NEW YORK STATE
DEPARTMENT OF PUBLIC SERVICE

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

WHITEPAPER REGARDING MARGINAL COST OF SERVICE STUDIES

Dated: March 27, 2023

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I. Background and Overview

1. Background

On April 18, 2019, the Public Service Commission (Commission or PSC) initiated a new proceeding to examine Marginal Cost of Service (MCOS) studies in the Commission's Value of Distributed Energy Resources (VDER) Value Stack Compensation Order.[1] The Commission explained that MCOS studies are critically important to dynamically evolving utility systems, but that significant variations in how the MCOS studies are conducted at 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) (collectively, the Joint Utilities) required meaningful external review to determine what methodologies will lead to the most accurate results.[2]

Simply put, marginal cost is the change in cost resulting from increasing or decreasing demand or output by one unit. Former PSC Chairman Alfred Kahn guided the Commission's initial effort to determine the relevance of marginal costs to electric rate structures, which culminated in PSC Opinion 76-15.[3] Since then, numerous Commission proceedings have recognized the importance of relying upon marginal costs in determining economically efficient price signals. For this proceeding, MCOS studies are used to quantify distribution values, specifically the avoided distribution costs associated with decreased use of the distribution system.

The Value Stack Compensation Order stated that previously approved MCOS studies would continue to be used for calculating Value Stack compensation for the Locational System

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

2 Value Stack Compensation Order, p. 16.

3 Case 26806, Proceeding on motion of the Commission as to 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) (Marginal Cost Rate Structure Order). Accessible at: https://documents.dps.ny.gov/search/Home/ViewDoc/Find?id=%7BE8AD4E1E-C893-4236-AAD2-F5D5DDE62596%7D&ext=pdf

Relief Value (LSRV) and the Demand Reduction Value (DRV) elements until the MCOS proceeding results in new MCOS studies approved by the Commission. Furthermore, the Value Stack Compensation Order directed Department of Public Service Staff (Staff) to develop and issue 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 in this proceeding.[4] Significant process was subsequently undertaken, including a stakeholder forum[5] 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 shall subsequently be performed.[7] The Staff letter indicated the whitepaper should be issued for initial and reply comments, followed by presentation to the Commission for consideration and decision making. The Joint Utilities responded to additional information requests from Staff with relevant information, which is attached to this whitepaper in the Appendix.

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4 Case 19-E-0283, Staff Letter Regarding Workplan and Schedule (filed June 6, 2019). https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={49FC5460-7B9F-480A-A7E1-912D983AAAFD}

See also the MCOS studies filed in Case 19-E-0283 by each of the Joint Utilities in response to Staff's letter on June 7, 2019. The MCOS study workpapers were filed on June 21, 2019. https://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=19-e-0283&CaseSearch=Search

5 Case 19-E-0283, Notice Announcing Marginal Cost Study Stakeholder Forum (issued June 5, 2019). https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={1DCD6372-52FC-4003-9332-7CA2E651DAB6}

6 The responses to CEP's and the City's questions were filed in Case 19-E-0283 on June 6, 2019, June 7, 2019, July 15, 2019, July 31, 2019, September 30, 2019, and November 6, 2019. https://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=19-e-0283&CaseSearch=Search

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

This whitepaper is the culmination of Staff, the Joint Utilities, and stakeholders' efforts since the Value Stack Compensation Order. It is Staff's expectation that after a public notice and comment period, the Commission may consider the recommendations contained herein for adoption, as appropriate, and direct the Joint Utilities to revise their MCOS studies accordingly.

2. Overview

Utility business MCOS estimates have traditionally been used for multiple purposes such as: 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. However, the focus of this proceeding is somewhat different. The Commission's Value Stack Compensation Order required investigating likely marginal distribution system cost reductions attributable to electricity injections from VDER-eligible distributed generators (VDGs). These estimates will be used to update the DRV and LSRV elements of the VDER Value Stack. This whitepaper is specifically focused on that purpose.

Marginal costs are often forward looking and thus, marginal costs are estimated as the expected change in cost resulting from a forecasted change in electricity demand (or load); here, the future costs are those electric delivery system cost that can be avoided when VDGs reduce net load on parts of the distribution system. 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 would seek rate recovery. The Joint Utilities should 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. Finally, although the Joint Utilities may have utilized differing modeling procedures to estimate marginal costs, it is imperative that those studies be theoretically consistent and based on consistent inputs and calculation parameters.

In the following sections, Staff compares the MCOS methodologies applied by the Joint Utilities in preparing their MCOS studies and presents stakeholder comments and Staff recommendations for modifications to each. This is followed by a discussion of various costing issues that pertain to all of the Joint Utilities' MCOS studies, including a summary of stakeholder comments and Staff proposals for modifications. Staff is primarily focused on maintaining consistency. Finally, near the end of this whitepaper, Staff recommends a MCOS study methodology to be utilized going forward.

II. Comparison of Marginal Cost of Service Study Methodologies

The Joint Utilities' marginal cost studies all begin by identifying the investment projects necessary to accommodate forecasted increases in the Joint Utilities' load. How the Utilities go about this initial step is the most distinguishing feature of their respective MCOS study methodologies.

1. Joint Utilities' Methodologies

Con Edison, O&R, NYSEG, and RG&E use actual load relief related capital projects as the primary input into their MCOS studies. These actual load relief projects were developed based on granular load forecasts, and, for the most part, are included in these companies' capital plans. To the extent the planned load relief investment projects resulted in an insufficient number of projects to be included in the study, some of these utilities added projects from historic data. Regardless of whether historic or planned, these actual load relief projects were designed by utility system planning engineers to handle a forecast of increased demand. The planned costs of the investment projects were then divided by the load intended to be served by the projects to produce a marginal cost per unit of demand.

Central Hudson and National Grid, similarly, begin their MCOS study processes by using load forecasts to identify those areas that will be constrained by load growth. A granular forecast of load growth is the first step in the study process for these utilities. The project costs identified by the Central Hudson and National Grid studies were estimated within proprietary cost models based on the load forecasts used as the first step in those modelling efforts. Central Hudson simulated numerous load trajectories for each network area to identify those areas in need of relief. Each simulated load growth trajectory is estimated using a statistical model. If five percent or more of the load trajectories result in load exceeding existing capacity ratings, then the cost model used algorithms developed with input from its planning engineers to estimate the cost for the relief projects needed to alleviate those constraints. The estimated annual costs of the identified investments are then divided by the load they are intended to serve to produce a marginal cost per unit of demand.

National Grid also uses granular forecasts of load growth as the first step in its Marginal Avoided Distribution Capacity (MADC) study process. National Grid's relatively advanced forecasts are then input into load flow modeling it then performs on all of its network areas to identify those areas in need of relief. Once load constrained areas are identified, National Grid relies upon its planning engineers to estimate the investment costs of the needed load relief. The estimated annual costs of the identified investments are essentially divided by the load they intend to serve, resulting in a marginal cost per unit of demand.

2. Stakeholder Comments

CEP contend that the six utility MCOS studies represent four distinct methodologies.[8] According to CEP, the method used by NYSEG and RG&E is distinguishable from the methods used by the other utilities since it was merely an extension of National Economic Research Associates' (NERA) traditional approach.[9] The first step was to identify pertinent capital investment projects, by examining the Companies' five-year capital investment plans and screening out any customer funded projects. All load growth projects formed the basis for the MCOS analysis. CEP indicate that although NYSEG and RG&E confirmed that the planning standards and design ratings are consistent with five-year capital plans, the cost estimates in the capital investment plans are not entirely consistent with the costs in the MCOS study.[10]

CEP also characterize Con Edison and O&R as using an identical method. Both NYC and CEP note this method is a departure from prior MCOS studies used to calculate system-wide values since the Con Edison and O&R studies first identified future investments in five distinct cost centers (Transmission, Area Station and Subtransmission, Primary Feeder, Transformer, and Secondary Cable). The investments were then grouped in order to derive marginal cost values at the network/substation level granularity.

CEP distinguish the Central Hudson and National Grid studies from those of the other utilities by characterizing the Central Hudson and National Grid studies as "avoided transmission

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8 Case 19-E-0283, CEP MCOS Comments (filed November 25, 2019) (CEP MCOS Comments), p. 7.

9 Staff notes that NERA has aided in the development of numerous MCOS studies for the Joint Utilities in the past.

10 CEP MCOS Comments, pp. 18-19.

and distribution (T&D) studies" as opposed to the "traditional marginal cost of services studies" that the other utilities relied upon.

According to CEP, the methodology involved in developing an Avoided T&D study may be different from a methodology associated with a traditional marginal cost of service study.[11] CEP contend the National Grid and Central Hudson studies more closely resemble a reasonable avoided T&D cost study approach which would contain the following specific steps:

- Develop a counterfactual 10-year load forecast that does not include future planned/forecasted Distributed Energy Resources (DERs). Future DERs include anything that is not online and operating at the time of forecasting.
- Conduct a load flow analysis to determine the system thermal and rating violations that would occur associated with a load forecast that does not include future DERs.
- Identify the traditional infrastructure investments that would be required to avoid these system violations associated with the counterfactual load scenario.
- Identify the traditional infrastructure investments that could conceivably be avoided or deferred due to the future/forecasted DER.
- Identify LSRV locations and develop a DRV and LSRV $/KW value based on the identified investments that have the potential to be avoided or deferred.

The Joint Utilities acknowledge that the analyses for some of the utilities are conducted based on forecasted load flows, while other utilities perform the analyses on the basis of capital budgets.[12] However, the utilities defend their use of various methodologies. The Joint Utilities state that they altered their methodologies to quantify, on a more granular locational basis, the avoided cost and associated potential to defer or avoid load-growth-related investments through the integration of emerging DERs. According to the Joint Utilities, a variety of utility-specific

[11] CEP MCOS Comments, p. 24.

[12] Case 19-E-0283, Joint Utilities Comments (filed on November 25, 2019), p. 2.

conditions have required methodological variations or differences in approaches among the utilities.

3. Staff Proposal

Attaining consistent MCOS estimates that reasonably reflect the actual incurred capital costs requires some standardization in study approach. A reasonable marginal cost study methodology for this proceeding should reflect the current likelihood that capacity relief projects would be required given recent expectations regarding load growth. When demand is growing, a marginal cost study must include identification of those portions of the utility's network for which the forecasted growth in demand will exceed the capacity limits of its equipment. In such instances, equipment must be augmented or replaced. Adding DERs can delay, sometimes indefinitely, the date at which capacity limits are exceeded, and avoid the need to replace equipment. Thus, MCOS studies are sometimes referred to as avoided cost studies.

The differences in how investment costs are determined are not as dramatic as CEP suggest, and the Central Hudson and National Grid studies should not be referred to as the only two avoided cost studies. All the Joint Utilities' MCOS studies are forward-looking and analyze how the costs to provide distribution service would change in order to provide an incremental increase in service. All of the study methodologies reflect the extent to which adding DERs can delay the date at which capacity limits are exceeded and avoid the need to replace equipment.

An advantage of the Con Edison, O&R, NYSEG, and RG&E approach 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 utilities. Nonetheless, this approach raises some issues which must be considered since results are highly driven by the investment projects that are selected for inclusion in the MCOS study. 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. If so, Staff seeks comments on what historic period should be considered when identifying marginal investments for inclusion in the study.

In contrast, an advantage of the Central Hudson and National Grid methods is that they both comprehensively evaluate the need for growth related projects over their entire service territories. Particularly, given the Commission's desire to develop more granular MCOS studies, Central Hudson and National Grid's ability to comprehensively identify the need for new growth-related investments across their entire networks is an important advantage. Central

Hudson estimated the need for load growth related investments by simulating load growth forecasts for each substation and transmission area.[13] National Grid developed a system-wide load flow model which utilized load and DER forecasts at the substation level.[14] National Grid then developed traditional utility solutions for each of the violations identified from the load flow analyses.[15]

All the Joint Utilities' MCOS studies are based on the identification of investments necessary to meet a forecasted growth in demand. However, the decision to allow a Utility to continue with its respective marginal cost study methodology will hinge on whether the inconsistencies and limitations raised in the following sections of this whitepaper can be reasonably addressed.

III. Costing Issues that Pertain to all filed Marginal Cost of Service Studies

A. "Run" of the MCOS Studies

1. Background

Marginal or incremental cost has been defined as the change in a firm'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). All expenditures that change as a result of these decisions are included in the marginal or incremental analysis.[16] A short-run cost analysis recognizes that many costs do not change in response to changes in demand. In contrast, a longer-run cost analysis would be reflective of changes in utility load that results in deferrals of investments.[17]

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13 Case 19-E-0283, Appendix E 2018 (filed June 7, 2019), p. 13.

14 Case 19-E-0283, National Grid's Enhanced MCOS Study Filing (filed June 7, 2019), p. 3.

15 Id., p. 4.

16 See, Case 89-C-198 Incremental Cost Study Manual, p.2. Accessible at: http://documents.dps.ny.gov/search/Home/ViewDoc/Find?id=%7BF52816A6-5A01-471A-B971-E07D57816055%7D&ext=pdf

17 In its order in 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 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. March 26, 2010 Order, 09-E-0428 p. 22.

2. Stakeholder Comments

The CEP note that an efficient allocation of resources occurs when consumers face the true long-run marginal cost of providing a good or service, and that "within the context of VDER, the long-run marginal cost utilities incur to serve an incremental unit of load represents the value or benefit attributable to DERs that avoid or delay utility investments in the distribution system."[18] Thus, CEP contend that to better capture the full avoided cost value provided by DERs and the ability for DERs to provide benefits to the system well beyond ten years, a minimum of a 10-year study methodology should be used.[19] The CEP contend that:

> there is no reason to attribute a zero value to the ability of DERs to defer or avoid secondary distribution system costs simply because a utility does not plan for these investments more than one year in advance. The value of DERs is not simply the ability to avoid specific, planned investments – it is the ability to avoid long-run costs that would otherwise be incurred if the DER was not present, even if these investments are made on a short term and emergency basis.[20]

In response to CEP's suggestion that utilities adopt a standardized approach for calculating feeder costs that could be avoided by DERs, the Joint Utilities note that incremental costs related to feeders can be relatively small. The Joint Utilities explain that "such costs are generally developed and incurred on a short time horizon as part of preparations prior to the height of the summer capability period. Thus, these utility investments may not be avoided by DER," and that "[a]ssumptions in the MCOS studies should match utility planning criteria and any actual capital planning processes and investments by the utilities."[21] The Joint Utilities also argue against quantifying marginal costs as they relate to hypothetical distribution systems.[22] Staff interprets this as an entirely long run cost study which would allow for the complete re-identification, relocation and costing out of all investments in the system.

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[18] CEP MCOS Comments, p. 6.

[19] CEP MCOS Comments, p. 28.

[20] CEP MCOS Comments, p. 42.

[21] Case 19-E-0283, Joint Utilities Reply Comment (filed December 13, 2019) (Joint Utilities Reply Comments), p. 2.

[22] Case 19-E-0283, Joint Utilities Comments (filed on November 25, 2019), p. 2.

3. *Staff Proposal*

It is particularly important to match the "run" of the costing analysis to the specific pricing decision being addressed. As the Commission has previously stated, "… deciding on the proper admixture of long-run and short-run marginal costs and the methodologies for measuring these costs, these matters relate to the manner in which the marginal cost calculations should be made and to the proposing of actual rates" [23] In other words, the pricing relevance or use case for the MCOS study should influence the "run" of the cost estimate.[24] For this proceeding, marginal costs will be used to inform VDER compensation. A short-run cost analysis recognizes that many costs do not change in response to changes in demand. Therefore, a short-run cost analysis would not be consistent with a VDER goal of substituting avoidable utility investment with DER investment. In contrast, a longer-run cost analysis could be reflective of substantial changes in utility load which could result in deferrals of investments. The key question is whether the Commission's VDER Value Stack compensation warrants evaluation of costs from a shorter versus longer run perspective. If the goal is to provide a market signal for the most efficient solutions, then purely short run approaches would not be a viable approach. [25] The Commission has previously indicated its preference that electric MCOS study cost calculations related to DER, such as energy efficiency, should reflect long-run, non-zero marginal costs regardless if segments of a Company's distribution system have no avoidable costs due to near term expected changes in demand.[26]

The run of the costing approach should be long enough to reflect the relevant incremental lumpy T&D investments that will be avoidable by the DER that will be receiving VDER compensation. Staff does not recommend a hypothetical system wide, completely long run marginal cost study which could involve reengineering and costing out the replacement of the

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[23] Opinion 76-15, p. 19.

[24] Case 89-C-198 Incremental Cost Study Manual, p. 8.

[25] See REV Track 2 order, p. 14, "rate design should be used to send value signals that enable the reduction of total system costs in the long run", and p 121, "rates should generally not be designed around a particular technology so that technology choices can be determined by price signals in the long term."

[26] Case 09-E-0428, Con Edison – Rates, Order Establishing Three-Year Electric Rate Plan (issued March 26, 2010), p. 22.

entire distribution system.[27] Although some of the investment calculations in the National Grid MADC and Central Hudson studies might be viewed as being somewhat hypothetical, Staff does not think that was what the Utilities were referring to in this statement.[28] Former PSC Chairman Alfred Kahn warned against using such a "blank slate" approach. "The blank-slate basis for marginal costing of individual network components ignores the fact that the most efficient or lowest marginal cost growth path for a firm with capacity already in existence will be constrained by the totality of its existing facilities; that will be true of each investment it makes henceforward in either additions to or replacements of existing facilities or equipment.[29] Staff does not propose such a hypothetical system wide long run marginal cost study in this proceeding.

Finally, although currently the primary use case for these MCOS studies is for the VDER proceeding, 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.[30] Demand response is called to offset peak hour loads to avoid the need for longer term investments.[31] A similar long-run view is reasonable for all of these use cases.

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[27] By definition, a strictly long run MCOS studies would treat no investment costs as fixed. Thus, a strictly long run costs study would allow for the complete re-identification of all investments in the system. However, long run marginal costing is often not strictly long-run in nature. See Volume 1, of the Economics of Regulation, Principles and Institutions, by Alfred E. Kahn, pp. 70 & 85.

[28] A hypothetical system wide long run marginal cost study involving the reengineering and costing out the replacement of the entire distribution system is what was done for the long run Hatfield Model cost estimates described on page 21 of PSC Opinion 97-2.

[29] See page 4, Whom the Gods Would Destroy or How Not to Deregulate, Alfred E. Kahn, AEI–Brookings Joint Center for Regulatory Studies, Washington, D.C., 2001

[30] Joint Utilities Technical Resource Manual (TRM), Appendix P: Effective Useful Life (EUL).

[31] Case 13-E-0573 – Tariff Filing by Consolidated Edison Company of New York, Inc to make revisions to its Demand Response Programs Rider S - Commercial System Relief Program and Rider U - Distribution Load Relief Program contained in P.S.C. No. 10 - Electricity., Order Adopting Tariff Revisions with Modifications (issued March 13, 2014), p. 8.

B. Planning Horizon of the Joint Utilities' MCOS Studies

1. Background

Given that these MCOS calculations should be long-run in nature, the demand changes which drive the marginal investments in those studies should be such that those demand changes impact planned utility investment levels. For some of the studies, the time horizon over which actual utility investment projects are chosen determines the extent to which investment changes are reflected in the studies. The demand forecasts which drive these studies have a temporal component and increase or decrease as the forecasts are carried out further in time. For other studies, investment changes are triggered when demand forecasts exceed the current level of headroom. Such demand changes could be static or dynamic.

The MCOS studies which rely upon investment cost figures taken from a sample of actual planned construction projects rely upon the planning horizon used by the engineers to develop those construction projects. Con Edison and O&R have a mix of planning horizons, 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).[32] NYSEG and RG&E identify projects based on five-year capital investment plans.[33] Thus, varying time horizons for the load changes and cost estimates are considered by these utilities when making investment decisions.

Somewhat differently, the National Grid MADC and Central Hudson simulation-based methodologies rely upon forecasting horizons. These studies cost out projects that their respective methodologies deem necessary to relieve load related constraints forecasted to occur over a ten-year horizon.[34] Demand forecasts associated with shorter or longer forecasting horizons could have been used in the studies and might have resulted in different sets of load relief projects triggered by those methodologies.

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32 Con Edison study, pp. 14-17.

33 Response to IR DSIP-18-003 (SEIA) RE [DSIP-18-003_Att_1_(16-M-0411).pdf] NYSEG and RG&E's five-year Capital Investment Plan reply on November 16, 2018.

34 National Grid MADC study, p. 4; Central Hudson study, p. 19.

2. Stakeholder Comments

The Joint Utilities contend that they are obligated to develop forecasts that reflect current conditions so that associated investments are efficient. Although increased electrification and extreme weather conditions should be considered as part of the forecasting process, the Joint Utilities argue that an MCOS approach taking into consideration such demand growth is premature.[35] In their MCOS studies, the Joint Utilities explain that the changes made between their 2016 and 2018 studies reflect a much shorter run approach.

The NYSEG and RG&E MCOS studies filed in this proceeding have lower cost estimates than their 2016 rate case studies. NYSEG and RG&E indicate that their 2018 studies no longer included costs for local primary and secondary lines and transformers because, "[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."[36] Con Edison also departed from its 2016 methodology which included investment costs for all areas. After discussions with its staff and observing the low load growth rate in load areas within certain boroughs, Con Edison assumed no secondary cable upgrades in those areas.[37]

In contrast, CEP note that the ability for DERs to provide benefits to the system extends well beyond ten years.[38] CEP point out that the New York Independent System Operator, Inc. (NYISO) load forecasting task force has modelled system growth impacts associated with the recently enacted Climate Leadership and Community Protection Act (CLCPA).[39] CEP argue

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35 Joint Utilities Reply Comments, p. 2.

36 Description of Methodology Used to Determine Marginal Costs on a System-Wide and Locational Basis Distributed System Implementation Plan July 2018

https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=8FF8A6B3-7A96-46F6-AE8A-3D825B584E8E

https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=23842374-5F94-49AB-BFC1-1E70796195A8

37 P. 21, Con Edison Marginal Cost of Service Study

38 CEP MCOS Comments, p. 28.

39 CEP MCOS Comments, p. 34.

that the utilities should use a minimum of a ten-year horizon in developing the avoided T&D study.[40]

The CEP suggest that the span of the MCOS studies should reflect a 10-year study horizon. Thus, CEP contend, the full avoided cost value provided by DERs can be better captured in the $/kW credit provided under the VDER tariff. Although the CEP note that the ability for DERs to provide benefits to the system extends well beyond ten years, a minimum of a 10-year study methodology is consistent with the "Commission order that allows DERs to lock in a ten-year rate for DRV based on the value of DRV at the point the DER comes online."[41]

In response, the Joint Utilities argue that the extent to which Electric Vehicle (EV) load and building electrification should be factored into forecasts is unclear until the New York State Department of Environmental Conservation adopts CLCPA rules.[42] Central Hudson does not believe the CLCPA goals will require more utility investment.[43] In response to CEP discovery questions on this issue, the Joint Utilities generally expressed an unwillingness to incorporate such CLCPA policies into their load forecasts until they are compelled to do so by the PSC.

3. Staff Proposal

The "run" of the study should not be confused with the time horizon of the study. The studies must be long-run in nature, regardless of the "time horizon" of the forecasts and/or planned projects that feed into the study's methodology. However, given that the marginal cost study estimates will be used to inform VDER compensation over a ten-year period, it is not surprising that parties have suggested that the MCOS studies should reflect those investments that can be avoided or deferred over that ten-year period.

With respect to marginal cost studies, the Commission has previously considered that "standard engineering practice calls for new distribution systems to be sized not simply large enough to meet expected future load growth, but intentionally oversized even beyond that, so as to minimize the probability that a costly future rebuild will be required", but then subsequently rejected that for such "parts of the distribution system, virtually no cost savings are associated

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40 CEP MCOS Comments, p. 28.

41 Id.

42 Joint Utilities Reply Comments, p. 2.

43 Response to SEIA-1, IR-002.

with reduced usage." The Commission recognized "that a number of old radial distribution circuits, upstate, though oversized when they were built, are now being stressed by levels of usage per home that have greatly exceeded expectations."[44] Thus, Staff rejects NYSEG and RG&E's proposal to exclude costs for local primary and secondary lines and transformers from their studies.[45]

For the same reason, Staff also rejects changes in other utilities' study methodologies to reflect more geographic granularity in such a manner such that some areas reflect no change in costs.[46] Existing, short run headroom in those areas should not drive those studies' results. All study areas should reflect long run changes in future costs. Similarly, the demand forecasts which drove the changes in investments needed for the National Grid and Central Hudson studies should have been increased in all areas such that those studies trigger investments to be costed out.

In sum, all MCOS studies should have been run with planning and forecasting horizons sufficient to have triggered marginal investments that are representative for all geographic areas and cost centers. Staff also notes that the CLCPA will have an impact on the Joint Utilities'

44 Case 08-E-1003, et al., Order Approving "Fast Track" Utility-Administered Electric Energy Efficiency Programs With Modifications (issued January 16, 2009), p. 36.

45 The 2018 NERA study for NYSEG and RG&E no longer include costs for local primary and secondary lines and transformers. "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." https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=8FF8A6B3-7A96-46F6-AE8A-3D825B584E8E

46 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.

investment planning.[47] Thus, CEP make a compelling argument that the horizon should be at least ten years, and possibly longer, regardless of whether some utility capital expenditure plans look ahead only five years.

Staff acknowledges that there is uncertainty regarding the level of demand growth the CLCPA will require utilities' distribution systems to handle. The NYISO, in its most recent Gold Book, indicates that electric demand will decline after 2023 and then return to current levels in about ten years, and continue to grow after that.[48] Staff's expectation is that the CLCPA will most likely trigger material investments in utility infrastructure.[49]

Staff recommends that all the Joint Utilities use a ten-year horizon for their MCOS studies. A ten-year horizon reasonably balances the concerns presented by the parties and better reflects the potential load growth resulting from the State's policy goals surrounding energy efficiency and peak load reductions. Addressing the added uncertainty associated with forecasts over a ten-year horizon will be discussed in the section on probabilistic forecasting below.

C. Reliability vs. Growth Related Investments

1. Background

Regarding the Con Edison, O&R, NYSEG, and RG&E studies, some of the projects included in a company's capital plan might not be undertaken to alleviate a capacity constraint.

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47 Case 20-E-0197, Proceeding on Motion of the Commission to Implement Transmission Planning Pursuant to the Accelerated Renewable Energy Growth and Community Benefit Act, Order on Transmission Planning Pursuant to the Accelerated Renewable Energy Growth and Community Benefit Act (issued May 14, 2020). See May order in the Transmission Planning Case 20-E-0197 which requires a study to identify new projects which would increase capacity on the local transmission and distribution system to allow for interconnection of new renewable generation resources necessary to meet the State's longer-term targets.

48 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

49 See p. 31, Figure 17 of Pathways to Deep Decarbonization in New York State June 24, 2020, Energy and Environmental Economics, Inc.(E3)

https://www.nyserda.ny.gov/-/media/Project/Nyserda/Files/EDPPP/Energy-Prices/Energy-Statistics/2020-06-24-NYS-Decarbonization-Pathways-Report.pdf

Therefore, these companies use their judgement to distinguish between the growth related and reliability and/or replacement projects in choosing growth related projects to include in their MCOS studies. This raises the concern that relevant projects could perhaps be left out of the growth-related sample. Furthermore, this study methodology is limited to those projects within each utility's capital planning horizon. If a company's planning horizon turns out to be unreasonably short, the marginal cost estimates could be biased by omitting projects that would have otherwise been included with a more appropriate planning horizon. Depending on the assumptions, the studies using this methodology could be based on a sample of investment projects which may not be reasonably representative of the forward-looking environment. Concerns regarding whether all of the relevant investment projects have been included in the MCOS study further increases the uncertainty associated with the resulting MCOS estimates.

The issue of reliability vs. growth investment projects is not pertinent to the National Grid and Central Hudson methodologies. Those studies identify all areas that would be constrained as a result of load growth, regardless of whether the current assets are already in need of upgrading irrespective of incremental load growth. The National Grid and Central Hudson methodologies do not identify costs associated with the replacement of an existing facility due to obsolescence or age in order to remain in business (including business viability in a limited geographic area).[50]

2. Stakeholder Comments

CEP state that the Utilities "have failed to justify not including costs related to other investment categories (apart from load growth categories) such as reliability and resiliency projects."[51]

3. Staff Proposal

Some of the Con Edison, O&R, NYSEG, and RG&E construction projects that were characterized as "reliability" related, and were therefore excluded from the samples of investment projects included in those studies, are also partially demand related. These

[50] Central Hudson response to SEIA 1-009 indicates that there was one historical project which was both growth and reliability based. In its response to SEIA 1-015-b Central Hudson stated that the avoided transmission and distribution study did not include the impact of any reliability-based projects.

[51] CEP MCOS Comments, p. 7.

companies included only capital projects identified solely as growth related in their MCOS studies. This contrasts with how several of the Joint Utilities characterize certain Non-Wires Alternative (NWA) opportunities as both load growth and reliability related, and treat avoided traditional utility investment costs as a benefit when analyzing those NWA projects. Any project that is a multi-value project, both load growth and reliability related, should be included in the MCOS study. The National Grid and Central Hudson methodologies identify all areas that would be constrained as a result of load growth, regardless of whether the current assets in that area are in need of an upgrade for reliability purposes.[52]

The Central Hudson and National Grid methodologies set out to identify the need for new growth-related investments across their entire networks. To the extent that Con Edison, O&R, NYSEG, and RG&E can be shown to have done this reasonably consistently, their methodologies based on actual investment projects would be more reasonable. However, to the extent that the projects included in those utilities samples is lacking in growth related projects, the sample of projects utilized in those studies must be expanded. For example, all of the projects included in the MCOS are associated with load relief programs and none come from the "Replacement Category" of Con Edison's Electric Infrastructure & Operations Panel (EIOP) Exhibit as filed in the 2019 Rate Case.[53] To the extent that some of the replacement projects could also be considered as growth-related projects, utilities should incorporate these multi-value projects in the sample of construction projects used to calculate $/kW investment costs for a traditional NERA method MCOS study.

D. Load Forecasting Methodology

1. Background

Con Edison, O&R, NYSEG, and RG&E use actual load relief related capital projects as the primary input into their MCOS studies. The load forecasts implicit in these studies are the

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[52] If Con Edison, O&R or NYSEG/RG&E were to perform two studies, one using their actual project-based method, and another using either the National Grid or Central Hudson method, it is our expectation that the study using the National Grid or Central Hudson study method would identify the need for investments in all of those multi-value project areas that were excluded from the actual project method study.

[53] Case19-E-0065 Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Consolidated Edison Company of New York, Inc. for Electric Service, Electric Infrastructure & Operations Panel.

actual load forecasts given to these utilities' planning staffs. Load relief projects are developed based on granular load forecasts.[54]

Central Hudson and National Grid similarly begin their MCOS study processes by using load forecasts to identify those areas that will be constrained by load growth. A granular forecast of load growth is also the first step in the study process for these utilities. However, the load forecasts are not the same as those used by the utility system planning engineers in developing five-year capital budgets. The project costs identified by the Central Hudson and National Grid studies were estimated within their cost models based on the load forecasts used as the first step in those modelling efforts. Central Hudson simulated numerous load trajectories for each network area to identify those areas in need of relief. Each simulated load growth trajectory is estimated using a statistical model.[55] If five percent or more of the load trajectories result in load exceeding existing capacity ratings, then the cost model used algorithms developed with input from its planning engineers to estimate the cost for the relief projects needed to alleviate those constraints.

National Grid also uses granular forecasts of load growth as the first step in its MADC study process. National Grid's relatively advanced forecasts are then input into load flow modeling, which it performs on all of its network areas to identify those areas in need of relief.

2. Stakeholder Comments

CEP make numerous recommendations regarding load forecasting methods.[56] CEP's load forecasting recommendations include the consideration of the Climate Action Council's

[54] Case 14-M-0101, 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).

[55] More specifically, Central Hudson's load trajectories are based on a relatively simplistic statistical model. Forecasted daily peaks are modeled as function of degree days, yearly, monthly and day of week dummy variables. The forecasted load trajectories are then based on Monte-Carlo simulations which vary the weather variable in the estimated demand model. Areas in need of relief are identified as those having a 5% probability of trajectories triggering a growth-related upgrade over the next 10 years. Central Hudson cost study, APPENDIX: ECONOMETRIC MODELS USED TO ESTIMATE HISTORICAL GROWTH, page 1.

[56] CEP MCOS Comments, pp. 36-38.

projections for electrification, accounting for rising temperatures, extreme weather events, and providing transparency in the assumptions that go into the utilities' respective forecasts.

3. Staff Proposal

The utilities which implicitly rely upon the forecasts used to size actual investment projects, Con Edison, O&R, NYSEG, and RG&E, should explain the forecasting methods used to identify the need for those actual projects and why the forecasting methods are reasonable for MCOS study purposes for this proceeding.

Regarding the load forecasts used to identify capacity violations for those MCOS studies which do not rely on actual projects, the National Grid integrated hierarchical bottom-up and top-down forecasting process, as set forth in its Distributed System Implementation (DSIP) Plan filings, seems to be superior as the forecast is granular down to the customer and/or circuit feeder level.[57] In contrast, Central Hudson relies upon autoregressive trend models which have a weather component to produce forecasted trajectories for each substation serving area.[58]

In future filings, all utilities should discuss the robustness of their forecasting methods over the 10-year planning horizon recommended in this whitepaper. The utilities should discuss how longer-term projections for electrification, rising temperatures, and extreme weather events are incorporated into their forecasts.

E. Counterfactual Load Forecast

1. Background

National Grid explains that it processed load flow assessments using forecasts considering two DER scenarios: (1) without additional rooftop solar beyond that presently installed; and (2) incorporating forecasted rooftop solar additions.[59]

2. Stakeholder Comments

The CEP recommend that forecasted load served by DERs be removed from the baseline load forecast used by each utility when evaluating DER deferral benefits and the value that new DERs bring to the utility system. In other words, the CEP would add back into the baseline

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[57] National Grid's 2018 DSIP Update, p. 255.

[58] Central Hudson Appendix E 2018, p. 43.

[59] National Grid study, p. 4.

forecast the load that would otherwise be delivered by the utility but for the DERs. The CEP initially stated 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] CEP subsequently revised this position in stating that the Joint Utilities' "counterfactual load forecast should not include any DERs that have not made a 25 percent construction cost down payment."[61] In other words, the utility's forecast should only reflect a reduction in load on the delivery system associated with those DERs that have made a 25 percent construction down payment. Such an approach would exclude reductions in 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]

In further support of their proposed counterfactual approach, the CEP refer to Central Hudson's statement that "including DERS that have not been built and installed into forecasts lowers load forecasts and dilutes the locational value of DER resources."[63] However, given its trend-based forecasting methodology, it is unclear the extent to which DERs have been included or excluded in Central Hudson's forecast.[64]

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[60] CEP MCOS Comments, p. 21.

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

[62] Using the phrase "include DER in the forecast" is confusing. It would be better to say, "use the forecast which reflects the decrease in company sales associated with the DER program." The counterfactual would be to "adjust the forecast to add back in sales that would have otherwise occurred but for the DER program." Staff believes this is what is meant by "remove DER from the forecast".

[63] Central Hudson MCOS study, p. 16.

[64] The CEP may be incorrectly characterizing Central Hudson's response to CEP-1, IR-001. This sentence in the response may be somewhat inaccurate. "The Central Hudson load forecasts did not include DERs that had not yet been built and connected to its distribution system". If what Central Hudson does in their forecast is based on the historical trend in sales, and then adjusts that forecasted trend for specific known new incremental DER programs, then those types of non-incremental DER programs that have occurred in the past, would continue in the future trend, even if those continuing programs result in DERs that have not yet been built and connected to the system.

3. Staff Proposal

The CEP illustrate how load forecasts are a main driver of the MCOS estimates and how the assumptions that go into those forecasts are essential to accurately estimating the value provided by DERs. One of those important assumptions is the extent to which those forecasts reflect decreases in utility load as more load is being served or offset by DERs. CEP point out that the Joint Utilities' MCOS studies rely on a forecast of future loads and the cost of building enough capacity to meet those loads.[65] The CEP explain that 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, CEP also note that 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.[66]

Marginal Costs are the relevant causative costs used for valuing the relative benefit of utility versus third party DERs to the distribution system. The avoided costs and benefits identified for NWA benefit cost analyses (BCA) calculations may provide some useful guidance here. 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 avoidable by the NWA is estimated based on a business as usual forecast which reflected yet to be built DERs which would occur absent the NWA proposal.[67] Thus, NWA's avoided investment costs are based on a counterfactual forecast, but that counterfactual may not reflect the removal of as many DERs as initially proposed by the CEP.[68] Also, important to note is that the compensation paid to the NWA solution provider is tied specifically to the traditional utility costs avoided in that location.

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[65] CEP MCOS Comments, p. 29.

[66] <u>Id.</u>

[67] Case 15-E-0229 - <u>Petition of Consolidated Edison Company of New York, Inc. for Implementation of Projects and Programs That Support Reforming the Energy Vision</u>, Order Approving Shareholder Incentives (issued January 25, 2017), p. 2.

[68] It is likely that the planning forecast used to size the traditional solution investments reflect reductions in load from certain types of DER, such as energy efficiency, that is baked into the projected trend of historical load.

Pricing relevance should be key to deciding this issue. Will the marginal costs be used to inform compensation for both existing and future DERs, or solely for purposes of compensating incremental DERs? If the latter, then the forecast used to size investments should not exclude cumulative load reduction of all DERs installed to date.[69] Determining appropriate compensation for incremental DERs is the primary use case for the marginal costs in this proceeding. Regarding the types of projects that would be covered under CEP's 25 percent interconnection costs down payment threshold,[70] it is Staff's interpretation that:

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

Though there might be many DER projects that do not require an interconnection construction down payment, the majority of the kW that actually affects the utility system and kW that planners must consider would be applicable to this threshold.

Thus, in Staff's view, the 25 percent down payment for interconnection cost threshold is reasonable. Excluding 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 also seems reasonable.[71] The Joint Utilities should clarify the extent to which DERs have been removed from their load forecasts.[72]

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[69] National Grid add backs in prior and expected solar generation to create its counterfactual load forecast. This would be reasonable if all existing and future solar were to be compensated based on the avoided cost estimates from this study.

[70] 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.

[71] 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

[72] For example, it is Staff's understanding that National Grid added back in historical Solar PV to the forecasts for some of the scenarios which were modelled in the MADC Study.

F. Probabilistic vs. Deterministic Load Forecasts

1. Background

The Department of Public Service Staff Whitepaper Guidance for 2018 DSIP Updates (DSIP Guidance Document) issued on April 26, 2018, indicates that the Joint Utilities should move toward probabilistic forecasting in their planning efforts. 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.

In response to information requests in this proceeding, the Joint Utilities provided more details on the demand forecasts which underpin their MCOS studies. While all of the Joint Utilities plan their investments to handle above normal weather, only Central Hudson used a probabilistic modelling approach. Con Edison and National Grid used deterministically relied upon single, above normal forecasts in their models, in that there is no randomness included in the application of their forecasts in their cost models. Con Edison used a 1-in-3 weather-year based forecast, meaning the weather conditions underpinning the forecast are assumed to be experienced one out of every three years. The National Grid MADC study evaluates two sets of forward-looking ten-year forecasts: a top-down forecast based on data available from the NYISO zonal level load data and growth trends, and a bottom-up forecast utilizing customer level information to develop feeder-specific, 8,760 hour load profiles over the study horizon. The top-down zonal forecasts (NYISO data growth trends, econometric, or population growth models regressed against historical data) are disaggregated down to individual substations and the bottom-up feeder-level forecasts (10 Year – 8,760 Hourly Forecast, each customer's net demand projected into feeder circuit model, accounts for changes in existing and new customers and DERs) are aggregated or "rolled up" to create similar substation views. The bottom-up forecasts include the load of existing customers and scaling factors to account for projected loads from new customers employs system-level, zonal forecasts. National Grid presents multiple weather scenarios (95/5, 90/10, 50/50), but ultimately utilizes the more extreme 95/5 weather event calibration.

Central Hudson's probabilistic model reflects load growth uncertainty via a Monte-Carlo simulation of 5,000 1-in-2 load growth trajectories for each location. The manner in which the fifty highest load forecast trajectories trigger load relief represents a probabilistic forecasting analysis. Central Hudson states that it was the first New York State utility to implement a location specific avoided T&D cost study that relies on probabilistic analysis and quantifies the option value of reducing peak demand.[73]

2. Stakeholder Comments

CEP opine that an advantage of Central Hudson's avoided T&D study, which makes it distinct from a traditional system-wide MCOS study, is the way Central Hudson's avoided T&D study utilizes probabilistic load growth forecasts and avoided cost estimates rather than straight-line forecasts.[74] CEP note the Commission's clear guidance on probabilistic forecasts in the DSIP Guidance Order and states "probabilistic load forecasts are better able to accommodate a diverse set of weather assumptions, load pattern changes, and other underlying factors that provide a more robust portrait of future system conditions and the opportunities for DERs to avoid or defer investments."[75]

3. Staff Proposal

Forecasting electric utility load has become increasingly uncertain. Given the future and somewhat unknown nature of load forecasts, those uncertainties should be considered. The most recent NYISO gold book forecasts reflect various scenarios regarding the impacts of energy saving programs and behind-the-meter generation.[76] Moreover, work at home restrictions associated with COVID-19 resulted in electricity demand dropping eight to 10 percent in the first

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[73] Central Hudson MCOS study, p. 3.

[74] CEP MCOS Comments, p. 13.

[75] CEP MCOS Comments, p. 25.

[76] See in particular, page 13 which contains Table I-1a which shows the NYCA Energy and Demand Forecasts for various scenarios.
https://www.nyiso.com/documents/20142/2226333/2022-Gold-Book-Final-Public.pdf

few months after those restrictions were implemented.[77] It is still unclear how this short-term decline will impact longer term forecasts. The Joint Utilities, except for Central Hudson, do not perform probabilistic forecasting to guide their marginal costing processes. The capital investments for these utilities are developed using a single forecasted level of peak demand, albeit a level that is based on worse-than-normal weather.

Given the increased uncertainty regarding load growth, Staff recommends that the Commission confirm its preference that the Joint Utilities rely upon probabilistic demand forecasts for distribution planning.[78] The flexibility to consider the potential for high-cost and low-cost outcomes is known as optionality in capital planning. Optionality refers to the ability of an asset owner to modify or change the use of an asset in response to different, initially unknown outcomes.[79] An example of utility T&D infrastructure investment optionality saving costs is Con Edison's Brooklyn-Queens Demand Response Management Program (BQDM), in which Con Edison's $200 million NWA investment has deferred a traditional substation investment of $1-1.2 billion for at least seven years. Subsequent load forecasts decreased significantly as predicted electricity demand had not materialized.[80] Given the uncertainties in energy price and demand forecasts and the changing needs of the electric system, the Commission recognizes

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77 See, https://www.nyiso.com/documents/20142/20986054/03%20NYISO%20COVID19%20Impacts%20Trends.pdf/06899a48-a3d3-b973-1222-85b5eb4bf13d

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

79 For example, if a 2MW/2MWh battery energy storage (BES) system is constructed to handle a short peak, and then peak duration increases, there are a few different options: Option 1. Build a new 2MW/2MWh BES (may not be possible, expensive) Option 2. Build a new 2MW/4MWh BES (may not be possible and even more expensive, and may decrease value of existing BES) Option 3. Expand the current system to 2MW/4MWh (provided the physical space, it should be much easier and cheaper to upgrade). Options #1 and #2 can always be done, but Option #3 is a new option due to the existing BES, and (presumably) is cheaper than #1 and #2. So, in probabilistic models without incorporating asset optionality, the model outcomes in the higher-demand portion of results may have higher than actual costs (or at least what actual costs needed to be) because cheaply expanding some assets is not considered.

80 New York State Energy Storage Roadmap and Department of Public Service/ New York State Energy Research and Development Authority Staff Recommendations (Roadmap), Case 18-E-0130,, p. 43

optionality's great value to the utilities.[81] The impact of adding optionality along with longer forecast periods is uncertain. All else equal, adding optionality would likely decrease expected values of marginal cost estimates, whereas increasing the forecast period will likely increase marginal cost estimates.

G. Salvage Value

1. Background

When utilities plan their budgets the cost of new investment projects include the anticipated cost of removal of the new investment as well as the salvage value of that investment.[82] Additionally, utilities may experience unanticipated removal cost and salvage values of assets being taken out of service due to the new project. Such forward looking costs, if significant, should be reflected in the MCOS studies. The Con Edison study indicates 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 value.[83] However, although Con Edison noted that they do recondition some assets for redeployment in the field, at the time of the study's preparation Con Edison concluded there is insufficient sample information for the salvage value estimates. Therefore, Con Edison and O&R set salvage values to zero for their respective studies for repurposed assets.[84]

No other utilities incorporated salvage values for repurposed assets when conducting their respective studies. After further discussions with NYSEG, RG&E, National Grid, and Central Hudson, those companies noted that though 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.

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[81] See page 49 of the Case 18-E-0130 Energy Storage Order issued on December 13, 2018.

[82] The carrying charge factors used by the utilities include a component for the recovery of removal cost and a component for the value of salvage.

[83] Con Edison study, p. 10.

[84] Con Edison's MCOS study, page 42 states "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. Should this review be difficult, an alternative approach in calculating the MCs may be to …"

2. Stakeholder Comments

Although Con Edison indicated that an internal review of the salvage values could improve its cost study results, there were no comments from stakeholders regarding salvage value prior to the issuance of this Staff Whitepaper.[85]

3. Staff Proposal

Staff understands there will likely be differences in what values go into these marginal cost estimates due to the topography and design criteria of each utility. Given its larger, network system design, it is understandable that Con Edison would have a much greater ability to repurpose transformers. That one utility may design a traditional solution differently than another, even for similar projects, does not necessarily mean that utility is wrong. Nor does it mean that all other utilities should immediately adopt the decisions of one utility.

Staff recommends that Con Edison and O&R continue to assess whether projects included in their studies have assets with expected salvage values and be clear in identifying those projects in their studies. All other utilities are encouraged to consider salvage values, but ultimately the projects included in their studies should mirror how they actually plan their system for load growth scenarios. Further, the costs in the study should reflect the costs of removal of any replaced assets, and any salvage value of those replaced assets because these are components of their forward-looking costs.

H. Spare Capacity & Reserve Margin

1. Background

How necessary spare capacity is addressed in the MCOS studies is especially relevant to excess capacity on lumpy distribution system investments such as distribution transformers. "Fill Factors" for the necessary spare capacity that is initially present as demand grows to eventually meet capacity ratings for new equipment was extensively addressed in the Department's telecommunications cost study proceedings.[86]

The 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

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[85] Con Edison study, p. 12

[86] Opinion 97-2, pp. 19, 23, and 48. http://documents.dps.ny.gov/search/Home/ViewDoc/Find?id=%7B3D6F1029-F474-4F0F-917E-530799C6DAFD%7D&ext=pdf

reliably in the event there is an unexpected increase in demand, or an unplanned outage. NYSEG and RG&E explicitly use a "Reserve Margin" adjustment in their MCOS studies. NYSEG's "typical reserve margin" is 29.56 percent and is noted as the "2013 median reserve margin (relative to summer normal rated capacity) of distribution substations with projected load growth-related investments in years 2014-2018." Whereas RG&E's "typical reserve margin" is 30.00 percent and is noted as being "sourced from the 2015 MCOS study performed by NERA."

NYSEG and RG&E explain that the typical reserve margin is reflective of their respective planning targets. According to NYSEG and RG&E, while there is variability on the loadings of specific distribution equipment in a particular year, the use of a typical reserve margin is appropriate because it aligns roughly with their planning targets. In addition, NYSEG and RG&E note that NERA recognizes that some parts of NYSEG and RG&E's systems are not constrained, therefore an adjustment is made to reflect excess capacity so that the marginal cost estimate can be used on a system-wide basis.[87]

In contrast, National Grid's MADC Study applied a Reserve Margin adjustment of 12 percent, which is consistent with the NYISO planning regarding reserve margin, to determine the quantity of DER required to defer the capacity enabled by a traditional infrastructure investment.[88]

Con Edison and O&R indicate that their MCOS studies do not explicitly apply a "Reserve Margin" adjustment in their analyses. However, they both note that the asset capacity numbers used in their respective studies reflect load contingency ratings where applicable.[89] Con Edison also explains that its MCOS study calculates the present value of unitized ($/kW of net investment/added capacity) costs for each cost center category. The unitized values reflect the difference in capacity added by the new equipment, when compared to the asset being replaced, rather than its installed capacity. Con Edison opines that this constitutes a valid approach to estimating a utility's transmission and distribution marginal costs as these unitized costs can be applied to the demand relief needed inclusive of the required (or planning) reserve.

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[87] Response to NYSEG-RG&E-015.

[88] Response to DPS-NG-01 NMPC-1, #3.

[89] Responses to DPS-CECONY-01, #3 and DPS-ORU-01, #1.

Central Hudson asserts that it did not include a "reserve margin" adjustment because the approaches used by NYSEG, RG&E and Central Hudson are distinct. Central Hudson notes that NYSEG and RG&E divided the cost of upgrades by the normal rating (in kW) of the capacity added. As Central Hudson understands it, NYSEG and RG&E included a "reserve margin" adjustment to factor in the difference between normal ratings and emergency ratings (for N-1 conditions). Central Hudson explains that the emergency ratings are also known as Long Term Emergency (LTE) ratings. Further, Central Hudson notes that its study directly analyzed the impact of load relief on T&D capital costs. According to Central Hudson, incremental load relief can help defer, avoid, or reduce capital infrastructure upgrades. Thus, Central Hudson calculated the load relief (kW) needed to attain the deferral and the value of deferring the capital investments, and notes the study does not recognize the “insurance” value of the additional capacity (capacity buffer) provided by a traditional T&D investment. Central Hudson states that in estimating the amount of load relief required to avoid capital investments, it used the normal or emergency ratings as appropriate.[90]

2. Stakeholder Comments

The treatment of necessary spare capacity was not raised by the non-utility parties in this proceeding but was noted by Energy and Environmental Economics, Inc. (E3) in their 2017 review of prior MCOS studies for the VDER proceeding as it relates to NYSEG and RG&E’s “Reserve Margin” adjustment.[91]

3. Staff Proposal

Clearly the installed capacity must be greater than the demand that triggered the investment. Although the Joint Utilities may go about it differently, it appears that each of the Joint Utilities factor in necessary reserve capacity when sizing the investments to be costed out in their studies. Thus, the discussion should then turn to the treatment of that necessary excess capacity, especially with respect to forward looking lumpy investments such as distribution transformers.

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90 Response to DPS-CH-01 IR-3.

91 http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=8787F6E7-8A84-4AAF-9393-C7CCC147485C

Each of the Joint Utilities generally calculate a unit investment cost by dividing the present value of the cost of the investments (numerator) by the added capacity (denominator). The issue here relates to what demand figure should be used in the denominator. Yet it is also clear that the extent to which such spare, reserve, and/or unused capacity is not factored into the denominator of the unit cost calculation, those unit costs will not recover the total cost of the investment. Moreover, Con Edison notes that the Commission's Case 89-C-198 Incremental Cost Study Manual describes the long-run incremental cost approach as one which "spreads the costs across capacity as it is expected to be used."[92] Con Edison contends that its MCOS study is consistent with that definition.

Staff recommends that the Commission direct the Joint Utilities to consistently reflect necessary reserve capacity in their respective unit cost estimates. Staff is not proposing to change the reserve margins used by the utilities in their respective system planning efforts. Staff is also recommending that, in future filings, each of the utilities consistently explain how their respective reserve margins are reflected in their MCOS estimates. 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.[93]

I. Input Costs

1. Background

The Joint Utilities' MCOS study methodologies all require forecasts of the equipment and labor prices used to estimate the costs of the investment projects identified in the first step of their studies.

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.[94] If the sample included historic project costs, historical input prices were escalated via an inflation factor being applied to the sampled project cost data.[95] For those studies that did not rely upon a sampling of actual project cost data, further

[92] Con Edison response to information request DPS-CECONY-01, number 3, 2/13/2020.

[93] Case 89-C-198 Incremental Cost Study Manual, p.3.

[94] Con Edison study, p. ix.

[95] Con Edison study, p. ix, fn. 10.

discovery indicates that the engineers who prepare cost estimates for capital planning purposes were relied upon to calculate the investment costs for the load relief projects identified by the MCOS study process. The Central Hudson investment cost calculation workpapers filed with the Records Access Officer as a supplement to its response to DPS-CH-01.1 indicate that Central Hudson's engineers rely upon actual engineering whitepapers to support the MCOS studies' calculated investment amounts.[96] Similarly, although the originally filed National Grid workpapers only included the total dollar value of investments costed out for MADC, the National Grid response to DPS-NG-01 NMPC-1.1, which requested additional backup, indicated that the same Cost Book Tool was used to estimate MADC costs as is used in National Grid's day-to-day operations. Moreover, the National Grid Cost Book Tool is calibrated to reconcile differences in estimates as compared to subsequent actual realized costs.

2. Stakeholder Comments

NYC 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.[97]

3. Staff Proposal

A reasonable marginal cost study should rely upon accurate estimates of unit costs (a.k.a. input prices) regardless of the modelling methodology used. Irrespective of how the various cost study methodologies identified the need for growth related investments, once identified the costs of those investments are developed with the use of equipment prices and installation costs that appear to be reflective of those that the Joint Utilities are actually facing. Thus, all Joint Utilities arguably meet Staff's interest that the MCOS studies be grounded on actual unit cost data that either currently are included on the company's books or will in the future.

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[96] CEP state that calculations for each of Central Hudson's study equipment costs were not provided. However, the workpapers having these calculations were subsequently provided in STATA code and engineering whitepapers requested by Staff and filed with the Records Access Officer.

[97] NYC November 25, 2019 comments, p 9.

J. Carrying Charge and Expense Factors

1. Background

A relevant marginal cost estimate requires a forward-looking forecast of investment carrying charges and operations and maintenance expense levels. Carrying charge and expense factors are used to develop the annual marginal cost in the Joint Utilities' service studies. First, 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. Second, annual O&M costs associated with those incremental or avoided investments are often estimated using 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.

With respect to the depreciation rates used to develop the carrying charge factors, Central Hudson, Con Edison, and O&R indicated the factors do not reflect forward looking depreciation rates. In contrast, National Grid responded that "the MADC Study used forward looking depreciation rates for all categories of utility plant in service." NYSEG and RG&E responded that, in a sense, the depreciation expenses reflected in their carrying charge factors are forward looking given that NYSEG and RG&E anticipate that these will be the depreciation rates that will prevail during the lives of the new investments.

To delve into the O&M factor calculations further than was explicitly addressed by the parties in their filings to date, Staff asked the following information requests of each member of the Joint Utilities:

> Do the carrying charge factors used to annualize costs in the MCOS studies include operations and maintenance expense factors which reflect the recent historical relationship between expense and investment amounts? Given the expected efficiencies associated with the REV related efforts, should those historic year-based expense factors (should *sic.)* be adjusted to be forward looking? Please discuss if forward looking MCOS should likely result in expense levels which sum to more, or to less, but not the same amounts as the historical cost which get fully distributed in a historical cost method.

NYSEG and RG&E responded that "[w]hile the carrying charge incorporates a return on and of the investment as well as taxes, the operating and maintenance costs needed to operate the equipment are not included in the carrying charge. Estimates of marginal O&M expenses are, however, included in the annualization process."[98] Based upon Staff's review, it appears that NYSEG and RG&E applied carrying charges and O&M factors in a similar fashion as compared to the other utilities.

2. Stakeholder Comments

CEP briefly note that "[p]roject costs were converted to levelized annual costs using the Company's revenue requirements framework,."[99] NYC also briefly mentions the Economic Carrying Charges used as a separate loader in the Con Edison study' annualizing calculation.[100]

3. Staff Proposal

Numerous considerations for the development of carrying charge and expense factors, and whether expense factors warrant a forward-looking adjustment, were explored with the Joint Utilities via Staff's information requests and in follow up discussions. A forward looking MCOS method will likely result in costs which sum to more or to less than the historical cost which gets fully distributed in a historical cost study method. The relevant question relates to whether those changes have been material. It appears that most of the companies have been tracking expense ratios over time and such ratios have not changed of late. Similarly, there did not appear to be material changes in the use of contractor work which would impact O&M expenses on a forward going basis and warrant an expense factor adjustment. National Grid did indicate that the depreciation rates used for its investment carrying charge factors used to annualize costs reflect forward looking depreciation rates. But again, adjustments to depreciation rates or the cost of capital used in carrying charge factors need only be adjusted to the extent that forward-looking rates are expected to be materially different than the recent historic factors used to annualize costs.

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98 See Appendix, p. 33

99 CEP MCOS Comments, p. 11.

100 Case 19-E-0283, Preliminary Comments of the City of New York (filed November 26, 2019), p. 10.

Finally, Staff issued interrogatories related to the level and allocation of joint and common costs in the MCOS studies. There is no clear methodological precedent for the allocation of joint and common costs in a MCOS study. Previously, Staff has argued that such MCOS study common costs allocations could be more economically efficient and forward looking if those allocations were reflective of relative demand elasticities. Parties should comment on whether common cost allocations used for MCOS studies should be reflective of relative demand elasticities.

Staff recommends that historic year-based expense factors should be adjusted to be forward looking if it would make a material difference in the estimates. Depreciation rates should also be adjusted to reflect a forward-looking useful life if material. Joint and common cost allocations should be as economically efficient as possible. This may require consideration of elasticities of demand.

K. Escalation Percentages

1. Background

Escalation percentages are used to determine how much the marginal cost estimate will increase over the duration of the study due to inflation in costs over time. Some cost elements that are escalated include: equipment, material, and labor.

2. Stakeholder Comments

NYC comments that Con Edison relied upon a 3 percent inflation rate loader when annualizing investment costs needed to accommodate incremental load growth, which NYC argues is overly high. Further, NYC notes that Con Edison assumed an unreasonably high inflation rate of 3.16 percent for purposes of calculating its separate Economic Carrying Charge loader which is also used in the investment annualizing calculation.[101] NYC asks that Con Edison be directed to instead use a 2.0 percent factor that more approximately represents current inflation rates. NYC opines that using a more-appropriate inflation rate of 2.0 percent for both the Economic Carrying Charge and investment annualization calculations would provide a valuable sensitivity analysis into the potential impact of inflation on marginal costs.

[101] Id.

3. Staff Proposal

Staff recommends that the escalation rates used in the MCOS studies should reflect current expectations about inflation and recommends that the Commission direct the Joint Utilities to use the current BlueChip consensus forecast of the Gross Domestic Price (GDP) implicit price deflator as the inflation rate for any for Economic Carrying Charge and investment annualization calculations. At the time the studies were performed, the BlueChip long-range forecast of inflation was 2.1 percent per year. Subsequently, in the months immediately following the COVID-19 shutdowns, nearer term inflation forecasts dropped to the 1.1 to 1.4 percent range. However, by April of 2021, the near-term forecast of inflation was back in the 2.1 percent range. By June of 2021, the near-term forecasts of inflation for calendar year 2021 and 2022 had increased to 2.9 percent and 2.4 percent, respectively. Subsequently, the November 2022 forecasts of near-term inflation were even higher at 7.0 percent for 2022 and 3.8 percent for 2023. However, the most recent near-term forecasts of inflation from the March 2023 issue forecasts near-term inflation of 3.6 percent for 2023 and 2.5 percent for 2024. The long-range forecast of inflation from the March 2023 issue of BlueChip remains in the 2.1 percent range. The final impact of COVID-19 on near-term and long-term inflation remains uncertain.[102] When revising their studies, the Joint Utilities should use the most up to date BlueChip consensus forecast of the GDP implicit price deflator as the inflation rate for any Economic Carrying Charge and investment annualization calculations.

L. Avoidable Asset Types to be Included in MCOS Studies

1. Background

The utilities' T&D systems are made up of many components. These range from higher voltage transmission lines, transmission substations, lower voltage transmission lines, to distribution substations, primary feeder lines and secondary lines. The parties 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 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

[102] Case 20-M-0266 - Proceeding on Motion of the Commission Regarding the Effects of COVID-19 on Utility Service, Order Establishing Proceeding (issued June 11, 2020).

which are recovered through federal tariffs.[103] In contrast, the Joint Utilities have not included transmission costs procured through NYISO Comprehensive System Planning Process (CSPP), as those costs are recovered through non-PSC jurisdictional rates. Thus, there is a disagreement regarding whether MCOS studies only relate to asset categories recovered in PSC jurisdictional rates. Additionally, there is dispute over which distribution level elements should be considered in the MCOS studies. All 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.

The Con Edison study includes two high voltage cost centers: the High Voltage System Cost Center, and the Load Area Substation and Sub-transmission Cost Center. The cost of these components is informed by Con Edison's "Area Substation and Sub-transmission Feeder Ten-Year Load Relief Plan" (LR Plan). The LR Plan is developed using a study that identifies asset upgrade needs for area stations and higher voltage level assets. The study used to develop the LR Plan effectively covers the two cost centers with higher voltage equipment over a ten-year period. 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 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 derived using a load flow analysis. National Grid's engineering team develops traditional utility solutions for each of the violations identified from the load flow analyses. National Grid has not estimated the capital investment that could potentially be deferred by DERs 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.[104] National Grid also indicates that feeder-level investments were excluded from the MADC Study methodology since DERs cannot be in place

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

[104] National Grid's Response to SEIA's September 16, 2019 Informal Information Requests – Questions 1a.

to defer investments made in the near-term under the Commission's required summer preparedness program[105]

NYSEG and RG&E include components in their MCOS studies related to their LSRV and DRV 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 explain that their 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.[106]

Central Hudson broadly categorizes their costs by Transmission and Distribution, ignoring costs below the substation level. Central Hudson refused to model distribution costs below the substation level, arguing 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.

2. *Stakeholder Comments*

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

- All transmission costs including those procured through NYISO CSPP 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.
- Costs related to other distribution planning investment categories apart from load growth related investments.[107]

[105] Response to DPS-NG-01 IR-2.

[106] As provided in response to CEP IR MCOS-19-007.

[107] CEP MCOS Comments, p. 39.

3. Staff Proposal

The MCOS studies filed in this proceeding are primarily intended to be used for calculating Value Stack elements. To best inform the Value Stack, reasonable marginal cost studies for this proceeding should estimate the avoidable costs of all demand sensitive portions of the Joint Utilities' transmission and distribution networks. To the extent that a significant level of costs associated with a transmission or distribution system element could be avoided, those costs should be included in future studies to be filed in this proceeding. Another key question that must be resolved is whether the MCOS studies should only relate to asset categories recovered in PSC jurisdictional rates. Staff notes that other external aspects of the Value Stack do not relate to costs recovered in PSC jurisdictional rates (e.g., value of carbon). Also, non-jurisdictional costs comprise a portion of the Value Stack as do non-jurisdictional Environmental values.[108] 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.

This jurisdictional question aside, it is clear the Commission was looking for some consistency in the MCOS studies.[109] National Grid notes that such below substation level costs were intentionally left out of National Grid's study, but does indicate that below substation costs could be estimated via National Grid's load flow modeling-based approach.[110] National Grid's contention that DERs cannot be in place to defer investments made in the near-term under the summer preparedness program since the program identifies needs only for upcoming summers is off point if Staff are to take a longer run costing approach. As discussed above, only Con Edison and O&R include low voltage investments below the substation level.

Staff also does not find Central Hudson's argument persuasive that it excludes below substation level costs since most feeder level growth is handled by load transfers which have insignificant costs. In its current study, most of the costs included by Central Hudson occur in a handful of locations, and when averaged over the entire Central Hudson network, might be

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[108] Case 15-E-0751, In the Matter of the 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.

[109] The Commission has been asking for consistency across utilities in REV-related orders.

[110] Response to DPS-NG-01 IR2.

considered insignificant. The pertinent question is to what extent Central Hudson can avoid feeder level costs in the longer run. In this context, Central Hudson's feeder level costs may be more significant than the 13 cents per kW presented by Central Hudson in its study. 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 the utilities be directed to include the cost of each portion of their T&D networks, including costs at the local distribution level.

M. Presentation of Costs

1. Background

In its REV Track 2 Order, the Commission adopted the policy direction that more granular rate design must be made available to engage customers efficiently in multi-sided DER markets.[111] The Commission had already recognized the need for Demand Response program designs to reflect the value of the marginal cost of avoided transmission and distribution investments, granular to the network or substation level, if possible, as well as granular load information at those same system levels.[112] In its Value Stack Compensation Order, which initiated this proceeding, the Commission confirmed its need to have the average system-wide marginal cost estimates de-averaged to reflect LSRV.[113] Thus, this proceeding was instituted to provide a thorough process to examine the MCOS studies and determine what methodologies will lead to the most accurate results,[114] specifically for purposes of the identification and valuation of LSRV zones.[115] The CEP note difficulty in evaluating the MCOS studies for this

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

[112] Case 14-E-0423, Order Instituting Proceeding Regarding Dynamic Load Management and Directing Tariff Filings (issued December 15, 2014), p. 2.

[113] Value Stack Compensation Order, p. 18

[114] Value Stack Compensation Order, p. 16

[115] Value Stack Compensation Order, p. 18

purpose, commenting that "the MCOS study results were presented in different forms across the utilities making it difficult to make meaningful comparisons."[116]

Con Edison results cover a ten-year period of 2018 through 2027 and the marginal costs for each year in the 10-year period are included in the study report. Con Edison also calculates the marginal cost for each of its 84 load areas within six regions[117] for the following five cost centers: (1) High Voltage System Cost Center; (2) Load Area Substation and Sub-transmission Cost Center; (3) Primary Feeder Cost Center; (4) Distribution Transformer Cost Center; and (5) Secondary Cable Cost Center. The results from the 84 load areas are used to create LSRV zones. Con Edison groups load area cost results using k-means clustering driven by individual area cost data and the load growth forecast. The groups are identified via a clustering of similar cost, demand, and load profile characteristics resulting in six groups, or "Aggregated Groups," with costs for each group, as well as a system average.[118] The methodology to calculate load area and system-average marginal costs for O&R are consistent with the methodology used by Con Edison for its radial system located in the Westchester region. The cost estimates are aggregated into three groups, consisting of three cost centers - High Voltage System Cost Center, Load Area Substation Cost Center, and Primary Feeder Cost Center.

Central Hudson's results cover a ten-year period, and they present marginal costs on an annual basis and on a levelized basis. Similarly, Central Hudson presents avoided costs for beneficial locations (LSRV related zones) on an annual basis and on a levelized basis by substation and load area. Central Hudson identified two LSRV related zones, arriving at the system wide value DRV by taking the weighted average of all LSRV related zones, noting that many of these locational specific values will be zero.[119]

National Grid's study and presentation of results cover a ten-year period. National Grid identified 68 unique areas (out of several hundreds) for which marginal investments would be necessary during the period of the study. To generalize the results of the MADC study across the

[116] CEP MCOS Comments, p. 19.

[117] The six regions consist of: Manhattan, the Bronx, Brooklyn, Queens, Staten Island, and Westchester.

[118] Con Edison study, p. 34.

[119] Central Hudson study, p. 41.

entire service territory, National Grid proposes essentially the same methodology as Central Hudson. Therefore, the DRV value is the product of the weighted value of the LSRV estimate and share of the system that projects in LSRV zones serve at the National Grid system peak load. Rather than presenting a different price for all LSRV zones, National Grid proposes to lump project costs into six pricing groups based on a size-weighted average of the projects in each group.[120] National Grid does not present their results on a year-by-year basis.

NYSEG and RG&E derive the DRV value differently by aggregating costs and load growth associated with those projects not located in LSRV zones. This is described as an iterative process. NYSEG and RG&E identify high value LSRV zones, by first computing the marginal distribution investment in each LSRV zone, then they compute the DRV value for all non-LSRV areas, by removing an LSRV zone, and re-computing the DRV, until DRV is greater than each LSRV as by definition the LSRV must be greater than zero. Therefore, the DRV is essentially an average value of all zero and non-zero areas up to and just before that value is more than the lowest LSRV zone not included in the DRV.[121] NYSEG and RG&E are notably different that the other utilities in that they only calculate marginal cost estimates for a single year.[122]

2. Stakeholder Comments

CEP explain that the manner in which the MCOS study results were presented in different forms across the utilities renders it difficult to make meaningful comparisons.[123] CEP attempts to describe the more comparable portions of the study in tabular form.[124]

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[120] National Grid MADC study, pp. 6-8.

[121] See pages 7 – 9 of NYSEG & RG&E presentation "Using Marginal Cost Studies to Estimate Demand Reduction Value (DRV) and Location System Relief Value (LSRV)," presented at the Case 19-E-0283 stake holder conference held on June 28, 2019.

[122] NYSEG and RG&E present "Total annual cost ($/kW-year)" figures. NYSEG and RG&E do not present costs on a year-by-year basis. The NYSEG and RG&E response to DPS-NYSEG/RGE #2 explains that the NYSEG and RG&E are looking at current marginal costs not future marginal costs.

[123] CEP November 25, 2019 comments, p. 19

[124] Table 3.2 on page 20 of CEP's November 25 comments provides a sample of the MCOS study results from each of the New York utilities' MCOS studies

Given the manner in which Con Edison's MCOS results were presented by cost center, CEP were able to summarize Con Edison's costs by high voltage and lower voltage cost centers.[125] In contrast, CEP point out that it is not clear whether "stations upstream of the distribution substations" in the NYSEG and RG&E studies include any transmission voltage equipment, or only equipment at the 69/46/34 kV level.[126]

The presentation of cost by time of day (TOD) was not raised by the parties in this proceeding but was addressed by the Commission in the REV proceeding. The Commission stated, "[w]e agree that expanding the use of opt-in TOU rates is a necessary step toward a more comprehensive reform of rate design."[127] The Commission adopted Rate Design Principles which included that rates should reflect cost causation and should encourage the policy outcome of peak load reduction.[128]

3. Staff Proposal

CEP are correct in noting that differences in the presentation of MCOS study results makes it difficult to compare the studies across the utilities. Presentation of the costs on a year-by-year basis as well as on a levelized basis would make the result more comparable. The presentation of costs for all locations would also aid in comparing similar areas within a utility's service territory and between similar service territories. MCOS estimates for all utility locations would provide the Commission with the flexibility to group together LSRV areas however it thinks most fitting. The Joint Utilities should then provide a companion analysis which groups those individual estimates into LSRV and DRV areas.

Staff recommends that marginal cost estimates be made and presented separately for utility substation serving area locations. The Joint Utilities should also present their cost estimates for each year of the ten-year study for each location in addition to providing a ten year levelized cost estimate. This would provide the Commission with the maximum flexibility in grouping together LSRV areas for compensation purposes.

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[125] CEP MCOS Comments, p. 8.

[126] CEP MCOS Comments, p. 19.

[127] REV Track 2 Order, p. 133.

[128] REV Track 2 Order, p. 122 and Appendix.

Finally, Staff recommends that the parties provide comments on whether the MCOS studies should be expanded to address the variation in costs by time of day. How should costs be determined at peak times by time of day? Staff also recommends that parties comment on whether costs should be presented for various levels of interconnection (e.g., high voltage vs low voltage).

IV. Recommendation of Preferred Method

1. Background

Earlier in this paper Staff stated that all the Joint Utilities' MCOS studies are based on the identification of investments necessary to meet a forecasted growth in demand. Staff also raised the question whether the Utilities should be allowed to continue with their respective marginal cost study methodologies to produce MCOS estimates so long as the inconsistencies and limitations discussed in the sections of this whitepaper above are addressed.

2. Stakeholder Comments

CEP states that "National Grid and CHG&E have developed load forecasts that exclude future DERs. The remaining utilities should employ similar methodologies to identify capital investments that can be avoided by DERs through a counterfactual load forecast that excludes additional DER deployment."[129]

The Joint Utilities acknowledge that the analyses for some of the utilities are conducted based on forecasted load flows, while other utilities perform the analyses on the basis of capital budgets.[130] However, the utilities defend their use of various methodologies. The Joint Utilities state that they altered their methodologies to quantify, on a more granular locational basis, the avoided cost and associated potential to defer or avoid load-growth-related investments through the integration of emerging DERs. According to the Joint Utilities, a variety of utility-specific conditions have required methodological variations or differences in approaches among the utilities.[131]

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[129] CEP MCOS Comments, p. 25.

[130] Joint Utilities Comments, p. 2.

[131] Joint Utilities Comments, p. 2.

3. Staff Proposal

Implementing the State's carbon reduction and distributed energy resources goals has increased the importance of identifying reasonable long-run marginal costs estimates going forward. To best ensure that those long-run marginal cost estimates are reasonable, all utilities should use a similar, comprehensive costing methodology which addresses Staff's recommended modifications. These modifications were intended to align methodologies and take into consideration recent Commission decisions. However, one final issue must be considered. Some of the study methodologies are more administratively burdensome and time consuming than others, and likely unreasonably so. Thus, Staff recommends a continuation of the traditional NERA method with more recent methodological issues corrected as discussed herein. To ensure that the studies are reasonably long-run in nature, 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.[132]

LSRV costs should be estimated via an iterative process similar to the procedure used by NYSEG and RG&E.[133] Staff recommends stable long run estimates for service territory wide applications like DRV and Energy Efficiency. Demand Response programs and LSRV can rely on more dynamic, and sometimes area specific, approaches.[134]

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[132] 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 companies should cost out those projects more completely and include them in the costing sample.

[133] See Value Stack Compensation Order, p. 19, and NYSEG and RG&E Description of Methodology Used to Determine Marginal Costs on a System-Wide and Locational Basis Distributed System Implementation Plan July 2018 https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=8FF8A6B3-7A96-46F6-AE8A-3D825B584E8E

[134] Pages 19-21 of the Value Stack Compensation Order discuss changes in the $/kW-year DRVs over time, and vintaging as a means for dealing with those changes. Nothing in the Value Stack Compensation order indicates that the average system-wide marginal cost based DRVs could be averages of granular cost estimates which are inclusive of zero marginal costs estimated for certain areas.

V. Process Issues

1. Background

The Value Stack Compensation Order and Staff's June 6, 2019 letter and workplan and Staff's subsequent October 24, 2019 letter have thus far established the process for this proceeding. In addition, the Commission requires utility MCOS studies to be filed along with each biennial DSIP filing, the next of which is due June 30, 2023.[135]

2. Stakeholder Comments

The City and CEP both recommend that VDER compensation for DERs through the Value Stack and other mechanisms be immediately adjusted to reflect information provided by the Joint Utilities in this proceeding. CEP also request that a proxy value for MCOS should be established should the Commission require multiple DSIP cycles to establish values or methodologies. Some companies respond that they have declining marginal costs, DER adoption in their territories will lower investment need over time, and thus grandfathered rates could overcompensate DERs. The Joint Utilities also argue against the use of proxy adders if such adders are unrelated to avoided distribution costs. Finally, CEP propose technical conferences to resolve outstanding issues on load forecasting and types of avoidable costs to be included.

3. Staff Proposal

Staff recommends that the focus of this stage of the efforts in this proceeding should be on costing used to develop the marginal cost estimates as opposed to pricing for compensation. The Value Stack Compensation Order states that "current DRV and LSRV values are based on the last MCOS studies accepted by the Commission for use in VDER tariffs and will not be updated until that proceeding is complete and has resulted in new MCOS studies approved by the Commission."[136] Thus, Staff does not recommend using proxy values for VDER compensation at this time. Compensation rates are now in place based on the older MCOS study estimates. Given that the DSIP filing cycle will likely not align with the decision timeline in this proceeding, Staff recommends that the Commission address the process for how results from future MCOS studies shall be reflected in DRV and LSRV values going forward. To inform that

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[135] Case 16-M-0411, In the Matter of Distributed System Implementation Plans, Ruling on Extension Request (issued October 13, 2022).

[136] Value Stack Compensation Order, p. 16.

decision making, the Joint Utilities should provide comments on the estimated time that would be necessary to complete new MCOS studies following a Commission decision on the recommendations in this whitepaper. In addition, stakeholders should provide comment on whether or not the Commission should require the filing of the next approved MCOS studies off-cycle from the DSIP filings.

VI. Conclusion

Given the complexity of the costing issues raised in the proceeding to date, Staff recommends that a technical conference be held within 45 days of the issuance of this whitepaper for purposes of aiding stakeholders in preparing comments on this whitepaper. Staff also recommends that sufficient notice of this whitepaper be issued seeking initial and reply comments.

Finally, given that the Joint Utilities' revised cost studies will be used to inform compensation, for auditing purposes it is essential that all workpapers, including engineering whitepapers with associated project cost estimates, electronic spreadsheet files with formulae intact, and results files should be provided to Staff and/or the Records Access Officer at the time of filing the next round of the MCOS studies.

Susan Vercheak*
Associate General Counsel

February 24, 2020

VIA E-MAIL

Ted Kelly
Associate Counsel
New York Department of Public Service
Three Empire State Plaza
Albany, NY 12223-1350

Re: Case 19-E-0283 – Proceeding on Motion of the Commission to Examine Utilities' Marginal Cost of Service Studies

Dear Mr. Kelly:

In response to your letter of February 13, 2020, attached please find the responses of Consolidated Edison Company of New York, Inc. and Orange and Rockland Utilities, Inc. to DPS-CECONY-01 and DPS-ORU-01 in the above matter.

Please contact me if you have any questions.

Very truly yours,

Susan Vercheak

Enclosures

cc: Yan Flishenbaum

*Admitted only in New Jersey

Consolidated Edison Company of New York, Inc.
4 Irving Place New York NY 10003 212 460 4333 212 677 5850 fax vercheaks@coned.com

19-E-0283
Marginal Cost of Service Studies

Staff of the Department of Public
Service Information Request

Request No.:	DPS-CECONY-01
Requested By:	Richard Schuler
Date of Request:	2/13/2020
Responded By:	Yan Flishenbaum
Subject:	Con Edison Marginal Cost of Service Study

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1. Regarding the workpapers of the Marginal Cost of Service (MCOS) Study of Consolidated Edison filed on June 21, 2019, in Case 19-E-0283, please confirm that the same Economic Carrying Charge of 9.67% and the same Common Plant percentage of 7.59% was applied to all primary feeder, secondary cable, distribution transformer, area substation, and high voltage investments that were costed out in the study. Please indicate if the forward looking useful lives are expected to be the same for all of the investments in these asset categories. If not, please indicate how the Economic Carrying Charges might vary if based on forward useful lives specific to the plant categories modeled in the study. Please discuss why the same allocation of common costs is appropriate for all such assets. Please indicate why no "Plant A&G Costs" were applied to primary feeder or secondary cable investments.

   Response:

   In the Company's MCOS study filed in Case 19-E-0283, Economic Carrying Charge of 9.67% and Common Plant loading factor of 7.59% were applied to all cost centers presented in the study (i.e., high voltage system, area substation, primary feeder, distribution transformers and secondary cable. The Economic Carrying Charge is developed using an average useful life of the entire transmission and distribution system and is applied accordingly in the study. Individual economic carrying charges specific to each cost center have not been explored in this analysis. Similarly, the Common Plant loading factor was developed for the entire transmission and distribution system.

   The Plant A&G loading factor reflects property insurance. It does not apply to primary feeder and secondary cable cost centers as the Company does not procure insurance coverage for these asset types.

2. Please discuss how the Con Edison distribution transformer total installation cost amounts provided in the "T_ProjectDetails" tab of the worksheet file provided in the Company's response to SEIA-10 match up with project investment amounts included Con Edison's Electric Infrastructure & Operations Panel (EIOP) exhibits in the current Con Edison rate case.

Response:

The distribution transformer installation costs, provided in response to SEIA-10, total approximately $18 M. This includes the population of 2015-2017 load relief projects in the Network Transformers Load Relief program. This corresponds to the historical elements of expense shown in EIOP-4 from the Company's recent rate case, approximately $15 M (see page 34 of the Company's EIOP-4 Update, filed in June 2019). Additionally, the Company's Engineering teams identified a small number of New Business projects in the 2015-2017 period which increased system capacity beyond the customer's service. These projects were added to the sample data used in the MCOS study to more accurately capture distribution transformer capacity increases.

3. NYSEG and RG&E explicitly apply a "Reserve Margin" adjustment in their MCOS studies. Please indicate if Con Edison's MCOS study contains a similar adjustment. If not, explain why.

Response:

The Company's MCOS study does not explicitly apply a "Reserve Margin" adjustment in its analysis. However, asset capacity numbers used in the study reflect load contingency ratings where applicable.

4. Staff is concerned with the treatment of excess capacity on forward looking lumpy investments such as distribution transformers modelled in the MCOS studies. Please confirm that Con Edison levelized investment costs by essentially dividing the present value of the investment cost (numerator) by the added capacity (denominator). Given the relatively lumpy nature of some distribution system investments, and since the installed capacity can be much larger than MW need that triggered the investment, should the levelization ideally be the present value of the investment divided by the present value of the demand? See NYPSC case 89-C-198 Incremental Cost Study Manual, p. 3.

Response:

The Company's MCOS study calculates the present value of unitized ($/kW of net investment/added capacity) costs for reach cost center category. The unitized values reflect the difference in capacity added by the new equipment, when compared to the asset being replaced, rather than its installed capacity. This constitutes a valid approach to estimating utility's transmission and distribution marginal costs.

Moreover, the NYPSC case 89-C-198 Incremental Cost Study Manual referenced in the question, describes the long-run incremental cost approach as one which "spreads the costs across capacity as it is expected to be used." (p.3) The Company's MCOS study is consistent with that definition. The manual also states that "the LRIC approach captures the relevant incremental costs of lumpy investments inherent to the telecommunications network. This is not to say that the LRIC is the standard to be used in all situations. The decision under analysis may dictate that other approaches to costing (i.e., short-run or intermediate-run) are appropriate." (p.3)

5. Do the carrying charge factors used to annualize costs in the Con Edison MCOS study reflect forward looking depreciation rates?

   Response:

   No.

6. Do the carrying charge factors used to annualize costs in the Con Edison MCOS study reflect the same percentage allocation of common costs for all outputs? Should economically efficient common costs allocations used for MCOS should be reflective of relative demand elasticities?

   Response:

   Please see response to question 1.

7. Do the carrying charge factors used to annualize costs in the Con Edison MCOS study include operations and maintenance expense factors which reflect the recent historical relationship between expense and investment amounts? Given the expected efficiencies associated with the REV related efforts, should those historic year based expense factors should be adjusted to be forward looking? Please discuss if forward looking MCOS should likely result in expense levels which sum to more, or to less, but not the same amounts as the historical cost which get fully distributed in a historical cost method.

   Response:

   Yes, operation and maintenance (O&M) loading factors used in the Company's MCOS study reflect recent historical relationship between expenses and investments amounts. They are developed using a ratio of current (at the time of the study) O&M costs to capital costs adjusted using reproduction estimates.

   To the extent there has not been nor is anticipated to be drastic technological changes in the make up of transmission and distribution equipment analyzed in the study, the use of current O&M loading factors is appropriate.

19-E-0283
Marginal Cost of Service Studies

Staff of the Department of Public Service
Information Request

Request No.:	DPS-ORU-01
Requested By:	Richard Schuler
Date of Request:	2/13/2020
Responded By:	Yan Flishenbaum
Subject:	Orange & Rockland Marginal Cost of Service Study

1. NYSEG and RG&E explicitly apply a "Reserve Margin" adjustment in their MCOS studies. Please indicate if Orange & Rockland's MCOS study contains a similar adjustment. If not, explain why.

   Response:

   The Company's MCOS study does not explicitly apply a "Reserve Margin" adjustment in its analysis. However, asset capacity numbers used in the study reflect load contingency ratings where applicable.

2. Staff is concerned with the treatment of excess capacity on forward looking lumpy investments such as distribution transformers modelled in the MCOS studies. Please confirm that Orange & Rockland levelized investment costs by essentially dividing the present value of the investment cost (numerator) by the added capacity (denominator). Given the relatively lumpy nature of some distribution system investments, and since the installed capacity can be much larger than MW need that triggered the investment, should the levelization ideally be the present value of the investment divided by the present value of the demand? See NYPSC case 89-C-198 Incremental Cost Study Manual, p. 3.

   Response:

   The Company's MCOS study calculates the present value of unitized ($/kW of net investment/added capacity) costs for reach cost center category. The unitized values reflect the difference in capacity added by the new equipment, when compared to the asset being replaced, rather than its installed capacity. This constitutes a valid approach to estimating utility's transmission and distribution marginal costs.

   Moreover, the NYPSC case 89-C-198 Incremental Cost Study Manual referenced in the question, describes the long-run incremental cost approach as one which "spreads the costs across capacity as it is expected to be used." (p.3) The Company's MCOS study is consistent with that definition. The manual also states that "the LRIC approach captures the relevant incremental costs of lumpy investments inherent to the telecommunications network. This is not to say that the LRIC is the standard to be used in all situations. The decision under analysis may dictate that other approaches to costing (i.e., short-run or intermediate-run) are appropriate." (p.3)

3. Do the carrying charge factors used to annualize costs in the Orange & Rockland MCOS study reflect forward looking depreciation rates?

   Response:

   No.

4. Do the carrying charge factors used to annualize costs in the Orange & Rockland MCOS study reflect the same percentage allocation of common costs for all outputs? Should economically efficient common costs allocations used for MCOS should be reflective of relative demand elasticities?

   Response:

   The Economic Carrying Charge and the Common Plant loading factor used in the Company's MCOS study have been developed using system average characteristics. Individual common plant loading factors specific to each cost center have not been explored in this analysis.

5. Do the carrying charge factors used to annualize costs in the Orange & Rockland MCOS study include operations and maintenance expense factors which reflect the recent historical relationship between expense and investment amounts? Given the expected efficiencies associated with the REV related efforts, should those historic year based expense factors should be adjusted to be forward looking? Please discuss if forward looking MCOS should likely result in expense levels which sum to more, or to less, but not the same amounts as the historical cost which get fully distributed in a historical cost method.

   Response:

   Yes, operation and maintenance (O&M) loading factors used in the Company's MCOS study reflect recent historical relationship between expenses and investments amounts. They are developed using a ratio of current (at the time of the study) O&M costs to capital costs adjusted using reproduction estimates.

   To the extent there has not been nor is anticipated to be drastic technological changes in the make up of transmission and distribution equipment analyzed in the study, the use of current O&M loading factors is appropriate.

Request No.: DPS-CH-01 IR-1
Requested by: Richard Schuler
Date of Request: February 13, 2020
Witness: Paul E. Haering
Subject: Central Hudson Marginal Cost of Service Study

Question:

This question relates to Central Hudson's response to SEIA-1, IR-015 from Synapse Energy Economics on behalf of the Solar Energy Industries Association (SEIA), dated October 17, 2018, in reference the avoided cost estimates shown in Table 12 on Page 31 of the Avoided T&D cost study filed along with Central Hudson's 2018 DSIP. In particular, regarding part b which requested "the Excel workbook (or similar electronic file) used to calculate the avoided cost estimates, with all formulas intact," Central Hudson responded that "due to the volume to data and number of simulations, the analysis was not conducted in Excel nor is this information publicly available in a format that can be shared."

Please provide any, workpapers STATA ".do" file code, STATA ".dta" data files, Excel ".xlsx" and ".csv" load data files, and Project Budget and Asset Planning ".pdf" files associated with CHG&E's 2018 DSIP avoided cost study similar to the confidential information filed with the DPS Records Access Officer on October 27, 2016 pertaining to Central Hudson's location specific avoided/marginal cost study filed in Cases 14-M-0101/16-M-0411 associated with its 2016 DSIP.

Response:

Due to the volume to data and number of simulations, the analysis was not conducted in Excel nor is this information publically available in a format that can be shared. We have provided as DPS-CH-01 IR-1 Attachment 1 and DPS-CH-01 IR-1 Attachment 2 the SEIA IR-015 Exhibits 1 and 2 with this response.

We are providing the detailed results from the simulations in CSV format, including key inputs. Please note that the file is too large for Excel. This will be provided as DPS-CH-01 IR-1 Attachment 3 and DPS-CH-01 IR-1 Attachment 4. These are the same files as previously provided to SEIA IR-015 Exhibits 3 and 4 and again due to the size will be provided through an FTP site.

Document(s) Attached:

DPS-CH-01 IR-1 Attachment 1
DPS-CH-01 IR-1 Attachment 2
DPS-CH-01 IR-1 Attachment 3
DPS-CH-01 IR-1 Attachment 4

Response by: Paul E. Haering
Title(s): Senior Vice President Engineering and Operations
Date of Response: February 25, 2020

Request No.: DPS-CH-01 IR-2
Requested by: Richard Schuler
Date of Request: February 13, 2020
Witness: Paul E. Haering
Subject: Central Hudson Marginal Cost of Service Study

Question:

Central Hudson excludes below substation level costs in its MCOS study. 2018 Avoided T&D Cost Study, p. 3. Central Hudson's response to SEIA 1-008 indicates that the 2018 Avoided T&D Cost Study identified three substations in which upgrades can be deferred for longer periods of time through relatively low-cost distribution upgrades and load transfers. However, Central Hudson's response to SEIA 2-005 indicates that primary feeder and secondary distribution level investments are not reviewed as part of the Avoided T&D Study due to the overall complexity of the analysis and the dynamic nature of the distribution system level. To what extent has Central Hudson engaged in feeder level load transfers in the past ten years? Please provided a list of feeder level load transfer projects over the past ten years along with the investment costs associated with those feeder level load transfer projects.

Response:

Central Hudson Gas & Electric Corporation ("Central Hudson") does not track this data. Switching associated with load transfers is expense related work and there is no investment/return on investment for this work. The cost to complete distribution level switching is typically below $10,000 per occurrence. A part of Central Hudson's on-going distribution automation program, our ability to complete low cost, real time switching/load transfers will significantly increase over the next several years. This will provide greater capacity to utilize our existing infrastructure to meet operating demands.

Document(s) Attached:

Response by: Paul E. Haering
Title(s): Sr VP Engineering and Operations
Date of Response: February 25, 2020

Request No.: DPS-CH-01 IR-3
Requested by: Richard Schuler
Date of Request: February 13, 2020
Witness: Paul E. Haering
Subject: Central Hudson Marginal Cost of Service Study

Question:

NYSEG and RG&E explicitly apply a “Reserve Margin” adjustment in their MCOS studies. Please indicate if Central Hudson’s MCOS study contains a similar adjustment. If not, explain why.

Response:

No. Central Hudson Gas & Electric Corporation (“Central Hudson”) did not include a "reserve margin" adjustment because the approaches used by NYSEG-RG&E and Central Hudson are distinct.

NYSEG and RG&E divided the cost of upgrades by the normal rating (in kW) of the capacity added. As we understand it, NYSEG and RG&E included a "reserve margin" adjustment to factor in the difference normal ratings and emergency ratings (for N-1 conditions). The emergency ratings as also known as Long Term Emergency (LTE) ratings.

The Central Hudson study directly analyzed the impact of load relief on T&D capital costs. Incremental load relief can help defer, avoid or reduce capital infrastructure upgrades. Central Hudson calculated the load relief (kW) needed to attain the deferral and the value of deferring the capital investments. In estimating the amount of load relief required to avoid capital investments, we used the normal or emergency ratings as appropriate.

Document(s) Attached:

Response by: Paul E. Haering
Title(s): Senior Vice President Engineering and Operations
Date of Response: February 25, 2020

Request No.: DPS-CH-01 IR-4
Requested by: Richard Schuler
Date of Request: February 13, 2020
Witness: Paul E. Haering
Subject: Central Hudson Marginal Cost of Service Study

Question:

Staff is concerned with the treatment of excess capacity on forward looking lumpy investments such as distribution transformers modelled in the MCOS studies. Please confirm that Central Hudson levelized investment costs by essentially dividing the present value of the investment cost (numerator) by the added capacity (denominator). Given the relatively lumpy nature of some distribution system investments, and since the installed capacity can be much larger than MW need that triggered the investment, should the levelization ideally be the present value of the investment divided by the present value of the demand? See NYPSC case 89-C-198 Incremental Cost Study Manual, p. 3.

Response:

The Central Hudson Gas & Electric Corporation MCOS study levelized the investments costs but not in the manner described. The value of deferring the capital investment was divided by the load relief (MW) needed to avoid the investment and subsequently levelized over the expected deferral period.

Document(s) Attached:

Response by: Paul E. Haering
Title(s): Senior Vice President Engineering and Operations
Date of Response: February 25, 2020

Request No.: DPS-CH-01 IR-5
Requested by: Richard Schuler
Date of Request: February 13, 2020
Witness: Paul E. Haering
No, Central Hudson Marginal Cost of Service Study

Question:

Do the carrying charge factors used to annualize costs in the Central Hudson MCOS study reflect forward looking depreciation rates?

Response:

No, the factors do not reflect forward looking depreciation rates.

Document(s) Attached:

Response by: Paul E. Haering
Title(s): Senior Vice President Engineering and Operations
Date of Response: February 25, 2020

Request No.: DPS-CH-01 IR-6
Requested by: Richard Schuler
Date of Request: February 13, 2020
Witness: Paul E. Haering
Subject: Central Hudson Marginal Cost of Service Study

Question:

Do the carrying charge factors used to annualize costs in the Central Hudson MCOS study reflect the same percentage allocation of common costs for all outputs? Should economically efficient common costs allocations used for MCOS should be reflective of relative demand elasticities?

Response:

The carrying charge factors were developed by facility type. While economically efficient common cost allocations could reflect relative demand elasticities, the actual costs utilized in the development of the carrying charge factors are not maintained at the necessary level of granularity.

Document(s) Attached:

Response by: Paul E. Haering
Title(s): Senior Vice President Engineering and Operations
Date of Response: February 25, 2020

Request No.:	DPS-CH-01 IR-7
Requested by:	Richard Schuler
Date of Request:	February 13, 2020
Witness:	Paul E. Haering
Subject:	Central Hudson Marginal Cost of Service Study

Question:

Do the carrying charge factors used to annualize costs in the Central Hudson MCOS study include operations and maintenance expense factors which reflect the recent historical relationship between expense and investment amounts? Given the expected efficiencies associated with the REV related efforts, should those historic year based expense factors should be adjusted to be forward looking? Please discuss if forward looking MCOS should likely result in expense levels which sum to more, or to less, but not the same amounts as the historical cost which get fully distributed in a historical cost method.

Response:

Yes, the operation and maintenance expense ("O&M") factors included in the carrying charge factors reflect the relationship between expense and investment. As there are currently no studies that document verified plant-related O&M shifts resulting from Reforming the Energy Vision related efforts, it would be premature to prospectively adjust such O&M factors, either up or down. Moreover, to the extent that there have not been any recent significant technological changes in the transmission and distribution equipment that is the subject of Central Hudson Gas & Electric Corporation's MCOS study, nor are any anticipated, the continued use of the instant methodology remains appropriate.

Document(s) Attached:

Response by:	Paul E. Haering
Title(s):	Senior Vice President Engineering and Operations
Date of Response:	February 25, 2020

May 20, 2020

Jessica Vigars, Esq.
Records Access Officer
New York State Public Service Commission
Three Empire State Plaza
Albany, NY 12223

Re: Case 19-E-0283 - Central Hudson Gas & Electric Corporation's Request for Confidential Treatment (Supplemental Response to DPS-CH-01)

Dear Ms. Vigars:

In response to an informal request from Department of Public Service Staff, Central Hudson Gas & Electric Corporation ("Central Hudson") is submitting the attached protected material which contains trade secrets and confidential commercial information, and is therefore protected material. Specifically, the protected material is a supplemental response to DPS-CH-01 which includes proprietary workpapers associated with Central Hudson's marginal cost study. A file-share link and password to access the files will be supplied separately due to file size and volume.

Central Hudson seeks confidential treatment of the protected material pursuant to 16 NYCRR Part 6-1, as detailed below.

I. Trade Secrets, Records Submitted by a Commercial Enterprise and Records Derived from Information Obtained from a Commercial Enterprise

The protected material constitutes a trade secret pursuant to Section 87 of the Public Officers Law and Part 6-1 of the Regulations. That request is supported by Section 87, as well as the decisions in *Verizon New York Inc. v. New York State Public Service Com'n*, 23 N.Y.S.3d 446 (2016), *New York Telephone Company v. Public Service Commission*, 58 N.Y.2d 213 (1982) and *Matter of Encore College Bookstores, Inc. v. Auxiliary Services Corporation of the State University of New York at Farmingdale*, 87 N.Y.2d 410 (1995).

Section 87 provides an exception from public disclosure for records that “are trade secrets or are submitted to an agency by a commercial enterprise or derived from information obtained from a commercial enterprise and which if disclosed would cause substantial injury to the competitive position of the subject enterprise.” N.Y. Public Officers Law § 87.2(d) (McKinney 2014). The protected material submitted to the New York State Public Service Commission (“Commission”) is trade secret because it is a compilation of information that is used in Central Hudson’s business and that provides Central Hudson with an opportunity to obtain an advantage over competitors who do not know or use the information. The information concerns the underlying data for the Marginal Cost of Service Study and the information was costly and time consuming to compile and is not publicly available.

The information submitted to the Commission, by Central Hudson, a commercial enterprise, is also information obtained from a commercial enterprise, Central Hudson and vendors, which if disclosed would cause substantial injury to Central Hudson, vendors and its customers.

Disclosure would harm Central Hudson and its affiliates by impairing their ability to protect confidential information, including trade secret and commercial enterprise information. The Commission promulgated Part 6-1 of the Regulations to further define what constitutes a trade secret or confidential commercial information. Section 6-1.3(b)(2) of the Regulations contains the factors the Commission will consider in determining trade secret status and/or confidential commercial information status.[1]

The Court of Appeals has considered what constitutes trade secret material and has determined that information is trade secret if it is “any formula, pattern, device or compilation of information which is used in one's business, and which gives him an opportunity to obtain an advantage over competitors who do not know or use it.”[2]. The Court held that once information is determined to be trade secret the inquiry ends and no additional inquiry is required.[3]

[1] The factors are: i) the extent to which the disclosure would cause unfair economic or competitive damage; ii) the extent to which the information is known by others and can involve similar activities; iii) the worth or value of the information to the person and the person’s competitors; iv) the degree of difficulty and cost of developing or duplicating the information by others without the person’s consent; and v) other statute(s) or regulations specifically excepting the information from disclosure. 16 N.Y.C.R.R. § 6-1.3(b)(2).

[2] *Verizon New York Inc. v. New York State Public Service Com'n*, 23 N.Y.S.3d 446 (2016) (referring to *Verizon New York Inc. v. New York State Public Service Com'n*, 46 Misc.3d 858 (2014)).

[3] *Id*.

Similarly, exemption in the Public Officers Law Section 87(2)(d) is triggered when public disclosure of confidential commercial information would "cause substantial harm to the competitive position of the person from whom the information was obtained."[4] The Court determined that the party seeking commercial information protection need not establish actual competitive harm; "rather, actual competition and the likelihood of substantial competitive injury is all that need be shown." In determining whether substantial harm exists, the Court determined that the existence of substantial competitive harm depends on the "commercial value of the requested information to competitors and the cost of acquiring it through other means." The Court concluded, "where FOIA disclosure is the sole means by which competitors can obtain the requested information, the inquiry ends here."

The protected material falls within the definition of trade secret material and confidential commercial material. The information concerns protected material that would damage Central Hudson and/or its affiliates if it is forced to incur increased costs as a result of a disadvantageous market position and the disclosure of pricing information, and customers may be harmed because they may need to pay higher prices for utility service or competitive goods and services. Similarly, Central Hudson's affiliates, contractors and consultants would be harmed if their proprietary information contained in any of the protected material became available to competitors. None of the information is publicly available. If the information is disclosed it would provide others with a competitive advantage to the detriment of Central Hudson, its vendors and affiliates and, ultimately, their customers.

The Commission is empowered to exempt from public disclosure material that constitutes a trade secret and or confidential commercial information.[5] The Company, for the reasons stated above, respectfully requests that the protected material be deemed confidential material exempt from public disclosure under Public Officers Law Section 87 and, where applicable, Part 6-1 of the Commission's Regulations.

[4] *Encore College Bookstores, Inc. v. Auxiliary Services Corporation of the State University of New York at Farmingdale*, 87 N.Y.2d 410 (1995).

[5] *New York Telephone Company v. Public Service Commission*, 56 N.Y.2d 213 (1982).

Please contact the undersigned at (845)486-5831 or pcolbert@cenhud.com with any questions regarding this matter.

Respectfully submitted,

/s/*Paul A. Colbert*

Associate General Counsel
Regulatory Affairs

cc: Lindsey Overton
Raquel Parks
Richard Schuler

Date of Request: February 13, 2020
Due Date: February 24, 2020

Request No. DPS-NG-01 NMPC-1
NMPC Req. No. NM-1

NIAGARA MOHAWK POWER CORPORATION d/b/a National Grid

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

Request for Information

FROM: Richard Schuler

TO: National Grid

SUBJECT: National Grid Marginal Cost of Service Study

Request:

1. Regarding the supporting workpapers in Excel format for National Grid's enhanced Marginal Cost of Service (MCOS) study filed on June 21, 2019, in Case 19-E-0283, please provide the supporting documentation and workpapers for each of the "POTENTIAL INVESTENT GRADE COST ($M)" amounts that are hard coded in column O of the "T + V Violations (Input)" tab of the Excel ".xlsx" workbook.

2. National Grid's response to SEIA-10 appears to indicate that distribution circuit level investments were not included in the 2018 MADC Study as the 2018 MADC Study was not designed to calculate avoided marginal costs below the substation level. Please indicate the feasibility of, and what steps would be taken to include below substation level avoided costs into National Grid's load flow modelling and marginal cost estimation methodologies.

3. NYSEG and RG&E explicitly apply a "Reserve Margin" adjustment in their MCOS studies. Please indicate if National Grid's MCOS study contains a similar adjustment. If not, explain why.

4. Staff is concerned with the treatment of excess capacity on forward looking lumpy investments such as distribution transformers modelled in the MCOS studies. Please confirm that National Grid levelized investment costs by essentially dividing the present value of the investment cost (numerator) by the added capacity (denominator). Given the relatively lumpy nature of some distribution system investments, and since the installed capacity can be much larger than MW need that triggered the investment, should the levelization ideally be the present value of the investment divided by the present value of the demand? See NYPSC case 89-C-198 Incremental Cost Study Manual, p. 3.

5. Do the carrying charge factors used to annualize costs in the National Grid MCOS study reflect forward looking depreciation rates?

6. Do the carrying charge factors used to annualize costs in the National Grid MCOS study reflect the same percentage allocation of common costs for all outputs? Should economically efficient common costs allocations used for MCOS should be reflective of relative demand elasticities?

7. Do the carrying charge factors used to annualize costs in the National Grid MCOS study include operations and maintenance expense factors which reflect the recent historical relationship between expense and investment amounts? Given the expected efficiencies associated with the REV related efforts, should those historic year based expense factors should be adjusted to be forward looking? Please discuss if forward looking MCOS should likely result in expense levels which sum to more, or to less, but not the same amounts as the historical cost which get fully distributed in a historical cost method.

Response:

1. The MADC Study identified system constraints by performing multiple load flow scenarios through contingency analysis. When the model identified constraints, engineers identified the traditional solution to mitigate the potential thermal or voltage issue. The costs of the traditional solutions, presented in column O of the "T + V Violations (Input)" tab, were based on Niagara Mohawk Power Corporation d/b/a National Grid's ("National Grid" or the "Company") Electric Cost Book ("Cost Book"), which uses actual historical project costs to develop high-level estimates that are within a standard of +50% / -25% accuracy. The Cost Book is continuously updated such that it relies on the actual historic costs from the last three-year period. The Cost Book is the tool used routinely by distribution/sub-transmission planners to estimate all projects including load additions, area expansions, or distributed generation projects. The tool relies on a database backend and does not support simple export to Excel format. The Company can provide Department of Public Service Staff ("Staff") with an in-person overview of the Cost Book tool and its functionality including a demonstration of how the estimates were developed for the MADC Study.

2. It is feasible to include areas of the system below the substation level, including feeders, into National Grid's load flow modeling. An important step in including those costs below the substation level will be differentiating those that are undertaken as part of the Company's normal summer preparedness program from those identified by the MADC Study. Identifying and addressing needed feeder-level system upgrades is currently done through the Company's summer preparedness program as required by the Commission. Under the summer preparedness program, National Grid identifies relevant projects in the winter which must be addressed on a near-term basis for the following summer. The Company's summer preparedness report to Staff is due by March 31st of each year. Feeder-level investments were thus excluded from the MADC Study methodology since distributed energy resources ("DER") could not be in place to defer investments made in the near-term under the summer preparedness program.

   Although there are some feeder upgrades that are driven by the arrival of spot loads, such as load from DC Fast Chargers, which do not appear in National Grid's feeder forecasts, predicting where these loads will show up in advance for inclusion in the MADC Study is extremely difficult if not impossible.

Name of Respondent:
Michael Falls

Date of Reply:
February 24, 2020

3. Yes, National Grid's MADC Study applied a Reserve Margin adjustment of 12 percent to translate the capacity of the system need into the quantity of DER required to defer the traditional infrastructure investment.

4. National Grid's MADC Study assessed the value to customers in terms of the revenue requirement avoided by deferring the traditional infrastructure through the 10-year study period. The MADC Study reported the net present value of the avoided revenue requirements, which was in turn divided by the necessary capacity, including the 12 percent Reserve Margin adjustment referenced in the Company's response to Question 3 above, to produce a $/MW value.

   The Company's MADC Study did use the present value, measured in dollars, of the investment needed to satisfy the constraint identified in the load flow model as the numerator. As the denominator, National Grid used the full size of the planning need, grossed up for the Reserve Margin adjustment discussed in the Company's response to Question 3 above.

5. The MADC Study used forward looking depreciation rates for all categories of utility plant in service, in alignment with the accounting practices across other revenue requirements calculations, consistent with the Company's current rate plan (Case 17-E-0238).

6. Yes, the carrying charge factors used to annualize costs in National Grid's MCOS Study are consistent with the Company's cost of capital and reflect the same percentage allocation of common costs for all cost outputs.

   The MADC Study did not allocate common costs across rate classes; its target was finding the total value of deferring the traditional solution. Thus, there was no basis to introduce relative demand elasticities.

7. Yes, the National Grid MADC Study assigned operations and maintenance expenses based on the experience of the Company's Distribution Planning and Asset Management team using the same methodology as the Company's non-wires alternatives assessments and other planning processes.

   The MADC Study captures the costs of using traditional solutions with current technologies. Thus, using current O&M loading factors is appropriate.

Anticipating changes in technologies which may drive significant changes in the ratio of expenses to capital investment was not in the scope of the MADC Study.

Name of Respondent:
Toby Hyde

Date of Reply:
February 24, 2020

MADC Study IR Follow-Up Questions

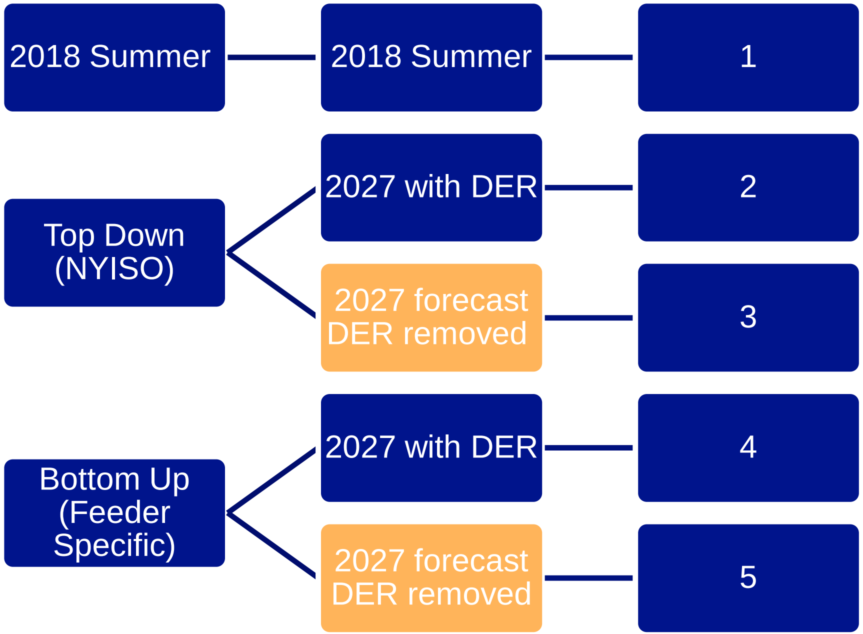
Case 19-E-0283

May 15, 2020

nationalgrid

Marginal Avoided Distribution Capacity ("MADC") IR Follow-Up Questions

The MADC Study used five forecasts to run scenario analysis



National Grid calibrated to 95/5 loading levels, consistent with traditional planning practices, including the Capital Investment Plan (CIP).

The MADC Study was originally filed July 31, 2018.

All scenarios used 2017 as a baseline.

In 2018, National Grid planners used scenario 1 as the basis for summer preparedness, and 2 and 4 as inputs to longer-term planning processes.

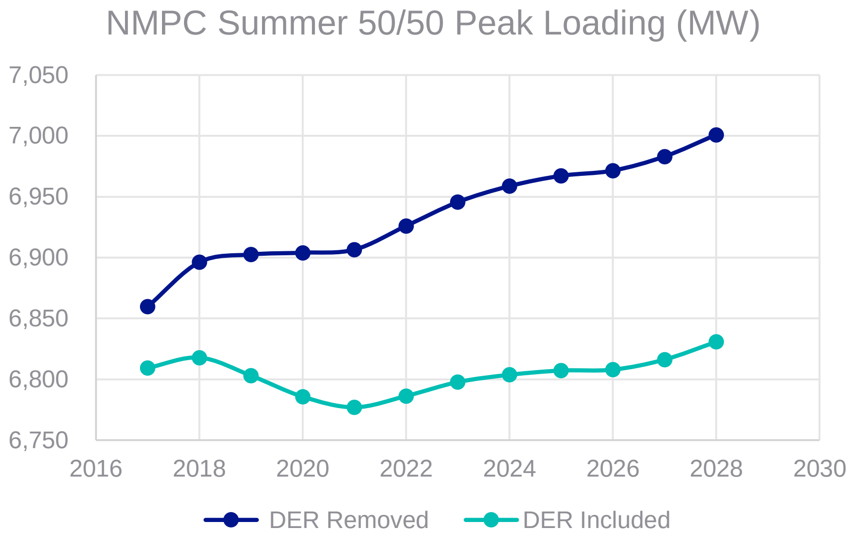
DER in the MADC Study Forecasts

- Solar PV was the only injecting DER explicitly modeled in the forecast for the MADC Study.
- National Grid files its annual forecasts, which include its DER projections, with the PSC and publicly posts on its System Data Portal.
- The method for predicting the quantity of solar PV in each zone was derived from NYISO Gold Book Forecasts at the time:
  - Short-term (1-3 years): NYISO forecasts adjusted by solar in queue and average installation time
  - Mid-term (3-6 years): solar in NMPC service territory is a pro-rata share, by load, of the State's policy goal in place at the time, consisting of 3,000 MW by 2023

Solar PV had a modest impact on peak in 2017 forecasts

NMPC Summer 50/50 Peak Loading (MW)

Year	DER (PV) Removed	DER (PV) Included	DER (PV) Reduction	PV Share of Peak
2017	6,860	6,809	50	0.73%
2018	6,896	6,818	78	1.14%
2019	6,903	6,803	99	1.44%
2020	6,904	6,786	118	1.71%
2021	6,907	6,777	129	1.87%
2022	6,926	6,786	140	2.02%
2023	6,946	6,798	148	2.13%
2024	6,959	6,804	155	2.23%
2025	6,967	6,807	160	2.29%
2026	6,971	6,808	163	2.34%
2027	6,983	6,816	167	2.39%
2028	7,001	6,831	170	2.43%



Forecasts drove outputs of the load flow model

- The MADC Study identified 68 unique traditional projects which could solve the violations identified in the load flow model.
- The top-down forecast indicated the most load growth and produced the greatest number of system planning criteria violations.
- For both the top-down and bottom-up forecasts, the **case without DER** produced higher levels of loading, which led to an increased number of violations and increased magnitude of the needs, measured in MW.
- Approximately 20% of all violations appeared in both the top-down and bottom-up model runs.
- National Grid took the most conservative course and included ALL violations which appeared in any of the model runs in the MADC Study. Where a violation appeared in multiple models at differing size, National Grid sized the solution for the largest modeled violation.

Forecasting methods have improved since 2017/2018

- The MADC Study relied on the first full run of the bottom-up forecast.
- The Company's long-term plan has been to move away from the top-down forecasts to feeder-level forecasts for basic planning purposes.
- Notable additions to forecast scenarios since 2017/2018:
  - Addition of modules to model ground-mount solar and solar + storage
    - Forecast compares net returns under the Value Stack with project costs
  - Addition of load scenarios (e.g., three electric vehicle (EV) adoption scenarios)
  - Addition of EV charging behavior based on POLARIS* modelling of commuter patterns
  - Modeling Climate Leadership and Community Protection Act (CLCPA) compliant scenarios

Planning is taking steps to fully adopt the feeder level (bottom-up) forecasts.

*POLARIS is an integrated network demand model developed by Argonne National Laboratory

The MADC Study did not explicitly model salvage value

- The MADC Study analyzed the *potential* savings to customers, measured in avoided revenue requirement over a 10-year horizon, of deferring a traditional solution
- The traditional solution does not reach the assets' end of useful life during the MADC Study period
- The MADC Study did not account for the salvage value of any assets which the traditional solution replaced
    - Netting salvage values of either the traditional solution or the assets it replaced, would lower the net cost of the traditional solution and thus the value of a DER solution

The MADC Study considered two types of O&M Costs

- The MADC Study included both (1) initial OpEx costs; and (2) ongoing O&M costs associated with a traditional solution in the value of deferring that project over the 10-year study horizon.
- National Grid calculated potential deferred OpEx costs using assumptions consistent with its 2018 rate case informed by historic actual costs.
- Initial OpEx set at 9.64...% of capital cost
- Ongoing O&M costs (ongoing OpEx):
  - Varies by FERC account category for the traditional solution number based on historic spending
    - To estimate a forward-looking rate: divide historic O&M spending by historic capital spending. The same actuals fed the allocated cost of service study (ACOS).
    - O&M spending is not traditionally tracked by FERC account number. For the MADC and other similar studies of deferral value, National Grid allocated O&M by FERC account number.
  - Where a traditional solution would have *replaced* existing assets, National Grid set the ongoing incremental O&M to zero to account for the O&M associated with the existing assets.

Requesting Party: Richard Schuler (DPS)

Response No.: NYSEG-RGE-015

Request Date: February 13, 2020

Due Date: February 28, 2020

Reply Date: February 27, 2020

Responder: Mark Marini, Kurt Strunk (NERA)

Subject: NYSEG and RG&E Marginal Cost of Service Studies

Question:

1. NYSEG and RGE explicitly apply a "Reserve Margin" adjustment in their MCOS studies. The NYSEG "typical reserve margin" is 29.56% and is noted as the "2013 median reserve margin (relative to summer normal rated capacity) of distribution substations with projected load growth-related investments in years 2014-2018." The RG&E "typical reserve margin" is 30.00% and is noted as being "sourced from the 2015 MCOS study performed by NERA for RG&E." Please provide the workpapers used in creating these typical reserve margin estimates. Please discuss the variability of reserve margins across the many NYSEG and RG&E distribution substations and why it is reasonable to use a typical reserve margin figure.

2. Staff is concerned with the treatment of excess capacity on forward looking lumpy investments such as distribution transformers modelled in the MCOS studies. Please confirm that NYSEG and RG&E levelized investment costs by essentially dividing the present value of the investment cost (numerator) by the added capacity (denominator). Given the relatively lumpy nature of some distribution system investments, and since the installed capacity can be much larger than MW need that triggered the investment, should the levelization ideally be the present value of the investment divided by the present value of the demand? See NYPSC case 89-C-198 Incremental Cost Study Manual, p. 3.

3. Do the carrying charge factors used to annualize costs in the NYSEG and RG&E MCOS studies reflect forward looking depreciation rates?

4. Do the carrying charge factors used to annualize costs in the NYSEG and RG&E MCOS studies reflect the same percentage allocation of common costs for all outputs? Should economically efficient common costs allocations used for MCOS should be reflective of relative demand elasticities?

5. Do the carrying charge factors used to annualize costs in the NYSEG and RG&E MCOS studies include operations and maintenance expense factors which reflect the recent historical relationship between expense and investment amounts? Given the expected efficiencies associated with the REV related efforts, should those historic year-based expense factors should be adjusted to be forward looking? Please discuss if forward looking MCOS should likely result in expense levels which sum to more, or to less, but not the same amounts as the historical cost which get fully distributed in a historical cost method.

Response:

1. Please see Confidential attachments 1 and 2.

The typical reserve margin is reflective of the planning targets used by NYSEG and RG&E. While there is variability on the loadings of specific distribution equipment in a particular year, the use of a typical reserve margin is appropriate because it aligns roughly with the companies' planning targets. In addition, NERA recognizes that some parts of the companies' systems are not constrained and makes an adjustment to reflect excess capacity so that the marginal cost estimate can be used on a system-wide basis.

2. The NERA marginal cost model seeks to estimate the *typical* investment per kW of load growth, not capacity addition. Use of an average over the planning horizon smooths out the lumpiness.

NERA does not see a need to use the present value of the demand because we are looking at current marginal costs not future marginal costs. NERA's model therefore uses the near-term investment per kW of load growth to measure the marginal cost. It is economically appropriate to send price signals based on the current marginal costs, not projected future marginal costs. Furthermore, discounting the streams of incremental investment and load growth would imply that the year-by-year increments in the two streams are directly related, when in fact they are generally not, which creates the lumpiness.

3. NERA's carrying charge model contains assumptions regarding tax and book depreciation for different types of network investments, as supplied by the companies. NERA anticipates that these will be the depreciation rates that prevail during the lives of the new investments. In this sense, they are forward-looking rates.

4. NERA's carrying charges are marked up by a factor that accounts for *marginal* administrative and general expenses related to plant, as determined by a statistical regression analysis. It is not an allocation *per se* and we do not see a reason to take relative demand elasticities into account.

5. While the carrying charge incorporates a return on and of the investment as well as taxes, the operating and maintenance costs needed to operate the equipment are not included in the carrying charge. Estimates of marginal O&M expenses are, however, included in the annualization process. Ideally the marginal O&M expense estimates would reflect near-term changes in these expenses and we incorporate budgeted levels of O&M in the calculations when feasible. We typically rely on recent historical levels of O&M as a starting point, making adjustments with advice from the

companies to levels of historical expenses that are not likely to be representative of near-term marginal levels.

We are not aware of any detailed studies that show likely levels of increased or reduced O&M expenses in the future.

Follow up from May 12, 2020 conference call regarding Marginal Cost Study (19-M-0283)

1. The Companies to check with capital planners regarding if there might be cost information on projects of between the end of the 5 years covered by the capital budgets, and the 10-year planning horizon that other utilities use for possible use in the MCOS study.

   Response: The Companies do have high level, non-public capital forecasts with a 10-year planning horizon. In the near term, The Companies can consider using the 10-year forecast for growth related projects that are planned to start prior to year 6 in its next marginal cost update. Projects starting in year 6 or later have less certainty and should not be reflected in the marginal cost study or included as part of the LSRV/DRV calculation. In the long-term, Case 20-E-0197 should include more definitive and robust project plans that can be used to inform the MCOS study.

2. Staff asked if the NYSEG and RG&E capital planners use a single, forecasted load number, specific to each investment location, in designing each of the investment projects included in the MCOS study. If so, Staff asked if that load number would include some amount of DER in the historical trend? The Companies indicated perhaps as a load modifier but would double check.

   Response: The Companies use specific load forecasts for the capital projects. Transmission Planners will use load flow models to determine capital project needs. Distribution Planners use actual peak load reads for each capital project. The actual peak load reads include the amount of connected DER generation on-line during the time of the read.

   DER currently on the Companies system is included in transmission modeling or actual distribution load.

3. Staff asked if there were changes specific to any individual O&M expense items for recent trends in NYSEG and RG&E expense levels.

   Response: NERA can confirm that we relied upon a 5-year historic period to determine the actual O&M expenses per kW of upstream or distribution substation investment. We did not make any adjustments to the historic data.