

STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

CASE 15-E-0751 - In the Matter of the Value of Distributed Energy Resources.

CASE 19-E-0283 - Proceeding on Motion of the Commission to Examine Utilities' Marginal Cost of Service Studies.

ORDER ADDRESSING MARGINAL COST OF SERVICE STUDIES

Issued and Effective: August 19, 2024

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STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

At a session of the Public Service
Commission held in the City of
Albany on August 15, 2024

COMMISSIONERS PRESENT:

Rory M. Christian, Chair
David J. Valesky
John B. Maggiore
Uchenna S. Bright
Denise M. Sheehan, recusing
Radina R. Valova

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BY THE COMMISSION:

INTRODUCTION

On April 18, 2019, the Public Service Commission (Commission) issued the Value Stack Compensation Order, which initiated a new proceeding in Case 19-E-0283 to examine Marginal Cost of Service (MCOS) studies that would be used in determining several components of the Value of Distributed Energy Resources (VDER) Value Stack (commonly referred to as "the MCOS proceeding").¹ The Commission explained that MCOS studies are critically important to dynamically evolving utility systems and to inform updates to the VDER Value Stack, but that significant

¹ Case 15-E-0751, Order Regarding Value Stack Compensation (issued April 18, 2019) (Value Stack Compensation Order).

variations existed in how the MCOS studies are conducted across the Joint Utilities, which include Central Hudson Gas & Electric Corporation (Central Hudson), Consolidated Edison Company of New York, Inc. (Con Edison), New York State Electric & Gas Corporation (NYSEG), Niagara Mohawk Power Corporation d/b/a National Grid (National Grid), Orange and Rockland Utilities, Inc. (O&R), and Rochester Gas and Electric Corporation (RG&E). Accordingly, the Commission determined that an inquiry into the MCOS study methodologies was required to ensure the most accurate estimates of the likely marginal distribution system cost reductions attributable to electricity injections from VDER-eligible distributed generators.² The MCOS proceeding was intended to help identify future electric delivery system costs that can be avoided when VDER-eligible distributed generators reduce net load on parts of the distribution system. Specifically, the Commission focused on the Locational System Relief Value (LSRV) and the Demand Reduction Value (DRV) components of the VDER Value Stack.³

The Value Stack Compensation Order also stated that previously approved MCOS studies would continue to be used for calculating the LSRV and DRV components of the Value Stack until the MCOS proceeding results in new MCOS studies approved by the Commission. Thus, the Value Stack Compensation Order directed Department of Public Service Staff (Staff) to develop and issue

² Marginal costs are estimated as the expected change in cost resulting from a forecasted change in demand (or load).

³ The Commission explained that LSRV compensation is available only in locations that the utility has identified as having needs that can be addressed by Distributed Energy Resources (DERs), and based on the higher, specific distribution costs offset by injections in that area. DRV compensation is based on the distribution costs offset by injections, averaged across the utility's service territory. Value Stack Compensation Order, p. 4.

a workplan and schedule for the MCOS proceeding. In compliance with the Commission's directives, Staff filed the required workplan and schedule regarding the review of the MCOS studies, which also requested that each of the Joint Utilities refile their MCOS studies and supporting workpapers.⁴ Although PSEG-LI was not an active stakeholder in the MCOS proceeding, it also performed a marginal cost study to develop location specific avoided distribution system costs and indicated that it will apply any modifications consistent with the Commission's determinations.

Significant process was undertaken in the MCOS proceeding, including an initial stakeholder forum⁵ and multiple rounds of information requests from the Solar Energy Industries Association (SEIA) jointly with other Clean Energy Parties (collectively, CEP or the Clean Energy Parties) and the City of New York (the City).⁶ In a subsequent filing, Staff stated that it would be beneficial for Staff to develop a whitepaper addressing the MCOS filings, with recommendations on how such studies should subsequently be performed, and to receive comments on the whitepaper for consideration and decision-making by the Commission.⁷

On March 27, 2023, Staff submitted a Whitepaper Regarding Marginal Cost of Service Studies (Staff Whitepaper) in

⁴ See Case 19-E-0283, Staff Letter Regarding Workplan and Schedule (filed June 6, 2019). The Joint Utilities refiled their studies in Case 19-E-0283 on June 7, 2019.

⁵ Case 19-E-0283, Notice Announcing Marginal Cost Study Stakeholder Forum (issued June 5, 2019).

⁶ The responses to CEP's and the City's questions were filed in Case 19-E-0283 on June 7, 2019, July 31, 2019, September 30, 2019, and November 6, 2019.

⁷ Case 19-E-0283, Staff Letter Regarding Schedule (filed October 25, 2019).

Case 19-E-0283.⁸ Staff also held a technical conference on May 2, 2023, to provide an opportunity for interested entities to engage with Staff regarding the Staff Whitepaper proposals and to better inform their comments. On July 20, 2023, the Joint Utilities, CEP, and the City submitted initial comments in response to the proposals outlined in the Staff Whitepaper. Reply comments were filed by these entities on August 18, 2023.

As part of the comments filed by the Joint Utilities on July 20, 2023, they raised, for the first time, a proposal to use a deferral value approach for MCOS in LSRV areas and for Non-wires Solution areas.⁹ Technical conferences were held on November 28, 2023, and January 10, 2024, so that the Joint Utilities could elaborate and respond to questions on their LSRV area proposal. Interested entities submitted initial comments on the Joint Utilities' proposal on January 16, 2024, and reply comments on February 6, 2024.

In this Order, the Commission adopts the proposals in the Staff Whitepaper, as modified in the discussion below, establishing a methodology for estimating marginal costs to inform system wide applications such as DRV. The Commission directs the Joint Utilities to file MCOS studies contemporaneously with their next round of Distribution System Implementation Plans (DSIPs) that are due on June 30, 2025.¹⁰ The Commission also directs Staff to initiate a collaborative process in Case 15-E-0751 to discuss issues related to forward

⁸ The Joint Utilities' responses to additional information requests from Staff with relevant information were attached as an appendix to the Staff Whitepaper.

⁹ The Joint Utilities proposed to use a traditional MCOS study for territory-wide programs and the DRV.

¹⁰ See Case 16-M-0411, Distributed System Implementation Plans, Ruling on Extension Request (issued February 7, 2024).

looking costing and compensation, especially as it relates to DRV and LSRV values.

THE STAFF WHITEPAPER

The Staff Whitepaper focuses on updating the LSRV and DRV, distinct from the traditional role of MCOS studies to inform utility regulatory matters.¹¹ The Staff Whitepaper presents various recommendations to assist in addressing the issues identified in the Value Stack Compensation Order. Staff's overarching recommendation is that the MCOS estimates be reflective of the costs that the respective utility would be expected to incur and for which they otherwise would seek rate recovery. Staff recommends that the Joint Utilities be required to demonstrate how their marginal cost studies tie back to actual and forecasted capital spending and operation and maintenance (O&M) cost data.

With respect to load, Staff recommends that the Joint Utilities demonstrate how their MCOS studies are informed by the granular load forecasts which drive their capital spending and operational decisions and, hence, costs. Although the Joint Utilities may have utilized differing modeling procedures to estimate marginal costs, Staff opines that those studies should have been theoretically consistent and based on consistent inputs and calculation parameters.

The Staff Whitepaper compares the MCOS methodologies applied by the Joint Utilities in preparing their MCOS studies

¹¹ Utility business MCOS estimates have traditionally been used for multiple purposes, including: informing rate designs (i.e., estimating the short- or long-run cost impacts caused by increasing load at various times for various durations); determining a price floor for economic development rates; and determining the avoided cost benefit associated with energy efficiency load reduction programs.

and describes Staff's view of the pros and cons of each methodology. With a focus on achieving consistency, Staff also makes recommendations on various costing issues that pertain to all the Joint Utilities' MCOS studies, regardless of the methodology, and notes stakeholder comments on those issues. Finally, to better ensure consistency, Staff recommends that a single MCOS study methodology be utilized by all the Joint Utilities going forward.

PUBLIC NOTICE

On April 7, 2023, the Secretary to the Commission (Secretary) issued a Notice Announcing Technical Conference and Soliciting Comments (Secretary's Notice), related to the Staff Whitepaper. In addition, pursuant to the State Administrative Procedure Act (SAPA) §202(1), a Notice of Proposed Rule Making (SAPA Notice) regarding the Staff Whitepaper was published in the State Register on April 19, 2023 [SAPA No. 19-E-0283SP1].

On May 2, 2023, Staff held a virtual technical conference to provide an opportunity for interested entities to engage with Staff regarding the Staff Whitepaper proposals and to better inform their comments. Interested entities were invited to submit questions in advance and during the technical conference.

The time for submission of comments of comments on the Staff Whitepaper was initially set at June 20, 2023, for initial comments, and July 11, 2023, for reply comments. The Secretary subsequently extended those deadlines until July 20, 2023, for initial comments, and August 18, 2023, for reply comments.¹²

¹² Case 19-E-0283, Notice Extending Comment Period (issued June 15, 2023).

Comments were received from the Joint Utilities, the City, and CEP, and are addressed in the Discussion section below.

LEGAL AUTHORITY

The Public Service Law (PSL) grants the Commission broad legal authority to prescribe regulatory requirements necessary to carry out the provisions contained therein. For instance, PSL Section 5(1) grants the Commission jurisdiction over the sale or distribution of electricity. Furthermore, PSL Section 5(2) permits the Commission to "encourage all . . . corporations subject to its jurisdiction to formulate and carry out long-range programs, individually or cooperatively, for the performance of their public service responsibilities with economy, efficiency, and care for the public safety, the preservation of environmental values and the conservation of natural resources."

Pursuant to PSL Section 65(1), every electric corporation must safely and adequately "furnish and provide [electric] service, instrumentalities, and facilities as shall be safe and adequate and in all respects just and reasonable." Section 66(1) extends general supervision to electric corporations having authority to maintain infrastructure "for the purpose of . . . furnishing or transmitting electricity." Pursuant to Section 66(2), the Commission may "examine or investigate the methods employed by . . . corporations . . . in manufacturing, distributing, and supplying . . . electricity," as well as "order such reasonable improvements as will best promote the public interest . . . and protect those using . . . electricity." The actions taken within this Order fall within the scope of this authority.

DISCUSSION

Marginal Cost of Service Methodology

The Staff Whitepaper summarizes the similarities and differences in the various MCOS study methodologies used by the Joint Utilities in their initial cost study submissions. Staff observes that each of the Joint Utilities' marginal cost studies are, in some way, based on a forecast of electric load as marginal costs are defined as the change in cost resulting from a change in demand. Further, Staff points out that the Joint Utilities' studies are similar in that they all identify where investment projects are necessary to accommodate any forecasted increases in electric distribution system load. However, the Staff Whitepaper observes that the methodologies used to identify the capital investments necessary to accommodate those forecasted changes in load is what most differentiates the studies. Staff also notes that the studies differ somewhat in how they estimate the costs of those investments. Further, the Staff Whitepaper explains that once the costs of the load relief projects are estimated, the Joint Utilities all essentially divide the annualized capital and operating costs associated with the identified investment projects by the load intended to be served by those projects. This results in a marginal cost per unit of demand.

The Staff Whitepaper also explains that the methodologies of Con Edison, O&R, NYSEG, and RG&E are similar in that they use actual load relief related capital projects as the primary input into their MCOS studies. Staff notes that MCOS studies which rely upon actual load relief projects follow the National Economic Research Associates' (NERA) MCOS approach.¹³

¹³ A description of the traditional NERA methodology, as modified for estimating system wide marginal costs in this proceeding is contained in the Appendix to this Order.

NERA has aided the Joint Utilities with applying this method for numerous MCOS studies in the past. The load relief projects selected for the MCOS studies are, for the most part, included in the Joint Utilities' capital plans.¹⁴ These actual load relief projects are designed by utility system planning engineers to handle granular forecasts of increased demand.

The Staff Whitepaper contrasts this actual load relief project method to the proprietary cost modelling methods used by Central Hudson and National Grid. Although Central Hudson and National Grid similarly begin their MCOS study processes by using granular load forecasts to identify those areas that will be constrained by load growth, the forecasts input into the costing models need not necessarily be reflective of the planning forecasts being used by Central Hudson and National Grid to run their business. The costs of investment projects

¹⁴ In situations where there was an insufficient number of projects to study, some of the Joint Utilities added projects that had recently been completed. See Case 19-E-0283, Con Edison Study (filed June 7, 2019), p. 17.

necessary to handle the forecasted load growth are estimated within their proprietary models.¹⁵

The Staff Whitepaper concludes that attaining consistent MCOS estimates that reasonably reflect the actual incurred capital costs requires some standardization in study approach. Although the Staff Whitepaper acknowledges some advantages of the Central Hudson and National Grid methods, such as they both comprehensively evaluate the need for growth related projects over their entire service territories, Staff recommends relying upon the traditional NERA-based method.¹⁶ The Staff Whitepaper notes that an advantage of the Con Edison, O&R, NYSEG, and RG&E methodologies is that the resultant cost estimates are based upon expected project costs that will be booked (or in some cases have already been booked) by the Joint Utilities.

¹⁵ Central Hudson's methodology uses a statistical model to simulate numerous forecasted load growth trajectories for each network area to identify those areas in need of relief. Cost model algorithms developed with input from Central Hudson's planning engineers were then used to estimate the cost for the relief projects needed to accommodate the added load. National Grid's methodology uses its actual, relatively advanced, granular forecasts of load growth as the first step in its Marginal Avoided Distribution Capacity study process. National Grid's forecasts are input into load flow modelling that it then performs on all its network areas to identify those areas in need of relief. Once load-constrained areas are identified, National Grid relied upon its planning engineers and "cost book" tool to estimate the investment costs of the needed load relief marginal cost per unit of demand. Case 19-E-0283, Central Hudson and National Grid Studies (filed June 7, 2019).

¹⁶ Central Hudson estimated the need for load growth related investments by simulating load growth forecasts for each substation and transmission area. National Grid developed a system-wide load flow model which utilized load and DER forecasts at the substation level.

In arriving at its recommendation to use the traditional NERA method, Staff also notes that the proprietary cost modelling-based study methodologies are more administratively burdensome and time consuming, and likely are unreasonable. Nonetheless, Staff recognizes that use of the NERA-based approach raises some issues which must be considered since NERA's results are highly driven by the investment projects that are selected for inclusion in the MCOS study.¹⁷ To ensure that the studies are reasonably long-run in nature, Staff recommends that all growth related, multi-value (i.e., growth and reliability) related projects planned under a 10 year horizon, should be included in the investment cost sample.

Stakeholder Comments

The Joint Utilities comments, filed July 20, 2023, no longer defend using different MCOS methodologies across the Joint Utilities and agree that the NERA method presents an appropriate approach for quantifying system wide marginal costs for each of the Joint Utilities.¹⁸ The Joint Utilities explain that the NERA MCOS study methodology produces marginal costs on a per kW of system peak basis. As such, these estimates can be applied to the reductions in system peak associated with Energy Efficiency programs targeted at all customers across a utility's entire service territory. These estimates do not reflect the

¹⁷ For instance, data on recently completed projects might be used for the study if there is an insufficient number of planned future projects identified in the capital forecast.

¹⁸ Case 19-E-0283, Joint Utilities comments (filed July 20, 2023), p. 4. This is a change in position from what the Joint Utilities stated in their comments on November 25, 2019, indicating that a variety of utility-specific conditions requires methodological variations or differences in approaches among the utilities. However, the Joint Utilities disagree with some of the modifications to the NERA method proposed in the Staff Whitepaper.

unique impacts of programs targeted only at customers in specific locations.¹⁹

CEP and the City also agree with the use of the NERA method, although CEP argue that the Joint Utilities must demonstrate that they have a robust set of projects included in the study.²⁰

In their comments filed January 16, 2024, the Joint Utilities state their continued support to use the NERA-based MCOS methodology outlined in their filed comments on the Staff Whitepaper.²¹

Determination

Staff and the commenting stakeholders all now agree that the NERA approach is the most reasonable method for developing more system wide marginal costs in this proceeding. As Staff indicated, to best ensure that those long-run marginal cost estimates are reasonable, each of the Joint Utilities shall use a similar, comprehensive costing methodology. The general NERA marginal cost of service study approach, with the modifications discussed below, shall be used by all the Joint Utilities for future marginal cost studies.²²

The Commission next turns to specific costing issues raised in the Staff Whitepaper, as discussed below. Having

¹⁹ Case 19-E-0283, Joint Utilities comments (filed July 20, 2023), p. 4.

²⁰ CEP comments, p. 4 (filed July 20, 2023).

²¹ In referring to the NERA methodology, we understand this to be the pre-2018 NERA methodology, and not the 2018 method that the Brattle Group consultants modified for the Con Edison study filing in this proceeding to include estimates of zero marginal costs for serving areas that do not have planned capital projects.

²² Marginal costing for LSRV areas is discussed below in a separate section of this Order.

decided upon the NERA method going forward, our need to decide certain matters is limited.²³

"Run" of the MCOS Studies

In matching the "run" of the costing analysis to the specific pricing decision being addressed, the Staff Whitepaper explains that, for the MCOS proceeding, marginal costs would be used to inform VDER compensation, and that a short-run cost analysis would not be consistent with a VDER goal of substituting avoidable utility investment with DER investment and would not provide a market signal for the most efficient solutions.²⁴ However, a longer-run cost analysis would be reflective of changes in utility load that results in deferrals

²³ Given that the NERA method relies upon the costs of actual projects that are currently in the Joint Utilities' capital plans, the forecasts used to develop those projects cannot be readily modified to reflect a different planning horizon. Similarly, the amount of spare capacity to be reflected in the studies is significantly resolved as the spare capacity is reflected by the Joint Utilities' planning staffs in the sizing of the actual projects that will form the basis of the MCOS studies. Finally, the input prices used to cost out those investment projects have already been applied before the inclusion of those projects in the capital plans.

²⁴ See Case 14-M-0101, Reforming the Energy Vision, Order Adopting a Ratemaking and Utility Revenue Model Policy Framework (issued May 19, 2016) (REV Track 2 Order). The Commission noted that "rate design should be used to send value signals that enable the reduction of total system costs in the long run", and that "rates should generally not be designed around a particular technology so that technology choices can be determined by price signals in the long term." REV Track 2 Order, pp. 14 and 121.

of investments.²⁵ Thus, the Staff Whitepaper recommends a long run costing approach that reflects the relevant incremental lumpy Transmission & Distribution (T&D) investments that will be avoidable by the DERs that will be receiving VDER compensation.²⁶

In making this long-run recommendation, Staff notes that, with respect to marginal cost studies, the Commission has previously considered that the practice of oversizing investments would result in short-run spare capacity.²⁷ Thus, Staff disagrees with NYSEG and RG&E's proposal to exclude from

²⁵ In its order on the 2009 Con Edison rate case, the Commission reaffirmed that marginal cost studies should be performed to enable the evaluation of the costs and benefits of the energy efficiency programs operating in Con Edison's service area and ordered Con Edison to use the analysis obtained from the long-range planning study to develop its estimate of distribution marginal costs. See Case 09-E-0428, Con Edison - Rates, Order Establishing Three-Year Electric Rate Plan (issued March 26, 2010), p. 22.

²⁶ Although the VDER Compensation Order establishes the primary use case for these MCOS studies for the VDER compensation purposes, these MCOS estimates will also be used to evaluate energy efficiency and demand response proposals. Staff notes that energy efficiency proposals often have longer useful lives. See Case 14-M-0101, "Appendix P: Effective Useful Life (EUL)" of the "The New York Standard Approach for Estimating Energy Savings from Energy Efficiency Programs - Residential, Multi-family, and Commercial/Industrial Measures, Version 11", dated October 6, 2023 (filed October 10, 2023). The Staff Whitepaper also notes that demand response is called to offset peak hour loads to avoid the need for longer term investments. See Case 14-E-0423, Develop Dynamic Load Management Programs, Order Instituting Proceeding Regarding Dynamic Load Management and Directing Tariff Filings (issued December 15, 2014), p. 4. The pricing relevance or use case for the MCOS study should influence the "run" of the cost estimate. See Case 89-C-198, Letter Approving Cost Study Manual (dated July 13, 1995).

²⁷ See Case 08-E-1003, et al., Orange and Rockland Utilities, Inc. - Energy Efficiency Portfolio Standard, Order Approving "Fast Track" Utility-Administered Electric Energy Efficiency Programs with Modifications (issued January 16, 2009), p. 36.

their studies the costs for local primary and secondary lines and transformers.²⁸ For the same reason, Staff also disagrees with changes in other utilities' study methodologies to reflect more geographic granularity in such a manner that some areas reflect no change in costs.²⁹ According to the Staff Whitepaper, existing, short-run headroom in certain areas should not drive the studies' results.

Stakeholder Comments

The Joint Utilities comments, filed on July 20, 2023, agree with the Staff Whitepaper that stable long-run estimates for service territory wide applications like DRV and Energy Efficiency are appropriate. The CEP contend that the purpose of the DRV in the Value Stack compensation formula is to provide a long-run price signal regarding the value of DERs. The CEP explain that DERs are being compensated to supplant long-lived utility assets that are deployed via long-term planning and development processes.³⁰

Determination

²⁸ The 2018 NERA study for NYSEG and RG&E no longer includes costs for local primary and secondary lines and transformers. As the utilities indicate, "[t]he MCOS study does not capture local distribution facilities costs (local primary and secondary lines and transformers) and does not capture customer-related facilities. The Companies have determined that it is not possible, at the current time, to defer or avoid any local facilities or customer-related costs in response to DER."

²⁹ The 2016 Con Edison MCOS study used the \$/kW costs identified for sampled projects in a borough for all load serving areas within that borough. In contrast, the 2018 study assigns \$/kW values of zero for load serving areas within a borough which do not exhibit a near term need for new facilities.

³⁰ Case 19-E-0283, CEP comments (filed July 20, 2023), p. 4.

The MCOS studies to be filed in this proceeding shall be based on planning and forecasting horizons sufficient to trigger marginal investments that are representative for all geographic areas and cost centers. As indicated previously, MCOS study cost calculations related to DERs, such as energy efficiency, should reflect long-run, non-zero marginal costs regardless of whether segments of a utility's distribution system have no avoidable costs due to near term expected changes in demand. A longer-run study is appropriate for this need.

Planning Horizon of the Joint Utilities' MCOS Studies

The Staff Whitepaper recommends a ten-year planning horizon to be the basis for determining the projects that go into the NERA methodology advocated by Staff. The filed MCOS studies, which relied upon the NERA method's sampling of investment projects, utilized construction projects that were developed on various planning horizons. For example, Con Edison's study had a mix of planning horizons,³¹ whereas NYSEG and RG&E identified projects based on five-year capital investment plans.³² Staff criticizes those studies for failing to reflect the impact of the rebound in demand that is expected to take place within the next ten years.³³ Thus, Staff rejects the Joint Utilities' shorter-run MCOS study approaches which no

³¹ Con Edison's planning horizons were roughly categorized as: High-voltage (from ten-year load relief programs), feeder investments (from five-year feeder budget), and lower voltage (which for facilities below the area substation level the planning horizon is the next year to year and a half). Con Edison study, pp. 14-17 (filed June 7, 2019).

³² Staff Whitepaper, p. 12.

³³ Staff Whitepaper, p. 10. The New York Independent System Operator, Inc. (NYISO), in its 2022 Gold Book, indicated that electric demand will decline after 2023 and then return to

(continued...)

longer include costs for investments with short-term headroom, such as local primary and secondary lines and transformers, and which produced lower cost estimates than their 2016 rate case studies.

Furthermore, Staff agrees with the CEP that the ability for DERs to provide benefits to the system extends well beyond ten years³⁴ given Staff's expectation that the Climate Leadership and Community Protection Act (CLCPA) will most likely trigger material investments in utility infrastructure.³⁵

The Staff Whitepaper concludes that since the marginal cost study estimates will be used to inform VDER compensation over a ten-year period, the MCOS studies should reflect those investments that can be avoided or deferred over that ten-year period and that a ten-year horizon reasonably balances the concerns presented by the stakeholders and better reflects the potential load growth resulting from the State's policy goals surrounding energy efficiency and peak load reductions.³⁶

Stakeholder Comments

The CEP's comments, filed July 20, 2023, support Staff's recommended 10-year planning horizon as being well grounded and sufficient to support CLCPA related distribution system needs associated with building and transportation

current levels in about ten years, and continue to grow after that. See p. 24, Table I-3a of the 2022 NYISO Gold Book. <https://www.nyiso.com/documents/20142/2226333/2022-Gold-Book-Final-Public.pdf>.

³⁴ Case 19-E-0283, CEP comments (filed November 25, 2019), pp. 28 and 34.

³⁵ See Pathways to Deep Decarbonization in New York State, Energy and Environmental Economics, Inc., p. 31, Figure 17 (dated June 24, 2020). Available at: <https://www.nyserda.ny.gov/-/media/Project/Nyserda/Files/EDPPP/Energy-Prices/Energy-Statistics/2020-06-24-NYS-Decarbonization-Pathways-Report.pdf>.

³⁶ Staff Whitepaper, p. 14.

electrification.³⁷ CEP also supports Staff's rejection of short run headroom analysis as a rationale for claiming zero marginal costs. The City, similar to CEP, supports Staff's proposal to use a ten-year horizon.³⁸

The Joint Utilities' comments, filed July 20, 2023, argue that while a ten-year horizon is appropriate for MCOS studies, annual results for more than just the first five years of the study do not need to be provided because a subsequent study will likely be filed.³⁹ In response to this argument, the CEP warn that focusing on the near term years would result in an insufficient and misaligned price signal.⁴⁰

Determination

Given New York's ambitious initiatives to speed electrification, a shorter-run headroom analysis along the lines of what the Joint Utilities propose is inconsistent with the needed "run" and time horizon for the marginal cost studies in this proceeding.⁴¹ Because our policies regarding building and transportation electrification are resulting in significantly increased demands on the Joint Utilities' T&D systems, we do not expect to see large areas of the Joint Utilities' service territories having zero, longer run marginal costs. CEP make a compelling argument that the horizon must be at least ten years, and possibly longer, regardless of whether some utility capital expenditure plans look ahead only five years. However, we decline to go beyond 10 years, at this time, and direct the

³⁷ Case 19-E-0283, CEP comments (filed July 20, 2023), p. 5.

³⁸ Case 19-E-0283, City comments (July 20, 2023), p. 2.

³⁹ Case 19-E-0283, Joint Utilities comments (July 20, 2023), p. 23.

⁴⁰ Case 19-E-0283, CEP comments (filed August 18, 2023), p. 7.

⁴¹ Case 19-E-0283, CEP comments (filed July 20, 2023), p. 5.

Joint Utilities to use a ten-year planning horizon when producing their MCOS study estimates.

Reliability Versus Growth Related Investments

The Staff Whitepaper recognizes that the NERA method's reliance on a sampling of projects requires the Joint Utilities to use their judgement to distinguish between the load growth-driven and the reliability and/or replacement projects in choosing growth related investment projects to include in their MCOS studies.⁴² The Staff Whitepaper explains that marginal or incremental cost has been defined as the change in a utility's total cost resulting from a business decision to: a) respond to a change in demand; or b) replace an existing facility in order to remain in business (e.g., rehabilitation).⁴³ According to Staff, a longer-run costing lens would include rehabilitation projects as also being demand related.

The Staff Whitepaper addresses whether the marginal cost estimates could be biased by omitting projects that would have otherwise been included with a reasonably long planning horizon.⁴⁴ To find a reasonable balance, the Staff Whitepaper recommends including projects that are solely growth related and also including multi-value projects that are both load growth and reliability related. Staff proposes to exclude projects driven solely for reliability purposes. As further support for including multi-value projects, the Staff Whitepaper notes that Non-Wires Alternative (NWA) opportunities have been

⁴² Staff Whitepaper, p. 17.

⁴³ See Incremental Cost Study Manual approved in Case 89-C-198, p.2. Case 89-C-198, Letter Approving Cost Study Manual (dated July 13, 1995).

⁴⁴ Staff Whitepaper, p. 17.

characterized as both load growth and reliability related and treat avoided traditional utility investment costs as a benefit when analyzing those NWA projects.⁴⁵

Stakeholder Comments

The City maintains that Con Edison needs to revise their study to include multi-value projects.⁴⁶ Similarly, the CEP argue that a robust and representative list of projects should include multi-value projects that have a system expansion component.⁴⁷ The CEP also recognize that allocating project costs between growth and reliability may not be straightforward or possible, but initially propose that multi-value projects be included if greater than a 10 percent capacity expansion threshold is met.⁴⁸ The Joint Utilities initially argued that dual purpose investments should not be included in the sample of investment projects, but indicate in reply comments that a more reasonable threshold would include multi-value projects for which expansion costs represent more than 50 percent of the total cost of the project.⁴⁹

Determination

To ensure that the studies are reasonably long-run in nature, multi-value projects (i.e., simultaneously growth and reliability related) shall be included in the study. We agree with the CEP concern regarding the difficulty of allocating

⁴⁵ Staff Whitepaper, p. 18.

⁴⁶ Case 19-E-0283, City comments (filed July 20, 2023), p. 3.

⁴⁷ Case 19-E-0283, CEP comments (filed July 20, 2023), p. 4.

⁴⁸ Case 19-E-0283, CEP comments (filed July 20, 2023), p. 7; Case 19-E-0283, CEP comments (filed August 18, 2023), p. 6.

⁴⁹ Case 19-E-0283, Joint Utilities comments (filed August 18, 2023), p. 7.

costs of a multi-value project between growth and reliability purposes. Thus, we do not support the Joint Utilities' 50 percent allocation percentage threshold. Moreover, including multi-value projects without a threshold qualification, which by itself is entirely subjective in nature, ensures robust and stable cost studies that reasonably anticipate utility costs. Accordingly, all load growth related and multi-value (i.e., growth and reliability) related projects planned under a 10-year horizon shall be included in the investment cost sample.⁵⁰

Load Forecasting Methodology

The Staff Whitepaper describes how Con Edison, O&R, NYSEG, and RG&E use actual load relief related capital projects as the primary input into their MCOS studies and that therefore, the load forecasts used by the planning staffs to identify the need for those projects are the load forecasts that implicitly drive the results of those NERA method based MCOS studies.⁵¹ Informed by stakeholder concerns regarding transparency in the assumptions that go into the utilities' respective forecasts (e.g., consideration of the Climate Action Council's projections for electrification, accounting for rising temperatures, extreme weather events), Staff's Whitepaper recommends that the Joint Utilities be required to explain the forecasting methods used to

⁵⁰ To the extent that some projects in the 5-to-10-year portion of the time horizon may be planned, but not as thoroughly costed out, the Joint Utilities should cost out those projects more completely and include them in the costing sample.

⁵¹ Staff also noted that these actual load relief projects should be developed based on granular load forecasts. See Case 14-M-0101, supra, Order Adopting Distributed System Implementation Plan Guidance (issued April 20, 2016), pp. 29-30 (including a discussion of the forecasting improvements expected in the utilities' DSIP filings).

identify the need for those actual projects and why the forecasting methods are reasonable for MCOS study purposes.⁵²

Stakeholder Comments

The City maintains that load forecasting is perhaps the most critical input into the MCOS studies.⁵³ The CEP are concerned that the Joint Utilities current forecasting methods are outdated and undervalue energy efficiency, demand response, and DERs. Also worrisome to CEP is that the Joint Utilities' forecasts do not reflect transportation electrification and clean heat adoption. The CEP insist that forecasting methodologies must be aligned with the state policy goals.⁵⁴

The Joint Utilities are adamant that the Commission should not mandate a single forecasting methodology. They explain that each of the Joint Utilities' forecasting methods is what is actually used to produce expected costs.⁵⁵ The Joint Utilities contend that the focus of the cost studies should be on the capital investments that will likely be included in future rate cases, and not on the forecasting approach used to develop those investment plans.⁵⁶

Determination

One intent of the DSIP process is to ensure that each of the Joint Utilities have reasonable, consistent, and advanced

⁵² Staff Whitepaper, p. 20.

⁵³ Case 19-E-0283, City comments (filed July 20, 2023), p. 3.

⁵⁴ Case 19-E-0283, CEP comments (filed July 20, 2023), p. 12.

⁵⁵ Case 19-E-0283, Joint Utilities comments (filed July 20, 2023), p. 10.

⁵⁶ Case 19-E-0283, Joint Utilities comments (filed August 18, 2023), p. 10.

forecasting methodologies. Therefore, we will rely on the DSIP process to ensure that the Joint Utilities' forecasts are reasonably transparent, advanced/current/up-to-date and reflective of energy efficiency, demand response, and DERs. We also note that the Joint Utilities' forecasting for system planning purposes is regularly addressed in the Joint Utilities' management and operational audits.⁵⁷ Therefore, we will allow each of the Joint Utilities to use their own forecasting method. However, we agree with the Staff Whitepaper recommendation that, in future filings, each of the Joint Utilities should include in their MCOS study filings a discussion of the robustness of their forecasting methods over the 10-year planning horizon to be used for the studies. The Joint Utilities shall include a discussion of how longer-term projections for electrification, rising temperatures, and extreme weather events are incorporated into their load forecasts.

Counterfactual Load Forecast

Load forecasts are a main driver of the MCOS estimates and the assumptions that go into those forecasts are essential to accurately estimating the value provided by DERs. If a utility has sufficient capacity on its system, and if load growth is expected to be slow over the planning horizon, then the value of a kilowatt of peak demand reduction will be low. In contrast, if the utility system is demand constrained and load is expected to grow rapidly, then the value of a kilowatt of demand reduction is high.⁵⁸ Thus, as load forecasts are

⁵⁷ See, e.g., Case 21-M-0193, Comprehensive Management and Operations Audit of Consolidated Edison Company of New York, Inc. and Orange and Rockland Utilities, Inc., Order Initiating a Management and Operations Audit (issued May 13, 2021), Request for Proposals, p. 16.

⁵⁸ The CEP aptly explain this. See Case 19-E-0283, CEP comments (filed November 25, 2019), p. 29.

adjusted downward to reflect that an increasing number of DERs are reducing loads on the distribution system, the costs triggered by those load forecasts also go down.⁵⁹ Accordingly, the assumptions made about counterfactual load forecasts that reflect load levels that would have materialized without DERs can have a significant impact on some of the utilities cost study estimates.

In making its proposal, the Staff Whitepaper does not agree with CEP's initial recommendation that "a counterfactual approach in which all forecasted DERs are removed from the load forecast should be used to determine the value that new DERs deliver to the utility system."⁶⁰ Staff viewed CEP's proposal as adding back into the baseline forecast the forecasted incremental load that would otherwise be delivered by the utility but for the DERs. But Staff's proposal does reflect CEP's subsequently revised position that the utility's counterfactual baseline forecast should only reflect a load on the delivery system associated with those DERs that have made a 25 percent construction down payment.⁶¹ Staff agrees with the

⁵⁹ To estimate the value that DERs can provide in terms of avoided distribution costs, some studies analyzed different scenarios regarding DER load growth. For example, the National Grid study considered two DER forecast scenarios in its load flow modelling. The National Grid study evaluated costs based on a forecast of load without additional rooftop solar beyond that which was already installed, and also based on a forecast which incorporated forecasted rooftop solar PV additions. See Case 19-E-0283, National Grid study (filed June 7, 2019), p. 4.

⁶⁰ See Case 19-E-0283, CEP comments (filed November 25, 2019), p. 21.

⁶¹ See Case 19-E-0283, CEP January 28, 2020 Correspondence to DPS Staff (filed June 5, 2020), p. 3 (stating that "[t]he counterfactual scenario describes what would have happened in the absence of the intervention, in this case DER deployments.

(continued...)

CEP explanation that the 25 percent interconnection down payment threshold would not reflect load from speculative DERs that could be influenced by the level of DER compensation from the forecast that is used to size the investments.⁶²

Staff's Whitepaper suggests that a comparison to the avoided costs and benefits identified for NWA benefit cost analyses (BCA) calculations might be instructive. For NWA projects, the traditional solution's forward-looking avoidable cost signal is based on the planned investment cost for the location in which the NWA will alleviate a constraint. The planned investment cost which can be avoided by the NWA is estimated based on a business-as-usual forecast that does not reflect a reduction in load from the DERs that will be put in place as a result of the proposed NWA.⁶³ Thus, the NWA's avoided investment costs are based on a soon-to-be counterfactual forecast.⁶⁴ Similarly, determining appropriate compensation for incremental DERs more broadly is the primary use case for the marginal costs in this proceeding.

To further support the 25 percent interconnection downpayment threshold, Staff's Whitepaper explains that the following types of projects would not be covered under this threshold:

A counterfactual scenario is sometimes referred to as a baseline scenario.").

⁶² Id., p. 1.

⁶³ See Case 15-E-0229, Consolidated Edison Company of New York, Inc. - Reforming the Energy Vision Projects and Programs, Order Approving Shareholder Incentives (issued January 25, 2017), p. 2.

⁶⁴ It is likely that the planning forecast used to size the traditional solution investments reflect reductions in load from certain types of DERs, such as energy efficiency, that is incorporated into the projected trend of historical load.

1. Residential projects do not require an interconnection down payment and therefore would not be included in the group of DERs covered by the 25 percent down payment threshold. Thus, the load reductions from residential projects would not be added back to the forecast when creating the counterfactual forecast.
2. Smaller commercial projects that have modest upgrade costs (~\$10k) that are paid immediately and would not be covered by the 25 percent down payment threshold. Thus, the load reductions from such small commercial projects would not be added back to the forecast when creating the counterfactual forecasts.⁶⁵

Further, Staff notes that although many DER projects do not require an interconnection construction down payment, the majority of the kW's that actually affects the utility system and kW's that planners must consider do require the 25 percent down payment. Thus, in Staff's view, the 25 percent down payment for interconnection cost threshold is reasonable. Adding back only the load for incremental interconnection related DERs that have made a 25 percent construction cost down payment from the forecasts which drive the MCOS studies seems reasonable to Staff.⁶⁶

Stakeholder Comments

⁶⁵ Staff notes that, although most interconnection projects which pay the down payment move forward, not all do. Such instances would add to the general load forecasting error which is associated with planning forecasts. The CEP provided more details on the attrition of projects that have made the 25 percent interconnection downpayment. See Case 19-E-0283, CEP Reply Comments (filed August 18, 2023), p. 5.

⁶⁶ Information on whether a 25 percent construction cost down payment has been made for an interconnection project can be found at: <https://dps.ny.gov/distributed-generation-information>.

The Joint Utilities comment that Staff's Whitepaper proposal is based on an unrealistic demand forecast that implicitly assumes zero DER growth beyond those projects that have made the initial down payment.⁶⁷ The CEP support the Staff Whitepaper's proposed 25 percent down payment interconnection cost threshold and the CEP agree with Staff that the utilities should clarify the extent to which DERs have been removed from the utility load forecasts.⁶⁸ The City is unopposed to the 25 percent down payment for interconnection threshold. However, the City also requests clarification on which projects meet the threshold. The City would like the counterfactual DER information to be updated annually.⁶⁹

In their supplemental reply comments, the Joint Utilities state that they strongly oppose including only those new DERs that made a 25 percent down payment for their interconnection costs in load forecasts because it will produce inaccurate and unrealistic results.⁷⁰ The Joint Utilities point out that using the 25 percent threshold omits residential projects that do not require a down payment, and would also exclude smaller commercial projects with modest upgrade costs.⁷¹ The Joint Utilities ask the Commission to consider the experience in California and reject use of a counterfactual forecast for MCOS and avoided cost estimates.⁷²

⁶⁷ Case 19-E-0283, Joint Utilities comments (filed August 18, 2023), p. 2.

⁶⁸ Case 19-E-0283, CEP comments (filed July 20, 2023), p. 13.

⁶⁹ Case 19-E-0283, City comments (filed July 20, 2023), p. 6.

⁷⁰ Case 19-E-0283, Joint Utilities comments (filed February 6, 2024), p. 2.

⁷¹ Id., p. 3.

⁷² Id., p. 7.

The Joint Utilities point to California Public Utility Commission (CPUC) language regarding a zero new DER scenario. The Joint Utilities opine that the CPUC's most recent avoided costing procedure to use the latest adopted system plan for each utility is a better alternative to the no new DER scenario.

Determination

The Commission views this as another issue that is not as impactful now that we have decided upon using the NERA method for the avoided cost studies. The development of the counterfactual baseline forecast was most relevant to the Central Hudson and National Grid methodologies which rely upon the forecasting assumptions input into those simulation-based costing methodologies. In contrast, the NERA method more closely draws upon the actual forecasts used by each utility's system planners. Thus, there is no need to rule on the bright line associated with the 25 percent interconnection threshold proposal recommended in the Staff Whitepaper. The actual load forecasts used by the utility planners when developing their capital projects should be reflective of a reasonable amount of counterfactual growth if those planners are making investment decisions in the most efficient manner possible.

Furthermore, we agree with Staff, CEP, and the City that the Joint Utilities should clarify the extent to which load, which would be serviced by the Joint Utilities' systems but for growth in DERs, has been reflected in their planning load forecasts. A detailed explanation of the extent to which existing and forecasted DER related load reductions are reflected in actual planned investment projects shall be included in the MCOS study filings.

Probabilistic vs. Deterministic Load Forecasts

The Staff Whitepaper looks to the DSIP proceeding in arriving at the conclusion that the MCOS studies should reflect

the use of probabilistic forecasting in the Joint Utilities' planning efforts.⁷³ Given the increased uncertainty regarding load growth, Staff recognizes the ability of probabilistic demand forecast based distribution planning to have the flexibility to consider the potential for high-cost and low-cost outcomes, and the associated value of this optionality in capital planning.

Stakeholder Comments

The Joint Utilities explain that even though their forecasts may appear to be deterministic, in many instances they reflect an assessment of the probability of certain events occurring in the future.⁷⁴ Moreover, the DSIPs filed in 2023 indicate that utilities are already using probabilistic forecasts to varying degrees. The CEP comment that probabilistic forecasts are necessary for cost-optimized solutions (i.e., optionality).⁷⁵ The City supports adoption of

⁷³ The DSIP Guidance Document asked the Joint Utilities to provide additional details which are specific to the utility resources and capabilities which support integrated electric system planning. Specifically, the DSIP Guidance Document asked the Joint Utilities to: 1) provide information on how the utility's means and methods enable probabilistic planning which effectively anticipates the inter-related effects of distributed generation, energy storage, electric vehicles, beneficial electrification, and energy efficiency; and 2) describe the advanced forecasting capabilities which are/will be implemented to enable effective probabilistic planning methods. See Case 16-M-0411, Department of Public Service Staff Whitepaper Guidance for 2018 DSIP Updates (filed May 29, 2018) (DSIP Guidance Document).

⁷⁴ Case 19-E-0283, Joint Utilities comments (filed July 20, 2023), p. 10.

⁷⁵ Case 19-E-0283, CEP comments (filed August 18, 2023), p. 2.

probabilistic demand forecasts and load sensitivity analyses in the MCOS studies based upon different forecasts.⁷⁶

Determination

This issue is no longer as relevant with our choice of the traditional NERA method. The actual planned projects which will be used in the cost studies are based upon each of the Joint Utilities' respective demand forecasts. However, we take this opportunity to confirm our preference that the Joint Utilities rely upon probabilistic demand forecasts for distribution planning.⁷⁷ To the extent probabilistic planning is present in the development of each utility's actual planned projects, the efficiencies of probabilistic planning will be reflected in the MCOS studies' estimates.

Salvage Value

The Staff Whitepaper addresses an inconsistency in the MCOS studies regarding whether, when utilities plan their budgets, the cost of new investment projects should include the anticipated cost of removal of the new investment as well as the salvage value of that investment.⁷⁸ In its MCOS filing, Con Edison indicated that the investment cost used for its study should be the incremental cost of the new asset rather than the entire cost of the new asset. This incremental cost would be calculated by Con Edison as the cost of the new investment grossed up for the cost of removal and net of the salvage

⁷⁶ Case 19-E-0283, City comments (filed January 16, 2024), p. 3.

⁷⁷ See Case 14-M-0101, supra, Order Adopting Distributed System Implementation Plan Guidance (issued April 20, 2016), p. 47 and Attachment 1, p. 15.

⁷⁸ The carrying charge factors used by the Joint Utilities include a component for the recovery of removal cost and a component for the value of salvage.

value.⁷⁹ However, Con Edison stated that it did not have a sufficient sample of salvage value estimates to include in the study even though Con Edison does recondition some assets for redeployment in the field. Therefore, Con Edison and O&R set salvage values to zero for their respective studies for repurposed assets.⁸⁰

No other utilities incorporated salvage values for repurposed assets when conducting their respective studies. NYSEG, RG&E, National Grid, and Central Hudson noted that although they may not repurpose assets as a normal course of business, they are not opposed to Con Edison considering salvage value in its marginal cost estimates.

The Staff Whitepaper recognizes that difference in salvageable investments might come about due to differences in the topography and design criteria of each utility. For example, given its larger, network system design, it is understandable that Con Edison would have a much greater ability to repurpose some assets such as transformers. The Staff Whitepaper recommends that Con Edison and O&R continue to assess whether projects included in their studies have assets with expected salvage values and encourages all other utilities to consider salvage values.

Stakeholder Comments

The Joint Utilities recognize that, given the characteristics of Con Edison's service territory and its

⁷⁹ See Case 19-E-0283, Con Edison MCOS Study (filed June 7, 2019), p. 10 (Con Edison MCOS Study).

⁸⁰ The Con Edison MCOS study states that "the Study assumes zero salvage value for any asset that is being replaced. An internal review of the salvage values could improve the Study results. Similar to the cost estimates, data collected over multiple years can also be used to estimate future salvage values."

ability to repurpose transformers, salvage value is likely most relevant to Con Edison. However, the remaining utilities indicated they would explore whether salvage value is applicable.⁸¹

Determination

The forward-looking costs developed in the studies shall reflect the actual expected costs of removal of any replaced assets, and any salvage value of those replaced assets. But, as suggested by Staff, the projects included in the Joint Utilities' MCOS studies shall mirror how the utilities actually plan their system for load growth scenarios. Salvage values, if non-negligible, shall be included in the MCOS studies. Con Edison and O&R shall continue to assess the amount of salvage value included their MCOS studies. The remaining utilities shall explore the extent to which salvage values are significant, and therefore, reflected in their marginal cost estimates.

Spare Capacity & Reserve Margin

Spare capacity must be addressed in the MCOS studies as it reflects the excess capacity on lumpy distribution system investments such as distribution transformers that must be installed to serve an increase in demand. Electric utility system reserve margin is the difference between available capacity and expected peak demand. The reserve margin is intended to allow the utility to operate reliably in the event there is an unexpected increase in demand, or an unplanned outage. Spare capacity and reserve margins must be considered by a reasonable marginal cost study.

⁸¹ Case 19-E-0283, Joint Utilities comments (filed July 20, 2023), p. 16.

The Staff Whitepaper lays out in detail the various methods by which the Joint Utilities reflected reserve margins and their respective excess capacity associated with sizing the lumpy investments that were costed out in their studies. Staff recommends that the Commission direct the Joint Utilities to consistently reflect necessary reserve capacity in their respective unit cost estimates. Staff does not propose changing the reserve margins used by the Joint Utilities in their respective system planning efforts. Staff also recommends that, in future filings, each of the Joint Utilities should consistently explain how their respective reserve margins are reflected in their MCOS estimates.⁸²

Stakeholder Comments

Although the Joint Utilities may already include reserve margin in their MCOS studies, the CEP comment that the utilities must explain how spare capacity and reserve margins are reflected in their MCOS studies.⁸³

In their July 2023 comments, the Joint Utilities note that: (1) the utilities do not plan for a build when there is excess capacity; (2) forecasts identify the point at which the reserve margin indicates a need to build to preserve the margin at a targeted level; and (3) these two considerations are integral elements in the development of a capital investment plan.⁸⁴

⁸² The Staff Whitepaper observed that leveling unit cost, to reflect the present value of the investment divided by the present value of the demand, would spread costs across capacity as it is expected to be used. See Incremental Cost Study Manual, approved in Case 89-C-198, p. 3. Case 89-C-198, Letter Approving Cost Study Manual (dated July 13, 1995).

⁸³ Case 19-E-0283, CEP comments (filed July 20, 2023), p. 14.

⁸⁴ Case 19-E-0283, Joint Utilities comments (filed July 20, 2023), p. 16.

Determination

This is another issue that is significantly rendered moot by our choice of the NERA method for use by all the Joint Utilities. The amount of spare capacity and reserve margins to be reflected in the studies is significantly resolved as spare capacity headroom is considered by utilities' planning staffs in the sizing of the actual projects that will form the basis of the MCOS studies. However, the Joint Utilities shall fully explain how spare capacity and reserve margins are reflected in their NERA method MCOS studies.

Input Prices

Determining the costs of the marginal investment projects that MCOS study methodologies identify as being necessary to serve an increase in demand requires forecasts of the equipment and labor prices used to estimate those project costs. For those studies that rely upon a sampling of actual project cost data, project costs reflect the costs of purchasing physical plant and equipment, and the labor costs to engineer, furnish, and install that plant and equipment.⁸⁵ The Staff Whitepaper discusses in detail how the various MCOS methodologies develop their input prices via various combinations of escalated historical project input prices, actual engineering whitepapers and/or "Cost Book" tools. The Staff Whitepaper explains that a reasonable marginal cost study should rely upon accurate estimates of unit costs (i.e., input prices) that the utilities are actually facing in the marketplace regardless of the modelling methodology used.⁸⁶

⁸⁵ Con Edison MCOS Study, p. ix.

⁸⁶ From a theoretical economic perspective, marginal cost should reflect the most efficient solution, and this should require investment projects that were developed on the most reasonable/efficient/accurate longer-range demand forecasts as
(continued...)

Stakeholder Comments

The City agrees with Con Edison that improving both the data quality used to estimate the various projects used to estimate the costs of upgrades in the future will lead to better marginal cost calculations.⁸⁷ CEP agree with Staff that the MCOS studies should reflect accurate estimates of unit costs.⁸⁸

Determination

Given that the NERA method relies upon the costs of actual projects that are currently in the Joint Utilities' capital plans, the input prices used to develop the cost estimates for those projects cannot readily be modified. The estimated costs of these projects will be submitted and reviewed in rate cases. If it turns out that the rate case reviews indicate that unreasonable forecasts of input prices are resulting in unreasonable estimates of project costs, input prices for the MCOS studies should be adjusted accordingly.

Carrying Charge and Expense Factors

Carrying charge and expense factors are used to develop the annual marginal cost in the Joint Utilities' service studies. The Staff Whitepaper explains that the carrying charges for the marginal investments needed (or identified by the studies) are generally calculated by multiplying the identified capital investment costs by a factor which represents the ratio of the sum of the annual depreciation expenses, annual return paid to investors, and annual taxes to the incremental investment costs. The annual O&M costs associated with those incremental or avoided investments are often estimated using

possible and costed out using the most efficient input prices as possible.

⁸⁷ Case 19-E-0283, City comments (filed November 25, 2019), p. 9.

⁸⁸ Case 19-E-0283, CEP comments (filed July 20, 2023), p. 14.

expense factors, which are the ratio of historical annual O&M expenses to historical annual capital costs. Finally, carrying charges and expenses are typically grossed up to include allocations of joint and common costs. The Staff Whitepaper explains that relevant marginal cost estimates require forward-looking forecasts of investment carrying charges and operations and maintenance expense levels and describes how tracking historical factors over time would reveal any material changes in economic carrying charge and expense factor ratios. For example, Staff recommends that depreciation rates be adjusted to reflect a forward-looking useful life, if material. Finally, Staff recommends that joint and common cost allocations be as economically efficient as possible.⁸⁹

Stakeholder Comments

The Joint Utilities support forward looking factors and will make modifications to the extent forward looking adjustments make a material difference.⁹⁰ CEP comment that carrying charge and expense factors should be adjust if forward looking rates are expected to be materially different from recent historic factors. CEP further note that considering demand elasticities for common cost allocations introduces unnecessary complexity.⁹¹ The City supports Staff's recommendation that forward-looking adjustments should be made to carrying charges and depreciation rates if it makes a material impact on forecasted costs.⁹²

⁸⁹ Staff explains that an economically efficient allocation may require consideration of elasticities of demand.

⁹⁰ Case 19-E-0283, Joint Utilities comments (filed July 20, 2023), p. 17.

⁹¹ Case 19-E-0283, CEP comments (filed July 20, 2023), p. 15.

⁹² Case 19-E-0283, City comments (filed July 20, 2023), p. 3.

Determination

The Commission finds, based on the comments, that MCOS studies shall include forward-looking adjustments to historic carrying charge and expense ratios if it makes a material impact on forecasted costs. Depreciation rates shall also be adjusted to reflect forward-looking useful lives of materials. Although CEP make a reasonable point about the complexity of joint and common cost allocations, such complicatedness may become necessary as material shifts in electric and gas usage occur in the future.

Escalation Percentages

Various cost elements, including equipment, material, and labor, are escalated in the marginal cost studies to reflect the expected impact of inflation over time. Staff and the stakeholders note inconsistencies in the MCOS study's inflation rates, as well as dramatic changes in inflation rates over the pendency of this proceeding.⁹³ The Staff Whitepaper recommends that the escalation rates used in the MCOS studies reflect current expectations about inflation from the most up to date BlueChip consensus forecast of the Gross Domestic Price (GDP) implicit price deflator.⁹⁴ The Staff Whitepaper recommends using this forecast of the inflation rate for any Economic Carrying Charge and investment annualization calculations.

Stakeholder Comments

The Joint Utilities state that the Staff Whitepaper's recommendation to use the GDP Implicit Price Deflator is

⁹³ See Case 19-E-0283, City comments (filed November 25, 2019).

⁹⁴ The GDP Implicit Price Deflator and the GDP Price Index are different names for the same index.

reasonable.⁹⁵ The City agrees that the most current forecasts of inflation should be used.⁹⁶ Quite differently, CEP recommend a 50/50 blend of recent historic inflation and the 10-year break even inflation rate published by the St Louis Fed.⁹⁷

Determination

The City is correct that studies should reflect the most recently available forecast of inflation. The Commission has a long-standing precedent of relying upon the BlueChip Economic Indicators' consensus forecast of inflation as measured by the GDP Implicit Price Deflator and therefore the most recent BlueChip consensus forecast of the GDP Implicit Price Deflator shall be used for MCOS studies.⁹⁸ Our goal is to accurately estimate inflation going forward. Thus, the CEP's proposal to rely, in part, upon historic inflation is rejected.

Avoidable Asset Types to be Included in MCOS Studies

The Staff Whitepaper explains that the Joint Utilities' T&D systems are made up of many components or segments. These range from higher voltage transmission lines, transmission substations, lower voltage transmission lines, to distribution substations, primary feeder lines, and secondary lines. The stakeholders disagree on which components of the T&D system should be included in the MCOS studies developed for this proceeding. The CEP understood the use of the MCOS studies for

⁹⁵ Case 19-E-0283, Joint Utilities comments (filed July 20, 2023).

⁹⁶ Case 19-E-0283, City comments (filed July 20, 2023), p. 3.

⁹⁷ Case 19-E-0283, CEP comments (filed July 20, 2023), p. 16.

⁹⁸ To avoid an inordinate amount of time spent by stakeholders in arguing over the appropriate inflation rate, the Commission has historically relied on using the consensus forecast.

calculating Value Stack elements as requiring the avoided costs of all parts of the Joint Utilities' transmission and distribution system to be included in the marginal cost estimates, including transmission costs which are recovered through federal tariffs.⁹⁹ In contrast, the Joint Utilities have not included transmission costs procured through NYISO Comprehensive System Planning Process, as those costs are recovered through non-Commission jurisdictional rates. Thus, there is a disagreement regarding whether MCOS studies only relate to asset categories recovered in Commission jurisdictional rates.

Additionally, there is dispute over which distribution level elements should be considered in the MCOS studies. All of the Joint Utilities include substation costs, however, there is a varying degree of distribution system components that operate below the substation level included in the Joint Utilities' studies. Con Edison's MCOS study includes two high voltage cost centers: the High Voltage System Cost Center, and the Load Area Substation and Sub-transmission Cost Center.¹⁰⁰ The cost of these components is informed by Con Edison's "Area Substation and Sub-transmission Feeder Ten-Year Load Relief Plan." Investment needs for everything below the area substation level (Primary Feeders, Distribution Transformers, and Secondary Cables) are typically studied and identified only a year to a year and a half in advance. The Con Edison MCOS Study relies on historical data to estimate future below-area-substation costs

⁹⁹ Case 19-E-0283, CEP January 28, 2020 Correspondence to DPS Staff (filed June 5, 2020).

¹⁰⁰ These facilities, which operate at levels typically considered transmission, serve a function akin to distribution facilities.

and investment timing. CEP note that these primary and secondary costs for Con Edison and O&R are significant.

National Grid's MCOS study includes those T&D system components which were identified from a load flow analysis. National Grid's load flow analysis method was not applied at the transmission level as it claims that the required scope of the study was to develop marginal distribution system costs that may be avoided by DERs. National Grid also excludes feeder-level investments from its study as it argues DERs cannot be in place to defer such feeder-level investments made in the near-term under the Commission's required summer preparedness program.

NYSEG and RG&E include components in their MCOS studies related to specific voltage levels: 1) upstream distribution defined as High-voltage stations and upstream lines (69 kV, 46 kV, 34kV, and some 115 kV); and 2) distribution substations and trunkline primary feeders (34 kV, 12 kV, 4 kV). NYSEG and RG&E's MCOS studies do not capture costs associated with local primary and secondary lines and transformers as the companies have determined that it is not possible, at the current time, for DERs to enable deferment or avoidance of any local facilities.

Central Hudson broadly categorizes their costs by Transmission and Distribution, ignoring costs below the substation level. Central Hudson does not model distribution costs below the substation level based on its view that most feeder level growth is handled by load transfers which have insignificant costs. Central Hudson further opines that low voltage needs could be very area specific and thus most appropriately handled via NWAs, which have their own process for identifying avoided costs.

The Staff Whitepaper recognizes that the MCOS studies filed in this proceeding are primarily intended to inform the

VDER Value Stack. To the extent that a significant level of costs associated with a transmission or distribution system element could be avoided, Staff recommends that those costs should be included in future studies to be filed in this proceeding. Staff notes that the marginal cost studies for this proceeding should estimate the avoidable costs of all demand sensitive portions of the Joint Utilities' transmission and distribution networks. According to Staff, this would result in the MCOS studies including asset categories recovered in non-Commission jurisdictional rates. Staff notes that other external aspects of the Value Stack do not relate to costs recovered in Commission jurisdictional rates (e.g., value of carbon). Also, non-jurisdictional costs comprise a portion of the Value Stack as do non-jurisdictional Environmental values.¹⁰¹ Thus, Staff recommends that the Joint Utilities separately identify and include both jurisdictional and non-jurisdictional costs in their MCOS Studies and let the Commission resolve the issue on what asset categories should be compensated at a later date. According to Staff, including all of the jurisdictional and non-jurisdictional cost components in the MCOS studies would provide consistency in the MCOS studies.

Staff notes that only Con Edison and O&R include low voltage investments below the substation level. Staff also does not find persuasive Central Hudson's argument that it excludes below substation level costs since most feeder level growth is handled by load transfers which have insignificant costs. Staff explains that in its current study, most of the costs included by Central Hudson occur in a handful of locations, and when

¹⁰¹ Case 15-E-0751, Value of Distributed Energy Resources, Order on Net Energy Metering Transition, Phase One of Value of Distributed Energy Resources, and Related Matters (issued March 9, 2017), p. 15.

averaged over the entire Central Hudson network, might be considered insignificant. Staff states that the pertinent question is to what extent can Central Hudson avoid feeder level costs in the longer run, and concludes in this context that Central Hudson's feeder level costs may be more significant than the 13 cents per kW presented by Central Hudson in its study. Staff also notes that NYSEG and RG&E do not provide adequate support for their contention that their MCOS studies do not capture local distribution facilities since they have determined that it is not possible, at the current time, to defer or avoid any local facilities.

Given the importance to which these marginal cost estimates will be utilized to inform compensation for projects and programs that will help the State meet its CLCPA goals, Staff recommends that the utilities be directed to include the cost of each portion of their T&D networks, including costs at the local distribution level. Staff's Whitepaper rejects NYSEG and RG&E's proposals to exclude costs for local primary and secondary lines and transformers from their studies.¹⁰²

Stakeholder Comments

CEP contend that the estimated costs that can be avoided by DERs will be understated if the Joint Utilities do not include the following in their MCOS studies:

¹⁰² The 2018 NERA study for NYSEG and RG&E no longer include costs for local primary and secondary lines and transformers, stating: "The MCOS study does not capture local distribution facilities costs (local primary and secondary lines and transformers) and does not capture customer-related facilities. The Companies have determined that it is not possible, at the current time, to defer or avoid any local facilities or customer-related costs in response to DER." Case 19-E-0283, NYSEG and RG&E MCOS study methodology description (filed June 7, 2019).

- All transmission costs including those procured through the NYISO Comprehensive System Planning Process to meet reliability needs, public policy requirements, and resource adequacy;
- All costs downstream of the distribution substation level (i.e., feeder level costs, distribution transformers, and secondary cable costs); and
- Costs related to other distribution planning investment categories apart from load growth related investments.¹⁰³

Regarding the Staff Whitepaper's proposal, the Joint Utilities state that costs associated with Federal Energy Regulatory Commission-regulated bulk transmission systems could be considered in MCOS studies, however the Utilities note there are complexities in monetizing those values.¹⁰⁴ The CEP comments that including avoidable transmission cost would be consistent with Commission practice in other areas.¹⁰⁵

The City supports including costs of each portion of the T&D networks, including at the local distribution level.¹⁰⁶ In their January 2024 comments, the CEP state that it is unclear from the Joint Utilities proposal how a Non-wires Solution-based study approach would incorporate the avoided transmission capacity.¹⁰⁷

Determination

¹⁰³ Case 19-E-0283, CEP comments (filed November 25, 2019), p. 39.

¹⁰⁴ Case 19-E-0283, Joint Utilities comments (filed July 20, 2023), p. 25.

¹⁰⁵ Case 19-E-0283, CEP comments (filed July 20, 2023), pp. 2 and 17.

¹⁰⁶ Case 19-E-0283, City comments (filed July 20, 2023), p. 3.

¹⁰⁷ Case 19-E-0283, CEP comments (filed January 16, 2024), p. 4.

The MCOS studies filed in this proceeding are primarily intended to be used for calculating VDER Value Stack elements. To best inform the Value Stack, reasonable marginal cost studies for this proceeding shall estimate the avoidable costs of all demand sensitive components of the Joint Utilities' transmission and distribution networks. The Joint Utilities' MCOS studies shall therefore present the costs of each segment of their T&D networks, including Federal Energy Regulatory Commission-regulated bulk transmission system costs, down to costs at the local distribution primary and secondary line level.

Presentation of Costs

The Staff Whitepaper observes that marginal cost study estimates that had been used for earlier energy efficiency program and non-targeted demand response programs have typically been presented on a utility system wide level.¹⁰⁸ The Staff Whitepaper also notes, however, that the REV Track 2 Order adopted the policy direction that more granular rate design must be made available to engage customers efficiently in multi-sided DER markets.¹⁰⁹ Subsequently, the Value Stack Compensation Order initiated the MCOS proceeding to develop MCOS studies for purposes of the identification and valuation of LSRV zones.¹¹⁰

The Joint Utilities each filed more granular MCOS estimates in this proceeding. However, the CEP noted difficulty in evaluating the more locationally specific cost information, commenting that "the MCOS study results were presented in

¹⁰⁸ Con Edison, however, has previously presented costs on a borough area basis.

¹⁰⁹ Case 14-M-0101, supra, Order Adopting a Ratemaking and Utility Revenue Model Policy Framework (issued May 9, 2016), p. 123.

¹¹⁰ Value Stack Compensation Order, pp.16 and 18.

different forms across the utilities making it difficult to make meaningful comparisons.”¹¹¹

The Staff Whitepaper concludes that presenting marginal costs on a year-by-year basis, as well as on a levelized basis, would make the results more comparable. In addition, the Staff Whitepaper recommends that the presentation of costs for each substation serving an area location would also aid in comparing similar areas within a utility’s service territory and between similar service territories. Staff notes that MCOS estimates for all utility locations would provide the flexibility to group together LSRV areas however the Commission decides is most reasonable.¹¹² The Staff Whitepaper proposes that the Joint Utilities also provide a companion analysis which groups individual area estimates into LSRV and DRV areas.

Stakeholder Comments

The CEP agree with Staff regarding the presentation of marginal cost estimates at the substation level of granularity.¹¹³ Related to the specific area station detail requested in the Whitepaper, the Joint Utilities indicate that it would take time to implement that approach in their studies, but that they would commit to providing more granular estimates in subsequent studies if required by the Commission.¹¹⁴

The CEP support Staff’s proposal to present annual costs for each year of the 10-year study period.¹¹⁵ However, the

¹¹¹ Case 19-E-0283, CEP comments (filed November 25, 2019), p. 19.

¹¹² Staff Whitepaper, p. 43.

¹¹³ Case 19-E-0283, CEP comments (filed July 20, 2023), p. 18.

¹¹⁴ Case 19-E-0283, Joint Utilities comments (filed July 20, 2023), pp. 20-21.

¹¹⁵ Case 19-E-0283, CEP comments (filed July 20, 2023), p. 18.

Joint Utilities argue that annual information should only be provided for a shorter time-period (less than five years). The Joint Utilities opine that the most important years in the ten-year study period are the first few years. The Joint Utilities explain that regular updates of MCOS studies will result in the later years in a study today being rendered irrelevant by new MCOS results two years from now.¹¹⁶

Determination

As explained further below, the importance in presenting costs at a level of granularity that includes the substation serving area level is now required to best inform future determinations. Regarding the Joint Utilities' concerns about the results for later years of the studies becoming irrelevant, we recognize that forward looking economic analysis and forecasts are unreliable. However, for economically efficient compensation and planning purposes, it is paramount that the best estimate of forward-looking costs informs decisions. Marginal costs shall therefore be presented for each year of the 10-year study period. Study results shall be listed separately for all 10 years, regardless of the cadence of the eventual study filings.

In-Service Projects

Subsequent to agreeing to use the NERA-based method for all their marginal cost studies, in their February 6, 2024, Supplementary Reply Comments, the Joint Utilities propose that projects should be eliminated from the study once they reach their in-service date. The Joint Utilities argue that MCOS estimates should change as these projects go into service. However, given a ten-year planning horizon, the Joint Utilities

¹¹⁶ Case 19-E-0283, Joint Utilities comments (filed July 20, 2023), p. 20.

also recognize that additional capital expenditure projects would be proposed that are also not included in the study.¹¹⁷ Regardless, the Joint Utilities note that the expected two-year cadence for filing MCOS studies would result in a timely refresh the projects in the MCOS studies.¹¹⁸

Determination

The Commission notes that because this proposal was made in the most recent reply comments, the other stakeholders have not had an opportunity to respond to the Joint Utilities' suggestion to eliminate projects from the MCOS studies once they reach their in-service date. However, we do not find that this proposal should be adopted. The MCOS studies should produce the best estimate of marginal costs at the point in time in which they are filed. Other changes in the slate of capital investment projects will likely arise after the MCOS studies are performed, but before completely new studies are filed. For example, some projects in the study might be delayed, or even removed, given unanticipated reductions in load. Conversely, unanticipated increases in loads might prompt projects that will be newly proposed after the MCOS studies are performed, but before completely new studies are filed. Finally, non-demand related considerations might change the status of the proposed projects included in the studies. To selectively remove certain projects from the studies once they reach their in-service dates could potentially bias the study results. Thus, we reject the Joint Utilities proposal to eliminate projects from the study. The two-year MCOS study filing cadence provides for a reasonable updating of the MCOS study inputs.

¹¹⁷ Case 19-E-0283, Joint Utilities comments (filed February 6, 2024), p. 7.

¹¹⁸ Id.

Utilities' Avoided Cost Proposal for LSRV And NWA

In their comments on Staff's Whitepaper proposals, the Joint Utilities proposed, for the first time, to use a deferral value approach¹¹⁹ for determining MCOS in LSRV areas and for Non-wires Solution areas and to use the traditional MCOS studies for territory-wide programs and the DRV. The Joint Utilities contend that for location specific applications such as compensation related to LSRV or Non-wires Solution areas, avoided cost studies more accurately reflect the value DERs provide.¹²⁰

In response to the Joint Utilities deferral value approach proposal, CEP requested a technical conference focused on LSRV calculation methods.¹²¹ The CEP claimed that the Commission is not in a position to reconcile the two proposed LSRV methods - the NERA iterative method and the Joint Utilities' proposed avoided cost method. A technical conference was held on November 28, 2023, to provide DPS staff and interested stakeholders with an opportunity to engage with the Joint Utilities regarding the proposal made by the Joint Utilities. A follow-up technical conference was held on January 10, 2024.

Stakeholder Comments

In their January 2024 comments, the CEP note that it is important to distinguish between deferral values and marginal costs and recognize that they represent two distinct costing

¹¹⁹ The Joint Utilities also refer to their deferral value approach as an avoided cost approach. See Case 19-E-0283, Joint Utilities comments (filed July 20, 2023), p. 6; and Joint Utilities reply comments (filed August 18, 2023), p. 9.

¹²⁰ Case 19-E-0283, Joint Utilities comments (filed July 20, 2023), p. 2.

¹²¹ Case 19-E-0283, CEP comments (filed August 18, 2023), p. 9.

calculations and serve materially different use cases. During the November 2023 and January 2024 technical conferences, stakeholders raised numerous issues regarding how marginal costing should relate to pricing in LSRV and NWA areas.¹²²

In their January 2024 comments, the CEP contend that LSRV zones be maintained as a middle ground between Non-wires Solution projects and rest-of-system DRV pricing to attract DERs to places where load growth indicates a higher potential for future system upgrades. However, the CEP do not oppose some LSRV areas being converted to Non-wires Solution areas.

The City summarized the January 10, 2024, technical conference, noting that discussions persisted among the Joint Utilities and interested stakeholders. As the City reports, CEP highlighted problems with using deferral values based on avoided cost studies to determine appropriate DER compensation in constrained areas. CEP also questioned whether the Joint Utilities' approach would fairly reflect avoided transmission costs. After discussion, Staff clarified that the primary focus of the MCOS proceeding is to identify the most effective approach for MCOS studies, and that pricing issues related to DER values should be addressed in the VDER proceeding. The City concludes by noting that it was determined that comments due in the MCOS proceeding should focus on how the MCOS study should be conducted.¹²³

Determination

During the technical conference on January 10, 2024, stakeholders agreed that the MCOS proceeding is not the most efficient place to take up the Joint Utilities' deferral value

¹²² See Case 19-E-0283, CEP presentation slides from January 10, 2024 technical conference (filed January 12, 2024).

¹²³ Case 19-E-0283, City comments (filed January 16, 2024), p. 3.

proposal. The stakeholders also agreed that issues related to the quantification of the LSRV and DRV elements should be addressed in the VDER Proceeding.

Given the numerous questions raised during the November 2023 and January 2024 technical conferences, we recognize that additional process is needed to inform our decision-making and that any determinations on pricing issues should await the outcome of such process. While we establish such process below, the Joint Utilities are directed to proceed to perform comprehensive MCOS studies based upon the traditional NERA method, as modified herein.

Process and Next Steps

The Joint Utilities state that the MCOS studies should be filed every two years as part of the DSIP filings.¹²⁴ The Joint Utilities remark that, depending on the timing of a Commission order, it may be possible to have MCOS studies prior to the June 2025 DSIP filings.¹²⁵

The CEP support a requirement to file the next approved MCOS studies off-cycle from the DSIP filings. Otherwise, VDER compensation rates could not be adjusted until the next DSIP filings are provided in two years.¹²⁶ To ensure efficient investment decisions, the City would like MCOS studies to be considered on an expedited schedule.¹²⁷

In their reply comments filed on February 6, 2024, the Joint Utilities contend that LSRV values should not be adjusted

¹²⁴ Case 19-E-0283, Joint Utilities comments (filed July 20, 2023), p. 7.

¹²⁵ Case 19-E-0283, Joint Utilities comments (filed August 18, 2023), p. 11.

¹²⁶ Case 19-E-0283, CEP comments (filed July 20, 2023), pp. 19-20.

¹²⁷ Case 19-E-0283, City comments (filed July 20, 2023), p. 7.

until they are fully addressed in the VDER Proceeding. However, the Joint Utilities indicate that they will continue to submit MCOS studies as part of rate case filings.¹²⁸

Determination

As noted above, an extension has been granted for the filing of the next round of DSIPs by June 30, 2025.¹²⁹ The Joint Utilities shall file their MCOS studies on or before June 30, 2025, in these proceedings, consistent with the methodology discussed in this Order. The Joint Utilities shall include those MCOS studies in their DSIP filings due June 30, 2025. This filing date should give the Joint Utilities adequate time to develop consistent MCOS estimates per the methodology discussed in this Order. Given that a few of the Joint Utilities will have to refile studies based on a methodology different from what they originally utilized, we do not find it reasonable to require an earlier, off-DSIP cycle filing date. We also note that MCOS studies filed herein, and with the DSIPs, can inform numerous other decisions besides VDER compensation. Thus, this two-year cadence of MCOS filings is essential.

Staff shall convene a technical conference with the stakeholders within 45 days of the issuance of this Order to set up a process in the VDER proceeding in Case 15-E-0751 to discuss how to calculate costs for informing LSRV and DRV pricing considerations for Value Stack compensation. Staff shall also

¹²⁸ Case 19-E-0283, Joint Utilities comments (filed February 6, 2024), p. 3.

¹²⁹ Case 16-M-0411, Distributed System Implementation Plans, Ruling on Extension Request (issued February 7, 2024).

develop and issue a workplan and schedule for this collaborative process.

CONCLUSION

Numerous Commission proceedings have recognized the importance of relying upon marginal costs to determine economically efficient price signals.¹³⁰ The Value Stack Compensation Order recognized the critical importance of the MCOS studies to our dynamically evolving utility systems. By this Order, the Commission adopts a reasonable and consistent

method for performing MCOS studies for informing numerous pricing and compensation decisions.¹³¹

¹³⁰ Former Commission Chairman Alfred Kahn guided the Commission's initial effort to determine the relevance of marginal costs to electric rate structures, which culminated in Commission Opinion 76-15. Case 26806, Rate Design for Electric Corporations, Opinion No. 76-15 Opinion and Order Determining Relevance of Marginal Costs to Electric Rate Structures (issued August 10, 1976).

¹³¹ Because this Order addresses utility practices in developing MCOS studies that will be used to inform rates included in utility tariff schedules, the actions undertaken by the Commission relate to the administration and management of utility functions considered Type 2 actions for the purposes of the State Environmental Quality Review Act (16 NYCRR §§7.2(a) and 7.2(b)(2)(i) and (ii)), and accordingly no
(continued...)

The Commission orders:

1. Central Hudson Gas & Electric Corporation, Consolidated Edison Company of New York, Inc., New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation d/b/a National Grid, Orange and Rockland Utilities, Inc., and Rochester Gas and Electric Corporation shall file, in conformance with the discussion in the body of this Order, Marginal Cost of Service studies in these proceedings on or before June 30, 2025, and include those studies in their Distribution System Implementation Plan filings due on or before June 30, 2025.

2. Department of Public Service Staff shall convene a collaborative stakeholder process in Case 15-E-0751 to discuss pricing issues within 45 days of the issuance of this Order.

3. Department of Public Service Staff shall develop and file a workplan and schedule for the collaborative process on development of a Locational System Relief Value and Demand Reduction Value in Case 15-E-0751.

4. In the Secretary's sole discretion, the deadlines set forth in this Order may be extended. Any requests for an extension must be in writing, must include a justification for the extension, and must be filed at least three days prior to the affected deadline.

further review is required under that statute. Likewise, consistent with Sections 7(2) and 7(3) of the Climate Leadership and Community Protection Act (CLCPA) (Chapter 106 of the Laws of 2019), the Commission finds that such actions will neither interfere with the attainment of the statewide greenhouse gas emissions limits established under the CLCPA nor disproportionately burden a Disadvantaged Community.

5. These proceedings are continued.

By the Commission,

(SIGNED)

MICHELLE L. PHILLIPS
Secretary

**Description of Traditional NERA Methodology, as Modified for
Estimating System Wide Marginal Costs in this Proceeding.**

This description of marginal cost estimation below describes generally what is more fully outlined in the body of this Order.¹³²

The methodology employed by NERA to determine the marginal costs has been used for decades by NERA economists and builds upon the work of the late Dr. Alfred Kahn. In theory, marginal cost is the change in total cost with respect to a small change in output. In practice, the marginal cost estimation process seeks to understand what drives new investment and operating decisions, and how changes in consumption affect utility system operations.

The first step in a marginal cost of service (MCOS) study involves an examination of the utilities actual capital investment plans to identify load growth related projects. In this instance, that study period is ten years. Resiliency-only projects are removed leaving load-growth only and multi-value projects.

To estimate the costs of the load relief projects, the anticipated load each of these projects will serve must be calculated based on the actual load forecasts used by the utility planners when developing those capital projects. Therefore, cost estimates should already reflect a reasonable amount of spare capacity and reserve margin. The study must also reflect the actual expected costs of removal of any replaced assets and any salvage value of those replaced assets. Marginal cost estimates are developed for the various transmission and distribution network components, including Federal Energy Regulatory Commission-regulated bulk transmission system costs, down to costs at the local distribution primary and secondary line level.

¹³² This description follows in part from the description of the traditional NERA method included as part of a filing made by NYSEG and RG&E on June 7, 2019, in Case 19-E-0283.

The MCOS study must then annualize the investment costs using economic carrying charges, apply factors to add on expected levels of operating and maintenance expenses, and an allocation of administrative and general expenses. The resulting marginal costs are expressed in \$/kW of peak demand met by the investment.

Any carrying charges, expense ratios that are used in the study, must be adjusted to be forward looking to the extent that historic factors and ratios used to develop them are not materially reflective of expected future relationships. Similarly, the escalation of project costs must be based on the most recently available forecast of inflation. For these purposes, that forecast of inflation is from the BlueChip Economic Indicators' consensus forecast of inflation, as measured by the GPD-PI. Depreciation rates should also be adjusted to reflect forward-looking useful lives of investments.