STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

At a session of the Public Service Commission held in the City of Albany on September 9, 2021

COMMISSIONERS PRESENT:

John B. Howard, Chair
Diane X. Burman, concurring
James S. Alesi
Tracey A. Edwards
David J. Valesky
John B. Maggiore
Rory M. Christian

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 LOCAL TRANSMISSION AND DISTRIBUTION PLANNING PROCESS AND PHASE 2 PROJECT PROPOSALS

(Issued and Effective September 9, 2021)

BY THE COMMISSION:

## INTRODUCTION

This Order continues the Public Service Commission's (Commission) implementation of the Accelerated Renewable Energy Growth and Community Benefit Act (the Act).[1] Among other things, the Act requires the Commission and New York's utilities to plan the electric transmission infrastructure necessary to meet the clean energy and climate goals set by the Climate Leadership and Community Protection Act (CLCPA).[2]

[1] Chapter 58 (Part JJJ) of the laws of 2020.

[2] Chapter 106 of the laws of 2019.

Implementation of the Act began with the Commission's May 14, 2020 Initiating Order, which required the Joint Utilities[3] to (1) file criteria for evaluating, funding, and prioritizing the local transmission and distribution (LT&D) investments needed to meet CLCPA objectives, and (2) conduct a study of their LT&D systems identifying potential upgrades.[4] On November 2, 2020, the Joint Utilities and the Long Island Power Authority (LIPA) (together, the Utilities) filed proposed project assessment criteria and the results of their study (the Filing).[5] The Utilities grouped their proposed LT&D upgrades into two categories, denominated "Phase 1" and "Phase 2," based on the availability of regulatory approval and funding mechanisms. On November 18, 2020, Department of Public Service Staff (Staff) filed a proposal that included a Phase 2 funding mechanism not considered in the Filing. On February 11, 2021, the Commission issued an order providing guidance on the Phase 1 projects and deferred action on the proposed investment criteria and Phase 2 upgrades.[6]

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[3] The Joint Utilities consist of Central Hudson Gas and Electric Corporation (Central Hudson), Consolidated Edison Company of New York, Inc. (Con Edison), New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation d/b/a National Grid (National Grid), Orange and Rockland Utilities, Inc. (O&R), and Rochester Gas and Electric Corporation.

[4] Case 20-E-0197, Order on Transmission Planning Pursuant to the Accelerated Renewable Energy Growth and Community Benefit Act (issued May 14, 2020) (the Initiating Order).

[5] Case 20-E-0197, Utility Transmission and Distribution Investment Working Group Report (filed November 2, 2020).

[6] Case 20-E-0197, Order on Phase 1 Local Transmission and Distribution Project Proposals (issued February 11, 2021) (the Phase 1 Order). The LT&D study included in the Filing is referred to herein as the Utility Study and is described in detail in the Phase 1 Order, pp. 10-12.

Shortly thereafter, on March 16, 2021, based on its review of the Filing, Staff filed a Straw Proposal for assessing the grid's ability to integrate additional renewable energy, proposing an alternative approach to the methodologies the Utilities used in developing their candidate projects.[7]

This Order makes two broad determinations. First, the Commission addresses the CLCPA investment criteria and Phase 2 upgrades. We find that several aspects of those proposals need further elaboration and require the Joint Utilities to revise and re-submit them consistent with the guidance provided herein. Second, this Order adopts Staff's recommendations for improving headroom calculations and directs the Joint Utilities to provide updated headroom data to stakeholders.

## NOTICES OF PROPOSED RULE MAKING

Pursuant to the State Administrative Procedure Act (SAPA) §202(1), the Filing was the subject of a Notice of Proposed Rulemaking published in the State Register on November 18, 2020 [SAPA No. 20-E-0197SP3]. The time for submission of comments pursuant to this notice expired on January 19, 2021. Comments were received from 22 stakeholders. The comments received are summarized in Appendix A to this Order.

In addition, a Notice of Proposed Rulemaking for the Straw Proposal was published in the State Register on March 31, 2021. The original time for submission of comments on the Staff Straw Proposal pursuant to this notice expired on June 1, 2021. However, on May 28, 2021, the Secretary granted the Utilities' request to extend the comment period until June 22, 2021. Eight

[7] Case 20-E-0197, Staff Straw Proposal for Conducting Headroom Assessments (filed March 16, 2021) (Straw Proposal).

stakeholders filed comments, which are also summarized in Appendix A.

## DISCUSSION

As stated in the Initiating Order, the Act requires the Commission to "revisit the traditional decision-making framework that the Commission and the utilities have relied on up to now for investing in transmission and distribution infrastructure."[8] That order expressly called on the Joint Utilities to help revise the traditional framework in order to meet the Act's central mandate: the requirement to identify transmission system investments needed to meet climate targets. The Utilities' November 2020 submission outlines a path toward an updated framework for these important investments.

The Commission appreciates the significant work already put into addressing the Initiating Order's directives. However, many of the Utilities' proposals for CLCPA investment criteria require revision or clarification before any Phase 2 projects can be fully reviewed or approved. This Order identifies the issues that require further elaboration and establishes principles to guide the development of the revised proposals. The Commission also adopts the Staff Straw Proposal, in order to support ongoing renewable energy procurements in the interim.

The Commission's responses to the Filing and directions for further effort with respect to the Phase 2 proposals are set forth below, followed by the discussion on headroom. Each element of the Filing and Straw Proposal is summarized in a corresponding section below, along with the Commission's associated determination.

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[8] Initiating Order, p. 4.

## A. Investment Criteria and Project Prioritization

The Initiating Order sought, among other things, the Utilities' proposals for (1) an approach to account for CLCPA benefits in planning and investment criteria; (2) an approach to prioritizing CLCPA-driven investments in the context of the Utilities' other capital needs and CLCPA timeframes; and (3) a benefit/cost analysis (BCA) to apply in evaluating potential CLCPA upgrades.[9]

In their response, the Utilities explain that LT&D investments have traditionally been driven by specific factors, including (1) reliability, safety and compliance; (2) system capacity/load growth; (3) customer requests, including distributed energy resources (DER) interconnections and public requirements, (4) asset condition/aging infrastructure and resiliency, and (5) environmental impacts.[10] Under this traditional approach, the Utilities use these factors to identify the projects they submit, with estimated capital spending needs, to the Commission in rate case filings. The Utilities identify their funded projects in their annual Capital Expenditure Plans (CEP). When the Commission establishes net plant targets as part of a rate plan, the utility retains the flexibility to organize, prioritize, and deliver the capital projects based on system needs and conditions.

In their Filing, the Utilities proposed to adopt new criteria for the assessment of LT&D investments identified as supporting CLCPA goals. Under the proposal, the Utilities would evaluate a potential Phase 2 investment in light of several criteria:

(1) Renewable Utilization: This criterion recognizes the role of local transmission infrastructure as the bridge

[9] Initiating Order, pp. 7-8.

[10] Filing, p. 14.

between the bulk power transmission facilities (BPTF) and the distribution system. It would be used to evaluate a project's capability to move renewable generation either to the bulk system or to load centers, as appropriate.

(2) Timing: This criterion considers CLCPA timelines and whether the investment should be accelerated or prioritized within that context.

(3) Expandability: This criterion describes the project's ability to be expanded to accommodate additional renewable energy development.

(4) Cost Effectiveness: The cost-effectiveness criterion estimates the net benefits and benefit/cost ratio, over a 40-year period, associated with the investment.

(5) Flexibility: This criterion refers to the project's contribution to the utility's ability to operate its T&D systems efficiently in areas of high renewable energy penetration. It examines the capacity to improve system flexibility to accommodate greater intermittency.

(6) Firmness: The firmness criterion requires an assessment of the likelihood of renewable generation interconnecting in a given area of the utility's territory.[11]

The Utilities explain that they would use these criteria in conjunction with net benefits and BCA calculations to develop Phase 2 projects for inclusion in future rate case filings. According to the Filing, as those cases proceed, a utility's T&D investment portfolio would expand to include Phase 1 and Phase 2 proposals in addition to traditional reliability, safety, and compliance projects. The Utilities recommend that their proposed approach be integrated with existing LT&D planning processes going forward without replacing or

[11] Id. at 16.

undermining any of those existing planning imperatives.[12] The Utilities state that CLCPA projects would be prioritized in the overall portfolio in a manner that would allow for the most efficient deployment and recovery of the CLCPA benefits identified in the evaluation process.

Commission Determination

The Commission finds that the Utilities' Phase 2 proposals address one of the fundamental objectives articulated in the Initiating Order: the integration of CLCPA needs with the Utilities' traditional planning processes. The Act expands their planning obligations to include planning for the State's climate goals in a manner akin to the way they currently manage reliability and other traditional system needs. The process outlined in the Filing would accomplish that by fixing evaluation criteria applicable to LT&D solutions and incorporating the resulting projects in a utility's investment portfolio. However, at this time, the Commission is not prepared to adopt the specific criteria or to conclude that there may not be other relevant factors, in part because of its significant concerns about the BCA proposal. These are discussed at length below.

B. Benefit/Cost Analysis

The Utilities assert that a simple, consistent, repeatable BCA method is needed to allow them to cost effectively prioritize investments designed or expanded to meet CLCPA mandates. While the Commission agrees that an appropriate BCA should be applied when evaluating potential transmission investments, the Utilities' approach falls short of what is needed.

[12] Filing, p. 29.

The Utilities' proposed BCA determines the CLCPA-related benefit of a potential LT&D upgrade based on the megawatt hour (MWh) quantities of the renewable generation that is unbottled and the dollar value of those MWh. The cost of the proposed LT&D upgrade included in the BCA is the annual revenue requirement associated with the project.

Under the Utilities' proposal, once the annual MWh quantities of unbottled renewable generation attributable to an LT&D project are identified, those quantities would then be valued at the cost to construct a new renewable energy resource elsewhere in the State to deliver the same quantity of renewable generation. This renewable unbottling value would be estimated based on the energy, capacity, and renewable energy credit (REC) costs that would be incurred through additional procurements. The sum of the energy, capacity, and REC costs — scaled up to account for the fact that a portion of the replacement renewable generation would also be curtailed — is meant to reflect the total cost of developing the additional renewable generation resource.[13]

The Utilities propose to base the energy costs associated with replacing the otherwise curtailed renewable generation on estimated locational based marginal pricing (LBMP) from the latest NYISO Congestion Assessment and Resource Integration Study analysis (interpolated and extrapolated as needed).[14] The Utilities would base the REC value on the most recent REC (and offshore wind REC (OREC)) prices posted or

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[13] To account for the typical curtailments of new resources, the Utilities propose to scale up this levelized cost estimate to arrive at the following formula:

Unbottling benefit = MWh unbottled x (LBMP + ICAP + REC or OREC price) / (1 - average curtailment %).

[14] The LBMP would be the projected wholesale energy price for the load zone of the proposed LT&D project.

estimated by NYSERDA and the capacity value on DPS forecasts (also extrapolated as needed).[15] The Utilities state that the sum of these energy, REC, and capacity values is a proxy for the levelized cost of adding new (less constrained) renewable energy resources elsewhere in the State.[16]

The Utilities would then compare this proxy "renewable unbottling value" with the estimated annual cost of the proposed LT&D upgrade over a 40-year assumed life, using traditional ratemaking methods. The present values of the benefits and costs would then be calculated for a 40-year evaluation period, discounted at the Utilities' blended after-tax weighted average cost of capital (after-tax WACC). The Filing proposes to use the average of all Utilities' after-tax WACC on the grounds that CLCPA benefits are societal and not specific to any individual utility.

The Utilities explain that the proposed BCA framework would apply to additional MWh exported from constrained generation pockets (i.e., unbottled on-ramps that avoid renewable generation curtailments), as well as to any additional MWh imported into constrained load pockets (i.e., unbottled off-ramps that allow for imports to displace local fossil-fired generation).

The Utilities suggest additional factors that the Commission should consider in assessing the proposed methodology. First, the Utilities opine that LT&D projects have economic lives substantially longer than the 40-year analysis period, which results in additional benefits that are not captured by this analysis; and second, that additional unquantified benefits are likely to be associated with the LT&D

[15] Filing, pp. 31-32.

[16] Id. at 33.

investments, such as market efficiency, resiliency, and flexibility benefits. For these reasons, the Utilities recommend that projects not be required to have a BCA ratio greater than 1 to be ranked for relative cost-effectiveness.

Commission Determination

At the outset, it is important to establish the key objective of the BCA in the context of CLCPA planning. In the Commission's view, the overall goal here is to arrive at the most cost-effective set of Phase 2 LT&D upgrades and associated renewable resources. Put slightly differently, the purpose of the BCA is to guide the Utilities toward the most cost-effective expenditure of ratepayer dollars to meet the CLCPA mandates. The Utilities' proposal is not properly tailored to satisfy this objective.

The Commission is concerned with whether the proposed BCA provides an accurate estimate of the relevant benefits and considers an adequate scope of alternatives. On the first point, the Commission agrees with the comment submitted by Potomac Economics in which Potomac states that the Utilities' BCA may overstate the benefits of LT&D upgrades. Potomac asserts that the proposal relies too heavily on the NYISO's 70x30 Congestion Assessment and Resource Integration Study (CARIS), which it explains was not specifically intended as an accurate forecast of either the specific locations of new generation or the technologies that would be developed in response to the CLCPA.[17] Rather, Potomac states that the 70x30 CARIS models two hypothetical buildouts of renewable energy

[17] As part of its comprehensive system planning process, the NYISO conducts a CARIS every two years, which assesses historic and projected congestion on the bulk power transmission system, the findings of which are published in a report. The 2019 CARIS Report included a 70x30 scenario based on the CLCPA.

facilities absent consideration of any economic or viability criteria to determine the location or technology mix of the future renewable energy projects. According to Potomac, reliance on this model could lead the Utilities' BCA approach to "forecast large benefits by unbottling [theoretical] projects that would likely never be built."[18]

Potomac further points out that the Utilities' BCA framework: (1) does not use LBMP estimates that are specific to the pricing nodes, and hours, where and when renewable curtailment would be relieved; (2) does not adjust renewable ICAP values for the expected future impacts of their increasing saturation level; and (3) uses the full average REC value per MWh, even if an additional REC could be obtained in an unconstrained area, potentially leading to a double-counting of this "benefit."

NY-BEST and Potomac also take issue with the Utilities' proposed BCA for its narrow "Comparison to Traditional Investments" approach, noting that such approach overlooks alternatives such as energy storage. Potomac states that energy storage, alternative siting of generation, competitive transmission investment (including merchant facilities or facilities funded by market participants), demand-side solutions, and other NYISO transmission siting processes that should also be evaluated.[19]

To address these shortcomings, the Commission finds that the Utilities should revise and resubmit the proposed BCA for Phase 2 upgrades. When Phase 2 upgrades are proposed, the Utilities must be able to demonstrate both that the upgrades are the least cost or highest value options as compared to advanced

[18] Potomac Comments, p. 8.

[19] Potomac Comments, pp. 4-5.

technology solutions and other potentially viable alternatives. The Commission believes a more appropriate BCA should be based on long-term capacity expansion modeling that considers the costs and market revenues of various types of resources across multiple scenarios with appropriate bounds for the uncertainty of key assumptions. This capacity expansion model should be used, along with screening criteria, in an iterative process to arrive at the most cost-effective set of LT&D upgrades with associated bulk or LT&D connected renewable resources, and integrated with the statewide planning process required by this Order.[20] The Commission will also require the Utilities to apply the non-wires alternatives (NWA) suitability criteria - either before developing traditional solutions to address needs, or as part of the full gamut of potential alternatives included - when attempting to derive the least cost approach to meeting CLCPA requirements.

The revised BCA approach must include periodic updating of the capacity expansion model and estimates to account for changing conditions, and proposed protocols for how NWAs will be incorporated. The Commission notes that the more transparent and coordinated planning process envisioned in this Order will help with the identification of the most efficient alternative solutions. In addition, the revised headroom methodology adopted in this Order will support more accurate assessments of costs and benefits.[21]

The Commission agrees that the revised BCA approach for CLCPA-driven LT&D investments should be as consistent as possible with the Commission's BCA framework used to evaluate

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[20] See infra at Section C.

[21] See discussion of headroom in Part G of this Order.

distributed energy resources.[22] For example, the Commission generally concurs with the Utilities' proposal to calculate and consider two BCA metrics relevant to the prioritization of LT&D projects: (1) net benefits; and (2) a benefit-to cost ratio. In addition, the Utilities should calculate and consider ratepayer bill impacts. Finally, because Phase 2 LT&D projects fall into two general categories – on-ramping renewable energy to the transmission system and off-ramping generation to lower voltage levels -- the revised BCA approach should address any overlapping benefits arising from each category of projects to ensure there is no double counting of benefits.

The Commission does not agree with Multiple Intervenors' comment to preemptively require a BCA ratio greater than one. In justifying proposals, the Utilities can discuss if there are ancillary benefits not included in the BCA metric, for whatever reason, or if there are other reasons why a project should be considered in addition to its benefit-cost and bill impact assessments.

Nor does the Commission agree with Potomac's suggestion to use a 20-year period of analysis to evaluate project benefits on the basis that generation assets are assumed to have shorter economic life than transmission assets. While that assumption may be true, the expectation is that the generation asset would be replaced with another renewable generation asset after 20 years, thereby extending the unbottling benefits of the transmission asset. Although the typical depreciation life of transmission facilities exceeds 40 years, the 40-year evaluation period is reasonable because the present value of any revenue requirements beyond 40 years will

[22] Case 14-M-0101, supra, Order Establishing the Benefit Cost Analysis Framework (issued January 21, 2016) (BCA Framework Order).

be very small. Therefore, the calculation of costs for the BCA analysis should be based on a 40-year economic life of the transmission asset.[23]

We do not agree with Potomac's argument that the use of the Utilities' average cost of capital in the BCA methodology would not allow ratepayers to secure CLCPA benefits at a lower cost. Although Potomac is correct that a "merchant" cost of capital – one that is aligned with the risks associated with generation projects that rely on NYISO market revenues - may be higher compared to that of regulated transmission owners, Potomac is incorrect in suggesting that a higher discount rate should be used in the BCA for determining how ratepayer dollars are spent. The purpose of this BCA is to determine the most cost-effective use of ratepayer dollars to meet the CLCPA mandates.[24] The expected cost to ratepayers of renewable projects built in less constrained areas should be compared to the costs of constrained renewable projects and the necessary transmission investments to unbottle such projects. As explained in the BCA Framework Order, the purpose of a discount rate is to evaluate alternatives to utility expenditures, and thus, that discount rate should reflect the opportunity cost of capital for those utility expenditures.[25] The Utilities shall confirm that the WACC to be used for discounting in their BCA

[23] The cost formula should also consider any maintenance capital expenditures that may be necessary in the later years of the LT&D investment's useful life.

[24] This determination is confined to the discounting of the projected costs and benefits in the final BCA and rate payer impact metrics. The expansion planning analysis that in part, determines the expected costs of new renewable generation that will feed into the BCA metrics, should use the appropriate WACC to accurately forecast the REC bids NYSERDA is likely to receive, with guidance from Staff and NYSERDA.

[25] BCA Framework Order, p. 25.

proposal is the weighted average of each after-tax WACC as filed in the Utilities' respective distributed system implementation plan (DSIP) filings, or the Utility's after-tax WACC if updated by a rate case order subsequent to a DSIP filing.

Finally, the Commission agrees with LS-Power's comment that the cost effectiveness of each unbottling effort must be evaluated. Evaluating projects using a portfolio approach could result in approval of a project that would not make sense on its own, but benefits from being grouped with other projects that are cost effective. However, we do not preemptively rule out the potential to tie together the benefits of multiple projects in certain instances. Meeting CLCPA requirements in the most economically efficient manner will require understanding the interaction of the economic impacts between new transmission, generation, and other projects. In some instances, the most economic set of projects considered jointly may differ from the group of projects selected individually in a serial fashion. Under the Act and Commission precedent, the Utilities have an obligation to find the most efficient overall investment solution. The coordinated planning and Phase 2 review process described later in this Order will support the Utilities' efforts to meet this obligation.

In conclusion, the Utilities are directed to revise their BCA proposal and to file the revision within 90 days of the date of this Order, following consultation with Staff. The Utilities are further directed to reconsider their proposed criteria in light of the changes to the BCA and to resubmit them if modifications or additions are warranted.

## C. Stakeholder Engagement and Planning

The Initiating Order requested proposals from the Joint Utilities for "[a] transparent planning process, to be implemented by the utilities with as much consistency and interoperability as possible, that will identify additional projects on the distribution and local transmission systems that support achievement of CLCPA goals."[26] In response, the Utilities do not propose major changes to their planning processes but recommend enhancing their stakeholder engagement initiatives. The Commission finds this proposal does not meet the requirements of the Act.

In the Filing, the Utilities note that they share planning responsibilities with the NYISO. They explain that the NYISO, under its Federal Energy Regulatory Commission (FERC) tariff, has responsibility for identifying reliability needs on the Bulk Power Transmission Facilities (BPTF). The NYISO performs this function through its Comprehensive System Planning Process (CSPP), which includes the quarterly Short-term Reliability Process (STRP), the biennial Reliability Needs Assessment (RNA), and Comprehensive Reliability Plan (CRP). The NYISO also carries out economic planning through the Congestion Assessment and Resource Integration Study (CARIS) and identifies solutions to public policy needs through the Public Policy Transmission Planning Process (PPTPP).

As the entities ultimately responsible for the reliable operation of their transmission and distribution systems, the Utilities explain that they provide information and data to inform the NYISO's studies. They assess local transmission needs based on utility planning criteria and may also consider Public Policy Requirements and specific planning and investment criteria relating to local needs. The Utilities develop their Local Transmission Plans (LTPs) and provide them to the NYISO under existing NYISO Open Access Transmission

[26] Initiating Order, p. 7.

Tariff (OATT) and FERC orders, which dictate rules for transparency and stakeholder involvement.

The Utilities state that stakeholder forums for LTPs have historically consisted of individual utility presentations to the NYISO Electric System Planning Working Group (ESPWG) and the Transmission Planning Advisory Subcommittee (TPAS) at least once every two years, and more frequently if circumstances change. Those stakeholders include generators, developers, end-use customers, other utilities, environmental parties, and government agencies. They explain that these interactions are intended to afford stakeholders an opportunity to ask questions and provide input.

The Utilities propose to build on the existing process by adding an annual stakeholder meeting to review both the past and upcoming LTP, prior to its submission to the NYISO. The Utilities' proposal contemplates holding the additional meeting in January of a given year, following which the Utilities would start their LTP analysis, and includes a potential August stakeholder briefing to obtain additional feedback. Further briefings for stakeholders in collaboration with the NYISO would occur in the September/October time frame. The LTP cycle would start again with the incorporation of NYISO inputs into the Utilities' LTPs in November or December of the year.

Regarding distribution planning, the Utilities state that stakeholders have a number of opportunities to be informed and provide input. The Utilities list the rate cases, the Joint Utilities Advisory Group, and DSIP stakeholder outreach programs as examples of those existing opportunities and do not propose additional procedures specific to CLCPA planning.

Commission Determination

The Commission finds that the Utilities have not adequately addressed the Initiating Order's call for development of a CLCPA-focused planning process. In the near term, the proposal to offer additional stakeholder engagement opportunities in the LTP planning cycle is a positive and necessary step.[27] However, the Commission notes that many of the engagement mechanisms described in the Filing appear to be more geared towards the dissemination of utility information rather than to allowing stakeholders to provide recommendations and input into the planning process. The level of impact stakeholder information has on the planning process is unclear. Pointedly, the engagement process proposed by the Utilities does not appear to have had input from stakeholders in its development.

Furthermore, the Utilities' focus on the LTP is too limited. The Act and the Initiating Order require a more comprehensive examination of utility planning and even the implementation of new approaches. In fact, the Act specifically requires the Utilities to develop CLCPA-focused plans for their territories.[28] The Commission finds that more is required to meet the Act's objectives.

The Commission believes that the State's bulk transmission, local transmission, and distribution planning processes need to be revised. Recommendations made by Staff and its consultant Brattle in their review of the Filing (the Initial Report) identify several shortcomings in the Utilities' planning processes. These observations are supported by a number of commentators. Because planning is key to meeting the CLCPA goals, the Commission finds that an expeditious effort to build more effective processes is necessary. Specifically, the

[27] Thus, the Utilities should plan for stakeholder meetings in the beginning of 2022, as they proposed in the Filing.

[28] Act, §7(3).

Commission finds there is an urgent need to act on the following Staff-supported recommendations:

- Improve planning processes to better coordinate the studies performed by the Utilities with the NYISO's bulk-power system planning and generation interconnection processes.
- Improve the integration of LT&D and bulk system studies with NYSERDA's renewable generation and storage procurements.
- Improve forecasting of renewable generation development for specific locations on the LT&D and bulk transmission grid.[29]

The Commission further finds that a properly coordinated planning processes must meet certain minimum objectives. It must support all existing grid planning needs and criteria; it must identify upgrades at all levels needed to ensure the timely and cost-effective attainment of CLCPA policy goals; and it must provide accurate and actionable information to market actors, policy makers, and other key stakeholders.[30]

Therefore, the Commission directs the Utilities to consult with Staff, NYSERDA, and the NYISO and to develop and file a coordinated power grid planning process. That proposal should consider the planning recommendations made in the Initial Report and meet the objectives identified here, in the Act, and in the May Order. The filing should explain what the coordinated planning cycle will look like (e.g., through planning schedules and flow diagrams), when in this planning cycle information (such as generation forecasts and NYSERDA procurement data) will be collected and considered, how and when the results of the planning will be made available to stakeholders, how often the cycle will be repeated, who the

[29] Case 20-E-0197, Initial Report on the Power Grid Study (January 2021), p. 100.

[30] The information needed of course includes the data supporting the BCA, revised according to this Order.

participating planning parties will be, and how the Utilities (including LIPA), NYISO, NYPA, and NYSERDA will coordinate their individual planning obligations within this larger process.[31]

The Commission recognizes that making the changes in planning directed here will be a significant undertaking, involving both technical and practical issues. While stakeholder engagement can be difficult to manage in the short run, the Commission strongly believes that the planning process required here will benefit from informed interactions with stakeholders. Thus, the Commission encourages the Utilities to engage with stakeholders on this project. The Commission directs the Utilities to consult regularly with Staff through the development of their proposal for a CLCPA-supporting process.

The Commission also recognizes that the Initial Report includes a number of recommendations for improving planning studies, in addition to the headroom recommendations addressed in this Order. These are intended to increase the consistency and validity of those studies while making them more transparent and more useful to participating stakeholders. In particular, the Report recommends developing a unified and detailed data base and power system model for the state.[32]

The Commission directs the Utilities to demonstrate in their responsive filing how the new planning process will ensure consistency in input data, planning assumptions, planning models, and the planning approaches used by the different planning entities so that the utility-specific plans (as well as

[31] The Commission notes that forward-looking support of NYSERDA's procurements may require certain information to be updated on an annual cycle.

[32] For further discussion of this issue, see Part G of this Order.

the overall planning outcomes) accurately and comparably capture the interdependence of distribution, local transmission, and bulk transmission in the various portions of the State's power grid.

Finally, the Commission notes that the success of the planning process will depend significantly on the quality of the stakeholder input. This is critical because any grid expansion must both respond to and accurately predict generation development. For this reason, stakeholder engagement should meet certain minimum objectives. First, the process should facilitate education and cross-training of both stakeholders and utility planners to improve mutual understanding of power system characteristics and individual project developments, as well as how these components inter-relate. Second, the process must ensure timely data-sharing to ensure decisions are based on the most current information and sound forecasts. Third, working group forums should be leveraged to share insights and help resolve issues through group collaboration, to the fullest extent possible.

The Commission directs the Utilities to make the filing required here within 90 days of the date of this order. If the Utilities conclude that development of the fully coordinated process described in this order should proceed in stages, the filing should include a detailed implementation schedule indicating what elements are proposed for deployment in the near term and what work remains to be done. The Commission stresses that providing information in support of the NYSERDA procurement process is a high priority, as those solicitations continue on an annual schedule.[33]

## D. Funding Phase 2 Upgrades

[33] NYSERDA states that the next solicitation will start in the second quarter of 2022.

The Commission recognized in the Initiating Order that funding mechanisms for CLCPA-driven projects do not exist at the present time.[34] By contrast to traditional LT&D, which benefits a particular utility's ratepayers and thus is charged only to those ratepayers, LT&D projects intended to facilitate compliance with the CLCPA, by definition, benefit all ratepayers. The Commission acknowledged that identifying such mechanisms presents "novel issues including how to identify who benefits from these CLCPA-targeted investments and by how much, as well as how to recover these costs" and asked the utilities to propose solutions so that uncertainty about funding does not delay achievement of the State's climate goals.[35] The Utilities responded in Section V of the Filing by proposing alternative options to both (1) allocate CLCPA costs among ratepayers, and (2) recover those costs.

1. Cost Allocation

On this issue, the Utilities assert that the costs of Phase 2 upgrades should be shared equally across all customers in the State consistent with the CLCPA mandates, which are also statewide. In support of their position, the Utilities point out that a load-ratio share allocation is used to recover the costs of other statewide mandates, including NYSERDA's Zero Emissions Credit (ZEC), REC, and OREC programs. They assert that the same statewide benefits that accrue to those programs also accrue to the Phase 2 LT&D programs discussed here.

Commission Determination

The Commission agrees with the Utilities that, in this context, the statewide allocation to all customers of the Phase 2 investment costs is appropriate – both for new projects and

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[34] Initiating Order, p. 9.

[35] Id.

incremental investments to "business as usual" projects that capture CLCPA benefits.[36] Allocating these costs pursuant to a volumetric load share ratio is consistent with the funding principles underlying the existing REC, OREC and ZEC purchase obligations.[37]

Thus, the Commission finds that the costs associated with Phase 2 projects shall be allocated to the Utilities pursuant to the volumetric load ratio share. However, a number of details regarding this allocation have not yet been addressed. Other issues that should be addressed include: the frequency for updating the allocation factor since the factors will be developed using a previous period, the period over which the allocation factors should be developed (i.e., one year or multiple years); and whether any adjustments are appropriate. For these reasons, we direct the Utilities to develop the details of this allocation mechanism, in consultation with Staff, and to submit their response within 90 days of the date of this Order.

2. Cost Recovery

The Filing identifies four potential mechanisms for recovering the costs of Phase 2 local transmission projects - the Rate Case Based Approach, Voluntary Utility Agreements, NYSERDA Payments, and Renewable Generator Sponsorship – and evaluates the benefits and challenges of each. On November 18, 2020, Staff filed an additional cost recovery mechanism in its

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[36] Case 15-E-0302, et al., Large-Scale Renewable Program and Clean Energy Standard, Order Adopting a Clean Standard (issued August 1, 2016), p. 149-50.

[37] There may be instances in which a utility finds incremental investment in a Phase 2 project will provide other benefits, such as reliability or improved load serving capability, that are specific to the sponsoring utility. In such instances, the incremental investment costs should be allocated using traditional cost of service allocation methodologies.

Supplement to the Filing. These various proposals include some common elements, as discussed below.

(a) Rate Case Based Approach

Under the Rate Case Based Approach, a utility would include its Phase 2 LT&D projects in its rate case filing and would recover the costs from its customers in the same manner as for a traditional utility investment. Through the rate case process, the utility would work with Staff and intervenors to identify a final list of CLCPA projects, which the utility would implement during the term of the rate plan through its regular capital budget and planning process.

While this straightforward approach has some advantages, such as its fit with the existing rate case process, the Commission believes that it also poses challenges. Primary among these is that the Commission's ratemaking precedents do not provide a mechanism for charging project costs across utilities. Without such a mechanism, allocating CLCPA costs to a utility's customers is not likely to result in an equitable distribution of the ultimate cost burden across the State. The Filing acknowledges this problem by proposing to use an imputed load ratio share cost allocation mechanism and a regular true-up process, which would be implemented by the Commission. The Utilities state that the Commission could conduct a review of CLCPA transmission expansion costs to identify any imbalance between the actual project costs and the Commission-approved revenue allocation. The Commission could initiate a reconciliation process for any imbalances identified in that review.

(b) Voluntary Utility Agreements

Under this approach, the Utilities would charge their share of CLCPA costs to their respective delivery customers through either (1) voluntary co-tenancy arrangements (referred to as co-ownership agreements), or (2) voluntary participant-funding agreements. Under a co-tenancy model, utilities would commit capital to acquire equity interests in one another's Phase 2 projects. Each utility's delivery customers would fund the project in proportion with its ownership share, and the utility would recover the costs through its rate case. Under a participant-funded rate agreement, which the Utilities assert requires approval by the FERC, the utilities would agree, on behalf of their customers, to fund the costs of other utilities' projects, without acquiring any equity interest in them.

Both approaches would follow the same process which would begin by the Utilities identifying a list of projects. The Commission would determine which projects would move forward, using the approved CLCPA investment criteria. Under this option, the Utilities state that the Commission would direct them to make a subsequent filing demonstrating the CLCPA benefits of those projects whose costs should be regionally allocated. The Utilities would propose cost allocation and cost recovery framework(s) for the projects through the relevant Commission or FERC procedure. In both cases, the agreements would be revisited on a regular cycle.

The Utilities assert that the voluntary agreements mechanism has the potential to produce an equitable cost sharing arrangement among companies and may enable development of larger projects. Conversely, they acknowledge that these agreements take time to negotiate and ultimately may not come to fruition, may be challenged in utility rate cases, and/or may require FERC approval either in whole or in part. Additionally, the co-tenancy model would be problematic for both LIPA and NYPA. LIPA is precluded from entering into co-ownership agreements for facilities outside of its service territory, and NYPA may not be able to pass on the costs of such agreements to its customers with long-term contracts.

(c) NYSERDA Payments

Under this approach, NYSERDA would reimburse the Utilities for CLCPA-driven LT&D projects through revenues collected from the existing or an expanded System Benefits Charge (SBC), or a similar alternative mechanism. The Utilities would propose cost allocation and cost recovery framework(s) for projects, which would be approved by Commission order. NYSERDA would begin collecting funds through the SBC, or a new similar mechanism, and the utilities would initially recover the costs through rate cases. Thereafter, the revenues received from NYSERDA would be reconciled and imputed into future rate filings as an offset to base rates. Any overcollections would be refunded to customers or retained by NYSERDA to fund future shortfalls.

According to the Utilities, this approach has the potential to produce an equitable cost sharing arrangement, may enable development of larger projects and, if structured appropriately, allows for the participation of LIPA and NYPA. This new mechanism, however, would take time to implement, may require FERC approval, and creates an administrative and financial burden for NYSERDA. The Utilities note, however, that the mechanism could be constructed in such a manner that would minimize those impacts. For example, the Utilities state that the volume of payments flowing to and from NYSERDA could be reduced to reflect only the difference between the costs the Utilities actually recover through rate cases and the amount for which their delivery customers should be responsible pursuant to a load ratio share allocation of all CLCPA transmission investments across the State.

(d) Renewable Generator Sponsorships

Under this model, the renewable generation owner or developer would voluntarily agree to pay for its share of the cost of investments necessary to unbottle and deliver energy for its projects. The Utilities recommend implementing this approach on a voluntary basis because it would be difficult to mandate across all generators. The utility would work with existing and prospective generators to identify a CLCPA-driven LT&D project to unbottle the generators' projects. Thereafter, the utility and generators would enter into an agreement and file a rate at FERC for cost recovery of the project. At the time either the generator or the transmission project enters service, whichever is later, the generator would be charged for costs reflecting its usage of the new transmission facilities as provided in the agreement filed at FERC. To the extent a project is not fully subscribed, the utility would continue to recover the costs attributable to the unsubscribed capacity from its delivery customers through its Commission rate case.

This approach would maintain locational pricing signals and, unlike the first three options, would directly assign the cost burden of transmission upgrades to the generators. The costs would be allocated across the State to the extent that generators recover such costs through the REC or OREC payments or NYISO market revenues they receive. These voluntary agreements, however, may not be realized, especially since the NYISO does not administer any firm transmission rights to guarantee energy delivery. In addition, this approach requires FERC approval, involves additional parties, risks utility customers bearing the cost of unsubscribed capacity, and could raise free ridership concerns, as a generator may benefit from a project funded by another generator or utility customers.

(e) Staff Supplemental Proposal

Under DPS Staff's November 18, 2020 proposal, the Utilities would recover the costs of multi-value and CLCPA-driven projects through retail rates from delivery customers set through the rate case process. Any imbalance between the project costs and the proper revenue allocation would be reviewed and reconciled on a periodic basis by a Commission-approved, non-FERC-jurisdictional adjustment mechanism.

The Staff proposal has the potential to realize an equitable cost sharing amongst utilities. However, creation of a mechanism that reallocates funds associated with multi-value and CLCPA-driven LT&D projects among utilities would create an uncertain path. For example, the timing of the rate case likely would not line up with the timing of another utility's financing and construction of a Phase 2 project, an issue that is discussed further below.

Commission Determination

Each of these cost recovery options has its advantages and disadvantages. In order to select among them, the Commission believes it is important to recognize some basic principles.[38] First, the Commission finds that establishing the revenue requirements and rates of return for Phase 2 projects lies squarely within the Commission's ratemaking jurisdiction and should remain so. Any cost recovery agreement must recognize this foundational principle. Second, the Commission concurs with the Utilities' view that establishing certainty of cost recovery once those rates are set is critical to meeting

[38] This discussion concerns local transmission investments. The Commission has recently addressed cost allocation and recovery for distribution-level upgrades in Case 20-E-0543, Petition of Interconnection Policy Working Group Seeking a Cost-Sharing Amendment to the New York State Standardized Interconnection Requirements, Order Approving Cost Sharing Mechanism and Making Other Findings (issued July 16, 2021).

the CLCPA’s ambitious deadlines. In addition, procedural complexity should be avoided, in the interests of both certainty and transparency.

All of the utility cost recovery proposals acknowledge that projects will be approved, and rates will be set under the Commission’s authority in the rate case process. However, on close examination, relying on the rate case paradigm, as suggested by the Utilities, is problematic. Since rate cases are typically settled and the resulting rate plans determine rates for multiple rate years, a significant amount of time will pass between rate filings. Because the rate years for most utilities are different, those differences, in combination with the proposed periodic true-up process, would pose administrative challenges. Initially collecting Phase 2 project revenue requirements through one process and truing-up those collections through another process could result in a utility’s customers being temporarily unfairly burdened.

Thus, an alternative forum for the review and approval of Phase 2 investments is needed. That forum should allow the Commission to make the same kinds of determinations that it routinely makes in rate cases, but with a focus on cost-effectively achieving CLCPA objectives. The Commission believes it can align the process for funding decisions (outside the rate case) with the revised system planning process to be developed pursuant to this Order. To accomplish this, the Commission will establish a proceeding in which the Utilities will submit the portfolio of LT&D upgrades that they have determined, through the coordinated planning process, support timely achievement of CLCPA targets and meet the relevant criteria and approved BCA.

Such a proceeding would allow for a holistic review of proposed projects and costs across the state and would also provide Staff and other interested parties opportunities to evaluate and comment on those proposals. Following the review of the project portfolio, the Commission would approve, modify, or reject proposed investments and determine the resulting revenue requirements, just as it would do in a rate case.[39]

The Commission also concurs with the Utilities in their suggestion that the Commission should review CLCPA projects and costs on a regular and predictable cycle. This concept is consistent with this Order's guidance for CLCPA planning. However, the four-year cycle established in the Act for program review may not be frequent enough to ensure upgrades are evaluated in time to meet CLCPA deadlines. For the immediate future, the Commission will require the Utilities to submit any Phase 2 project applications to the Commission by January 1, 2023, the date of the first program review set forth in the Act.[40] The Commission also directs the Utilities to propose in the planning filing a cycle for Phase 2 submissions beyond that date. The Commission believes that a three-year planning cycle is advisable given that it generally comports with the three-years rate cycles generally used by the Utilities.

The specific mechanism for recovery of Commission-approved Phase 2 costs remains to be decided. Considering the options presented in the Filing, the Commission believes the participant funding model can efficiently accomplish the balancing necessary to achieve an equitable cost distribution throughout the State. Thus, the next step would be development of an agreement among the Utilities, and the Commission

[39] Proposed project filings must be of a rate case quality consistent with the requirements described in the Phase 1 Order.

[40] Applications related to the Areas of Concern identified in this Order are excepted from this requirement, as discussed at infra, pp. 34-39.

understands that effectuating cost recovery of a voluntary statewide participant funding agreement would require FERC's approval.[41] The Utilities are directed to develop such a cost recovery agreement, recognizing the foundational principle identified above, to be filed within 120 days of the date of this Order. The Utilities should consult with Staff, as necessary, during the process to develop a single, fully supported agreement. Since a voluntary participant funding agreement between the Utilities is essential to effectuate recovery of Phase 2 costs as described above, the Utilities are directed to file a status report with the Commission, within 120 days of the date of this Order, if they are unable to reach consensus on an agreement. The status report should explain the reasons why they have not been able to develop the agreement and identify the remaining issues to be resolved.

DPS Staff notes that, in other cases, the NYISO administers cost recovery under its tariffs; thus, it may be possible for the NYISO similarly to administer the collection and payment of the Commission-approved revenue requirements once Phase 2 projects go into service. This possibility is to be explored and the details of administering a participant funding agreement for Phase 2 projects through the NYISO should be identified. The Commission will require the Utilities to consult with Staff and the NYISO concerning this possible cost recovery mechanism and to file a report on the feasibility of this proposal within 120 days of the date of this Order.

In sum, the Joint Utilities are to jointly file a coordinated portfolio of Phase 2 projects by January 1, 2023, and on a regular basis thereafter, that meet the requisite

[41] Given the Utilities' stated concern for certainty in this area, the Commission encourages the companies to work diligently towards such an agreement.

investment criteria. Filings should be of rate case quality and must include appropriately supported cost estimates. This would create a transparent process – including public review and comment – by which all of the Utilities' proposed Phase 2 projects would be examined by the Commission in a single proceeding and order. The cost of Phase 2 projects approved by the Commission would then be allocated across Utilities based upon a volumetric MWh load ratio share methodology and be subject to a participants' agreement and cost recovery arrangement approved by FERC. As noted, it may be advisable for the NYISO to administer the collection and payment of project costs across each of the Utilities – a role it currently plays with respect to Public Policy Transmission Planning projects. Such an approach should be fully considered, including those reflective of the Commission's ratemaking jurisdiction, as FERC has recently expressed a willingness to consider voluntary cost sharing agreements as a way for states to "prioritize, plan, and pay for transmission facilities…."[42]

E. Phase 2 Projects

Part 2 of the Filing identifies possible LT&D upgrades necessary or appropriate to accelerate progress toward achievement of the CLCPA mandates. As des/cribed in the Filing, Phase 1 projects are those that are needed to address reliability, safety, and compliance issues, but that can also capture CLCPA benefits. In contrast, Phase 2 projects are those specifically designed to achieve CLCPA targets by increasing the capacity on the local transmission and distribution system to allow for interconnection and delivery of new renewable generation resources.

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[42] See Docket No. PL21-2-000, State Voluntary Agreements to Plan and Pay for Transmission Facilities, Policy Statement (issued June 17, 2021).

In the Filing, the Utilities identified a number of potential Phase 2 projects within their respective service territories.[43] These are illustrative proposals presented at a conceptual level that do not fully demonstrate either the actual effectiveness of possible solutions or their likely costs. For example, the Filing includes conceptual-level Phase 2 portfolio cost estimates for local transmission and distribution upgrades as high as $10 billion. These estimates suggest the potential range of expenditures; however, actual program costs will be determined through the evaluation of specific proposals based on full engineering analysis and the application of the investment and other criteria to future submissions pursuant to this Order.

Compared with the Phase 1 projects, the Phase 2 local transmission proposals are generally more complex and also less fully developed, requiring additional evaluation, design and engineering. Many are traditional line and substation types of projects, including rebuilding or reconductoring circuits, substation reconfigurations, expansions or rebuilds, construction of new substations, and installation of additional transformers. The utilities considered several new and emerging technologies in their potential Phase 2 projects, including power flow control devices, dynamic line ratings, and energy storage.

Distribution Phase 2 potential projects are similarly driven by their ability to provide CLCPA benefits. Distribution Phase 2 projects aim to deliver additional distributed generation (DG) interconnection headroom in network areas where there are high levels of generator interconnection activity and existing system constraints or bottlenecks. Similar to the local transmission projects, potential distribution Phase 2

[43] O&R does not propose any Phase 2 projects.

solutions include, among other things, reconductoring, new stations, new circuits, transformer replacements.

Commission Determination

The Commission finds that action on the Phase 2 proposals is premature at this time, in light of this Order's determination that the Phase 2 investment criteria and BCA require revision. Further, the Commission rejects the proposal to review Phase 2 projects in rate cases. The Commission believes that future Phase 2 project submissions should reflect the coordinated planning process contemplated in this Order and should be made in a common proceeding, as discussed above. However, as explained below, some of the proposed Phase 2 projects would address pressing concerns that require a more expedited process.

In the course of this proceeding, certain areas of the State have been identified by the Utilities, Staff, NYSERDA, and commenters as in critical need of Phase 2 local transmission investment. These areas are characterized by the presence of existing renewable generation that is already experiencing curtailments and a strong level of developer interest that exceeds the capability of the local transmission system. These areas are identified by NYSERDA as Hornell and South Perry (NYSEG/RG&E), the Watertown/Oswego/Porter subzone (National Grid), and an area of southeastern New York consisting of facilities owned by NYSEG, National Grid, and Central Hudson. The Hornell and South Perry and Watertown/Oswego/Porter locations were also included in the priority areas identified by ACE NY in comments. The same locations are also identified by the NYISO in the CARIS as Z1, X2 and X3, and Y1 and Y2. Each of these utilities submitted initial proposals addressing these constrained areas in the Utility Study. We will refer to these as "Areas of Concern," as noted on Figure 1 on the next page.

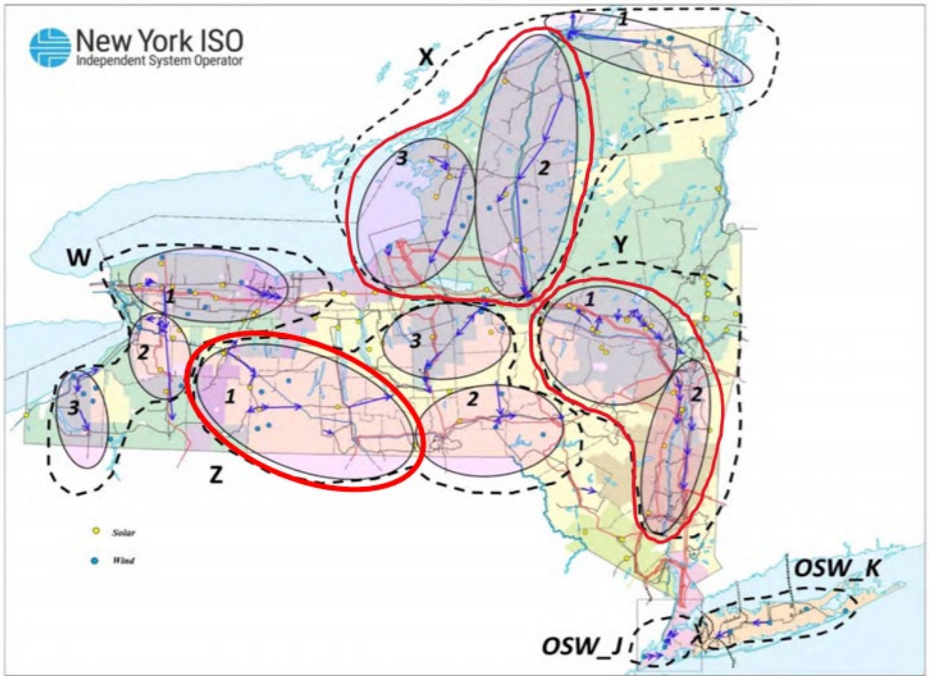


Figure 1: Areas of Concern

The Commission finds that the problem of existing and likely future curtailments in these areas justifies an immediate effort to explore cost-effective solutions. Therefore, the Commission directs NYSEG/RG&E, National Grid, and Central Hudson to reconsider the proposals they made in the Filing for local transmission upgrades in these areas and to submit new or revised solutions to the Commission within 120 days of the date of this Order. These may be submitted by petition and should respond to the guidance given below.

Requests for approval or funding related to the Areas of Concern must provide sufficient information on which the Commission can fairly assess their costs and benefits. A close focus on the costs and benefits is needed because the Commission can only assess and prioritize Phase 2 projects on a well-supported and location-specific understanding of how the proposed upgrades support progress towards meeting the State's goals. Thus, each of the filings must provide data and analysis that explore the need for the projects. The filings must also provide the Commission with an understanding of that need over different time horizons and show that the Phase 2 project is superior to alternatives, such as a possible Phase 1 investment or a bulk solution. In addition, as we determined in the Phase 1 Order, the utilities must show they have considered advanced technologies in their analysis and deployed such technologies where appropriate.

Since the assessment criteria proposed in the Filing are not approved, the Commission will require the utilities to support their proposed solutions for the areas noted using the criteria described below.

First, the sponsoring utility must establish the capacity (in MW) of the near-term CLCPA Phase 2 need (Near-Term CLCPA Need) in each area. The Near-Term CLCPA Need is satisfied by the incremental local transmission system investment necessary to unbottle the renewable energy projects that have reached an advanced development status. For these purposes, the Commission considers projects in advanced development to include: (1) projects with awards from prior NYSERDA auctions; (2) projects that are operating or under construction; (3) projects that are the subject of a complete application for siting approval; and (4) projects deemed likely to enter into operation. In cases where the utility deems a project likely to enter into operation and the project does not meet any of the other advanced development status criteria, the utility must provide a strong justification for this assessment on a case-by-case basis. One such example includes projects pending in the NYISO interconnection queue. The sponsoring utilities are directed to work with Staff to identify a specific development milestone within the NYISO interconnection process that will ensure a reasonable level of maturity for the purposes of establishing the Near-Term CLCPA Need.

Once the renewable energy projects in an advanced development status are identified, the utility shall set the Near-Term CLCPA Need to be in incremental headroom needed to ensure deliverability of those renewable energy projects, after taking into account the existing headroom of the local transmission system, the incremental headroom created by approved Phase 1 projects and any additional planned upgrades to the local transmission system.[44]

The Commission realizes there can be varying interpretations of the threshold that should be used to determine when a renewable energy project is deemed to be unbottled. For example, if a renewable energy project is expected to have 10 percent of its generation curtailed without a Phase 2 upgrade, the utility could propose a local transmission upgrade that eliminates one hundred percent of the expected curtailment risk. Alternatively, the utility could propose a less costly upgrade that eliminates most but not all of the curtailment risk.

The Commission recognizes that Phase 2 solutions for each area may have varying deliverability benefits and levels of cost-effectiveness. Transmission and distribution upgrades can be inherently "lumpy" in their design and cost characteristics. A simple upgrade may be able to addresses a base level of design criteria, curtailment risk mitigation or deliverability; however, making the jump to the next level of incremental headroom may require a significantly enhanced design, which could result in a significant increase in cost and extend the headroom beyond the Near-Term CLCPA Need.

Therefore, the Commission directs the utilities to present a minimum of two options for each Area of Concern that

[44] Headroom calculations shall follow the revised methodology approved in this order.

identify the most cost-effective Phase 2 upgrades on a dollar per MW basis. The utility proposals should fully eliminate the curtailment risk for the Near-Term CLCPA Need and potentially enable additional headroom availability beyond the Near-Term CLCPA Need. The second option should eliminate most, but not all, of the curtailment risk for the Near-Term CLCPA Need. The Company may propose additional options for consideration, with a description of the associated benefits and costs.[45] All options should include relevant assumptions as well as resulting levels of headroom availability or remaining curtailment risk.

Second, the Commission recognizes that a significant quantity of renewable energy will need to be developed beyond the projects currently in advanced development status, in order to meet New York's CLCPA goals. However, predicting the location of future renewable projects is highly uncertain. In order to evaluate proposed solutions for the Areas of Concern, the Commission directs the sponsoring utilities to estimate their long-term development potential (Long-Term Development Potential) using appropriate forecasts. Forecasts and resources the utilities must consider when establishing the Long-Term Development Potential include the Zero Emissions Study, the most recent NYISO CARIS 70x30 case, NYSERDA surveys, the NYISO interconnection queue, the estimated resource potential for each area[46], or other relevant sources of market intelligence related

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[45] If the utility determines that the least cost solution to the Near—Term CLCPA Need can be modified to increase the amount of headroom at a low cost per MW of additional headroom, the utility shall provide an alternate proposal with the expanded local transmission upgrade in addition to the two required options. The Commission will evaluate such expanded solutions in relation to the Areas of Concern's potential for future renewable development.

[46] For example, the utilities may work with NYSERDA to identify local resource quality, siting risk, and other relevant

to the Areas of Concern. Given the speculative nature of this evaluation, the sponsoring utilities are each expected to use the most conservative sources or estimates in their submissions.

F. Article VII Recommendations

In the Filing, the Utilities provide several recommendations for the transmission siting review process ranging from what should be included in siting applications pursuant to Public Service Law (PSL) Article VII to standardizing Certificates of Environmental Compatibility and Public Need (Certificates) to how the settlement process should proceed. As a practical matter, many of the Utilities' recommendations can be addressed without the need for any regulatory intervention. Moreover, as a legal matter, some of their recommendations have already been addressed through the recent promulgation of rules for the expedited Article VII process.[47]

Initially, the Utilities recommend that Staff review siting application requirements to determine which remain useful and continue to provide data that are necessary to reach siting determinations on environmental compatibility and public need. For example, the Utilities recommend the removal or revision of application requirements that are determined to serve no useful purpose or are routinely waived (maps scale and the timeliness of aerial photos).[48]

PSL Article VII guidance documents are publicly available for applicants and other parties and are updated to account for changes in Article VII filing requirements. Removal or revision of archaic application requirements that are no

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factors that impact the feasibility of future growth. See NYSERDA CES 2.0 Whitepaper, Appendix A, figures 3 and 7.

[47] 16 NYCRR Parts 85-3.1 et seq.

[48] Filing, pp. 67-68.

longer available is reasonable and can be implemented through the rulemaking process through the SAPA. Until such a rulemaking is implemented, applicants for transmission projects subject to PSL Article VII may continue to seek waivers, which as noted are routinely granted.

Next, the Utilities suggest that regulations could be revised to expedite review processes by restricting the scope of necessary project reviews. For example, they state that archeological resource studies should be limited to areas to be newly disturbed by the proposed project, such as new substations, laydown yards, and new rights-of-way (ROW). Existing ROW and access roads should be assumed to have been previously disturbed and not require testing or concurrence from the New York State's Historic Preservation Office. Moreover, they state that consistency within comment periods for projects should also be set forth.

PSL Article VII was recently amended to require the Commission to issue a determination on Certificate applications within 12-months after a completeness determination by the Secretary (PSL §123(3)) subject to certain tolling exceptions (e.g., settlement). In addition, an expedited nine-month process is now available for projects that qualify under recently promulgated new regulations also subject to certain tolling exceptions (e.g., settlement). Accordingly, while DPS Staff is encouraged to expedite its review of projects where it sees opportunities to do so, the recent amendments to PSL Article VII requiring Commission determinations within 12-months for all projects and nine-months for certain qualifying projects should address the Utilities' concerns for expedited reviews.

The Utilities further suggest that Article VII Certificate conditions should be standardized where possible and adopted by the Commission. The Utilities recommend removing any certificate conditions that should be covered by the Environmental Management and Construction Procedures (EM&CP)[49] and move any certificate conditions that identify what should be included in the EM&CP to the EM&CP specification documents that will be attached to any Joint Proposal or Order. They state that by doing so would benefit applicants preparing responsive documentation and assist DPS Staff reviewing applications to determine whether any deficiency exists.[50]

PSL Article VII requires the Commission to make separate findings on every request for a Certificate.[51] While we note that many Certificate conditions have become standardized, each project must be reviewed on a case-by-case basis and determinations must be made based on the unique set of facts for each record. Over time, EM&CPs have similarly become standardized, but again each case is unique and must be reviewed and evaluated based on its particular facts. Nevertheless, we note that standard EM&CP guidance is publicly available and should assist applicants in their respective filings.[52] To the extent an applicant believes a proposed Certificate condition would be better addressed through the EM&CP process, parties are free to pursue that solution in the case.

Regarding the EM&CPs specifically, the Utilities recommend that in an effort to promote timing and decrease

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[49] EM&CPs contain a set of procedures for the development of PSL Article VII transmission projects to ensure environmental protection and compatibility. Each EM&CP contains sub-sections designed to mitigate environmental impacts of transmission construction. An EM&CP also finalizes the design of the transmission facility (e.g., pole locations, work pad sizes, access roads, culvert replacements, etc.).

[50] Filing, p. 68.

[51] PSL §126.

[52] New York State Department of Public Service, Specification for Development of Environmental Management and Construction Plan.

redundant data requirements, an official guidance document should specify what information should be added to the EM&CP, and not included in other documents in the Article VII process, such as the application. For example, the Utilities state that such guidance should allow the EM&CP to be submitted and reviewed together with a draft Storm Water Pollution Prevention Plan (SWPPP), rather than waiting for the approved local approval of the SWPPP. Concurrent submittal and review of the draft SWPPP and draft EM&CP would assist in providing information in a timely manner and would allow any necessary conforming changes to be made before the time of final siting approval. Moreover, the final EM&CP could be used for the review and approval of the SWPPP. Additionally, the required vegetation impact review could be included under the environmental impact section within the EM&CP.[53]

The Commission notes that EM&CP guidance is publicly available to any applicant or party to a proceeding. Moreover, nothing precludes an applicant from submitting a draft EM&CP or SWPPP prior to a determination on an issuance of a Certificate to expedite review; however, final design and route must be approved before the EM&CP can be considered as any change may result in changes to the draft EM&CP and SWPPP ultimately approved. Finally, the timing of the approval of the SWPPP lies with the New York State Department of Environmental Conservation (DEC) and applicants are thus encouraged to work with DEC in aligning the timing of the SWPPP approval with the EM&CPs.

Finally, the Utilities provided additional suggestions that purport to make the negotiations process in Article VII proceedings more efficient. For example, the Utilities recommend that the assigned Administrative Law Judge (ALJ) hold

[53] Filing, p. 69.

the parties to a settlement negotiation schedule to maintain forward momentum and progress. Additionally, they state that parties could be held to more frequent negotiation conferences, including all-day events if necessary. Starting settlement negotiations earlier in the process, they submit, would also serve to identify issues promptly, which would give the applicant time to be responsive to requests for additional information or to cure deficiencies. An initial pre-application meeting, according to the Utilities, could be a productive means to identify such issues at the onset of the process. With opportunities to identify issues earlier in the process, the Utilities state that the assigned ALJ could limit issues and potentially reject objections that are raised late in the process, such as after a joint filing is proposed.[54]

With the adoption of the recent amendments to PSL Article VII requiring a determination on a Certificate within 12-months or nine-months, respectively, the opportunity for settlement will necessarily be more structured. Moreover, nothing precludes day-to-day settlement and more frequent negotiations (including all day events), but that is of course subject to the respective parties' schedules and consents. ALJs do conduct preliminary issue conferences to refine issues for adjudication and issue litigation schedules. The assigned ALJs are encouraged to do so as early as practicable in the hearing process and to use all tools available to them to discipline the process and facilitate resolution of cases.

In sum, the Commission understands that Staff is examining the PSL Article VII regulations to remove unnecessary requirements, such as those that are routinely waived. Outside of that examination, the Commission prefers to see how the new

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[54] Id.

expedited Article VII process is implemented in practice prior to taking any further action.

G. Headroom Assessment

As noted, on March 16, 2021, DPS Staff published a Straw Proposal for conducting headroom assessments relating to the LT&D systems that describes modifications to the methodologies the Utilities used in developing their Phase 2 projects. Headroom assessments allow the Utilities and stakeholders to estimate the existing electric system's ability to support renewable energy generation. It is also used to illustrate the incremental capability that transmission investments may provide. Establishing a reliable method of calculating headroom is an important foundation for planning CLCPA investments.

The Straw Proposal recommends several improvements to the data sets, assumptions, and models used by the Utilities in performing headroom calculations. These improvements include the development of a common and unified set of planning models and a common methodology for calculating capacity and energy headroom for local transmission projects. The Straw Proposal also identifies improvements to headroom calculations methodologies for various local transmission and distribution configurations. It includes numerical examples for calculating existing and incremental capacity headroom for a local transmission project and for calculating energy headroom for the same local transmission project.

Commission Determination

The Straw Proposal received strong support from commenters, including the Utilities. The Commission finds that applying the Straw Proposal will result in more accurate and more consistent headroom determinations, and thus provide a better foundation for evaluating both existing LT&D transmission capabilities and the incremental levels of headroom provided by proposed upgrades. The Commission finds that implementing the Straw Proposal, as set forth in this Order, will improve the State's planning processes and support the attainment of CLCPA goals. For these reasons, the proposal is adopted and the Commission directs the Utilities to apply it when calculating headroom for the existing grid and for proposed LT&D investments.

In their comments, the Utilities proposed some refinements to the Straw Proposal. Of these, the Commission accepts the companies' recommendation to use existing switching stations or other appropriate substations as potential interconnection locations for the headroom calculations. The Commission concurs in their suggestion that calculations should be made for model years 2030, 2035, and 2040. The Commission will not require production cost modeling as part of the energy headroom computation because it is unclear what the incremental value or accuracy of such analysis would be with respect to defining energy headroom. With regard to evaluation of the bulk transmission system as part of the energy headroom calculation, to the extent that the NYISO Economic Planning Process can address the impact LT&D energy headroom studies have on the bulk system, separate bulk system energy headroom studies by the Utilities would not be required.

Having accepted the Straw Proposal, with these clarifications, the Commission expects the Utilities to integrate the new methodology into the planning processes that are to be developed pursuant to this Order. As those processes will take some time to put in place, the Commission believes the Utilities should take the following near-term actions to make improved data available to stakeholders and regulators.

First, the Commission recognizes that improved and more consistent headroom information will support the success of NYSERDA's Large Scale Renewables procurement program. Therefore, the Commission directs the Utilities to provide updated headroom estimates to Staff, NYSERDA, and potential bidders no later than February 1, 2022, in advance of the 2022 Tier 1 solicitation, subject to reasonable confidentiality protections to the extent required by applicable law. Headroom estimates shall specify, to the extent practical, data for individual lines and substations as opposed to general areas. The Commission directs DPS Staff to consult with NYSERDA and the Utilities on the feasibility and usefulness of holding a technical conference on the headroom data in conjunction with the 2022 procurement, and to convene a conference if Staff determines it will benefit the procurement process.

Second, as NYSERDA and other commenters note, headroom estimates should be made available on a predictable cycle, consistent with regulatory programs, planning requirements, and stakeholder needs. The information should provide a level of detail that is helpful to renewable generation developers, advanced technology providers, regulators, and other stakeholders. The cycle and presentation detail topics should be addressed in the development of the revised planning procedures required by this Order, but in the interim, the Commission will require the Utilities to update their headroom assessments for both capacity and energy every six months, starting with the February 1, 2022 date, and to provide appropriate explanations likely to inform interested parties.

Last on this issue, the Commission agrees with comments supporting close integration of LT&D planning with the NYISO's planning processes. To that end, the Commission directs the Utilities to work with the NYISO when developing the unified and shared data base and models called for in the Straw Proposal. Ultimately, the objective of this effort is to establish a set of power flow models that incorporate the bulk power system, LT&D systems and, as necessary, sub-transmission and distribution systems.

This endeavor should originate with the NYISO power system models as foundations to build more detailed and consistent statewide representations. A global perspective is particularly important for portions of the system in which two or more utility systems heavily intertwine and are interdependent, and/or where local systems interact more closely with the bulk power system. A schedule and ongoing mechanism for the utilities and NYISO to collaborate in the future on modeling issues that may arise, periodically update models as circumstances change, and facilitate sharing of the most current information, should be developed and included in the statewide planning process required by this Order.

## CONCLUSION

The Utilities have made significant progress in proposing Phase 2 LT&D projects and processes that are necessary and appropriate to facilitate the timely achievement of CLCPA mandates, although additional work is necessary before the Commission is in position to approve specific Phase 2 investments. We believe this Order and the compliance filings required herein provide the pathway to establishing the local and state-wide upgrade plans required by the Act.

The Commission orders:

1. Central Hudson Gas & Electric Corporation, Consolidated Edison Company of New York, Inc., New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation d/b/a National Grid, Orange and Rockland Utilities, Inc., and

Rochester Gas and Electric Corporation shall consult with the Long Island Power Authority and Department of Public Service Staff and develop a revised benefit cost analysis proposal, to be filed no later than 90 days following the issuance date of this Order, as described herein.

2. Central Hudson Gas & Electric Corporation, Consolidated Edison Company of New York, Inc., New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation d/b/a National Grid, Orange and Rockland Utilities, Inc., and Rochester Gas and Electric Corporation shall consult with the Long Island Power Authority, Department of Public Service Staff, the New York State Energy Research and Development Authority and the New York Independent System Operator to develop and file, no later than 90 days following the issuance date of this Order, a coordinated grid planning proposal, consistent with the discussion in the body of this Order.

3. Central Hudson Gas & Electric Corporation, Consolidated Edison Company of New York, Inc., New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation d/b/a National Grid, Orange and Rockland Utilities, Inc., and Rochester Gas and Electric Corporation shall consult with the Long Island Power Authority and Department of Public Service Staff and develop the details of the volumetric load share ratio allocation mechanism, which shall be filed within 90 days of the issuance date of this Order.

4. Central Hudson Gas & Electric Corporation, Consolidated Edison Company of New York, Inc., New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation d/b/a National Grid, Orange and Rockland Utilities, Inc., and Rochester Gas and Electric Corporation shall consult with the Long Island Power Authority and file a participant funding agreement for recovery of Commission-approved Phase 2 costs,

including the feasibility of using the New York Independent System Operator to administer such costs, and shall file such plan within 120 days of the issuance date of this Order. If Central Hudson Gas & Electric Corporation, Consolidated Edison Company of New York, Inc., New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation d/b/a National Grid, Orange and Rockland Utilities, Inc., and Rochester Gas and Electric Corporation are unable to reach consensus on an agreement, they shall file a status report, within 120 days of the date of this Order, as described in the body of this Order.

5. Central Hudson Gas & Electric Corporation, Consolidated Edison Company of New York, Inc., New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation d/b/a National Grid, Orange and Rockland Utilities, Inc., and Rochester Gas and Electric Corporation shall consult with the Long Island Power Authority and submit a coordinated portfolio of Phase 2 projects that meet the requisite investment criteria and benefit cost analysis by January 1, 2023, and on a regular basis thereafter, as discussed in the body of this Order.

6. Central Hudson Gas & Electric Corporation, New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation d/b/a National Grid, and Rochester Gas and Electric Corporation shall consult with Department of Public Service Staff regarding presentation of a minimum of two options for each Area of Concern that identifies the most cost-effective Phase 2 upgrades on a dollar per megawatt basis, which shall be filed within 180 days of the issuance of this Order.

7. Central Hudson Gas & Electric Corporation, Consolidated Edison Company of New York, Inc., New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation d/b/a National Grid, Orange and Rockland Utilities, Inc., and Rochester Gas and Electric Corporation shall apply the Staff

Straw Proposal for Conducting Headroom Assessments when calculating headroom for the existing grid and all proposed local transmission and distribution investments.

8. Central Hudson Gas & Electric Corporation, Consolidated Edison Company of New York, Inc., New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation d/b/a National Grid, Orange and Rockland Utilities, Inc., and Rochester Gas and Electric Corporation shall provide updated headroom estimates to Staff, NYSERDA, and potential bidders no later than February 1, 2022, as discussed in the body of this Order.

9. Department of Public Service Staff is directed to consult with the New York State Energy Research and Development Authority and Central Hudson Gas & Electric Corporation, Consolidated Edison Company of New York, Inc., New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation d/b/a National Grid, Orange and Rockland Utilities, Inc., Rochester Gas and Electric Corporation and the Long Island Power Authority on the feasibility and usefulness of holding a technical conference on the headroom data in conjunction with the 2022 procurement, and to convene a conference should Staff determine it will benefit the procurement process.

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

11. This proceeding is continued.

By the Commission,

(SIGNED) MICHELLE L. PHILLIPS
Secretary

APPENDIX A

# Stakeholder Comments on the Utility Study Related to Phase 2 Projects

## Investment Criteria

New York Battery and Energy Storage Consortium (NY BEST) assert that the investment criteria are too focused on unbottling renewable energy from constrained generation pockets, and that they should be expanded to maximize renewable energy utilization. NYSERDA encourages the Commission to include land-use as an investment criterion to prioritize underutilized lands, such as brownfields. According to the Utility Intervention Unit of the Department of State (UIU), the Utility Study is not clear on how investment criteria will be applied; therefore, UIU suggests that the JU be required to provide an alternative analysis and explanation of the screening process for each project proposed. UIU also underscores the need for consistent standards and clear processes to review investments statewide.

## Benefit-Cost Analysis (BCA)

MI, UIU, and LS Power argue that it is unclear how and when the BCA will be applied. MI states that Phase 2 projects are in early stages and need to be further developed before a BCA should be applied; MI also is concerned that projects will be considered with a BCA below 1.0. UIU questions the reliability of the BCA analysis given that the Utilities have only provided order-of-magnitude cost estimates for Phase 2 projects. LS Power notes that the Utilities have not applied the BCA framework to any Phase 1 or Phase 2 projects, and, therefore, is concerned with how the Commission will approve or deny the projects. If the BCA framework is not used, LS Power proposes the Commission use a cost per kW ratio as the basis of approving projects, with the ratio defined as the cost of a proposed project to the incremental renewable generation capacity enabled. LS Power notes that many Phase 2 projects have high cost per kW ratios and recommends setting an upper threshold of $300-500/kW above which proposed projects would be denied. LS Power also urges the Commission to avoid approving excess transmission costs that benefit specific generators.

Multiple commenters raise concerns that the BCA methodology is not comprehensive enough. Specifically, NextEra Energy Transmission New York (NEETNY) and NY BEST state that the BCA does not consider all potential alternatives, such as energy storage or bulk power transmission solutions. MI argues that the BCA does not currently consider all identified benefits. Potomac Economics comments that the BCA relies too heavily on one scenario of resource buildout - the NYISO Congestion Assessment and Resource Integration Study's (CARIS) 70x30 case. Potomac Economics recommends that the Commission develop a resource forecast based on economic principles and consider multiple alternative scenarios to capture a range of realistic project benefits.

Multiple commenters critique or provide suggestions for the BCA methodology. NEETYNY argues that the proposed methodology inflates the net benefit calculation of the unbottled renewable energy by using a 40-year period and levelized cost of energy to calculate the avoided cost benefit, and also uses a curtailment percentage that may overstate the net benefits of a proposed solution. Potomac Economics has multiple recommendations for the BCA including: 1) valuing projects using Locational Based Marginal Price (LBMP) values for energy prices; 2) using an Unforced Capacity (UCAP) percentage consistent with resources' expected capacity value at levels of penetration consistent with Climate Leadership and Community Protection Act (CLCPA) targets; 3) using a 20-year period instead of a 40-year period, consistent with the shorter economic life of generation assets as compared to transmission assets; 4) using a cost of capital aligned with estimates for generation projects in New York that rely on NYISO market revenues, which would more accurately reflect the risk borne by ratepayers and avoid biasing the calculation in favor of local transmission over competing market-driven solutions; and 5) using a discounted renewable energy credit (REC) value component, claiming that using the full REC price likely represents an overestimate of a transmission project’s environmental value.

**Project Prioritization**

NYSERDA recommends that the Commission prioritize improvements in areas where there are local deliverability concerns for existing renewables or for future renewables that are under development. Given its extensive analyses of renewable integration, NYSERDA recommends that the Commission prioritize projects in the following areas: the Southern Tier Region (CARIS Z1 generation pocket), the North Country Region (CARIS X2 and X3 generation pockets), and the Capital Region (CARIS Y1 and Y2 generation pockets). NYSERDA highlights that renewable development in these areas is outpacing the in-service dates of the proposed local transmission projects identified in the Utility Report. NYSEIA recommends that the Commission prioritize distribution investments where there is system need and collaborate with NYSERDA to ensure the investments complement NY-Sun. UIU states that the Utility Study raises questions regarding how CLCPA-related projects should be considered and prioritized. Specifically, UIU questions whether a project that meets only one criterion should be approved, and whether all criteria should be given the same weighting.

**Planning Process and Stakeholder Engagement**

***Coordination***

NYSERDA, the New York Power Authority, EDF Renewables, and Alliance for Clean Energy New York, Advanced Energy Economy Institute, American Clean Power Association and Natural Resources Defense Council (collectively, the Renewable Energy Advocates) assert that the planning of LT&D projects should be coordinated with bulk transmission development. NYSERDA elaborates that bulk system improvements need to be explored and sequenced with lower-voltage system upgrades to ensure that transfer capability can accommodate new expected renewable generation. NYSERDA emphasizes that, if not addressed, high levels of expected curtailment may threaten the development and operation of both NYSERDA contracted projects and additional projects proposed by private developers. NYPA comments that the impacts of LT&D upgrades across the different utility service territories and on the bulk transmission system need to be identified to ensure solutions do not negatively impact one system over the other. According to Renewable Energy Advocates, separate planning of the bulk and LT&D systems will lead to suboptimal outcomes that will incur additional ratepayer costs and make it more difficult to meet CLCPA targets. EDF Renewables raises similar concerns, suggesting that there is a need for further evaluation of proposed Phase 2 projects or alternatives that include both low-voltage and high-voltage upgrades to ensure the most effective transmission solutions are identified and ultimately approved. NYSEIA supports a more integrated approach to system planning, including stakeholder input and consideration of factors spanning both bulk and distribution systems.

To address the issue of planning both bulk and local system upgrades, NYPA, NYSERDA, and Renewable Energy Advocates recommend more coordinated planning between the Utilities, NYPA, and the NYISO. NYSERDA further recommends that the NYISO, the Utilities, and NYSERDA collaborate during each annual NYSERDA solicitation to identify potential deliverability issues associated with projects bid to NYSERDA and assess potential impacts on existing renewable generators and in-development projects.

In addition to more coordination between the Utilities and the NYISO, stakeholders recommend more coordination between the Utilities. NYPA states that there is a need for transmission owners/the Utilities to coordinate their studies in transmission areas of close proximity to avoid upgrades that could either be too costly due to over-builds or be inadequate due to under-builds. Similarly, the NYISO recommends that the Commission's review of the Utilities' capital plans go beyond individual service territories, and holistically consider interactions among proposed projects as they relate to addressing the transmission-constrained generation pockets identified in CARIS report.

Borrego Solar Systems recommends that the Commission consider initiating a pending distribution queue mechanism to facilitate renewable energy utilization of Phase 1 and Phase 2 investments to allow interconnection customers to submit applications while a long-lead capital project or solution is being developed.

***Scenarios***

Both NYBEST and NYSERDA recommend additional scenarios for the assessment of LT&D needs. NYSERDA proposes a scenario that fully incorporates CLCPA goals and includes all operating renewable projects, as well as projects in development and under contract with NYSERDA. NYBEST recommends scenarios that consider different resource and load growth locations. Additionally, NYBEST recommends a scenario-based planning approach in which the value of projects' "optionality" is considered in order to reduce the risk of sub-optimal economic outcomes. NYBEST proposes specific scenarios that capture different locations for resource development and load growth.

***Alternative Technologies***

Both NYBEST and NYSERDA encourage the Commission and Utilities to consider alternatives to traditional transmission in the planning process – in particular energy storage and advanced technologies. NYBEST recommends that the Commission require the Utilities to evaluate the potential for energy storage to defer, replace, or expand the scope of solutions while lowering customer costs. At a minimum, NYBEST requests that the Commission require the Utilities to reevaluate their Phase 2 projects with full consideration of energy storage solutions.

***Stakeholder Engagement***

NYSEIA, Invenergy, Borrego Solar Systems, EDF Renewables, and Renewable Energy Advocates all recommend that the Commission establish an expanded stakeholder process such that stakeholders can actively engage in the refinement and evaluation of Phase 2 projects. In particular, Invenergy asserts that Phase 2 projects should be assessed by a larger working group that includes NYISO Staff and developers, with the working group convening no later than the second quarter of 2021. NYSEIA proposes a collaborative process that allows Phase 2 plans to be developed and submitted by the fourth quarter of 2021. Renewable Energy Advocates propose that the Utilities work with an industry advisor group to refine and finalize Phase 2 projects by the end of 2021.

EDF Renewables and Renewable Energy Advocates maintain that a process should be established whereby interested parties are able to obtain more specific details of proposed transmission projects to enable developers and others to more accurately model renewable projects, including the risk of congestion.

Renewable Energy Advocates further comment that stakeholder engagement will be critical for Phase 2 distribution projects to ensure upgrades occur in regions where there is a system need and adequate incentive to attract distribution generation development. They further recommend that the Commission collaborate with NYSERDA on how best to leverage distribution investments and ensure that renewable energy development will occur in those areas.

***Competitive Process***

NEETNY states that the CLCPA projects should be subject to an investment and voltage threshold – specifically, that projects below 200kV that cost less than $25 million should be advanced through rate cases while larger, more complex projects that exceed 200kV or $25 million should be advanced through the NYISO public policy planning process. NEETNY states that the six criteria identified in Utility Study may be used as part of NYISO Public Policy Transmission Needs (PPTN) process. LS Power contends that the definition of "local transmission" in the Utility Study is overly broad and may allow significant facilities to bypass the competitive process, thereby increasing costs to ratepayers. LS Power instead suggests using a definition consistent with the NYISO Tariff to ensure that Bulk Power Transmission Facilities are excluded from this LT&D planning process and, instead, are planned through a competitive process.

***Miscellaneous***

Roger Caiazza claims that the Utility Study does not adequately consider ancillary transmission grid services and raises concerns that only two of the Utilities, LIPA and NYSEG/RG&E, included projects targeted to address ancillary services. He further states that the risks of adverse inverter-based resource behavior and voltage instability must be quantified.

**Phase 2 Projects**

Several stakeholders, including NEETNY, LS Power, UIU and the City of New York (the City) raise concerns about the lack of detail presented for many of the Phase 2 projects; in particular, they raise concerns about the lack of detail on costs, benefits, and alternatives for each project. The City urges the Commission to direct the Utilities to develop a proper record on benefits, costs and cost-effectiveness of the proposed projects, along with their contribution to CLCPA goals, including assessment of alternatives. LS Power and the City raises particular concerns with the level of detail contained in Con Edison's Phase 2 proposals. The City recommends that Con Edison be required to file complete descriptions of projects with all supporting information and stakeholders should be given opportunity to comment. UIU emphasizes that each component of a utility's project portfolio should include estimated costs and contribution to the increased capacity transfer. UIU further recommends that the Commission establish a separate proceeding to address Phase 2 projects.

NEETNY and LS Power raise concerns that some of the Phase 2 projects identified by Con Edison and LIPA appear to extend beyond the definitions for local transmission upgrades and should instead be considered through the NYISO PPTN process. They note that Con Edison's Clean Energy Hubs appear to be at the 345 kV level and, therefore, do not qualify as local transmission. They also note that several of LIPA's Phase 2 projects were recommended by LIPA to the Commission as a PPTN in July 2020. LS Power and NEETNY encourage the Commission not to consider these projects as local transmission, but to keep them within the PPTN process.

Invenergy raises concerns that the proposed transmission projects in the Southern Tier do not address constraints identified in the Utility Study. For example, Invenergy is concerned with the relief of constraints in the Hornell Division, noting that the proposed Phase 1 and 2 projects in this area only address one of the constraints identified by the NYISO’s CARIS 2019 report. Invenergy recommends that investments and upgrades in the Southern Tier region should be reviewed to identify solutions and should be strongly prioritized. Invenergy also comments that independent third-party studies support the creation of a second 230 kV corridor in the Southern Tier, parallel to the existing 115 kV lines, as a possible solution to the local constraints. Invenergy further asserts that this upgrade could be considered through the PPTN process if deemed to be outside of the scope of the Utilities’ LT&D investments.

LS Power provides specific comments on each utility’s Phase 2 project proposals and analyses. LS Power claims that Central Hudson’s analysis assumes locations for future renewable generation that are not based on any currently proposed generation and, therefore, recommends that Central Hudson’s Phase 2 projects not be approved until it is known where renewable generation will be interconnected in the area. LS Power states that LIPA’s Phase 2 projects are based on assumptions on the future locations of offshore wind interconnection, which are uncertain, and notes LIPA’s acknowledgment that the transmission constraints are dependent on the locations of these interconnections. Given this uncertainty, LS Power recommends that LIPA’s Phase 2 projects not be approved at this time. LS Power states that some of National Grid’s projects appear to be cost effective and should be considered for approval while others are not and should not be approved.  Lastly, LS Power urges the Commission to reject NYSEG and RG&E's proposed ownership of energy storage for renewable integration.

**Cost Containment**

UIU, MI and the City stress that cost containment mechanisms and consumer protections should be instituted.  MI argues that cost containment measures are particularly necessary for projects approved outside of a rate case process.  MI suggests using the PPTP Process framework, which requires developers to provide highly detailed proposals with detailed cost and design information and a cost cap.  Alternatively, MI recommends that the Commission set a threshold above which the utility would be required to demonstrate the prudence of the expenditure pursuant to an Order To Show Clause.  The City emphasizes the need for cost containment for large projects and encourages the Commission to solicit ideas and proposals for cost containment mechanisms from interested parties.

**Cost Allocation and Cost Recovery**

NYSERDA states that cost recovery mechanisms should not impede project development.  Specifically, NYSERDA supports the participant funding model as the most flexible and legally proven approach, but notes that this method would necessitate filing the agreement with FERC. The terms of the agreement would, according to NYSERDA, designate the Commission as the arbiter of which transmission investments are driven by needs of CLCPA, which would preserve the Commission's discretion. It also notes that the option presented by Department of Public Service (DPS) Staff in its November 18, 2020 supplemental filing should be considered as an alternative in the event that a participant funding agreement is unworkable.

NYPA supports the supplemental proposal filed by DPS Staff, which would work similarly to a participant funding agreement but under the jurisdiction of the Commission. In its comments, NYPA also evaluates the four mechanisms proposed in the Utility Study. With respect to the rate case-based approach, NYPA states that its customers would be able to pay their share of CLCPA-driven investments, but the approach may not be equitable for customers, particularly those who live in a service territory with more CLCPA projects than others. NYPA proposes that projects should instead be allocated by load-ratio share. With respect to voluntary agreements, NYPA comments that a co-tenancy agreement could work between utilities where the NYPA customers would pay their fair share of local distribution charges, but NYPA could not sign such an agreement because it would be unable to pass costs on to its customers. NYPA states that a participating funding agreement would capture NYPA customers and equitably distribute costs based on load-ratio share but would require approval by FERC and cost recovery through NYISO charges. With respect to the NYSERDA payments option, NYPA notes the following issues: 1) NYPA customers do not pay regional System Benefits Charges), and 2) NYSERDA does not have the legal authority to charge NYPA's municipal customers. Lastly, NYPA does not support the renewable generator sponsorship approach because it is not consistent with the May 14, 2020 Order on Transmission Planning Pursuant to the Accelerated Renewable Energy Growth and Community Benefit Act. NYPA notes that the approach would likely hinder development and investments by creating a business risk that developers may be unable or unwilling to incur.

While NYPA and the Joint Utilities support a load-ratio share based approach for cost allocation, MI opposes this form of cost allocation. Instead, MI supports a rate case-based approach in which “beneficiaries pay.” MI recommends that all other cost allocation/cost recovery options be rejected, claiming that they do not follow cost-causation principles. Separately, NYSEIA recommends that the Commission consider implementing a Coordinated Electric System Interconnection Review cost-sharing mechanism.

UIU and the City support an equitable and transparent cost allocation and recovery process. UIU and the City recommend an additional planning process, including stakeholder input, that further explores cost allocation and recovery issues before deciding on an approach. The City emphasizes that the approach should maintain the Commission’s jurisdiction. UIU recommends that the Utilities be required to identify costs associated with complying with other proceedings (e.g., Case 20-E-0543) and explain how the cost recovery approach would apply. UIU also highlights the absence of a discussion in proposals (JU and DPS Staff) as to cost allocation between service classifications. UIU recommends that CLCPA-related LT&D costs be separately tracked and bill impacts clearly communicated.

EDF Renewables and the Renewable Energy Advocates support a flexible and expedited approach for cost recovery. In particular, the Renewable Energy Advocates support cost recovery outside of the rate case process both to enable expedited development of projects and to provide a transparent and accessible stakeholder process.

**Advanced Technologies**

The comments filed by NYSEIA, Renewable Energy Advocates, and the City address the joint R&D effort on advanced technologies. NYSEIA and Renewable Energy Advocates urge NYSERDA to appoint an Ombudsman to facilitate interaction with stakeholders. The City supports the joint R&D effort, but states that the scope of the working group should be expanded to include other transmission owners and industry trade groups. The City urges the Commission to require the Utilities to seek appropriate protections for their projects (e.g., patent, trademark, copyright) and retain rights to license or sell technology. The City argues that the majority of revenues received should go to benefit of ratepayers through a possible sharing of net revenues. The City also states that joint projects should be funded through NYSERDA, with existing R&D funding reallocated to the joint projects and incremental funding only approved once the R&D effort has demonstrated positive results.

Both NYSEIA and Renewable Energy Advocates recommend the accelerated deployment of advanced technologies, suggesting that it should be a priority for the R&D working group to move from pilot studies to implementation. Both recommend prioritization of distribution level technologies, with NYSEIA suggesting the widespread deployment of distributed energy resources management systems and smart inverters. Borrego Solar Systems also supports distribution-level advanced technologies and recommends that the Utilities consider near-term opportunities to implement curtailment solutions such as those proposed by Avangrid (the "Flexible Interconnection Capacity Solution") and National Grid (the "Active Resource Integration Programs").

NYSERDA, NY-BEST, EDF Renewables and CTC Global Corporation (CTC Global) encourage the Commission and the Utilities to consider innovative, advanced technology solutions during the development of projects as these solutions have the potential to reduce costs and add flexibility to the proposed projects. NY-BEST notes that the deployment of hardware and software solutions on the LT&D grid can substantially increase hosting capacity of distributed energy resources. EDF Renewables is generally supportive of employing advanced technologies (e.g., power flow control technologies, dynamic line rating and topology optimization), which can be deployed independently or in combination with new transmission build. NYSERDA notes that storage and advanced transmission technologies may be able to be implemented more quickly and cost-effectively than traditional transmission technologies. CTC Global points to numerous deficiencies in the advanced technology section of the Utility Study. For example, according to CTC Global, the discussion of high-temperature, low-sag conductors fails to mention many well-established technologies, such as CTC Global's ACCC® Conductors.

## Stakeholder Comments on the Staff Headroom Straw Proposal (Staff Proposal)

### Joint Utilities

Central Hudson Gas & Electric Corp., Consolidated Edison Company of New York, Inc., Long Island Power Authority, Niagara Mohawk Power Corporation d/b/a National Grid, New York State Electric & Gas Corporation, Orange and Rockland Utilities, Inc. and Rochester Gas and Electric Corporation (collectively, the Joint Utilities) maintain that it is critical that the headroom assessment process afford flexibility both in recognition that service territories and design criteria vary and may therefore require distinct treatment and that unforeseen situations may arise in the future requiring modification. The Joint Utilities propose to collaborate with the NYISO on a periodic basis to develop a common set of sources for headroom calculations.

The Joint Utilities begin by raising some limitations of the headroom assessment, for instance, that such assessments must balance the need for consistent, robust information against complexity, time and resource burdens of the process. In addition, the Joint Utilities note that the availability of property, ease of permitting and status of other projects in the interconnection queue are a few of the many other important considerations that weigh into project location decisions; thus, headroom values do not guarantee system capability or deliverability.

The Joint Utilities identify some specific concerns with the Staff Headroom Straw Proposal. With respect to unified transmission and distribution modeling, the Joint Utilities first note that the differences in their existing planning models reflect their distinct system topologies. The effort to align the planning methods across the Joint Utilities would, they say, require a significant commitment of time and resources; therefore, they suggest considering a unified method only when distributed energy resources (DERs) have upstream constraints. Second, the Joint Utilities assert that there are existing processes for determining Hosting Capacity on the distribution system that produce similar information to what Department of Public Service (DPS) Staff seeks through the headroom calculation process. According to the Joint Utilities, developing a new distribution level headroom assessment could introduce confusion and cause frustration among developers, the Joint Utilities and ultimately the Commission. Third, the Joint Utilities recommend that the NYISO develop a load forecast with input from the Joint Utilities that accounts for DER for use in transmission planning.

With respect to the headroom assessment location, the Joint Utilities propose to use existing switching stations or other substations that generators frequently target as potential locations in the assessment. According to the Joint Utilities, this approach will maximize the value of the headroom calculations by employing actual developer insight without requiring utility assumptions on other siting considerations, including application fees, local laws and land availability.

The Joint Utilities support biennial updates to their headroom assessments for the key CLCPA milepost years – 2030, 2035 and 2040. They do not support mandating production cost modeling as part of the headroom calculation as they believe it would provide limited incremental precision over other methodologies using existing tools. The Joint Utilities maintain that they can establish an energy headroom test through the methodologies proposed in the Staff Headroom Straw Proposal. The Joint Utilities, however, strongly oppose the use of an energy headroom test to support the 2030 Phase 1 projects as these projects satisfy reliability, safety and compliance requirements and, therefore, would be built even absent CLCPA mandates.

The Utilities generally support Staff's energy headroom analysis but recommend that it not include bulk transmission interface limits, citing a lack of clarity on how interface ratings affect the energy headroom calculation. The Utilities note that the NYISO has regularly and appropriate performed this analysis and should continue to include the CLCPA impacts as a scenario in its Economic Planning assessments.

**New York Independent System Operator (NYISO)**

The NYISO supports a consistent headroom calculation methodology to ensure more informed decisions with regard to system planning as a whole, and urges the Commission to direct the NYISO to employ its power flow and production cost modeling tools to conduct energy deliverability modeling of the bulk and local transmission systems. The NYISO states that energy headroom on the bulk and LT&D system can be more accurately calculated by combining the Utilities' expertise in power flow modeling on their respective local systems with the NYISO's production cost simulation capabilities. The NYISO notes that it is coordinating with the Utilities to enhance the modeling process in 2021 and will continue to improve the analysis moving forward. However, to allow for more comprehensive planning, the NYISO recommends that auxiliary files enabling accurate simulations of local contingencies and post-contingency operating procedures be available to interested parties with proper procedures and safeguards to protect Confidential and Critical Energy Infrastructure Information.

The NYISO asserts that temporal production cost simulations should be employed in concert with power flow simulations for system planning as they can capture the dynamic system conditions occurring through the entire study period. According to the NYISO, simply modeling potential power flow conditions and temporarily extrapolating the results can lead to over/under estimation of actual headroom under baseline and project conditions. Thus, the NYISO states, a production cost model must be employed to account for realistic operating conditions. The NYISO explains that it first begins with power flow analyses then uses production cost simulation tools to conduct an 8,760-hour assessment to calculate the amount of energy that can be produced and consumed over a given year, as compared to a snapshot in time. This analysis quantifies the amount of energy that would be produced by each resource considering the impact of transmission constraints, as compared to the total amount of energy that such resource is capable of producing absent the transmission constraints (while also accounting for fuel availability for each resource type).

The NYISO encourages the Commission to issue clear directives on both the approved headroom calculation methodology and the guidelines interested parties should follow in employing the methodology. Specifically, the NYISO notes that developers would benefit from a clear understanding of the various aspects of the methodology, including the assumptions, modeling, interpretation of the results and where to direct questions should they arise. The NYISO also requests that the Commission distinguish the term "headroom" in the context of renewable energy deliverability from the term "headroom" in the NYISO's interconnection process (Attachment S of the NYISO Open Access Transmission Tariff) in any final document adopting a methodology.

Lastly, the NYISO offers some clarifications to statements addressing purported shortcomings of production cost simulations made by Staff in its example for conducting energy headroom assessments filed on June 7, 2021, in the instant proceeding. According to the NYISO, production cost simulations: 1) are able to calculate hourly generation output and transmission flows, including post-contingency transmission flows; 2) are commercially available through numerous vendors with ready-to-simulate databases, similar to power flow tools or can be conducted by the NYISO when requested through its Requested Economic Planning Study process; and 3) provide the appropriate level of precision for energy headroom calculations as they can truly calculate energy (MWh) metrics.

**New York State Energy Research and Development Authority (NYSERDA)**

NYSERDA fully supports the proposal to conduct a regular headroom assessment and to make that information available in a timely manner to help inform project siting and the more efficient use of existing and future resources. NYSERDA agrees that this framework should be used to address the prioritization of Phase 2 projects, particularly in three areas identified by the NYISO as the likeliest to experience increased congestion and curtailment rates absent new upgrades: 1) Avangrid's Genesee Valley, Hornell and South Perry, Elmira and Bath and Ithaca local transmission project, 2) National Grid's Watertown/Oswego/Porter sub-zone and 3) Central Hudson's Northwest transmission areas.

NYSERDA recommends that the headroom estimates be published at regular and predicable intervals to allow developers to estimate and understand the headroom potential at proposed points of interconnection. Specifically, NYSERDA suggests that the estimates be published annually prior to the launch of NYSERDA's annual Tier 1 Renewable Energy Certificate (REC) procurements and presented in a manner for stakeholders to easily understand, including an explanation of results and assumptions. According to NYSERDA, without transparent headroom data, Tier 1 REC prices may be improperly inflated due to inaccurate congestion and curtailment risk assumptions, resulting in additional costs that would ultimately be borne by the Utilities' ratepayers.

NYSERDA argues that it should be a priority to establish a headroom methodology that can be implemented in a timely manner to inform near-term generation and siting decisions and then improved upon through future updates. NYSERDA also recommends publishing the results of power flow cases individually to better inform siting and policy decisions. The methodology should, according to NYSERDA, prescribe the set of projects that are included in each case.

NYSERDA maintains that a standardized process to assess energy headroom should be established, as opposed to only assessing capacity headroom, to facilitate longer-term planning. While NYSERDA generally supports the energy headroom assessment methodology advanced by Staff, it points out that CLCPA clean energy targets are generation-based and stresses that energy headroom data is vital to meeting the CLCPA mandates. However, NYSERDA notes that the need for energy headroom data should not supersede the need for near-term capacity headroom data to inform project development. Therefore, if a near-term solution assessing capacity headroom is the most practical approach, NYSERDA recommends that the Utilities, NYISO and Staff expand the approach to include an energy headroom analysis as soon as practical. NYSERDA suggests that the NYISO be consulted on its ability to expand the existing CARIS analysis to include not only expected congestion but also energy headroom.

Lastly, NYSERDA argues that the standardized methodology should account for headroom estimates on both the bulk power system and lower voltage distribution system. NYSERDA agrees with Staff that detailed sub-transmission and distribution models should be included as a component of unified planning models. While NYSERDA acknowledges the complexity and labor associated with modeling lower voltages, it argues that this assessment is important for producing results that help determine whether large-scale projects proposing to interconnect at voltages less than 115 kV are sited at viable points of interconnection. NYSERDA further explains that it could employ this headroom data to inform its evaluation of bids and selection of projects.

**Alliance for Clean Energy-New York (ACE-NY)**

ACE-NY encourages the Commission to act on an initial set of grid prioritization decisions prior to finalizing and fully implementing the headroom assessment methodology. Specifically, ACE-NY encourages the Commission to approve proposed projects in three priority areas – 1) Genesee, Lockport and Lancaster, 2) Hornell and South Perry; and 3) Watertown, Oswego and Porter.

ACE-NY generally supports the implementation of a consistent headroom assessment methodology provided the benefits outweigh the potential challenges associated with developing a joint model. Specifically, ACE-NY is concerned that a joint model development process could take many months, or perhaps years, with potential little added value in some certain circumstances. ACE-NY suggests that an alternative would be to use a model developed by the NYISO with detailed explanations of the changes made by each utility and/or coordination with neighboring utilities, which would provide an expedited approach to assessing upgrades and providing necessary flexibility in updating headroom values. ACE-NY encourages DPS Staff to engage with the NYISO to assess the best and timeliest path forward for developing a model and to consider a stakeholder process for input, review and validation of key inputs.

ACE-NY also recommends that the assessment methodology examine both energy and capacity headroom. According to ACE-NY, energy headroom assessments using production cost simulation models and an 8,760-hourly representation of load and clean energy generation better represent the percentage of energy that must be curtailed due to transmission limitations. ACE-NY maintains that the utilities should have the flexibility to present such an assessment as a complement or replacement to an energy or capacity headroom calculation.

To avoid a piecemeal expansion of the electric grid, ACE-NY recommends that the model look out five, 10 and 15 years. ACE-NY notes that, although there is more uncertainty in the long-term, given the long lead time associated with the upgrades, it is practical to look at both medium-term and long-term needs to inform more efficient system upgrades and minimize the costs that will be borne by ratepayers.

ACE-NY supports an annual update of headroom methodology calculations, with some flexibility to account for the service territories that have not experienced significant change since the previous assessment. In addition, ACE-NY states that the headroom assessment assumptions and results should be well documented in order to inform the planning process. ACE-NY also maintains that additional, more detailed information is necessary for developers to accurately model the potential impact of an upgrade, including a facility’s name and specific parameters of the upgrade (e.g., reactance, resistance, normal and emergency rating, both pre- and post-upgrade, conductor type and existing and updated ratings as currently done in the NYISO Gold Book). Lastly, ACE-NY asserts that Grid Enhancing Technologies and distribution technologies should be integrated into headroom assessments.

**EDF Renewables (EDFR)**

EDFR supports the idea of a consistent and transparent approach for assessing current and future grid limitations, as well as the potential improvements enabled by a transmission or distribution upgrade. EDFR, however, encourages the Commission to incorporate flexibility into the model given the considerable amount of time and effort that will be required for the Joint Utilities to coordinate their efforts. EDFR also recommends using longer-term models that go out a minimum of 10-15 years given the long lead time associated with grid investments. This would, according to EDFR, avoid a piece-meal expansion of the grid which could ultimately be more costly for ratepayers. EDFR supports both capacity and energy headroom analyses, and also encourages a non-deliverability metric as a proxy for curtailment as part of the energy headroom analysis or as a complementary metric from a production cost simulation type of analysis. In order to be successfully utilized, EDFR recommends that the headroom results be well documented and, in the case of critical assumptions, should provide sensitivity cases. Lastly, EDFR maintains that the headroom methodology should include both N-0 and N-1 conditions or, at a minimum, a sensitivity to an N-1 dispatch.

EDFR agrees that a more consistent and transparent headroom analysis is necessary but maintains that evidence and studies already exist to support the prioritization of an initial set of grid updates. Specifically, EDFR points to the need to prioritize the following regions:

1) Hornell and South Perry – The NYISO CARIS study identified severe risk of curtailment and congestion due to several constraints. According to EDFR, Phase 1 upgrades are not able to meaningfully reduce congestion in this area, which threatens the successful completion of several projects in the area, including the 1700 MW renewable projects with a NYSERDA award in the Southern Tier.
2) Watertown/Oswego/Porter – The NYISO CARIS study also projected severe curtailment in this area due to multiple constraints. EDFR states that Phase 1 upgrades are also insufficient in this area as there are close to 700MW of NYSERDA-awarded renewable energy projects expected to come online. EDFR notes that the necessary upgrades must be accelerated, citing to the comments filed by NYSERDA on January 18 in this proceeding.

EDFR encourages the Commission to 1) allow utilities to refine Phase 2 upgrades at least for the areas to be prioritized and/or 2) declare public policy needs that will enable additional solutions to be proposed and/or 3) allow for priority transmission projects in these regions via participation of the New York Power Authority under its authority conferred by the Accelerated Renewable Energy Growth and Community Benefit Act. According to EDFR, these actions will allow better coordination of the in-service dates of generators and the associated transmission solutions and will provide certainty to developers that significant congestion risks will be addressed through a timeline for future grid updates.

**New York Battery and Energy Storage (NY-BEST)**

NY-BEST argues that the Staff Proposal's reliance on a single headroom maximizing scenario for generational location is insufficient and problematic. NY-BEST acknowledges that modeling efforts can be refined and updated, as explained in the Proposal, but takes issue with basing decisions on one estimate of renewable interconnection locations. Instead, NY-BEST asserts that probabilistic analysis with a true range of outcomes is the metric that should be used to compare transmission solutions.

NY-BEST also believes that the methodology should holistically consider energy storage deployments in the State, including the role for energy storage to time shift energy, and hybrid projects. NY-BEST also argues that the methodology should maximize utilization of renewable energy generation both now and in the future and specifically notes its concerns about the lack of consideration of potential renewable overgeneration in the future.

**New York Solar Energy Industries Associates (NYSEIA)**

NYSEIA recommends annual updates to the headroom calculations to provide stakeholders with critical up-to-date data on T&D headroom. NYSEIA, however, recommends some flexibility to account for situations where a utility has not observed significant changes from the previous year's assessment. According to NYSEIA, it is critical that the T&D planning process account for headroom and upgrades needed to achieve any new distributed solar targets set by the State. In particular, NYSEIA emphasizes the Straw Proposal's approach to model the distribution electrical system beyond the substation transformer to capture the effects of load, storage variations, circuit characteristics and protection, which it believes is critical for enabling necessary distribution upgrades.

NYSEIA recommends expanding the term Grid Enhancement Technologies to include grid modernization technologies for the distribution system, as opposed to limiting it to technology that solely improves transmission. NYSEIA strongly recommends that the headroom assessments identify and integrate opportunities to implement distribution technologies, including the "Flexible Interconnection Capacity Solution" proposed by Avangrid as a Phase 2 solution. According to NYSEIA, the layering of implementable distribution technologies on infrastructure upgrades can provide greater incremental headroom.

**Transource Energy, LLC and Transource New York, LLC (collectively, Transource**

Transource supports the use of a consistent methodology to calculate headroom across the State. Transource urges the Commission to direct the Joint Utilities to issue biennial system headroom reports to be updated in six-month intervals, as necessary, to account for material system changes expected over the next decade as the system evolves to meet the CLCPA mandates. Relatedly, Transource argues that the Joint Utilities should be required to make available the models used to produce the reports (with confidentiality protections, as necessary) to allow investors to effectively plan to address evolving system conditions and respond effectively to future solicitations.

Transource also argues that the Commission must act in the near term to set the structure and associated timelines to address the necessary system upgrades needed to meet the CLCPA mandates. Transource, however, acknowledges that the Commission is undertaking a complex effort to carefully coordinate system upgrades on the bulk, distribution and local levels. According to Transource, it will be just as critical that the Commission identify advanced technologies to more efficiently and cost effectively address these system upgrades.