution capacity infrastructure and avoided O&M".[40] Since avoided transmission costs are evaluated to determine the value of demand response and within the BCA frameworks, it is logical, and consistent with Commission actions to date, that avoided transmission infrastructure costs be evaluated within the MCOS studies.

DERs deployed at scale have a material impact on load flows at the transmission level and a complete assessment of the costs avoidable due to DERs should include a counterfactual analysis of the loads on the transmission system and the potential that they may be avoidable through increased DER deployment. While the revenue requirement of the transmission companies may not be the purview of the Department and Commission, the decisions made by the Commission have a strong influence on peak loads and transmission needed to deliver renewable energy projects and thereby strongly influence the magnitude of those revenue requirements and the costs that customers must pay as a result. Staff is correct to recommend that the Joint Utilities separately identify and include both jurisdictional distribution costs and non-jurisdictional transmission costs in their MCOS Studies and the CEP urge the Commission to provide the direction that non-jurisdictional transmission infrastructure costs should be included in MCOS studies.

XIII. Presentation of Costs

The CEP agree with the Staff recommendations to present marginal cost estimates at substation level granularity with estimated annual costs for each year of the 10-year study period along with 10-year levelized cost estimates. (p. 43). Presentation of results in this manner will illustrate the spatial and

[38] Case 14-M-0101, Staff White Paper on Benefit-Cost Analysis in the Reforming Energy Vision Proceeding, 7/1/2015, p. 12
[39] Case 14-M-0101, Staff White Paper on Benefit-Cost Analysis in the Reforming Energy Vision Proceeding, 7/1/2015, p. 12
[40] Case 14-M-0101, Order Establishing the Benefit Cost Analysis Framework, 1/21/2016, Appendix C, p. 6

temporal variations in marginal costs enabling a transparent process to identify LSRV areas, as highlighted by Staff.

In this section, Staff requested that parties comment on whether costs should be presented for various levels of interconnection (e.g., high voltage vs low voltage). The CEP observe that there are material differences in voltage levels used for service and ratemaking amongst the utilities and that these differences may prove challenging to the objective of consistency in MCOS studies across the utilities. Conceptually a distinction in MCOS results by voltage level is reasonable, but further study is required to determine how this may be accomplished while maintaining consistency and where the line between high and low voltage should be drawn.

Staff also requested comments on whether the MCOS studies should be expanded to address the variation in costs by time of day. The CEP contend that there is already significant complexity in the task at hand which is arriving at consistent, transparent, and accurate MCOS study methods across the utilities. As a result, the CEP recommend deferring consideration of temporal variations to the portion of the process where rates and price signals such as DRV windows are derived. At the present time, NYSEG provides an example of a system with the potential for winter and summer peaks and DRV hours that reflect this. The winter DRV period is a price signal to dispatchable VDER assets such as storage and demonstrates that temporal variations can be addressed in ratemaking.

XIV. Recommendation of the Preferred Method

The CEP are supportive of Staff's recommendation to continue use of the NERA MCOS method with the modifications recommended by Staff. The CEP also concur with Staff's recommendations that LSRV costs be estimated via an iterative process similar to the procedure used by NYSEG and RG&E and that DRV have stable service territory wide values. (p. 45)

XV. Comments Regarding Process

The CEP are fully aligned with Staff in their recommendation that the focus of this stage of the efforts in this proceeding at the present time should be on costing used to develop the marginal cost estimates as opposed to pricing for compensation. (p. 46). The CEP support a requirement to file the next approved MCOS studies off-cycle from the DSIP filings. The next round of DSIP filings are over two years away and VDER compensation rates cannot be adjusted without revised MCOS studies. As a result, CEP maintain that an off-cycle MCOS study timeline is necessary to avoid an unnecessarily prolonged timeline to update VDER rates.

XVI. Comments Regarding the Derivation of DRV and LSRV from MCOS Study Results

In addition to producing accurate MCOS studies, it is critical that these study results be used to create clear, effective price signals for distributed generation projects to respond to. The improvements to the MCOS methodology outlined in the Staff Proposal are an important step toward providing more accurate compensation for DERs. However, the CEP note that the method by which DRV and LSRV are derived from MCOS are relatively rudimentary and the utilities have not uniformly allocated LSRV capacity to DERs in a manner that optimally compensates DERs or defers grid upgrade costs. Improvements to the value stack, as well as the methods by which LSRV eligibility is determined and capacity is allocated/reallocated, are needed to optimize New York's use of DERs. The CEP encourage the Commission to expeditiously initiate stakeholder discussions regarding how MCOS results translate into VDER value stack compensation so improvements can be considered and implemented in parallel with MCOS improvements.

XVII. Conclusion

The CEP thank the Commission and Staff for their work in this proceeding and in developing the Whitepaper. The CEP look forward to continued engagement with stakeholders to refine the proposals in the Whitepaper and work towards devising an updated MCOS methodology that satisfies stakeholder objectives for accuracy, transparency, and comparability among MCOS studies for the New York utilities.