10 Krey Boulevard, Rensselaer, NY 12144
Ph: 518.356.6000 | Fax: 518.356.8899

January 19, 2021

By Electronic Portal

Hon. Michelle L. Phillips
Secretary to the Commission
New York State Public Service Commission
Empire State Plaza Agency Building 3
Albany, NY 12223-1350

Subject: 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

Dear Secretary Phillips:

Pursuant to the Notice of Proposed Rulemaking published November 18, 2020 in the State Register, enclosed are the comments of the New York Independent System Operator in the above-entitled proceeding.

If you have any questions, please call or email me.

Respectfully submitted,

/s/ Carl Patka
Carl Patka
Assistance General Counsel
New York Independent System Operator, Inc.
10 Krey Boulevard
Rensselaer, NY 12144
Tel: (518) 356-6220
email: cpatka@nyiso.com

STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

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.

COMMENTS OF THE NEW YORK INDEPENDENT SYSTEM OPERATOR, INC. ON COMPLIANCE REPORT BY ELECTRIC UTILITIES ON DEVELOPING DISTRIBUTION AND LOCAL TRANSMISSION IN RESPONSE TO STATE CLIMATE CHANGE LAWS, AND ON TECHNICAL CONSULTANTS' STUDIES

Pursuant to the Notice of Proposed Rulemaking published November 18, 2020 in the State Register,[1] the New York Independent System Operator, Inc. ("NYISO") respectfully submits these comments on the Utilities' Local Transmission and Distribution Report filed by electric utilities[2] in compliance with the May 14, 2020 Order ("May Order") on Transmission Planning Pursuant to the Accelerated Renewable Energy Growth and Community Benefit Act[3] ("AREGCBA" or "Act") issued by the New York State Public Service Commission ("PSC" or "Commission"). The NYISO is commenting on the Utilities' Local Transmission and Distribution Report to discuss the need for transmission expansion for the purpose of compliance with the Act for the Commission's consideration in this proceeding and in implementing the Act. In addition, the NYISO respectfully submits these comments in response to the Notice of Technical Conference and presentations filed in this proceeding by the New York Department of Public Service ("DPS") and the New York State Energy Research and Development Authority

[1] 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*, Notice of Proposed Rulemaking, NYS Register, I.D. No. PSC-46-20-00008-P, November 18, 2020, at 16-17.

[2] The Utility Transmission and Distribution Investment Working Group Report (dated November 2, 2020) ("Report") was filed by 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 & Rockland Utilities, Inc., and Rochester Gas and Electric Corporation ("the Utilities").

[3] 2020 Laws of N.Y. Ch. 58, Part JJJ.

("NYSERDA") on studies conducted by technical consultants on New York's bulk power transmission system needs to integrate and deliver offshore wind energy to consumers. The NYISO provides these comments on the technical consultants' presentations in order to provide input on key factors that may drive the need for bulk transmission expansion for consideration in further studies.

BACKGROUND

The AREGCBA directs the Commission to take actions to provide that New York's electric grid will support the state's Climate Leadership and Climate Protection Act ("CLCPA") mandates.[4] The Act calls for the PSC to "commence a proceeding to establish a bulk transmission investment program . . . that identifies bulk transmission system investments that the commission determines are necessary or appropriate to achieve the CLCPA targets (the state 'bulk transmission investment plan')."[5] The PSC will "establish a prioritized schedule for implementation of the state bulk transmission investment plan, and in particular shall identify projects which shall be completed expeditiously to meet the CLCPA targets."[6]

The Act provides that:

> The commission shall utilize the state grid operator's public policy transmission planning process to select a project necessary for implementation of the state bulk transmission investment plan, and shall identify such projects no later than eight months following a notice of the state grid operator's public policy transmission planning process cycle, except that for those projects for which the commission determines there is a need to proceed expeditiously to promote the state's public policy goals, such projects shall be designated and proceed in accordance with subdivision five of this section.[7]

[4] 2019 Laws of New York, ch. 106. The CLCPA requires that seventy percent of energy consumed in New York State be produced by renewable resources by 2030. By 2040 energy consumed must be completely emissions free.

[5] *Id.* at §7(4).

[6] *Id.*

[7] *Id.*

The Act authorizes the New York Power Authority ("NYPA") to undertake the development of such bulk transmission investments, on its own or in partnership with others, found by the Commission to be needed expeditiously to achieve CLCPA targets.[8] On July 2, 2020, the DPS and NYPA filed a petition requesting that the Commission adopt criteria to use in evaluating and prioritizing transmission needs, and determining which bulk transmission investments qualify as priority projects to be developed by NYPA under the Act.[9]

On October 15, 2020, the Commission issued an Order on Priority Transmission Projects that adopted some of the proposed criteria for designating priority transmission projects and designated the Northern New York transmission projects for development by NYPA.[10]

On November 2, 2020, the Utilities filed the Utility Transmission and Distribution Investment Working Group Report which, as noted above, was noticed for public comment in the State Register. On November 5, 2020, the DPS and NYSERDA issued a Notice of Technical Conference in this proceeding to address certain studies that "form the basis of establishing New York's bulk transmission investment plan and the local transmission plans of the New York utilities."[11] On November 23, 2020, the DPS and NYSERDA convened a technical conference that included presentations on the Power Grid Study that is comprised of three components: (i) Utility Local Transmission Studies, presented by electric utilities, (ii) New York Offshore Wind

[8] *Id.* at § 5.

[9] NYPSC Case No. 20-E-0197, *Proceeding on Motion of the Commission to Implement Transmission Planning Pursuant to the Accelerated Renewable Energy Growth and Community Benefit Act*, Petition Requesting Adoption of Criteria for Guiding Evaluation of Whether a Bulk Transmission Investment Should Be Designated as a Priority Transmission Project, and for Designation of Certain Transmission Investments in Northern New York as a Priority Transmission Project (July 2, 2020).

[10] *Id.*, Order on Priority Transmission Projects (October 15, 2020).

[11] *Id.*, Notice of Technical Conference (November 5, 2020).

Integration Study, presented by DNV-GL, PowerGEM, and WSP, and iii) Zero-Emission Electric Grid in New York by 2040, presented by Siemens.[12]

The NYISO offers comments in this proceeding to emphasize:

(i) the importance of additional transmission infrastructure to meet the state's climate change policy objectives;

(ii) the factors contributing to the need for bulk transmission expansion to achieve the state's climate change policy objectives; and

(iii) the value of the NYISO's Public Policy Process to solicit, evaluate and select efficient and cost effective bulk transmission solutions eligible for cost allocation and recovery through its tariffs.

The NYISO appreciates the extensive efforts by the DPS, NYSERDA, and the Utilities in conducting the Power Grid Study. As part of this filing, the NYISO's comments on the New York Offshore Wind Integration Study and the Zero-Emission Electric Grid in New York by 2040 are based on the discussions and interim results released at the Technical Conference, and will be further refined when the Commission seeks public comments on its bulk power system Power Grid Study.[13] Considering the impacts of these study findings on the Commission's decisions on transmission system investments in this proceeding, we encourage the NYSERDA and the DPS to provide details such as study methodology and assumptions as part of the final report.

[12] On November 24, 2020, the DPS and NYSERDA submitted the presentations as part of the record in this proceeding.

[13] The NYISO understands that the Commission will issue a draft bulk power system study for public comment under the State Administrative Procedure Act.

COMMENTS

I. To Meet the State's Climate Change Targets, Renewable Resources Will Likely Be Developed in Regions Where Transmission Expansion Will Be Necessary.

The bulk power system envisioned in the state's climate change laws will likely operate under a very different set of resources and demands. Rather than relying on traditional fossil-fueled generating units to meet the electricity demand, new renewable generating units will need to be interconnected throughout the New York Control Area ("NYCA") to provide emission-free power. Due to the availability of the solar and wind natural resources that serve as the "fuel" for renewables, and driven by the need for large real estate footprints to accommodate them, renewable resources have different siting and sizing considerations when compared to traditional fossil-fueled generation.

These natural resources and the land needed to site renewable resources tend to be in the northern and western regions of upstate New York State, including the Southern Tier, and off the coasts of New York City and Long Island. As a result, renewable generation investments will necessarily concentrate in certain geographic areas where bulk transmission facility expansion will be required in order to deliver the renewable energy to consumers, as confirmed by NYSERDA awards of renewable energy credits (RECs) to date.[14]

The NYISO Interconnection Queue also indicates where developers are considering siting within New York State. Based on the NYISO Interconnection Queue as of Nov. 30 2020,[15] over 90% of the land-based renewable capacity outside of New York City and Long Island is located in NYISO Zones A through E, and less than 10% is located in Zones F and G. Those

[14] Recent land-based awards, such as 18 out of the 21 large-scale renewable energy projects awarded in the 2020 solicitation and 18 out of the 20 projects awarded in the 2019 solicitation, are located in the upstate regions mentioned above.

[15] NYISO Interconnection Queue is available at the following link: https://www.nyiso.com/interconnections

areas in Zones A through E are mostly remote from New York's existing bulk power transmission facilities.

A. The NYISO's "70 by 30" Analysis Demonstrates the Need for Transmission Infrastructure to Deliver Energy from Generation Pockets to Consumers Statewide

The NYISO has conducted assessments to provide insights into renewable generation pockets that are likely to form in upstate New York due to limited transmission capability in the areas where wind and solar resources are likely to be constructed. These renewable generation pockets are regions in the state where renewable generation resources cannot be fully delivered to consumers statewide due to transmission constraints.

When generation exceeds the transmission limits and load within a pocket in a given hour, the generation output must be reduced, or "curtailed." Curtailments result from the hourly balancing of generation and load subject to transmission constraints. For any given hour, the output of a wind or solar plant may range from fully curtailed (zero output) to full output. Curtailment of existing wind generators is already observed in New York, in certain months as high as 3%.[16]

Without additional transmission expansion, the curtailment is expected to increase in the future as more renewable resources interconnect to the system. The NYISO's 2019 Congestion Assessment and Resource Integration Study ("CARIS"),[17] released in July 2020, provides key insights into the potential value of additional transmission capability across the NYCA.[18] The

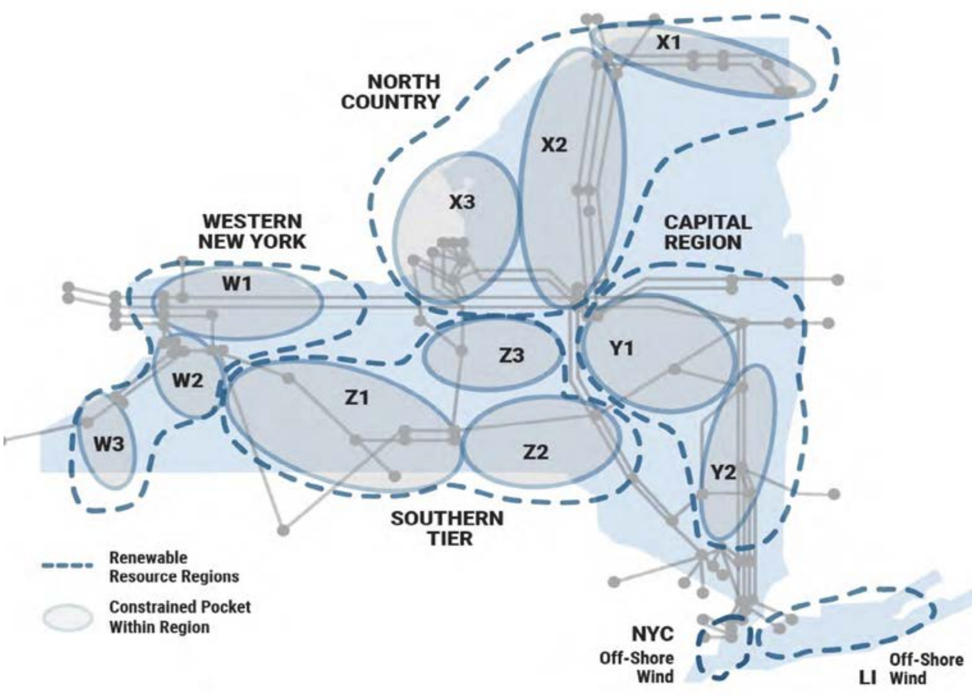
[16] November 2020 Monthly Operations Report, at slide 10. The document is available at the following link: https://www.nyiso.com/documents/20142/17478687/03_Operations_Report_202011_v1.pdf/ada0989d-8540-bfbb-d487-537bc52fa0e8

[17] The 2019 CARIS Report, Congestion Assessment and Resource Integration Study (July 2020) is included as Attachment I to these comments.

[18] The 2019 CARIS report is available at the following link: https://www.nyiso.com/documents/20142/2226108/2019-CARIS-Phase1-Report-Final.pdf/bcf0ab1a-eac2-0cc3-a2d6-6f374309e961?t=1595619194867. The NYISO is submitting the 2019 CARIS Study for the Commission's consideration as part of the record in this proceeding.

CARIS study assessed projected congestion patterns in the NYCA under several scenarios; the most informative of which was the 70 by 30 Scenario representing the CLCPA target of 70% renewable energy by 2030. In the 70 by 30 Scenario simulations, approximately 11% of the annual total potential renewable energy production would be curtailed across the New York system.[19]

The assessment shows that renewable generation pockets will likely result from both the existing renewable resources and the large amount of expected additional wind and solar resources. This supports the conclusion that additional transmission expansion, at both bulk and local levels, will be necessary to efficiently deliver renewable power to New York consumers. The figure below depicts the generation pockets from the NYISO's 70 by 30 Scenario:



CARIS Renewable Generation Pockets Map

[19] 2019 CARIS report, at 91.

B. Review of Utilities' Local Transmission and Distribution Capital Plans Should Holistically Consider Interactions Among The Plans

In recognition of the renewable generation pockets identified in the CARIS report, the Utilities utilized the NYISO's assessment as a starting point for more focused and detailed assessments of the Utilities' local systems in the Local Transmission and Distribution Report.[20] The resulting Utilities' Report contains proposals and recommendations in fulfilment of the requirements of the May Order to address the need for local transmission and distribution needs. The Utilities appropriately establish project investment criteria and prioritization recommendations, as well as identify candidate projects for transmission expansion within their respective service territories. The Utilities should identify the projects they consider firm as part of their Local Transmission Owner Plan within the NYISO's Comprehensive System Planning Process. Consistent with its base case inclusion rules and other planning procedures, the NYISO will incorporate these facilities into its planning processes when planning for the bulk transmission system. These projects will also require evaluation in the NYISO's transmission expansion process if the modification or expansion results in an impact to the system that exceeds the established thresholds in the NYISO's tariff.[21]

The projects identified are likely an effective first step in addressing some level of anticipated local renewable curtailments, but the Commission's consideration of the Utilities' proposed local transmission and distribution capital plans should also go beyond the individual Utilities' service territories. To meet the requirements of the state's climate change laws, the PSC should holistically consider the interactions among the proposed projects as they relate to addressing the transmission-constrained generation pockets identified in the CARIS report.

[20] Utilities Local Transmission and Distribution Report, at 74.
[21] *See generally*, OATT §§ 3.7.1; 22.3; NYISO Transmission Expansion and Interconnection Manual § 2.

In 2020, the NYISO and its consultants conducted the Climate Change Impact and Resilience Study ("Climate Change Study")[22] to identify potential system impacts as the state moves to an emission-free electric grid in 2040. The Climate Change Study confirmed that additional transmission capability is necessary to alleviate constraints on the system and maximize the potential contribution of the renewable resources. As discussed above, the distribution of renewable resources across New York is heavily weighted to the upstate region due to land availability and ease of siting. As a result, the significant addition of renewable resources required to meet 100 percent emission-free grid by 2040 leads to congestion as the existing system's interregional transfer capability cannot allow for sufficient flows to meet downstate demand. Without transmission expansion, congestion would result in an average of 3,565 MW of renewable power being curtailed in each hour (this is equivalent to 9.4 percent of total NYCA load) during the winter period.

II. The Commission Should Consider the Full Range of Factors Contributing to the Need for Bulk Transmission Expansion to Achieve the State's Climate Change Policy Objectives

When meeting the state's climate change policy objectives, the power system will likely operate under a very different set of resources and demands, and will likely encounter new challenges in system planning and operation. Transmission expansion can be planned more effectively and efficiently by incorporating multi-faceted drivers such as federal and state policies, bulk and local transmission development, resource availability, market signals, environmental regulations, and demand growth. When conducting any long-term planning analysis, the assumptions made in a study regarding these key drivers necessarily have significant impacts on the study findings.

[22] The Climate Change Impact Phase II, An Assessment of Climate Change Impacts on Power System Reliability in New York State - FINAL REPORT (September 2020) is included as Attachment II to these comments.

Understanding that limited bulk transmission expansions were identified from the New York Offshore Wind Integration Study[23] and Zero-Emission Electric Grid in New York by 2040 studies[24], the NYISO has identified key factors such as maintaining reliability, land-based renewable generation siting and sizing, offshore wind cable routing, and substation interconnections that directly impact the finding and scope of transmission infrastructure needs.

A. The Importance of Continuously Maintaining Reliability

The Climate Change Study, in assessing future system conditions associated with an emission-free electric grid, identified the need for "dispatchable and emission-free resources"[25] to cover any circumstances where the renewable resources are insufficient to meet identified demand, and to evaluate what attributes such a dispatchable resource must have to help meet reliability needs. The study also recognized that building additional transmission capacity will both increase renewable energy production and increase grid reliability and resiliency.

A major goal of the Climate Change Study was to analyze the impact of climate-related disruptions, including include intense impacts that affect power system reliability, such as more frequent and severe storms, extended extreme temperature events, and other meteorological events (*e.g.*, wind lulls, droughts, and ice storms). Increased transfer capability was found to improve the resilience of the power system for all localized events, such as offshore storms or wind lulls that only affect the upstate or downstate regions. Increased transfer capability also improves the ability of the grid to respond to some disruptions that affect load and generation across the state, such as heat waves and cold snaps.

[23] New York Offshore Wind Integration Study (November 23, 2020), at slide 41.

[24] Zero-Emission Electric Grid in New York by 2040 studies (November 23, 2020), at slide 29.

[25] Climate Change Impact and Resilience Study, at 32. The report is available at the following link: https://www.nyiso.com/documents/20142/16884550/NYISO-Climate-Impact-Study-Phase-2-Report.pdf/e9214fd4-9c52-036d-b92b-15f282e686e6, at 32. The NYISO is submitting this report for the Commission's consideration as part of the record in this proceeding.

Separately, E3 was engaged by NYSERDA and conducted the "New York State Decarbonization Pathways Analysis.[26]" The study also concluded that: "Firm capacity [will be] needed to meet multi-day period of low wind and solar output" and that "[t]he need for dispatchable resources is most pronounced during winter periods of high demand for electrified heating and transportation and lower wind and solar output".[27] This approach seems to align with the methodology adopted by the DPS's consultants in the Zero Emission Grid by 2040 assessment, where it was noted that "Siemens performed analysis to ensure New York has enough available capacity to cycle up/down in the 1 to 10-minute horizon to cover variability in load and renewable generation."

The NYISO has not been able to ascertain the extent to which dispatchable or other resources were included in the studies presented at the Technical Conference. Given the significance of maintaining reliability continuously, the NYISO recommends that the final Zero Emission Grid by 2040 report include more information on how this available capacity was calculated, and to clarify how the reliability needs were met with these flexible capacity. We also encourage the PSC and NYSERDA to consider the NYISO's Climate Change Study submitted in this proceeding to supplement the findings of the Zero Emission Grid by 2040 report for a clearer view of potential system reliability needs in a future all-renewable resources power system.

B. The Ability of Energy Storage to Fulfill Future Bulk Power System Reliability Needs

The NYISO's 2019 CARIS 70 by 30 Scenario found that energy storage could decrease congestion, and when dispatched effectively, energy storage would help to increase the

[26] New York State Decarbonization Pathway Analysis; available at the following link: https://climate.ny.gov/Meetings-and-Materials.

[27] *Id.,* at slide 17.

utilization of the renewable generation, particularly the solar generation tested in the analysis.[28] However, the targeted analysis showed that energy storage likely cannot by itself completely resolve the transmission limitations in the pockets analyzed.

Recognizing the ability to store energy when there is excess, and to discharge that energy when there is shortfall, this modeling approach again seems to align with the methodology adopted by the DPS's consultants. In the land-based portion of the New York Offshore Wind Integration Study, the DPS's consultants assumed 3,000 MW of energy storage was deployed across the state, and some were sited at preferable locations to maximize renewable generation utilization, and centrally operated to mitigate potential reliability violations. The description of the energy storage modeling was limited in the materials released at the Technical Conference on Nov. 23, 2020, and we encourage more details to be released at the final report. Careful consideration should be given to how storage resources should be represented in a bulk power system model, such as reflecting the charging and discharging cycles of storage in operations and the probability of their availability.

C. The Availability of Interconnection Points and Transmission Capability to Deliver Upstate and Offshore Wind Energy to Consumers for Renewable Generators

When studying transmission system needs, the assumptions made about where future renewable generation will be sited directly impacts the resulting transmission congestion and curtailment patterns. These patterns drive whether bulk transmission expansion is needed to achieve the state's climate change policy targets. As discussed above, in upstate New York if more renewable resources are assumed to locate in Western New York, Northern New York, and

[28] 2019 CARIS report, at 103.

the Southern Tier as development trends suggest, it is likely new transmission system facilities will be needed to provide renewable energy delivery to consumers.

The NYISO understands, however, that the Zero-Emission study assumed that more renewable generators will be located downstream of the Central East interface, such as in NYISO Zones F and G. Given this assumption, it is foreseeable that transmission expansion needs may be overlooked. Regarding offshore wind integration, injection of smaller MW amounts but at more points of interconnection could potentially require less transmission expansion. Certain sites tested in the New York Offshore Wind Integration Study have as little as 300 MW at each point of interconnection (POI), and as many as five POIs in New York City and five POIs in Long Island.[29] In comparison, the projects awarded Offshore Renewable Energy Credits ("ORECs") in the NYSERDA 2018 and 2020 offshore wind solicitations each seek to inject in excess of 800 MW at each point of interconnection. The transmission and substation expansions required to accommodate injection of large projects can be exponentially more extensive than projects of smaller sizes.

ConEdison[30] and LIPA[31] have both pointed out the need for substation expansion in the Utility Report given that most major substations in this area have already been fully utilized and will need to be expanded to accommodate the new offshore wind interconnections. Based on the cable routing study conducted by the DPS's technical consultant, there appear to be limited available cable routings through the New York City harbor.[32] If each project has independent radial connections, opportunities for necessary cabling to achieve the full offshore wind goal of 9,000 MW will be limited.

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[29] New York Offshore Wind Integration Study (November 23, 2020), at slides 17 and 29.
[30] Utilities' Local Transmission and Distribution Report, at 112.
[31] Utilities' Local Transmission and Distribution Report, at 130.

These interconnection concerns are not fully addressed in the consultants' studies, but will directly impact whether feasible interconnection points exist for offshore wind projects or will have to be built. Such needs will also be identified in the NYISO's interconnection studies that are being conducted for proposed generators. These studies will identify system upgrade facilities required to reliably interconnect generators. The NYISO encourages the DPS, NYSERDA and their consultants to take the cost efficiency and time required to build these potential system upgrade facilities into consideration in future studies.

In conclusion, the NYISO notes that neither of the consultants' studies identifies the need for bulk transmission expansions in their preliminary findings. We encourage consideration of alternate assumptions and scenarios, such as those evaluated in the Climate Change Study, CARIS, and the referenced E3 study to more fully understand the potential outcomes as the State's climate policies are pursued.

III. The NYISO's Public Policy Process Provides for the Solicitation, Evaluation and Selection of More Efficient and Cost Effective Transmission Solutions

Timely and coordinated transmission system expansion will be more efficient and cost effective for ratepayers and for the achievement of state policy targets. As discussed in the NYISO's comments on proposed Public Policy Transmission Needs for the 2020-2021 cycle,[33] the NYISO supports the PSC's identification of Public Policy Transmission Needs and utilization of the NYISO's Public Policy Process to solicit competitive solutions, and select more efficient and cost effective transmission solutions for cost recovery under its tariff.

In determining the designation of transmission needs as either priority transmission projects needed expeditiously or as needs for consideration in the Public Policy Process, the PSC

[33] *See* Case 20-E-0497, *In the Matter of New York Independent System Operator, Inc.'s Proposed Public Policy Transmission Needs for Consideration for 2020, Comments of the New York Independent System Operator*, Inc. (January 19, 2021).

should consider whether transmission needed to meet the CLCPA's 2030 and 2040 goals must be completed more quickly than the cumulative time expected by the NYISO's streamlined Public Policy Process, the Commission's siting process under Public Service Law Article VII, and construction and entry into service. Considering typical schedules for siting processes, engineering, procurement, and construction, the NYISO estimates that the total timeline for projects pursued through the NYISO Public Policy Process from the PSC's declaration of a need to entry of a transmission project into service could span approximately five to six years.[34]

Given the multi-year lead time necessary for transmission development in New York, the NYISO supports the Commission finding the need for transmission to achieve the CLCPA to be addressed in the NYISO's Public Policy Transmission Planning Process ("Public Policy Process").[35] The NYISO has made significant enhancements to its Public Policy Process to expand its consideration of certain aspects of transmission project proposals, such as capital cost containment, and to streamline its timeline for consideration and selection of Public Policy Transmission Projects. The NYISO has outlined an estimated timeline to complete the Public Policy Process of approximately 18 months following the PSC's identification of a Public Policy Transmission Need.

CONCLUSION

The NYISO respectfully submits its studies of the state's 2030 and 2040 renewable energy targets, together with its comments on the Utilities Local Transmission and Distribution Report and the DPS/NYSERDA technical consultant's studies, in order to assist the Commission

[34] This timeframe is an estimate that is dependent on many factors through the evaluation process, siting and permitting processes, engineering, procurement and construction.

[35] Capitalized terms not otherwise defined in this document are defined by Attachment Y to the NYISO Open Access Transmission Tariff ("OATT") and otherwise in the OATT and Market Administration and Control Area Services Tariff.

with the important decisions it is considering in this proceeding on New York's future transmission infrastructure needs. The addition of transmission infrastructure is essential to achieving New York State's climate change policy targets under the CLCPA and the Accelerated Renewable Energy Growth and Community Benefit Act. The priority transmission project process and the NYISO's Public Policy Process can work in tandem with the Utility Local Transmission & Distribution infrastructure initiative to fulfill these significant transmission needs. The NYISO looks forward to continuing its work with the DPS, NYSERDA, and the Utilities to address the state's infrastructure needs.

Dated: January 19, 2020

Respectfully submitted,

/s/ *Carl F. Patka*

Carl F. Patka
Assistant General Counsel
Brian Hodgdon
Senior Attorney
New York Independent System Operator, Inc.
10 Krey Boulevard
Rensselaer, NY 12144
Tel: (518) 356-6000
CPatka@nyiso.com
BHodgdon@nyiso.com

CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document upon each person designated on the official service list compiled by the Secretary in this proceeding.

Dated at Rensselaer, NY this 19th day of January 2021.

/s/ Joy A. Zimberlin
Joy A. Zimberlin
New York Independent System Operator, Inc.
10 Krey Blvd.
Rensselaer, NY 12144
(518) 356-6207

Attachment I

2019 CARIS REPORT

Congestion Assessment and Resource Integration Study

A Report by the
New York Independent
System Operator

July 2020

2019 Congestion Assessment and Resource Integration Study

Comprehensive System Planning Process

A Report by the
New York Independent System Operator

July 24, 2020

Caution and Disclaimer

The contents of these materials are for information purposes and are provided "as is" without representation or warranty of any kind, including without limitation, accuracy, completeness or fitness for any particular purposes. The New York Independent System Operator ("NYISO") assumes no responsibility to the reader or any other party for the consequences of any errors or omissions. The NYISO may revise these materials at any time in its sole discretion without notice to the reader.

NYISO System and Resource Planning staff can be reached at 518-356-6000 to address any questions regarding this CARIS report or the NYISO's economic planning processes.

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Executive Summary

Overview

With the publication of this 2019 Congestion Assessment and Resource Integration Study ("CARIS"), the New York Independent System Operator, Inc. ("NYISO") has completed the first phase ("CARIS Phase 1") of its two-phase economic planning process.[1] This CARIS Phase 1 report provides information to market participants, policymakers, and other interested parties for their consideration in evaluating projects designed to address transmission congestion identified in the study. The report presents an assessment of historic (2014-2018) and projected (2019-2028) congestion on the New York State bulk power transmission system, and provides an analysis of the potential costs and benefits of mitigating that congestion using generic transmission, generation, demand response, and energy efficiency solutions.

The study presents a series of metrics for a wide-range of potential future scenarios. The CARIS Base Case can be viewed as a "status quo" or "business as usual" case, incorporating only incremental resource changes based on known planned projects with a high degree of certainty. The NYISO also conducted scenario analyses to evaluate the impact on transmission congestion of changed conditions in the Base Case assumptions. Scenario analyses can provide useful insight on the sensitivity of projected congestion values to differing assumptions included in the Base Case. The scenarios were selected by the NYISO in collaboration with its stakeholders. The scenarios modify the Base Case to address variations in key input assumptions like the forecasts of electric demand and fuel prices. The highlight of this report is the "70x30" scenario, which is based on the policies set forth in the Climate Leadership and Community Protection Act (CLCPA). This 2019 state law mandates that 70% of New York State's end-use energy be generated by renewable energy systems by 2030 ("70x30"). The scenario models two hypothetical build-outs of renewable energy facilities and identifies transmission-constrained pockets throughout New York State that could prevent full utilization of that renewable energy.

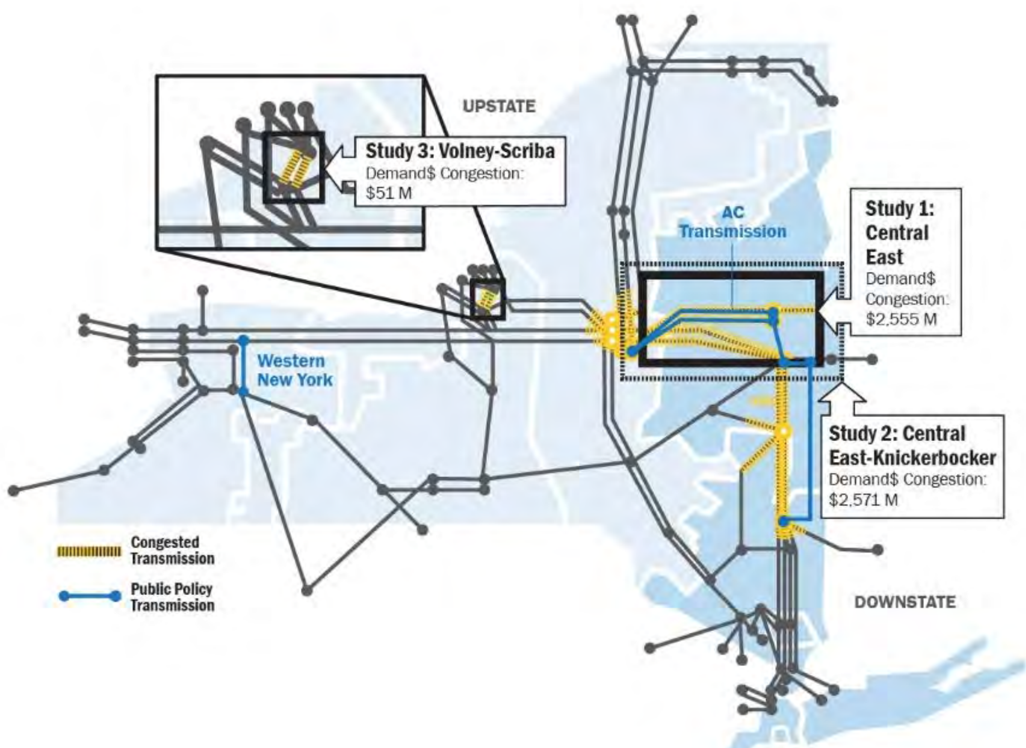
The study findings do not account for currently changing patterns in system-wide energy consumption resulting from the response to COVID-19. Rather, the study provides in-depth analysis of long-term system usage trends and of system congestion and curtailment patterns over the next decade that are likely to persist notwithstanding the lower energy forecasts for 2020 and 2021 that the NYISO produced for the 2020 Gold Book.

1 Capitalized terms not otherwise defined herein have the meaning set forth in Section 1 and Attachment Y of the NYISO's OATT.

Base Case Findings

The CARIS Base Case study simulates each hour of each year from 2019 through 2028, incorporating system plans consistent with the 2019-2028 Comprehensive Reliability Plan, issued in July 2019. Notably, this CARIS Base Case includes the Western New York and AC Transmission Public Policy Transmission Projects that are planned to enter into service in June 1, 2022 and December 31, 2023, respectively. The study assumptions were developed with stakeholders using the best information available when the database was established in August 2019, per the CARIS process requirements. The Base Case results, while informative to a degree, are borne of a generation-rich system with limited changes to load and resource mix from the existing electric grid. As a result, the Base Case results mirror past studies in identifying limited opportunities for transmission build-out based solely on production-cost reductions. The following map depicts the congestion for the top three congested transmission corridors identified by this CARIS cycle for further study: Study 1) Central East, Study 2) Central East-Knickerbocker, and Study 3) Volney-Scriba.

Figure 1: Base Case Congestion of Top 3 Congested Groupings, 2019-2028 ($2019M)



For each of these corridors and respective studies, the NYISO assessed how production cost, demand congestion, and other economic metrics are impacted by modeling four similarly-sized generic solutions (*i.e.*, transmission, generation, demand response and energy efficiency). The NYISO sizes the modeled generic solutions such that the capacity (MW) of generation, demand response, and energy efficiency results in an equivalent increase in transfer capability across the relevant interface to the transmission solution. For Study 1 and Study 2, the generic solutions increased transfer capability by approximately 400 MW across Central East, while for Study 3, the generic solution increased transfer capability by approximately 200 MW across the Oswego Export interface (Volney-Scriba).

Figure 2: Generic Solutions

Generic Solutions			
Studies	**Central East (Study 1)**	**Central East-Knickerbocker (Study 2)**	**Volney-Scriba (Study 3)**
TRANSMISSION			
Transmission Path	Edic-New Scotland	Edic-New Scotland-Knickerbocker	Volney-Scriba
Voltage	345 kV	345 kV	345 kV
Miles	85	100	10
GENERATION			
Unit Siting	New Scotland	Pleasant Valley	Volney
Blocks	340 MW	340 MW	340 MW
DEMAND RESPONSE			
Blocks	Zone F : 100 MW Zone G : 100 MW Zone J : 200 MW	Zone F : 100 MW Zone G : 100 MW Zone J : 200 MW	Zone F : 100 MW Zone G : 100 MW
ENERGY EFFICIENCY			
Blocks	Zone F : 100 MW Zone G : 100 MW Zone J : 200 MW	Zone F : 100 MW Zone G : 100 MW Zone J : 200 MW	Zone F : 100 MW Zone G : 100 MW

Consensus on the costs for each type of generic solution was achieved through engagement with stakeholders in the NYISO's shared governance process. Recognizing that the costs, points of interconnection, timing, and characteristics of actual projects may vary significantly, a range of costs (low, mid, and high) was developed for each type of resource based on publicly available sources. Such costs may differ from those submitted by potential developers in a competitive bidding process.

The sole benefit metric for a CARIS project, per the NYISO's Tariff, is the reduction in New York Control Area (NYCA)-wide production costs. Each generic solution was modeled and simulated to determine the resulting production cost savings over the ten-year study period as shown in Figure 3. Those savings were compared to the cost estimates to determine benefit/cost ratios. The benefit/cost ratios are summarized from 2019-2023 and 2024-2028 in Figure 4 to illustrate the shift in benefits for each generic solution following the AC Transmission Public Policy projects entering service by the beginning of 2024.

The NYISO's Tariff does not permit other benefits, such as reductions in load costs, ancillary service costs, or capacity costs, to be accounted for in the benefit/cost analysis of proposed projects.

Figure 3: Production Cost Savings 2019-2028 ($2019M)

Study	Ten-Year Production Cost Savings ($2019M)			
	Transmission Solution	Generation Solution	Demand Response Solution	Energy Efficiency Solution
Study 1: Central East	115	103	17	1,061
Study 2: Central East-Knickerbocker	117	110	17	1,061
Study 3: Volney-Scriba	22	137	9	530

Figure 4: Benefit/Cost Ratios (High, Mid, and Low Cost Estimate Ranges)

Study	2019-2023			2024-2028		
Transmission Solution	**Low**	**Mid**	**High**	**Low**	**Mid**	**High**
Study 1: Central East	0.37	0.25	0.20	0.18	0.12	0.09
Study 2: Central East-Knickerbocker	0.37	0.25	0.20	0.16	0.11	0.09
Study 3: Volney-Scriba	0.44	0.30	0.24	0.52	0.35	0.28
Generaton Solution	**Low**	**Mid**	**High**	**Low**	**Mid**	**High**
Study 1: Central East	0.15	0.11	0.09	0.26	0.20	0.16
Study 2: Central East-Knickerbocker	0.15	0.11	0.09	0.24	0.18	0.15
Study 3: Volney-Scriba	0.20	0.15	0.12	0.44	0.33	0.26
Demand Response Solution	**Low**	**Mid**	**High**	**Low**	**Mid**	**High**
Study 1: Central East	0.08	0.06	0.05	0.11	0.08	0.06
Study 2: Central East-Knickerbocker	0.08	0.06	0.05	0.11	0.08	0.06
Study 3: Volney-Scriba	0.17	0.13	0.11	0.25	0.19	0.15
Energy Efficiency Solution	**Low**	**Mid**	**High**	**Low**	**Mid**	**High**
Study 1: Central East	0.32	0.24	0.19	0.43	0.32	0.26
Study 2: Central East-Knickerbocker	0.32	0.24	0.19	0.43	0.32	0.26
Study 3: Volney-Scriba	0.41	0.31	0.25	0.55	0.41	0.33

Four additional scenario analyses of the Base Case were conducted through incremental changes to specific input assumptions to evaluate the impacts of those scenarios on the top three congested transmission corridors. The additional scenarios provide insight into how the transmission congestion identified in the CARIS Base Case may change because of changes to load levels or natural gas prices.

Changes to natural gas prices have a significant impact on transmission corridor congestion. Upstate and Downstate generators are supplied by different pipelines, and changes to the price differential between generators in those regions result in a shift in energy production within the fossil fleet. The high-cost natural gas forecast scenario modeled a 31% increase in fuel prices and the low-cost natural gas forecast scenario modeled a 13% decrease, relative to the August 2019 fuel forecasts. The table below shows the changes in total NYISO congestion that result from these variations.

Energy demand changes in the load forecast scenario had a smaller total impact on transmission corridor congestion than the natural gas forecast scenarios. Of the two load levels evaluated, the high-load forecast had the highest incremental impact. The high-load scenario modeled a 2.7% increase in energy demand while the low-load scenario modeled a 16% decrease. As load changed, so did the commitment of generators that impact the Central East interface limit. The inverse relationship observed between changes in load forecast and congestion on the transmission corridors can be observed in Figure 5.

Figure 5: Impact on Demand$ Congestion (%)

Constraints	Scenarios: Change in 2028 Demand$ Congestion from Base Case (%)			
	High Load Forecast	Low Load Forecast	High Natural Gas Prices	Low Natural Gas Prices
Central East	-34%	15%	87%	-31%
Central East-Knickerbocker	-36%	12%	85%	-31%
Volney-Scriba	-3%	0%	-16%	-8%

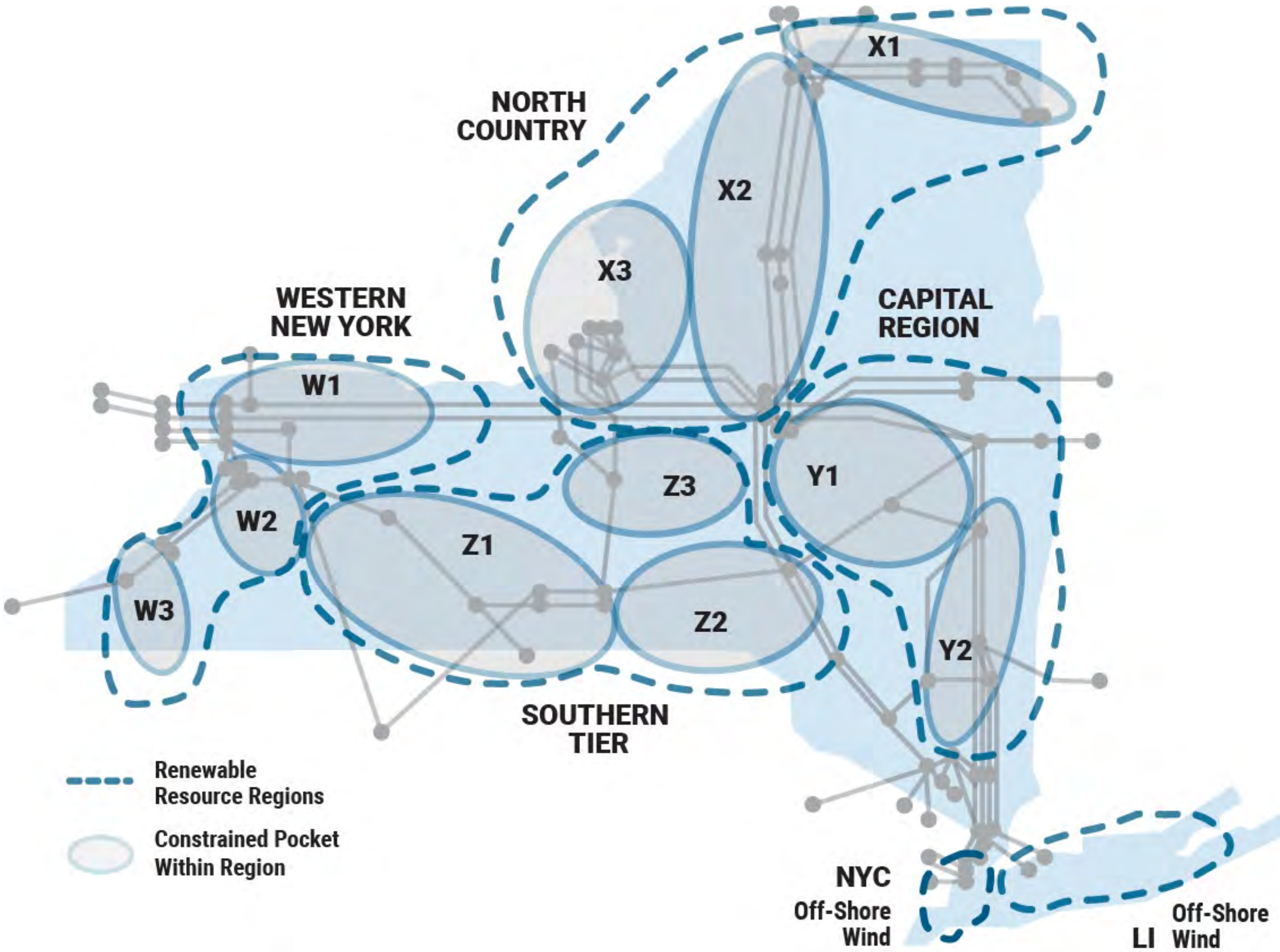
"70x30" Scenario

The CLCPA mandates that 70% of New York's end-use energy consumption be served by renewable energy by 2030 ("70x30"), including specific technology-based targets for distributed solar (6,000 MW by 2025), storage (3,000 MW by 2030), and offshore wind (9,000 MW by 2035). Ultimately, the CLCPA establishes that the electric sector will be emission free by 2040. The "70x30" scenario models these targets through 2030 for two potential load forecasts and identifies system constraints, renewable generation curtailments, and other potential operational limitations.

The 70x30 Scenario is not intended as a roadmap for compliance with the mandates of the CLCPA, but does provide insights into renewable generation pockets that are likely to form due to limited transmission capability in the areas where wind and solar resources are likely to be constructed. Renewable capacity build-out assumptions were developed in collaboration with stakeholders utilizing the NYISO interconnection queue as a reference point. Approximately 110 sites of land-based wind, offshore wind, and utility-scale solar were added to the system model along with additional behind-the-meter solar across the system. Renewable resources were added to the system until the renewable energy equaled approximately 70% of the energy consumed in New York, taking into consideration the "spillage" of generation over the course of a year. Spillage occurs when there is more generation than load within the New York Control Area, and could take the form of an export to a neighboring system or curtailment of renewable resources. This process results in a system model of up to approximately 15,000 MW utility-scale solar, 7,500 MW behind-the-meter solar, 8,700 MW land-based wind, and 6,000 MW offshore wind total capacity. A sensitivity analysis also modeled the policy target of 3,000 MW of energy storage.

An hour-by-hour simulation of this resource mix was conducted under both “relaxed” conditions (*i.e.*, without transmission constraints) and constrained conditions. By comparing these simulation results, the analysis determines the amount of renewable energy that is curtailed due to transmission constraints. As part of the study effort, a new screening tool was developed to identify transmission constraints on the lower-voltage systems (*e.g.,* 115 kV) that may inhibit the delivery of renewable energy. With this detailed information, the NYISO identified constrained “renewable generation pockets” consisting of transmission at 115 kV or higher. These renewable generation pockets are regions in the state where renewable generation resources cannot be fully delivered to consumers statewide due to transmission constraints.

Figure 6: Map of Projected Renewable Generation Pockets



The following renewable resource regions were identified, each of which include constrained transmission pockets:

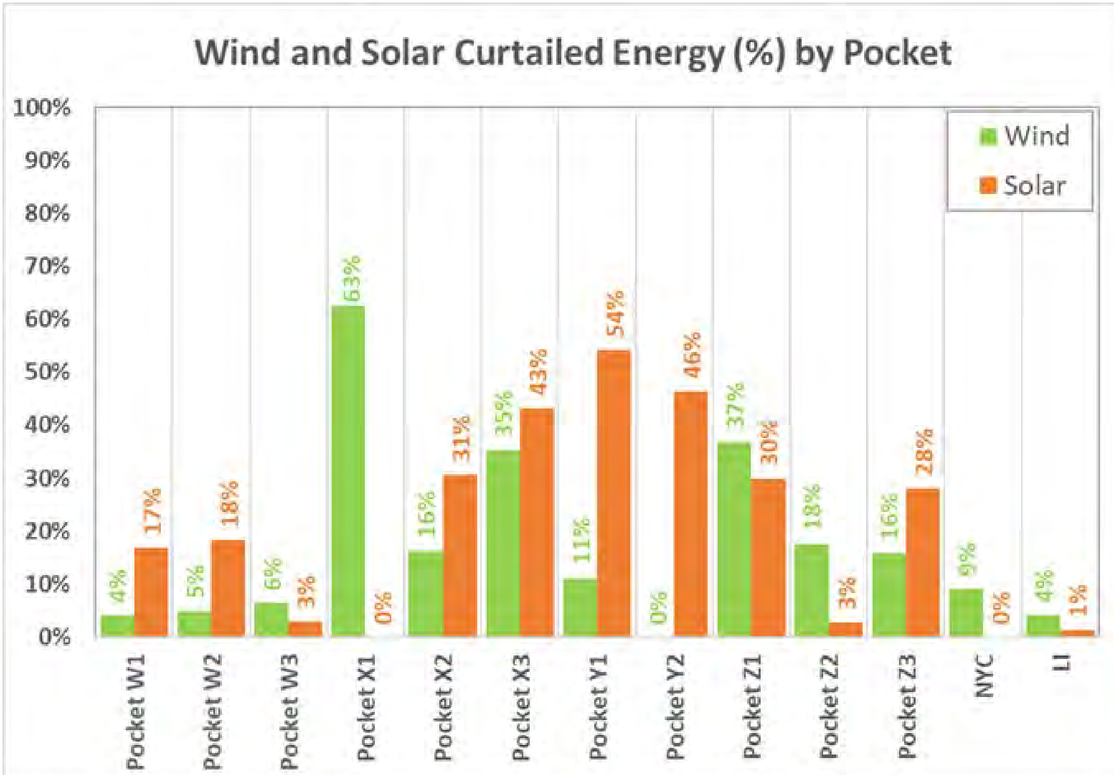
- **Western New York (Pocket W)**: Western New York constraints, mainly 115 kV in Buffalo and Rochester areas
- **North Country (Pocket X)**: Northern New York constraints, including the 230 kV and 115 kV facilities in the North Country
- **Capital Region (Pocket Y)**: Eastern New York constraints, mainly the 115 kV facilities in the Capital Region

- **Southern Tier (Pocket Z)**: Southern Tier constraints, mainly the 115 kV facilities in the Finger Lakes area
- **Offshore Wind:** offshore wind generation connected to New York City (Zone J) and Long Island (Zone K)

In this 70x30 Scenario, approximately 11% of the annual total potential renewable energy production of 128 TWh is curtailed across the New York system. However, some pockets are much more constrained than others. Curtailments result from the hourly balancing of generation and load subject to transmission constraints. When generation exceeds the transmission limits and load within a pocket in a given hour, the generation output must be reduced, or "curtailed". For any given hour, the output of a wind or solar plant may range from fully curtailed (zero output) to full output.

The simulation shows that generation pockets result from both the existing renewable resources and the large amount of additional wind and solar resources. Within the four major pockets that are observed for land-based renewable resources, constrained transmission sub-pockets arise as shown in Figure 6. Figure 7 shows the annual curtailment rates of wind and solar by sub-pocket for the higher energy forecast evaluated in this scenario. In particular, North Country pockets exhibit the highest level of curtailment by percentage, the highest curtailed energy by GWh, and the most frequent congested hours. These curtailments are generally due to lack of a strongly interconnected network to deliver power, at both the bulk power and local system levels. Two additional pockets are observed in areas of offshore wind connecting to New York City (Zone J) and Long Island (Zone K) due to transmission constraints on the existing grid after the power is brought to shore.

Figure 7: Wind and Solar Curtailment by Pocket



This scenario analysis also provides insights into how fossil-fired generation may operate differently in the future. With the substantial addition of intermittent renewable generation, output from the fossil fleet is lower in comparison to the status quo CARIS Base Case. In many cases, however, the reduced output is accompanied by an increased number of generator starts, indicating the need for dispatchable and flexible operating capabilities in the future. Fossil fleet operation can also be highly dependent on transmission constraints. In particular, comparison of operations in the relaxed and constrained cases makes apparent that simple-cycle combustion turbines may run more and start more often due to transmission constraints.

With the overall reduced output from the fossil fleet, the analysis shows that emissions would be significantly reduced due to the renewable generation additions. However, the long-term impact and achievement of economy-wide emission reductions of 40% by 2030 and 85% by 2050, as well as the emission-free power sector requirement in 2040, are topics beyond this scenario.

Key Findings

- The results for the Base Case are consistent with those in prior CARIS studies. The solutions studied for the top three congested paths offered a measure of congestion relief and production costs savings, but did not result in projects with benefit/cost ratios in excess of 1.0.
- The Base Case includes the selected AC Transmission Public Policy Projects starting in year 2024. As expected, the congestion level decreased substantially with the AC Transmission projects in-service as compared with prior study years. Central East is still, however, the most congested transmission corridor over the ten-year study period (2019-2028) because of high congestion during the five-year period preceding the AC Transmission projects (2019-2023). Following the energization of the AC Transmission projects, the congestion is substantially reduced and shifts to the Central East-Knickerbocker corridor.
- The "70x30" scenario represents possible resource portfolios that are consistent with state-mandated policy goals. Results show that renewable generation pockets are likely to develop throughout the state as the existing transmission grid would be overwhelmed by the significant renewable capacity additions. In each of the five major pockets observed, renewable generation is curtailed due to the lack of sufficient bulk and local transmission capability to deliver the power. The results support the conclusion that additional transmission expansion, at both bulk and local levels, will be necessary to efficiently deliver renewable power to New York consumers.
- The level of renewable generation investment necessary to achieve 70% renewable end-use energy by 2030 could vary greatly as energy efficiency and electrification adoption unfolds. Two scenarios with varying energy forecasts and associated renewable build-outs were simulated. Both scenarios resulted in the observation that significant transmission constraints exist when adding the necessary volume of renewable generation to achieve the 70% target.
- Given that the 70% renewable target is based on the level of end-use energy, energy efficiency initiatives will have significant implications for the level of renewable resources needed to meet the CLCPA goals. For this assessment, utilizing an illustrative set of various renewable sources, nearly 37,600 MW of renewable resources was modeled to approximate a system potentially capable of achievement of the 70x30 policy goal at the base load forecast. By comparison, nearly 31,000 MW of renewable resources were added to cases with demand reduced by energy efficiency polices.

- The large amount of renewable energy additions to achieve the CLCPA goals would change the operations of the fossil fuel fleet. Overall, the annual output of the fossil fleet would decline. The units that are more flexible would be dispatched more often, while the units that are less so may be dispatched less or not at all. In addition, sensitivity analysis indicates that if the statewide nuclear generation fleet retired, emissions from the fossil fuel fleet would likely increase; the degree of that impact is dependent on the timing of nuclear retirements and the pace of renewable resource additions.
- Sensitivity analysis indicates that energy storage could decrease congestion, and when dispatched effectively, energy storage would help to increase the utilization of the renewable generation, particularly the solar generation tested in this analysis. The targeted analysis showed that energy storage likely cannot by itself completely resolve the transmission limitations in the pockets analyzed.

Next Steps

The NYISO will continue to monitor and track system changes. Subsequent studies, such as the 2020 Reliability Needs Assessment and the Climate Change Impact & Resilience Study, will build upon the findings of the 70x30 Scenario. To inform policymakers, investors and other stakeholders as implementation unfolds, these forward-looking studies will provide further assessments of the CLCPA focusing on other aspects of system planning such as transmission security and resource adequacy.

Phase 2 of the economic planning process begins following approval of this 2019 CARIS Phase 1 report by the NYISO Board of Directors. In Phase 2, developers are encouraged to propose projects to alleviate the identified congestion. The NYISO will evaluate proposed specific economic transmission projects upon a developer's request to determine the extent such projects alleviate congestion, and whether the projected economic benefits would make the project eligible for cost recovery under the NYISO's tariffs. While the eligibility criterion is production cost savings, zonal LBMP load savings (net of Transmission Congestion Contract ("TCC") revenues and bilateral contracts) is the metric used in Phase 2 for the identification of beneficiary savings and the determinant used for cost allocation to beneficiaries for a transmission project.

For a transmission project to qualify for cost recovery through the NYISO's Tariff, the project has to have:

a) a capital cost of at least $25 million,

b) benefits that outweigh costs over the first ten years of operation, and

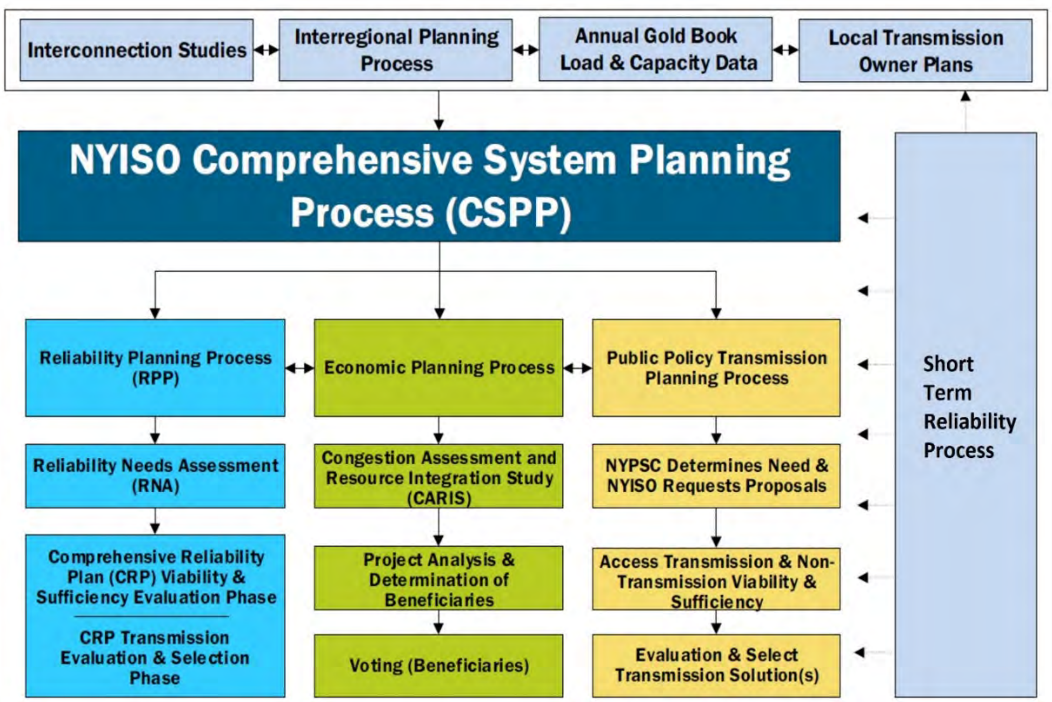
c) received approval to proceed from 80% or more of the actual votes cast by beneficiaries on a load weighted basis.

Having met these conditions, the developer will be able to obtain cost recovery of their transmission project through the NYISO's Tariff, subject to the developer's filing with the Federal Energy Regulatory Commission ("FERC") for approval of the project costs and rate treatment.

1. Introduction

Pursuant to Attachment Y of the New York Independent System Operator, Inc. ("NYISO") Open Access Transmission Tariff ("Tariff"), the NYISO has performed the first phase of the 2019 Congestion Assessment and Resource Integration Study ("CARIS"). CARIS is the primary component of the NYISO's Economic Planning Process, which is one of the three processes that comprise the NYISO's Comprehensive System Planning Process (see Figure 8). The study assesses both historic and projected congestion on the New York bulk power system and estimates the economic benefits of relieving congestion.

Figure 8: NYISO Comprehensive System Planning Process



This final Report documents the methodologies and Baseline[2] assumptions used in identifying the congested pathways. It presents how the Baseline metrics such as system-wide production cost are impacted by solutions to the Baseline congestion. These solutions can be considered as upgrades in system topology (new transmission lines), system resource composition (new generation facilities), and system load characteristics (incremental demand response and energy efficiency). The Report concludes with a comparison of the benefits of such generic solutions with high-level cost estimates.

[2] The term "Baseline" refers to data and assumptions from the NYISO Load and Capacity Data Manual ("Gold Book")

Increasingly, New York State is focused on deploying clean energy resources in support of reducing carbon dioxide emissions from the power sector. The pace of this transition is driven primarily by state policy, notably New York's Climate Leadership and Community Protection Act ("CLCPA"), which, among other things, establishes in law requirements to expand clean and renewable resources supplying the grid and eliminate emissions from the power sector.

In the 2019 CARIS Phase 1 study, the NYISO conducted three studies of the most congested pathways in New York, as prescribed by its tariff. The NYISO also performed supplemental scenarios – including addressing projected resource and demand shift in New York – in order to provide its stakeholders with additional insights into NYCA congestion patterns under system conditions varying from the Baseline. These full ten-year (2019-2028) scenarios complement the base ten-year studies. Moreover, the NYISO conducted a single-year scenario for 2030 to analyze the target that 70 percent of end use energy be generated by renewable resources in that year ("70 x 30") included in the CLCPA.

This Report documents the 2019 CARIS Phase 1 study results and provides objective information on the nature of congestion in the NYCA. Developers can use this information to decide whether to proceed with transmission, generation, demand response, or energy efficiency projects. Developers of any type of solution may choose to pursue a project on a merchant basis, or to enter into bilateral contracts with Load-Serving Entities or other parties. Only those Developers proposing transmission solutions to the identified congestion may seek cost-recovery through the NYISO Tariffs in the second phase of the CARIS process ("CARIS Phase 2"). *See* NYISO Open Access Transmission Tariff ("OATT") § 31.5.4. This report does not make recommendations for specific projects, and does not advocate any specific type of resource addition or other actions.

The projected congestion in this report will be different than the actual congestion experienced in the future. CARIS simulations are based upon a limited set of long-term assumptions for modeling of grid resources throughout the ten-year planning horizon. A range of cost estimates was used to calculate the cost of generic solution projects (transmission, generation, demand response, and energy efficiency). These costs are intended for illustrative purposes only, and are not based on any feasibility analyses. Each of the generic solution costs are utilized in the development of benefit/cost ratios.

The NYISO Staff presented the Phase 1 Study results in a written draft report to the Electric System Planning Working Group (ESPWG) and the Transmission Planning Advisory Subcommittee (TPAS) for review. After that review, the draft report was presented to the NYISO's Business Issues Committee and the Management Committee for discussion and action. Finally, the draft report was submitted to the NYISO's Board of Directors for approval.

2. Economic Planning Process

The objectives of the economic planning process are to:

1. Project congestion on the New York State Bulk Power Transmission Facilities over the ten-year Comprehensive System Planning Process planning horizon;

2. Identify, through the development of appropriate scenarios, factors that might produce or increase congestion;

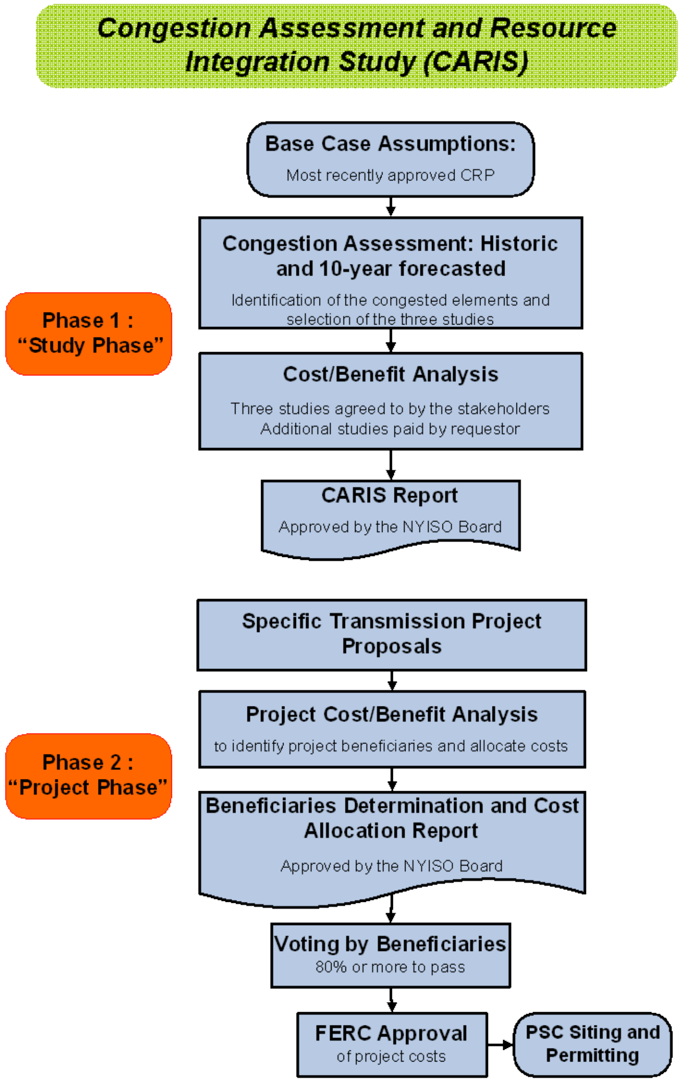
3. Provide a process whereby projects to reduce congestion identified in the economic planning process are proposed and evaluated on a comparable basis in a timely manner. This process includes providing information to Market Participants, stakeholders and other interested parties on solutions to reduce congestion and to create production cost savings, which are measured in accordance with the Tariff requirements. It also includes a process for the evaluation and approval of regulated economic transmission projects for regulated cost recovery under the NYISO Tariff.

4. Provide an opportunity for development of market-based solutions to reduce the congestion identified; and

5. Coordinate the ISO's congestion assessments and economic planning process with neighboring Control Areas.

See OATT § 31.1.4. These objectives are achieved through the two phases of the process, which are graphically depicted in Figure 9.

Figure 9: Economic Planning Process Diagram



Phase 1 – Study Phase

Phase 1 of the economic planning process commences after the viability and sufficiency phase of the Comprehensive Reliability Plan is completed, or upon NYISO Board approval of the Comprehensive Reliability Plan should no Reliability Needs be identified in the Reliability Needs Assessment. Market Participants, Developers and other parties provide the data necessary for the development of the CARIS. *See* OATT § 31.3.1.4. The NYISO, in collaboration with Market Participants, identifies the most congested elements in the New York bulk power system and conducts transmission congestion studies based on those elements. In identifying the most congested elements, the NYISO performs both a five-year historic and a ten-year forward-looking congestion assessment to identify the most congested elements and, through a relaxation process, develops potential groupings and rankings based on the highest projected production cost savings resulting from the relaxation. The NYISO Tariff calls for the top three ranked elements or groupings to be studied. For each of these studies the NYISO conducts a benefit/cost analysis of generic solutions. All resource types – generation, transmission, demand response, and energy efficiency – are considered on a comparable basis as generic solutions to congestion. The solutions analyzed are not specific projects, but rather represent generic transmission, generation, demand response, and energy efficiency resources. Such resources are placed individually in the congested locations on the system to calculate their effects on relieving each of the three most congested elements and the resulting economic benefits.

The principal metric for measuring the economic benefits of each generic solution is the NYCA-wide production cost savings that would result from each generic solution, expressed as the present value over the ten-year planning horizon. The CARIS report also presents data on additional metrics, including estimates of reductions in losses, changes in Locational-Based Marginal Pricing ("LBMP") load payments, generator payments, changes in Installed Capacity costs, changes in emissions costs and changes in payments for Transmission Congestion Contracts ("TCCs"). The TCC payment metric in Phase 1 is simplified to include congestion rent calculations only, and is different from the TCC revenue metric contained in Phase 2. Each of the CARIS metrics is described in more detail in the "CARIS Methodology and Metrics" section below.

The NYISO also conducts scenario analyses to assess the congestion impact of various changes to Base Case assumptions. Scenario results are presented as the change in system congestion on the three study elements or groupings, as well as other constraints throughout NYCA.

Phase 2 – Regulated Economic Transmission Project (RETP) Cost Allocation Phase

Updating and extending the CARIS database for CARIS Phase 2 is conducted after the approval of the CARIS Phase 1 report by the NYISO Board. The Phase 2 model for analysis of specific project proposals will be developed from the CARIS 1 database using an assumptions matrix developed after discussion with Electric System Planning Working Group and with input from the Business Issues Committee. The Phase 2 database will be updated, consistent with the CARIS manual, to reflect all appropriate and agreed upon system modeling changes required for a 10 year extension of the model commencing with the proposed commercial operation date of the project. *See* OATT Section 31.5.4.3.1.

Developers of a potential regulated economic transmission project (RETP) that has an estimated capital cost in excess of $25 million may seek regulated cost recovery through the NYISO Tariff. Such Developers must submit their projects to the NYISO for a benefit/cost analysis in accordance with the Tariff. The costs for the benefit/cost analysis will be supplied by the Developer of the project as required by the Tariff. Projects are eligible for regulated cost recovery only if the present value of the NYCA-wide production cost savings exceeds the present value of the costs over the first ten years from the proposed commercial operation date for the project. In addition, the present value over the first ten years of LBMP load savings, net of TCC revenues and bilateral contract quantities, must be greater than the present value of the projected project cost revenue requirements for the first ten years of the amortization period.

Beneficiaries will be Load-Serving Entities in Load Zones determined to benefit economically from the project, and cost allocation among those Load Zones will be based upon their relative economic benefit. The beneficiary determination for cost allocation purposes will be based upon each Zone's net LBMP load savings. The net LBMP load savings are determined by adjusting the LBMP load savings to account for TCC revenues and bilateral contract quantities; all Load-Serving Entities in the Zones with positive net LBMP load savings are considered to be beneficiaries. The net LBMP load savings produced by a project over the first ten years of commercial operation will be measured and compared on a net present value basis with the project's revenue requirements over the same first ten years of a project's life measured from its expected in-service date. Once the project is placed in-service, cost recoveries within a Zone will be allocated according to each Load-Serving Entity's zonal megawatt hour load ratio share.

In addition to the NYCA-wide production cost savings metric and the net LBMP load savings metric, the NYISO will also provide additional metrics, for information purposes only, to estimate the potential benefits of the proposed project and to allow Load-Serving Entities to consider other metrics when evaluating or comparing potential projects. These additional metrics will include estimates of reductions in losses, changes in LBMP load payments, changes in generator payments, changes in Installed Capacity ("ICAP") costs, changes in emissions costs, and changes in TCC revenues. *See* OATT § 31.3.1.3.5. The TCC revenue metric that will be used in Phase 2 of the CARIS process is different from the TCC payment metric used in Phase 1. In Phase 2, the TCC revenue metric will measure reductions in estimated TCC auction revenues and allocation of congestion rents to the Transmission Owners. For more detail on this metric see the "CARIS Methodology and Metrics" section of this report and the Economic Planning Process Manual - Congestion Assessment and Resource Integration Studies Manual.[3]

The NYISO will also analyze and present additional information by conducting scenario analyses, at the request of the Developer after discussions with ESPWG, regarding future uncertainties such as energy and peak demands, fuel prices, new resources, retirements, emissions data and emission allowance costs, as well as other qualitative impacts, such as improved system operations, potential environmental regulations, and public policies supporting energy efficiency and the integration of renewable resources. *See* OATT § 31.3.1.5. Although this data may assist and influence how a benefiting Load-Serving Entity

3 See https://www.nyiso.com/documents/20142/2924447/epp_caris_mnl.pdf/6510ece7-e0a6-7bee-e776-694abf264bae

votes on a project, it will not be used for purposes of cost allocation.

The NYISO will provide its benefit/cost analysis and beneficiary determination for particular projects to the Electric System Planning Working Group for comment. Following that review, the NYISO benefit/cost analysis and beneficiary determination will be forwarded to the Business Issues Committee and Management Committee for discussion and action. Thereafter the benefit/cost analysis and beneficiary determination will be forwarded to the NYISO Board of Directors for review and approval.

After the project benefit/cost and beneficiary determinations are approved by the NYISO Board of Directors and posted on the NYISO's website, the project will be brought to a special meeting of the beneficiary Load-Serving Entities for an approval vote, utilizing the approved voting procedure (See Section 3.4.5 of the Economic Planning Process Manual - Congestion Assessment and Resource Integration Studies Manual). The specific provisions for voting on cost allocation are set forth in the Tariff. Pursuant to the Tariff, "[t]he costs of a RETP shall be allocated under this Attachment Y if eighty percent (80%) or more of the actual votes cast on a weighted basis are cast in favor of implementing a project." *See* OATT § 31.5.4.6.3. If the project meets the required vote in favor of implementing the project, and the project is implemented, all beneficiaries, including those voting "no," will pay their proportional share of the cost of the project through the NYISO Tariff. This process will not relieve the Developer of the responsibility to file with FERC for approval of the project costs that were presented by the Developer to the voting beneficiaries, and with the appropriate state authorities to obtain siting and permitting approval for the project.

3. Methodology and Metrics

Methodology

The first step in the CARIS study is the development of a 15-year assessment of congestion on the NYISO transmission system, comprised of a ten-year look ahead and a five-year look back. For the purposes of conducting the ten-year forward-looking CARIS analysis, the NYISO utilizes MAPS[4] software, executed with a production cost database developed in consultation with the Electric System Planning Working Group. The details and assumptions in developing this database are summarized in Appendix C.

Metrics

The principal benefit metric for the CARIS Study Phase analysis is the NYCA-wide production cost savings that would result from each of the generic solutions. Additional benefit metrics are analyzed as well, and the results are presented in this report and accompanying appendices for informational purposes only. All benefit metrics are determined by measuring the difference between the projected CARIS Base Case value and a projected solution case value when each generic solution is added. The discount rate of 7.08% used for the present value analysis was the current Weighted Average Cost of Capital for the New York Transmission Owners, weighted by their annual gigawatt hour load in 2018.

One of the key metrics in the CARIS analysis is termed Demand Dollar Congestion (Demand$ Congestion). Demand$ Congestion represents the congestion component of load payments which ultimately represents the cost of congestion to consumers. For a Load Zone, the Demand$ Congestion of a constraint is the product of the constraint shadow price, the Load Zone shift factor on that constraint, and the zonal load. For NYCA, the Demand$ Congestion is the sum of all of the zonal Demand$ Congestion.

These definitions are consistent with the reporting of historic congestion for the past thirteen years. Demand$ Congestion is used to identify and rank the significant transmission constraints as candidates for grouping and the evaluation of potential generic solutions. It does not equate to total payments by load because it includes the energy and losses components of the LBMP.

Principal Benefit Metric[5]

The principal benefit metric for the CARIS Study Phase analysis is the present value of the NYCA-wide production cost savings that are projected to result from implementation of each of the generic congestion

4 GE's Multi-Area Production Simulation software

5 Section 31.3.1.3.4 of the Tariff specifies the principal benefit metric for the CARIS analysis.

mitigation solutions. The NYCA-wide production cost savings are calculated as those savings associated with generation resources in the NYCA and the costs of incremental imports/exports priced at external proxy generator buses of the solution case. This is consistent with the methodology utilized in prior CARIS cycles. Specifically, the NYCA-wide production cost savings are calculated using the following formula:

$$\text{NYCA-wide Production Cost Savings} = \text{NYCA Generator Production Cost Savings} - \sum \left\{ \left[\frac{\text{Import}}{\text{Export Flow}}\right]_{\text{Solution}} - \left[\frac{\text{Import}}{\text{Export Flow}}\right]_{\text{Base}} \right\} * \text{ProxyLMP}_{\text{Solution}}$$

Where:

$\text{ProxyLMP}_{\text{Solution}}$ is the LMP at one of the external proxy buses;

$(\text{Import/Export Flow})_{\text{Solution}} - (\text{Import/Export Flow})_{\text{Base}}$ represents incremental imports/exports with respect to one of the external systems; and the summations are made for each external area for all simulated hours.

Additional Benefit Metrics

The additional benefits, which are provided for information purposes only, include estimates of reduction in loss payments, LBMP load costs, generator payments, ICAP costs, emission costs, and TCC payments. All the quantities, except ICAP, will be the result of the forward looking production cost simulation for the ten-year planning period. The NYISO, in collaboration with the Electric System Planning Working Group, determined the additional informational metrics to be defined for this CARIS cycle given existing resources and available data. The collaborative process determined the methodology and models needed to develop and implement these additional metrics requirements, which are described below and detailed in the Economic Planning Process Manual - Congestion Assessment and Resource Integration Studies Manual. An example illustrating the relationship among some of these metrics is provided in Appendix E.

Reduction in Losses – This metric calculates the change in marginal losses payments. Losses payments are based upon the loss component of the zonal LBMP load payments.

LBMP Load Costs – This metric measures the change in total load payments. Total load payments include the LBMP payments (energy, congestion and losses) paid by electricity demand (load, exports, and wheeling). Exports will be consistent with the input assumptions for each neighboring control area.

Generator Payments – This metric measures the change in generation payments by measuring only the LBMP payments (energy, congestion, losses). Thus, total generator payments are calculated for this information metric as the sum of the LBMP payments to NYCA generators and payments for net imports. Imports will be consistent with the input assumptions for each neighboring control area.

ICAP Costs –The latest available information from the installed reserve margin, locational minimum installed capacity requirement, and ICAP Demand Curves are used for the calculation. The NYISO first calculates the NYCA megawatt impact of the generic solution on Loss of Load Expectation. The NYISO then forecasts the ICAP cost per megawatt-year point on the ICAP demand curves in Rest of State and in each locality (Lower Hudson Valley, Zone J, and Zone K) for each planning year. There are two variants for calculating this metric, both based on the megawatt impact. For more detail on this metric, see the Section 31.3.1.3.5.6 of the Tariff.

Emission Costs – This metric captures the change in the total cost of emission allowances for CO_2, NO_X, and SO_2, emissions on a zonal basis. Total emission costs are reported separately from the production costs. Emission costs are the product of forecasted total emissions and forecasted allowance prices.

TCC Payments – The TCC payment metric is calculated differently for Phase 1 than it is calculated for Phase 2 of the CARIS process, as described in the NYISO Tariff. The TCC Payment is the change in total congestion rents collected in the day-ahead market. In this CARIS Phase 1, it is calculated as (Demand Congestion Costs + Export Congestion Costs) – (Supply Congestion Costs + Import Congestion Costs). This is not a measure of the Transmission Owners' TCC auction revenues.

4. Model Assumptions

The implementation of the economic planning process requires the gathering, assembling, and coordination of a significant amount of data, in addition to that already developed for the reliability planning processes. The 2019 CARIS Phase 1 Study Period aligns with the ten-year planning horizon for the 2019-2028 Comprehensive Reliability Plan, and study assumptions are based on any updates that met the NYISO's inclusion rules as of the August 1, 2019 lock-down date.

The CARIS Base Case can be viewed as a "Business as Usual" case starting with the most recent Reliability Planning Process Base Case and incorporating incremental resource changes based on the NYISO's Reliability Planning Process study inclusion rules.[6] Appendix C includes a detailed description of the assumptions utilized in the CARIS analysis.

The key assumptions for the Base Case are presented below:

1. The load and capacity forecasts are updated using the 2019 Load and Capacity Data Report ("Gold Book") Baseline forecast for energy and peak demand by Zone for the ten-year Study Period. New resources and changes in resource capacity ratings were incorporated based on the Reliability Needs Assessment inclusion rules.

2. The power flow case uses the 2018 Reliability Planning Process (RPP) case as the starting point and is updated with the latest information from the 2019 Gold Book.

3. The transmission and constraint model utilizes a bulk power system representation for most of the Eastern Interconnection, as described below. The model uses transfer limits and actual operating limits from both the 2018 Reliability Needs Assessment and the 2018 Comprehensive Reliability Plan.

4. The production cost model performs a security constrained economic dispatch of generation resources to serve the load. The production cost curves, unit heat rates, fuel forecasts and emission costs forecast were developed by the NYISO from multiple data sets, including public domain information, proprietary forecasts and confidential market information. The model includes scheduled generation maintenance periods based on a combination of each unit's planned and forced outage rates.

6 *See* Reliability Planning Process Manual, Manual No. 36, § 3.2.

Figure 10 below contains a summary of the modeling changes that can have significant impacts on the congestion projections.

Figure 10: Major Modeling Inputs and Changes

Major Modeling Inputs	
Input Parameter	**Change from 2017 CARIS**
Load Forecast	Lower
Natural Gas Price Forecast	Lower
CO_2 Price Forecast	Same
NO_X Price Forecast	Ozone NO_X, same; Annual NO_X, lower
SO_2 Price Forecast	Higher
Hurdle Rates	Lower
Modeling Changes	
Description	**Change from 2017 CARIS**
MAPS Software Upgrades	Latest GE MAPS Version 14.300 09/06/2019 Release was used for production cost simulation
PJM/NYISO JOA	Western tie to carry 46% of PJM-NYISO AC Interchange
	5018 line to carry 32% of PJM-NYISO AC Interchange plus 80% of RECO load
	PAR A to carry 7% of PJM-NYISO AC Interchange plus 100MW OBF(operational base flow), PAR B and C are modeled as out of service
	PAR JK to carry 15% of PJM-NYISO AC Interchange minus 100MW OBF
	OBF reduced to zero as of Nov.1, 2019
NY Transmission Upgrades	Erie – South Ripley series reactor(2019)
	Rainey-Corona PAR (2019)
	Leeds Hurley SDU(2020)
	L33P (Ontario PAR) out of service until 1/2022
	Empire State Line Project/Western PP Selected project(2022)
	Selected Segment A and Segment B AC Transmission Projects (2024)
	Expanded monitoring and securing of lower voltage system consistent with NYISO market operations

Figure 11 presents the timeline of projected resource and topology changes that are modeled by the NYISO in each of the cases and that have material impacts on the results.

Figure 11: Timeline of Major NYCA Modeling Changes for 2019 CARIS Phase 1

Year	Year-to-year Modeling Changes
2019	Riverhead Solar, 20 MW, in-service: 5/1/2019
	Ball Hill Wind, 100MW, in-service: 12/1/2019
2020	Cayuga 1, 151MW, retired on 1/1/2020
	Cricket Valley Energy Center, 1,020 MW, in-service: 3/1/2020
	Indian Point 2, 1,016MW, retired on 4/30/2020
	Cassadaga Wind, 126MW, in-service: 12/1/2020
2021	Taylor Biomass, 19MW, in-service: 4/1/2021
	Indian Point 3, 1,038MW, retired on 4/30/2021
2022	
2023	
2024	Athens SPS retired on 1/2024
2025	
2026	
2027	
2028	

Load and Capacity Forecast

The load and capacity forecast used in the Business as Usual case, provided in Figure 12, was based on the 2019 Gold Book and accounts for the impact of programs such as the Energy Efficiency Portfolio Standard. Appendix C contains similar load and capacity data, broken out by fuel type, for the modeled external control areas.

Figure 12: CARIS Base Case Load and Resource Table[7]

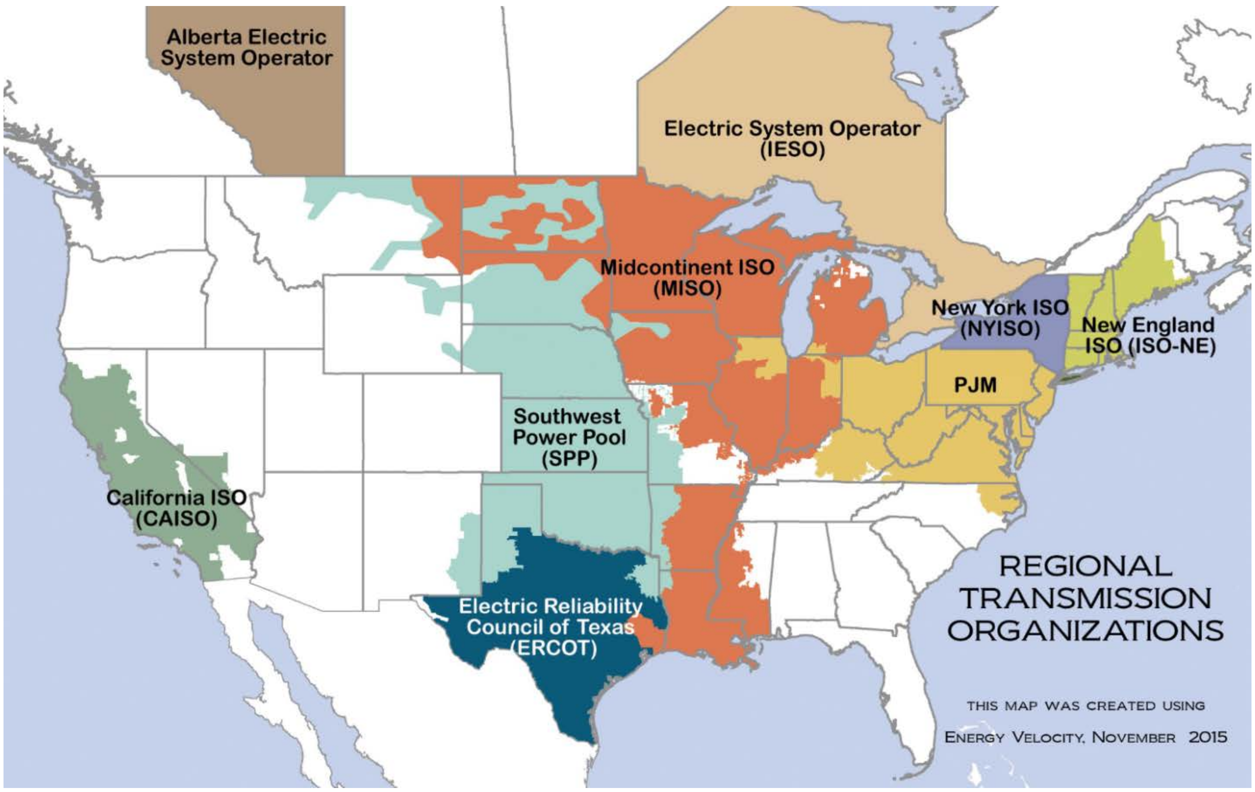
Peak Load (MW)										
Area	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
NYCA	32,382	32,202	32,063	31,971	31,700	31,522	31,387	31,246	31,121	31,068
Zone J	11,608	11,651	11,695	11,704	11,608	11,598	11,616	11,616	11,598	11,589
Zone K	5,240	5,134	5,056	5,035	4,969	4,894	4,823	4,758	4,719	4,730
Capacity (MW)										
Area	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
NYCA	39,596	39,546	38,654	38,673	38,673	38,673	38,654	38,654	38,654	38,673
Zone J	9,570	9,570	9,570	9,570	9,570	9,570	9,570	9,570	9,570	9,570
Zone K	5,157	5,157	5,157	5,157	5,157	5,157	5,157	5,157	5,157	5,157

[7] Annual Capacity changes due to additions, re-ratings, and retirements reference a cutoff date of June 1. SCR, UDR, external purchase, and external sale capacity is not included in the values presented.

Transmission Model

The CARIS production cost analysis utilizes a bulk power system representation for the entire Eastern Interconnection, which is defined roughly as the bulk electric network in the United States and Canadian Provinces East of the Rocky Mountains, excluding the Western Electricity Coordinating Council and Texas. Figure 13 below illustrates the North American Electric Reliability Corporation Regions and Balancing Authorities in the CARIS model. The CARIS model includes an active representation for bulk power systems of the NYISO, ISO-New England, IESO Ontario, and PJM Interconnection Control Areas. The transmission representation of these three neighboring control areas is based off the most recent CRP case and includes changes expected to significantly impact NYCA congestion.

Figure 13: Areas Modeled in CARIS (Include NYISO, ISO-New England, IESO Ontario, and PJM Interconnection)



Source: FERC - https://www.ferc.gov/industries/electric/indus-act/rto/elec-ovr-rto-map.pdf

New York Control Area Transfer Limits

CARIS utilizes normal transfer criteria for MAPS software simulations for determining system production costs. However, for the purpose of calculating the ICAP cost metric, the model adopts emergency transfer criteria for MARS[8] software simulations in order to estimate the projected changes in NYCA and locational reserve margins due to each of the modeled generic solutions. Normal thermal interface transfer limits for the CARIS study are not directly utilized from the thermal transfer analysis performed using TARA software.[9] Instead, CARIS uses the most limiting monitored lines and contingency sets identified either from analysis using TARA software or from historical binding constraints.

For voltage and stability based limits, the normal and emergency limits are assumed to be the same. For NYCA interface stability transfer limits, the limits are consistent with the operating limits.[10] Central East was modeled with a unit sensitive nomogram reflective of the algorithm utilized by NYISO Operations.[11]

Fuel Forecasts

The fuel price forecasts for CARIS are based on the U.S. Energy Information Administration's ("EIA")[12] current national long-term forecast of delivered fuel prices, which is released each spring as part of its Annual Energy Outlook. The figures in this forecast are in nominal dollars. The same fuel forecast is utilized for all study cases and scenarios, except for the high and low natural gas price scenarios.

New York Fuel Forecast

In developing the New York fuel forecast, adjustments were made to the EIA fuel forecast to reflect regional adjustments for fuel prices in New York. Key sources of data for estimating the relative differences for fuel-oil prices in New York are the Monthly Utility and non-Utility Fuel Receipts and Fuel Quality Data reports based on the information collected through Form EIA-923.[13] The regional adjustments for natural gas prices are based on a comparative analysis of monthly

8 GE's Multi-Area Reliability Simulation software.

9 PowerGEM's Transmission Adequacy and Reliability Assessment ("TARA") software is a steady-state power flow software tool with modeling capabilities and analytical applications.

10 https://www.nyiso.com/documents/20142/3691079/NYISO_InterfaceLimtsandOperatingStudies.pdf/c0cd6dc2-f666-0b12-2cf8-edba51d0daae

11 https://www.nyiso.com/documents/20142/3692791/CE_VoltageandStability_Limit_ReportFinalOCApproved3-17-2016.pdf

12 www.eia.doe.gov

13 Prior to 2008, this data was submitted via FERC Form 423. 2008 onwards, the same data are collected on Schedule 2 of the new Form EIA-923. See http://www.eia.doe.gov/cneaf/electricity/page/ferc423.html. These figures are published in Electric Power Monthly.

national delivered prices published in EIA's Short Term Energy Outlook and spot prices for selected trading hubs. The base annual forecast series from the Annual Energy Outlook are then subjected to an adjustment to reflect the New York prices relative to the national delivered prices as described below.

Natural Gas

For the 2019 CARIS study, the New York Control Area is divided into four (4) gas regions: Upstate (Zones A to E), Midstate (Zones F to I), Zone J, and Zone K.

Given that gas-fueled generators in a specific NYCA zone acquire their fuel from several gas-trading hubs, each regional gas price is estimated as a weighted blend of individual hubs – where the weights are the sub-totals of the generators' annual generation megawatt-hour levels. The regional natural gas price blends for the regions are as follows:

- Zones A to E – Dominion South (65%), Columbia (5%), & Dawn (30%);
- Zones F to I – Iroquois Zone 2 (30%), Tennessee Zone 6 (45%), Tetco M3 (20%), & Iroquois Waddington (5%);
- Zone J – Transco Zone 6 (100%);
- Zone K – Iroquois Zone 2 (60%) & Transco Zone 6 (40%)

The forecasted regional adjustment, which reflects the differential between the blended regional price and the national average, is calculated as the 3-year weighted-average of the ratio between the regional price and the national average delivered price from the Short-Term Energy Outlook.[14] Forecasted fuel prices for the gas regions are shown in Figure 14 through Figure 17.

Fuel Oil

Based on EIA forecasts published in its Electric Power Projections by Electricity Market Module Regions (see Annual Energy Outlook 2019, Reference Case), price differentials across regions can be explained by a combination of transportation/delivery charges and taxes. Regional adjustments were calculated based on the relative differences between EIA's national and regional forecasts of Distillate (Fuel Oil #2) and Residual (Fuel Oil #6) prices. This analysis suggests that for New York, Distillate and Residual Oil prices will be the same as the national average. For illustrative purposes, forecasted prices for Distillate Oil and for Residual Oil are shown in Figure 14 through Figure 17.

14 The raw hub-price is 'burdened' by an appropriate level of local taxes and approximate delivery charges. In light of the high price volatility observed during winter months, the 'basis' calculation excludes data for January, February and December.

Coal

The data from EIA's Electric Power Projections by Electricity Market Module Regions was also used to arrive at the forecasted regional delivered price adjustment for coal. (The published figures do not make a distinction between the different varieties of coal; *i.e.,* bituminous, sub-bituminous, and lignite).

Seasonality and Volatility

All average monthly fuel prices, with the exception of coal and uranium, display somewhat predictable patterns of fluctuations over a given 12-month period. In order to capture such seasonality, the NYISO estimated seasonal-factors using standard statistical methods.[15] The multiplicative factors were applied to the annual forecasts to yield forecasts of average monthly prices.

The data used to estimate the 2019 seasonal factors are as follows:

- Natural Gas: Raw daily prices from S&P Global/Platts for the various trading hubs incorporated in the regional price blends.
- Fuel Oil #2: EIA's average daily prices for New York Harbor Ultra-Low Sulfur No. 2 Diesel Spot Price. CARIS assumes the same seasonality for both types of fuel oil.

The seasonalized time-series represents the forecasted trend of average monthly prices. Because CARIS uses weekly prices for its analysis, the monthly forecasted prices are interpolated to yield 53 weekly prices for a given year. Furthermore, "'spikes" are layered on these forecasted weekly prices to capture typical intra-month volatility, especially in the winter months. The "spikes" are calculated as 5-year averages of deviations of weekly (weighted-average) spot prices relative to their monthly averages. The "spikes" for a given month are normalized such that they sum to zero.

15 This is a two-step process: First, deviations around a centered 12-month moving average are calculated over the 2014-2018 period; second, the average values of these deviations are normalized to estimate monthly/seasonal factors.

Figure 14: Forecasted fuel prices for Zones A-E (nominal $)

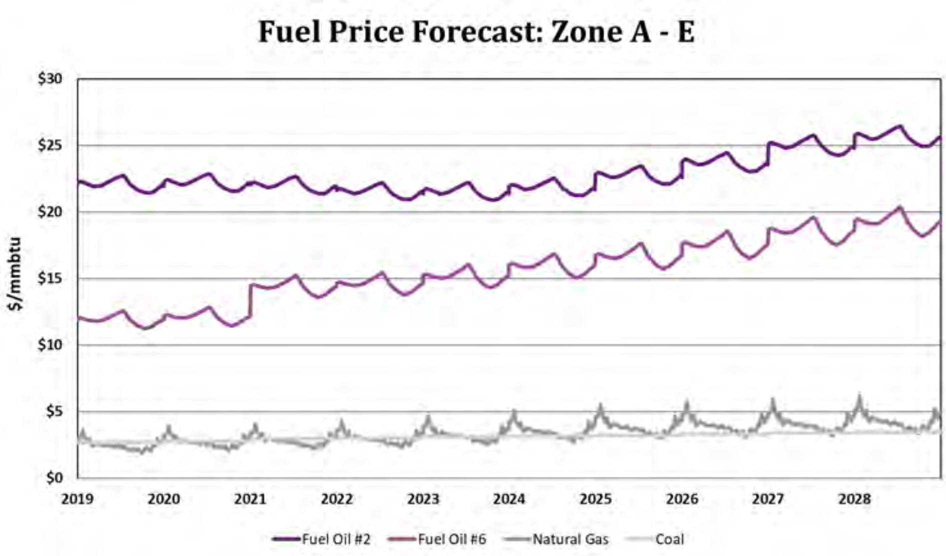


Figure 15: Forecasted fuel prices for Zones F-I (nominal $)

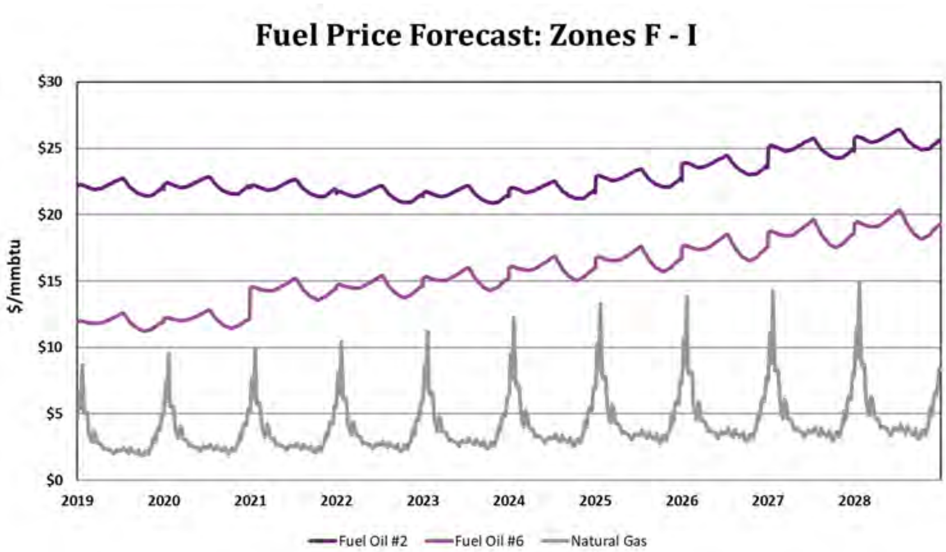


Figure 16: Forecasted fuel prices for Zone J (nominal $)

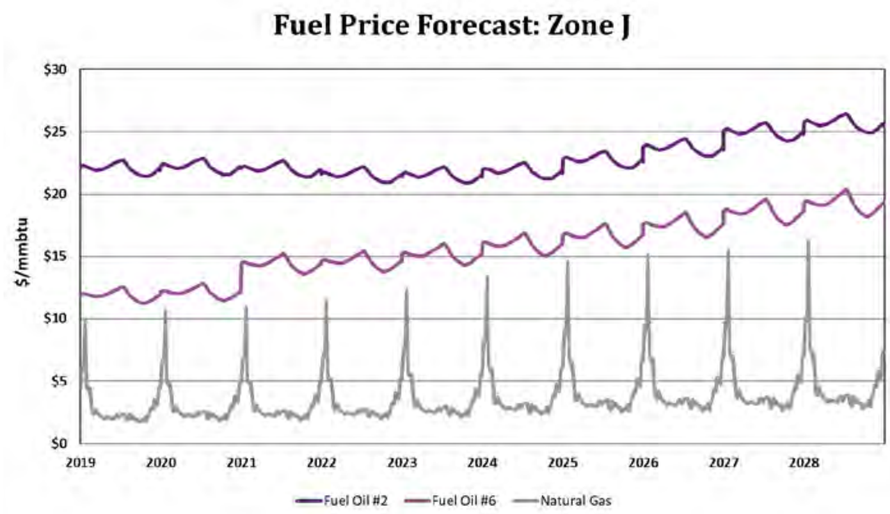
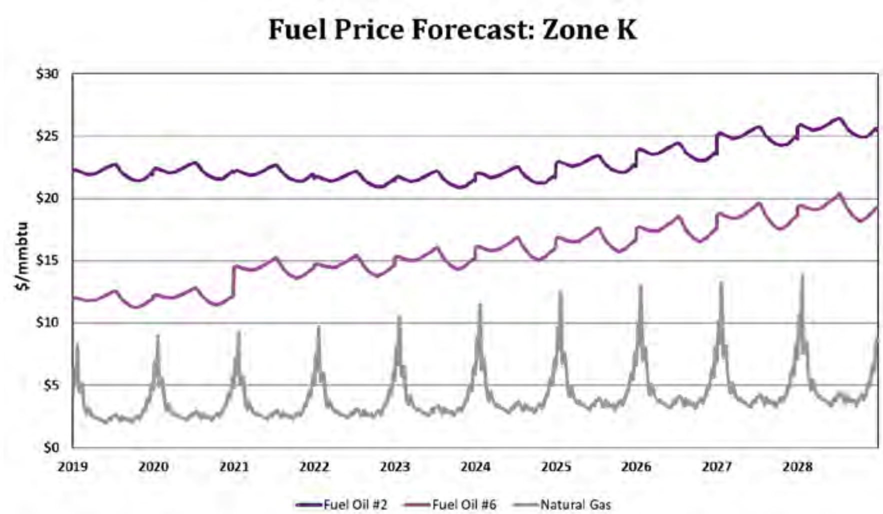


Figure 17: Forecasted fuel prices for Zone K (nominal $)



External Areas Fuel Forecast

The fuel forecasts for the three external Control Areas, ISO-New England, PJM Interconnection and IESO Ontario, were also developed. For each of the fuels, the 'basis' for ISO-New England North, ISO-New England South, PJM-East and PJM-West forecasts are based on the EIA data obtained from the same sources as those used for New York. With respect to the IESO Ontario control area, the relative price of natural gas is based on spot-market data for the Dawn hub obtained from SNL Energy[16]. CARIS does not model any IESO Ontario generation as being fueled by either oil or coal. External price forecasts are provided in Appendix C.

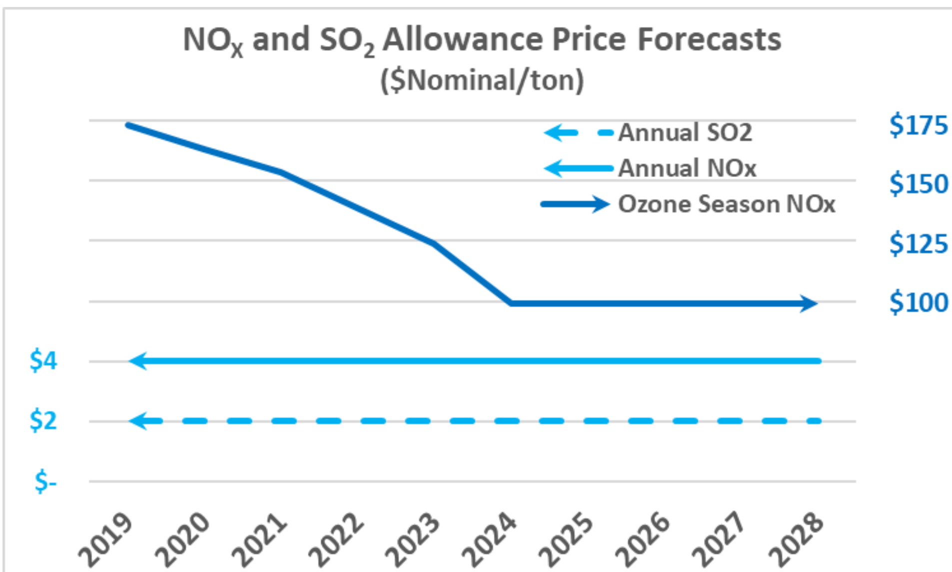
16 Copyright © 2018, SNL Financial LLC

Emission Cost Forecast

The costs of emissions allowances are an increasing portion of generator production costs. Currently, all NYCA fossil fuel-fired generators greater than 25 MW and most generators in many surrounding states are required to procure allowances in amounts equal to their emissions of SO_2, NO_X, and CO_2.

Business-as-usual case allowance price forecasts for annual and seasonal NO_X and SO_2 emissions are developed using representative prices at the time the assumptions are finalized. The Cross-State Air Pollution Rule NO_X and SO_2 allowances prices reflect the persistent oversupply of annual programs, and the expectation that stricter seasonal limitations in the Cross-State Air Pollution Rule Update will continue to be manageable program-wide, leading to price declines as market participants adjust to new operational limits. Figure 18 shows the assumed NO_X and SO_2 allowance price forecasts used in this study.[17]

Figure 18: NO_X and SO_2 Emission Allowance Price Forecasts



The Regional Greenhouse Gas Initiative (RGGI) program for capping CO_2 emissions from power plants includes the six New England states as well as New York, Maryland, Delaware, and New Jersey. Historically, the RGGI market has been oversupplied and prices have remained near the floor. In January 2012, the RGGI States chose to retire all unsold RGGI allowances from the 2009-2011 compliance period in an effort to reduce the market oversupply. Additionally, RGGI Inc. conducted a mid-program review in 2012 that became effective in 2014. The emissions cap was

17 Annual NO_X allowance prices are used October through May; ozone season NO_X allowance prices in addition to Annual NO_X allowance prices are used in May through September.

reduced to 91 million tons in 2014 and decreases to 78 million tons in 2020.

Following the cap reduction, the emissions cap became binding on the market, thereby triggering the Cost Containment Reserve. In 2014, five million additional CO_2 allowances were sold at auction, followed by an additional ten million Cost Containment Reserve allowances in 2015. In February 2016, the Supreme Court stayed implementation of the EPA Clean Power Plan. The market response to this ruling was a reduction in RGGI prices. RGGI undertook another program review in 2016-2017 proposing additional changes to the program structure, including a 30% cap reduction between 2020 and 2030. An Emission Containment Reserve was added to provide price support by holding back allowances from auction if prices do not exceed predefined threshold levels.

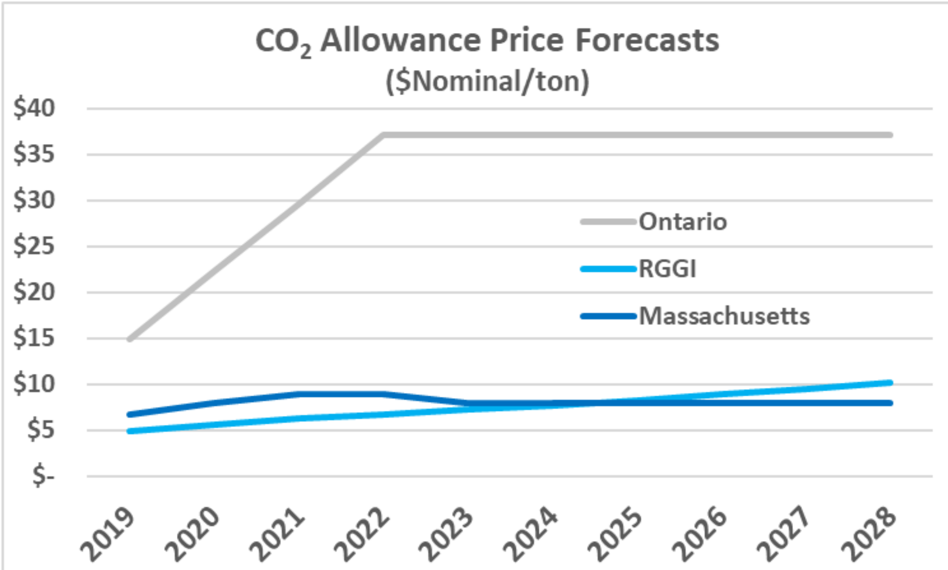
The allowance price forecast assumes that auctions will clear in line with the Emission Containment Reserve trigger price through the study period. In the past, CARIS studies assumed that a federal CO_2 program, similar to the RGGI program, would take effect in 2020, however the expectation of such a program have since dampened and currently no national program is assumed within the 10 year study period. New Jersey has rejoined RGGI in 2020. Virginia has completed legislative action to rejoin RGGI as soon as 2021. Pennsylvania is also considering joining RGGI. When the stated intentions are developed into promulgated rules, it will be timely to include the cost of CO_2 emission allowances in the production models for these states. In this study, only New Jersey is reflected as joining RGGI through application of the RGGI price to generators in the state above 25MW beginning in 2020.

Massachusetts began implementing its own single state cap-and-trade program in 2018, which is similar to RGGI but with more restrictive caps applicable to generators located in Massachusetts.[18] MassDEP held the first auction of the new program in December 2018 with CO_2 prices cleared at $6.71 metric ton ($6.09/ton), and more recently in December 2019 clearing above $8/metric ton. Massachusetts allowance prices assumed in this study are incremental to RGGI allowance prices imposed upon Massachusetts's emitting generators. The study assumes a distinct CO_2 allowance price forecast applicable to IESO Ontario generation based upon CO_2 prices in Canada's Greenhouse Gas Pollution Pricing Act.[19]

18 https://www.mass.gov/guides/electricity-generator-emissions-limits-310-cmr-774
19 https://www.canlii.org/en/ca/laws/stat/sc-2018-c-12-s-186/latest/sc-2018-c-12-s-186.html

Figure 19 shows the emission allowance price forecasts by year in $/ton.

Figure 19: CO_2 Emission Allowance Price Forecasts



5. Base Case Results

This section presents summary level results of the six steps of the 2019 CARIS Phase 1 for the Base Case. These six steps include: (1) congestion assessment; (2) ranking of congested elements; (3) selection of studies; (4) generic solution applications; (5) benefit/cost analysis; and (6) scenario analysis. Study results are described in more detail in Appendix E.

Congestion Assessment

CARIS begins with the development of a ten-year projection of future Demand$ Congestion costs. This projection is combined with the past five years of historic congestion to identify and rank significant and recurring congestion. The results of the historical and future perspective are presented in the following two sections.

In order to assess and identify the most congested elements, both positive and negative congestion on constrained elements are taken into consideration. Whether congestion is positive or negative depends on the choice of the reference point. All metrics are referenced to the Marcy 345 kV bus near Utica, NY. In the absence of losses, any location with LBMP greater than the Marcy LBMP has positive congestion, and any location with LBMP lower than the Marcy LBMP has negative congestion. The negative congestion typically happens due to transmission constraints that prevent lower cost resources from being delivered towards the Marcy bus.

Historic Congestion

Historic congestion assessments have been conducted at the NYISO since 2005 with metrics and procedures developed with the ESPWG and approved by the NYISO Operating Committee. Four congestion metrics were developed to assess historic congestion: Bid-Production Cost as the primary metric, Load Payments metric, Generator Payments metric, and Congestion Payment metric. Starting 2018, followed by Tariff changes in Appendix A of Attachment Y to the OATT, only the following historic Day-Ahead Market congestion-related data are reported: (i) LBMP load costs (energy, congestion and losses) by Load Zone; (ii) LBMP payments to generators (energy, congestion and losses) by Load Zone; (iii) congestion cost by constraint; and (iv) congestion cost of each constraint to load (commonly referred to in CARIS as “demand dollar congestion” by constraint). The results of the historic congestion analysis are posted on the NYISO website. For more information on the historical results below see:

https://www.nyiso.com/ny-power-system-information-outlook

Historic congestion costs by Zone, expressed as Demand$ Congestion, are presented in Figure 20, indicating that the highest congestion is in New York City and Long Island.

Figure 20: Historic Demand$ Congestion by Zone 2014-2018 (nominal $M)[20]

Zone	2014	2015	2016	2017	2018
West	$36	$83	$116	$63	$65
Genesee	$9	$9	$7	$12	$10
Central	$38	$34	$29	$40	$37
North	$3	$5	$7	$6	$15
Mohawk Valley	$12	$10	$7	$10	$7
Capital	$149	$123	$95	$90	$80
Hudson Valley	$95	$86	$64	$66	$50
Millwood	$30	$26	$19	$21	$16
Dunwoodie	$55	$49	$41	$44	$34
New York City	$531	$459	$378	$443	$405
Long Island	$409	$404	$339	$287	$303
NYCA Total	**$1,367**	**$1,287**	**$1,102**	**$1,082**	**$1,024**

Figure 21 below lists historic congestion costs, expressed as Demand$ Congestion, for the top NYCA constraints from 2014 to 2018. The top congested paths are shown below.

Figure 21: Historic Demand$ Congestion by Constrained Paths 2014-2018 (nominal $M)

Constraint Path	2014	2015	2016	2017	2018	Total
CENTRAL EAST	$1,136	$915	$641	$598	$540	$3,829
DUNWOODIE TO LONG ISLAND	$155	$138	$164	$88	$133	$677
LEEDS PLEASANT VALLEY	$42	$111	$63	$101	$9	$327
EDIC MARCY	$7	$0	$32	$125	$107	$271
PACKARD HUNTLEY	$7	$41	$54	$30	$41	$172
GREENWOOD	$13	$19	$31	$18	$62	$143
DUNWOODIE MOTTHAVEN	$40	$2	$2	$30	$65	$139
NIAGARA PACKARD	$18	$22	$44	$12	$9	$104
EGRDNCTY 138 VALLYSTR 138 1	$20	$18	$8	$17	$20	$82
NEW SCOTLAND LEEDS	$9	$32	$13	$18	$5	$76

* Ranking is based on absolute values.

Projected Future Congestion

Future congestion for the Study Period was determined from a MAPS software simulation using a base case developed with the Electric System Planning Working Group (the "Base Case"). As reported in the "Historic Congestion" section above, congestion is reported as Demand$ Congestion. MAPS software simulations are highly dependent upon many long-term assumptions, each of which

20 Reported values do not deduct TCCs. NYCA totals represent the sum of absolute values. DAM data include Virtual Bidding and Planned Transmission Outages.

affects the study results. The MAPS software model utilizes input assumptions listed in Appendix C.

When comparing historic congestion costs to projected congestion costs, it is important to note that there are significant differences in assumptions used by Market Operations production software and Planning MAPS software. MAPS software, unlike Market Operations software, did not simulate the following: (a) virtual bidding; (b) transmission outages; (c) price-capped load; (d) generation and demand bid price; (e) Bid Production Cost Guarantee payments; and (f) co-optimization with ancillary services. As in prior CARIS cycles, the projected congestion is below historic levels due to the factors cited. Such factors could also lead to lower projections of production cost savings attributable to new projects (*e.g.,* transmission, generation, energy efficiency, demand response) constructed or implemented to address system congestion.

Discussion

Figure 22 presents the projected congestion from 2019 through 2028 by Load Zone. The relative costs of congestion shown in this table indicate that the majority of the projected congestion is in the Downstate Zones – New York City and Long Island. Year-to-year changes in congestion reflect changes in the model, which are discussed in the "Baseline System Assumptions" section above.

Figure 22: Projection of Future Demand$ Congestion 2019-2028 by Zone for Base Case (nominal $M)

Demand Congestion ($M)	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
West	$87	$55	$36	$4	$1	$9	$11	$12	$11	$8
Genesee	$4	$2	$1	$2	$1	$5	$6	$7	$6	$5
Central	$28	$22	$21	$14	$9	$12	$10	$10	$12	$13
North	$6	$7	$5	$4	$3	$4	$3	$3	$3	$3
Mohawk Valley	$10	$7	$7	$5	$3	$4	$3	$3	$4	$4
Capital	$116	$91	$92	$73	$34	$31	$15	$15	$19	$27
Hudson Valley	$66	$56	$62	$51	$28	$20	$11	$12	$14	$19
Millwood	$20	$17	$18	$15	$8	$6	$3	$3	$4	$6
Dunwoodie	$39	$35	$37	$31	$17	$12	$6	$7	$8	$11
NY City	$392	$349	$356	$292	$165	$132	$78	$87	$106	$131
Long Island	$218	$195	$193	$163	$116	$105	$75	$77	$80	$96
NYCA Total	**$986**	**$838**	**$827**	**$655**	**$387**	**$338**	**$219**	**$235**	**$268**	**$322**

Note: Reported costs have not been reduced to reflect TCC hedges and represent absolute values.

Based on the positive Demand$ Congestion costs, the future top congested paths are shown in Figure 23.

Figure 23: Projection of Future Demand$ Congestion 2019-2028 by Constrained Path for Base Case (nominal $M)

Demand Congestion ($M)	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
CENTRAL EAST	$668	$508	$521	$411	$183	$188	$84	$84	$114	$167
DUNWOODIE TO LONG ISLAND	$41	$36	$28	$25	$25	$31	$25	$26	$25	$28
CHESTR SHOEMAKR	$9	$34	$79	$68	$52	$0	$0	$0	$0	$0
PACKARD 115 NIAGBLVD 115	$85	$53	$29	$0	$0	$0	$0	$0	$0	$0
DUNWOODIE MOTTHAVEN	$8	$9	$10	$7	$5	$14	$13	$14	$18	$15
GREENWOOD	$12	$10	$6	$6	$6	$8	$8	$10	$11	$10
N.WAV115 LOUNS 115	$2	$2	$3	$4	$4	$13	$10	$13	$12	$11
VOLNEY SCRIBA	$6	$7	$6	$7	$7	$6	$5	$7	$9	$9
NORTHPORT PILGRIM	$6	$4	$9	$10	$8	$5	$4	$5	$4	$4
EGRDNCTY 138 VALLYSTR 138 1	$6	$5	$3	$2	$5	$4	$5	$4	$5	$4
FERND 115 W.WDB 115	$2	$5	$10	$9	$9	$1	$0	$0	$1	$2
NIAGARA PACKARD	$19	$16	$10	$0	$0	$0	$0	$0	$0	$0

Ranking of Congested Elements

The identified congested elements from the ten-year projection of congestion are appended to the past five years of identified historic congested elements to develop fifteen years of Demand$ Congestion statistics for each initially identified top constraint. The fifteen years of statistics are analyzed to determine recurring congestion or the mitigation of congestion from future system changes incorporated into the base CARIS system that may lead to exclusions. Ranking of the identified constraints is initially based on the highest present value of congestion over the fifteen-year period with five years of historic and ten years projected congestion.

Figure 24 lists the ranked elements based on the highest present value of congestion over the fifteen years of the study, including both positive and negative congestion. Central East, Dunwoodie-Long Island, and Leeds-Pleasant Valley continue to be the paths with the greatest projected congestion. The top elements are evaluated in the next step for selection of the three study cases.

Figure 24: Ranked Elements Based on the Highest Present Value of Demand$ Congestion over the 15 Yr Aggregate (Base Case)[21]

Present Value of Demand$ Congestion ($2019M)			
Element	Hist. Total	Proj. Total	15Y Total
CENTRAL EAST	$5,021	$2,555	$7,576
DUNWOODIE TO LONG ISLAND	$873	$230	$1,103
LEEDS PLEASANT VALLEY	$423	$9	$432
EDIC MARCY	$317	$0	$317
DUNWOODIE MOTTHAVEN	$172	$83	$254
GREENWOOD	$174	$67	$241
PACKARD HUNTLEY	$215	$0	$215
CHESTR SHOEMAKR	$0	$212	$212
NIAGARA PACKARD	$135	$44	$179
PACKARD 115 NIAGBLVD 115	$0	$166	$166
SCH-NE-NY	$135	$28	$163
EGRDNCTY 138 VALLYSTR 138 1	$105	$33	$139
NEW SCOTLAND LEEDS	$99	$0	$100
E179THST HELLGT ASTORIAE	$48	$15	$63
SHORE_RD 345 SHORE_RD 138 1	$59	$0	$59
VOLNEY SCRIBA	$3	$51	$55
N.WAV115 LOUNS 115	$0	$52	$52

The frequency of actual and projected congestion is shown in Figure 25. The figure presents the actual number of congested hours by constraint, from 2014 through 2018, and projected hours of congestion, from 2019 through 2028. The change in the number of projected hours of congestion, by constraint after each generic solution is applied, is shown in Appendix E.

Figure 25: Number of Congested Hours by Constraint (Base Case)

# of DAM Congested Hours	Actual					CARIS Base Case Projected									
Constraint	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
CENTRAL EAST	3,022	4,091	4,636	5,062	4,031	3,145	3,266	2,831	2,649	1,500	1,245	700	723	723	878
DUNWOODIE TO LONG ISLAND	5,583	7,738	6,085	8,212	8,624	7,629	7,833	7,546	7,420	6,812	7,329	6,940	6,682	6,867	6,953
LEEDS PLEASANT VALLEY	384	965	623	982	83	20	17	20	24	28	-	-	-	-	-
GREENWOOD	1,438	7,456	7,347	7,573	7,310	4,431	4,504	4,603	4,797	4,719	4,704	4,592	4,620	4,480	4,471
PACKARD HUNTLEY	308	1,720	1,425	821	818	-	-	-	-	-	-	-	-	-	-
EGRDNCTY 138 VALLYSTR 138 1	5,142	3,191	3,479	6,178	5,442	6,394	5,975	4,757	4,813	4,846	4,937	5,162	5,058	5,102	5,074
NIAGARA PACKARD	-	756	1,279	501	458	253	202	76	38	-	20	-	-	-	-
DUNWOODIE MOTTHAVEN	190	231	134	1,281	2,743	846	922	1,918	1,643	1,537	2,120	2,052	2,048	2,191	2,349
EDIC MARCY	-	11	164	307	312	-	-	-	-	-	-	-	-	-	-
RAINEY VERNON	641	2,073	2,438	2,655	2,700	541	344	287	222	183	250	233	284	261	306
MOTTHAVEN RAINEY	-	80	188	1,900	208	692	718	328	239	97	253	241	168	285	275
STOLLE GARDENVILLE	-	318	429	-	-	25	8	3	-	-	-	-	-	-	-
E179THST HELLGT ASTORIAE	990	1,672	1,864	6,406	6,345	2,838	2,879	1,801	1,993	1,713	1,821	1,585	1,668	1,591	1,285
NEW SCOTLAND LEEDS	173	556	214	314	106	1	-	-	4	2	-	-	-	-	-
SHORE_RD 345 SHORE_RD 138 1	-	505	172	120	56	-	-	-	-	-	-	-	-	-	-
VOLNEY SCRIBA	-	146	46	324	254	1,434	1,593	1,224	1,330	1,444	1,258	1,334	1,486	1,798	1,745

[21] The absolute value of congestion is reported.

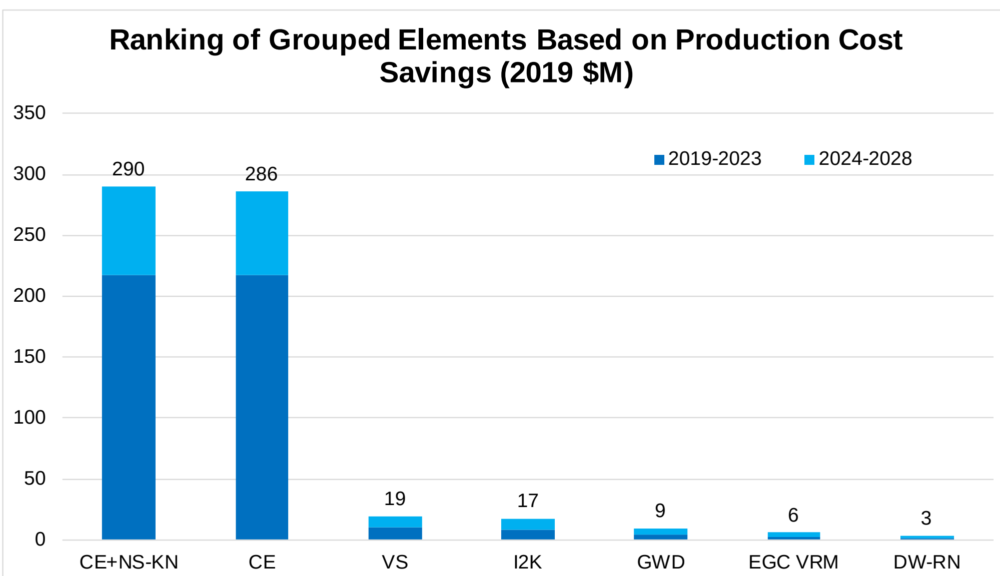
Top Three Congestion Groupings

Selection of the CARIS studies is a two-step process in which the top ranked constraints are identified and utilized for further assessment in order to identify potential for grouping of constraints.[22] The resultant grouping of elements for each of the top ranked constraints is utilized to determine the CARIS studies. For the purpose of this selection exercise, the Base Case, as described above in the "Base Case Modeling Assumptions" section, was utilized.

In Step 1, the top five congested elements for the fifteen-year period (both historic (5 years) and projected (10 years)) are ranked in descending order based on the calculated present value of Demand$ Congestion for further assessment.

In Step 2, the top congested elements from Step 1 are relieved independently by relaxing their limits. This step determines if any of the congested elements need to be grouped with other elements, depending on whether new elements appear as limiting with significant congestion when a primary element is relieved. See Appendix E for a more detailed discussion. The assessed element groupings are then ranked based upon the highest change in production cost, as presented in Figure 26.

Figure 26: Ranking of Grouped Elements Based on Production Cost Savings ($2019M)



Per the NYISO Tariff, the three ranked interface groupings with the largest change in production cost are then selected as the set of CARIS studies. For the 2019 CARIS Phase 1, these are

22 Additional detail on the selection of the CARIS studies is provided in Appendix E.

Central East-New Scotland-Knickerbocker ("CE+NS-KN"), Central East ("CE") and Volney-Scriba ("VS"). Other interfaces with noted changes in production cost are I to K ("I2K"), the Greenwood Load Pocket ("GWD"), East Garden Center-Valley Stream ("EGC VRM"), and Dunwoodie-Rainey ("DW-RN"). Figure 27 and Figure 28 present the Base Case congestion associated with each of the three studies in nominal and real terms.

Figure 27: Demand$ Congestion for the Three CARIS Studies (nominal $M)

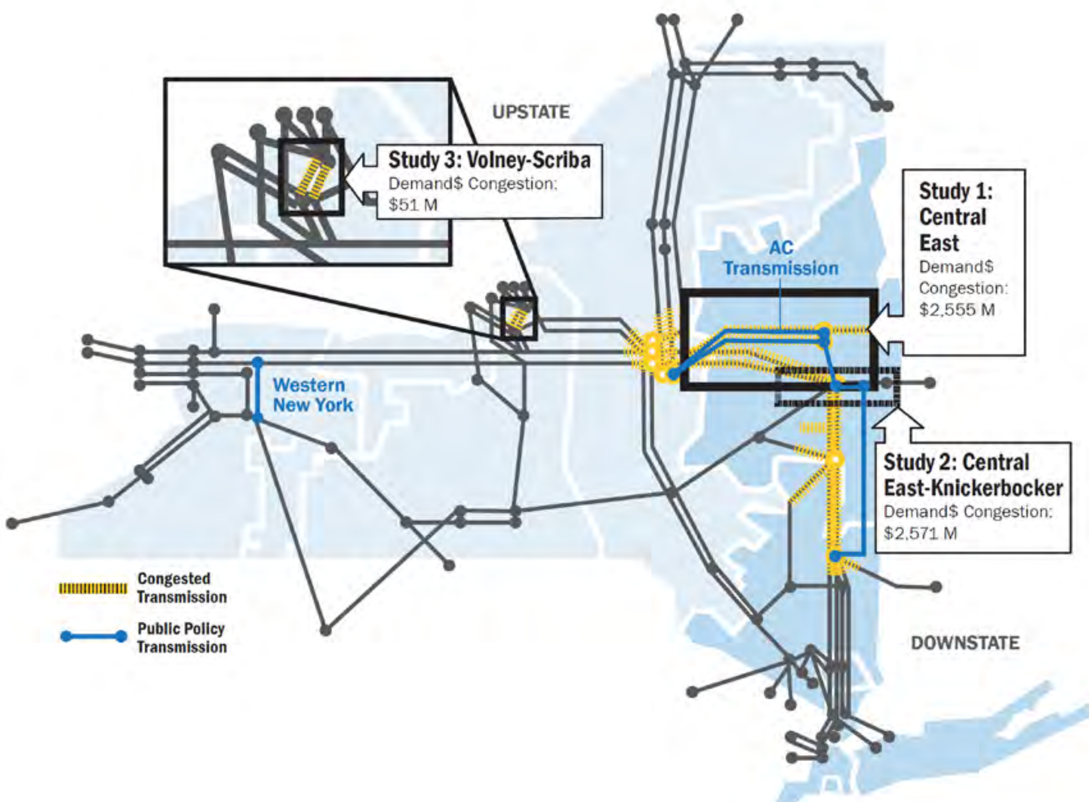
Study	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Study 1: Central East	668	508	521	411	183	188	84	84	114	167
Study 2: Central East-Knickerbocker	668	508	521	411	183	192	87	91	120	173
Study 3: Volney Scriba	6	7	6	7	7	6	5	7	9	9

Figure 28: Demand$ Congestion for the Three CARIS Studies ($2019M)

Study	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Study 1: Central East	691	491	470	347	144	139	57	54	69	93
Study 2: Central East-Knickerbocker	691	491	470	347	144	141	60	58	72	96
Study 3: Volney Scriba	6	6	6	6	5	4	4	4	5	5

The location of the top three congested groupings, along with the present value of congestion (in 2019 dollars) for the three studies, is presented in Figure 29.

Figure 29: Base Case Congestion of Top 3 Congested Groupings, 2019-2028 ($2019M)



Generic Solutions

Generic solutions are evaluated by the NYISO for each of the CARIS studies utilizing each resource type (generation, transmission, energy efficiency and demand response) as required in Section 31.3.1.3.3 of the Tariff. Consensus on the costs for each type of generic solution was achieved through engagement with stakeholders in the NYISO's shared governance process. Recognizing that the costs, points of interconnection, timing, and characteristics of actual projects may vary significantly, the NYISO developed a range of costs (low, mid, and high) for each type of resource based on publicly available sources. Such costs may differ from those submitted by potential developers in a competitive bidding process. This methodology utilizes typical megawatt block size generic solutions, a standard set of assumptions without determining actual project feasibility, and order of magnitude costs for each resource type.

The cost estimates for generic solutions are intended only to set forth an order of magnitude of the potential projects' costs for benefit/cost ratio analysis. These estimates should not be assumed as reflective or predictive of actual projects or imply that facilities can necessarily be built for these estimated costs or in the locations assumed.

Resource Block Sizes

Typical resource block sizes are developed for each resource type based on the following guidelines:

- Block size should reflect a typical size built for the specific resource type and geographic location;
- Block size should be small enough to be additive with reasonable step changes; and
- Blocks sizes should be in comparable proportions between the resource types.

The block sizes selected for each resource type are presented in Figure 30 through Figure 32.

Figure 30: Transmission Block Sizes[23]

Location	Line System Voltage (kV)	Normal Rating (MVA)
Zone C	345	1,986
Zone E-G	345	1,986

23 Solution size is based on a double-bundled ACSR 1590 kcmil conductor rated for 3,324 Amps.

Figure 31: Generation Block Sizes[24]

Plant Location	Plant Block Size Capacity (MW)
Zone C	340
Zone F-G	340

Figure 32: EE and DR Block Sizes

Location	Resource Quantity (MW)
Zone F-G	100
Zone J	200

Guidelines and Assumptions for Generic Solutions

Developing cost estimates for these resource types depends on many different parameters and assumptions and without consideration of project feasibility or project-specific costs.

The following guidelines and assumptions were used to select the generic solution:

Transmission Resource

- The generic transmission solution consists of a new transmission line interconnected to the system upstream and downstream of the grouped congested elements being studied.
- The generic transmission line terminates at the nearest existing substations of the grouped congested elements.
- If there is more than one substation located near the grouped congested elements that meets the required criteria, then the two substations that have the shortest distance between the two are selected. Space availability at substations (*i.e.,* room for substation expansion) was not evaluated in this process.

Generation Resource

- The generic generation solution consisted of the construction of a new combined cycle generating plant connecting downstream from the grouped congested elements being studied.
- The generic generation solution terminates at the nearest existing substation of the

24 Proposed generic unit is a Siemens SGT6-5000F(5).

grouped congested elements.

- If there is more than one substation located near the grouped congested elements that meets the required criteria, the substation that has the highest relative shift factor was selected. Space availability at substations (*i.e.,* room for substation expansion) was not evaluated in this process.
- The total resource increase in megawatts should be comparable to the megawatt increase in transfer capability due to the transmission solution.

Energy Efficiency

- Block sizes limited to 200 MW or 5% of zonal peak load, whichever is lower. If one zone reaches a limit, energy efficiency may be added to other downstream zones.
- Aggregated at the downstream of the congested elements.
- The total resource increase in megawatts should be comparable to the megawatt increase in transfer capability due to the transmission solution.

Demand Response

- Blocks of demand response modeled at 100 peak hours as reduction in zonal hourly load.
- Use the same block sizes in the same locations as energy efficiency.

Generic Solution Pricing Considerations

Three sets of cost estimates for each of the four resource types are designed to reflect the differences in labor, land and permitting costs among Upstate, Downstate and Long Island, as set forth below. The considerations used for estimating costs for the three resource types and for each geographical area are listed in Figure 33.

Figure 33: Generic Solution Pricing Considerations

Transmission	Generation	Energy Efficiency	Demand Response
Transmission Line Cost per Mile	Equipment	Energy Efficiency Programs	Demand Response Programs
Substation Terminal Costs	Construction Labor & Materials	Customer Implementation Costs	Customer Implementation Costs
System Upgrade Facilities	Electrical Connection & Substation		
	Electrical System Upgrades		
	Gas Interconnect & Reinforcement		
	Engineering & Design		

Low, mid, and high cost estimates for each element were provided to stakeholders for comment. The transmission cost estimates were reviewed by Market Participants, including Transmission Owners; and the estimated cost data for the mid-point of the generation solutions are obtained from the 2016 Demand Curve Reset report. The low and high point of the generic cost estimates for energy efficiency were derived from DPS filings on energy efficiency costs from the relevant Transmission Owners.[25] Finally, the mid-point of the demand response costs was extracted from most recent New York Public Service Commission filings by utilities on Commercial System Relief Program costs and enrollments.[26] This approach establishes a range of cost estimates to address the variability of generic projects. The resulting order of magnitude unit pricing levels are provided in the "Cost Analysis" section below. A more detailed discussion of the cost assumptions and calculations is provided in Appendix E.

Production Cost Savings

For each of the three studies, demand congestion is mitigated by individually applying one of the generic resource types; transmission, generation, energy efficiency and demand response. The resource type is applied based on the rating and size of the blocks determined in the Generic Solutions Cost Matrix included in Appendix E and is consistent with the methodology explained earlier in this report. Resource blocks were applied to relieve a majority of the congestion. Additional resource blocks were not added if diminishing returns would occur.

25 Case 18-M-0084 – In the Matter of a Comprehensive Energy Efficiency Initiative

26 Case 14-E-0423 – Proceeding on Motion of the Commission to Develop Dynamic Load Management Programs

Concerning the generic solutions, it is important to note the following:

- Other solutions may exist that will alleviate the congestion on the studied elements.
- No attempt has been made to determine the optimum solution for alleviating the congestion.
- No engineering, physical feasibility study, routing study or siting study has been completed for the generic solutions. Therefore, it is unknown if the generic solutions can be physically constructed as studied.
- Generic solutions are not assessed for impacts on system reliability or feasibility.
- Actual projects will incur different costs.
- The generic solutions differ in the degree to which they relieve the identified congestion.
- For each of the Base Case and solution cases, Hydro Quebec imports are held constant.

The discount rate of 7.08% used for the present values analysis is the weighted average of the after-tax Weighted Average Cost of Capital for the New York Transmission Owners. The weighted average is based on the utilities' annual gigawatt hour energy consumption for 2018.

Figure 35, Figure 38, and Figure 41 present the impact of each of the solutions on Demand$ Congestion for each of the studies in 2019$. Transmission has the greatest impact on reducing Demand$ Congestion (24% to 100%) because adding a transmission solution addresses the underlying system constraint that was driving the congestion. The generation solution had negligible impact on demand$ congestion (<2%) for Study 1 and Study 2 except for study 3 (89%) as the generic unit did not displace significant generation in the Base Case. This is attributable in Study 1 and Study 2 to a resource-rich environment downstream of the constraints, including Indian Point Energy Center (up to 2021), the Bayonne expansion, and the new Cricket Valley and CPV Valley combined-cycle facilities. In Study 3 (Volney-Scriba), the generic generation solution is sited directly downstream of the congested element, which helps in pushing back the flow on the congested line, hence relieving most of the congestion. The demand response solution had nearly no impact on demand$ congestion (<1%) since this solution is essentially a limited summer season resource and, as such, is not operational during the winter hours in which Central East is most heavily congested. The energy efficiency solution, reducing load across the full year, reduced demand$ congestion by about 6% across all three studies.

Figure 36, Figure 39, and Figure 42 present the impact of each of the solutions on production costs for each of the studies in 2019$. Transmission had higher impacts than the generation solutions in Study 1 and Study 2. For Study 3, the generation solution has the higher impact on production cost. The impact of the transmission solution on production costs ranges from $22M - $117M. The generation solution reduced production costs by $103M - $137M. The demand response solution resulted in the least production cost savings ($9M - $17M), again, as expected, since this solution impacted only the top 100 load hours. The energy efficiency solution shows the largest production cost savings (by $530M - $1,061M) because it directly reduces the energy production requirements.

The results of the four generic solutions are provided below with more detail in Appendix E. The following generic solutions were applied for each study:

Study 1: Central East

The following generic solutions were applied for the Central East Study under base conditions. Costs for transmission and generation solutions are presented as overnight costs:

- Transmission: A new 345 kV line from Edic to New Scotland, 85 Miles. The new line increases the Central East voltage transfer limit by about 400 MW. Cost estimates are: $340M (low); $510M (mid); and $638M (high).
- Generation: A new 340 MW plant at New Scotland. Cost estimates are: $450M (low); $600M (mid); and $750M (high).
- Demand Response: 100 MW demand response in Zone F; 100 MW in Zone G; 200 MW in Zone J. Cost estimates are $203M (low); $270M (mid); and $338M (high).
- Energy Efficiency: 100 MW energy efficiency in Zone F; 100 MW in Zone G; 200 MW in Zone J. Cost estimates are $2,985M (low); $3,980M (mid); and $4,975M (high).

Figure 34 shows the demand$ congestion of Central East for 2023 and 2028 before and after each of the generic solutions is applied. The Base Case congestion numbers, $183M for 2023 and $167M for 2028, are taken directly from Figure 27 representing the level of congestion of Study 1 before the solutions.

Figure 34: Demand$ Congestion Comparison for Study 1 (nominal $M)

Study 1: Central East						
Resource Type	2023			2028		
	Base Case	Solution	%Change	Base Case	Solution	%Change
Transmission	183	135	(26%)	167	97	(42%)
Generation-340MW	183	161	(12%)	167	175	5%
Demand Response-400MW	183	182	(1%)	167	168	1%
Energy Efficiency-400MW	183	168	(8%)	167	156	(7%)

Figure 35 shows the demand$ congestion reduction for the 10-year Study Period in 2019 dollars from 2019 to 2028 for the Central East study after generic solutions were applied.

Figure 35: Demand$ Congestion Comparison for Study 1 ($2019M)

Study 1: Central East												
Resource Type	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	Total	%Change
Transmission	(139)	(133)	(103)	(67)	(38)	(66)	(30)	(29)	(31)	(39)	(675)	(26%)
Generation-340MW	(20)	7	(3)	(10)	(17)	(4)	3	(7)	(3)	4	(51)	(2%)
Demand Response-400MW	1	0	0	1	(1)	(0)	1	(0)	0	1	4	0%
Energy Efficiency-400MW	(33)	(27)	(28)	(20)	(12)	(13)	(5)	(12)	(5)	(6)	(159)	(6%)

Figure 36 shows the production cost savings expressed as the present value in 2019 dollars from 2019 to 2028 for the Central East study after generic solutions were applied.

Figure 36: NYCA-wide Production Cost Savings for Study 1 ($2019M)

Study 1: Central East											
Resource Type	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	Total
Transmission	(22)	(20)	(20)	(15)	(9)	(7)	(6)	(5)	(5)	(6)	(115)
Generation-340MW	(2)	(7)	(12)	(15)	(11)	(9)	(7)	(10)	(13)	(17)	(103)
Demand Response-400MW	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(1)	(17)
Energy Efficiency-400MW	(108)	(109)	(110)	(107)	(108)	(106)	(107)	(106)	(101)	(98)	(1,061)

Note: Totals may differ from sum of annual values due to rounding.

The Edic-New Scotland 345 kV transmission solution is projected to relieve the congestion across Central East Interface by 26% in 2023 and 42% in 2028 respectively, as shown in Figure 34. As presented in Figure 36 total 10-year NYCA-wide production cost savings is $115 million (2019$) as the result of better utilization of economic generation in the state made available by the large scale transmission upgrades represented by this generic transmission solution.

The generation solution is projected to reduce congestion by 12% in 2023 and increase congestion by 5% in 2028. The 10-year production cost savings of $103 million (2019$) are due to its location downstream of system constraints and the assumed heat rate of the generic generating unit compared to the average system heat rate. Efficient generator solutions reduce imports from neighbors and enable a more efficient and lower cost NYCA generation market. Savings accrue in lower production cost as well as reduced congestion.

The Zones F, G and J demand response solution is projected to have no significant impact on congestion in 2023 and 2028, while the 10-year total production cost savings is $17 million (2019$). Demand response solutions show lower reduction in production cost than the generation, transmission and energy efficiency solutions due to the limited hours impacted by the solution.

The Zones F, G and J energy efficiency solution is projected to reduce congestion by 8% in 2023 and 7% in 2028, while the 10-year total production cost saving is $1,061 million (2019$). The relatively large value of production cost saving is mainly attributable to the reduction in energy use of the energy efficiency solution itself. For this reason, energy efficiency solutions show significantly greater reductions in production cost than the generation, transmission or demand response solutions.

Study 2: Central East -Knickerbocker

The following generic solutions were applied for the Central East-Knickerbocker study. Costs for transmission and generation solutions are presented as overnight costs:

- Transmission: A new 345 kV line from Edic to New Scotland to Knickerbocker, 100 miles (85 miles 345 kV circuit same as Study 1, additional 15 miles from New Scotland to Knickerbocker assumed in service after 2024). The new line increases the Central East voltage limit by approximately 400 MW. Cost estimates are: $400M (low); $600M (mid); and $750M (high) for the entire 100 mile solution over 10 years.
- Generation: A new 340 MW plant at Pleasant Valley. Cost estimates are: $505M (low); $675M (mid); and $845M (high).
- Demand Response: 100 MW demand response in Zone F; 100 MW in Zone G; 200 MW in Zone J. Cost estimates are $203M (low); $270M (mid); and $338M (high).
- Energy Efficiency: 100 MW energy efficiency in Zone F; 100 MW in Zone G; 200 MW in Zone J. Cost estimates are $2,985M (low); $3,980M (mid); and $4,975M (high).

Figure 37 shows the demand$ congestion of Central East-New Scotland-Knickerbocker for 2023 and 2028 before and after each of the generic solutions is applied.

Figure 37: Demand$ Congestion Comparison for Study 2 (nominal $M)

Study 2: Central East-Knickerbocker						
Resource Type	2023			2028		
	Base Case	Solution	%Change	Base Case	Solution	%Change
Transmission	183	135	(26%)	173	126	(27%)
Generation-340MW	183	161	(12%)	173	176	2%
Demand Response-400MW	183	182	(1%)	173	168	(3%)
Energy Efficiency-400MW	183	168	(8%)	173	163	(6%)

Figure 38 shows the demand$ congestion reduction for the 10-year Study Period in 2019 dollars from 2019 to 2028 for the Central East study after generic solutions were applied.

Figure 38: Demand$ Congestion Comparison for Study 2 ($2019M)

Study 2: Central East-Knickerbocker												
Resource Type	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	Total	%Change
Transmission	(139)	(133)	(103)	(67)	(38)	(46)	(22)	(20)	(20)	(26)	(614)	(24%)
Generation-340MW	(15)	9	0	(8)	(18)	4	4	(4)	1	2	(25)	(1%)
Demand Response-400MW	1	0	0	1	(1)	(0)	1	(0)	0	1	4	0%
Energy Efficiency-400MW	(33)	(27)	(28)	(20)	(12)	(11)	(4)	(13)	(4)	(5)	(156)	(6%)

Figure 39 shows the NYCA-wide production cost savings expressed as the present value in 2019 dollars from 2019 to 2028 for the Central East study after generic solutions were applied.

Figure 39: NYCA-wide Production Cost Savings for Study 2 ($2019M)

Study 2: Central East-Knickerbocker											
Resource Type	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	Total
Transmission	(22)	(20)	(20)	(15)	(9)	(8)	(6)	(5)	(6)	(6)	(117)
Generation-340MW	(2)	(8)	(13)	(16)	(12)	(9)	(7)	(11)	(14)	(18)	(110)
Demand Response-400MW	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(1)	(17)
Energy Efficiency-400MW	(108)	(109)	(110)	(107)	(108)	(106)	(107)	(106)	(101)	(98)	(1,061)

Note: Totals may differ from sum of annual values due to rounding.

The addition of the Edic-New Scotland-Knickerbocker line is projected to relieve the Central East-Knickerbocker congestion by 26% in 2023 and 27% in 2028. The total 10-year production cost savings of $117 million (2019$) are again due to increased use of lower cost generation in Upstate and increased levels of imports compared to the Base Case.

The generation solution is projected to reduce congestion by 12% in 2023 and increase congestion by 2% in 2028. The 10-year production cost savings of $110 million (2019$) are derived from the heat rate efficiency advantage of the new generic unit compared to the average system heat rate. Efficient generator solutions reduce imports from neighbors and enable a more efficient and lower cost NYCA generation market. Savings accrue in lower production cost as well as reduced congestion.

The Zones F, G and J demand response solution is projected to have a negligible impact on congestion in 2023 and in 2028, while the 10-year total production cost saving is $17 million (2019$). Demand response solutions show lower reduction in production cost than the generation, transmission and energy efficiency solutions due to the limited hours impacted by the solution.

The Zones F, G, and J energy efficiency solution is projected to reduce congestion by 8% in 2023 and 6% in 2028, while the 10-year total production cost saving is $1,061 million (2019$). The relative large value of production cost saving is mainly attributable to the reduction in energy use of the energy efficiency solution itself. Energy efficiency solutions typically show greater reductions in production cost than the generation, transmission and demand response solutions because load is reduced in all hours, reducing the total megawatt hours required to serve load.

Study 3: Volney-Scriba (Base Conditions)

The following generic solutions were applied for the Volney-Scriba Study. Costs for transmission and generation solutions are presented as overnight costs:

- Transmission: A new 345 kV line from Volney to Scriba, 10 Miles. Cost estimates are: $40M (low); $60M (mid); and $75M (high).
- Generation: A new 340 MW plant at Volney. Cost estimates are: $395M (low); $525M (mid); and $655M (high).
- Demand Response: 100 MW demand response in Zone F; 100 MW in Zone G. Cost estimates are $38M (low); $50M (mid); and $63M (high).
- Energy Efficiency: 100 MW energy efficiency in Zone F; 100 MW in Zone G. Cost estimates are $1,204M (low); $1,605M (mid); and $2,006M (high).

Figure 40 shows the demand$ congestion of Volney-Scriba for 2023 and 2028 before and after each of the generic solutions is applied.

Figure 40: Demand$ Congestion Comparison for Study 3 (nominal $M)

Study 3: Volney Scriba						
Resource Type	2023			2028		
	Base Case	Solution	%Change	Base Case	Solution	%Change
Transmission	7	0	(100%)	9	0	(100%)
Generation-340MW	7	1	(86%)	9	0	-
Demand Response-200MW	7	7	(3%)	9	9	(3%)
Energy Efficiency-200MW	7	7	(4%)	9	8	(6%)

Figure 41 shows the demand$ congestion reduction for the 10-year Study Period in 2019 dollars from 2019 to 2028 for the Volney-Scriba study after generic solutions were applied.

Figure 41: Demand$ Congestion Comparison for Study 3 ($2019M)

Study 3: Volney Scriba												
Resource Type	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	Total	%Change
Transmission	(6)	(6)	(6)	(6)	(5)	(4)	(4)	(4)	(5)	(5)	(51)	(100%)
Generation-340MW	(4)	(5)	(5)	(5)	(5)	(4)	(4)	(4)	(5)	(5)	(46)	(89%)
Demand Response-200MW	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	0	(0)	(1%)
Energy Efficiency-200MW	(1)	(1)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(3)	(5%)

Figure 42 shows the NYCA-wide production cost savings expressed as the present value in 2019 dollars from 2019 to 2028 for the Volney-Scriba study after the generic solutions were applied.

Figure 42: NYCA-wide Production Cost Savings for Study 3 ($2019M)

Study 3: Volney Scriba											
Resource Type	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	Total
Transmission	(2)	(3)	(2)	(2)	(2)	(2)	(3)	(2)	(2)	(2)	(22)
Generation-340MW	(1)	(9)	(12)	(15)	(16)	(12)	(13)	(15)	(20)	(23)	(137)
Demand Response-200MW	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(9)
Energy Efficiency-200MW	(54)	(55)	(55)	(54)	(54)	(52)	(54)	(53)	(50)	(49)	(530)

Note: Totals may differ from sum of annual values due to rounding.

The Volney-Scriba 345 kV transmission solution is projected to relieve the congestion across existing Volney-Scriba corridor completely in both 2023 and 2028, as shown in Figure 40. As presented in Figure 42, total 10-year NYCA-wide production cost savings is $22 million (2019$) as the result of better utilization of economic generation in the state.

The generation solution is projected to reduce congestion by 86% in 2023 and does not impact line congestion in 2028. The 10-year production cost savings of $137 million (2019$) are due to its location downstream of system constraints and the assumed heat rate of the generic generating unit compared to the average system heat rate. Efficient generator solutions can replace less efficient NYCA generation upstream of the load centers, which can have the effect of reducing differentials across the constraints. The displacement of certain Zone F generation, however, may lower the Central East voltage transfer limit and actually increase congestion under certain circumstances. The running of lower-cost generation will in general lower production cost as well.

The Zones F and G demand response solution is projected to have a negligible impact on congestion in 2023 and 2028, while the 10-year total production cost saving is $9 million (2019$). Demand response solutions show lower reduction in production cost than the generation, transmission and energy efficiency solutions due to the limited hours impacted by the solution.

The Zones F and G Energy Efficiency solution is projected to reduce congestion by 4% in 2023 and 6% in 2028, while the 10-year total production cost saving is $530 million (2019$). The relatively large value of production cost saving is mainly attributable to the reduction in energy use of the energy efficiency solution itself. For this reason, energy efficiency solutions show significantly greater reductions in production cost than the generation, transmission or demand response solutions.

The NYCA-wide production cost savings of the four generic solutions for the three studies are summarized and shown in Figure 43.

Figure 43: Total NYCA-wide Production Cost Savings 2019-2028 ($2019M)

Production Cost Savings ($2019M)			
Solution	**Central East (Study 1)**	**Central East-Knickerbocker (Study 2)**	**Volney-Scriba (Study 3)**
Transmission	115	117	22
Generation	103	110	137
Demand Response	17	17	9
Energy Efficiency	1,061	1,061	530

Benefit/Cost Analysis

The NYISO conducted the benefit/cost analysis for each generic solution applied to the three studies described above. The CARIS benefit/cost analysis assumes a levelized generic carrying charge rate of 16% for transmission and generation solutions. Therefore, for a given generic solution pertaining to a constrained element, the carrying charge rate, in conjunction with an appropriate discount rate (see description in Section 5.3.2 above) yields a capital recovery factor, which, in turn, is used to calculate the benefit/cost ratio.

$$\text{Benefit/Cost Ratio} = \frac{\text{Present Value of Production Cost Savings}}{\text{Overnight Costs x Capital Recovery Factor}}$$

The 16% carrying charge rate used in these CARIS benefit/cost calculations reflects generic figures for a return on investment, federal and state income taxes, property taxes, insurance, fixed operation and maintenance costs, and depreciation (assuming a straight-line 30-year method). The calculation of the appropriate capital recovery factor, and, hence, the benefit/cost ratio, is based on the first 10 years of the 30-year period,[27] using a discount rate of 7.08%, and the 16% carrying charge rate, yielding a capital cost recovery factor equal to 1.16.

Costs for the demand response and energy efficiency solutions are intended to be comparable to the overnight installation costs of a generic transmission facility or generating unit and, therefore, represent equipment purchase and installation costs. Recognizing that these costs vary by region, zonal-specific costs were developed utilizing Transmission Owner data reported to the NYPSC in energy efficiency and demand response proceedings.

27 The carrying charge rate of 16% was based on a 30-year period because the Tariff provisions governing Phase 2 of CARIS refer to calculating costs over 30 years for information purposes. See OATT Attachment Y, Section 31.5.3.3.4.

Cost Analysis

Figure 44 includes the total cost estimate for each generic solution based on the unit pricing and the detailed cost breakdown for each solution included in Appendix E. Such costs may differ from those submitted by potential developers in a competitive bidding process. The costs represent simplified estimates of overnight installation costs, and do not include any of the many complicating factors that could be faced by individual projects. Ongoing fixed operation and maintenance costs and other fixed costs of operating the facility are captured in the capital cost recovery factor.

Figure 44: Generic Generation with Overnight Costs, Demand Response, and Energy Efficiency Solution Costs for Each Study[28]

Generic Solutions Cost Summary ($M)			
Studies	Central East (study 1)	Central East-Knickerbocker (Study 2)	Volney-Scriba (Study 3)
GENERATION			
Unit Siting	New Scotland	Pleasant Valley	Volney
# of 340 MW Blocks	1	1	1
High	$750	$845	$655
Mid	$600	$675	$525
Low	$450	$505	$395
DEMAND RESPONSE			
Location (# of Blocks)	F(1), G(1), and J(1)	F(1), G(1), and J(1)	F(1) and G(1)
Total # of Blocks	3	3	2
High	$338	$338	$63
Mid	$270	$270	$50
Low	$203	$203	$38
ENERGY EFFICIENCY			
Location (# of Blocks)	F(1), G(1), and J(1)	F(1), G(1), and J(1)	F(1) and G(1)
Total # of Blocks	3	3	2
High	$4,975	$4,975	$2,006
Mid	$3,980	$3,980	$1,605
Low	$2,985	$2,985	$1,204

28 Appendix E contains a more detailed description of the derivation of the generic solution costs.

Figure 45: Generic Transmission Solution Overnight Costs for Each Study

Generic Solutions Cost Summary ($M)			
Studies	**Central East (Study 1)**	**Central East-Knickerbocker (Study 2)**	**Volney-Scriba (Study 3)**
TRANSMISSION			
Transmission Path	Edic-New Scotland	Edic-New Scotland-Knickerbocker	Volney-Scriba
Voltage	345 kV	345 kV	345 kV
2019-2023			
Miles	85	85	10
High	$638	$638	$75
Mid	$510	$510	$60
Low	$340	$340	$40
2024-2028			
Miles	85	100	10
High	$638	$750	$75
Mid	$510	$600	$60
Low	$340	$400	$40

Primary Metric Results

The primary benefit metric for the three CARIS studies is the reduction in NYCA-wide production costs. Figure 46 shows the production cost savings used to calculate the benefit/cost ratios for the generic solutions. In each of the three studies, the energy efficiency solution produced the highest production cost savings because it directly reduces the energy production requirements. Similarly, in Studies 1 and 2, the transmission solutions produced higher production cost savings than generation. In all cases, the demand response solution had the least impact on production cost savings due to the limited hours impacted by the solution.

Figure 46: Production Cost Generic Solutions Savings 2019-2028 ($2019M)

Study	Transmission Solution	Generation Solution	Demand Response Solution	Energy Efficiency Solution
Ten-Year Production Cost Savings (2019 $M)				
Study 1: Central East	115	103	17	1,061
Study 2: Central East-Knickerbocker	117	110	17	1,061
Study 3: Volney-Scriba	22	137	9	530
Production Cost Savings 2019-2023 (2019 $M)				
Study 1: Central East	86	46	9	542
Study 2: Central East-Knickerbocker	86	51	9	542
Study 3: Volney-Scriba	12	54	4	272
Production Cost Savings 2024-2028 (2019 $M)				
Study 1: Central East	29	57	8	519
Study 2: Central East-Knickerbocker	31	59	8	519
Study 3: Volney-Scriba	10	83	4	258

Benefit/Cost Ratios

Figure 47 shows the benefit/cost ratios for each study and each generic solution. The results are consistent with those in prior CARIS studies. The solutions studied for the top three congested paths offered a measure of congestion relief and production costs savings, but did not result in projects with benefit/cost ratios in excess of 1.0. As expected, the congestion level decreased substantially with the AC Transmission projects in-service as of the beginning of 2024, thus affecting the benefits provided by the generic solutions.

Figure 47: Benefit/Cost Ratios (High, Mid, and Low Cost Estimate Ranges)

Study	2019-2023			2024-2028		
Transmission Solution	**Low**	**Mid**	**High**	**Low**	**Mid**	**High**
Study 1: Central East	0.37	0.25	0.20	0.18	0.12	0.09
Study 2: Central East-Knickerbocker	0.37	0.25	0.20	0.16	0.11	0.09
Study 3: Volney-Scriba	0.44	0.30	0.24	0.52	0.35	0.28
Generaton Solution	**Low**	**Mid**	**High**	**Low**	**Mid**	**High**
Study 1: Central East	0.15	0.11	0.09	0.26	0.20	0.16
Study 2: Central East-Knickerbocker	0.15	0.11	0.09	0.24	0.18	0.15
Study 3: Volney-Scriba	0.20	0.15	0.12	0.44	0.33	0.26
Demand Response Solution	**Low**	**Mid**	**High**	**Low**	**Mid**	**High**
Study 1: Central East	0.08	0.06	0.05	0.11	0.08	0.06
Study 2: Central East-Knickerbocker	0.08	0.06	0.05	0.11	0.08	0.06
Study 3: Volney-Scriba	0.17	0.13	0.11	0.25	0.19	0.15
Energy Efficiency Solution	**Low**	**Mid**	**High**	**Low**	**Mid**	**High**
Study 1: Central East	0.32	0.24	0.19	0.43	0.32	0.26
Study 2: Central East-Knickerbocker	0.32	0.24	0.19	0.43	0.32	0.26
Study 3: Volney-Scriba	0.41	0.31	0.25	0.55	0.41	0.33

Study 1: Central East			
Solution	**Low**	**Mid**	**High**
Generation	0.20	0.15	0.12
Demand Response	0.08	0.06	0.05
Energy Efficiency	0.36	0.27	0.21

Study 2: Central East-Knickerbocker			
Solution	**Low**	**Mid**	**High**
Generation	0.19	0.14	0.11
Demand Response	0.08	0.06	0.05
Energy Efficiency	0.36	0.27	0.21

Study 3: Volney Scriba			
Solution	**Low**	**Mid**	**High**
Generation	0.30	0.23	0.18
Demand Response	0.24	0.18	0.14
Energy Efficiency	0.44	0.33	0.26

Additional Metrics Results

Additional metrics, which are provided for information purposes in Phase 1, are presented in Figure 48, Figure 49, Figure 50 and Figure 51 to show the 10-year total change in: (a) generator payments; (b) LBMP load payments; (c) TCC payments (congestion rents); (d) losses; (e) emission costs/tons; and (f) ICAP MW and cost impact, after the generic solutions are applied. The values represent the generic solution case values less the Base Case values for all the metrics except for the ICAP metric. While all but the ICAP metric result from the production cost simulation program, the ICAP metric is computed using the latest available information from the installed reserve margin locational capacity requirement and the ICAP Demand Curves.[29] The procedure for determining the megawatt impacts, as prescribed in the NYISO Tariff[30], is used to forecast changes to such reserve requirements that would be expected with the addition of the actual generic solutions. However, the procedure does not replicate the methodology employed in determining the Installed Reserve Margin and Locational Capacity Requirements.

29 https://www.nyiso.com/documents/20142/5624348/ICAP-Translation-of-Demand-Curve-Summer-2019.pdf/e1988852-3fcf-281c-4ac7-dff12d078507 ;
https://www.nyiso.com/documents/20142/4461032/011519%20ICAPWG%20final-LCRs2.pdf/bdfc4d6e-d360-f863-df58-57e623546d09

30 Section 31.3.1.3.5.6 of the NYISO OATT.

For Variant 1 ("V1"), the ISO measured the cost impact of a solution by multiplying the forecast cost per megawatt-year of Installed Capacity (without the solution in place) by the sum of the megawatt impact. For Variant 2 ("V2"), the cost impact of a solution is calculated by forecasting the difference in cost per megawatt-year of Installed Capacity with and without the solution in place and multiplying that difference by 50 percent of the assumed amount of NYCA Installed Capacity available. Details on the ICAP metric calculations and 10 years of results are provided in Appendix E.

Figure 48: Ten-Year Change in Load Payments, Generator Payments, TCC Payments and Losses Costs ($2019M)[31]

Study	Solution	LOAD PAYMENT	NYCA LOAD PAYMENT	EXPORT PAYMENT	GENERATOR PAYMENT	NYCA GENERATOR PAYMENT	IMPORT PAYMENT	TCC PAYMENT	LOSSES COSTS
TRANSMISSION SOLUTIONS									
Study 1: Central East	Edic-New Scotland	$215	$112	$103	$233	$214	$20	($212)	($25)
Study 2: Central East-Knickerbocker	Edic-New Scotland-Knickerbocker	$264	$141	$123	$271	$251	$20	($206)	($16)
Study 3: Volney Scriba	Volney-Scriba	($54)	($72)	$18	$384	$398	($15)	($432)	$13
GENERATION SOLUTIONS									
Study 1: Central East	New Scotland	($117)	($176)	$59	($88)	($11)	($77)	($26)	$17
Study 2: Central East-Knickerbocker	Pleasant Valley	($109)	($163)	$55	($61)	$13	($74)	($38)	($17)
Study 3: Volney Scriba	Volney	($228)	($313)	$85	$122	$234	($111)	($319)	$55
DEMAND RESPONSE SOLUTIONS									
Study 1: Central East	F(100) G(100) J(200)	($69)	($70)	$1	($51)	($47)	($4)	($15)	($3)
Study 2: Central East-Knickerbocker	F(100) G(100) J(200)	($69)	($70)	$1	($51)	($47)	($4)	($15)	($3)
Study 3: Volney Scriba	F(100) G(100)	($29)	($30)	$1	($23)	($21)	($2)	($5)	($1)
ENERGY EFFICIENCY SOLUTIONS									
Study 1: Central East	F(100) G(100) J(200)	($1,316)	($1,497)	$182	($1,165)	($1,002)	($163)	($99)	($64)
Study 2: Central East-Knickerbocker	F(100) G(100) J(200)	($1,316)	($1,497)	$182	($1,165)	($1,002)	($163)	($99)	($64)
Study 3: Volney Scriba	F(100) G(100)	($612)	($715)	$103	($562)	($475)	($87)	($43)	($12)

Note: A negative number implies a reduction in payments

Figure 49: Year 2028 ICAP MW Impact

Study	Solution	MW Impact (MW)			
		J	G-J	K	NYCA
Study 1: Central East	Transmission	0	0	0	0
	Generation	54	81	29	220
	Energy Efficiency	142	212	77	574
	Demand Response	122	182	66	493
Study 2: Central East-Knickerbocker	Transmission	0	0	0	0
	Generation	54	81	29	220
	Energy Efficiency	142	212	77	574
	Demand Response	122	182	66	493
Study 3: Volney Scriba	Transmission	0	0	0	0
	Generation	54	81	29	220
	Energy Efficiency	36	54	19	145
	Demand Response	30	44	16	120

31 Load Payments and Generator Payments are Tariff-defined additional metrics. The NYCA Load Payment and Export Payment values provide a breakdown of Load Payments by internal and external loads. The NYCA Generator Payment and Import Payment provide a breakdown of Generator Payments by internal and external generators.

Figure 50: Cumulative ICAP Impact ($2019M)

Study	Solution	ICAP Saving ($2019M) V1	ICAP Saving ($2019M) V2
Study 1: Central East	Transmission	0	0
	Generation	66	524
	Energy Efficiency	173	1,345
	Demand Response	149	1,158
Study 2: Central East-Knickerbocker	Transmission	0	0
	Generation	66	524
	Energy Efficiency	173	1,345
	Demand Response	149	1,158
Study 3: Volney Scriba	Transmission	0	0
	Generation	66	524
	Energy Efficiency	44	347
	Demand Response	36	288

The 10-year changes in total New York emissions resulting from the application of generic solutions are reported in Figure 51 below. The Base Case 10-year emission totals for NYCA are: CO_2 = 321,297 thousand-tons, SO_2 = 16,791 tons and NO_X = 118,674 tons. The study results reveal that all of the generic solutions impact emissions by less than 4% for CO_2 emissions. Energy efficiency had the most significant impact with reductions in the 1.6%-3.5% range. Generation solutions slightly increased the CO_2 emissions in the range of 0.4% - 0.5% due an increase in New York generation and an associated decrease in imports. Demand response had reductions of less than 0.1% in CO_2 emissions. SO_2 emission impacts ranged from an increase of 13% for the Study 2 transmission solution to a reduction of 1.8% for the Study 3 generation solution. The NO_X emission impacts ranged from an increase of 6.2% for the Study 1 generation solution to a reduction of 3.4% for the energy efficiency solution in Studies 1 and 2.

Figure 51: Ten-Year Change in NYCA SO_2, CO_2, and NO_X Emissions

Study	Solution	SO_2 Tons	SO_2 Cost ($2019M)	CO_2 1000 Tons	CO_2 Cost ($2019M)	NOx Tons	NOx Cost ($2019M)
TRANSMISSION SOLUTIONS							
Study 1: Central East	Edic-New Scotland	2,071	$0	455	$3	381	($0)
Study 2: Central East-Knickerbocker	Edic-New Scotland-Knickerbocker	2,189	$0	650	$4	465	($0)
Study 3: Volney Scriba	Volney-Scriba	203	$0	163	$1	(387)	($0)
GENERATION SOLUTIONS							
Study 1: Central East	New Scotland	615	$0	1,319	$8	738	$0
Study 2: Central East-Knickerbocker	Pleasant Valley	563	$0	1,149	$7	462	$0
Study 3: Volney Scriba	Volney	(303)	($0)	1,718	$10	632	($0)
DEMAND RESPONSE SOLUTIONS							
Study 1: Central East	F(100) G(100) J(200)	6	$0	(173)	($1)	(221)	($0)
Study 2: Central East-Knickerbocker	F(100) G(100) J(200)	6	$0	(173)	($1)	(221)	($0)
Study 3: Volney Scriba	F(100) G(100)	(52)	($0)	(77)	($0)	(66)	($0)
ENERGY EFFICIENCY SOLUTIONS							
Study 1: Central East	F(100) G(100) J(200)	(153)	($0)	(11,177)	($61)	(4,043)	($0)
Study 2: Central East-Knickerbocker	F(100) G(100) J(200)	(153)	($0)	(11,177)	($61)	(4,043)	($0)
Study 3: Volney Scriba	F(100) G(100)	(14)	($0)	(5,234)	($29)	(1,567)	($0)

Base Case Scenario Analysis

Scenario analysis is performed to explore the impact on congestion associated with variables to the Base Case. Since this is an economic study and not a reliability analysis, these scenarios focus upon factors that impact the magnitude of congestion across constrained elements.

A forecast of transmission congestion is impacted by many variables for which the future values are uncertain. Scenario analyses are methods of identifying the relative impact of pertinent variables on the magnitude of congestion costs. The CARIS scenarios were presented to the Electric System Planning Working Group (ESPWG) and modified based upon the input received and the availability of NYISO resources. The simulations were conducted for the horizon year 2028 for fuel price and load forecast scenarios.

Scenario 1: Higher Load Forecast

This scenario examined the impact of a higher load forecast on the cost of congestion. The Higher Load Forecast assumes higher penetration of electric vehicles as compared to the Baseline forecast in the 2019 Gold Book and partial electrification of space heating. While the 2019 Gold Book reflects a statewide adoption of around 1.2 million light-duty vehicles by 2028, this forecast assumes around 2 million. Rising penetration of heat-pumps is projected to raise energy usage for space-heating by around 35%. With all other assumptions being the same as the Baseline forecast, the combination of these two factors imply that the annual NYCA energy forecast for 2028 will be 2.7% higher than the 2019 Gold Book forecast. The forecasted figures by NYCA Load Zone for the Higher Load Forecast are presented in Appendix K.

Scenario 2: Lower Load Forecast

This scenario examined the impact of a lower load forecast on the cost of congestion. The Lower Load Forecast is based on greater impacts attributable to energy efficiency and behind-the-meter photovoltaic installations, as compared to the Baseline forecast in the 2019 Gold Book. The energy efficiency impacts incorporated in the forecast reflect the attainment of targets delineated in the Climate Leadership & Community Protection Act and the NYSERDA "New Efficiency" white paper[32] implying incremental savings of 30,000 GWh by 2025 above what was achieved through 2014, plus approximately 2,000 GWh per year over 2026-28. While the Baseline forecast reflects the installation of just over 4,000 MW of solar PV capacity by 2028, the Lower Load Forecast assumes a level 75% higher than that. With all other assumptions being the same as in the case of the Baseline forecast, the combination of these two factors imply that the annual NYCA energy forecast will be

32 https://www.nyserda.ny.gov/About/Publications/New-Efficiency

over 16% lower in 2028. The forecasted loads by NYCA Load Zone for the Lower Load Forecast are presented in Appendix K.

Scenario 3: Higher Natural Gas Prices

This scenario examines congestion costs when natural gas prices are projected to be higher than in the Base Case. In this scenario, the NYISO utilized the high-range gas price forecast provided by the EIA in its 2019 Annual Energy Outlook. Consequently, as compared to the Base Case, the high natural gas price case uses prices approximately 31% higher for the NYCA.

Scenario 4: Lower Natural Gas Prices

This scenario examines congestion costs when natural gas prices are projected to be lower than in the Base Case. In this scenario, the NYISO utilized the low-range gas price forecast provided by the EIA in its 2019 Annual Energy Outlook. Consequently, as compared to the Base Case, the low natural gas price case uses prices around 13% lower for the NYCA. Figure 52 presents the impact of four scenarios selected for study. Those impacts are expressed as the change in congestion costs between the Base Case and the scenario case.

Figure 52: Comparison of Base Case and Scenario Cases, 2028 (nominal $M)

Demand Congestion ($M)	High Load	Low Load	High Natural Gas	Low Natural Gas
CENTRAL EAST	(56)	26	145	(52)
DUNWOODIE TO LONG ISLAND	14	(2)	10	(3)
CHESTR SHOEMAKR	0	0	0	0
PACKARD 115 NIAGBLVD 115	(0)	(0)	(0)	(0)
DUNWOODIE MOTTHAVEN	(3)	(10)	10	(1)
GREENWOOD	(3)	(8)	4	(1)
N.WAV115 LOUNS 115	(1)	4	(11)	3
VOLNEY SCRIBA	(0)	(6)	(1)	(1)
NORTHPORT PILGRIM	(1)	(4)	(3)	1
EGRDNCTY 138 VALLYSTR 138 1	2	(3)	2	(1)
FERND 115 W.WDB 115	0	(2)	1	(1)
NIAGARA PACKARD	0	0	0	0
CE-NSL-KB	(61)	21	146	(53)

Figure 53 below presents a summary of how each of the three transmission groupings chosen for the Base Case study is affected by each of the scenarios for 2028. Figure 54 presents the percentage impact on demand$ congestion for each of the scenarios for each of the constraints. As shown, among the scenarios studied, the level of natural gas prices continues to be positively correlated with congestion cost as gas prices directly drive the level of price separation between Downstate and Upstate New York.

Figure 53: Impact on Demand$ Congestion ($2019M)

Constraints	Scenarios: Change in 2028 Demand$ Congestion from Base Case ($2019M)			
	High Load Forecast	Low Load Forecast	High Natural Gas Prices	Low Natural Gas Prices
Central East	(32)	14	81	(29)
Central East-Knickerbocker	(34)	12	82	(29)
Volney-Scriba	(0)	0	(1)	(0)

Figure 54: Impact on Demand$ Congestion (%)

Constraints	Scenarios: Change in 2028 Demand$ Congestion from Base Case (%)			
	High Load Forecast	Low Load Forecast	High Natural Gas Prices	Low Natural Gas Prices
Central East	-34%	15%	87%	-31%
Central East-Knickerbocker	-36%	12%	85%	-31%
Volney-Scriba	-3%	0%	-16%	-8%

Figure 55 through Figure 57 show the congestion impact results of the four scenarios performed. While the figure above shows the congestion impact from the scenarios for each of the most congested constraints, the figures below separately show how each of the three transmission groupings chosen for study are affected by each of the scenarios. In each case the bars represent the change in demand$ congestion between the Base Case and the scenario case.

Figure 55: Scenario Impact on Central East Congestion

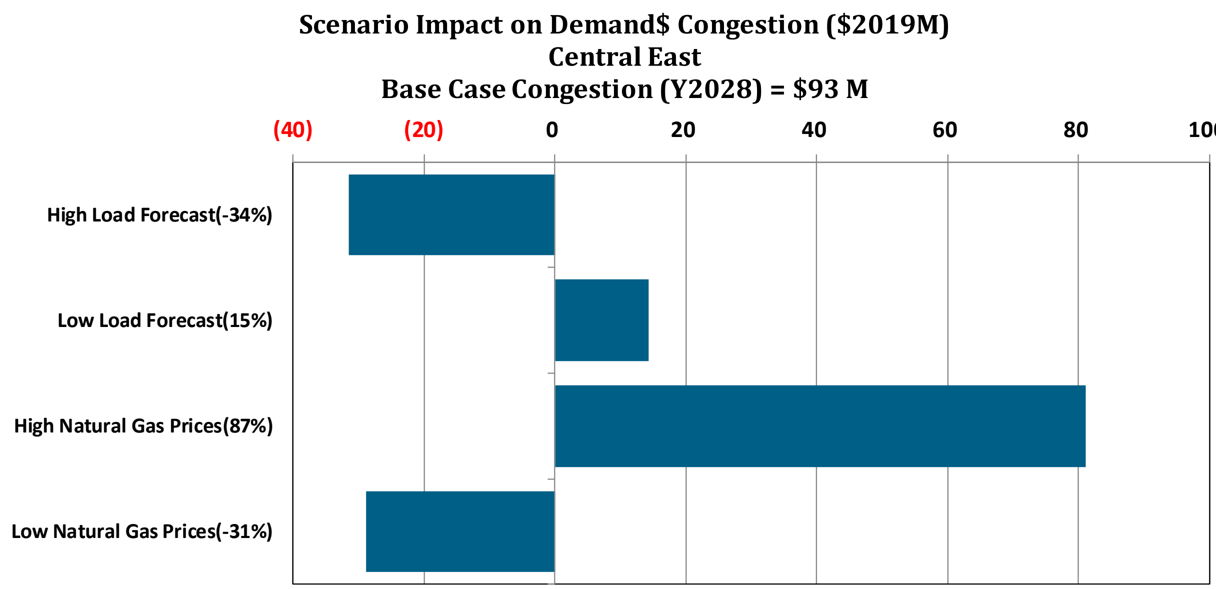


Figure 56: Scenario Impact on Central East - Knickerbocker Congestion

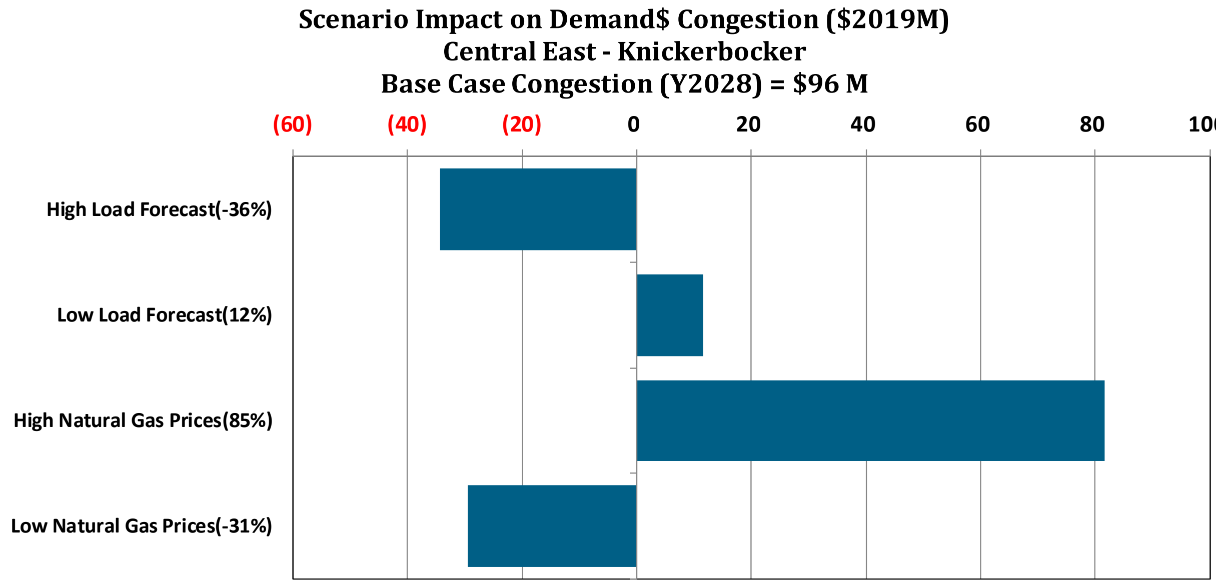
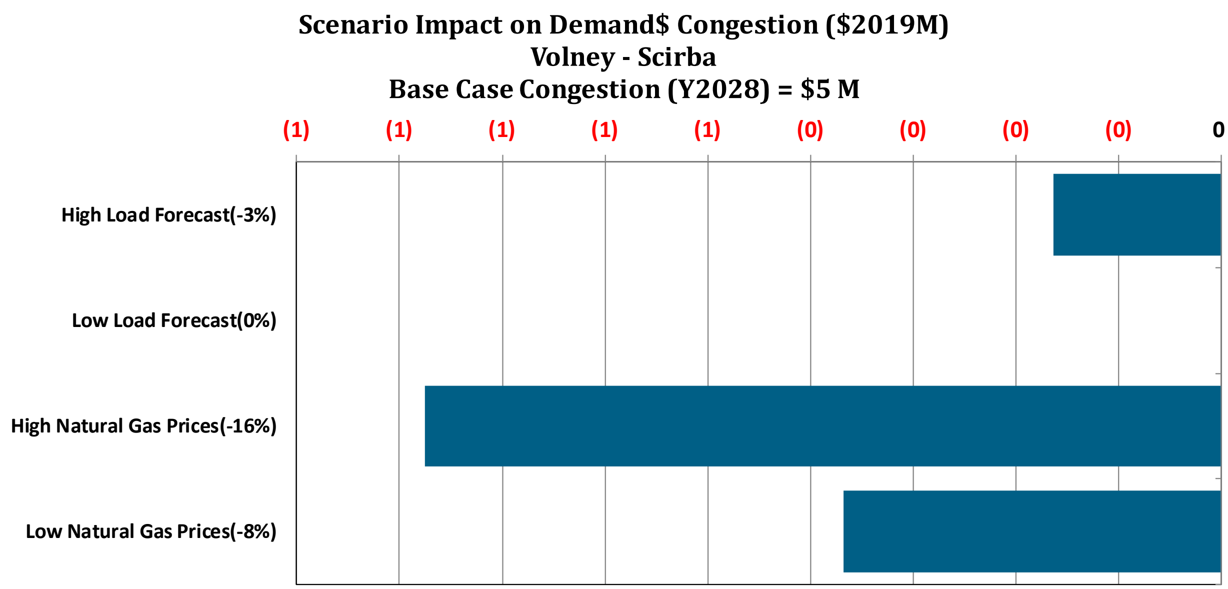


Figure 57: Scenario Impact on Volney - Scriba Congestion



6. “70x30” Scenario

The Climate Leadership and Community Protection Act (CLCPA) mandates that New York consumers be served by 70% renewable energy by 2030 (“70x30”). The CLCPA includes specific technology based targets for distributed solar (6,000 MW by 2025), storage (3,000 MW by 2030), and offshore wind (9,000 MW by 2035), and ultimately establishes that the electric sector will be emissions free by 2040.[33] Significant shifts are expected in both the demand and supply sides of the electric grid, and these changes will affect how the power system is currently planned and operated. To assist the evaluation of these impacts, the CARIS “70x30” scenario kicks off the assessment using production cost simulation tools to provide a “first look.” Focusing on the impact to energy flows, the NYISO modeled these policy targets for the year of 2030 in order to examine potential system constraints, generator curtailments, and other operational limitations. Subsequent studies, such as the 2020 Reliability Needs Assessment and the Climate Change Impact and Resilience Study, will build upon the findings of this CARIS scenario and provide further assessment of CLCPA implementation focusing on other aspects such as transmission security and resource adequacy.

Scope

The 70x30 Scenario consists of a series of sensitivity cases to study the impact of transmission constraints on a potential hypothetical renewable energy (RE) build out which otherwise may achieve a 70% renewable energy mix. This study does not define the formula to calculate the percentage of renewable energy relative to end-use energy, (*i.e.,* how to account for 70% renewable energy for the “70 by 30” target). The findings are intended to provide insight of the extent to which transmission constraints may prevent the delivery of renewable energy to New York consumers.

This scenario examines two potential renewable build-out levels for one assumed distribution pattern across the state, as well as multiple sensitivities to gauge the impact of specific drivers. The transmission constraints identified in this assessment are grouped into geographic pockets to pinpoint the specific areas within New York that could experience a generation bottleneck. The generation pockets identified in this study represent the interaction of existing transmission limits and RE generation with the assumed RE additions across both load levels.

33 https://www.nysenate.gov/legislation/bills/2019/s6599

As policymakers advance on the implementation plan of CLCPA, this NYISO assessment is intended to complement their efforts, and is not intended to define the specific steps that must be taken to achieve the policy goals. The boundaries of the generation pockets are for illustration purposes only, and this study does not provide solutions to relieve identified congestion in the pockets.

A number of key modeling assumptions and approaches may have major impact on the results. To help readers understand the scope of this assessment, considerations that are outside of the scope of this analysis are described below:

- **Percentage of renewable energy relative to end-use energy:** This study does not define the formula to calculate the percentage of renewable energy relative to end-use energy, (*i.e.,* how to account for 70% renewable energy for the "70 by 30" or "70x30" target). Rather, two potential renewable build-out levels were modeled for corresponding load levels to approximate the potential future resource mix in 2030.
- **Renewable energy modeling**

  I. **Siting and sizing**: New RE generators are modeled as interconnecting to 115 kV or greater bus voltage levels, guided by the NYISO Interconnection Queue. There are many alternative possible interconnection points, but this assessment assumes a single approach for sizing and siting of renewable generation. Impacts of siting generators at lower voltage buses are outside the scope of this study. Nevertheless, the NYISO recognizes that constraints at the distribution level will affect the downstream constraints, which may change the energy flows at the higher voltage level. The principle intent of this study is to analyze transmission bottlenecks and identify constrained pockets rather than define specific locations and capacity requirements.

  II. **Operational constraints:** Renewable resources are modeled such that their outputs can change on an hourly basis (as hourly resource modifiers or "HRM") with defined generation profiles for each unit. These generation profiles are synthetically generated resource shapes constructed using publicly available data and tools. This deterministic modeling approach will not capture the uncertainty involved with particular renewable resources. Since the lowest temporal resolution in MAPS is hourly, sub-hourly variation in RE generation is not captured in this study.

- **Constraint impact on curtailment:** These scenario cases secure additional 115 kV constraints obtained from a 'round trip analysis' performed using TARA software. Securing additional contingencies on lower voltage lines and the addition of RE generation results in increases and shifts in the congestion patterns and curtailment of RE generation. Identifying the relationship between specific constraints and the resulting curtailment impacts are beyond the scope of this study. The local transmission system constraints identified in this assessment do not equate to the necessity of upgrading these facilities one by one. There are a number of options to expand the transmission system at the bulk power level and/or at lower voltage levels that could efficiently address the congestion and the curtailment of RE generation.
- **Transmission system modeling:** This scenario is not an interconnection level assessment of the RE buildouts, and does not review detailed engineering requirements, such as the impacts from N-1-1 contingencies, voltage or stability impacts, capacity deliverability, or impact to the New York system reserve margin. All transmission facilities are assumed in-service, and unscheduled forced outages of transmission facilities are not modeled. Due to software limitations, the impacts of outages on congestion are not captured in this study; therefore congestion and curtailment amounts from this analysis are underestimated.
- **Fossil fuel-fired generator modeling:** The modeling of fossil fuel-fired resources in MAPS will commit and dispatch generation in order to: (i) serve load in the absence of sufficient renewable resources, (ii) meet locational reserve requirements, (iii) meet Local Reliability Rules, (iv) serve steam contracts, or (v) reflect operational limitations such as minimum generation levels and minimum generation runtime. The inherent modeling of fossil fuel-fired resources in MAPS does not include: (i) ramp rates and real-time sub-hourly variations, (ii) energy and ancillary service co-optimization; and (iii) fuel availability or gas system constraints. In addition, while regular maintenance outages are included in the model, unscheduled forced outages are not considered.
- **External area representation:** As the neighboring regions develop their own plans to achieve higher renewable generation penetration, those regions' demand, generation supply, and transmission system may change. At the time of this report, the plans for NYISO's neighboring regions are taking shape. Due to lack of detailed information, the external area representation remains consistent with the Base Case. If the neighboring

areas increase their renewable generation, it's possible that the congestion and curtailment amounts in the New York system from this analysis are underestimated.

- **Market bidding:** Unlike the Day Ahead Market, GE-MAPS did not simulate the following: (a) virtual bidding; (c) price-capped load; (d) generation and demand bid price; (e) Bid Production Cost Guarantee payments. Similar to the results from Base Case and Scenarios, congestion costs are likely underestimated in the 70x30 scenario.
- **COVID-19 impacts:** Due to the rapidly evolving nature of the pandemic, the impacts to the load forecast and other economic indicators are difficult to predict, and are not included in this scenario.

Methodology

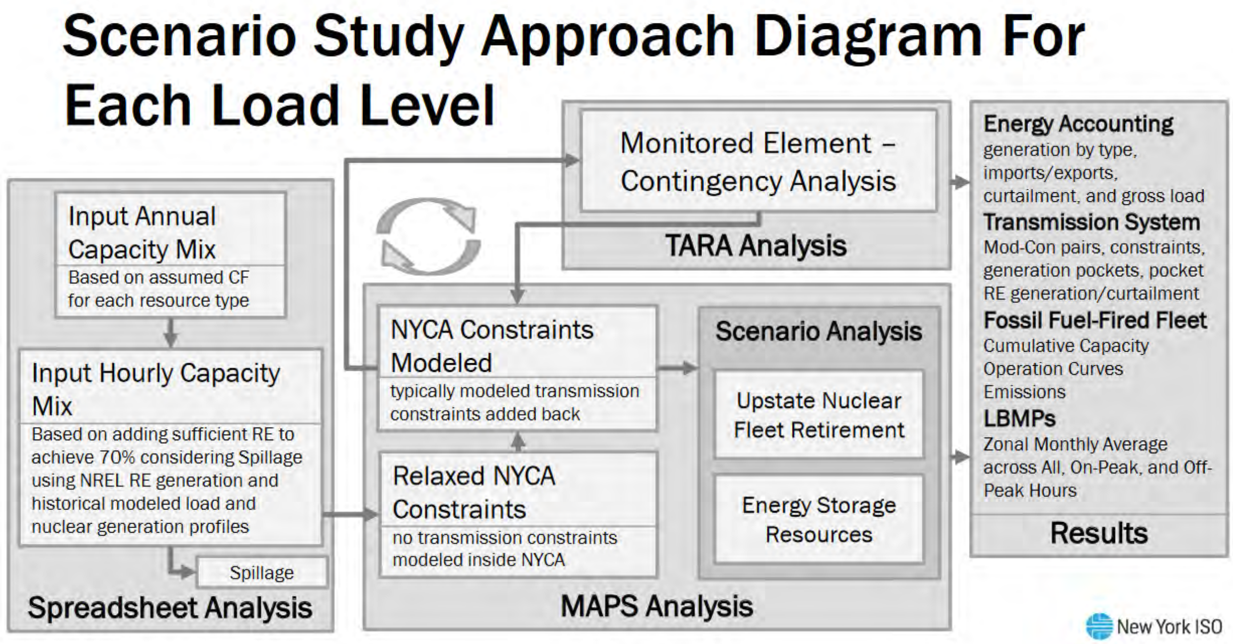
The 70x30 Scenario cases were developed using the following overall study approach, which is also shown graphically in Figure 58:

1. Develop assumptions for major drivers that may impact transmission congestion patterns:
    a. Develop a 70x30 Scenario Load forecast for comparison with the Baseline load forecast ("Base Load")
    b. Add renewable generation to approximate achievement of the 70% renewable energy target for each load forecast, considering renewable energy "spillage" (*i.e.,* generation exceeds load)
2. Evaluate system production under "relaxed" conditions:
    a. Model the resulting resource mix in GE-MAPS without internal NYCA transmission system constraints to establish a baseline for the system dispatch when there are no transmission constraints
3. Evaluate the impact of transmission constraints on renewable energy production for the assumed renewable resource mix:
    a. Identify transmission constraints that cause renewable curtailments (*i.e.,* renewable generation pockets)
    b. Quantify the magnitude and frequency of the curtailments for each assumed resource mix
4. Sensitivity analysis to understand impacts to system production and transmission constraints:
    a. Sensitivity analysis of retirement of the entire nuclear fleet

b. Sensitivity analysis of 3,000 MW of Energy Storage Resources (ESR)

c. Sensitivity analysis of reduced exports to neighboring regions

Figure 58: 70x30 Scenario Study Approach Process Flow Diagram



Utilizing the above approach at each load level, the NYISO developed the cases shown in Figure 59 as part of the 70x30 Scenario. Sensitivities at each load level/generation mix included the assumed retirement of the entire remaining Upstate nuclear generation fleet, and the inclusion of 3,000 MW of energy storage resources (ESR). All sensitivity cases, at both the Base Load and Scenario Load levels, assume that: (i) all coal generation is retired, and (ii) generic new gas turbine replacements will be added to address the potential resource deficiencies that may result following implementation of the Peaker Rule, as identified in the 2019-2028 Comprehensive Reliability Plan.

Figure 59: Summary of Sensitivities analyzed in the 70x30 Scenario

Case	Load	Relaxed/ Constrained	Nuclear Sensitivity	ESR Sensitivity
Base Case	Base Case	Constrained		
BaseLoad Relaxed	Base Load	Relaxed		
BaseLoad Constrained	Base Load	Constrained		
BaseLoad Constrained NuclearRetired	Base Load	Constrained	Nuclear Retired	
BaseLoad Constrained Storage PSH* Method	Base Load	Constrained		PSH Method
BaseLoad Constrained Storage HRM** Method	Base Load	Constrained		HRM Method
ScenarioLoad Relaxed	Scenario Load	Relaxed		
ScenarioLoad Constrained	Scenario Load	Constrained		
ScenarioLoad Constrained NuclearRetired	Scenario Load	Constrained	Nuclear Retired	
ScenarioLoad Constrained Storage PSH Method	Scenario Load	Constrained		PSH Method
ScenarioLoad Constrained Storage HRM Method	Scenario Load	Constrained		HRM Method

* Pumped Storage Hydro (PSH) Method
** Hourly Resource Modifier (HRM) Method

An additional sensitivity was performed to assess the impact on the assumed capability of neighboring regions to accept NYISO exports in the absence of explicitly modeled RE buildouts within these regions.

Transmission Constraint Screening

With the addition of large amounts of renewable capacity added throughout New York, the NYISO developed and performed a detailed hourly contingency screening analysis to capture new constraints/overloads that were not captured in the initial Base Case analysis. The hourly production cost simulation of GE-MAPS uses the transmission network model, and it is necessary to pre-define the monitor/contingency pairs in the simulation runs. This process involves creating multiple power flow cases with MAPS hourly results, and performing contingency screening analysis using TARA iteratively so that constraints caused by temporal factors, such as load shape and renewable generation, can be secured in successive MAPS runs.

Figure 60: Roundtrip MAPS/TARA Analysis

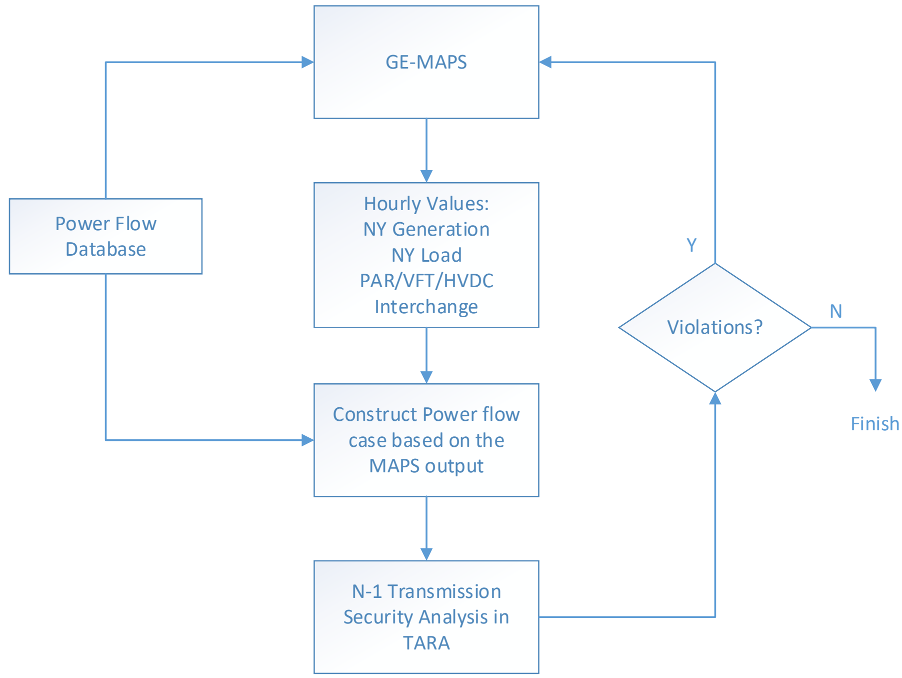


Figure 60 shows the flowchart for Roundtrip MAPS/TARA Analysis. This iterative analysis has three steps:

1. Start with the MAPS production cost run with constraints modeled in the Base Case. The resulting hourly MAPS output is utilized to construct power flow cases and solve in PSS/E using information including hourly NYCA zonal loads, hourly NYCA generation dispatches, and hourly NYCA interchange tie line flows.
2. Perform N-1 transmission security analysis on all created cases in TARA while monitoring NYCA facilities 115 kV and above, taking into account all bulk transmission system contingencies as well as local transmission system contingencies. Identify the resulting additional monitored facility/contingency pairs.
3. Add the reported monitored facility and contingency pairs from TARA analysis into the existing production cost database. Secure the expanded list of monitor facilities and contingency pairs in the successive runs.

MAPS output results iteratively interact with TARA analysis until all of the overloaded constraints as reported from TARA are exhaustively modeled within the production cost database.

Assumptions

Demand Forecast

In order to assess the impact of potential policies upon future load levels, an alternate additional zonal hourly forecast was developed for comparison to forecasted load levels in the 2019 Gold Book. The 70x30 Scenario Load forecast includes non-uniform distribution of energy efficiency and electrification (*e.g.*, space heating and vehicles) across the year and Zones in the NYCA. Figure 61 outlines the assumptions across four components of policies and technologies included in the Base Load and 70x30 Scenario Load forecasts. The 70x30 Scenario Load forecast was designed to incorporate state policies through 2030, while the Base Load forecast correspond to load levels in the CARIS Base Case and the 2019 Gold Book Baseline load forecasts for the year 2028 with modified BTM-PV forecast.

Figure 61: Base Load and 70x30 Scenario Load Forecast Assumption Details

Technology/Policy	Base Case Load Forecast	70x30 Scenario Load Forecast
Electric Vehicles	1.3 million Light-duty vehicles by 2030	2.2 million Light-duty vehicles by 2030
Space Heating Electrification	None	2015 estimate of 13,600 GWh in 2015 grows by 50% by 2030 for NYCA
Behind-the-Meter Photovoltaic	3,000 MWDC behind-the-meter by 2023	6,000 MWDC behind-the-meter by 2025
Energy Efficency	23,500 GWh of incremental savings by 2030 beyond the 11,000 GWh achieved by 2014	Additional 30,000 GWh* of savings by 2025 beyond 2014 achievements plus around 2,000 GWh/year** for 2026-30

* This target is based on the retail sales of investor-owned utilities implied by the 2015 Gold Book forecast for the year 2025.

** This is based on the targets expressed in the Clean Energy Fund documents.

Salient differences in assumptions of Base Load vs. 70x30 Scenario Load forecasts include:

Electric Vehicles Impact: While the Base Load forecast assumes that electrification of transportation will lead to 1.3 million light-duty vehicles and a modest penetration of medium- and heavy-duty vehicles including trucks, transit buses and school buses, the 70x30 Scenario assumes 2.2 million light-duty vehicles plus a relatively higher penetration of medium- and heavy-duty vehicles.

Space Heating Electrification Impact: The Base Load forecast assumes an electric-heating load consistent with current usage – *i.e.*, that the overwhelming bulk of heating-related energy consumption is due to resistance heating in relatively older housing stock. However, the 70x30 Scenario models, which include a growing level of electrification of space heating due to the adoption of heat-pumps (both air-source and ground-source), imply an annual electric heating load that is 50% higher than what it was in 2015 – approximately 19,600 GWh. This approach assumes that current resistance heating will be replaced with the more efficient electric heat-pumps.

Energy Efficiency Impact: Starting with a cumulative impact of 11,000 GWh through 2014, the Base Load forecast assumes that utility and New York State-guided initiatives will add another 23,500 GWh of savings through 2030. The 70x30 Scenario Load forecast, on the other hand, adopts energy efficiency targets outlined under the CLCPA that amount to an additional 45,700 GWh beyond what was achieved through 2014 – *i.e.*, a total of 56,700 GWh through 2030.

Behind-the-Meter Photovoltaic (BTM-PV) Impact: Both the Base Load and the 70x30 Scenario Load forecasts adopt the same BTM-PV target, 6,000 MWDC installed by 2030.

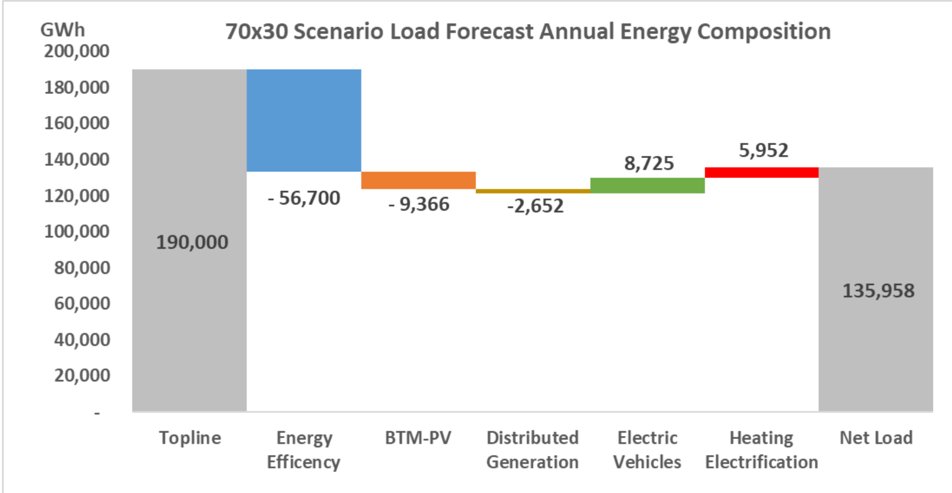
Figure 62: 70x30 Scenario Load and Base Load Forecasts Metrics

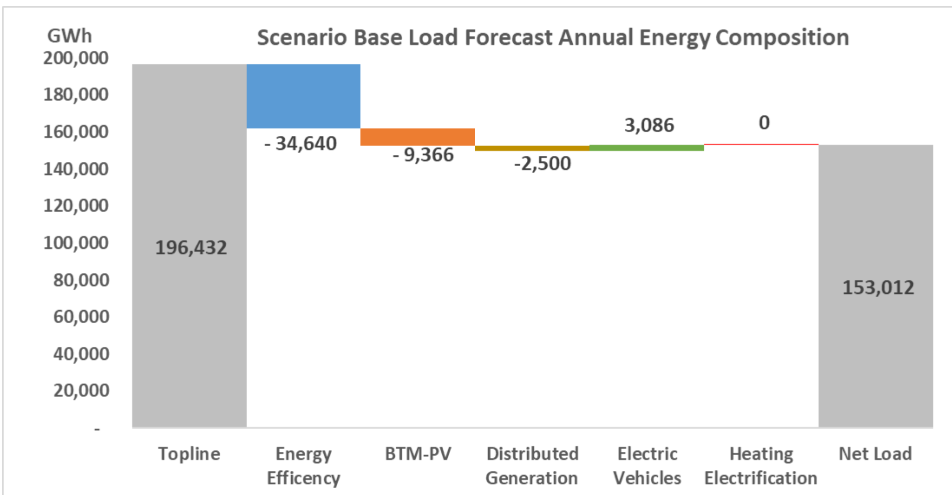
Net Load Energy (GWh)	A	B	C	D	E	F	G	H	I	J	K	NYCA
Base Load Forecast	14,590	9,695	15,394	5,337	7,095	11,312	9,544	2,807	5,881	51,749	19,608	153,012
Scenario Load Forecast	13,034	7,757	12,626	5,101	5,694	9,654	7,911	2,848	5,952	46,354	19,026	135,958

Figure 62 shows the zonal Annual Energy net load forecasts for the Base Load and the 70x30 Scenario Load forecasts. Comparing to the 2019 Gold Book Baseline forecast, the salient aspects of the 70x30 Scenario Load forecast are: (a) a lower summer peak largely attributable to efficiency gains in cooling technology, (b) a relatively higher winter peak due to electrification of space heating and transportation, and (c) a noticeably lower annual energy usage due to the considerable impact of energy efficiency that more than offsets the increased load due to electrification. Several Upstate Zones become winter peaking by 2030 in the 70x30 Scenario Load forecast even as the state remains summer peaking. Net load includes the impacts of BTM-PV.

Figure 63 exhibits the breakdown of the annual NYCA energy usage in the two forecasts across broad categories impacted by policy, and highlights their relative magnitudes. While the impact of BTM-PV is the same in both cases, the lower energy usage in the 70x30 Scenario Load forecast is explained by the reductive effect of aggressive energy efficiency initiatives despite the 14,600 GWh increase in load due to electrification of space heating and transportation.

Figure 63: 70x30 Scenario and Scenario Base Load Forecasts Energy Component Breakdown





In summary, the demand in 2030 could be reduced by 11% (135,958 GWh) compared to business as usual (153,012 GWh) due to the impact of energy efficiency. However, the long-term impact of CLCPA in 2040 and 2050 is likely to increase system demand due to electrification. NYISO continues to monitor and provide long-term forecast data, which is contained in the NYISO's annual Gold Book.

Transmission Modeling

The transmission model is based on the Base Case, and includes the transmission projects listed below:

1. Empire State Line Project (Western New York Public Policy project),
2. AC Transmission Public Policy projects (Segments A and B), and
3. NYPA rebuild of Moses-Adirondack 230 kV circuits.

The NYISO used normal ratings to secure 115 kV facilities secured in the production cost database for (N-0) and short-term emergency (STE) ratings to secure for (N-1) constraints with a 10 MW Capacity Resource Margin assumed. This representation is consistent with the current operational practice on existing 115 kV facilities secured in the NYISO's market model.

The starting point of the contingencies utilized in the study are from 2019 NERC TPL-001-4 planning assessments. Considering the significant resource shift assumed in the 70x30 Scenario, system conditions will be different and new system constraints could arise. Approximately 1,000 new contingencies were identified in the MAPS/TARA contingency screening process, and were used in the GE-MAPS hourly simulations for the 70x30 Scenario.

Renewable Energy Generation Modeling

A principle component of the 70x30 Scenario is the development of the renewable energy resource capacity mix assumed in the modeled cases. Assumptions regarding the resource technology mix, the siting locations, and the hourly profiles utilized in these scenario cases are discussed in this section.

CLCPA resource targets include 6,000 MW of BTM-PV by 2025, 3,000 MW of ESR by 2030, and 9,000 MW of off shore wind (OSW) by 2035. For the 70x30 Scenario the assumed capacity of OSW (6,098 MW) and BTM-PV (7,542 MW) are informed by the CLCPA targets. A separate sensitivity was performed to evaluate the impact of ESRs. Land-based wind (LBW) and utility-scale solar (UPV) resources were added to reach a nominal 70% RE capacity mix using the approach described in this section.

An additional assumption in the 70x30 Scenario cases relates to the direct importation of hydroelectric generation into NYCA. These cases assume that Hydro-Quebec imports count as renewable energy towards the 70% CLCPA target. In addition, an assumed generic incremental HVDC connection of 1,310 MW between Hydro-Quebec and New York City is included in these cases and also counts as RE towards the 70% target. The dispatch of the generic HVDC facility was modeled by scaling the existing HQ dispatch profile. Without this assumption, the amount of RE capacity placed in New York would increase due to two major factors: 1) the hydro RE import has a relatively high capacity factor compared to land-based wind (LBW) or utility-scale solar PV (UPV), and 2) the import is assumed to inject into New York City without going through in-state transmission constraints. An estimated combination of 6,000 MW of LBW and UPV or 3,000 MW of solely OSW, could replace this incremental HVDC injection, though either alternative would likely increase curtailment and congestion.

The assumed gap in RE generation and the 70% target were satisfied with equal amounts of added UPV and LBW. This process was initially performed on an annual energy basis, using nominal fleet capacity factor assumptions to estimate expected energy output of the assumed RE resources. The results of the initial annual calculation are shown in Figure 64, where percentage of renewable energy (%RE) is the ratio of RE to gross load.

Figure 64: Initial Annual Capacity Mix at Scenario Load

	OSW	LBW	UPV	BTM-PV	Hydro	Hydro Imports	RE	Net Load	Gross Load	%RE
Base Case Capacity (MW)	-	2,212	77	4,011						
Additional Capacity (MW)	6,098	1,641	6,345	3,531						
2030 Capacity (MW)	6,098	3,853	6,422	7,542						
2030 Capacity Factor (%)	44%	30%	18%	14%						
2030 Calculated Energy (GWh)	23,344	10,126	10,126	9,366	28,832	19,941	101,735	135,970	145,335	70%

However, recognizing the disparity in the hourly production of renewable energy and the NYCA load level, the NYISO developed an additional step to examine the 70% requirement on an hourly basis, prior to modeling in MAPS. The hourly approach considers the impact of assumed nuclear generation and input RE profiles in relation to the hourly load level to define the RE capacity mix to include in these scenario cases.

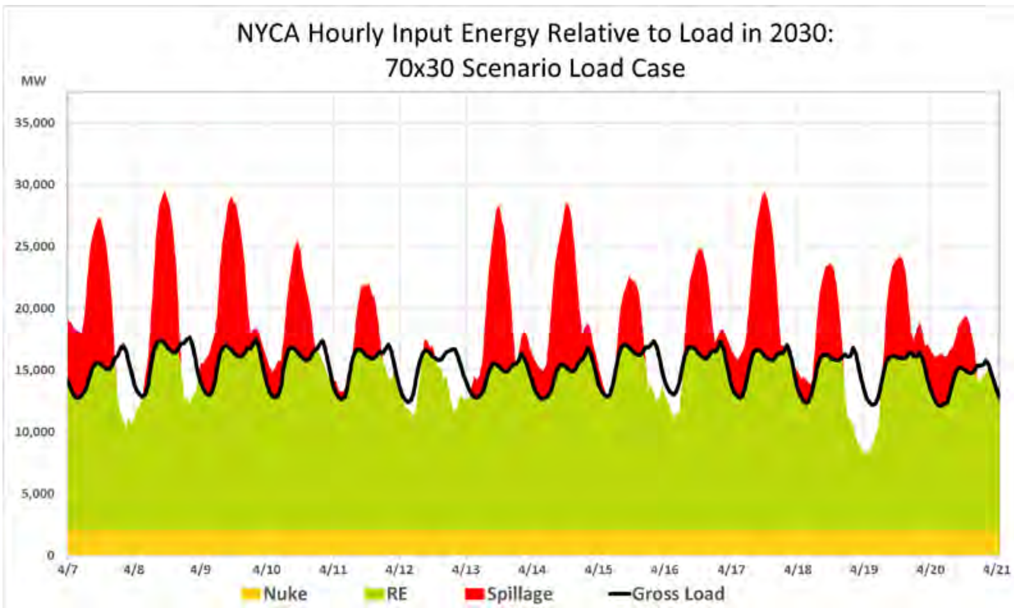
Hourly input renewable energy production profiles were primarily obtained from databases created for the purpose of modeling RE generation in forward-looking grid modeling studies. BTM-PV profiles have been created to model distributed solar resources in the CARIS Base Case. In the 70x30 Scenario cases, the Base Case BTM-PV shapes were scaled to match the assumed annual output. More information on the Base Case modeling assumptions are presented elsewhere in this report. UPV shapes for New York were obtained from NREL's Solar Power Data for Integration Studies[34] database by aggregating five-minute "actual" data to the hourly level.

LBW and OSW profiles relevant to potential sites within New York and offshore in the New York Bight in the Atlantic Ocean were obtained via NREL's Wind Toolkit.[35] Five-minute production profiles were obtained across hundreds of individual sites in the database and aggregated to the hourly level. Sites were geographically aggregated to the county and/or zonal level for ease of modeling LBW additions. Offshore NREL wind sites were clustered into groups to represent generic OSW project level additions as well as to explicitly represent currently contracted OSW projects (*i.e.*, the South Fork, Sunrise, and Empire OSW projects).

34 https://www.nrel.gov/grid/solar-power-data.html
35 https://www.nrel.gov/grid/wind-toolkit.html

Spillage occurs when there is more generation than load within the New York Control Area, and could take the form of an export to a neighboring system or curtailment of the renewable resource. Figure 65 displays an example of a two-week period to illustrate the hourly approach. Comparison of the input nuclear generation and renewable energy profiles to the hourly load on the NYCA level allows the over-generation of renewables, or "spillage," to be identified. Final capacity mixes were defined when annual aggregate RE production (*i.e.*, the green area in Figure 65) represents 70% of the area under the gross load line.

Figure 65: Hourly Input Approach Illustration



The assumption that the UPV and LBW would have nominally equal amounts of input RE persisted in the hourly analysis as well, and resulted in the annual energy balance shown in Figure 66, including the calculated spillage. The values in this table are derived from simulating the zonal RE generation mix using hourly input profiles and comparing the generation profiles to the load profile on an hourly basis within a simple spreadsheet calculation. The percentage of renewable energy is calculated as the ratio of total annual renewable energy input (RE_{input}) less spillage compared to the total annual gross load. Here, gross load includes the load served by BTM-PV.

Figure 66: Hourly Input Approach Energy Balance Results[36]

Annual Energy (GWh)	OSW	LBW	UPV	BTM-PV	Hydro	Hydro Imports	RE_{Input}	Spillage	Gross Load	%RE
Scenario Load	23,359	16,874	16,651	9,366	28,702	19,941	114,892	12,605	145,324	70%
Base Load	23,359	23,233	23,264	9,366	28,702	19,941	127,864	13,524	162,378	70%

36 Including the additional generic 1,310 MW HVDC from HQ

The corresponding capacities are developed by incorporating assumptions related to the zonal capacity distribution of each RE technology type. Total assumed OSW capacity is split between Zones J and K on a load (energy) ratio share. The BTM-PV is represented as a scaling of the assumed BTM-PV capacity distribution within the Base Case. OSW and BTM-PV are consistently modeled at both load levels as shown in Figure 66 and Figure 68.

The assumed zonal capacity distribution of recently awarded contracts resulting from NYSERDA administered solicitations for Tier 1 RECs is leveraged to distribute LBW and UPV capacity on a zonal basis. Figure 67 displays the assumed capacity distribution of incremental utility resources as a percentage of the full NYCA MW addition for both UPV and LBW.

Figure 67: Assumed Zonal Capacity Distribution for Incremental Land Based Bulk Resources

Nameplate Capacity Distribution												
	A	B	C	D	E	F	G	H	I	J	K	NYCA
UPV	27%	3%	20%	0%	10%	25%	15%	0%	0%	0%	0%	100%
LBW	30%	5%	30%	15%	20%	0%	0%	0%	0%	0%	0%	100%

Combining the assumed total LBW and UPV energy from Figure 66 with the assumed zonal capacity distribution (in Figure 67) and hourly RE profiles allows the final zonal capacity distribution for each RE generation type to be computed. The results of this tabulation are shown in Figure 68 as the total RE capacity at the Scenario Load and Base Load levels modeled in the 70x30 Scenario cases. Each RE capacity mix was modeled consistently across all scenario cases for the load levels identified. A total of nearly 31,000 MW of renewable generation is modeled within New York for the Scenario Load level, while a total of nearly 37,600 MW is modeled at the Base Load level.

Figure 68: Total Zonal Capacity of Renewable Generation in 70x30 Scenario Case at Two Load Levels Studied (MW)[37]

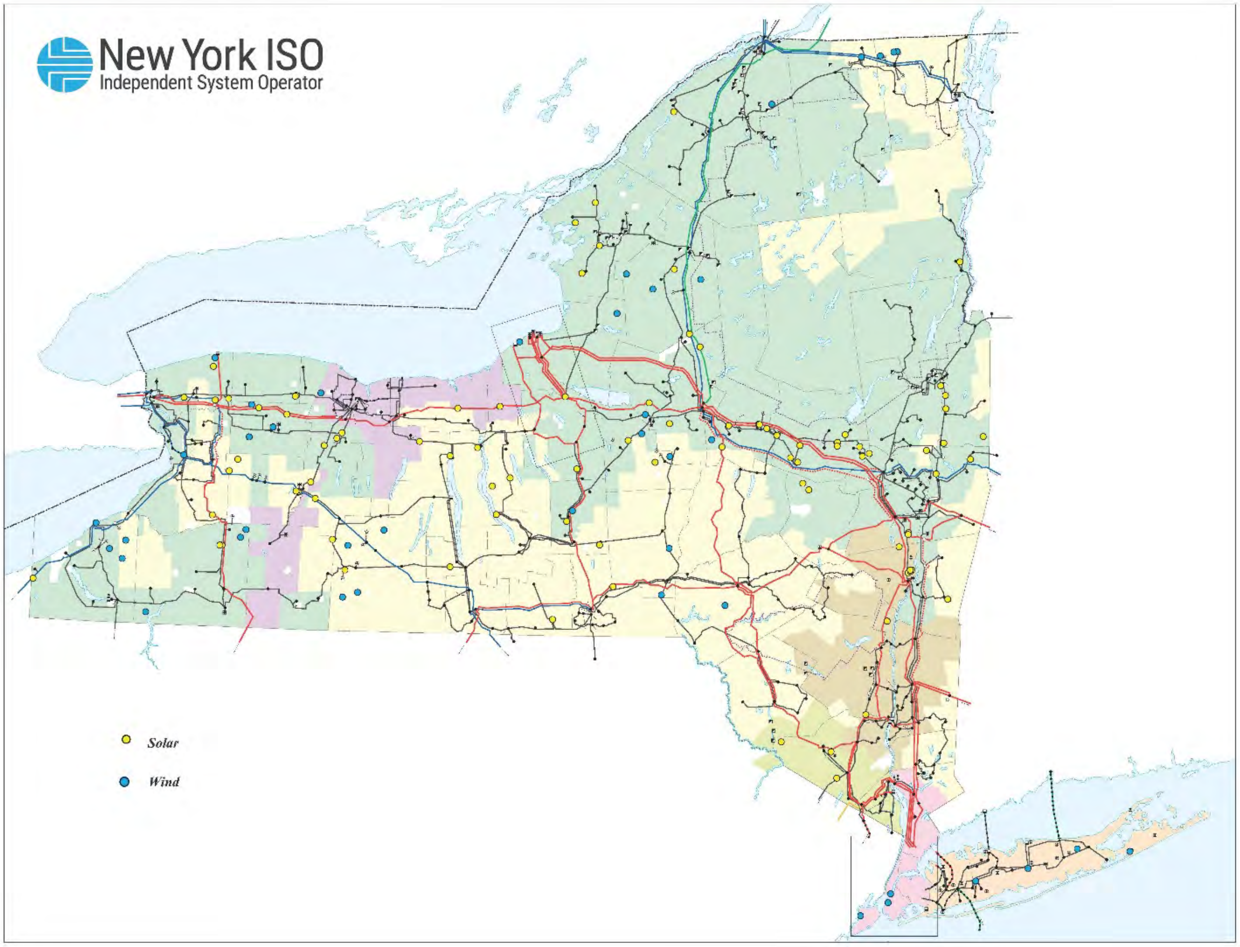
70x30 Scenario Load					Base Load				
2030 MW	**OSW**	**LBW**	**UPV**	**BTM-PV**	**2030 MW**	**OSW**	**LBW**	**UPV**	**BTM-PV**
A		1,640	3,162	995	**A**		2,286	4,432	995
B		207	361	298	**B**		314	505	298
C		1,765	1,972	836	**C**		2,411	2,765	836
D		1,383		76	**D**		1,762		76
E		1,482	1,247	901	**E**		2,000	1,747	901
F			2,563	1,131	**F**			3,592	1,131
G			1,450	961	**G**			2,032	961
H				89	**H**				89
I				130	**I**				130
J	4,320			950	**J**	4,320			950
K	1,778		77	1,176	**K**	1,778		77	1,176
NYCA	6,098	6,476	10,831	7,542	**NYCA**	6,098	8,772	15,150	7,542

Individual projects were located at over 110 sites in the MAPS model by utilizing project level information from the Interconnection Queue.[38] This approach preserves the capacity distribution by RE type within a Zone by distributing the total zonal capacity by type on a *pro-rata* basis to the Interconnection Queue project locations based on total zonal capacity in the Interconnection Queue. For projects that propose points of interconnection at new substations, the nearest existing substation was assumed as the point of interconnection in the scenario cases. The location and type of generators included in the capacity build out are shown in Figure 69.

[37] Not including the additional 1,310 MW generic HVDC from HQ.

[38] https://www.nyiso.com/documents/20142/11738080/11_70x30_RE_Buildout_BaseLoad_ESPWG_2020-04-06.xlsx/a4528988-44a6-573e-7525-36dd1559a2d1

Figure 69: 70x30 Scenario Renewable Buildout Map



Impacts of Transmission Constraints

To understand the impact of existing transmission limits on the delivery of higher levels of renewable energy, cases were first run with the NYCA internal transmission system limits "relaxed". This modeling approach is the equivalent of having infinite transmission capability within the NYCA, which provides an understanding of "ideal" system behavior. In the "constrained" cases the NYCA transmission limits are all reset to their values in the Base Case.

Comparison of Energy

Annual generation by type, net imports by neighboring control area, curtailment, and gross load output from each case in GWh are shown in Figure 70, as well as the comparison between the relaxed and constrained cases at the Scenario Load and Base Load levels.

Figure 70: Base, Relaxed, and Constrained Case Annual Energy Results

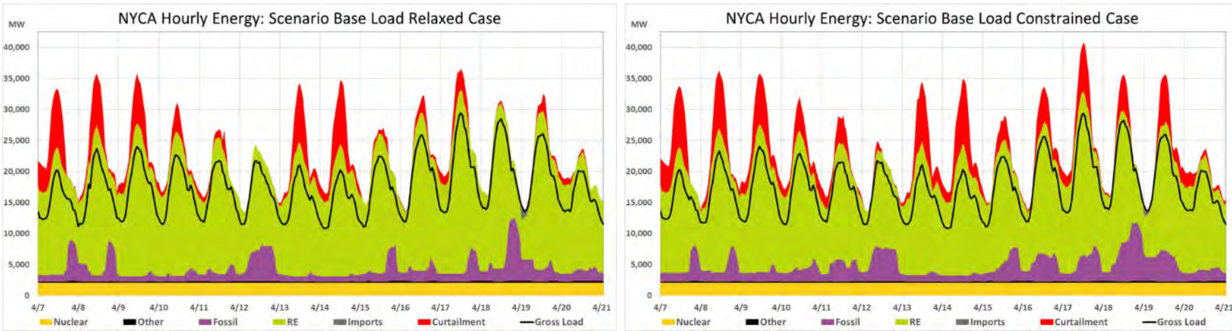
Energy (GWh)	Base Case	ScenarioLoad Relaxed	ScenarioLoad Constrained	BaseLoad Relaxed	BaseLoad Constrained
Nuclear	27,091	27,435	27,433	27,436	27,433
Other	2,368	2,164	2,110	2,158	2,102
Fossil	69,028	26,390	28,185	31,268	35,181
Hydro	28,832	28,082	28,050	27,974	28,020
Hydro Imports	11,564	19,803	19,775	19,780	19,769
LBW	5,038	13,960	13,290	19,243	17,117
OSW	-	22,775	21,625	22,656	21,592
UPV	115	14,764	12,666	21,782	17,982
BTM-PV	4,988	9,269	9,266	9,302	9,327
Pumped Storage	(447)	(878)	(822)	(930)	(868)
Storage	-	-	-	-	-
IESO Net Imports	(2,862)	(5,550)	(5,817)	(6,030)	(6,250)
ISONE Net Imports	(535)	(7,791)	(6,418)	(6,710)	(5,073)
PJM Net Imports	12,239	(5,479)	(4,446)	(5,996)	(4,528)
Renewable Generation	50,537	108,653	104,672	120,736	113,808
Curtailment	0	6,218	10,151	7,124	14,020
Non-Renewable Generation	98,488	55,990	57,728	60,861	64,717
GrossLoad	157,418	144,948	144,897	161,934	161,807

Relaxation of the transmission constraints results in reductions in fossil generation and curtailments with an increase in RE generation and net exports (*i.e.,* negative net imports). In order to examine the system condition more closely, four two-week periods across the annual hourly simulations were reviewed that are representative of combinations of RE generation and load levels:

- January: during winter peak load and low renewable generation period
- April: during spring low net load period (high renewable generation during low load)
- July: during summer peak load period
- October: during fall low load and low renewable generation period

A closer examination reveals that relaxing transmission constraints on an hourly basis mirrors the outcomes in the annual energy comparisons. Generally, the results are consistent across the seasons and are provided in the appendix for both load levels. Figure 71 displays NYCA generation output, curtailment, and gross load over a two-week period in early April in the relaxed and constrained cases at the Base Load level.

Figure 71: Base Load Relaxed and Constrained Cases Hourly Results across a Low Net Load Period



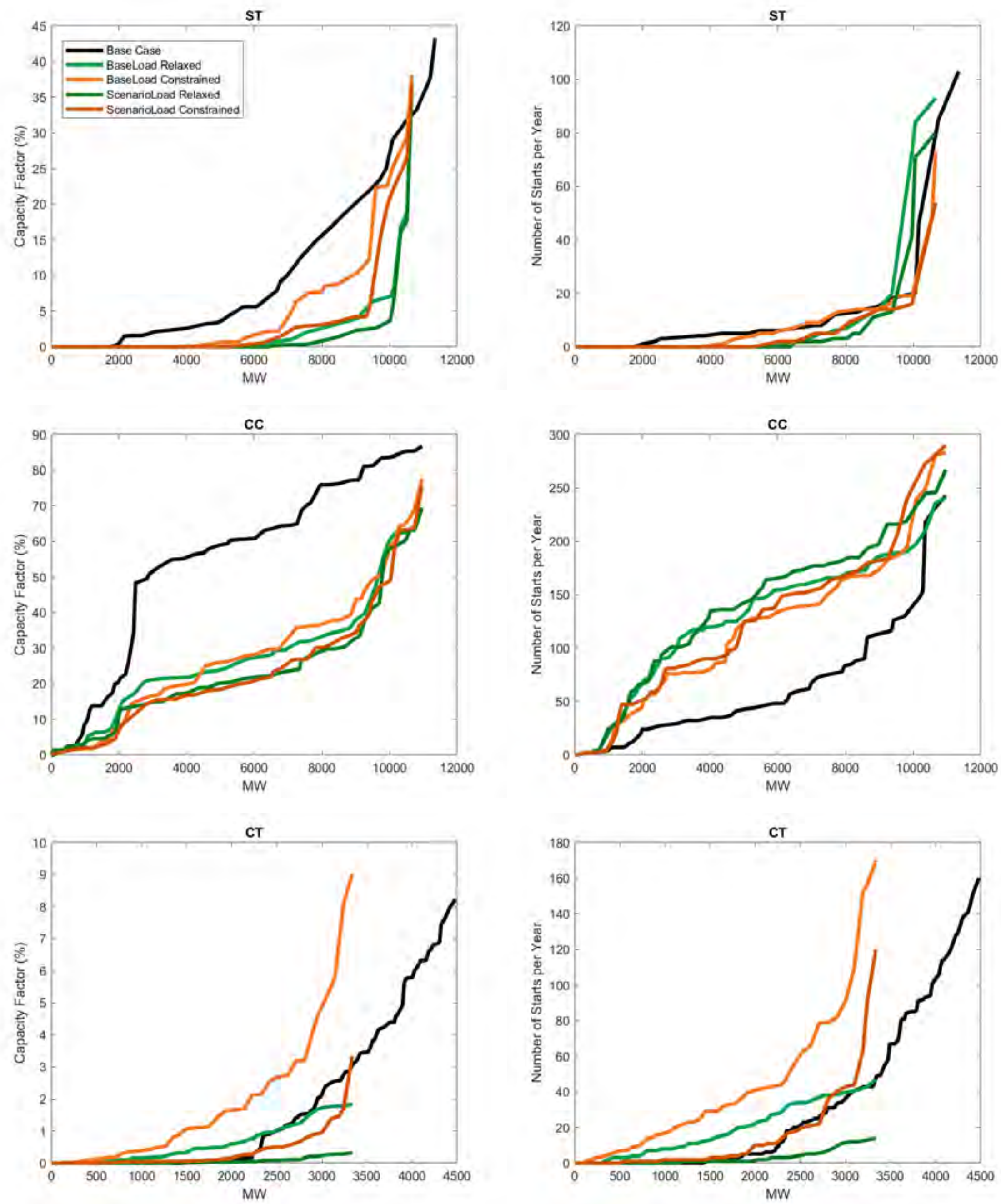
Comparison of Fossil Fleet Operations

The impact of increased RE, transmission system modeling assumptions, and differing load profiles could impact the operation of the fossil fuel-fired fleet. Cumulative capacity curves display the amount of capacity that operated at or below a given parameter value, as each point on the curve represents one unit's annual operation. To concisely illustrate independent operational aspects of fossil generator operations, the unit level annual capacity factors and number of unit starts are displayed in Figure 72.

With the substantial addition of intermittent renewable generation modeled in the scenario cases, output from the fossil fleet is lower in comparison to the Base Case, however in many cases the reduced output is accompanied by an increased number of starts indicating the need for a more flexible operating regimen. With lower load, as represented in the Scenario Load case, fossil output is lower compared to the higher Base Load case. The fossil fleet dispatch can also be highly dependent on transmission constraints. In particular, comparison of simple-cycle combustion turbine (CT) operation between the relaxed and constrained cases makes apparent that CTs may run more and start more often due to transmission constraints.

In short, the large amount of intermittent renewable energy additions will change the operations of the existing fossil fleet. It is likely that the units that are more flexible will be dispatched more often, while the units that are less so may not be dispatched as often or at all.

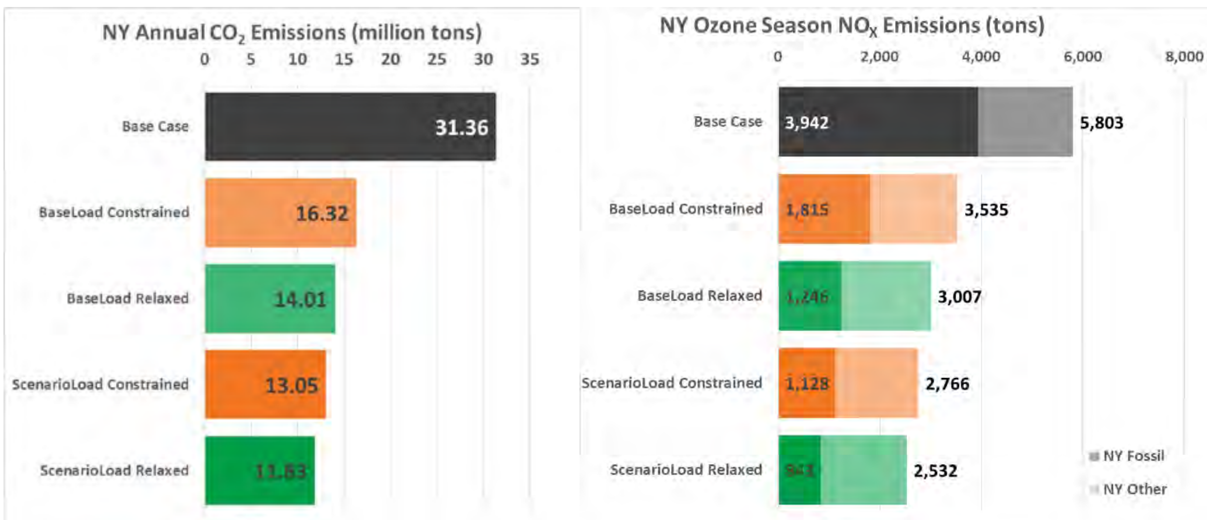
Figure 72: Base Load Relaxed and Constrained Cases Fossil Fleet Cumulative Capacity Curves



Comparison of Emissions

Carbon dioxide (CO_2) emissions decrease significantly across the scenario cases due to lower loads, increased RE output, and corresponding decreased fossil fleet operations relative to the Base Case, as depicted in Figure 73. The higher loads in the Base Load cases relative to the Scenario Load cases also result in comparatively higher emission levels. The modest emission reductions observed between the constrained and relaxed cases can partially be explained by the relative increase in exports in the relaxed cases which are partially met with increased fossil generation in state. The emissions of ozone season NO_X are split between fossil and other generators by type. Here and elsewhere in the report the term "Other" refers to methane (biogas), refuse (solid waste), and wood fuel-fired generators. As no changes in assumptions were made for this fleet of generators in the scenario cases, their emissions are similar across all cases including the Base Case. These "Other" associated NO_X emissions become a significant portion of projected ozone season NO_X emissions as the fossil emissions decrease.

Figure 73: Base Load Relaxed and Constrained Cases CO_2 and Ozone Season NO_X Emissions Projections



The assessment shows that emissions could be significantly reduced due to the RE generation additions. However, the long-term impact and achievement of economy-wide emission reductions of 40% by 2030 and 85% by 2050, and the emission-free power sector requirement in 2040 are topics beyond this scenario. These topics will likely be the subjects of future studies, including the NYISO Climate Change Impact and Resilience Study.

Renewable Generation Pockets

The primary purpose of the 70x30 Scenario is to identify transmission constraints that may prevent the delivery of renewable energy to achieve the policy target. Combining the congestion and constraint results from sensitivity cases, generation pockets are identified in areas within NYCA to illustrate transmission constraints that could prevent fully utilizing renewable generation.

The resulting renewable curtailment in the scenario could result from a combination of drivers, including: (i) resource siting location, (ii) size of renewable buildout, (iii) the congestion pattern of transmission constraints, and (iv) existing thermal unit operations. Renewable generation located upstream of transmission constraints is more likely to be curtailed compared with those located at downstream of the constraints. In general, renewable curtailments due to transmission constraints include constraints inside generation pockets, tie line constraints, and constraints outside of generation pockets.

Overall, the constraints on the bulk system level remain largely consistent pre- and post-RE build-out, but certain existing constraints could be more congested due to resource shifts. The most congested element in the NYCA system remains Central East, though the congestion has been significantly reduced with the addition of AC Transmission Public Policy projects. In general, the bulk power system is more interconnected, and designed to transfer large amounts of power. The underlying lower voltage system, however, was designed to serve load in the local area and in most cases not designed to deliver power to the bulk system. Much of the renewable generation build-out modeled in this scenario is constrained by the underlying system before the power ever reaches the bulk system. Figure 74 summarizes the NYCA demand congestion for bulk level constraints in the Base Case, Scenario Load, and Base Load cases.

Figure 74: 70x30 Scenario Bulk Level Demand$ Congestion (Nominal $M)

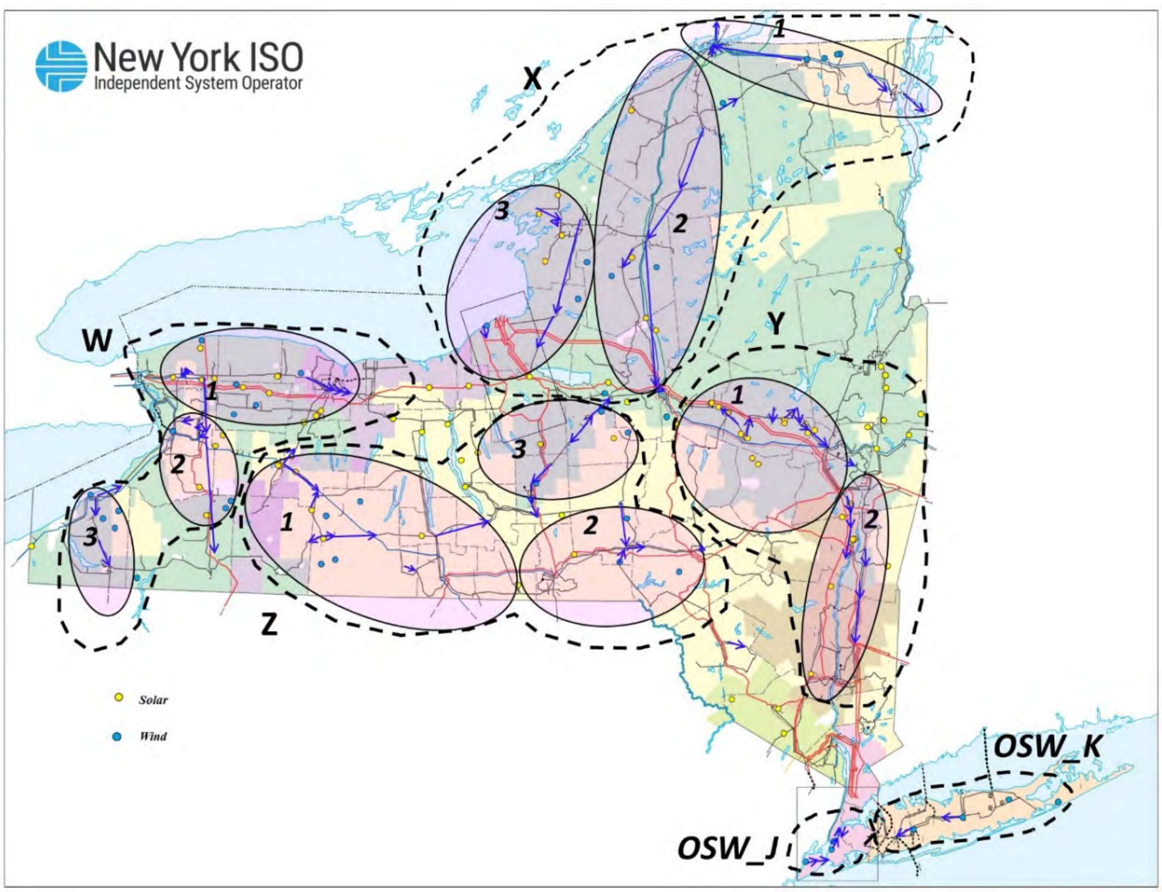
Constraints	Base Case	Scenario Load	Base Load
CENTRAL EAST	167	464	577
NEW SCOTLAND KNCKRBOC	5	113	161
PRNCTWN NEW SCOTLAND	-	57	112
DUNWOODIE TO LONG ISLAND	28	66	56
ISONE-NYISO	4	47	36
SUGARLOAF 138 RAMAPO 138	-	26	59
GREENWOOD	10	18	26
PJM-NYISO	2	19	18
N.WAVERLY LOUNS	11	7	20
DUNWOODIE MOTTHAVEN	15	1	13
EGRDNCTY 138 VALLYSTR 138 1	4	6	7
RAINEY VERNON	0	2	5
CRICKET VALLEY PLSNTVLY	3	0	0
E179THST HELLGT ASTORIAE	1	0	1
FARRAGUT GOWANUS	-	0	2
LOUNS STAGECOA	0	1	0
MOTTHAVEN RAINEY	0	0	0

Due to the resource shift, new constraints appear, and mostly at the lower kV level, mainly on the 115 kV network. To better understand the impacts from these new constraints, generation pockets are identified based on their geographical locations, and for each pocket, the following information and data is provided:

- Congested transmission facilities: the terminals of the transmission facilities and the voltage levels are listed to identify the constraint elements that result in the most congestion in this assessment;
- Congested hours: the hours that these transmission facilities in the pocket experience congestion and the hours are listed facility by facility. This is the number of hours out of the annual total of 8,760 hours. The higher the number, the more likely this transmission facility constrains the renewable generation from being fully utilized; and
- Curtailed energy percentage: the total curtailed energy for the generators in the pocket divided by the total energy, and counted by the resource type, such as hydro and land based wind. The higher the number, the less renewable generation in this pocket can be utilized by the load. The Input RE in GWh is also provided to put the curtailed energy (%) into context.

Figure 75 depicts the renewable generation pockets identified in this study.

Figure 75: Map of Renewable Generation Pockets and Constraints



The generation pocket assignments are defined by two main considerations; renewable generation buildout location, and the constraints congestion results from both the Scenario Load and Base Load levels. Each pocket depicts a geographic grouping of renewable generation, and the transmission constraints in a local area are further highlighted in sub-pocket. Generation in a pocket but not near the transmission constraints are not counted in sub-pockets. The arrow direction is the binding direction in MAPS.

The generation pockets identified in this analysis include:

- **Western NY (Pocket W)**: Western NY constraints, mainly 115 kV in Buffalo and Rochester areas:
    1) **W1**: Niagara-Orleans-Rochester Wind (115 kV)
    2) **W2**: Buffalo Erie region Wind & Solar(115 kV)
    3) **W3**: Chautauqua Wind & Solar(115kV)
- **North Country (Pocket X)**: Northern NY constraints, including the 230 kV and 115 kV facilities in the North Country:
    1) **X1:** North Area Wind (mainly 230 kV in Clinton County)
    2) **X2**: Mohawk Area Wind & Solar (mainly 115 kV in Lewis County)
    3) **X3**: Mohawk Area Wind & Solar (115 kV in Jefferson & Oswego Counties)
- **Capital Region (Pocket Y)**: Eastern NY constraints, mainly the 115 kV facilities in the Capital Region:
    1) **Y1**: Capital Region Solar Generation (115 kV in Montgomery County)
    2) **Y2**: Hudson Valley Corridor (115 kV)
- **Southern Tier (Pocket Z)**: Southern Tier constraints, mainly the 115 kV constraints in the Finger Lakes area:
    1) **Z1**: Finger Lakes Region Wind & Solar (115 kV)
    2) **Z2**: Southern Tier Transmission Corridor (115kV)
    3) **Z3**: Central and Mohawk Area Wind and Solar (115kV)
- **Offshore Wind:** offshore wind generation connected to New York City (Zone J) and Long Island (Zone K)

RE generation capacity by generation pockets assignment is shown in Figure 76 and Figure 77 by generator type in the Base Load and Scenario Load level cases, respectively. A majority of the RE capacity is located in pockets in Upstate New York and represents varying blends of RE capacity types.

Figure 76: Renewable Energy Capacity by Pocket (Scenario Load Case)

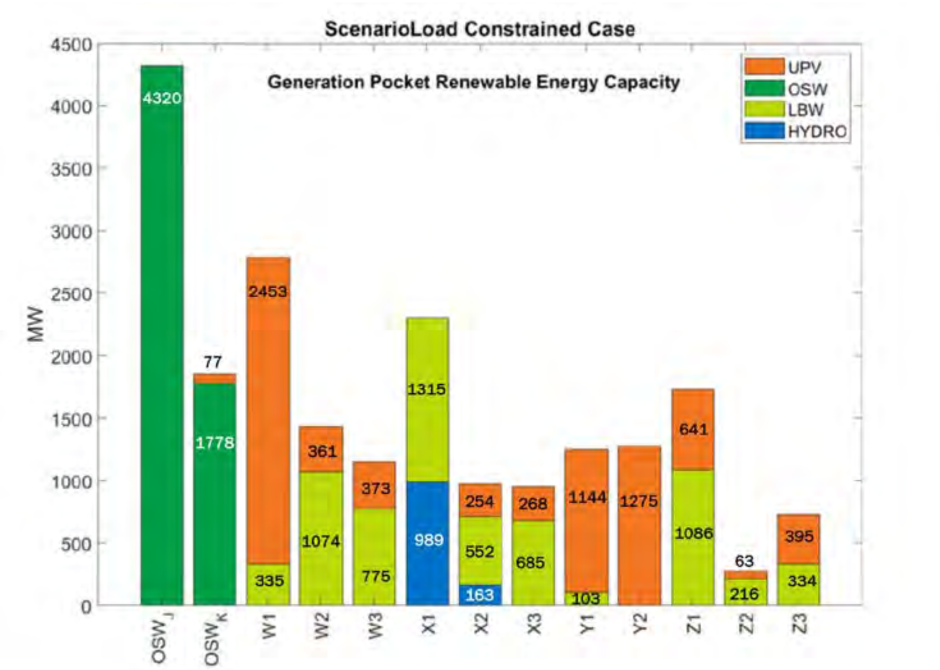
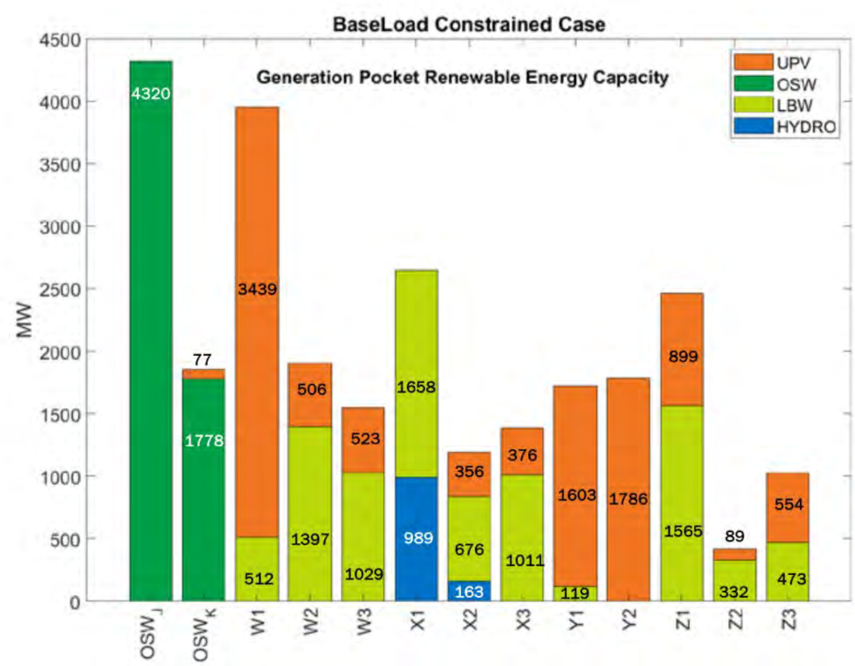


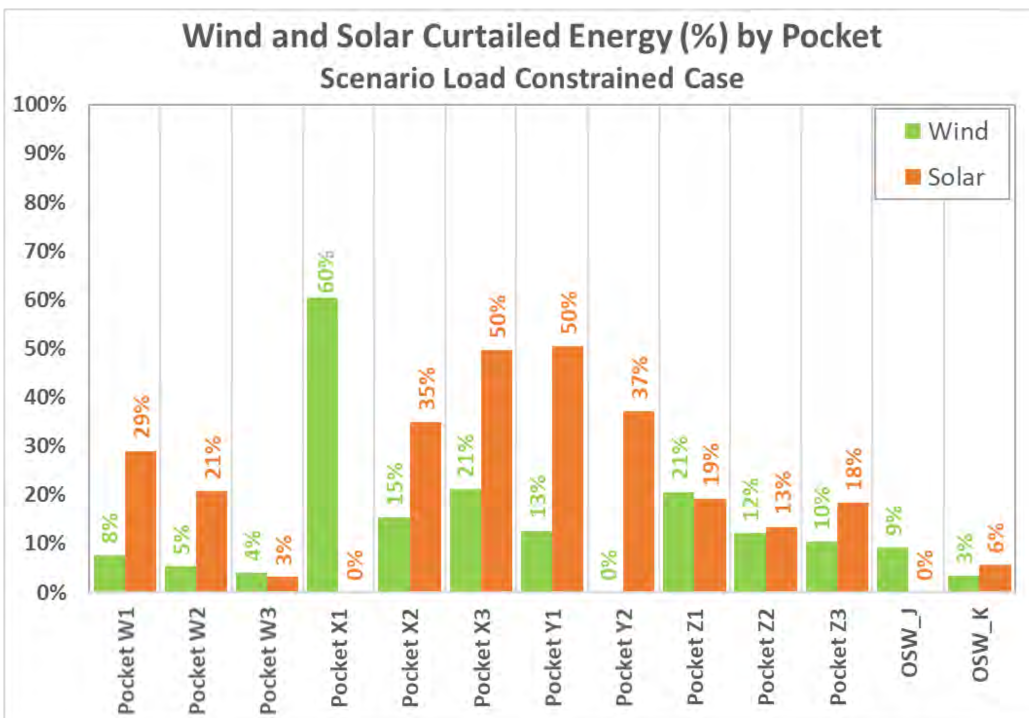
Figure 77: Renewable Energy Capacity by Pocket (Base Load Case)



Each RE generator is associated with an hourly generation profile for modeling purposes. Owing to the local load, RE generation, local transmission system topology and loading, and system transmission system conditions, a portion of potential RE generator output may be curtailed within the simulations. This is particularly prevalent when RE generators are located upstream of transmission bottlenecks or in local regions with limited export capability. As described above, the NYISO identified 13 renewable generation pockets based upon the combination of RE output and transmission system modeling assumptions. Aggregate RE curtailments within these generation pockets represents approximately 90% of the NYCA RE curtailments observed across the scenario cases.

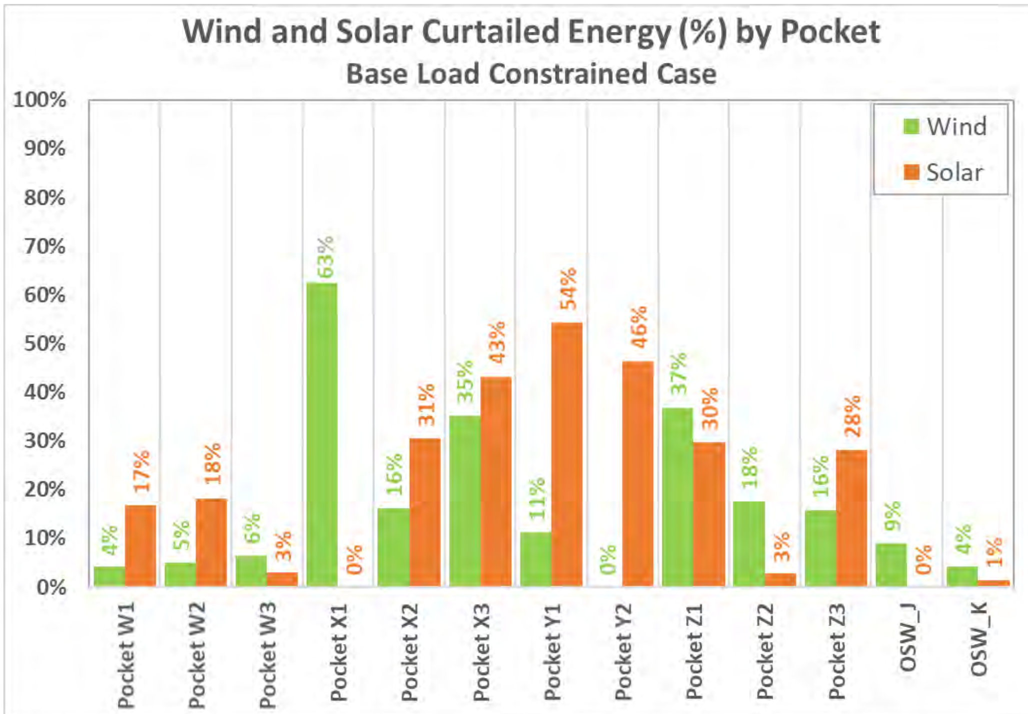
Figure 78 displays the summary of the generation pocket curtailments as a percentage of input RE energy by type across the generation pockets identified. In depth results for each pocket, including congested hours, input RE, and curtailed energy percentages, are reviewed in the following section. Additional detailed generator pocket information is available on the NYISO website.[39]

Figure 78: Curtailed Energy Percentage by Pocket (Scenario Load Constrained Case)



39 Annual metrics provided in https://www.nyiso.com/documents/20142/12126107/04%20CARIS2019_70x30Scenario_CaseOutputByTypeByPocket.csv/9a37bf26-d879-504f-271b-5ad7093b86ac and hourly information provided in https://www.nyiso.com/documents/20142/12126107/04%20CARIS2019_70x30Scenario_HourlyPocketInformation.xls/f10ab987-2171-a477-f51a-f59d9720203f

Figure 79: Curtailed Energy Percentage by Pocket (Base Load Constrained Case)



The simulation shows that generation pockets result from both the existing renewable resources and the large amount of additional resources. Four major pockets are observed in areas of land-based renewable resources: Western New York, North Country, Capital Region, and Southern Tier. In particular, North Country exhibits the highest level of curtailment by percentage, the highest curtailed energy by GWh, and the most frequent congested hours. These curtailments are generally due to lack of a strongly interconnected network to deliver power, at both bulk power and local system levels. Two additional pockets are observed in areas of offshore wind connecting to New York City (Zone J) and Long Island (Zone K) due to transmission constraints on the existing grid after the power is brought to shore.

Figure 80 summarizes the total renewable capacity (MW), the total input energy by renewable resources (GWh), and total curtailed energy by renewable resources (GWh) in each generation pocket. Further details for each sub-pocket is discussed in the section below.

Figure 80: Pocket Summary Table

Base Load	W	X	Y	Z	OSW_J	OSW_K
total renewable capacity (MW)	7,405	5,229	3,508	3,911	4,320	1,855
total input energy (GWh)	14,572	17,761	5,836	9,137	16,100	7,373
total curtailed energy (GWh)	1,421	4,411	2,807	2,703	1,462	306

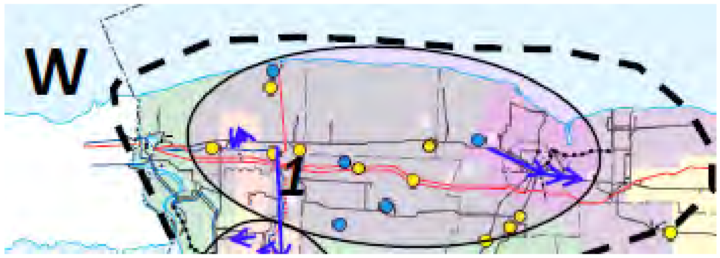
Scenario Load	W	X	Y	Z	OSW_J	OSW_K
total renewable capacity (MW)	5,371	4,227	2,522	2,735	4,320	1,855
total input energy (GWh)	10,515	15,483	4,215	6,311	16,100	7,373
total curtailed energy (GWh)	1,453	3,115	1,749	1,130	1,484	255

Western New York (Pocket W):

Significant hydro generation (Niagara) is already located in the Western New York pocket prior to the renewable generation additions in this study. Large additions of UPV are assumed in this pocket, particularly in the sub-pocket W1, and result in curtailments. Though the curtailment percentage is not as high as other pockets, the transmission facilities in this pocket could experience frequent congested hours.

Pocket W1 is located in Niagara-Orleans-Rochester area. UPV is curtailed at 29% and 17% for the Scenario Load and Base Load cases respectively in this pocket due to the significant solar buildout around Dysinger/Somerset area, which is located upstream of the 345 kV transmission corridor, as shown in Figure 81.

Figure 81: Pocket W1 Congestion and Curtailment Summary



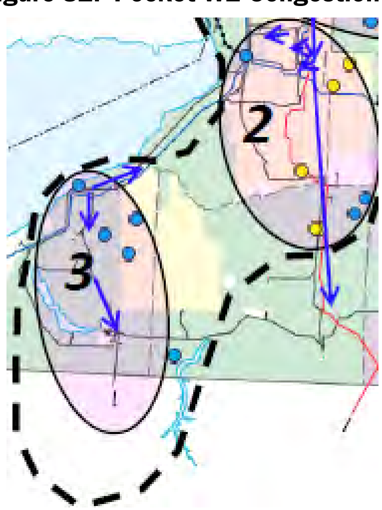
Pocket W1

Congested Hours	Scenario Load	Base Load
Q545A_DY 345.00-Q545A_DY 345.00	4,525	3,191
Q545A_ES 345.00-5MILE345 345.00	541	776
HINMN115 115.00-LOCKPORT 115.00	199	1
HINMN115 115.00-HARIS115 115.00	86	1
MORTIMER 115.00-SWDN-113 115.00	19	512
S135 115.00-S230 115 115.00	3,222	2,575
STA 89 115.00-PTSFD-25 115.00	301	431
PANNELLI 115.00-PTSFD-24 115.00	184	344
ROBIN115 115.00-A.LUD TP 115.00	-	1,065
ARS TAP 115.00-S82-1115 115.00	250	344
NIAGAR2W 230.00-NIAG115E 115.00	71	57

Type	Input RE (GWh)		Curtailed Energy (%)	
	Scenario Load	Base Load	Scenario Load	Base Load
LBW	975	1,497	8%	4%
UPV	3,452	4,838	29%	17%

Pocket W2 is located in the Buffalo area. UPV is curtailed at 21% and 18% for the Scenario Load and Base Load cases respectively in this pocket due to transmission limitations that constrain the ability of renewable generation to serve load in Buffalo area, as shown in Figure 82.

Figure 82: Pocket W2 Congestion and Curtailment Summary



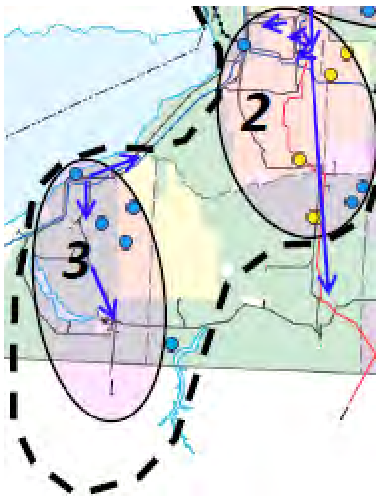
Pocket W2

Congested Hours	Scenario Load	Base Load
STOLE115 115.00-GIRD115 115.00	594	495
DEPEW115 115.00-ERIE 115 115.00	227	519
STOLE115 115.00-STOLE345 345.00	124	218
CLSP-181 115.00-YNG-181 115.00	50	25
SPVL-151 115.00-ARCADE 115.00	-	54
ERIE 115 115.00-PAVMT115 115.00	15	50

Type	Input RE (GWh)		Curtailed Energy (%)	
	Scenario Load	Base Load	Scenario Load	Base Load
LBW	2,882	3,837	5%	5%
UPV	583	817	21%	18%

Pocket W3 is located in Chautauqua County. LBW is curtailed at 4% and 6% for the Scenario Load and Base Load cases respectively in this pocket due to wind resources being mostly located upstream of the 115kV transmission corridor, as shown in Figure 83.

Figure 83: Pocket W3 Congestion and Curtailment Summary



Pocket W3

Congested Hours	Scenario Load	Base Load
FALCONER 115.00-MOON-161 115.00	718	1,272
EDNK-161 115.00-ARKWRIGH 115.00	270	645
EDNK-162 115.00-ARKWRIGH 115.00	15	71
SLVRC141 115.00-DUNKIRK1 115.00	29	226

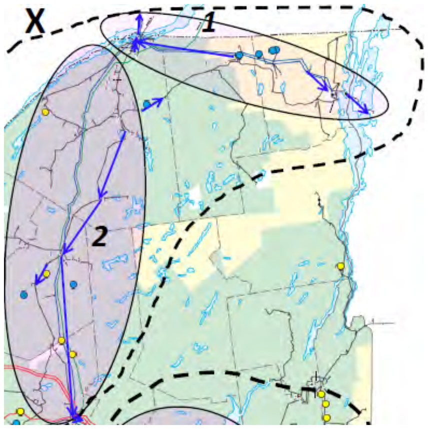
Type	Input RE (GWh)		Curtailed Energy (%)	
	Scenario Load	Base Load	Scenario Load	Base Load
LBW	2,099	2,847	4%	6%
UPV	525	737	3%	3%

North Country (Pocket X):

The North Country pocket already had significant hydro and wind plants prior to the additions assumed in these scenarios. In general, the wind and solar generation in this pocket experience very high curtailment percentage, and the transmission facilities in this pocket see the most congested hours among all pockets. This is mainly due to lack of strongly interconnected bulk power transmission facilities, and the geographical proximity to exporting constraints to Ontario and New England.

Pocket X1 is generally located in Clinton County in the North Country. Land Based Wind generators are curtailed 60% and 63% for Scenario Load and Base Load cases respectively in this pocket due to the wind being located much closer to the transmission constraints shown in Figure 84 compared with existing hydro generation. In this pocket, the two tie-line constraints connecting with ISO-NE toward the east side and connecting with Ontario toward the west side show significant congested hours in both the Scenario Load and Base Load cases. The 230 kV line between Duley and Plattsburg is also highly congested from wind generation existing to other areas in NYCA. The two constraints in the Alcoa/Dennison area are mainly due to constrained renewable generation to serve load in the Alcoa area.

Figure 84: Pocket X1 Congestion and Curtailment Summary



Pocket X1

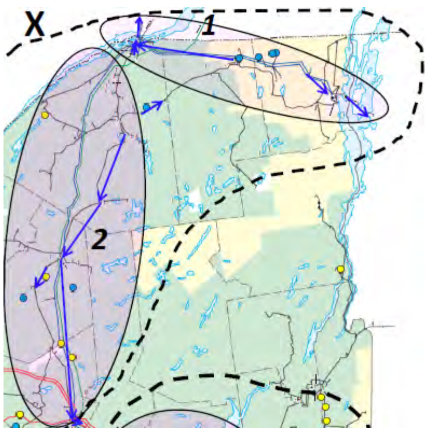
Congested Hours	Scenario Load	Base Load
TIE-LINES: NORTH -VT	8,113	8,014
NorthTie: OH-NY	8,751	8,755
ALCOA-NM 115.00-ALCOA N 115.00	839	766
DULEY 230.00-PLAT T#1 230.00	217	490
ALCOA-NM 115.00-DENNISON 115.00	387	355
MOSES W 230.00-WILLIS E 230.00	19	90

Type	Input RE (GWh)		Curtailed Energy (%)	
	Scenario Load	Base Load	Scenario Load	Base Load
Hydro	7,638	7,638	3%	3%
LBW	3,104	3,966	60%	63%

Pocket X2 is located in Lewis County of the Mohawk Area. UPV is curtailed at 35% and 31% for the Scenario Load and Base Load cases respectively in this pocket due to the UPV buildout being mostly located at upstream of the 115 kV transmission constraints(Brown Falls – Taylorville – Boonville), as shown in Figure 85. Hydro experiences considerable curtailment in this pocket, at 18% and 16% for the respective load scenarios, due to generation proximity to congested paths.

The 115 kV constraints in Pocket X2 are in parallel with the 230 kV corridor constraints from Adirondack to Porter. The renewable generation modeled in this pocket is mainly interconnected to the 115 kV system, therefore the congestion occurs more on the 115 kV versus 230 kV facilities in this pocket. Note that the congestion currently observed in the 230 kV path is mainly caused by transmission outages on the parallel Moses – Adirondack path. Due to software limitations, these outages and associated congestion are not captured in this study; therefore congestion and curtailment amounts from this analysis are underestimated.

Figure 85: Pocket X2 Congestion and Curtailment Summary



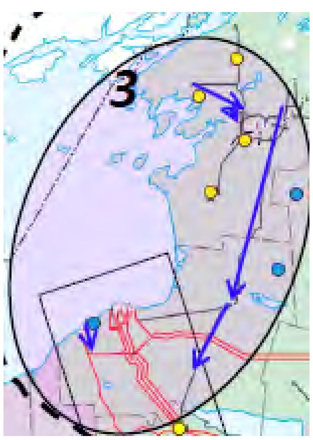
Pocket X2

Congested Hours	Scenario Load	Base Load
BREMEN 115.00-BU+LY+MO 115.00	1,025	2,233
LOWVILLE 115.00-BOONVL 115.00	633	1,712
BRNS FLS 115.00-TAYLORVL 115.00	170	238
BRNS FLS 115.00-HIGLEY 115.00	63	107
EDIC 345.00-PORTER 2 230.00	11	17
PORTER 2 230.00-ADRON B2 230.00	5	9
NICHOLVL 115.00-PARISHVL 115.00	33	7

Type	Input RE (GWh)		Curtailed Energy (%)	
	Scenario Load	Base Load	Scenario Load	Base Load
Hydro	960	960	18%	16%
LBW	1,354	1,661	15%	16%
UPV	336	471	35%	31%

Pocket X3 is located in Jefferson & Oswego Counties. UPV is curtailed at 50% and 43% for the Scenario Load and Base Load cases respectively in this pocket due to the UPV buildout being mostly located upstream of the 115kV transmission constraints, as shown in Figure 86. These limitations directly increase the utilization of the neighboring transmission facilities.

Figure 86: Pocket X3 Congestion and Curtailment Summary



Pocket X3

Congested Hours	Scenario Load	Base Load
HTHSE HL 115.00-MALLORY 115.00	2,530	3,718
HMMRMILL 115.00-WINE CRK 115.00	457	1,448
COFFEEN 115.00-E WTRTWN 115.00	535	883
COFFEEN 115.00-LYMETP 115.00	3	87
HTHSE HL 115.00-COPEN_PO 115.00	18	4
COFFEEN 115.00-GLEN PRK 115.00	706	1,156

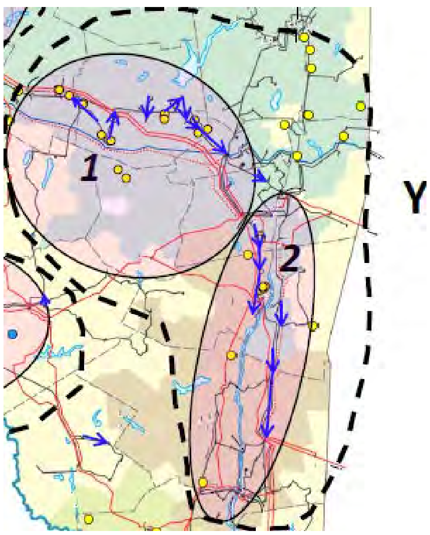
Type	Input RE (GWh)		Curtailed Energy (%)	
	Scenario Load	Base Load	Scenario Load	Base Load
LBW	1,735	2,567	21%	35%
UPV	356	498	50%	43%

Capital Region (Pocket Y):

The Capital Region pocket encompasses the Mohawk Valley and upper Hudson Valley regions, centered on the Albany metro area. A large amount of solar generation, mainly UPV, is modeled in this pocket, particularly on the 115 kV network. These new resources experience high levels of curtailment on the 115 kV network, which is generally not designed for high levels of generation injection.

Pocket Y1 is located in the vicinity of the Mohawk Valley of the Capital Region. UPV is curtailed at 50% and 54% for the Scenario Load and Base Load cases respectively in this pocket due to the UPV buildout being mostly located upstream of the 115 kV transmission constraints, as shown in Figure 87. The 115 kV transmission corridor runs in parallel with the 345 kV corridor utilized by Segment A of the AC Transmission Public Policy projects.

Figure 87: Pocket Y1 Congestion and Curtailment Summary



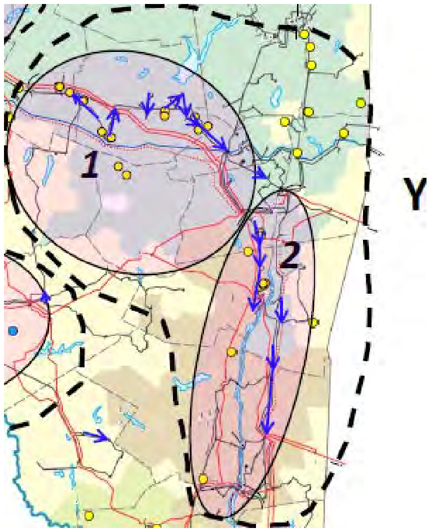
Pocket Y1

Congested Hours	Scenario Load	Base Load
RTRDM1 115.00-AMST 115 115.00	2,392	2,814
STONER 115.00-VAIL TAP 115.00	2,037	2,259
INGHAM-E 115.00-ST JOHNS 115.00	508	1,454
CHURCH-W 115.00-VAIL TAP 115.00	1,034	1,509
CLINTON 115.00-TAP T79 115.00	293	725
CHURCH-E 115.00-MAPLEAV1 115.00	293	543
AMST 115 115.00-CHURCH-E 115.00	149	302
CENTER-N 115.00-MECO 115 115.00	20	170
EVERETT 115.00-WOLF RD 115.00	149	7

Type	Input RE (GWh)		Curtailed Energy (%)	
	Scenario Load	Base Load	Scenario Load	Base Load
LBW	247	286	13%	11%
UPV	1,826	2,557	50%	54%

Pocket Y2 is located in the upper Hudson Valley corridor. UPV is curtailed at 37% and 46% for the Scenario Load and Base Load cases respectively in this pocket due to the UPV buildout being mostly located upstream of the 115 kV transmission constraints corridor as shown in Figure 88. The 115 kV transmission corridor runs in parallel with the 345 kV corridors utilized by Segment B of the AC Transmission Public Policy projects.

Figure 88: Pocket Y2 Congestion and Curtailment Summary



Pocket Y2

Congested Hours	Scenario Load	Base Load
N.CAT. 1 115.00-CHURCHTO 115.00	2,079	2,371
MILAN 115.00-PL.VAL 1 115.00	1,913	2,256
OW CRN E 115.00-BOC 7T 115.00	151	93
MILAN 115.00-BL STR E 115.00	145	282
JMC1+7TP 115.00-BLUECIRC 115.00	-	213
JMC2+9TP 115.00-OC W +MG 115.00	17	54
ADM 115.00-HUDSON 115.00	12	74
N.CAT. 1 115.00-BOC 2T 115.00	-	22

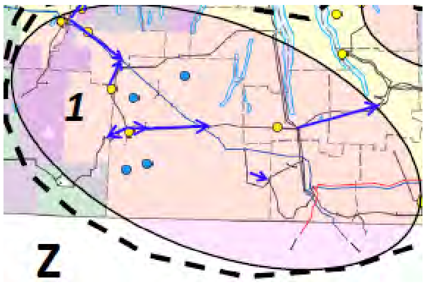
Type	Input RE (GWh)		Curtailed Energy (%)	
	Scenario Load	Base Load	Scenario Load	Base Load
UPV	2,142	2,993	37%	46%

Southern Tier (Pocket Z):

Large amounts of UPV and LBW are assumed to be added in the Southern Tier pocket, particularly in the sub-pocket of Z1. In general, the wind and solar generation in this pocket experience high levels of curtailments, and the transmission facilities in this pocket show high levels of congested hours. This congestion results mainly from the lack of strongly interconnected bulk power transmission facilities near injection points, and the 115 kV network was not designed for large power transfers.

Pocket Z1 is generally located in Finger Lakes Region. LBW is curtailed at 21% and 37% for the Scenario Load and Base Load cases respectively in this pocket due to the wind buildout being mostly located upstream of the 115 kV transmission corridor near the Benet area, as shown in Figure 89.

Figure 89: Pocket Z1 Congestion and Curtailment Summary



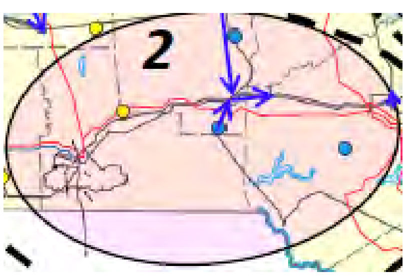
Pocket Z1

Congested Hours	Scenario Load	Base Load
HICK 115 115.00-WERIE115 115.00	1,966	3,115
BATH 115 115.00-HOWARD11 115.00	1,438	2,694
BENET115 115.00-PALMT115 115.00	1,456	1,738
MEYER115 115.00-S.PER115 115.00	1,371	2,307
S.PER115 115.00-S PERRY 230.00	-	20
S.PER115 115.00-STA 162 115.00	-	1
STA 162 115.00-STA 158S 115.00	304	466
MEYER115 115.00-MORAI115 115.00	611	847
BENET115 115.00-HOWARD11 115.00	346	893
CODNT115 115.00-MONTR115 115.00	2	12

Type	Input RE (GWh)		Curtailed Energy (%)	
	Scenario Load	Base Load	Scenario Load	Base Load
LBW	3,064	4,479	21%	37%
UPV	1,073	1,503	19%	30%

Pocket Z2 is located in the Southern Tier Region. LBW is curtailed at 12% and 18% for the Scenario Load and Base Load cases respectively in this pocket due to the wind buildout being mostly located upstream of the 115 kV transmission corridor, as shown in Figure 90.

Figure 90: Pocket Z2 Congestion and Curtailment Summary



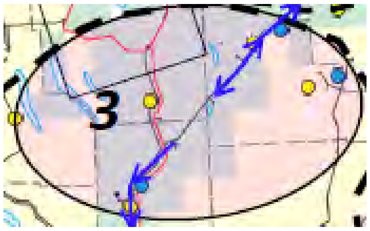
Pocket Z2

Congested Hours	Scenario Load	Base Load
DELHI115 115.00-DEL T115 115.00	994	301
JENN 115 115.00-SIDNT115 115.00	575	2,018
JENN 115 115.00-AFTON115 115.00	-	48
E.NOR115 115.00-JENN 115 115.00	6	190
STILV115 115.00-AFTON115 115.00	-	40
W.WDB115 115.00-FERND115 115.00	17	60

Type	Input RE (GWh)		Curtailed Energy (%)	
	Scenario Load	Base Load	Scenario Load	Base Load
LBW	531	817	12%	18%
UPV	107	149	13%	3%

Pocket Z3 is located in Central New York Region. UPV is curtailed at 18% and 28% for the Scenario Load and Base Load cases respectively in this pocket due to the solar buildout being mostly located upstream of the 115 kV transmission corridor, as shown in Figure 91.

Figure 91: Pocket Z3 Congestion and Curtailment Summary



Pocket Z3

Congested Hours	Scenario Load	Base Load
CORTLAND 115.00-TULLER H 115.00	14	476
CLARKCRN 115.00-TULLER H 115.00	-	895
DELPHI 115.00-OM-FENNR 115.00	-	123
CORTLAND 115.00-LABRADOR 115.00	75	431
WHITMAN 115.00-ONEIDA 115.00	1,816	2,905
WHITMAN 115.00-FEN-WIND 115.00	290	506

Type	Input RE (GWh)		Curtailed Energy (%)	
	Scenario Load	Base Load	Scenario Load	Base Load
LBW	883	1,276	10%	16%
UPV	653	913	18%	28%

Offshore Wind in Zone J:

Offshore wind is curtailed at 9% for both the Scenario Load and Base Load cases in the New York City pocket due to the wind resources being mostly located upstream of the 138 kV and 345 kV transmission corridors, as shown in Figure 92. There are three injection points in New York City, at the Freshkills 345 kV substation, Gowanus 345 kV substation, and Farragut 345 kV substation. The majority of the OSW curtailment results from the injection at the Freshkills substation in the Staten Island load pocket, which is constrained by the 138 kV facility from Freshkills to Willow Brook.

The study also shows that the OSW resources are much higher than the load in the Staten Island load pocket, as well as being constrained by the identified transmission facilities. Accordingly, the OSW resources cannot be transmitted out of the load pocket.

Figure 92: New York City Offshore Wind Congestion and Curtailment Summary

OSW_J

Congested Hours	Scenario Load	Base Load
WILOWBK2 138.00-FRESH KI 138.00	3,774	4,662
FARRAGUT 345.00-GOWANUS 345.00	2,273	2,250
E13ST 45 345.00-FARRAGUT 345.00	211	198
WILOWBK1 138.00-FRESH KI 138.00	116	97
RAINEY W 345.00-FARRAGUT 345.00	23	54

Type	Input RE (GWh)		Curtailed Energy (%)	
	Scenario Load	Base Load	Scenario Load	Base Load
OSW	16,100	16,100	9%	9%

Offshore Wind in Zone K:

Offshore wind is curtailed at 3% and 4% for both the Scenario Load and Base Load cases in the Long Island pocket due to the new wind resources being mostly located upstream of the 138 kV transmission corridor, as shown in Figure 93. There are four injection points in Long Island; the Holbrook 138 kV substation, Brookhaven 138 kV substation, Ruland Road 138 kV substation, and East Hampton 69 kV substation. The majority of the OSW curtailment on Long Island results from the injection at Holbrook substation that is constrained by the 138 kV facility from Holbrook to Ronkonk.

Figure 93: Long Island Offshore Wind Congestion and Curtailment Summary

OSW_K

Congested Hours	Scenario Load	Base Load
HOLBROOK 138.00-RONKONK 138.00	2,032	2,102
NEWBRGE 138.00-RULND RD 138.00	236	314

Type	Input RE (GWh)		Curtailed Energy (%)	
	Scenario Load	Base Load	Scenario Load	Base Load
OSW	7,259	7,259	3%	4%
UPV	115	115	6%	1%

Sensitivity Analysis

Nuclear Generation Retirement Sensitivity

The nuclear generation fleet, which is comprised of the Nine Mile I, Nine Mile II, Ginna and FitzPatrick facilities, are expected to continue in operation until at least March 2029 under the state support provided by Zero Emission Credit Requirements contained in the Clean Energy Standard. These units may continue in operation beyond 2029 and this sensitivity analysis should not be interpreted as forecasting their deactivation. This sensitivity examines what may be the impacts on the system generation output if those units discontinued operations under the Scenario Load and Base Load conditions in 2030. The existing nuclear generation fleet provides emission-free base-load generation with limited dispatch flexibility. Removal of large, consistent supply resources would result in higher utilization of a combination of intermittent and conventional generation. Figure 94 shows the annual energy by unit type and net imports across cases with and without the nuclear units in operation.

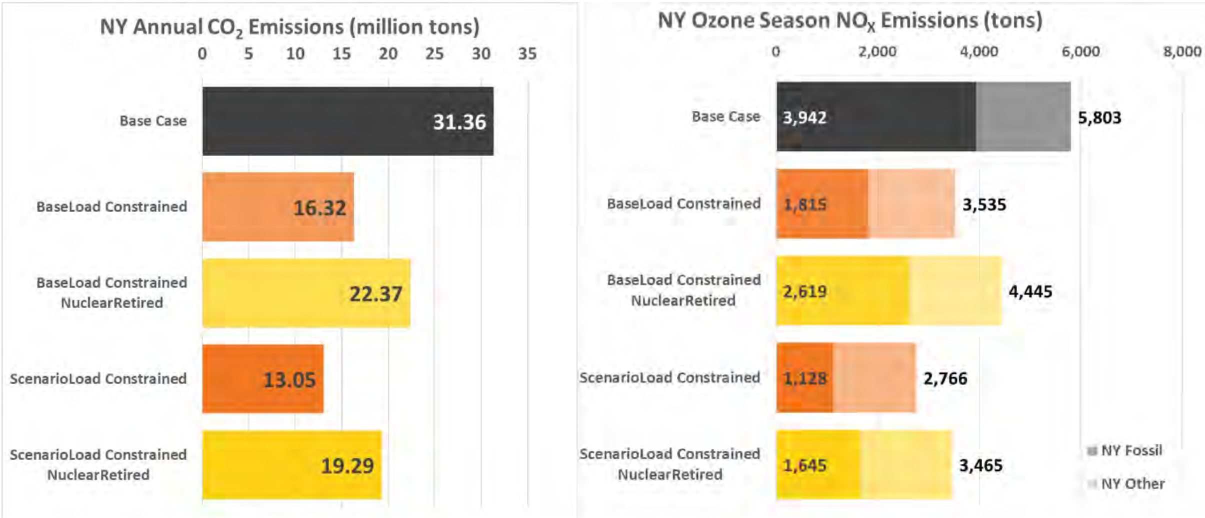
Figure 94: Base, Constrained, and Nuclear Retirement Sensitivity Case Annual Energy Results

Energy (GWh)	Base Case	ScenarioLoad Constrained	ScenarioLoad Constrained NuclearRetired	BaseLoad Constrained	BaseLoad Constrained NuclearRetired
Nuclear	27,091	27,433	-	27,433	-
Other	2,368	2,110	2,270	2,102	2,263
Fossil	69,028	28,185	42,924	35,181	49,448
Hydro	28,832	28,050	28,448	28,020	28,413
Hydro Imports	11,564	19,775	19,897	19,769	19,910
LBW	5,038	13,290	14,879	17,117	18,751
OSW	-	21,625	21,714	21,592	21,750
UPV	115	12,666	14,527	17,982	19,342
BTM-PV	4,988	9,266	9,356	9,327	9,359
Pumped Storage	(447)	(822)	(988)	(868)	(959)
Storage	-	-	-	-	-
IESO Net Imports	(2,862)	(5,817)	(4,090)	(6,250)	(4,264)
ISONE Net Imports	(535)	(6,418)	(4,385)	(5,073)	(2,867)
PJM Net Imports	12,239	(4,446)	287	(4,528)	591
Renewable Generation	50,537	104,672	108,821	113,808	117,525
Curtailment	0	10,151	6,069	14,020	10,338
Non-Renewable Generation	98,488	57,728	45,194	64,717	51,712
GrossLoad	157,418	144,897	144,838	161,807	161,733

With deactivation of the nuclear generation fleet, the model exhibits a significant increase in fossil fuel generation in the Scenario Load and Base Load cases, mostly in the Downstate region. The model also reveals an increase in wind and solar output from Upstate renewables that are able to utilize transmission capability previously consumed by the nuclear generation, while offshore wind output remains mostly consistent due to local congestion. The cases with the nuclear fleet retired also have notable reductions in exports to external regions across both the Scenario and Base Load levels.

Increased operation of fossil units in cases with the nuclear generation fleet retired results in increased in CO_2 and NO_X emissions, as shown in Figure 95. Emission levels are lower in the Scenario Load case compared the Base Load case owing to lower load and corresponding lower operation of fossil fuel generation.

Figure 95: Nuclear Retirement Sensitivity Case CO_2 and Ozone Season NO_X Emissions Projections



Energy Storage Resources (ESR) Sensitivity

State policies, including the CLCPA, support the installation of 3,000 MW of Energy Storage Resources (ESR) in New York by 2030. ESR modeling in production cost simulation is in the development stage at the time of this assessment, and the NYISO investigated different dispatch models, namely pumped storage hydro (PSH) method and hourly resource modifier (HRM) method. The detailed modeling approach and comparison of results are included in an appendix. For illustrative purposes, this section of the report focuses on HRM method, and the targeted impact examination of a small amount of ESR capacity to minimize curtailment from individual collocated RE generators in a generation pocket.

In the HRM approach all ESR are assumed to be four-hour duration with 85% round trip efficiency, meaning that ESR can discharge 85% of the energy consumed from charging. The losses associated with the cycle efficiency of ESR will increase the total energy consumption of the system. ESR will always inject less energy into the system than the energy it consumed during charging. As an example, a battery that consumes 100 MWh of energy can only inject 85 MWh back into the grid.

Results of the study conducted for the NYSERDA Energy Storage Roadmap[40] were used to inform the zonal MW capacity levels. ESRs were added to the model as a distributed resource at the load buses, on a zonal basis as shown in Figure 96.

[40] documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={2A1BFBC9-85B4-4DAE-BCAE-164B21B0DC3D}

Figure 96: Assumed ESR Zonal Power Capacity

Nameplate Capacity Distribution (MW)												
	A	B	C	D	E	F	G	H	I	J	K	NYCA
ESR	150	90	120	180	120	240	100	100	100	1,320	480	3,000

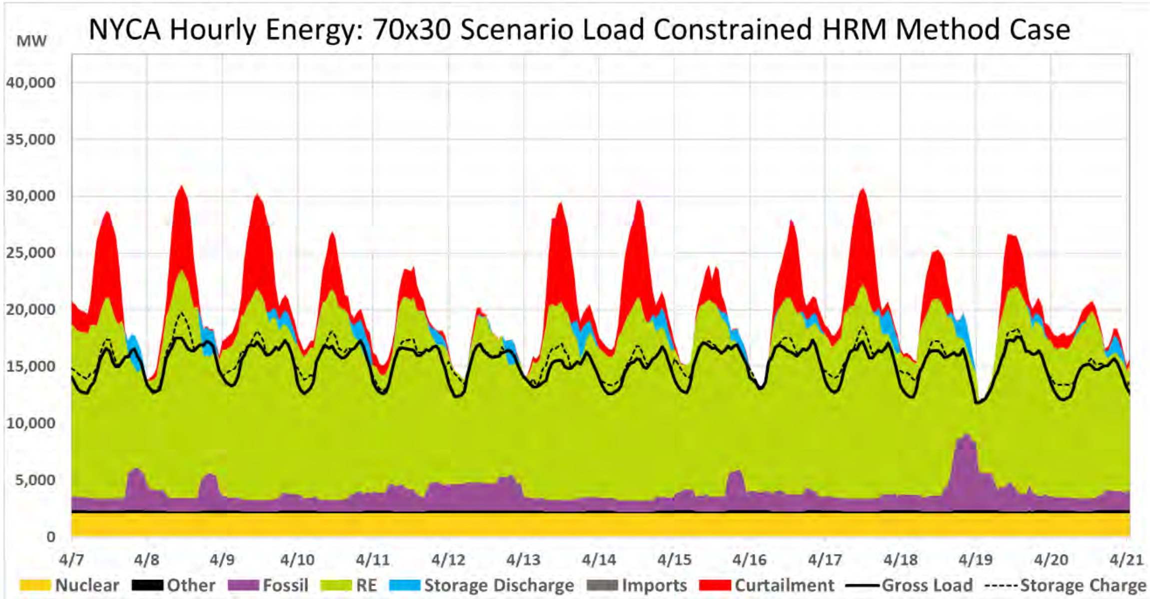
The primary impact of including ESR as a distributed resource in MAPS is a reduction in fossil generation, exports, and curtailments, with an observed increase in RE generation of approximately 1,000 GWh, or 0.9%. Figure 97 displays the annual energy composition of generation, net imports, curtailments, and gross load. Storage resources in the table are shown as net generation values (*i.e.*, net generation = discharge – charge), similar to the calculation of net generation for pumped storage resources.

Figure 97: Energy Storage Resource Sensitivity Case Results Energy Results (GWh)

Energy (GWh)	ScenarioLoad Constrained	ScenarioLoad Constrained HRM Method	BaseLoad Constrained	BaseLoad Constrained HRM Method
Nuclear	27,433	27,434	27,433	27,435
Other	2,110	2,126	2,102	2,117
Fossil	28,185	26,294	35,181	33,603
Hydro	28,050	28,114	28,020	28,091
Hydro Imports	19,775	19,808	19,769	19,808
LBW	13,290	13,532	17,117	17,376
OSW	21,625	21,743	21,592	21,821
UPV	12,666	13,124	17,982	18,350
BTM-PV	9,266	9,288	9,327	9,329
Pumped Storage	(822)	(630)	(868)	(671)
Storage	-	(693)	-	(756)
IESO Net Imports	(5,817)	(5,755)	(6,250)	(6,145)
ISONE Net Imports	(6,418)	(5,847)	(5,073)	(4,723)
PJM Net Imports	(4,446)	(3,648)	(4,528)	(3,838)
Renewable Generation	104,672	105,609	113,808	114,775
Curtailment	10,151	9,266	14,020	13,097
Non-Renewable Generation	57,728	55,853	64,717	63,155
GrossLoad	144,897	144,888	161,807	161,797

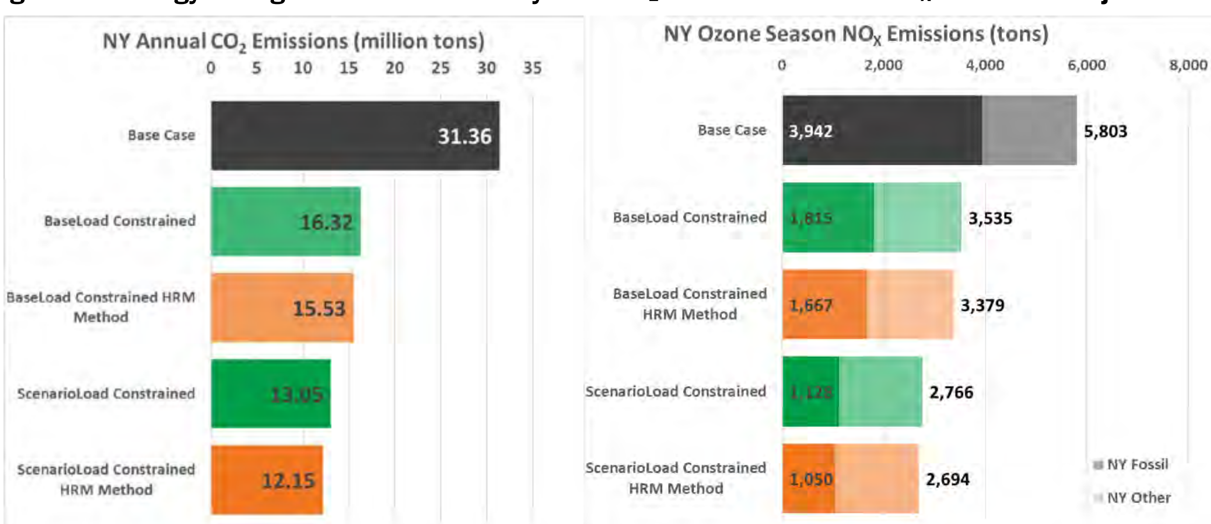
Graphs over two week sample periods, as shown in Figure 98, display the impacts of ESR on fossil, renewable, imports, and curtailments on an hourly granularity. Modeling distributed ESR resulted in less fossil generation during low net load periods compared, as ESR typically reduces peak fossil demand levels. It was also observed that some (mostly winter) hours during which ESR was charging were also hours when NYCA was a net importer. This implies that the increase charging demand could increase imports and fossil generation in some hours relative to a case without ESR. Renewable curtailments also decreased compared to cases without ESR.

Figure 98: HRM Energy Storage Resource Hourly Results across a Spring Low Net Load Period



The introduction of ESR does not inherently result in a reduction in emissions or output of fossil generators because ESR overall increase energy demand due to losses associated in the cycle from charging to discharging. Figure 99 the CO_2 and NO_X emissions of generators located in New York across the scenario cases and the Base Case. Emissions across all scenario cases decrease substantially from the Base Case results. The additional reduction of the distributed storage model are relatively small in comparison.

Figure 99: Energy Storage Resource Sensitivity Case CO_2 and Ozone Season NO_X Emissions Projections



An additional sensitivity examined the impact of ESR on RE curtailments in generation pockets. Generally speaking, solar generation profiles are more regular from day to day compared to wind generation, and relatively easier to identify a dispatch pattern for ESR. As a starting point, this investigative analysis focused on the impact of ESR in conjunction with solar generation.

In the Capital Region Pocket Y1, five UPV generators with the highest level of curtailed energy from the Scenario Load constrained case were chosen for this sensitivity. The five UPV units and their curtailed energy data is shown in Figure 100. An 8,760 hourly dispatch profile was created for each ESR unit to charge with the curtailed energy from the associated RE unit. In the absence of any curtailment of its associated RE unit, ESR would inject its stored energy into the transmission network. The ESR dispatch profiles were also limited by the power, energy, and efficiency constraints on the ESR itself. All ESR in these cases assumed an 85% charge-to-discharge cycle efficiency.

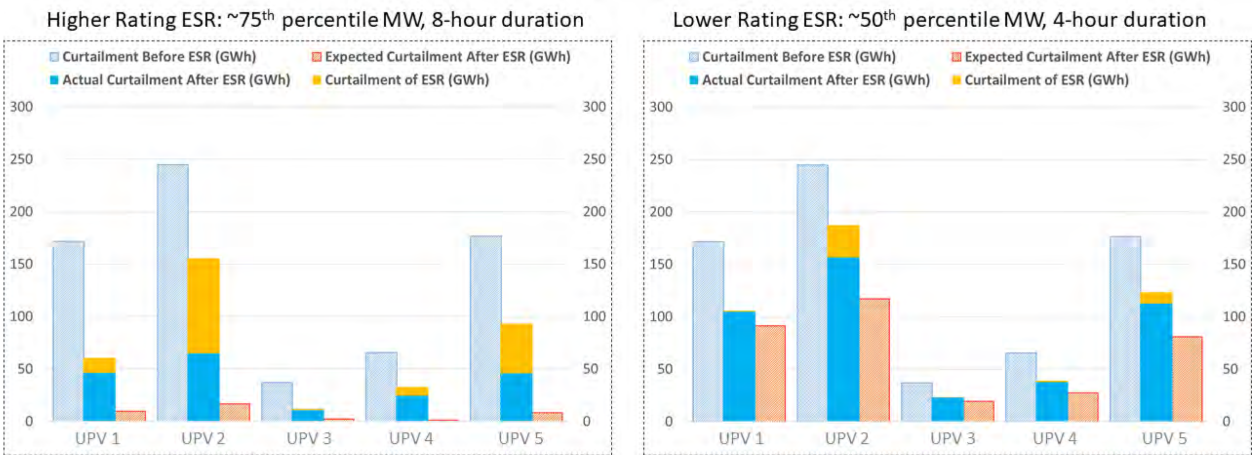
Figure 100: Information on Pocket RE Generator and Collocated ESR Capacity

RE unit	Capacity (MW)	Higher ESR Capacity (75th percentile) (MW)	Lower ESR Capacity (50th percentile) (MW)
UPV1	213	150	85
UPV2	196	130	100
UPV3	109	80	35
UPV4	87	70	40
UPV5	174	125	90

The power rating of the ESR was selected to capture approximately 75th and 50th percentiles of the hourly curtailments of each RE unit. The two power ratings of each ESR used in this sensitivity are shown in Figure 100.

ESR dispatch profiles were included in a MAPS simulation as hourly resource modifiers (HRM) collocated with the associated RE unit. Figure 101 shows the curtailment results for two MAPS simulations with two ESR rating levels (*i.e.*, higher and lower rated ESR units). It can be seen in Figure 101 that the MAPS simulation resulted in curtailment of ESR injections because the network constraints still existed in the absence of energy from the RE units. Lower ratings of ESR also resulted in higher curtailments from the associated renewable units with lower associated ESR curtailments. These results are based upon the modeling assumption that ESR discharge begins immediately following the end of each UPV curtailment event. The modeling did not attempt to optimize the temporal discharge within the inter-curtailment intervals each night. UPV curtailments were targeted as UPV follows a more characteristic and predictable diurnal pattern when compared to modeled wind curtailments. This ESR algorithm minimizes RE curtailment to determine how much curtailment may also be addressed by transmission and does not target production cost or profit optimization for ESR using LBMP differences.

Figure 101: Curtailment Results for Pocket RE Generator Collocated ESR Sensitivity Cases



These results show that while ESR can help in reducing curtailments in constrained pockets to some extent, the transmission limitations in the pockets cannot completely be solved with ESR. Ultimately, MAPS will curtail either the ESR injection or some other renewable unit if sufficient transmission capability to export from the pocket does not exist. Depending upon the temporal differences in wind and solar curtailment events and the ESR parameters, differing amounts of curtailments may be addressed by either ESR and/or transmission upgrades. The suitability of ESRs for resolving curtailments at a specific location is dependent on the curtailment amount and duration, resource distribution relative to local transmission network limitations, and local load levels.

Reduced Export Sensitivity

Based on stakeholder feedback, the NYISO performed an additional sensitivity to examine the impact of reduced exports to external regions (PJM, IESO and ISO-NE) on scenario study results. External areas will likely experience demand and resource shifts while different regions are moving towards their own individual renewable and emission reduction targets. The detailed plans of the neighboring areas are not available at the time of this report. Lacking such information, the 70x30 Scenario does not assume any renewable generation growth in the neighboring systems beyond limited additions prescribed by inclusion rules assumed in the Base Case analysis. The additional sensitivity effectuates reduced exports from the NYISO to external areas by substantially increasing the export hurdle rate on all ties in the export direction.

Hurdle rates are studied during benchmarking analysis to set inter-regional flows economically to historical averages and remain fixed throughout the Base Case study period. This sensitivity models export hurdle rates at 100 times the Base Case amount to reduce exports to neighboring regions. The results presented in Figure 102 for this sensitivity are intended only to show the directional impacts of increasing export hurdle rates. The NYISO has not optimized or studied hurdle rate values in depth. Instead, the NYISO selected a large value to study the directionality of flows and generation.

Increasing export hurdle rates results in decreased exports (and increased net imports) on all inter-regional interfaces, decreased New York renewable and fossil generation output. Higher hurdle rates also increased curtailments as it becomes more economic to curtail production than to export energy with such a high export cost.

Figure 102: Export Sensitivity Case Annual Energy Results

Energy (GWh)	Base Case	ScenarioLoad Constrained	ScenarioLoad Constrained 100xHurdleRate
Nuclear	27,091	27,433	27,419
Other	2,368	2,110	1,621
Fossil	69,028	28,185	21,434
Hydro	28,832	28,050	25,117
Hydro Imports	11,564	19,775	19,830
LBW	5,038	13,290	10,453
OSW	-	21,625	19,125
UPV	115	12,666	9,074
BTM-PV	4,988	9,266	9,072
Pumped Storage	(447)	(822)	(885)
Storage	-	-	-
IESO Net Imports	(2,862)	(5,817)	71
ISONE Net Imports	(535)	(6,418)	972
PJM Net Imports	12,239	(4,446)	1,616
Renewable Generation	50,537	104,672	92,671
Curtailment	0	10,151	18,985
Non-Renewable Generation	98,488	57,728	50,474
GrossLoad	157,418	144,897	144,921

Key Findings of the "70x30" Scenario

As policymakers advance an implementation plan for the CLCPA, this assessment is intended to complement their efforts and provide information about possible challenges. This "first look" at the CLCPA target of 70% renewable energy by 2030, identifies the following key findings:

- The "70x30" scenario builds on the Base Case to model state-mandated policy goals. Results show that renewable generation pockets are likely to develop throughout the state as the existing transmission grid would be overwhelmed by the significant renewable capacity additions. In each of the five major pockets observed, renewable generation is curtailed due to the lack of sufficient bulk and local transmission capability to deliver the power. The results support the conclusion that additional transmission expansion, at both bulk and local levels, will be necessary to efficiently deliver renewable power to New York consumers.
- The level of renewable generation investment necessary to achieve 70% renewable end-use energy by 2030 could vary greatly as energy efficiency and electrification adoption unfolds. Two scenarios with varying energy forecasts and associated renewable build-outs were simulated. Both scenarios resulted in the observation that significant transmission constraints exist when adding the necessary volume of renewable generation to achieve the 70% target.
- Given that the 70% renewable target is based on the level of end-use energy, energy efficiency initiatives will have significant implications for the level of renewable resources needed to meet the CLCPA goals. For this assessment, utilizing an illustrative set of various renewable sources, nearly 37,600 MW of renewable resources was modeled to approximate a system potentially capable of achievement of the 70x30 policy goal at the base load forecast. By comparison, nearly 31,000 MW of renewable resources were added to cases with demand reduced by energy efficiency polices.
- The large amount of renewable energy additions to achieve the CLCPA goals would change the operations of the fossil fuel fleet. Overall, the annual output of the fossil fleet would decline. The units that are more flexible would be dispatched more often, while the units that are less so may be dispatched less or not at all. In addition, sensitivity analysis indicates that if the statewide nuclear generation fleet retired, emissions from the fossil fuel fleet would likely increase; the degree of that impact is dependent on the timing of nuclear retirements and pace of renewable resource additions.

- Sensitivity analysis indicates that energy storage could decrease congestion, and when dispatched effectively, energy storage would help to increase the utilization of the renewable generation, particularly the solar generation tested in this analysis.

The NYISO will continue to monitor and track system changes. Subsequent studies, such as the 2020 Reliability Needs Assessment and the Climate Change Impact and Resilience Study, will build upon the findings of this 70x30 Scenario. To inform policymakers, investors and other stakeholders as implementation unfolds, these forward-looking studies will provide further assessment of the CLCPA focusing on other aspects such as transmission security and resource adequacy analysis.

7. Next Steps

In addition to the CARIS Phase 1 Study, any interested party can request additional studies or use the CARIS Phase 1 results for guidance in submitting a request for a CARIS Phase 2 study.

Phase 2 – Specific Transmission Project Phase

The NYISO staff will commence Phase 2 – the Project Phase – of the CARIS process following the approval of the Phase 1 report by the NYISO Board of Directors. *See* OATT § 31.3.2.4. The model for CARIS Phase 2 studies would include known changes to the system configuration that meet Base Case inclusion rules and would be updated with any new load forecasts, fuel costs, and emission costs projections upon review and discussion by stakeholders. Phase 2 will provide a benefit/cost assessment for each specific transmission project that is submitted by Developers who seek regulated cost recovery under the NYISO's Tariff.

Transmission projects seeking regulated cost recovery will be further assessed by the NYISO staff to determine whether they qualify for cost allocation and cost recovery under the NYISO Tariff.[41] To qualify, the total capital cost of the project must exceed $25 million, the benefits as measured by the NYCA-wide production cost savings must exceed the project cost measured over the first ten years from the proposed commercial operation date, and a super-majority (> 80%) of the weighted votes cast by the beneficiaries must be in favor of the project. *See* OATT § 31.5.4.3.5. Additional details on the Phase 2 process can be found in the Economic Planning Manual.[42]

Project Phase Schedule

The NYISO staff will perform benefit/cost analysis for submitted economic transmission project proposals for and, if a Developer seeks cost recovery, will determine beneficiaries and conduct cost allocation calculations. The results of the Phase 2 analyses will provide a basis for beneficiary voting on each proposed transmission project.

The next CARIS cycle is scheduled to begin in 2021.

Additional CARIS Studies

In addition to the reported CARIS studies, any interested party may request an additional study of congestion on the NYCA bulk power system. *See* OATT § 31.3.1.2.3. Those studies can analyze the

41 Market-based responses to congestion identified in Phase 1 of the CARIS are not eligible for regulated cost recovery, and therefore are not obligated to follow the requirements of Phase 2. Cost recovery of market-based projects shall be the responsibility of the Developer.

42 https://www.nyiso.com/documents/20142/2924447/epp_caris_mnl.pdf/0734b96b-3dcd-a8e8-4596-1dd41235b5f4

benefits of alleviating congestion with all types of resources, including transmission, generation and demand response, and compare benefits to costs.

Appendix A – Glossary

Ancillary Services: Services necessary to support the transmission of Energy from Generators to Loads, while maintaining reliable operation of the NYS Power System in accordance with Good Utility Practice and Reliability Rules. Ancillary Services include Scheduling, System Control and Dispatch Service; Reactive Supply and Voltage Support Service (or Voltage Support Service); Regulation Service; Energy Imbalance Service; Operating Reserve Service (including Spinning Reserve, 10-Minute Non-Synchronized Reserves and 30-Minute Reserves); and Black Start Capability. (As defined in the Services Tariff.)

Bid Production Cost: Total cost of the Generators required to meet Load and reliability Constraints based upon Bids corresponding to the usual measures of Generator production cost (e.g., running cost, Minimum Generation Bid, and Start Up Bid). (As defined in the NYISO Tariffs.)

Business Issues Committee (BIC): A NYISO governance committee that is charged with, among other things, the responsibility to establish procedures related to the efficient and non-discriminatory operation of the electricity markets centrally coordinated by the NYISO, including procedures related to Bidding, Settlements and the calculation of market prices. The BIC reviews the CARIS report and makes recommendations regarding review of the report by the Management Committee.

Capacity: The capability to generate or transmit electrical power (in MW), or the ability to reduce demand at the direction of the ISO, measured in MW. (As defined in the NYISO Tariffs.)

CARIS: The Congestion Assessment and Resource Integration Study for economic planning developed by the ISO in consultation with the Market Participants and other interested parties pursuant to Section 31.3 of this Attachment Y. (As defined in the NYISO OATT.)

Clean Energy Standard (CES): State initiative for 70% of electricity consumed in New York State to be produced from renewable sources by 2030.

Climate Leadership and Community Protection Act (CLCPA): State statute enacted in 2019 to address and mitigate the effects of climate change. Among other requirements, the law mandates that; (i) 70% of energy consumed in New York State be sourced from renewable resources by 2030, (ii) greenhouse gas emissions must be reduced by 40% by 2030, (iii) the electric generation sector must be zero greenhouse gas emissions by 2040, and (iv) greenhouse gas emissions across all sectors of the economy must be reduced by 85% by 2050.

Comprehensive Reliability Plan (CRP): A biennial study undertaken by the NYISO that evaluates projects offered to meet New York's future electric power needs, as identified in the Reliability Needs Assessment (RNA). The CRP may trigger electric utilities to pursue regulated solutions to meet Reliability Needs if market-based solutions will not be available by that point.

Comprehensive System Planning Process (CSPP): The Comprehensive System Planning Process set forth in this [OATT] Attachment Y, and in the Interregional Planning Protocol, which covers the reliability planning, economic planning, Public Policy Requirements planning, cost allocation and cost recovery, and interregional planning process (As defined in the OATT.)

Congestion: A characteristic of the transmission system produced by a constraint on the optimum economic operation of the power system, such that the marginal price of Energy to serve the next increment of Load, exclusive of losses, at different locations on the Transmission System is unequal. (As defined in the NYISO Tariffs.)

Congestion Rent: The opportunity costs of transmission Constraints on the NYS Bulk Power Transmission System. Congestion Rents are collected by the NYISO from Loads through its facilitation of LBMP Market Transactions and the collection of Transmission Usage Charges from Bilateral Transactions. (As defined in the OATT.)

Contingency: An actual or potential unexpected failure or outage of a system component, such as a Generator, transmission line, circuit breaker, switch or other electrical element. A Contingency also may include multiple components, which are related by situations leading to simultaneous component outages. (As defined in the NYISO Tariffs.)

Day Ahead Market (DAM): A NYISO-administered wholesale electricity market in which capacity, electricity, and/or Ancillary Services are auctioned and scheduled one day prior to use. The DAM sets prices as of 11 a.m. the day before the day these products are bought and sold, based on generation and energy transaction bids offered in advance to the NYISO. More than 90% of energy transactions occur in the DAM.

DC tie-lines: A high voltage transmission line that uses direct current for the bulk transmission of electrical power between two control areas.

Demand Response: A mechanism used to encourage consumers to reduce their electricity use during a specified period, thereby reducing the peak demand for electricity.

Eastern Interconnection Planning Collaborative (EIPC): A group of planning authorities convened to establish processes for aggregating the modeling and regional transmission plans of the entire Eastern Interconnection and for performing inter-regional analyses to identify potential opportunities for efficiencies between regions in serving the needs of electrical customers.

Economic Dispatch of Generation: The operation of generation facilities to produce energy at the lowest cost to reliably serve consumers.

Electric System Planning Working Group (ESPWG): A NYISO governance working group for Market Participants designated to fulfill the planning functions assigned to it. The ESPWG is a working group that provides a forum for stakeholders and Market Participants to provide input into the NYISO's CSPP, the NYISO's response to FERC reliability-related Orders and other directives, other system planning activities, policies regarding cost allocation and recovery for reliability projects, and related matters.

Energy Efficiency Portfolio Standard (EEPS): A statewide program ordered by the NYSPSC in response to the Governor's call to reduce New Yorkers' electricity usage by 15% of forecast levels by the year 2015, with comparable results in natural gas conservation. Also known as 15x15.

Exports: A Bilateral Transaction or purchases from the LBMP Market where the Energy is delivered to a NYCA Interconnection with another Control Area. (As defined in the NYISO Tariffs.)

External Areas: Neighboring Control Areas including Hydro Quebec, ISO-New England, PJM Interconnection, and IESO.

Federal Energy Regulatory Commission (FERC): The federal energy regulatory agency within the U.S. Department of Energy that approves the NYISO's tariffs and regulates its operation of the bulk electricity grid, wholesale power markets, and planning and interconnection processes.

FERC Form 715: An annual transmission planning and evaluation report required by the FERC – filed by the NYISO on behalf of the transmitting utilities in New York State.

FERC Order No. 890: Adopted by FERC in February 2007, Order 890 is a change to FERC's 1996 open access regulations (established in Orders 888 and 889). Order 890 added provisions establishing competition in transmission planning, transparency and planning in wholesale electricity markets and transmission grid operations, and strengthened the OATT with regard to non-discriminatory transmission service. Order 890 requires Transmission Providers – including the NYISO – to have a formal planning process that provides for a coordinated transmission planning process, including reliability and economic planning studies.

Grandfathered Rights: The transmission rights associated with: (1) Modified Wheeling Agreements; (2) Transmission Facility Agreements with transmission wheeling provisions; and (3) Third Party Transmission Wheeling Agreements (TWA) where the party entitled to exercise the transmission rights associated with such Agreements has chosen, as provided in the Tariff, to retain those rights rather than to convert them to Grandfathered TCCs. (As defined in the OATT.)

Grandfathered TCCs: The TCCs associated with: (1) Modified Wheeling Agreements; (2) Transmission Facility Agreements with transmission wheeling provisions; and (3) Third Party TWAs where the party entitled to exercise the transmission rights associated with such Agreements has chosen, as provided by the Tariff, to convert those rights to TCCs. (As defined in the OATT.)

Heat Rate: A measurement used to calculate how efficiently a generator uses thermal energy. It is expressed as the number of BTUs of thermal energy required to produce a kilowatt-hour of electric energy. Operators of generating facilities can make reasonably accurate estimates of the amount of heat energy a given quantity of any type of fuel. When thermal energy input is compared to the actual electric energy produced by the generator, the resulting figure tells how efficiently the generator converts fuel into electrical energy.

High Voltage Direct Current (HVDC): A transmission line that uses direct current for the bulk transmission of electrical power, in contrast with the more common alternating current systems. For long-distance distribution, HVDC systems are less expensive and suffer lower electrical losses.

Hurdle Rate: The conditions in which economic interchange is transacted between neighboring markets/control areas. The rate represents a minimum savings level, in $/MWh, that needs to be achieved before energy will flow across the interface.

Imports: A Bilateral Transaction or sale to the LBMP Market where Energy is delivered to a NYCA Interconnection from another Control Area. (As defined in the NYISO Tariffs.)

Independent System Operator (ISO): An organization, formed at the direction or recommendation of the Federal Energy Regulatory Commission (FERC), which coordinates, controls and monitors the operation of the electrical power system, usually within a single U.S. State, but sometimes encompassing multiple states.

Installed Capacity (ICAP): A generator or load facility that complies with the requirements in the Reliability Rules and is capable of supplying and/or reducing the demand for energy in the NYCA for the purpose of ensuring that sufficient energy and capacity are available to meet the Reliability Rules. (As defined in the OATT.)

Installed Reserve Margin (IRM): The amount of installed electric generation capacity above 100% of the forecasted peak electric consumption that is required to meet the NYSRC resource adequacy criteria. Most planners consider a 15-20% reserve margin essential for good reliability.

ISO Market Administration and Control Area Services Tariff (Services Tariff): Sets forth the provisions applicable to the services provided by the ISO related to its administration of competitive markets for the sale and purchase of Energy and Capacity and for the payments to Suppliers who provide Ancillary Services to the ISO in the ISO Administered Markets ("Market Services") and the ISO's provision of Control Area Services ("Control Area Services"), including services related to ensuring the reliable operation of the NYS Power System. (As defined in the Services Tariff.)

ISO Open Access Transmission Tariff (OATT): Every [FERC]-approved ISO or RTO must have on file with [FERC] an open access transmission tariff of general applicability for transmission services, including ancillary services, over such facilities. (As defined in the Code of Federal Regulations.)

Load: A term that refers to either a consumer of Energy or the amount of demand (MW) or Energy (MWh) consumed by certain consumers. (As defined in the NYISO Tariffs.)

Locational Capacity Requirement (LCR): Specifies the minimum amount of installed capacity that must be procured from resources situated specifically within a locality (Zone K and Zone J). It considers resources within the locality as well as the transmission import capability to the locality in order to meet the resource adequacy reliability criteria of the NYSRC and the NPCC.

Load Serving Entity (LSE): Any entity, including a municipal electric system and an electric cooperative, authorized or required by law, regulatory authorization or requirement, agreement, or contractual obligation to supply Energy, Capacity and/or Ancillary Services to retail customers located within the NYCA, including an entity that takes service directly from the NYISO to supply its own Load in the NYCA. (As defined in the Services Tariff.)

Load Zones: The eleven regions in the NYCA connected to each other by identified transmission interfaces. Designated as Load Zones A-K.

Local Transmission Planning Process (LTPP): The first step in the CSPP, under which stakeholders in New York's electricity markets participate in local transmission planning.

Locational Based Marginal Pricing (LBMP): The price of Energy at each location in the NYS Transmission System.

Management Committee: NYISO governance committee that reviews the CARIS report following review by the Business Issues Committee and makes recommendations regarding approval to the NYISO's Board of Directors.

Market Analysis and Portfolio Simulation (MAPS) Software: An analytic tool for market simulation and asset performance evaluations.

Multi-Area Reliability Simulation (MARS) Software: An analytic tool for market simulation to assess the reliability of a generation system comprised of any number of interconnected areas.

Market Based Solution: Investor-proposed projects that are driven by market needs to meet future reliability requirements of the bulk electricity grid as outlined in the RNA. Those solutions can include generation, transmission and Demand Response programs. .

Market Participant: An entity, excluding the NYISO, that produces, transmits sells, and/or purchases for resale capacity, energy and ancillary services in the wholesale market. Market Participants include: customers under the NYISO tariffs, power exchanges, TOs, primary holders, load serving entities, generating companies and other suppliers, and entities buying or selling transmission congestion contracts.

New York Control Area (NYCA): The area under the electrical control of the NYISO. It includes the entire state of New York, and is divided into 11 Load Zones.

New York Independent System Operator (NYISO): Formed in 1997 and commencing operations in 1999, the NYISO is a not-for-profit organization that manages New York's bulk electricity grid – a more than 11,000-mile network of high voltage lines that carry electricity throughout the state. The NYISO also oversees the state's wholesale electricity markets. The organization is governed by an independent Board of Directors and a governance structure made up of committees with Market Participants and stakeholders as members.

New York State Reliability Council (NYSRC): A not-for-profit entity the mission of which is to promote and preserve the reliability of electric service on the New York State Power System by developing, maintaining, and, from time-to-time, updating the Reliability Rules which shall be complied with by the New York Independent System Operator (NYISO) and all entities engaging in electric transmission, ancillary services, energy and power transactions on the New York State Power System.

New York State Bulk Power Transmission Facilities (BPTFs): The facilities identified as the New York State Bulk Power Transmission Facilities in the annual Area Transmission Review submitted to the NPCC by the ISO pursuant to NPCC requirements. (As defined in the OATT.) The BPTFs include (i) all NYCA transmission facilities 230 kV and above, (ii) all NYCA facilities identified by the NYISO to be part of the Bulk Power System, as defined by the NPCC and the NYSRC, and (iii) select 115 kV and 138 kV facilities that are considered to be bulk power transmission in accordance with the 2004 FERC Order.

Nomogram: Nomograms are system representations used to model electrical relationships between system elements. These can include; voltage or stability related to load level or generator status; two interfaces related to each other; generating units the output of which are related to each other; and operating procedures.

North American Electric Reliability Corporation (NERC): A nonprofit corporation based in Atlanta Georgia to promote the reliability and adequacy of bulk power transmission in the electric utility systems of North America. NERC establishes mandatory reliability standards that it enforces and that are enforced by the Northeast Power Coordinating Council.

Northeast Coordinated System Planning Protocol (NCSPP): ISO New England, PJM and the NYISO work together under the NCSPP, to analyze cross-border issues and produce a regional electric reliability plan for the northeastern United States.

Northeast Power Coordinating Council (NPCC): A not-for-profit corporation in the state of New York responsible for promoting and enhancing the reliability of the international, interconnected bulk power system in Northeastern North America. The NPCC encompasses Ontario, Quebec, New York and New England, and serves as the Regional Entity overseeing and enforcing the reliability standards of the North American Electric Reliability Corporation.

Operating Reserves: Capacity that is available to supply Energy or reduce demand and that meets the requirements of the NYISO. (As defined in the Services Tariff.)

Overnight Costs: Direct permitting, engineering and construction costs with no allowances for financing costs.

Phase Angle Regulator (PAR): Device that controls the flow of electric power in order to increase the efficiency of the transmission system.

Proxy Generator Bus: A proxy bus located outside the NYCA that is selected by the NYISO to represent a typical bus in an adjacent Control Area and for which LBMP prices are calculated. The NYISO may establish more than one Proxy

Generator Bus at a particular Interface with a neighboring Control Area to enable the NYISO to distinguish the bidding, treatment and pricing of products and services at the Interface. (As defined in the NYISO Tariffs.)

Public Policy Transmission Planning Process (PPTPP): The process by which the ISO solicits needs for transmission driven by Public Policy Requirements, evaluates all solutions on a comparable basis, and selects the more efficient or cost effective transmission solution, if any, for eligibility for cost allocation under the ISO Tariffs. (As defined in the OATT.)

Regional Greenhouse Gas Initiative (RGGI): A cooperative effort by ten Northeast and Mid-Atlantic states to limit carbon dioxide emissions using a market-based cap-and-trade approach.

Regulated Backstop Solution: Proposals required of Responsible TOs to meet Reliability Needs identified in the RNA as outlined in the OATT. Those solutions can include generation, transmission or Demand Response. Non-Transmission Owner developers may also submit regulated solutions. The NYISO may call for a Gap Solution if neither market-based nor regulated backstop solutions meet Reliability Needs in a timely manner. To the extent possible, the Gap Solution should be temporary and strive to be compatible with market-based solutions. The NYISO is responsible for evaluating all solutions to determine if they will meet identified Reliability Needs in a timely manner.

Regulation Service: The Ancillary Service defined by the FERC as "frequency regulation" and that is instructed as Regulation Capacity in the Day-Ahead Market and as Regulation Capacity and Regulation Movement in the Real-Time Market. .

Reliability Need: A condition identified by the NYISO in the RNA as a violation or potential violation of Reliability Criteria. (As defined in the OATT.)

Reliability Needs Assessment (RNA): A biennial report that evaluates resource adequacy and transmission system security over years three through ten of a ten-year planning horizon, and that identifies future needs of the New York electric grid. It is the first step in the NYISO's Reliability Planning Process.

Reliability Planning Process (RPP): The process set forth in this [OATT] Attachment Y by which the ISO determines in the RNA whether any Reliability Need(s) on the BPTFs will arise in the Study Period and addresses any identified Reliability Need(s) in the CRP, as the process is further described in Section 31.1.2.2. (As defined in the OATT.)

Security Constrained Unit Commitment (SCUC): A process developed by the NYISO, which uses a computer algorithm to dispatch sufficient resources, at the lowest possible Bid Production Cost, to maintain safe and reliable operation of the NYS Power System.

Shadow Price: The incremental economic impact of a constraint on system production cost. Calculated in linear program optimization for economic dispatch.

Short Term Reliability Process (STRP): The process set forth in this [OATT] Attachment FF by which the ISO evaluates and addresses the reliability impacts resulting from both: (i) Generator Deactivation Reliability Need(s), and/or (ii) other Reliability Needs on the BPTFs that are identified in a [Short Term Assessment of Reliability] STAR. The STRP covers years one through five of the Study Period, with a focus on Reliability Needs arising in years one through three.

Special Case Resource (SCR): Demand Side Resources whose Load is capable of being interrupted upon demand at the direction of the ISO, and/or Demand Side Resources that have a Local Generator, which is not visible to the ISO's Market Information System and is rated 100 kW or higher, that can be operated to reduce Load from the NYS Transmission System or the distribution system at the direction of the ISO. (As defined in the Services Tariff.).

Stakeholders: A person or group that has an investment or interest in the functionality of New York's transmission grid and markets.

Thermal transfer limit: The maximum amount of heat a transmission line can withstand. The maximum reliable capacity of each line, due to system stability considerations, may be less than the physical or thermal limit of the line.

Transfer Capability: The amount of electricity that can flow on a transmission line at any given instant, in MW, respecting facility rating and reliability rules.

Transmission Congestion Contract (TCC): The right to collect, or obligation to pay, Congestion Rents in the Day Ahead Market for Energy associated with a single MW of transmission between a specified Point Of Injection and Point Of Withdrawal. TCCs are financial instruments that enable Energy buyers and sellers to hedge fluctuations in the price of transmission. (As defined in the OATT.)

Transmission Constraint: Limitations on the ability of a transmission facility to transfer electricity during normal or emergency system conditions.

Transmission District: The geographic area in which a Transmission Owner, including LIPA, is obligated to serve Load, as well as the customers directly interconnected with the transmission facilities of the Power Authority of the State of New York. (As defined in the NYISO Tariffs.)

Transmission Interface: A defined set of transmission facilities that separate Load Zones and that separate the NYCA from adjacent Control Areas.

Transmission Owner (TO): The public utility or authority (or its designated agent) that owns facilities used for the transmission of Energy in interstate commerce and provides Transmission Service under the Tariff. (As defined in the NYISO Tariffs.)

Transmission Planning Advisory Subcommittee (TPAS): A group of Market Participants that advises the NYISO Operating Committee and provides support to the NYISO Staff in regard to transmission planning matters including transmission system reliability, expansion, and interconnection.

List of Key Acronyms

70x30	New York 70% End Use Renewable Energy by 2030 Goal
BTM-PV	Behind-The-Meter Photovoltaic Generation
CARIS	Congestion Assessment and Resource Integration Study
CC	Combined Cycle Generation
CE	Central East
CE+NS-KN	Central East-New Scotland-Knickerbocker
CLCPA	Climate Leadership and Community Protection Act
CO2	Carbon Dioxide
CT	Combustion Turbine
DMNC	Dependable Maximum Net Capacity
DW-RN	Dunwoodie to Rainey Interface
EGC-VRM	East Garden Center to Valley Stream Interface
EIA	U.S. Energy Information Administration
EPA	U.S. Environmental Protection Agency
ESPWG	Electric System Planning Working Group
ESR	Energy Storage Resource
FERC	Federal Energy Regulatory Commission
Gold Book	2019 Load and Capacity Data Report “Gold Book”
GWD	Greenwood Load Pocket
HRM	Hourly Resource Modifier
HQ	Hydro Quebec
I2K	Zone I to Zone K Interface
ICAP	Installed Capacity
LBMP	Locational-Based Marginal Pricing
MAPS software	Multi Area Production Simulation Software
MARS software	Multi-Area Reliability Simulation software
MUST	Managing and Utilizing System Transmission

MW	megawatt
MWh	megawatt hour
NOx	Nitrogen Oxide
NREL	National Renewable Energy Laboratory
NYCA	New York Control Area
NYISO	New York Independent System Operator
OATT	Open Access Transmission Tariff
PV	Photovoltaic or Solar Powered Generation
PSH	Pumped Storage Hydro Generation
RE	Renewable Energy
REC	Renewable Energy Credit
RETP	Regulated Economic Transmission Project
RGGI	Regional Greenhouse Gas Initiative
RPP	Reliability Planning Process
SCUC software	Security Constrained Unit Commitment software
TARA	Transmission Adequacy & Reliability Assessment
TCCs	Transmission Congestion Contracts
TPAS	Transmission Planning Advisory Subcommittee
TWh	terawatt hour
UPNY-SENY	Upstate New York – Southeast New York
UPV	Utility Scale Photovoltaic Solar Generation
VS	Volney - Scriba

New York ISO
Independent System Operator

10 Krey Boulevard, Rensselaer, New York 12144

518.356.6000 ■ www.nyiso.com

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Attachment II

Climate Change Impact and Resilience Study – Phase II

An Assessment of Climate Change Impacts on Power System Reliability in New York State

FINAL REPORT

Authors:

Paul J. Hibbard
Charles Wu
Hannah Krovetz
Tyler Farrell
Jessica Landry

September 2020

ANALYSIS GROUP

Acknowledgments

This report has been prepared at the request of the New York Independent System Operator (NYISO), and presents an assessment of the potential impacts on power system reliability in 2040 associated with system changes due to climate change and policies to mitigate its effects. Our work benefitted significantly from input and comment from the NYISO and its market participants and stakeholders.

About the Authors

Paul Hibbard is a former Chairman of the Massachusetts Public Utilities Commission, and has held positions in both energy and environmental agencies in Massachusetts. During his tenure on the Commission, Mr. Hibbard served as a member of the Massachusetts Energy Facilities Siting Board, and has testified before Congress, state legislatures, and federal and state regulatory agencies. Mr. Hibbard is now a Principal in Analysis Group's Boston office, and has public and private sector experience in energy and environmental technologies, economics, market structures, and policy.

Charles Wu, a Manager in Analysis Group's Boston office, is an expert in the assessment and design of wholesale electricity markets in Northeastern U.S. power market regions. Mr. Wu's work has included review and analysis of generating unit performance in and design parameters affecting capacity and energy markets in New England and New York; the development of power market models to evaluate unit performance and profitability; and the assessment of changing infrastructure and public policy on economic, consumer and environmental impacts through economic and production cost modeling.

Hannah Krovetz is a Senior Analyst in Analysis Group's San Francisco office, with experience in the application of economic analyses to challenges in energy and environmental markets and policy. Ms. Krovetz has focused in recent years on technical analysis and systems modeling related to power sector market design, power system reliability, and energy/climate policy matters.

Tyler Farrell is an Analyst in Analysis Group's Boston office, with background in evaluating the economic and financial aspects of electricity generation from both individual business and system operator perspectives. Mr. Farrell has focused in recent years on the design and implementation of models to evaluate wholesale market and reliability outcomes in the electric sector.

Jessica Landry is an Analyst in Analysis Group's Boston office, with background in the application of econometrics to the evaluation of international monetary issues, higher education, and antitrust/competition matters. Ms. Landry has recently focused on the emergence of the offshore wind sector in the Eastern U.S., and the refinement of power system modeling data and logic.

About Analysis Group

Analysis Group is one of the largest international economic consulting firms, with more than 1,000 professionals across 14 offices in North America, Europe, and Asia. Since 1981, Analysis Group has provided expertise in economics, finance, health care analytics, and strategy to top law firms, Fortune Global 500 companies, government agencies, and other clients worldwide.

Analysis Group's energy and environment practice area is distinguished by expertise in economics, finance, market modeling and analysis, regulatory issues, and public policy, as well as deep experience in environmental economics and energy infrastructure development. Analysis Group has worked for a wide variety of clients including (among others) energy producers, suppliers and consumers, utilities, regulatory commissions and other federal and state agencies, tribal governments, power-system operators, foundations, financial institutions, and start-up companies.

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I.Executive Summary

A. Background and Approach

In 2020, NYISO contracted with Analysis Group (AG) to complete Phase II of the *Climate Change Impact and Resilience Study* ("Phase II Study"). This Phase II Study is designed to review the potential impacts on power system reliability of the (1) the electricity demand projections for 2040 developed in the preceding *Climate Change Phase I Study*,[1] and (2) potential impacts on system load and resource availability associated with the impact of climate change on the power system in New York ("climate disruptions"). The climate disruptions considered include items that could potentially occur or intensify with a changing climate and that affect power system reliability, such as more frequent and severe storms, extended extreme temperature events (*e.g.,* heat waves and cold snaps), and other meteorological events (*e.g.,* wind lulls, droughts, and ice storms).

Notably, the 2019 New York State Climate Leadership and Community Protection Act (CLCPA) requires "…reducing 100% of the electricity sector's greenhouse gas emissions by 2040."[2] This means that step one in our analysis was the development of a "starting point" Climate Change Phase II resource set (the "CCP2 resource set") for the year 2040, one that starts with the 2019 Congestion Assessment and Resource Integration Study (CARIS) 70x30 resources, but by 2040 meets the requirements of the CLCPA. Given the extensive reliance today on generators that burn fossil fuels (primarily natural gas), a key input to the analysis was the establishment of a resource set that does not include the operation of existing fossil-fueled thermal power plants, yet has sufficient resources available to meet electricity demand in the year 2040 without emissions of greenhouse gases (GHG).

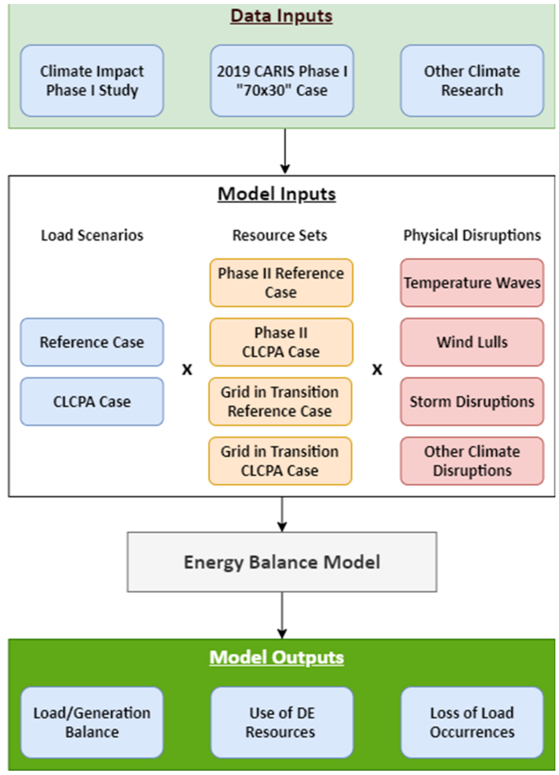
With these key parameters in mind, over the past nine months Analysis Group has carried out its analysis of climate change-related impacts to system reliability. This report summarizes the results of our analysis, and presents the purpose, analytic method, and observations drawn from Analysis Group's review. The project was completed with assistance from NYISO with respect to system data and analyses, and with input from stakeholders at the NYISO Electric System Planning Working Group (ESPWG) and the Transmission Planning Advisory Subcommittee (TPAS).

Ultimately, the purpose of this Phase II study is to simulate the potential impacts of climate change and climate policy on the reliable operation of the New York power system, and to present observations to enable the NYISO, market participants, policy makers and other stakeholders an opportunity to consider whether the potential impacts warrant changes to planning, operational practices, and/or market designs. Analysis Group's approach to the analysis is presented in detail in Section II. In summary, it consists of the following steps (depicted in Figure ES-1):

[1] In 2019, the New York Independent System Operator (NYISO) contracted with Itron to complete long-term energy, peak, and hourly load projections for the New York Control Area through the year 2050. The projections capture the impact of climate change on average temperatures and electricity demand, as well as the potential impact on demand of increased energy efficiency and electrification of the building and transportation sectors. That project - termed the Climate Change Phase I Study ("Phase I Study") - was completed in 2019, and included long-term energy, peak, and hourly load projections (for the NYISO system as a whole and each of the eleven NYISO load zones) that reflect the potential demand impacts of climate change and climate policy in New York. Itron, *New York ISO Climate Change Impact Study; Phase 1: Long-Term Load Impact*, December 2019.

[2] New York Climate Leadership and Community Protection Act (CLCPA), NY State Senate Bill S6599, 2019-06-18. The New York Department of Environmental Conservation (DEC) proposes to define GHGs as the following: GHGs are "[g]aseous constituents of the atmosphere that absorb and emit radiation at specific wavelengths within the spectrum of terrestrial radiation emitted by the Earth's surface, the atmosphere itself, and by clouds. For the purposes of the Part, this includes carbon dioxide, methane, nitrous oxide, perfluorocarbons, hydrofluorocarbons, and sulfur hexafluoride." https://www.dec.ny.gov/regulations/121059.html.

Figure ES-1: Energy Balance Model (EBM) Inputs and Outputs



- Configure Analysis Group's Energy Balance Model (EBM) to simulate power system operations in 2040, with separate balancing across and within 11 NYISO load zones;
- Review and input the ITRON Phase I hourly load forecasts for 2040, and extract data from the Phase I analysis to enable the modeling of changes in electricity demand with changes in meteorological conditions (*e.g.*, temperature); From each Phase I forecast we evaluate the peak-demand month in the winter (January) and summer (July), and the low-demand month in the shoulder season (April);
- Review state requirements encoded in the CLCPA, and consider potential scenarios for resource development consistent with state requirements and current technology trends;
- Based on this review, identify principles for constructing resource sets with sufficient resources to reliably meet NYISO seasonal peak demand, building on the 2019 CARIS Phase I 70X30 Case;
- Develop **four cases** to analyze, incorporating two Phase I Itron 2040 load forecasts (the "Reference Case" and the "CLCPA Case") and 2040 resource sets that reliably meet demand for each forecast: two that were developed for this Phase II Study, and two that were developed as part of the Grid in Transition (GIT) study.[3] Thus, the four cases analyzed are:
    - **CCP2-Reference**
    - **CCP2-CLCPA**
    - **GIT-Reference**
    - **GIT-CLCPA**
- Include in the resource sets a generic resource, the role of which is to identify the attributes of any additional resources that may be needed to avoid or reduce Loss of Load Occurrences (LOLO).[4] These resources - identified as dispatchable and emissions-free resources ("DE Resources") - are described in more detail below;

[3] The review of resource sets from both studies is intended to highlight differences in potential resource development pathways. The CCP2 resource sets are focused on achieving the CLCPA 2040 requirements with a primary focus on expansion of renewable resources and associated transmission. The GIT resource sets reflect less infrastructure development, and a stronger focus on resources like existing thermal generating resources operating on zero carbon fuels. See Section II for a more detailed description of the resource sets.

[4] Loss of Load Occurrences are not meant to be equivalent to Loss of Load Expectation in a resource adequacy context.

- Identify the potential impacts of a changing climate on the power system, including conditions or events that alter electricity demand, generating resource availability and operations, and inter-zonal transmission transfer capability. This research is used to construct "climate disruption scenarios";
- Run the climate disruption scenarios through Analysis Group's EBM for each of the four cases analyzed (the CCP2-Reference, CCP2-CLCPA, GIT-Reference, and GIT-CLCPA), for each seasonal month (where relevant);[5] and
- Generate results with respect to potential loss of load occurrences (LOLO) and reliance on DE resources, and draw observations related to power system operations based on the comparison of results across cases.

Section II contains a detailed summary of our analytic method, and of the structure and mechanics of the Analysis Group Energy Balance Model. Section III describes the cases we analyze, which include the climate change-induced physical disruptions layered on the four different cases. In Section IV we provide an overview of the metrics we evaluate through the EBM, and the form of model outputs for each case. Finally, in Section V we present the results of the analysis and our observations based on the results. The Appendices contain additional modeling details and a comprehensive set of results across all relevant cases and climate disruption scenarios.

B. Results and Observations

The context for our analysis includes both the impact of a changing climate on power system operations, and the energy and environmental policy response to the threat of climate change. In recent years, many states have moved towards establishing significant and progressive GHG emission reduction requirements that are directionally consistent with dramatically reducing GHGs from energy supply and use by the middle of the century, across all sectors of the economy. With the passage of the CLCPA, New York positioned itself at the forefront of these efforts to address climate change and initiated a fundamental transition in energy supply and use in general, and in the electric system in particular.

It is difficult to envision the specific pathway New York will take to achieve the required GHG emission reductions from the economy over just the next three decades, and from the electric sector over the next two decades. The scope of changes that will be needed to the state's building, transportation and electric sectors is unprecedented. Meeting this level of emission reductions will not only require rapid advancement of existing advanced energy technologies, but will also likely require technologies, policies, and programs that have not yet been conceived of or developed. This introduces significant uncertainty in modeling what the economy and power system look like in 2040, when the power system will operate under a very different set of resources, infrastructure, and end-use consumption patterns.

With these uncertainties in mind, we develop a model of the New York power system in 2040 that starts from the present, and is focused on the resources and policies that are taking shape at this time. We begin with the load forecasts developed in the Phase I Study, and the resources assumed in the most recent CARIS report for the 70X30 scenario. However, the load forecasts for 2040 result in electricity demand levels well in excess of the CARIS starting point resources, particularly in the CLCPA case, due to the assumed level of electrification of other sectors

[5] Some combinations of cases, climate disruption scenarios, and months are not relevant. For example, severe heat wave cases are only modeled for the summer month.

in the economy. Moreover, all of the existing fossil-fueled generating resources are removed from the resource set to be consistent with the requirements of the CLCPA. As a result, we must construct starting point resource sets by assuming a vast buildout of carbon-free resources sufficient to meet electricity demand in the peak hour of the year.

To develop the 2040 starting point CCP2 resource sets,[6] we prioritize the addition of wind, solar, demand response, and storage technologies alongside substantial build out of the state's transmission system. The reliance in the CCP2 resource sets on renewable resources[7] -- the potential of which is largely located in the upstate region -- requires significant increases in inter-zonal transfer capability across all NYISO zones.

Finally, both the CCP2 and GIT resource sets include undefined "backstop resources" to cover any circumstances where the resource sets are insufficient to meet identified demand, and to evaluate what attributes such a resource must have to help meet reliability needs. Since the resource generally needs to be *dispatchable* and compliant with *emission* requirements, we designate this the "DE Resource." As described in more detail below, the DE Resource is not tied to any particular technology. Table ES-1 summarizes the generation resources assumed in the CCP2-CLCPA resource set.

Table ES-1: Generation Capacity, CCP2-CLCPA Resource Set

Nameplate Capacity by Zone, MW	A	B	C	D	E	F	G	H	I	J	K	Total
Land-based Wind	10,815.9	1,566.9	7,726.2	7,774.5	7,316.4	-	-	-	-	-	-	**35,200.0**
Offshore Wind	-	-	-	-	-	-	-	-	-	14,957.8	6,105.2	**21,063.0**
Solar (Behind-the-meter)	1,408.5	436.4	1,192.8	138.2	1,345.5	1,653.4	1,367.3	121.2	179.4	1,343.1	1,692.2	**10,877.8**
Solar (Grid Connected)	11,496.0	1,312.0	7,170.0	-	4,536.0	9,322.0	5,272.0	-	-	-	154.0	**39,262.0**
Hydro Pondage	2,675.0	-	-	856.0	-	-	41.6	-	-	-	-	**3,572.6**
Hydro Pumped Storage	-	-	-	-	-	1,170.0	-	-	-	-	-	**1,170.0**
Hydro Run-of-River	4.7	63.7	70.4	58.8	376.2	282.5	57.1	-	-	-	-	**913.4**
Nuclear	-	581.7	2,782.5	-	-	-	-	-	-	-	-	**3,364.2**
Imports	-	-	-	1,500.0	-	-	-	-	-	1,310.0	-	**2,810.0**
Storage	4,232.0	20.0	3,160.0	4,168.0	2,296.0	292.0	84.0	-	-	1,096.0	252.0	**15,600.0**
Price Responsive Demand (Summer)	949.9	205.2	510.1	357.7	211.1	433.9	246.3	58.6	134.9	1,940.8	187.6	**5,236.0**
Price Responsive Demand (Winter)	619.0	133.7	332.4	233.1	137.5	282.7	160.5	38.2	87.9	1,264.7	122.3	**3,412.0**
DE Resources	465.4	674.2	1,513.4	370.0	312.7	3,390.4	6,887.2	79.8	-	11,848.1	6,595.4	**32,136.6**

With this model arrangement, we evaluate a range of climate disruption scenarios. These represent episodic circumstance and events driven by meteorological conditions that could become more frequent and/or more severe in a changing climate. The disruption scenarios are focused on those weather conditions known to disrupt power system operations, specifically coastal and inland storms, heat and cold spells, drought and icing events. And their effects on power system infrastructure and operations are modeled based on historical experience with similar events.

Based on our review of modeling results and the context for our analysis, we come to the following observations:

Climate disruption scenarios involving storms and/or reductions in renewable resource output (e.g., due to wind lulls) can lead to loss of load occurrences. Electrification, particularly in the building sector, transforms New York into a winter-peaking system. Thus loss of load occurrences due to climate disruptions in the winter are deeper and occur across more scenarios than in the summer. *See* Table ES-2. Specifically, in the winter severe wind storms, lulls in wind resource output (upstate or downstate), and icing events all lead to loss of load, as well as

[6] The GIT resource sets were developed as part of a separate NYISO Study.

[7] In this report we use the term "renewable resource" to refer to on-shore and off-shore wind, and grid-connected and behind-the-meter solar resources. In the EBM, renewable resource hourly output is modeled based on state-specific and resource-specific generation profiles from the National Renewable Energy Lab ("NREL"). For more detail on the modeling of renewable resources, see Section II.D below.

elevated reliance on the DE resource. In the summer, these events increase the system's reliance on the DE resource, but LOLOs are only triggered in the severe coastal (hurricane) and upstate wind storm events.

The variability of meteorological conditions that govern the output from wind and solar resources presents a fundamental challenge to relying on those resources to meet electricity demand. In scenarios involving LOLOs, or requiring substantial contributions from DE resources, periods of reduced output from wind and solar resources are the primary driver of challenging system reliability conditions, particularly during extended wind lull events. *See* Figure ES-2, showing results for the CCP2-CLCPA Case in the winter, including an extended wind lull. During the wind lull,[8] the state realizes losses of load in at least one zone for thirteen hours, with a total loss of over 14 gigawatt-hours (GWh). Moreover, during the wind lull the system relies *primarily* on the DE generating resource to avoid more severe LOLOs. Even outside the specific seven-day climate disruption wind lull period, one can see that base case reductions in wind output create periods of significant reliance on the DE resource to avoid losses of load.[9] Importantly, further increasing the nameplate capacity of such resources is of limited value, since when output is low, it is low for all similar resources across regions or the whole state.[10] As can also be seen across the full winter month, periods of solar output are not able to contribute during the early evening winter peak hours.

Table ES-2: Case Result Summaries, CCP2-CLCPA Case

	Loss of Load		DE Resource Generation				
	Total Hours with LOLO in at least one Load Zone	Aggregate LOLO (MWh)	Max Consecutive Hours with DE Resource Gen.	Total Hours with DE Resource Gen.	Aggregate DE Resource Gen. (MWh)	Max DE Resource Gen. (MW)	Max 1-hr. DE Resource Gen. Ramp (MW)
CLCPA Summer Scenario - Climate Impact Phase II Resource Set							
Baseline Summer	0	0	36	145	847,589	22,081	9,170
Heat Wave	0	0	36	147	964,668	22,081	8,642
Wind Lull - Upstate	0	0	37	179	1,171,656	23,361	9,447
Wind Lull - Off-Shore	0	0	40	196	1,116,165	23,170	9,170
Wind Lull - State-Wide	0	0	40	235	1,697,161	24,440	11,605
Hurricane/Coastal Wind Storm	26	20,168	171	322	1,892,046	22,081	8,642
Severe Wind Storm – Upstate	8	1,620	87	283	2,002,682	22,081	8,642
Severe Wind Storm – Offshore	0	0	36	167	1,079,462	22,163	10,015
Drought	0	0	36	166	1,148,649	23,595	10,610

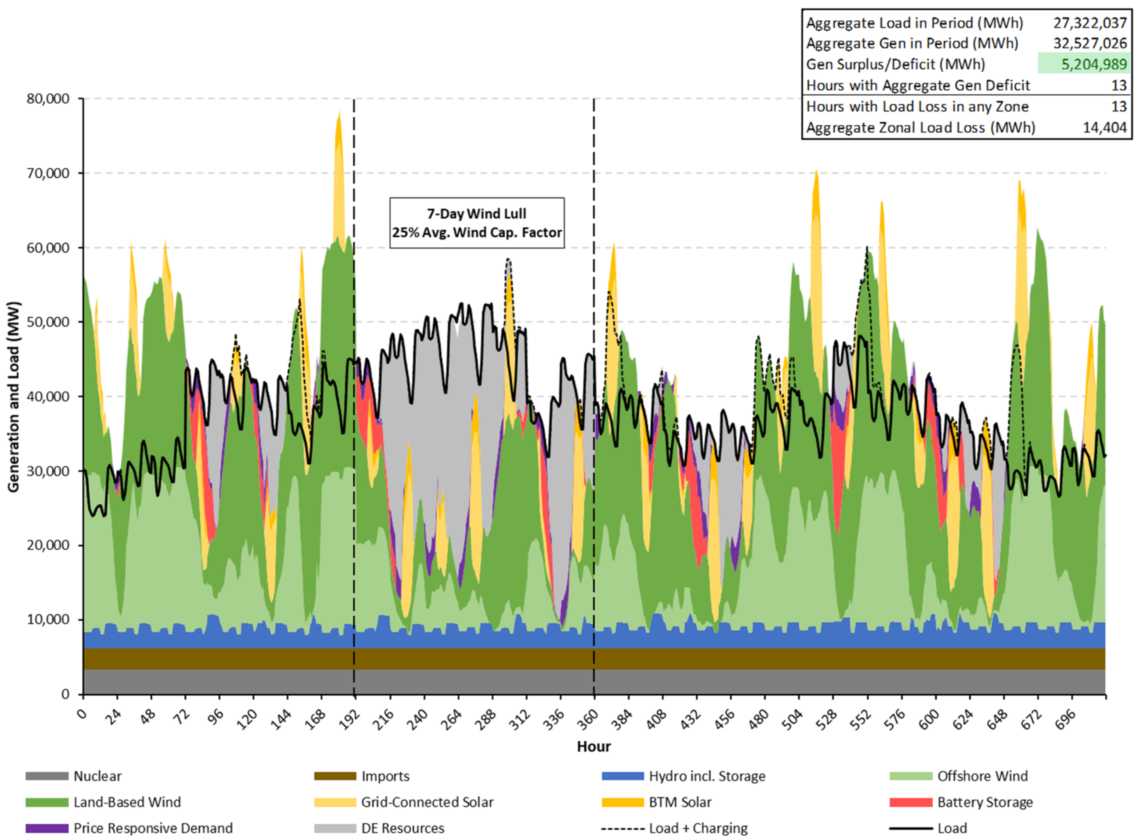
	Loss of Load		DE Resource Generation				
	Total Hours with LOLO in at least one Load Zone	Aggregate LOLO (MWh)	Max Consecutive Hours with DE Resource Gen.	Total Hours with DE Resource Gen.	Aggregate DE Resource Gen. (MWh)	Max DE Resource Gen. (MW)	Max 1-hr. DE Resource Gen. Ramp (MW)
CLCPA Winter Scenario - Climate Impact Phase II Resource Set							
Baseline Winter	0	0	62	255	2,866,203	32,135	11,716
Cold Wave	0	0	62	259	2,879,947	32,135	11,716
Wind Lull - Upstate	5	2,373	62	259	3,076,530	32,135	12,707
Wind Lull - Off-Shore	10	7,184	104	274	3,350,666	32,135	11,715
Wind Lull - State-Wide	13	14,404	105	278	3,653,404	32,135	12,403
Severe Wind Storm – Upstate	45	22,146	81	369	3,822,059	31,419	12,850
Severe Wind Storm – Offshore	9	4,203	103	304	3,609,785	32,135	11,715
Icing Event	2	88	62	273	2,909,437	32,135	11,716

[8] The wind lull is a seven-day period from hours 192-360 in Figure ES-2.

[9] *See* hours 72-144, and hours 408-480.

[10] As noted, the generation profiles used for the wind and solar resources are taken from NREL state-specific generation profiles, based on historical meteorological data. The resulting renewable resource output profile across each season's month affects both the amount of renewable capacity needed to meet 2040 peak demand, and the reliance on the DE Resource and occurrence of LOLOs across all hours of the month. Renewable generation technology development and/or the realization of meteorological conditions that are different than the underlying historical NREL profiles could result in fundamentally different contributions from such resources in 2040, and different levels and types of system impacts than those reported here. The significance of the modeled renewable generation technologies and profiles thus represents a key uncertainty in the analysis, and this should be considered in interpreting results.

Figure ES-2: Hourly Load/Generation Balance, CCP2-CLCPA Winter Wind Lull Case



Battery storage resources help to fill in voids created by reduced output from renewable resources, but periods of reduced renewable generation rapidly deplete battery storage resource capabilities. As described in Section II, the CCP2-CLCPA resource set includes the development and operation of over 15,600 MW (124.8 GWh) of new storage resources, configured as eight-hour batteries, and distributed throughout the state to maximize their ability to time shift excess generation from renewable resources.[11] At this level of development, battery storage makes significant contributions to avoiding loss of load and reliance on backstop generation for the immediate period following sharp declines in renewable resource output due to climate disruptions (and also due to normal wind/solar resource variability).[12] While this represents a substantial level of assumed growth in battery storage within New York, the contribution of storage is quickly overwhelmed by the depth of the gap left during periods of time with a drop off in renewable generating output over periods of a day or more. This is revealed by the fill in of the DE Resource (in grey) following depletion of the storage resources (in red) during various periods in Figure ES-2.

The DE resources needed to balance the system in many months must be significant in capacity, be able to come on line quickly, and be flexible enough to meet rapid, steep ramping needs. Our generic DE resource generates energy as needed to meet demand and avoid loss of load occurrences. This study does not make any assumptions

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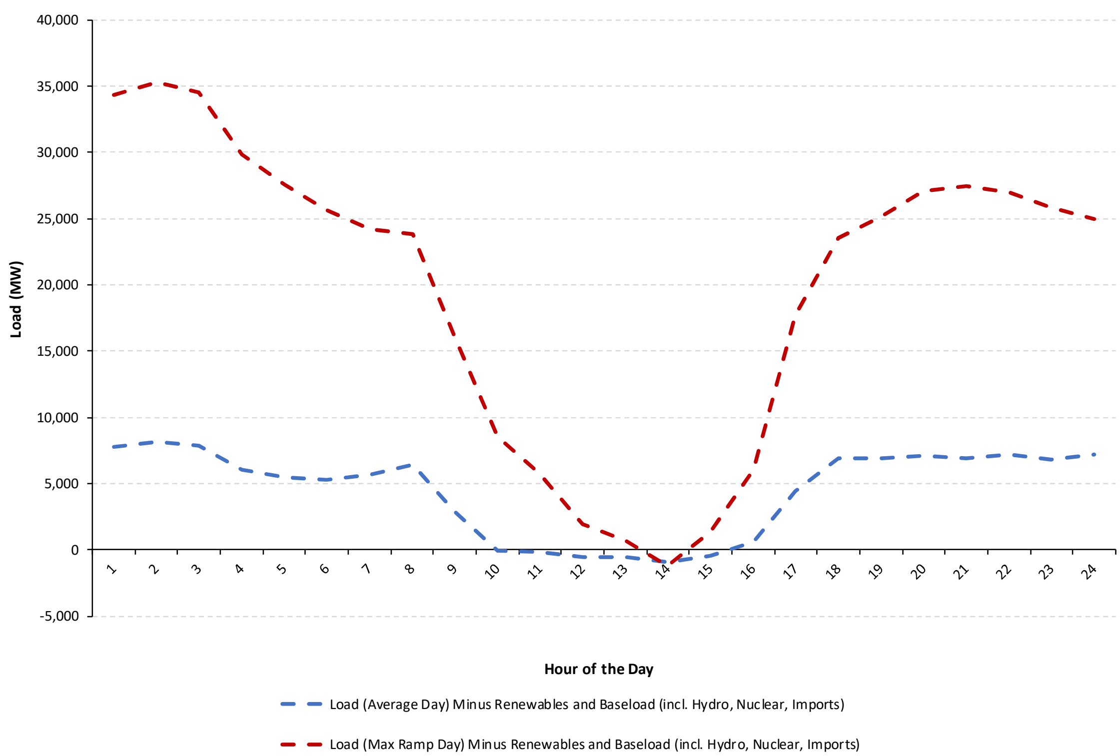
[11] As noted earlier, the development of the CCP2 resource sets requires a vast buildout of carbon-free resources to meet elevated electricity demand and the absence of existing fossil-fueled generating resources. This need drives the assumed amount of battery storage resources included in the resource sets; that is, the amount of battery storage assumed reflects an assumption of continuous and significant growth in storage technology over the next twenty years, and is well in excess of any existing mandates or near-term development expectations.

[12] *See*, e.g., Figure ES-2, hours 72-96, 192-216, and 410-440.

about what technology or fuel source can fill this role twenty years hence. Instead, the model includes the DE Resource to identify the attributes required of whatever resource (or resources) emerges to fill this role. Based on a review of the frequency and circumstances of reliance on the DE Resource to maintain reliability in the model, we can identify the characteristics required of the resource. In this, certain observations stand out. First, even in the baseline cases (*i.e.,* before layering in climate disruption events), there are periods of very low output from the renewable resources during periods of demand when resources need to be available to meet the bulk of the system's annual energy requirements. During such periods, the need for the DE Resource climbs very high - at times more than 30,000 MW. This is true even though the DE Resource is not significantly utilized on an annual energy basis, and has a very low capacity factor, at or less than ten percent. Second, the DE Resource needs to be highly flexible - it needs to be able to come on quickly, and be able to meet rapid and sustained ramps in demand. The results in Table ES-2 show that the minimum one-hour ramp requirement, even in the baseline CCP2-CLCPA case, approaches 12 GW, and climbs to nearly 13 GW in multiple CLCPA climate disruption cases. Moreover, as can be seen in Figure ES-3, the ramping capability of the DE Resource is even larger when viewed across multiple hours. For example, the four-hour period of greatest ramp in the CCP2-CLCPA case in the winter exceeds 20,000 MW.

Figure ES-3: Maximum Hourly Ramping Requirement, CCP2-CLCPA Winter Case



The assumed increase in inter-zonal transfer capability in the CCP2 resource sets enables a renewables-heavy resource mix and improves reliability, but also increases vulnerability to certain climate disruption scenarios. The CCP2 resource sets are designed to maximize the contribution of renewable resources which, due to available land area and ease of siting, are heavily weighted towards the upstate region. As a result, it is necessary to assume a major build out of the transmission system in New York, to enable the upstate renewable resources to contribute to meeting load in the downstate region. Across the climate disruption cases, the increased transfer capability improves the resilience of the power system to all events that are localized, such as offshore storms or wind lulls that only affect the upstate or downstate regions, as well as to some disruptions that affect load and generation across the state, such as heat waves and cold snaps. Conversely, the increased reliance on transmission increases the vulnerability of the system to climate disruption events that specifically impact transmission capability, including icing events or major storms that disable transmission capacity.

Cross-seasonal differences in load and renewable generation could provide opportunities for renewable fuel production. The CCP2 resource sets are constructed to be able to meet peak demand in the winter and summer seasons based primarily on production from renewable resources. However, this means that there is a substantial amount of renewable generation that is excess, or "spilled," in off-peak seasons and hours. This introduces the potential for a seasonal storage technology to help meet the needs represented in the analysis by DE Resource generation during the summer and winter. Such potential assumes the emergence of economic technologies capable of converting excess renewable energy to a fuel and storing it for later use, or the development of other long term storage technologies. For example, as seen in Table ES-3, the excess renewable generation in the shoulder season modeling period under the CCP2-CLCPA case totaled roughly 23,204 GWh, while the DE Resource use in the winter modeling period was just 4,401 GWh. This raises the possibility that, should such technologies or capabilities emerge, excess off-peak renewable generation could help meet the peak-month energy requirements represented in the model by generation from the DE Resource.

Table ES-3: Excess Renewable Generation

Season	Aggregate Excess Renewable Generation (GWh)	Average Hourly Excess Renewable Generation (MW)	Average Hourly Percentage of Excess Renewable Generation (%)
Winter	4,401	6,112	13.66%
Summer	3,926	5,453	13.95%
Shoulder	23,204	32,227	75.80%

The current system is heavily dependent on existing fossil-fueled resources to maintain reliability, and eliminating these resources from the mix will require an unprecedented level of investment in new and replacement infrastructure, and/or the emergence of a zero-carbon fuel source for thermal generating resources. A power system that is effectively free of GHG emissions in 2040 cannot include the continued operation of thermal units fueled by well-based natural gas. However, these are the very units that are currently vital to maintain power system reliability throughout the year. This is the fundamental challenge of the power system transition that will take place over the next two decades. Indeed, this transition must take place at the same time that electricity demand in the state will grow significantly if electrification of other economic sectors, such as transportation and heating, is needed to meet the economy-wide GHG emission reduction requirements. In all four cases studied, the required investment in and development of renewable resources is substantial, and far greater than anything previously experienced in New York. Table ES-4 shows the pace of development required for each case and resource set, compared to the historical capacity growth rate in New York.

Table ES-4: Required Rate of New Resource Development

	Nameplate Capacity (MW)		Required 2020-2040 Nameplate Capacity Growth Rate (MW/yr)	
	Wind (Land-based and Offshore)	Grid-Connected Solar	Wind (Land-based and Offshore)	Grid-Connected Solar
Existing Resources (2020)	1,985	57		
Climate Phase II Reference Case Resource Set (2040)	39,962	34,354	1,899	1,715
Climate Phase II CLCPA Scenario Resource Set (2040)	56,263	39,262	2,714	1,960
Grid in Transition Reference Case Resource Set (2040)	23,522	30,043	1,077	1,499
Grid in Transition CLCPA Scenario Resource Set (2040)	48,357	31,669	2,319	1,581
Historical Nameplate Capacity Growth Rate (2012-2020, MW/yr)			**71.4**	**3.1**

Overall, the key reliability challenges identified in this study are associated with both how the resource mix evolves between now and 2040 in compliance with the CLCPA, and the impact of climate change on meteorological conditions and events that introduce additional reliability risks. The climate disruption events modeled in the EBM may be more frequent and/or more severe than in the past, and this increases NYISO's challenges in managing reliability risks over time. Nevertheless, such events do not appear to be *qualitatively* different than similar events experienced in the past, and present reliability challenges that may be considered similar to those faced today. With sufficient planning and preparation such events could be managed to maintain reliability in much the same way current weather-based disruptions are managed. However, on top of this the analysis demonstrates that, based on current information and technologies, the evolution of the system to one focused on zero-carbon resources and the infrastructure needed to support such a resource mix could introduce a number of key vulnerabilities to system reliability. These challenges include the variability of the meteorological conditions affecting renewable generation, the temporal limitations of existing battery storage technologies, and the increased dependence on resources distant from load centers. Based on our analysis, managing this transition seems to introduce reliability challenges that may be more difficult than those arising from the conditions of a changing climate. *Most importantly, this analysis suggests that establishing electricity market designs and energy policies to encourage innovation and accelerate advanced energy resource development will be key to reliably and economically managing the transition in the electric sector in New York*.

Comparing the CCP2 resource sets to the GIT resource sets reveals key differences in how the system makeup in 2040 can affect reliability outcomes. There are key differences between the Climate Change Phase II resource sets and those developed for the Grid in Transition study. First, given the different mixes of resources, the proportion of load met by DE Resources in the CLCPA winter load scenario is roughly nine percent for the CCP2-CLCPA resource set, but about 20 percent for the GIT-CLCPA resource set. In addition, given differences in the assumed level of transmission on the system (the GIT resource set does not include any expansion of the current transmission system), constraints on the Total East and Total South interfaces are binding in a larger percentage of hours under the GIT resource set, which means that DE Resources downstate are dispatched to provide electricity in more hours. The differences also lead to changes in vulnerability to climate disruptions. There are more hours with loss of load occurrences in the state-wide and offshore wind lull cases under the CCP2 resource sets, given the smaller overall quantity of DE Resources and greater reliance on wind resources. Conversely, the lower level of inter-zonal transfer capability in the Grid-in-Transition study resource set leads to more severe load losses during scenarios that affect upstate resources, such as severe windstorm and icing events.

In this study, we provide results for two very different visions for the evolution of the power system - one that relies on renewables and transmission (the CCP2 resource sets), and one that places greater emphasis on the backstop resource - that is, the potential emergence of a zero-carbon generation or fuel source (the GIT resource sets). These are only two of a wide range of potential outcomes as the system and technologies change over the next two decades, but they represent in some sense two bookends to potential system changes - one focused on aggressive system infrastructure development, and one that looks more like the current system, but is dependent on the development of zero-GHG fuel sources. The key differences between them are the relative levels of investment in system infrastructure, and the degree of reliance on the DE Resource.

For example, if there is skepticism that an economic fuel or technology will emerge and be widely available, and that can deliver reliable capacity, energy, reserves, and flexible operating attributes with little or no emissions of GHGs, then the pathway may be more heavily tilted towards aggressive investment in and development of renewable and transmission infrastructure, such as in the CCP2 resource sets. This approach would allow the system to operate with relatively low annual generation from the DE Resource. Conversely, if such a fuel or technology were to emerge, be technologically and economically viable, and be widely available, then there is less need to invest the significant capital needed to build out renewable and transmission infrastructure to meet the CLCPA requirements. These differences provide useful insight into the challenges New York State will face in guiding and managing what will likely be a rapid transition over the next two decades.

II.Analytic Method

A. Overview of Analytic Method

Analysis Group developed and applied a multi-step energy balance analysis to assess the risks to the reliability of the NYISO power system posed by changes in system conditions and infrastructure due to climate change in New York State. The analysis is completed for 2040 based upon the state's CLCPA requirements for that year. It reflects both the Climate Change Phase I results with respect to climate-induced changes to system demand, and assumptions described further in this report with respect to system infrastructure available in 2040. Figure 4 presents the structure of the analysis used to generate results for all cases, and Figure 5 summarizes the inputs and logic of the energy balance model. Section II provides a more detailed description of the analytic method, model components, and data and information sources used in the analysis.

Figure 4: Structure of Analysis

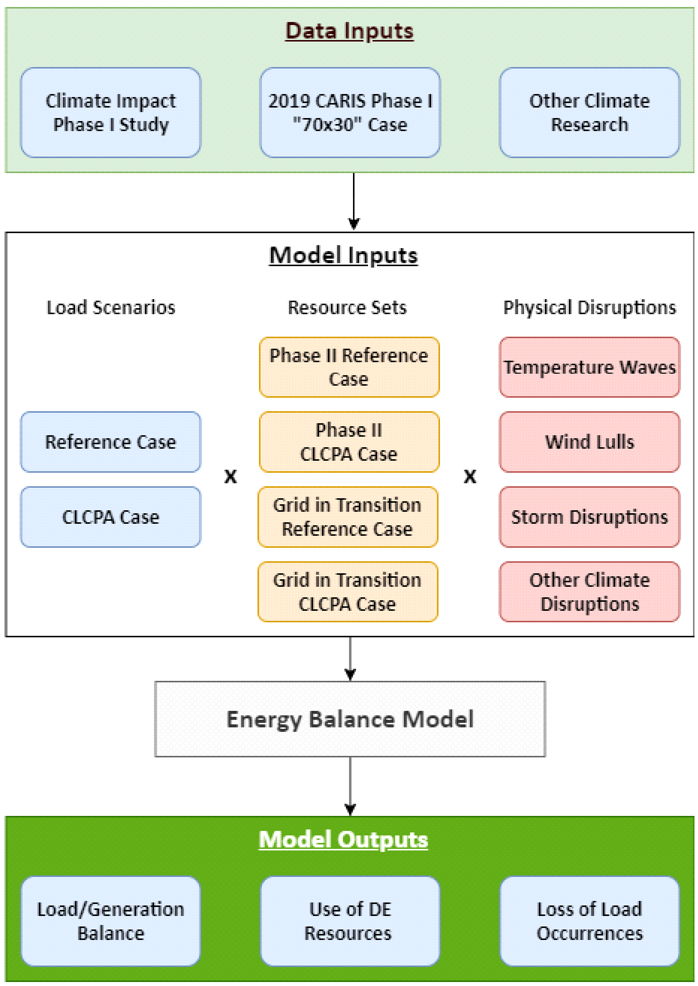
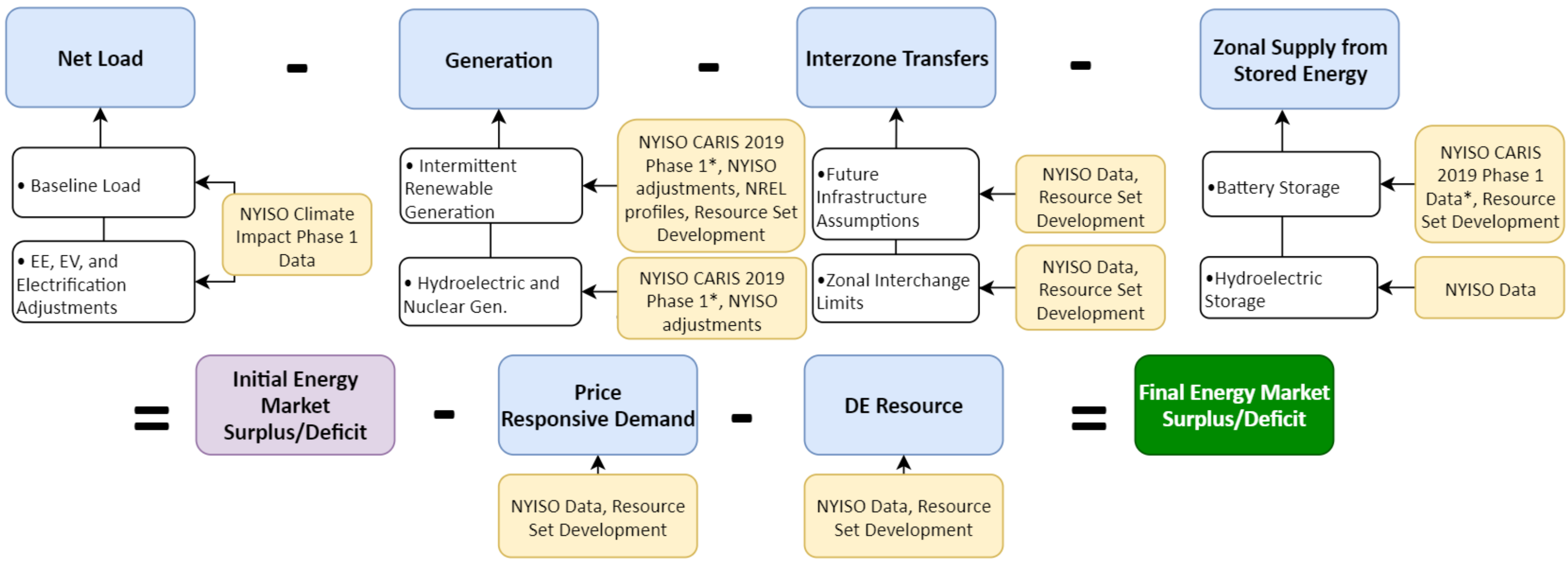


Figure 5: Energy Balance Model Steps and Data Sources



*CARIS 2019 is being leveraged as a starting point in the initial base case assumption

B. Framework for Energy Balance Analysis

Analysis Group's energy balance model is a deterministic, scenario-based assessment of system operations in a future year - 2040. The model evaluates system reliability under different combinations of load including assumptions regarding future loads and hourly shapes based on weather. It analyzes different resource sets and variations in future system resource mix and transmission topology. The model examines various climate disruptions under which altered climate conditions affect load, resource availability/generation, and transmission availability. Given that the load levels and the output of renewable generating capacity vary widely over the course of the year, we evaluate three representative seasonal modeling periods: summer, winter, and shoulder season. For each season we model a single month.

There are three core elements to the modeling framework - (1) Load, (2) Resources, and (3) Climate Disruptions:

(1) Load: The starting point for the analysis is expected system conditions for the future year of 2040, based on load scenarios developed by Itron in the NYISO Climate Impact Phase I study ("Phase I Study").[13] The Phase I load scenarios reflect the impact of climate change and state policy on electricity demand in New York State. We focus on two of the Phase I scenarios: 1) the Reference Case, which assumes average New York State temperatures will increase at 0.7 degrees F per decade without significant load impact from state policy; and 2) the CLCPA Case, which assumes the same temperature trend, but reflects load impacts from electrification of the transportation and building sectors in the state, and enhanced implementation of energy efficiency. These factors are described in more detail in Section II.C.1 below.

(2) Resources: The next step involves development of resource sets for each of the two load scenarios, based on the Analysis Group Climate Change Phase II (CCP2) set and the NYISO Grid in Transition (GIT) Study set. This leads to four resource sets: CCP2-reference, CCP2-CLCPA, GIT-reference, and GIT-CLCPA. The purpose of this step is to position the power system to reliably meet the Phase I 2040 demand levels. The resource sets are developed to maintain reliable system operations in the season with the highest peak load, which is summer for the Reference Case and winter for the CLCPA Case. For the CCP2 resource sets, the starting point for each resource set is the 2019 CARIS Phase I "70x30" case, which assumes specific quantities of renewable and nonrenewable resources by load zone. This resource set alone is insufficient to meet demand; thus, the analysis adds renewable generating capacity, storage capacity, transmission capability, and DE resource capacity in quantities sufficient to meet the seasonal peak demand.[14] The resource sets are described in more detail in Section II.D below.

(3) Climate Disruption Scenarios: With the Phase I load scenarios and reliable starting point resource sets in hand, we then identify a range of impacts on loads and resources associated with the impacts of a changing climate. These climate disruptions are used to define seasonal "cases," which are run through the energy balance model to identify any reliability risks associated with operations under those conditions. The results of the model identify the magnitude, frequency and duration of any periods where available generation was potentially insufficient to

[13] Itron, "New York ISO Climate Impact Study; Phase 1: Long-Term Load Impact," (hereafter "Phase I Study"), December 2019.

[14] Analysis Group developed the reliable resource sets for use in this study. As described in Section II.F below, we also evaluate system outcomes using the resource set assumed in the Grid in Transition study, which varies in the location and quantities of both renewable and DE resources across zones.

meet load over the duration of the seasonal modeling period, or where significant storage or DE resource output is needed to supplement renewable generation.[15]

The sections that follow describe the methods and data used in the model and analyses. Section II.C addresses the development of the load scenarios and seasonal modeling periods. Section II.D details the construction of resource sets by load scenario, which includes generation, storage resources, and transmission. Section II.E reviews the "dispatch" and intrastate power transfer logic that is applied across all cases, and finally Section II.F compares the resource sets developed for this study with those used in the *Grid in Transition* study.

C. Construction of Seasonal Modeling Periods and Load Scenarios

The model represents three 30-day seasonal modeling periods during 2040, under two load scenarios. The selection of these modeling periods was designed to represent normal winter peak, summer peak, and shoulder season weather conditions, and to reflect the associated electricity demand and load shapes, and the seasonal generation profiles of renewable resources. The analysis is a review of reliability under normal conditions; it is not meant to represent a severe or worst case scenario. This section describes (1) the load scenarios used to represent electrical demand and (2) the selection of the modeling periods.

1. Load Scenarios

The load profiles used in the energy balance model are derived from the NYISO Climate Impact Phase I study conducted by Itron in 2019.[16,17] For each day of the years from 2020 to 2050, the Phase I Study estimated daily peak loads and total energy based on historical average daily temperatures after adjustments for the temperature impacts of climate change, using a nonlinear model of load-temperature response.[18] In each scenario, hourly loads were further modified with adjustments to account for predicted energy efficiency and electrification of the transportation and building sectors. The daily peak and energy forecasts were then combined with a forecasted system hourly load shape to create an 8,760 hour baseline load forecast for each year.[19] The Phase I Study modeled four load scenarios: the Reference Case, the Reference Case with accelerated weather trend, the Policy Case, and the CLCPA case.

[15] We do not explicitly model operating reserves in this framework. In nearly all hours, there are sufficient DE resources available in the model to cover reserve needs in all zones across the state, and we do not model the degree of reserve drawdown as a metric in this analysis. This means that during the limited number of hours when the energy balance model predicts loss of load in one of the combination cases modeled, additional DE resources above those assumed would be needed to meet load and/or maintain reserves.

[16] Itron, "New York ISO Climate Impact Study; Phase 1: Long-Term Load Impact," December 2019.

[17] We note that other work is being performed toward forecasting future demand, such as the NYSERDA study "Pathways to Deep Decarbonization in New York State." NYSERDA, "Pathways to Deep Decarbonization in New York State," June 24, 2020, available at https://climate.ny.gov/-/media/CLCPA/Files/2020-06-24-NYS-Decarbonization-Pathways-Report.pdf.

[18] Phase I Study, pp. 29-41.

[19] Phase I Study, pp. 38-41.

This study focuses on two of the Phase I load scenarios, with the following underlying assumptions:

1) Reference Case
   a) 0.7 degrees F per decade increase in average New York state temperatures[20]
   b) Increases in energy efficiency over 2019 levels[21]
   c) Increases in electric vehicle charging load over 2019 levels[22]
2) CLCPA Case
   a) 0.7 degrees F per decade increase in average New York state temperatures
   b) Increases in energy efficiency (more extensive than Reference Case)[23]
   c) Increases in electric vehicle charging load (more extensive than Reference Case)[24]
   d) Increases in residential and commercial building electrification

The CLCPA Case in the Phase I study assumed significant electrification of both the residential and commercial building sectors.[25] This electrification load comprises three components: 1) base-use electrification, which includes replacement of existing gas-powered household appliances with electric-powered models; 2) cooling electrification, with additional summer load from cooling heat pumps and A/C units; and 3) heating electrification, with additional winter load from electric heat pumps. In the residential sector, the Phase I study assumed "fossil fuel heating is converted to cold climate heat pumps with resistance heat backup, gas water heaters are converted to electric water heaters, gas dryers are converted to electric dryers, and gas stoves are converted to electric stoves."[26] In the commercial sector, the Phase I study assumed "electric sales gains from commercial gas conversions are similar in proportion to residential electrification, based on similar size in total energy usage in the two sectors, and similar proportions of heating and cooling end uses."[27] Cooling and heating electrification are based on historical hourly profiles of loads, and vary with daily temperature. The additional heating electrification load is sufficient in the CLCPA Case to move the system as a whole from summer-peaking to winter-peaking, with highest loads in January. Total load impacts for each Phase I load scenario are provided in Appendix A.

The Phase I study load scenarios also account for expected growth in behind-the-meter solar generation, but this study removes that impact from loads and instead treats behind-the meter solar as a generating resource.

2. Seasonal Modeling Periods

Both loads and renewable generation vary considerably across the course of the year, and present different types of challenges for reliability during different seasons. For example, wind capacity factors are on average highest in winter, when solar capacity factors are lowest, and vice versa. In addition, the modeling periods needed to be long enough to capture multi-day or multi-week trends in generation resource availability and output, which are affected by natural variance in meteorological conditions over the course of a day, week, month, and season.

[20] 0.7 degrees F per decade is the historical trend based on weather station data from 1950 through 2018. Phase I Study, pp. 9, 16.

[21] According to the Phase I Study, "End-use efficiency projections include the expected impact of standards, naturally occurring efficiency gains, and utility efficiency (EE) programs such rebates and thermal shell improvement programs." Phase I Study, p. 30.

[22] EV charging load assumes that electric vehicles (both Battery Electric Vehicles and Plug-in Hybrid Electric Vehicles) account for 40% of passenger vehicles and light duty trucks by 2040. Additional penetration of commercial electric vehicles (medium and heavy duty trucks and buses) are also assumed, for total EV electric sales of 13,174 GWh in 2040. Phase I Study, p.37.

[23] The CLCPA Case assumes an additional 2,200 GWh per year in energy efficiency savings over the Reference Case. Phase I Study, p. 43.

[24] The CLCPA Case assumes "Stronger electric vehicle market penetration than the Reference Case." Phase I Study, p. 43.

[25] Phase I Study, pp. 46-50.

[26] Phase I Study, p. 46.

[27] Phase I Study, p. 48.

As a result, this study analyzes three 30-day representative modeling periods in 2040, one for the summer season, one for the winter season, and one for the shoulder season. The Phase I Study provided 8,760 hourly loads for all of 2040. The Phase II Study uses the first 30 days of the months of July, January, and April for the summer, winter and shoulder seasons. These months were selected because for each load scenario, July 2040 included the day with the forecasted summer peak load, January 2040 included the day with the forecasted winter peak load, and April 2040 had the lowest total energy consumed. Table 5 summarizes the load scenarios by peak and total energy.

Table 5: Summary of Load by Seasonal Modeling Period

		Summer	**Winter**	**Shoulder**
	Dates	7/1/2040 - 7/30/2040	1/1/2040 - 1/30/2040	4/1/2040 - 4/30/2040
Reference Case	Peak Load (MW)	38,666	28,010	23,507
	Total Energy (GWh)	19,013	14,111	11,385
CLCPA Case	Peak Load (MW)	48,589	57,144	27,060
	Total Energy (GWh)	22,476	27,322	12,497

D. Construction of Resource Sets by Load Case

This section describes the construction of the CCP2 resource sets underlying the analytic model, which are the generation and transmission inputs making up the supply side of the electrical system. Each resource set is specifically designed to establish a reliable starting point for the analysis, given the load forecasts from the Phase I report. With a reliable starting point, we then run scenarios that incorporate the physical disruptions associated with climate change impacts on load and system resources.

As a starting point, the CCP2 resource set is based on the 2019 CARIS 1 Phase 1 "70X30" Case for generation inputs, and assumes a transmission topology provided by NYISO that reflects current inter-zonal transfer limits. Intra-zonal and/or local transmission limitations were not assessed in this study. The CARIS generation inputs are designed to meet the CLCPA mandate that New York consumers be served by 70 percent renewable energy by 2030, and include significant additional development of renewable resources above current levels.

Two factors influence the resources added to get to a reliable system starting point. First, the Phase I CLCPA case requires additional resources to meet incremental load due to both temperature-induced demand increases and the assumed electrification of the transportation and building sectors. Second, the CLCPA establishes certain requirements that may affect the resources available to meet demand in 2040. Specifically, the Act requires 100 percent of the state's electricity supply to be emissions free by 2040,[28] and the state must reach at least 85% reduction on the way to net zero greenhouse gas emissions by 2050 across all economic sectors. This will require a significant transformation of the existing system in ways that are not easy to anticipate at this time.

In consideration of these factors, we constructed a set of additional resources to reliably meet system demand in 2040. In doing so, we recognize that there is a vast array of different resource types and pathways to meeting the CLCPA requirements, which potentially include resources, technologies, and fuels that are currently not commercially available. Further, even the resource options that we consider based on current information will evolve significantly in the coming decades, and each has different properties in terms of availability and generation profiles, maximum capacity potential, total energy potential, and cost. Thus our starting point resource set should be viewed as but one among a vast number of potential resource combinations, technologies or pathways that could reliably meet electricity demand in 2040.

Given the unique circumstances and focus of state law and policy in New York, the analysis developed a resource set prioritizing the development and operation of zero-carbon renewable resources and the expansion of high-voltage transmission capacity as needed to move generation to load within the state. Specifically, in order to identify a combination that fully met load in all hours of the modeling periods, the resource set was built from the following resources, in the following order:

1) **Assume the retention of existing zero-carbon resources**
   Maintain in 2040 the availability and operation of existing hydroelectric and nuclear capacity as baseload system resources.
2) **Maximize the development of renewable generating resources in New York state**
   Build out solar and land-based and offshore wind generating capability to the maximum feasible extent, based on an evaluation of need and a review of technical potential. Steps one and two are key to addressing aggregate incremental energy demand.
3) **Increase zero carbon resources imported from neighboring regions**

[28] NY Senate Bill S6599, pp. 4, June 18, 2019.

The analysis assumes that it is possible to increase the transfer of zero-emission capacity and generation from Canada through the addition of new transmission lines to the north. This resource provides assistance with both incremental energy needs and the ability to instantaneously balance system load.

4) **Mitigate the impact of electrification through demand modulation by the "shaping" of EV load**
The analysis assumes that with electrification of the transportation sector, electricity markets and pricing in New York will provide incentives for the management of demand associated with electric vehicle charging. Such incentives will assist with managing peak demand and instantaneous power needs, but they will not address aggregate energy deficits.
5) **Enable the efficient movement of diverse generation sources across the state through additional transmission**
The vast majority of land-based renewable resource potential is in upstate New York. A renewables-focused resource set will need significant increases in inter-zonal transfer capability, helping to reduce zonal bottlenecks.
6) **Maximize the participation in markets of price responsive demand**
The combination of wholesale market designs and new distributed resource initiatives and technologies will provide incentives for significant expansion of price responsive demand, helping meet instantaneous power needs.
7) **Continue the aggressive development of energy storage technologies**
The analysis assumes that current initiatives and changing economics will continue growth in the development of storage within the state, helping address instantaneous power needs
8) **Dispatchable and emissions-free resource**
Even with the substantial infrastructure and resource growth in steps 1-7, there will likely need to be a dispatchable resource with attributes needed to help balance the system under certain conditions, such as high loads, loss of resources, inter-zonal transfer limits, or limited output from variable resources. This report focuses on the attributes needed from such resources, without assuming we can anticipate what form they will take in 2040 as technologies continue to evolve.

As noted, the starting point CCP2 resource set represents only one possible pathway or outcome. The Grid in Transition resource set, reviewed in Section II.F., presents another, and very different, potential pathway for the development of resources to reliably meet 2040 system needs, one focused more on a DE resource, and less on renewables and transmission. In reality, it is likely that the manner in which the system evolves to meet the changing nature of electricity demand and resource requirements will involve some elements of both resource sets, but will not look exactly like either. Nonetheless, the results, and how they differ across these two resource sets, offer interesting insights into the challenges that will need to be addressed through market design, resource/technological development, and policy in the coming decades.

In the following sections, we describe in more detail our assumptions with respect to each of the categories of resources described above for the CCP2 resource sets.

1. Retention of Baseload Resources

The generation fleet used in the energy balance model assumes the continued operation of a number of baseload hydroelectric and nuclear units. Resource retirements are guided by 2019 CARIS Phase 1 "70X30" Case. CARIS performs a sensitivity to examine the impact of upstate nuclear operations beyond the currently regulated Zero Emission Credits ("ZECs") eligibility criteria.[29] This resource set assumes the operation of Nine Mile Point 1 & 2,

[29] NYISO, "2019 CARIS 1 70X30 Scenario Development", pp. 12, September 6, 2019.

James A. Fitzpatrick 1 and R.E. Ginna 1. We assume the plants will operate at a 100 percent capacity factor for all hours of the thirty day modeling period. Actual resource operations across the full year will be lower, based upon the dependable maximum net capability and forced outage rates of the nuclear resources in the future.

CARIS assumes that the majority of the existing hydro resources will continue in operation. Each resource set maintains 913 MW of run of river hydro and 3,573 MW of pondage hydro. The hourly capacity factor of run-of-river hydro units is based on historical 2018 generation data.[30] The Niagara units (Robert Moses and Lewiston) operate on a daily cycle that depends on season and load case. Niagara operations obey water levels set by an international water treaty and are synchronized with solar generation to generate in hours when need is greatest. The other hydro pondage units, including the St. Lawrence-Franklin D. Roosevelt unit, are assumed to operate at a 100 percent capacity factor for all hours of the modeling period. The Gilboa pumped storage unit behaves as a storage resource and is described in Section II.C.7. Additional baseload nuclear and hydroelectric resources are not included in the resource set.

2. Renewable Resources (CARIS Starting Point)

The model includes four types of renewable resources: land-based wind, offshore wind, utility-scale solar, and behind-the-meter solar. The starting point for the amount of wind and solar resources modeled is the nameplate capacity of these resources assumed in the 2019 CARIS Phase I study as of February 2020.[31] The 2019 CARIS Phase I CLCPA case starting point assumes an approximately an additional 17,500 MW of wind and 25,000 MW of solar, and aligns with renewable targets established in state policies, including 9,000 MW of offshore wind by 2035 and 6,000 MW of behind the meter solar capacity by 2025.[32] Solar and wind resources are distributed according to capacity shares by zone from the 2017 and 2018 CES REC solicitation awards and the interconnection queue.[33] The study does not assume any utility solar in Zones G, H, I, and J, in consideration of potential siting challenges and land costs. Similarly, no land-based wind is assumed in Zones F through K.

The generation profile assumed for the solar units, in terms of hourly capacity factors, are based on 2006 data from the NREL Solar Power database using 62 simulated solar farm sites across New York State, which provide separate estimates for BTM and grid-connected solar.[34] Two Zones did not have solar farm data. For Zone D BTM solar, a simple average of bordering Zones F and E was used. For Zone K grid-connected solar, the BTM solar data from Zone K was scaled up by the average ratio of utility to BTM solar capacity factors NYCA-wide. The hourly capacity factors assumed for the wind units are based on 2009 data at simulated 100 meter turbine height from the NREL's Wind Toolkit Database, using 721 weather sites in NY.[35] A summary of renewable resource capacity factors by season is listed in Table 6. As shown, solar capacity factors are higher on average in the summer modeling period than in the winter, and wind capacity factors are higher on average in the winter than in the summer.

[30] Aggregated Run of River Hydro Production Data collected from NYISO's Decision Support System.

[31] The 2019 CARIS Phase I study was ongoing at the time this study was conducted, and certain assumptions in the CARIS Phase I Study have been altered since February 2020.

[32] The CARIS starting point assumes 6,750 DC MW in behind-the-meter solar capacity in 2040 in the CLCPA case, which translates to 5,439 AC MW. For the purposes of this study, we use the AC MW as the basis for nameplate capacity of solar resources. This is a larger nameplate capacity for behind-the-meter solar in the CLCPA case as compared to the Reference case (3,629 AC MW).

[33] NYISO, "2019 CARIS 1 70X30 Scenario Development," pp. 15, September 6, 2019.

[34] NREL Solar Power Database, https://www.nrel.gov/grid/solar-power-data.html.

[35] NREL Wind Toolkit Database, https://www.nrel.gov/grid/wind-toolkit.html.

Table 6: Renewable Capacity Factor by Season

	Average Capacity Factor by Season		
Resource Type	**Summer**	**Winter**	**Shoulder**
Wind (Land-based)	27.31%	46.22%	51.72%
Wind (Offshore)	30.14%	47.81%	58.42%
Solar (Behind-the-meter)	17.98%	8.02%	18.20%
Solar (Grid-Connected)	20.23%	8.61%	20.25%

Notes:
[1] Wind capacity factors are based on 2009 historical data; solar capacity factors are based on 2006 historical data
Sources:
[1] NREL Solar Power Database, https://www.nrel.gov/grid/solar-power-data.html.
[2] NREL Wind Toolkit Database, https://www.nrel.gov/grid/wind-toolkit.html.

3. Renewable Resource: Additions to 2040

As noted, the approach used in developing the resource set assumes that renewable resources will be prioritized for development to help meet the CLCPA 100 percent emission-free resources requirement for 2040. This means that a significant quantity of new renewable resources needs to be added in the model, above and beyond the 2019 CARIS starting point resources, in order to meet electrical loads in that year.[36] Due to seasonal differences in capacity factors among renewable resource types, the optimal mix of renewable resources depends in part on characteristics of the load scenarios. For example, wind resources are more productive in winter months and therefore can generate more than solar resources of the same nameplate capacity, to ensure reliability in a winter-load-peaking scenario. On the other hand, in a summer-load-peaking scenario, additional solar resources may be more useful in meeting energy needs.

To capture these seasonal effects, additional renewable resources were added to the resource sets using an iterative marginal benefit analysis targeted at the seasonal modeling period with the greatest load for each scenario. These are the summer period for the Reference Case, and the winter period for the CLCPA Case. Starting from the CARIS starting point resource set, the nameplate capacity of wind and solar resources were each increased in specific increments of 25 percent of the CARIS starting point quantities. In each iteration, we added whichever technology type (either wind or solar) reduced the aggregate energy deficit the most. This process continued iteratively until the total energy deficit for the peak month was met. In addition, the total nameplate capacity for each resource type was not allowed to exceed an estimate of its technical potential in New York State.[37] This technical potential upper limit was reached in the CLCPA case for both land-based and offshore wind. The results of the marginal benefit analysis for each resource set can be found in Table 7.

[36] The CCP2 resource sets was constructed so that intermittent resources provide the bulk of energy through the peak modeling periods and then treated DE resources as backstops, similar to peaking resources. Resource sets developed using a preference for use of DE resources as baseload resources would result in less Intermittent resources needed to meet load.

[37] Technical Potential for land-based wind in New York is estimated by NREL to be 35,200 MW. Technical Potential for offshore wind is calculated at 21,063 MW from BOEM and DOE data, assuming maximum 3 MW/km^2 wind capacity is installed in the 7,021 km^2 New York Bight Lease Areas. NREL, Estimating Renewable Energy Economic Potential in the United States: Methodology and Initial Results, August 2016, Appendices A and F. Bureau of Ocean Energy Management, New York Bight, available at https://www.boem.gov/renewable-energy/state-activities/new-york-bight. Department of Energy, Computing America's Offshore Wind Energy Potential, September 9, 2016.

Table 7: Renewable Capacity by Resource Set

	Zone												
Technology Type	**A**	**B**	**C**	**D**	**E**	**F**	**G**	**H**	**I**	**J**	**K**	**Total**	**% Increase**
CARIS Starting Point													
Land-Based Wind	2,692	390	1,923	1,935	1,821	-	-	-	-	-	-	**8,761**	-
Offshore Wind	-	-	-	-	-	-	-	-	-	6,391	2,609	**9,000**	-
BTM Solar (CLCPA)	704	218	596	69	673	827	684	61	90	672	846	**5,439**	-
BTM Solar (Reference)	470	146	398	46	449	552	456	40	60	448	565	**3,629**	-
Grid-Connected Solar	5,748	656	3,585	-	2,268	4,661	2,636	-	-	-	77	**19,631**	-
CCP2 - Reference Case													
Land-Based Wind	6,057	878	4,327	4,354	4,097	-	-	-	-	-	-	**19,712**	125%
Offshore Wind	-	-	-	-	-	-	-	-	-	14,380	5,870	**20,250**	125%
BTM Solar	822	255	696	81	786	965	798	71	105	784	988	**6,351**	75%
Grid-Connected Solar	10,059	1,148	6,274	-	3,969	8,157	4,613	-	-	-	135	**34,354**	75%
CCP2 - CLCPA Case													
Land-Based Wind	10,816	1,567	7,726	7,774	7,316	-	-	-	-	-	-	**35,200**	302%
Offshore Wind	-	-	-	-	-	-	-	-	-	14,958	6,105	**21,063**	134%
BTM Solar	1,409	436	1,193	138	1,345	1,653	1,367	121	179	1,343	1,692	**10,878**	100%
Grid-Connected Solar	11,496	1,312	7,170	-	4,536	9,322	5,272	-	-	-	154	**39,262**	100%

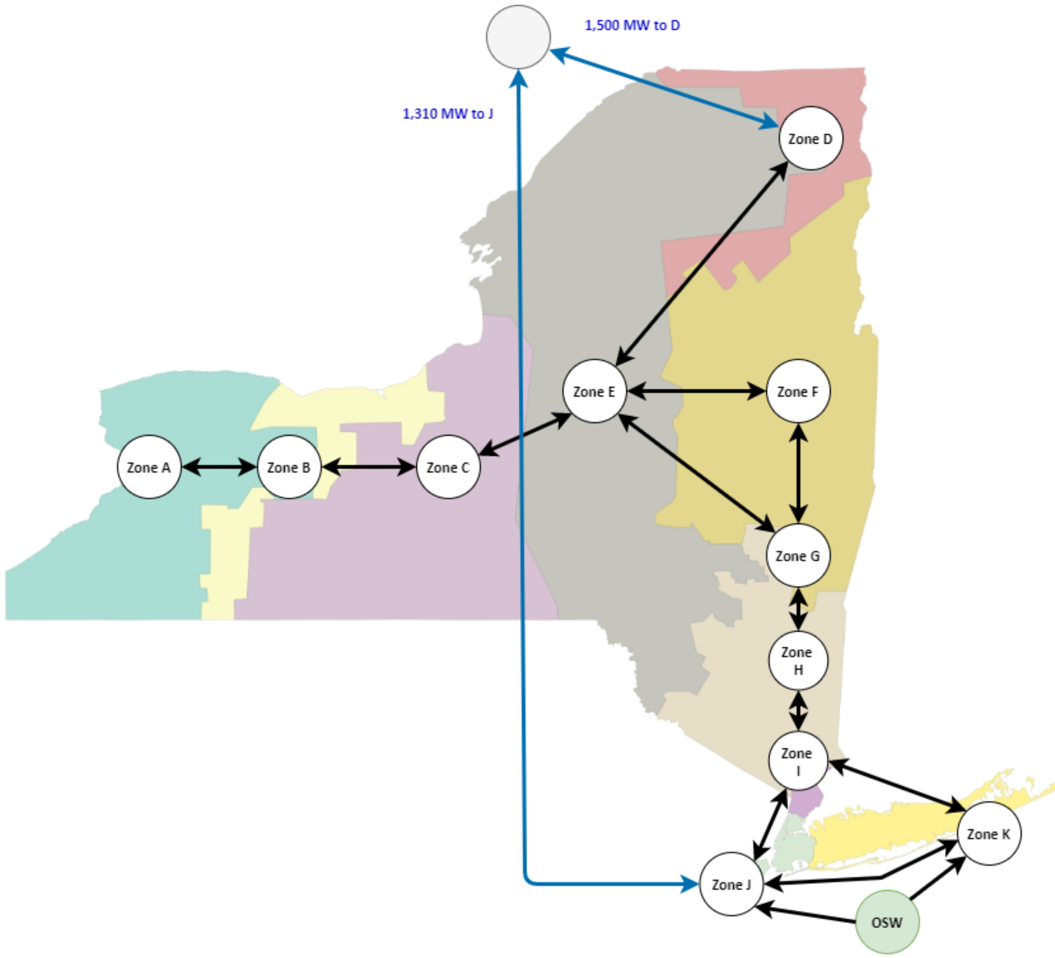
Notes:
[1] Technical Potential for land-based wind in New York is estimated by NREL to be 35,200 MW.
[2] Technical Potential for offshore wind is 21,063 MW calculated from BOEM and DOE data, assuming maximum 3 MW/km^2 wind capacity is installed in the 7,021 km^2 New York Bight Lease Areas.
Sources:
[1] NREL, Estimating Renewable Energy Economic Potential in the United States: Methodology and Initial Results, August 2016, Appendices A and F.
[2] Bureau of Ocean Energy Management, New York Bight, available at https://www.boem.gov/renewable-energy/state-activities/new-york-bight.
[3] Department of Energy, Computing America's Offshore Wind Energy Potential, September 9, 2016.

4. Imports from Neighboring Areas

Our analysis assumes fixed quantities of zero-carbon imports during the modeling period, but no other imports or exports into or out of New York.[38] Based on NYISO data on current import flows, a baseline level of 1,500 MW of imports into Zone D were assumed in each hour, and an additional 1,310 MW of imports in 2040 associated with a potential increase in imports through the development of additional transmission infrastructure. The assumed flows for imports are represented in Figure 6.

[38] The analysis assumes that New York's requirement for a GHG-emission free electric system in 2040 extends to imported power, and does not assume that neighboring U.S. regions will meet these requirements. Thus, for the purpose of this modeling exercise, the study does not assume any imports/exports between New York and neighboring U.S. regions. However, there are zero-emission resources available and potentially available in neighboring Canada, and there is interest in importing certifiable zero-carbon hydro resources if or as available. Thus, for the model assumes the availability in 2040 of energy and capacity imports from Canada.

Figure 6: Imports During Modeling Period



5. Modulation of EV Load Shape

The potential increase in electric vehicles and the transition of the electric generation sector to heavy reliance on renewable resources provides incentives and opportunities for efficient shifts in load over the course of a day. In particular, the daily load shape for electric vehicle charging demand set in the Phase I Study assumes a charging peak in the evening, around hour 20 (see Figure 7 below). However, a shift to a "flatter" load shape that is more equal across evening hours and/or all hours of the day could help reduce peak demand and better tailor the timing of demand to the pattern of generation from renewable resources.

The study models load management based on the NYSERDA report, *Electricity Pricing Strategies to Reduce Grid Impacts from Plug-in Electric Vehicle Charging in New York State.* That report shows that use of a time of use (TOU) rate could significantly shift the timing of daily peak EV load from evening hours to early morning hours.[39] A TOU rate varies the cost of electricity depending on the time of day, with higher rates during peak load hours and lower rates during off-peak hours. A TOU rate acts as an incentive for an EV owner to delay the start of charging to

[39] NYSERDA, "Electricity Pricing Strategies to Reduce Grid Impacts from Plug-in Electric Vehicle Charging in New York State", June 2015 https://www.nyserda.ny.gov/-/media/Files/Publications/Research/Transportation/EV-Pricing.pdf

periods of lower load. The reshaping of the EV load profile shows the shift from peak hours to off-peak hours. The total energy demanded for EV charging is unchanged, but the timing is altered to be highest overnight instead of during the peak evening hours. From a modeling perspective, we adjust the EV charging profile used in the Phase I Itron analysis to shift EV charging demand towards a profile consistent with that found in the NYSERDA study.

Figure 7: Electric Vehicle Daily Load Shape from Phase I Study

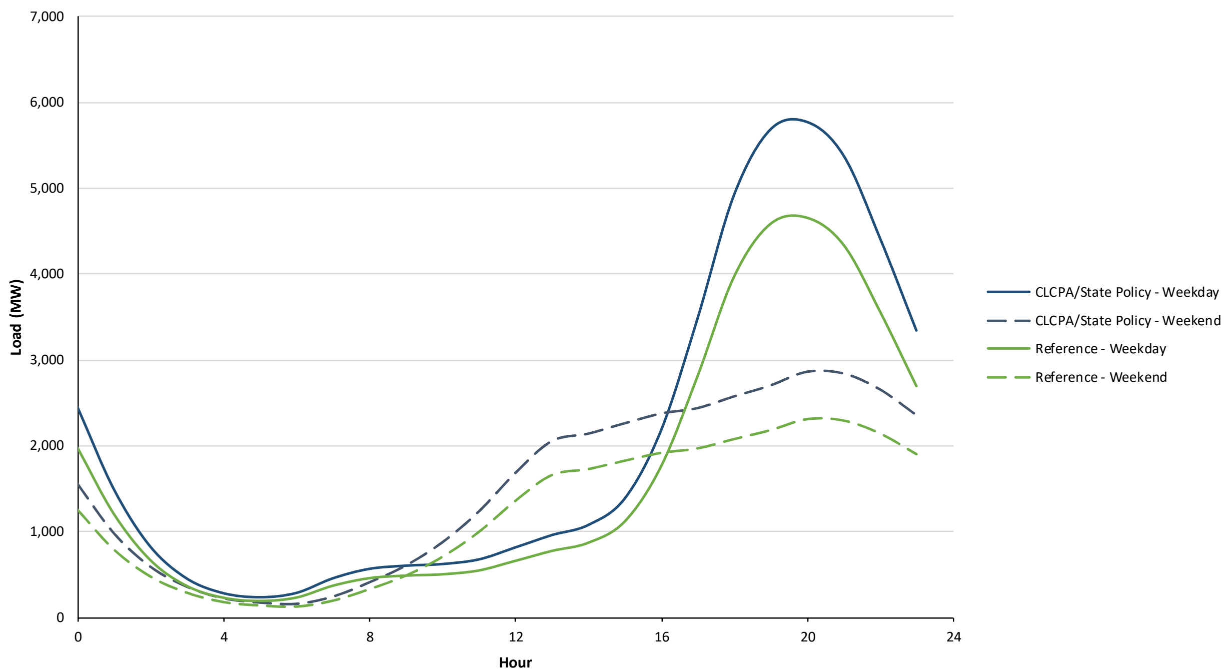
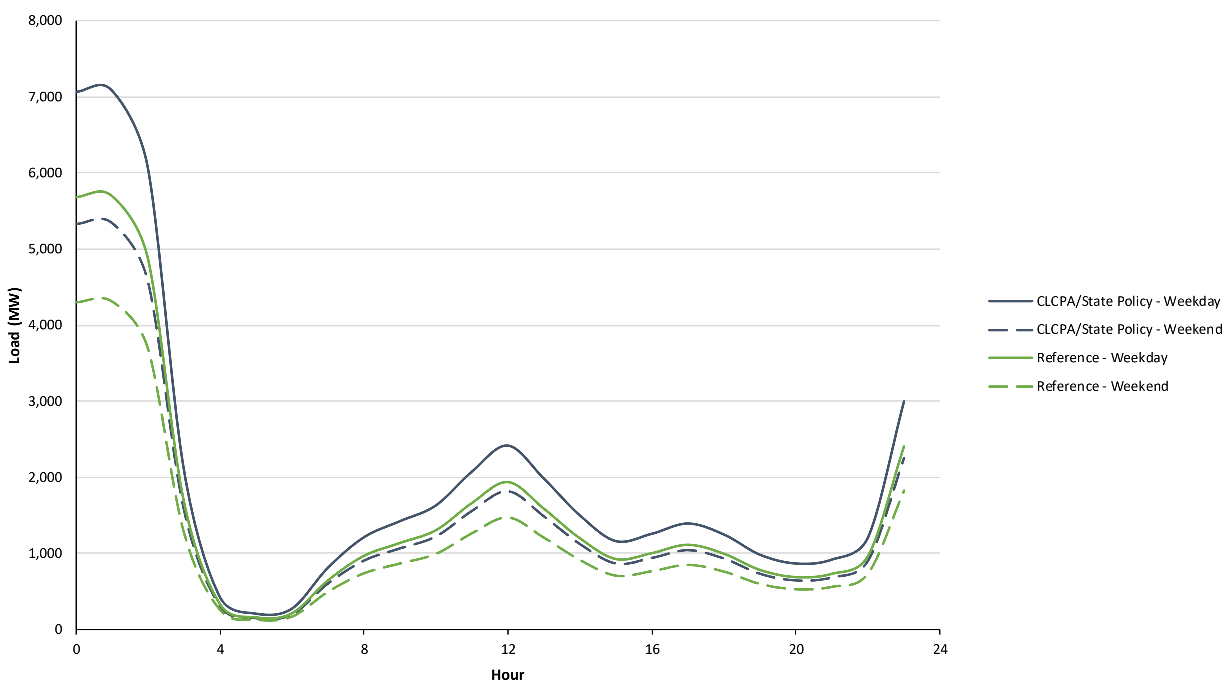


Figure 8: Electric Vehicle Daily Load Shape Adjusted for Off-peak Charging



6. Increase in Inter-zonal Transfer Capability

In order to capture geographic constraints on electrical generation and transmission, the model applies a simplified version of the NYISO transmission network. NYISO divides the state into 11 geographic load zones, A through K, which are individually modeled in this study. The energy balance model uses a set of transmission transfer limits for each interface between load zones. The starting point for these limits is based on an N-1 contingency analysis, as provided by NYISO (see Figure 9). The Western New York and AC Public Policy Transmission upgrades are assumed to be in-service.

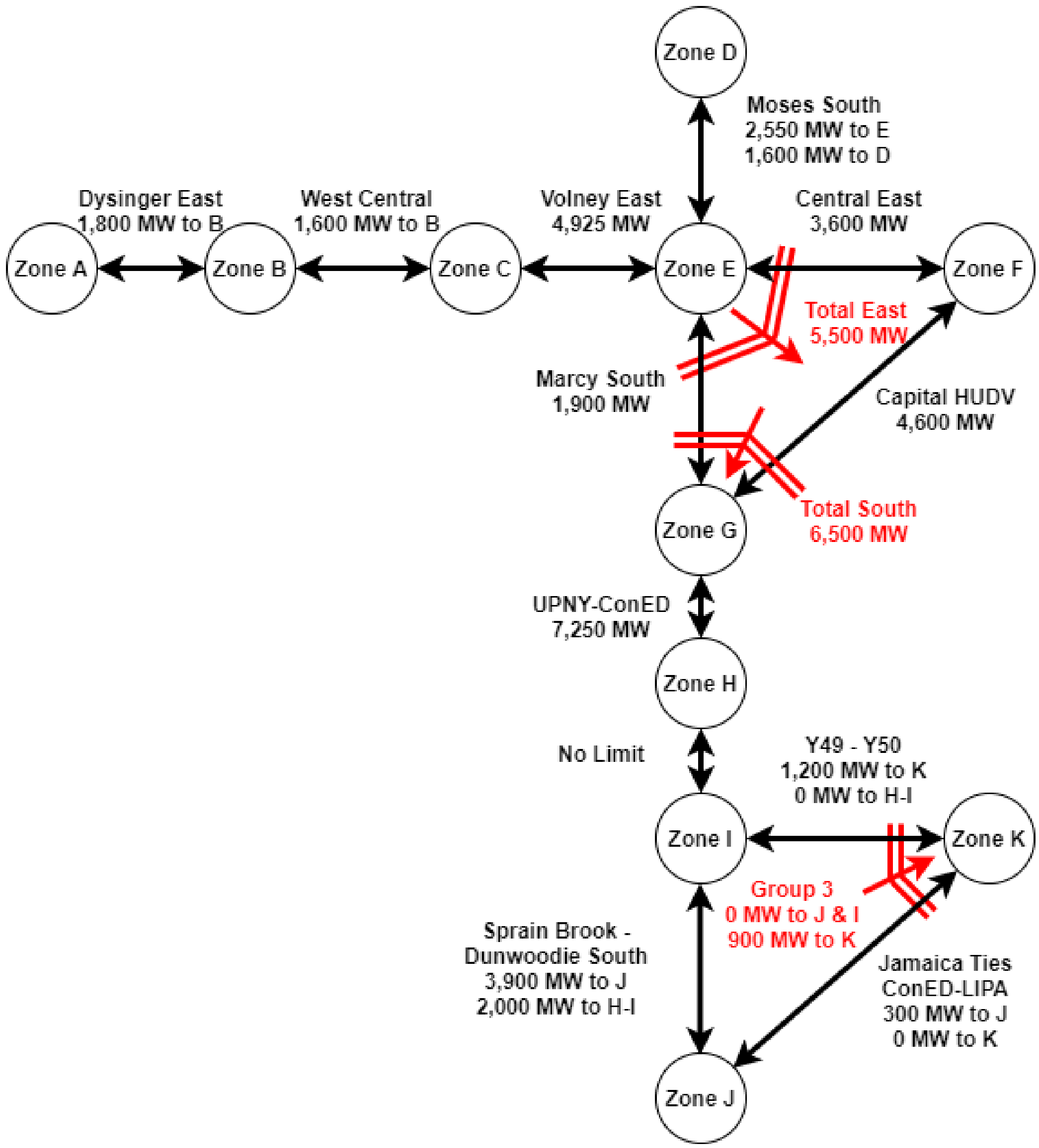
Importantly, the distribution of renewable resources across New York is heavily weighted to the upstate region, given the constraints on land availability and cost discussed previously. As a result, the addition of renewable resources across New York in the amounts we assume requires substantial increases in inter-zonal transfer capability to allow for sufficient flows to meet zonal demand. The starting point transfer limits restrict renewable resources' ability to help address zonal hourly load deficits due to congestion. In the CLCPA Winter modeling period, current transfer limits would result in an average of 3,565 MW of renewable power in each hour unable to help meet load requirements (this is equivalent to 9.4 percent of total NYCA load).

For each transmission interface between Zones, the model assumes an increase in transfer capability by calculating the transmission limits required to alleviate load losses in 90 percent of transmission-constrained hours. The results of the transmission analysis for each resource set can be found in Table 8.

Table 8: Transmission Limits by Resource Set

Interface	NYISO Limits (Starting Point)	90% Limits (CCP2 - Reference)	90% Limits (CCP2 - CLCPA)
A to B	1,800 MW	5,133 MW	7,149 MW
C to B	1,600 MW	1,600 MW	3,319 MW
C to E	4,925 MW	8,432 MW	11,357 MW
D to E	2,550 MW	4,161 MW	6,448 MW
E to G	1,900 MW	9,279 MW	13,932 MW
G to H	7,250 MW	14,713 MW	15,791 MW
I to J	3,900 MW	8,675 MW	10,585 MW
I to K	1,200 MW	4,520 MW	5,137 MW

Figure 9: Simplified Transmission Map and Limits, Starting Point



7. Energy Storage Resources

Renewable resources are dependent on variable meteorological conditions, and thus their generating output does not always coincide with load. Energy storage allows for time shifting of generation to meet the timing of demand. The starting point for storage resources used in our model is based on the 2019 CARIS Phase I "70x30" case. The starting point assumes 3,900 MW of battery energy storage and aligns with the specific CLCPA target of 3,000 MW by 2030.[40] The battery energy storage units are assumed to have eight hours of storage duration and operate with an 85 percent round trip efficiency.[41] It also assumes that the Gilboa hydro pumped storage unit is operating effectively as a single large battery contributing an additional 1,170 MW of storage capacity. The Gilboa unit assumes 12 hours of storage duration and operates with a 75 percent round trip efficiency.[42] The storage units only charge when there is excess renewable generation.[43]

For the Reference and CLCPA cases, additional battery energy storage resources above the amounts modeled in CARIS were added to meet instantaneous power needs. The analysis assumes a doubling of the 2019 CARIS capacity for the Reference case (adding 3,900 MW), and quadrupling of the CARIS capacity for the CLCPA case (adding 11,700 MW). The additional capacity is distributed geographically proportional to the total quantity of "excess" renewable generation in the peak month. That is, batteries were distributed across zones based on the potential to reduce the curtailment or "spilling" of renewable generation in each zone.

From a practical standpoint, the location of energy storage based on the available level of renewable generation improves the use of transmission over the course of a day. On days with high renewable generation upstate, solar and wind power is transmitted over lines from upstate to downstate during the daytime, while simultaneously charging energy storage devices upstate with "excess" energy - that is, energy produced in excess of available transfer capability. In the evening and night, once solar power has dropped to zero, the storage discharges and moves power from upstate to downstate over the same transmission lines. The location of the battery resources for each case is shown in Figure 10 and Figure 11.

[40] NY Senate Bill S6599S, pp. 9, June 18, 2019.

[41] Roundtrip efficiency of less than 100 percent implies that the units do not receive their full capacity of energy inflow when charging; therefore a battery with 8 hours of stored energy takes longer than 8 hours to charge.

[42] Dames and Moore, "An Assessment of Hydroelectric Pumped Storage", November 1981, pp.99.

[43] In effect, this means that the model does not allow the DE generating technology to charge energy storage devices. As described below, we position the DE resource to operate if and only if it is needed to avoid loss of load.

Figure 10: Battery and Renewables Location, CCP2 - CLCPA

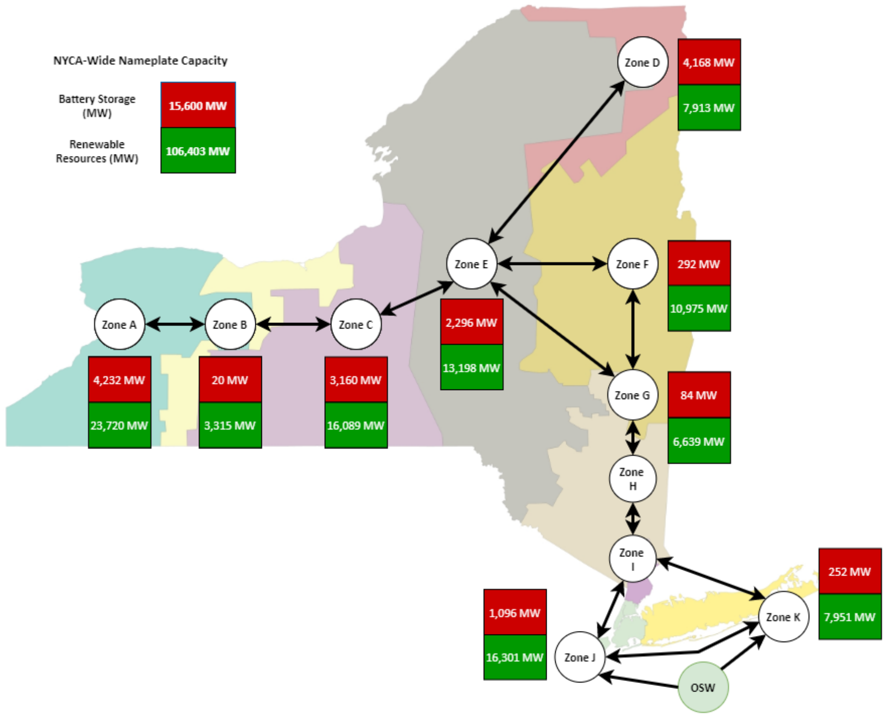
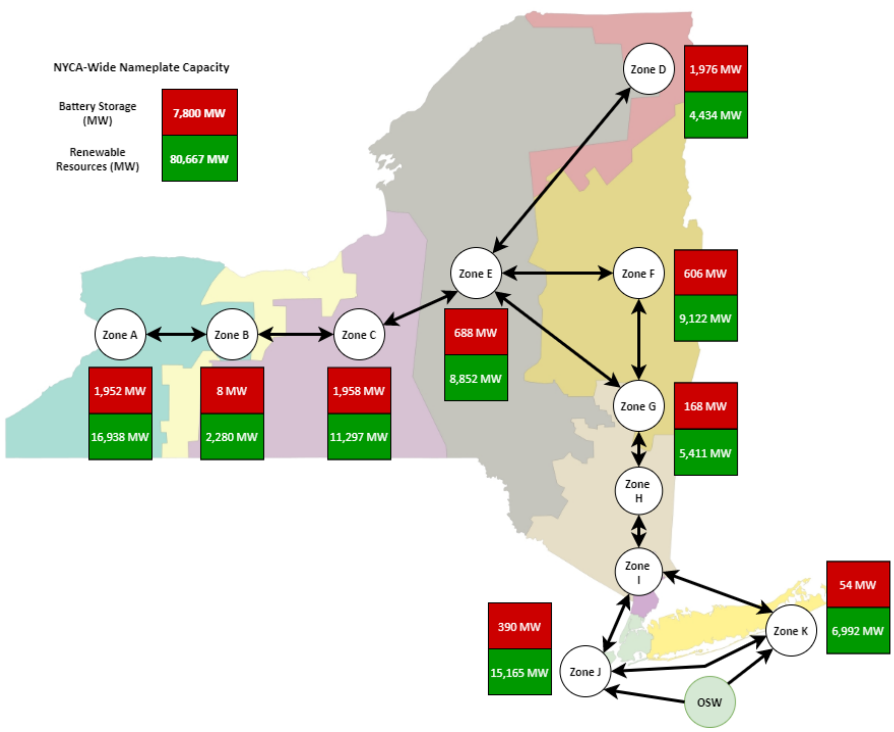


Figure 11: Battery and Renewables Location, CCP2 - Reference



8. Price Responsive Demand

Given the nature of the transition in energy supply and use in New York over the coming decades, the study assumes a significant expansion of price responsive demand (PRD) resources by the modeling year, 2040. The PRD resources used in the energy balance model are based on NYISO's Special Case Resource (SCR) Program and are assumed to be dispatchable by NYISO.[44] The starting point aligns with the 2019 summer and winter capacities from the 2019 NYISO Gold Book, 1,309 MW in the summer capability period and 853 in the winter for NYCA.[45]

Specifically, the study projects a quadrupling of the current levels by 2040 for the CLCPA case, and doubling the current levels by 2040 for the Reference Case. This results in 5,236 MW in the summer for the CLCPA case and 2,618 MW for the Reference Case, and, for the winter, 1,706 MW for the CLCPA case and 3,412 MW for the Reference Case.

9. Dispatchable and Emissions-Free Resource

The primary focus of our analysis is an evaluation of the potential impacts of a changing climate on power system operations, through (1) broad-based changes in load and supply/delivery infrastructure operations from changes in average temperature; and (2) episodic severe weather events that are expected to increase in probability or severity with the changing climate. Thus, our starting point in 2040 incorporates the Phase I impacts to electricity demand of average annual changes in temperature. The study further starts with a system load and resource mix that is consistent with current technology and policy trends. In this respect, the CLPCA has two major influences: First, the economy-wide focus of the Act means that the starting point should include load adjustments for electrification of the building and transportation sectors. In the CLCPA case, this adjustment is built into the 2040 load forecast. Second, to comply with the CLCPA, the study assumes that no fossil fuels that have positive net GHG emissions in operation may be included in the resource set.

This latter point raises a number of challenges for the development of a "starting point" resource set. As highlighted in Analysis Group's Fuel Security Study, New York is highly dependent on the availability and operation of thermal, dual-fuel (*e.g.,* natural gas and oil) generating resources in the downstate region to maintain reliability generally, and in particular in cold weather conditions.[46] In order to eliminate the need for generation from these carbon-emitting generators, the study removes them from the resource mix and supplant them with renewables, storage, demand response, and transmission, as described above. In particular, there is substantial "overbuild" of renewable resource capacity and increases in transfer capability in order to start with a system where peak annual demand in the Reference and CLCPA cases is met with zero-carbon resources. However, even with all these additions, the variability of renewable resource output leads to circumstances where, for both the Reference and CLCPA cases, there are periods of time that our resource mix is insufficient to meet load in all Zones. For these reasons, a DE resource is included to fill in the gap.

The analysis does not identify exactly what the resource is. It could be thermal generating resources that looks like the combustion turbines in operation today, but operating on a fuel that is at least net zero from a GHG emission perspective, such as turbines running on renewable natural gas or hydrogen. It could be some form of demand response. It could represent the emergence of a long-term economic storage technology. Or, of course, some

[44] SCRs are interruptible load customers whose load curtailments are activated by NYISO, and are part of NYISO's Reliability-Based Programs. NYISO, "Demand Response," https://www.nyiso.com/demand-response

[45] NYISO, "2019 Load & Capacity Data Gold Book," https://www.nyiso.com/documents/20142/2226333/2019-Gold-Book-Final-Public.pdf/

[46] Paul J. Hibbard and Charles Wu, *Fuel and Energy Security in New York State*, November 2019.

combination of all of the above. There is no way to know how advances in power system technologies, costs, policies, and consumer behavior can change the way the system meets demand twenty years hence.

Thus, the purpose of the DE resource is twofold. First, by seeing when the DE resource is relied on, this study helps identify the magnitude of the resource gap created by relying primarily on variable renewable generating resources to meet annual, state-wide energy needs. Second, the "operation" of the DE resource in the model defines *the attributes* needed from resources that meet this gap, in terms of when it is needed, in what zones, under what conditions, and with which system reliability attributes, such as cycling and ramping capabilities.

The DE resources are assumed to meet any remaining instantaneous power needs in the modeling period. They are modeled as able to dispatch on demand without any operational or duration restrictions. The quantity of capacity assumed in each resource set is calibrated to meet all remaining zonal load losses in the peak seasonal modeling period after all other resources have been exhausted. In the Reference Case, 17,059 MW is assumed to be available and operational in order to meet zonal load need in every hour of the summer modeling period. From a modeling perspective, the DE resource is zonally distributed proportional to the 2017 existing thermal capacity that fills a similar need. In the CLCPA case, 32,137 MW of DE resource availability is required to meet load in every hour of the winter modeling period. Of this quantity, 22,471 MW is placed in the same Zones as currently existing thermal capacity. The remaining DE capability is located strategically based on observed transmission bottlenecks and zonal load loss outcomes: 539 MW is located in Zone B, 3,409 MW in Zone G, 29 MW in Zone H, 4,258 MW in Zone J, and 1,431 MW in Zone K.

The climate disruption cases, described in Section III, involve circumstances and events that increase demand and/or reduce or eliminate the availability of renewable resources and transmission infrastructure. These cases, in some instances, did result in loss of load occurrences.

10. Resource Set Summaries for CCP2

Table 9: Generation Capacity, CCP2-CLCPA

Nameplate Capacity by Zone, MW	A	B	C	D	E	F	G	H	I	J	K	Total
Land-based Wind	10,815.9	1,566.9	7,726.2	7,774.5	7,316.4	-	-	-	-	-	-	**35,200.0**
Offshore Wind	-	-	-	-	-	-	-	-	-	14,957.8	6,105.2	**21,063.0**
Solar (Behind-the-meter)	1,408.5	436.4	1,192.8	138.2	1,345.5	1,653.4	1,367.3	121.2	179.4	1,343.1	1,692.2	**10,877.8**
Solar (Grid Connected)	11,496.0	1,312.0	7,170.0	-	4,536.0	9,322.0	5,272.0	-	-	-	154.0	**39,262.0**
Hydro Pondage	2,675.0	-	-	856.0	-	-	41.6	-	-	-	-	**3,572.6**
Hydro Pumped Storage	-	-	-	-	-	1,170.0	-	-	-	-	-	**1,170.0**
Hydro Run-of-River	4.7	63.7	70.4	58.8	376.2	282.5	57.1	-	-	-	-	**913.4**
Nuclear	-	581.7	2,782.5	-	-	-	-	-	-	-	-	**3,364.2**
Imports	-	-	-	1,500.0	-	-	-	-	-	1,310.0	-	**2,810.0**
Storage	4,232.0	20.0	3,160.0	4,168.0	2,296.0	292.0	84.0	-	-	1,096.0	252.0	**15,600.0**
Price Responsive Demand (Summer)	949.9	205.2	510.1	357.7	211.1	433.9	246.3	58.6	134.9	1,940.8	187.6	**5,236.0**
Price Responsive Demand (Winter)	619.0	133.7	332.4	233.1	137.5	282.7	160.5	38.2	87.9	1,264.7	122.3	**3,412.0**
DE Resources	465.4	674.2	1,513.4	370.0	312.7	3,390.4	6,887.2	79.8	-	11,848.1	6,595.4	**32,136.6**

Figure 12: Simplified Transmission Map and Limits, CCP2-CLCPA

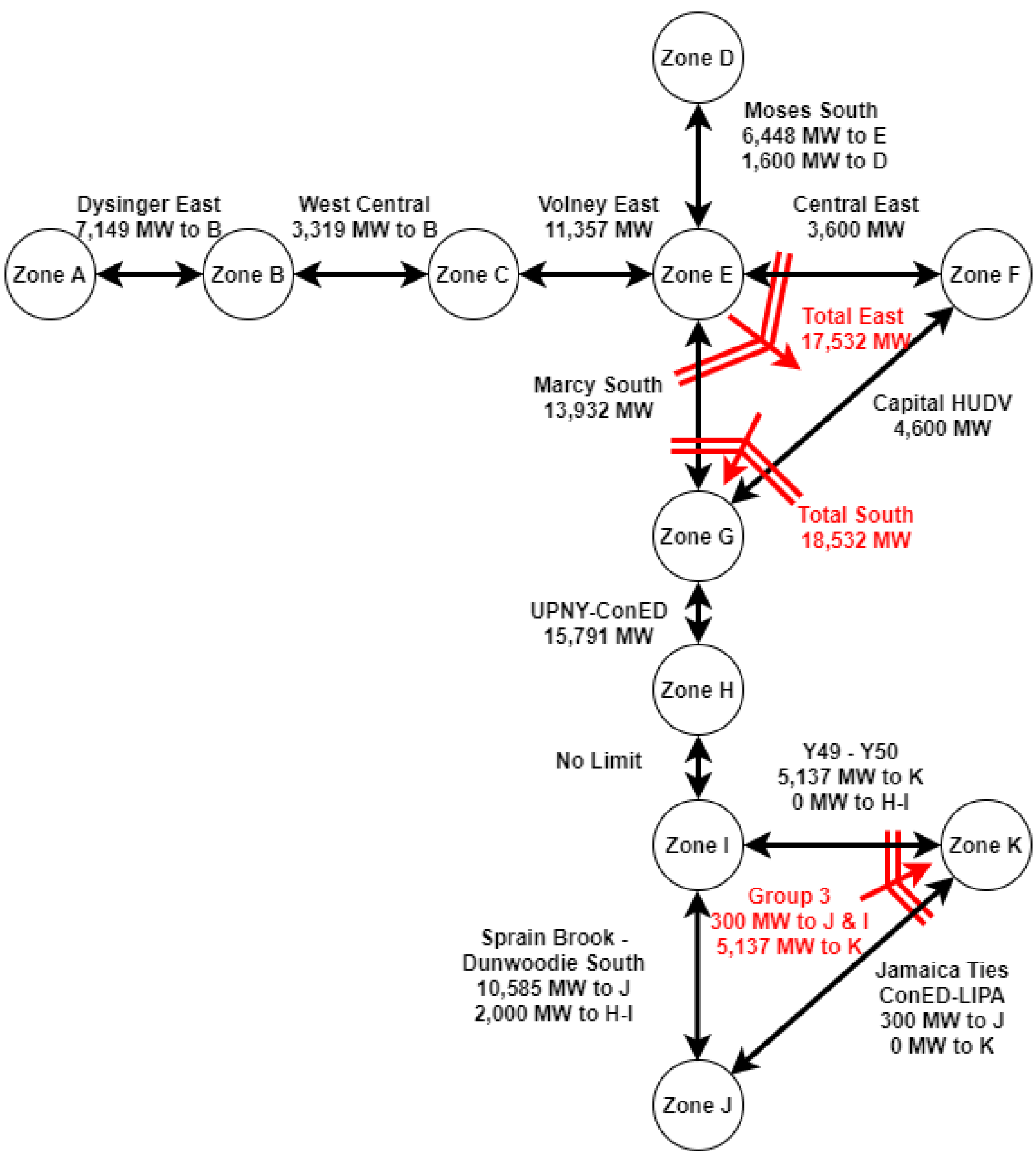
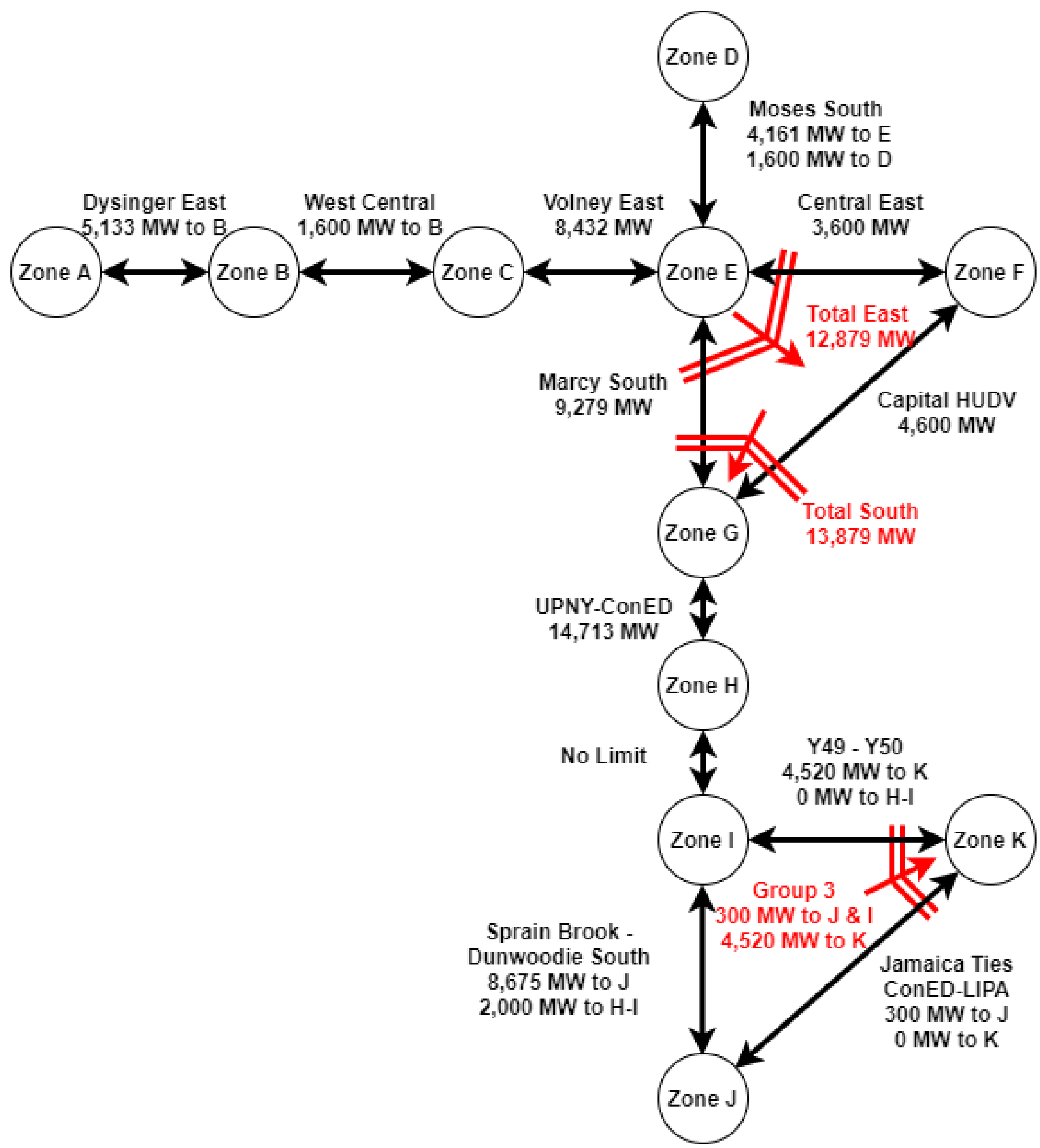


Table 10: Generation Capacity, CCP2-Reference

Nameplate Capacity by Zone, MW	A	B	C	D	E	F	G	H	I	J	K	Total
Land-based Wind	6,057.0	877.5	4,326.8	4,353.8	4,097.3	-	-	-	-	-	-	**19,712.3**
Offshore Wind	-	-	-	-	-	-	-	-	-	14,380.4	5,869.6	**20,250.0**
Solar (Behind-the-meter)	822.3	254.8	696.4	80.7	785.5	965.3	798.3	70.8	104.7	784.1	987.9	**6,350.7**
Solar (Grid Connected)	10,059.0	1,148.0	6,273.8	-	3,969.0	8,156.8	4,613.0	-	-	-	134.8	**34,354.3**
Hydro Pondage	2,675.0	-	-	856.0	-	-	41.6	-	-	-	-	**3,572.6**
Hydro Pumped Storage	-	-	-	-	-	1,170.0	-	-	-	-	-	**1,170.0**
Hydro Run-of-River	4.7	63.7	70.4	58.8	376.2	282.5	57.1	-	-	-	-	**913.4**
Nuclear	-	581.7	2,782.5	-	-	-	-	-	-	-	-	**3,364.2**
Imports	-	-	-	1,500.0	-	-	-	-	-	1,310.0	-	**2,810.0**
Storage	1,952.0	8.0	1,958.0	1,976.0	688.0	606.0	168.0	-	-	390.0	54.0	**7,800.0**
Price Responsive Demand (Summer)	474.9	102.6	255.1	178.8	105.5	216.9	123.1	29.3	67.4	970.4	93.8	**2,618.0**
Price Responsive Demand (Winter)	309.5	66.9	166.2	116.5	68.8	141.4	80.2	19.1	43.9	632.3	61.1	**1,706.0**
DE Resources	353.3	102.6	1,148.9	280.9	237.4	2,573.9	2,640.7	38.8	-	5,761.7	3,920.7	**17,059.0**

Figure 13: Simplified Transmission Map and Limits, CCP2-Reference



E. Representation of Electric System Operations

1. Transfer and Dispatch Logic

Electrical transfers and generation across New York were modeled using the 11-region transmission framework discussed in Section II.C.6. The electric system model is designed to meet load needs using available resources subject to transmission and operational constraints.[47] The model operates pursuant to a sequence of resource loading steps, subject to the transfer constraints.

First, hydroelectric and nuclear units are assumed to generate at fixed capacity factors based on historical averages and do not respond to load (see Section II.C.1). Next, renewable generation is dispatched in each region and then transferred throughout the state to maximize load served through the operation of system renewable resources. Solar and land-based wind units are assumed to generate based on hourly profiles used in the 2019 CARIS Phase 1 70x30 Scenario (see Sections II.C.2 and II.C.3). Load within each region is served by renewable generation in that region first, followed by inter-region transfers to distribute regional generation surpluses across the state. Any excess renewable generation in a given hour is used to charge storage units if there is sufficient storage headroom. The backup resource is not used to charge storage.

In the next step of the model, if any zonal generation deficits remain, batteries and PRD are dispatched, and power flows between Zones as needed based on load deficit severity, transmission headroom, and available stored energy.[48] If a zonal deficit is not filled by running PRD and batteries within that zone, PRD and batteries in other Zones are transferred to the zone with a deficit, until all deficits are filled.

2. Use of Dispatchable and Emissions-Free Resources

The final mechanism relied upon to meet load is the DE resource, which is dispatched in hours when the combination of baseload resources, renewable generation, inter-zonal transfers, batteries, and PRD is insufficient to meet demand. If there is sufficient headroom on transmission lines, power generated by DE resources are transferred to Zones with generation deficits.

F. Comparisons with Grid in Transition Resource Sets

In addition to the resource sets developed as described in Section II.D, this study also modeled two resource sets developed for the NYISO Grid in Transition (GIT) study,[49] which seeks to understand the reliability and market implications of the State's plans to transition to clean energy sources.[50] The GIT resource set is based on an economic simulation of the NYISO markets through 2040, in consideration of NYISO market operations and economic retirement/additions of capacity. The simulation was run with the GIT resource set for both the Reference Case and CLCPA load scenarios, without any increase in transmission transfer capability in the base

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[47] Note, however, that the analysis is not a production cost model which takes prices into account for unit dispatch.

[48] When PRD is dispatched, the entire PRD capacity is used in each zone where there is a deficit, mimicking how the current SCR program currently functions.

[49] New York's Evolution to a Zero Emission Power System, June 22, 2020, https://www.nyiso.com/documents/20142/13245925/Brattle%20New%20York%20Electric%20Grid%20Evolution%20Study%20-%20June%202020.pdf/69397029-ffed-6fa9-cff8-c49240eb6f9d.

[50] The Brattle Group, "NYISO Grid in Transition Study: Detailed Assumptions and Modeling Description," March 30, 2020.

case.[51] The two resource sets provide bookends on the quantity of transmission buildout: the CCP2 resource set developed under this study looks at significant increases in transmission, while the Grid-in-Transition resource set has no increase in transmission. This difference in transmission capability has a significant impact on where future renewable resources would be located.

For comparison purposes, this study tests the GIT resource set under both the reference and CLCPA load scenarios as alternative inputs into the energy balance model. As seen in Table 11, the Grid in Transition resource sets includes a much larger quantity of the dispatchable renewable natural gas resource and lower quantity of renewable resources to meet total energy needs.[52] In addition, the renewable resources in the GIT resource set are located primarily in the eastern half of the state, whereas the renewables included in the resource sets used in this study are more evenly spread across the state (For example, a large amount of solar generation is assumed in Zone F in the GIT resource set). Finally, to provide a reliable starting point for the physical disruption analyses, AG added additional DE resources to the resource sets to meet load in all hours of the modeling periods.

Table 11: Resource Sets from Grid in Transition Study

Grid in Transition Reference Case

Nameplate Capacity by Zone, MW	A-E	F	G-I	J	K	Total
Land-based Wind	9,754.8	0.0	0.0	-	-	9,754.8
Offshore Wind	-	-	-	9,173.5	4,593.8	13,767.3
Solar (Behind-the-meter)	452.1	2,606.7	265.0	779.9	2,009.4	6,113.1
Solar (Grid Connected)	4,771.7	20,838.5	4,376.0	-	56.4	30,042.6
Hydro Pondage + Run-of-River	4,431.7	485.6	100.7	-	-	5,018.0
Hydro Pumped Storage	-	1,171.3	-	-	-	1,171.3
Nuclear	2,095.9	-	-	-	-	2,095.9
Imports	1,100.0	-	-	-	-	1,100.0
Storage	1,973.5	3,276.9	895.4	2,645.5	1,945.0	10,736.3
Price Responsive Demand (SCR/EDRP)	1,054.9	216.3	318.5	938.0	634.9	3,162.6
Renewable Natural Gas Dispatchable	2,333.7	3,040.7	3,847.2	6,388.1	5,008.7	20,618.4
DE Resources (added by AG)	-	-	-	1,283.0	797	2,080.0

Grid in Transition CLCPA Case

Nameplate Capacity by Zone, MW	A-E	F	G-I	J	K	Total
Land-based Wind	23,254.8	0.0	0.0	-	-	23,254.9
Offshore Wind	-	-	-	17,938.0	7,164.1	25,102.2
Solar (Behind-the-meter)	537.5	2,843.1	265.0	779.9	2,009.4	6,434.9
Solar (Grid Connected)	4,907.1	21,378.9	5,326.8	-	56.4	31,669.3
Hydro Pondage + Run-of-River	4,431.7	485.6	100.7	-	-	5,018.0
Hydro Pumped Storage	-	1,171.3	-	-	-	1,171.3
Nuclear	2,156.4	-	-	-	-	2,156.4
Imports	1,100.0	-	-	-	-	1,100.0
Storage	5,894.2	3,014.9	260.1	2,620.7	2,317.0	14,106.9
Price Responsive Demand (SCR/EDRP)	1,462.9	306.2	472.5	1,348.9	909.1	4,499.5
Renewable Natural Gas Dispatchable	2,483.6	9,048.6	5,596.7	10,187.0	6,386.5	33,702.3
DE Resources (added by AG)	219.0	-	-	3,629.0	1,988.0	5,836.0

[51] Additional alternative scenarios were included in the NYISO Grid in Transition study but were not included in this analysis.

[52] The backup resource is described in the GIT study as renewable natural gas dispatchable capacity, which is used as a proxy for potential future zero emission technology development. The Brattle Group, "NYISO Grid in Transition Study: Detailed Assumptions and Modeling Description," March 30, 2020, slide 36.

III. Cases Analyzed: Combinations of Load Scenarios and Physical Disruptions

In order to test the resilience of the electrical system to different possible system conditions during future events, a number of potential "physical disruptions" were modeled, representing possible future effects of climate change on electricity demand and system infrastructure operations. The physical disruptions listed in Table 12 are primarily intended to simulate possible short-term adverse events with load, generation, and transmission impacts that coincide within the modeling period. The load scenarios, resource sets, and physical disruptions are combined into a series of cases, the results of which are evaluated through the AG system model. The sections that follow explain the modeled impacts for each physical disruption.

Table 12: Description of Physical Disruption Modeling

ID	Event	Model Toggles Adjusted	
Baseline	None		
A	Heat Wave	Wind Generation - 20% decrease for 7 days Solar Generation - Use solar profile from hottest day in Y2006 for 7 days Load - High temp 90° F or above for days 1-7, with daily zonal load increase of between 0% to 18.7% Transmission - 5% decrease for 7 days	
B	Cold Wave	Solar Generation - Use solar profile from coldest day in Y2006 for 7 days Load - Low temp of 0° F or below for days 1-7, with daily zonal load increase of between 2.3% to 25.6%	
		Summer	Winter
C	Wind Lull - Upstate	Wind Generation - 15% Average Capacity Factor in Zones A-E for 12 days	Wind Generation - 25% Average Capacity Factor in Zones A-E for 7 days
D	Wind Lull - Off-Shore	Wind Generation - 15% Average Capacity Factor in Zones J-K for 12 days	Wind Generation - 25% Average Capacity Factor in Zones J-K for 7 days
E	Wind Lull - State-wide	Wind Generation - 15% Average Capacity Factor in Zones A-K for 12 days	Wind Generation - 25% Average Capacity Factor in Zones A-K for 7 days
F	Hurricane/Coastal Wind Storm	Calibrated using Hurricane Sandy data Load - 30% decrease in Zones G-K for 1 day with 11 day recovery Transmission - Off in Zones G-K for 1 day with 14 day recovery Wind Generation - Off in Zones J-K for 1 day with 14 day recovery Solar Generation - 50% decrease in Zones G-K for 1 day with next day recovery DE Capacity - 40% decrease in Zones G-K for 1 day with 14 day recovery	
G	Severe Wind Storm – Upstate	Calibrated using Hurricane Sandy data Load - 30% decrease in Zones A-F for 1 day with 11 day recovery Transmission - Off in Zones A-F for 1 day with 14 day recovery Wind Generation - Off in Zones A-F for 1 day with 14 day recovery Solar Generation - 50% decrease in Zones A-F for 1 day with next day recovery DE Capacity - 40% decrease in Zones A-F for 1 day with 14 day recovery	
H	Severe Wind Storm – Offshore	Wind Generation - Off in Zones J-K for 1 day with 14 day recovery	
I	Drought	Hydro Generation - 50% decrease for 30 days	
J	Icing Event	Transmission - Off in Zones A-C for 1 day with 7 day recovery Load - 25% decrease in Zones A-C for 1 day with 7 day recovery Wind Generation - 50% decrease in Zones A-C for 1 day with 7 day recovery	

A. Physical Disruptions: Interruptions of Resources and Transmission

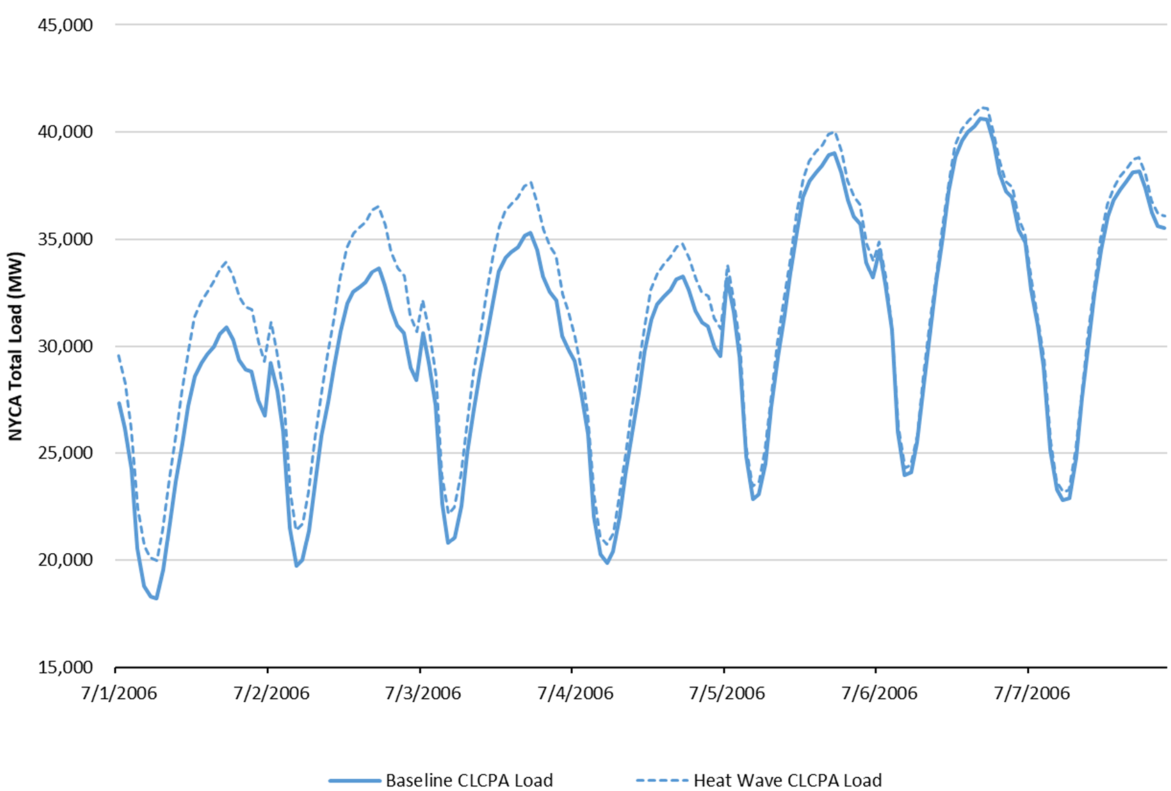
1. Temperature Waves

Periods of extreme heat or cold can have contemporaneous impacts on the bulk electric system due to increased load, changes in wind and solar generation, and impacts on transmission capacity. The temperature wave scenarios stress the power system with several days of severe temperatures across New York State.

The NYSERDA ClimAID report defines extreme temperatures for both hot and cold periods: heat waves are defined as periods of three or more consecutive days where daily high temperatures are at or above 90° Fahrenheit (F), and extreme cold days are defined as days with a minimum temperature at or below 0° F.[53] The model evaluates as a climate-change induced disruption an extended heat wave of seven days and an extended cold snap of seven days. These extreme hot/cold events are calibrated to historical heat and cold waves and adjusted for average temperature increases due to climate change using the Phase I Study modeling.

The load impacts from heat and cold temperature waves are based on zonal load-temperature sensitivities from the Phase I Study modeling. In the Phase I model, the impact of trending weather conditions are translated through the peak model heating and cooling loads to get a peak energy forecast. By adjusting the mean daily temperature across all Zones during the study period to meet the NYSERDA criteria for a period of extreme heat or cold, the analysis calculates an average load impact. The cold wave peak load impact average is about 110 percent across zones and the summer heat wave averages to about a 107 percent increase in peak load. Figure 14 shows loads in the CLCPA summer heat wave case.

Figure 14: Example of Heat Wave Increased Load: CLCPA Summer Load Scenario

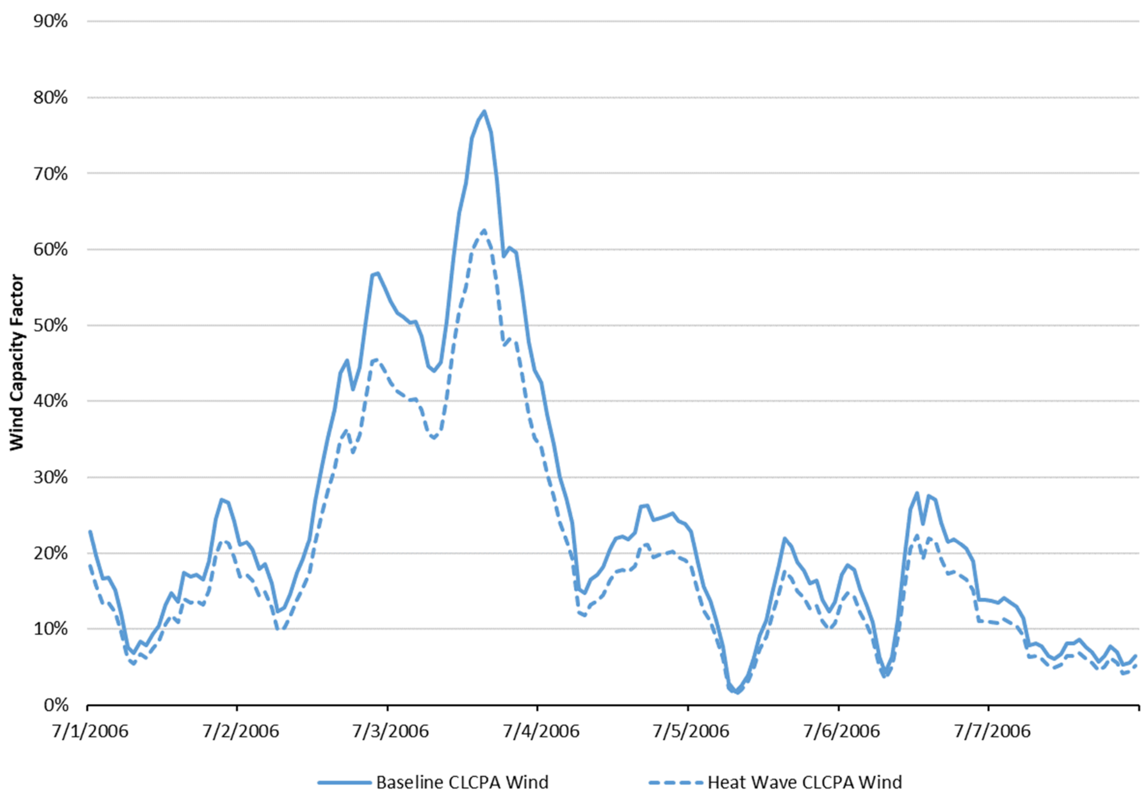


Evidence from the European heat wave of 2018 showed wind resources can decrease by as much as 20 percent below long-term averages during a heat wave.[54] In order to model a similar impact, a 20 percent wind capacity factor decrease is modeled during the heat wave climate scenario. Figure 15 shows a wind decrease in the CLCPA summer heat wave case. The study does not model any impact on wind output during the cold snap.

[53] NYSERDA, "Responding to Climate Change in New York State (ClimAID)," (hereafter "NYSERDA ClimAID "), pp. 2-3, 2014, https://www.nyserda.ny.gov/-/media/Files/Publications/Research/Environmental/ClimAID/2014-ClimAid-Report.pdf

[54] Renewable Energy Magazine, "Heatwave hits European wind energy but boosts solar energy generation," , August 2018, https://www.renewableenergymagazine.com/wind/heatwave-hits-european-wind-energy-but-boosts-20180814

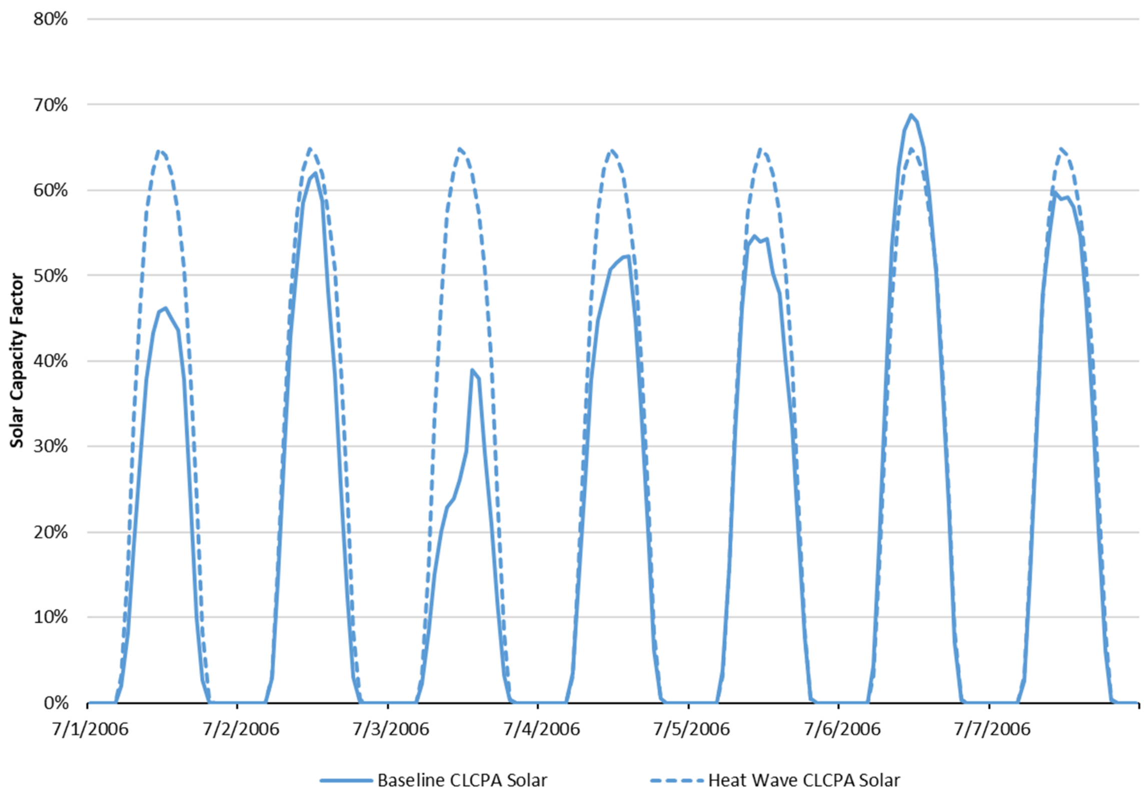
Figure 15: Example of Heat Wave Decreased Wind Production: CLCPA Summer Load Scenario



In heat waves solar irradiance is higher than long-term average irradiance, but PV efficiency decreases due to temperature effects.[55] During cold waves, solar irradiance can be variable but there is no impact on PV efficiency. To model the dual effect during temperature wave periods, this study uses zonal-aggregated National Renewable Energy Laboratory (NREL) PV output data from the hottest and coldest days during the summer and winter periods in 2006 as the load profiles for the model. As seen in Figure 16, using the solar generation profile from July 18, 2006 reveals that the majority of days in the seven days of the modeled heat wave experience an increase in solar generation.

[55] EnergySage, "How hot do solar panels get? Effect of temperature on solar performance," Updated July 21, 2020, https://news.energysage.com/solar-panel-temperature-overheating/

Figure 16: Heat Wave Solar Production: CLCPA Summer Load Scenario



There is more variability in the winter due to the impact of cloud cover on solar irradiance. Using the solar generation profile from the coldest day in January 2006, which occurred on the 16th, results in an increase in solar generation for the seven days of the modeled cold wave.

Finally, heat waves decrease transmission capacity due to reduction in thermal limits and conductor sag.[56] Accordingly, a five percent transmission MW transfer capability decrease is modeled during the heat wave. There is no impact to transmission modeled during the cold wave scenario.

As a result of the above findings, heat waves are modeled using the following model adjustments:

- Load - High temp 90° F or above for seven days, with daily zonal load increase of between 0 percent and percent 18.7 percent
- Wind Generation - 20 percent decrease for seven days
- Solar Generation - use solar profile from hottest day in Y2006 for seven days
- Transmission - five percent decrease for seven days

Cold waves are modeled using the following model adjustments:

[56] Bartos, Matthew, et. al., "Impacts of rising air temperatures on electric transmission ampacity and peak electricity load in the United States," *Environmental Research Letters,* Volume 11, 2016, https://iopscience.iop.org/article/10.1088/1748-9326/11/11/114008/pdf

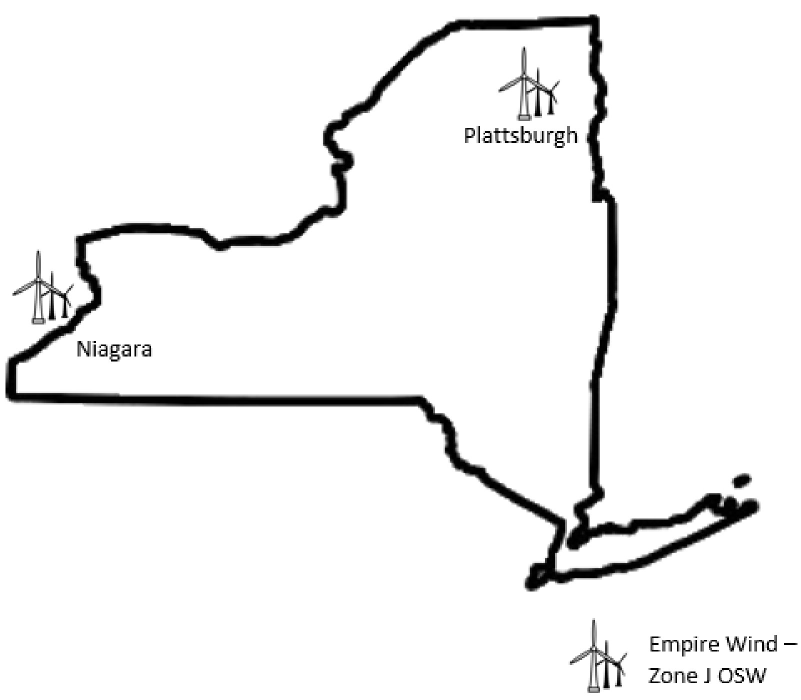
- Load - Low temp of 0° F or below for seven days, with daily zonal load increase of between 2.3 percent and percent 25.6 percent.
- Solar Generation - Use solar profile from coldest day in Y2006 for seven days

2. Wind Lulls

Although wind power provides a significant amount of aggregate generation, wind power production follows seasonal weather patterns and is variable in real time, which could include multi-day periods with relatively low capacity factors, or "wind lulls." A state-wide wind lull that affects both upstate and offshore wind generating plants could create a large instantaneous shortfall in power that would significantly stress the electrical system. In that case, the generation deficit would need to be filled in by other forms of generation.

To evaluate this potential variability, we include analysis of wind lulls based on historical NREL daily wind data, with capacity factor at simulated 100 meter turbine height, from the WIND Toolkit covering the period from 2007 through 2012. These data were used as a guide to establish the appropriate length and severity of a state-wide wind lull. Three sites representing upstate and offshore production were used: Niagara, Plattsburgh, and Empire Wind Zones, as shown in Figure 17. The locations of these representative sites roughly correspond with the share of wind nameplate capacity assumed in the modeled resource sets.

Figure 17: Wind Farm Locations used in Wind Lull Analysis



Due to the differences in seasonal wind patterns, wind lulls in the summer and winter were defined and assessed separately. A summer wind lull is defined as four or more consecutive days of a rolling average capacity factor of less than or equal to 15 percent. Because winter is a windier season on average, the threshold was raised to a capacity factor of less than or equal to 25 percent. Table 13 and Table 14 summarizes the historic statewide wind lulls by season in the years 2007 - 2012. Summer wind lulls were both more frequent and more severe; there were 19 wind lulls during summer months but only three wind lulls in the winter, even using a higher capacity factor threshold. The observed wind lulls occur during periods with both seasonally high and low temperatures, so are not limited to "heat wave" periods.

Table 13: Historical Summer Wind Lulls from NREL data, 2007-2012, ≤15 percent Implied Capacity Factor

Wind Lull Period	Number of Days	Average Wind Capacity Factor Across Regions	Statewide Average Temperature	Statewide Average High
7/21/2007 - 8/1/2007	12	14.2%	72°	80.9°
8/10/2009 - 8/16/2009	7	14.1%	74.7°	82.5°
6/10/2009 - 6/16/2009	7	13.7%	64.5°	72.4°
8/31/2009 - 9/5/2009	6	13.3%	65°	75.2°
7/27/2012 - 8/1/2012	6	14.4%	73.9°	81.6°
8/12/2008 - 8/16/2008	5	14.9%	67.4°	75.9°
7/6/2009 - 7/10/2009	5	14.3%	66°	74.6°
7/9/2012 - 7/13/2012	5	14.4%	73.8°	84.8°
8/18/2012 - 8/22/2012	5	14.7%	67.6°	77.3°

Notes:
[1] Based on NREL Wind Toolkit wind data at 100 meter height for points in Plattsburgh (North), Niagara Falls (West), and Empire Wind Zone.
[2] A wind lull is defined as four or more consecutive days where the average daily implied capacity factor is less than or equal to 15 percent.
[3] In addition to the listed wind lulls, there were 10 wind lulls of 4 days between 2007 - 2012.
Sources:
[1] NREL Wind Toolkit Database, https://www.nrel.gov/grid/wind-toolkit.html.

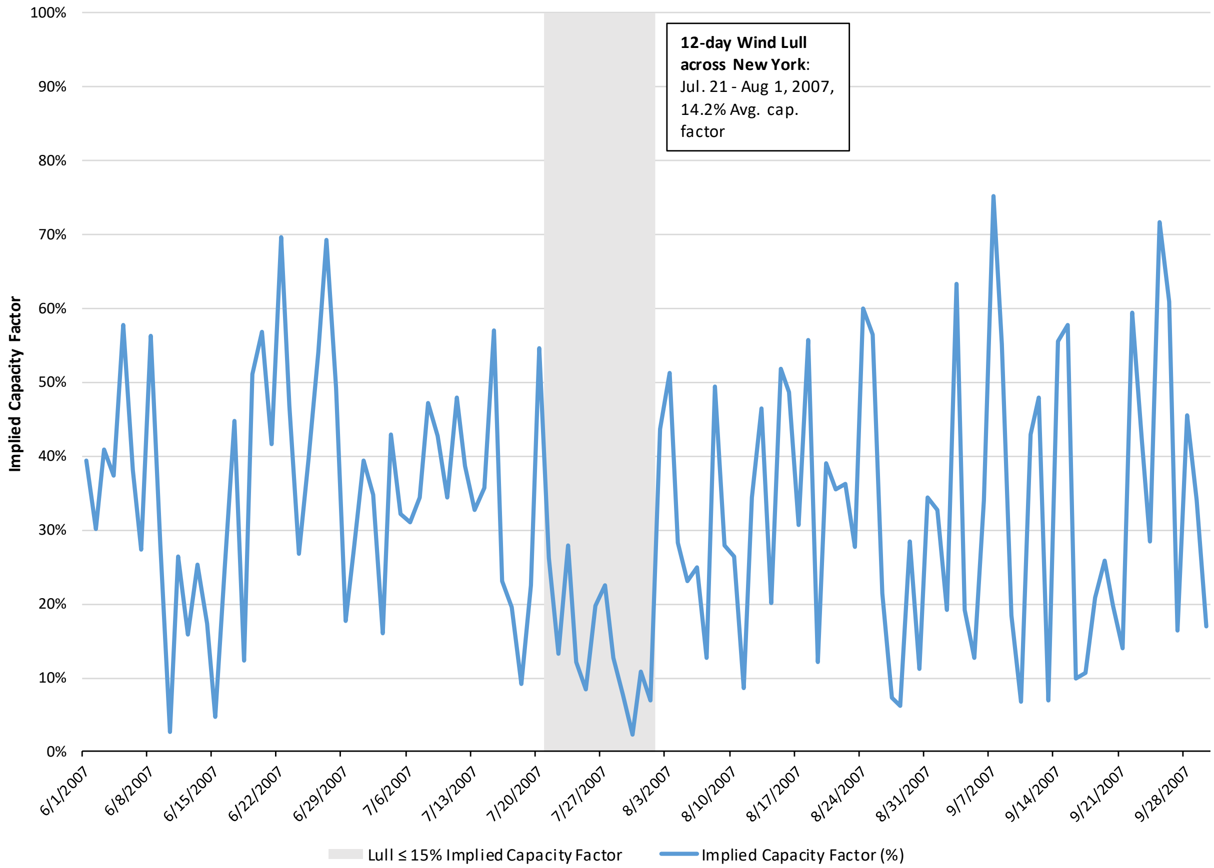
Table 14: Historical Winter Wind Lulls from NREL data, 2007-2012, ≤25 percent Implied Capacity Factor

Wind Lull Period	Number of Days	Average Wind Capacity Factor Across Regions	Statewide Average Temperature	Statewide Average High
2/25/2007 - 3/1/2007	5	21.7%	25.6°	33.6°
1/28/2011 - 2/1/2011	5	22.5%	22.2°	28.4°
2/2/2012 - 2/5/2012	4	24.3%	33.1°	40.2°

Notes:
[1] Based on NREL Wind Toolkit wind data at 100 meter height for points in Plattsburgh (North), Niagara Falls (West), and Empire Wind Zone.
[2] A wind lull is defined as four or more consecutive days where the average daily implied capacity factor is less than or equal to 25 percent.
Sources:
[1] NREL Wind Toolkit Database, https://www.nrel.gov/grid/wind-toolkit.html.

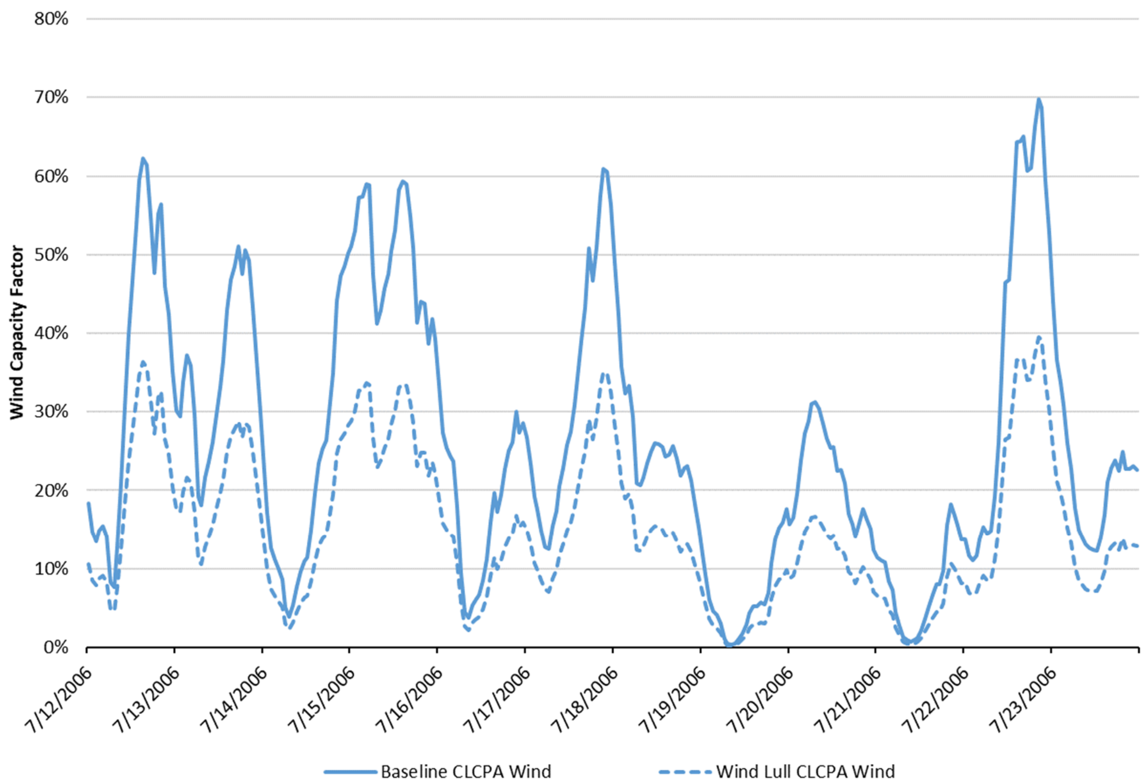
Figure 18 shows the daily capacity factor over the entire summer period in 2007, highlighting the capacity factor during the 12-day wind lull in July of 2007.

Figure 18: Summer Wind Lull Example - Summer 2007 Average Daily Wind Shape



The NREL data is a snapshot of six years of wind speeds. We recognize that while the trends are consistent over this six-year period, it is possible that there have been more severe wind lulls than in the time span we analyzed, and that there could be more severe wind lulls going forward, particularly if such outcomes are made more likely by climate change. Thus, in order to evaluate impacts associated with extended wind lulls, we set the winter wind lull used in the model to 7 days and set the summer wind lull in the model to the longest lull observed in the NREL data, 12 days. In order to evaluate potential impacts at times of high electricity demand, the wind lulls are timed to overlap with the 12- and 7-day periods of highest load for each month, (including the peak load day). Based on the historical wind lull data, we set the average capacity factors in a wind lull at 15 percent for 12 days in the summer, and 25 percent for seven days in the winter. In both seasons, the capacity for each day in the wind lull period was reduced by the same scaling factor so that the average capacity factor over the entire period was equal to 15 or 25 percent.

Figure 19: Example of Wind Lull Decreased Wind Production: CLCPA Summer Load Scenario



As a result of the above findings, summer wind lulls are modeled using the following model adjustments:

- Wind Generation - 15 percent Average Capacity Factor in all Zones for 12 days
- Wind Lull overlaps the 12-day period with highest load

Winter wind lulls are modeled using the following model adjustments:

- Wind Generation - 25 percent Average Capacity Factor in all Zones for seven days
- Wind Lull overlaps the seven-day period with highest load

3. Storm Scenarios

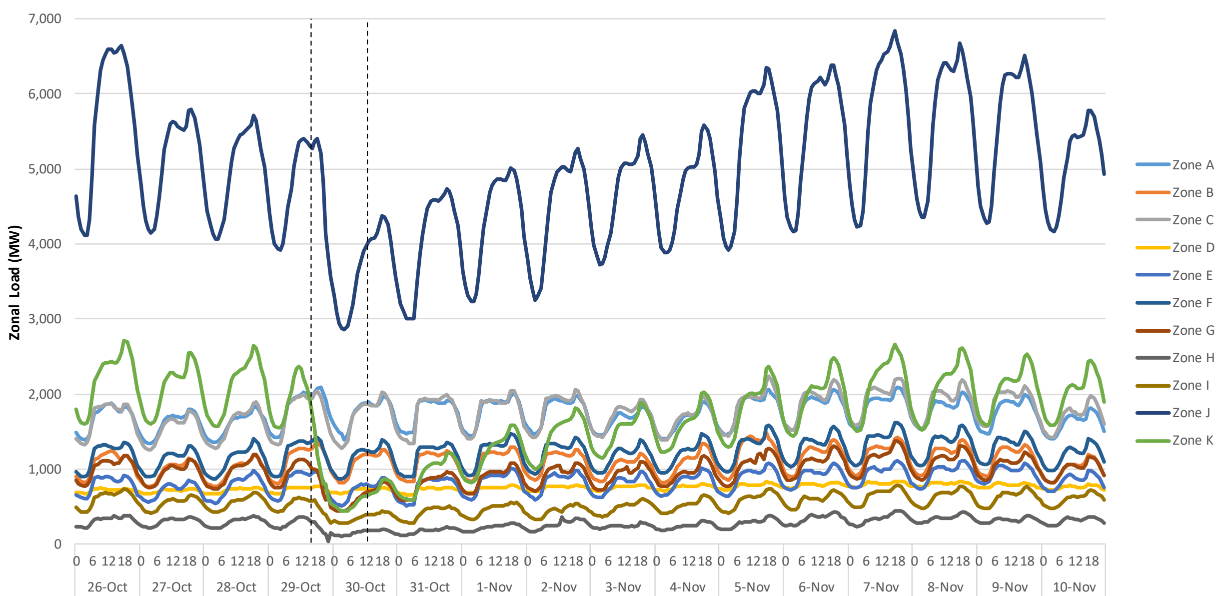
Severe storms stress the electrical system due to contemporaneous impacts on transmission, generation, transmission, and load. This analysis modeled scenarios cover severe storm impacts with sustained recovery periods of multiple days and weeks, and evaluated the potential for reliability impacts across the entire state, not just the area most directly affected by the storm event.

Hurricane Sandy, which made landfall in New York on October 29, 2012, affected load, fossil generation, and transmission assets. The storm scenarios in this study were developed based on historical observations from the

2013 NYISO Hurricane Sandy report[57] and NYISO-metered load data from the period of Hurricane Sandy and its immediate aftermath.

Large storms often cause local losses of load at the distribution system level due to physical damage from downed trees, flooding, or lightning. These distribution-level losses show up as reduced load that must be met by the electrical grid. During outages caused by Hurricane Sandy, NYISO-metered load decreased significantly in New York City and Long Island during the course of the storm (10/29/12 - 10/30/12, shown in Figure 20 with dashed line, with a nearly linear recovery. There was a nearly complete recovery of load levels by the weekend of Nov. 10. In the upstate zone, where there were fewer outages caused by the hurricane, there was a marginal decrease in load during the storm, but overall, upstate load remained consistent. [58]

Figure 20: NYISO-Metered Load during Hurricane Sandy and Recovery Period

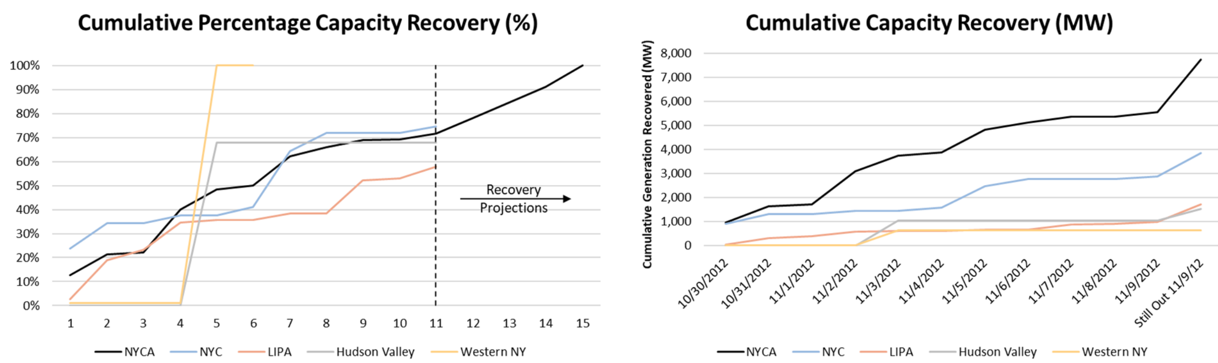


The impact of the hurricane on generation was primarily centered on nuclear and fossil units downstate. On the first day after the storm, about 20 percent of NYCA nameplate capacity was offline, and about 40 percent of New York City and Long Island capacity was offline. By day 11, the last day in the NYISO Hurricane Sandy study, approximately 30 percent of capacity was still offline. Based on the average pace of recovery, full capacity would have been back online on or about Day 15. See Figure 21 below. We apply these trends as a 40 percent reduction in DE resource capacity in the affected area with a linear recovery of generation over two weeks.

[57] NYISO, "Hurricane Sandy - A report from the New York Independent System Operator," March 27, 2013, http://www.nysrc.org/pdf/MeetingMaterial/RCMSMeetingMaterial/RCMS%20Agenda%20159/Sandy_Report___3_27_133.pdf

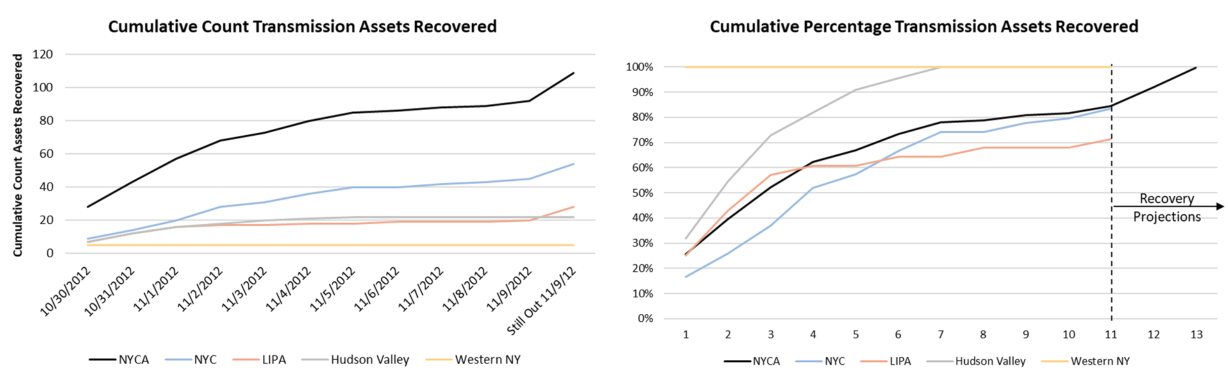
[58] NYISO, Load Data, https://www.nyiso.com/load-data

Figure 21: Cumulative Generating Capacity Recovery during Hurricane Sandy Recovery Period



The transmission impact was severe downstate and affected both interstate and intrastate transmission lines. According to the NYISO report: "Essentially, the seven southernmost interconnections to southeastern New York were disconnected, leaving Long Island and New York City only connected to the Eastern Interconnection via the Lower Hudson Valley 345 kV transmission lines."[59] By Day 11, approximately 15 percent of transmission assets were still offline. Based on the average pace of recovery, full capacity would have been back online on or about Day 13. See Figure 22 below. Thus, the study models transmission as being completely off line in the area affected by the storm, with a two week linear recovery period.

Figure 22: Cumulative Transmission Recovery during Hurricane Sandy Recovery Period



There is limited evidence of effects on renewable generation, in part because there were so few installations in Zones J and K in 2012. Sandy hit New York as a Category 1 hurricane, with max wind gusts under 100 mph during the storm.[60] Some wind generation damage would be expected given current turbine storm ratings, but future installations may be hardened to withstand Sandy-level wind speeds.[61] Solar panels are generally rated for 110-145 mph winds, and damage to both rooftop solar and grid-connected solar during Hurricane Sandy was limited.[62]

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[59] Hurricane Sandy A report from the New York Independent System Operator, http://www.nysrc.org/pdf/MeetingMaterial/RCMSMeetingMaterial/RCMS percent20Agenda percent20159/Sandy_Report___3_27_133.pdf

[60] National Weather Service, "Hurricane Sandy," https://www.weather.gov/okx/HurricaneSandy

[61] General Electric, "Riders On The Storm: GE Is Building A Wind Turbine That Can Weather Violent Typhoons, Hurricanes," June 17, 2018, https://www.ge.com/news/reports/riders-storm-ge-building-wind-turbine-can-weather-violent-typhoons-hurricanes?utm_source=feedburner

[62] IEEE Spectrum, "Rooftop Solar Stood Up to Sandy," November 16, 2012, https://spectrum.ieee.org/green-tech/solar/rooftop-solar-stood-up-to-sandy and Christian Science Monitor, "Are renewables stormproof? Hurricane Sandy tests solar, wind," November 19, 2012, https://www.csmonitor.com/Environment/Energy-Voices/2012/1119/Are-renewables-stormproof-Hurricane-Sandy-tests-solar-wind

Based on this information, wind generation is modeled as being off during the storm and then as having a two week linear recovery period for repairs. Solar generation is modeled at a 50 percent reduction due to cloud cover impacts during Day 1 of the storm, with a full next-day recovery after the storm ends.

The most recent historical experience is from Hurricane Sandy, but future storms may not necessarily be geographically centered on downstate zones. As a result, the study models upstate and offshore storm scenarios using the same level of impact as the downstate scenario, but with shifts in the geographic center of storm damage. For the upstate storm scenarios, the analysis models the same magnitude of effects, but focused on Zones A-F instead of G-K. For the offshore storm scenario, we similarly apply the same magnitude of effects, but only to impact offshore wind generation in Zones J and K.

As a result of the findings described above, the model setup for Hurricane/Coastal wind storm scenario is calibrated using the Hurricane Sandy data, as follows:

- Load: 30 percent reduction in load in Zones G-K; 11 day linear recovery period.
- Transmission: cut off transmission lines to downstate Zones G-K; 14 day linear recovery period.
- Generation:
  - Wind Generation - Off in Zones J-K during one-day storm; 14 day linear recovery period.
  - Solar Generation - 50 percent decrease in Zones G-K during one day storm; next day recovery.
  - DE Generation - 40 percent decrease in Zones G-K; 14 day linear recovery period.

Severe Wind Storm – Upstate is calibrated using the downstate Hurricane Sandy effects:

- Load: 30 percent reduction in load in Zones A-F; 11 day linear recovery period.
- Transmission: cut off transmission lines to upstate Zones A-F; 14 day linear recovery period.
- Generation:
  - Wind Generation - Off in Zones A-F during 1-day storm; 14 day linear recovery period.
  - Solar Generation - 50 percent Decrease in Zones A-F during one day storm; next day recovery.
  - DE Generation - 40 percent Decrease in Zones A-F; 14 day linear recovery period.

Severe Wind Storm - Offshore

- Wind Generation - Off in Zones J-K during one-day storm; 14 day linear recovery period.

4. Other Climate Impacts

In addition to the disruptions discussed above, we modeled two season-specific climate impacts: summer droughts and winter icing events.

A potential impact of climate change and rising average temperatures is the increased probability of a drought in New York, which would affect hydroelectric production during summer months. According to the NYSERDA ClimAID report, "[s]hort-duration warm season droughts will more likely than not become more common."[63] Based on NYISO operations information on historical low water periods, we assume a 50 percent reduction in hydroelectric production during the entire 30 day modeling period in the drought disruption:

[63] NYSERDA ClimAID, p.16

Summer drought

- Hydroelectric Generation - 50 percent of baseline production across all of New York State

Finally, NYISO historical experience with severe winter conditions has shown the potential for short-term icing events that would damage upstate transmission lines and would reduce wind production. Historical evidence is not fully available for the effect of icing in upstate New York on wind production, but one engineering study has shown the potential for up to 50 percent reduction in wind production at wind farms due to ice accretion on turbine blades.[64]

Icing Event (winter only)

- Load: 25 percent reduction in load in Zones A-C; seven day linear recovery period.
- Transmission: cut off transmission lines to upstate Zones A-C; seven day linear recovery period.
- Wind Generation - 50 percent reduction in Zones A-C during one-day event; seven day linear recovery period.

B. Construction of Combination Cases

Finally, to test the joint impact of differences in season, load scenarios, resource sets, and short-term physical disruptions, combination "cases" of each were modeled. All combination cases are presented in Table 15. The results from these cases are presented in Section V.

[64] Iowa State University News Service, "Engineers study icing/de-icing of wind turbine blades to improve winter power production," September 23, 2019.

Table 15: List of Modeled Combination Cases

		Climate Change Phase II Resource Set						Grid in Transition Resource Set			
		CLCPA			Reference			CLCPA		Reference	
ID	**Event**	**Summer**	**Winter**	**Shoulder**	**Summer**	**Winter**	**Shoulder**	**Summer**	**Winter**	**Summer**	**Winter**
Baseline	None	X	X	X	X	X	X	X	X	X	X
A	Heat Wave	X			X			X			
B	Cold Wave		X			X			X		
C	Wind Lull - Upstate	X	X		X	X		X	X		
D	Wind Lull - Off-Shore	X	X		X	X		X	X		
E	Wind Lull - State-Wide	X	X		X	X		X	X		
F	Hurricane/Coastal Wind Storm	X			X			X			
G	Severe Wind Storm – Upstate	X	X		X	X		X	X		
H	Severe Wind Storm – Offshore	X	X	X	X	X		X	X		
I	Drought	X			X			X			
J	Icing Event		X			X			X		

IV. Output Metrics

A. Model Output

The energy balance model is run for each case identified for analysis. As described in Section III, each case is a combination of a load scenario, resource set, and physical disruption. The model proceeds through an electricity transfer and dispatch sequence based on the data inputs described above, including physical constraints on unit operations and the flow of power between locations within New York. Results are presented along several metrics indicating system reliability performance, including the identification of potential loss of load occurrences. The results are assessed both individually for each case, and across all combination cases. This section describes the model output metrics and graphics, followed by the process used to distill case results into a set of key observations.

For each model run, the energy balance model estimates or tracks:

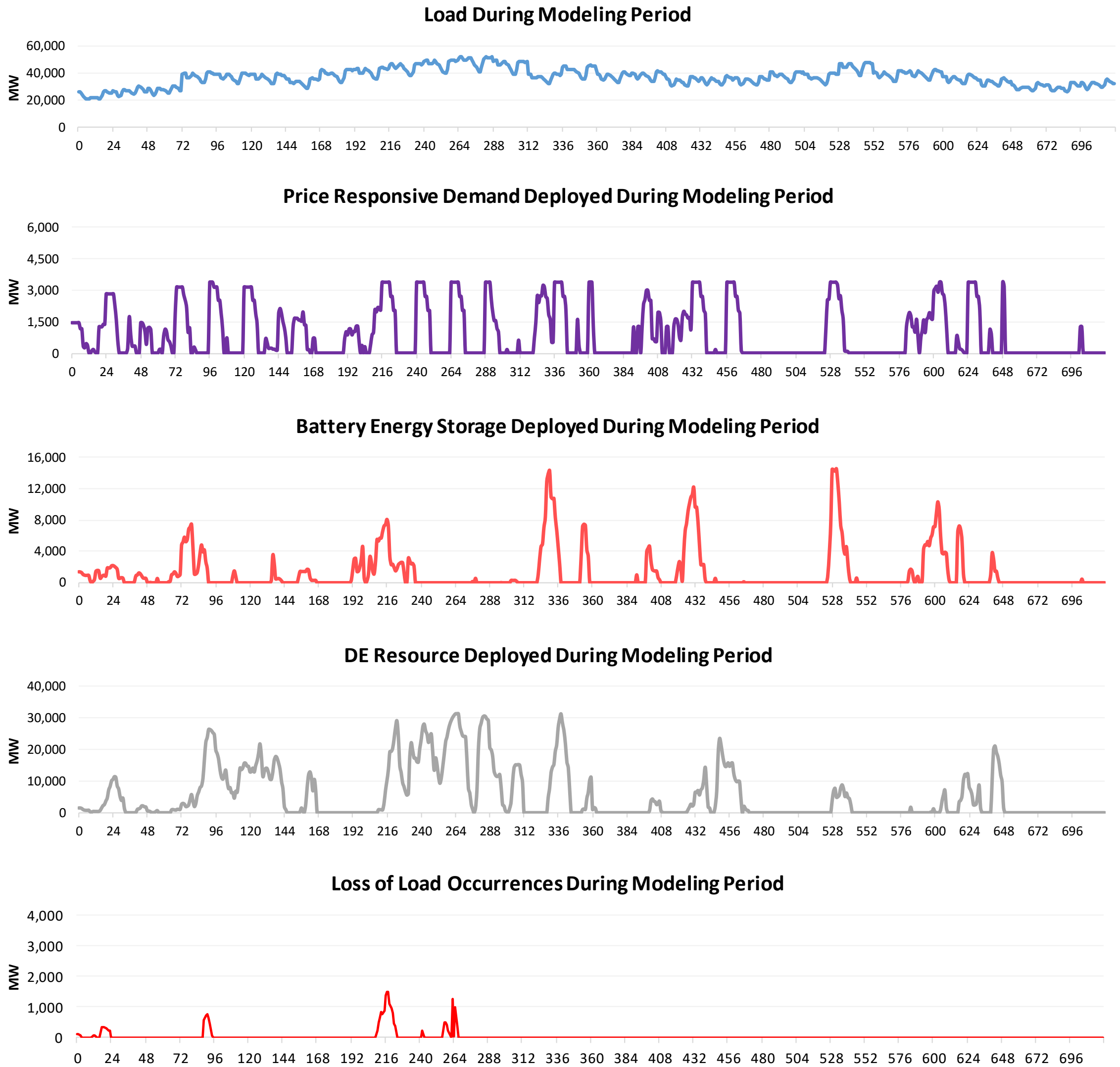
a. Hourly demand for electricity;
b. Hourly generation from renewable resources;
c. Hourly dispatch and stored energy for battery and pumped storage units;
d. Total hourly zonal generation relative to electrical demand;
e. Hourly capacity imports and transfers of power between Zones;
f. Hourly activation of price-responsive demand resources, when needed to avoid loss of load;
g. Hourly dispatch of DE resources, when needed to avoid loss of load;
h. Magnitude of potential loss of load on an hourly basis, in each zone, over the thirty-day modeling period.

The central focus of the model outputs are the magnitudes, duration and frequency of use of DE resources, and potential loss of load occurrences. In order to assist in the detailed analysis of each case, and for comparison of potential LOLO drivers across cases, the model generates a consistent set of tables and graphics for each case. For illustration of the reporting outputs on case outcomes, Figure 23 through Figure 28**Error! Reference source not found.** present an example of the full set of metrics generated in graphical and tabular form for one case - namely the case run with the most observed loss of load occurrences (CLCPA Winter Severe Wind Storm - Upstate).

Figure 23: Example of Hourly Results Summary

Hourly Results Summary

Case Name: CLCPA Case - Winter - Climate Change Phase II Resource Set - Severe Wind Storm - Upstate



Load	
Total Hrs.	720
Total MWh	26,633,154
Avg. MW	36,990.5

PRD Deployment	
Total Hrs.	325
Total MWh	623,946
Avg. MW	1,919.8

Battery Deployment	
Total Hrs.	262
Total MWh	856,262
Avg. MW	3,268.2

DE Resource Deployment	
Total Hrs.	369
Total MWh	3,822,059
Avg. MW	10,357.9

Loss of Load Occurrences	
Total Hrs.	45
Total MWh	22,150
Avg. MW	492.2

Figure 24: Example of Full Period Results Summary

Figure 25: Example of NYCA Hourly Generation by Fuel Group

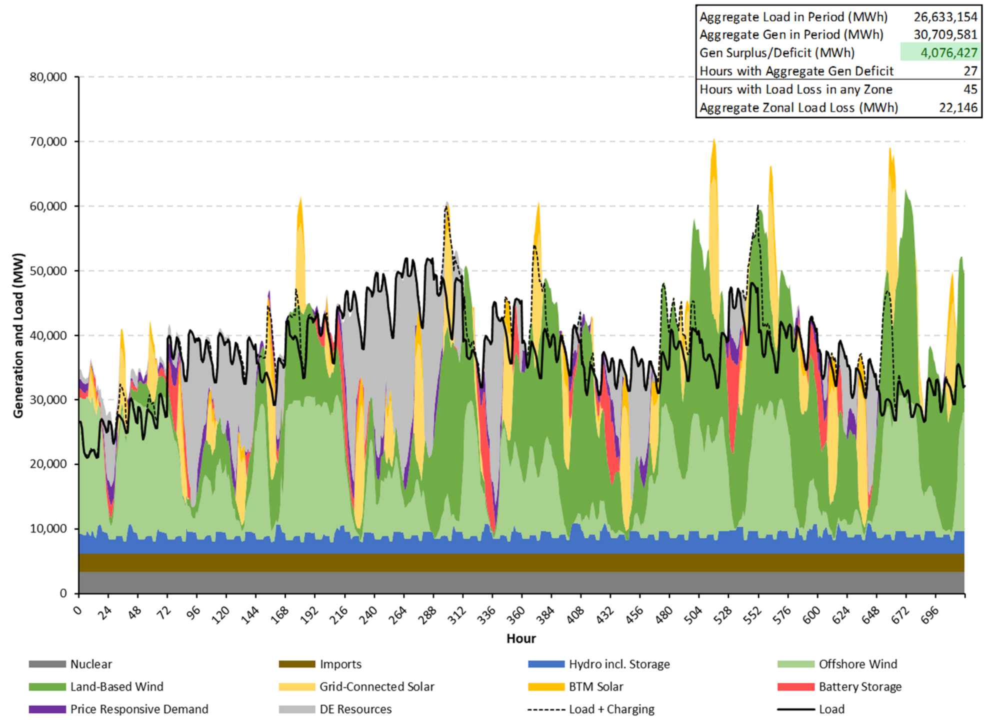


Figure 26: Example of Generation by Resource Type over Modeling Period

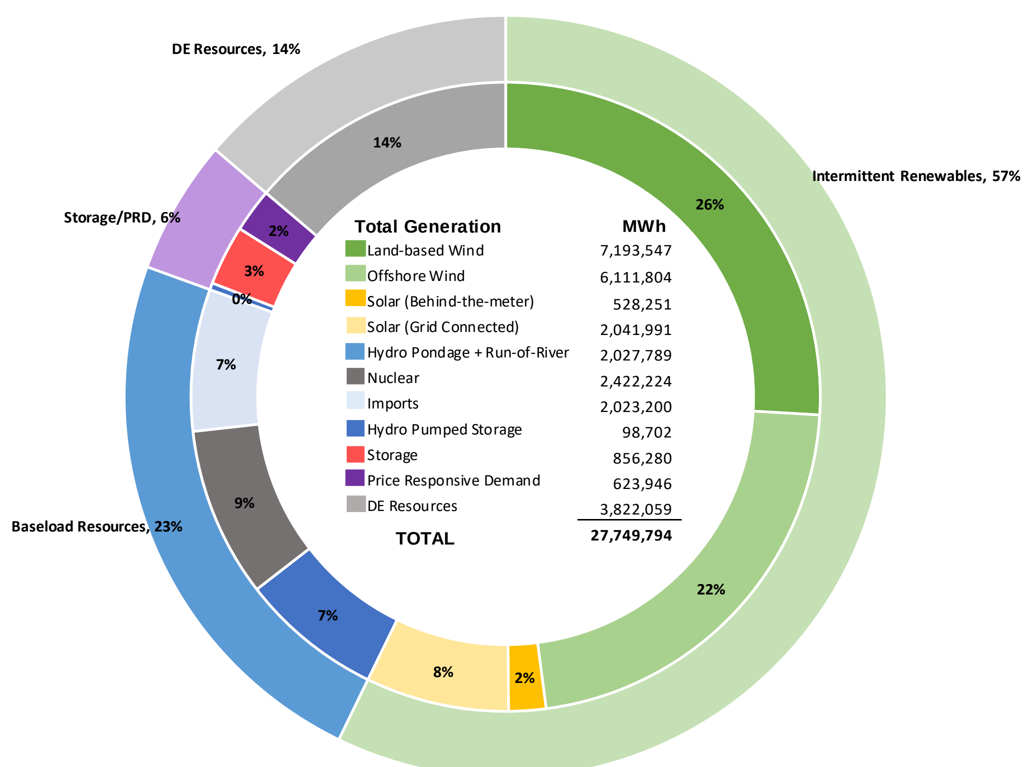


Figure 27: Example of NYCA DE Resources Generation Duration

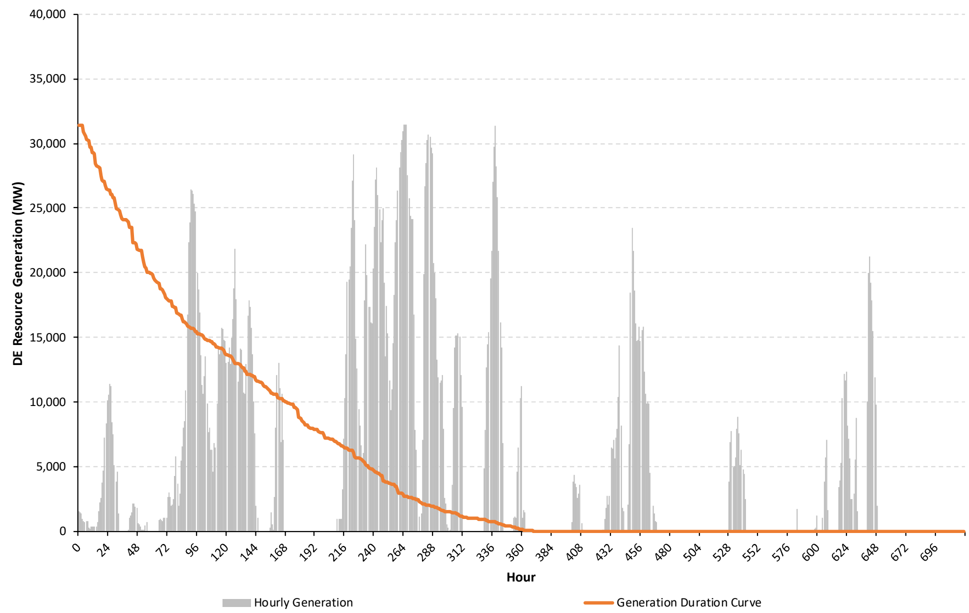
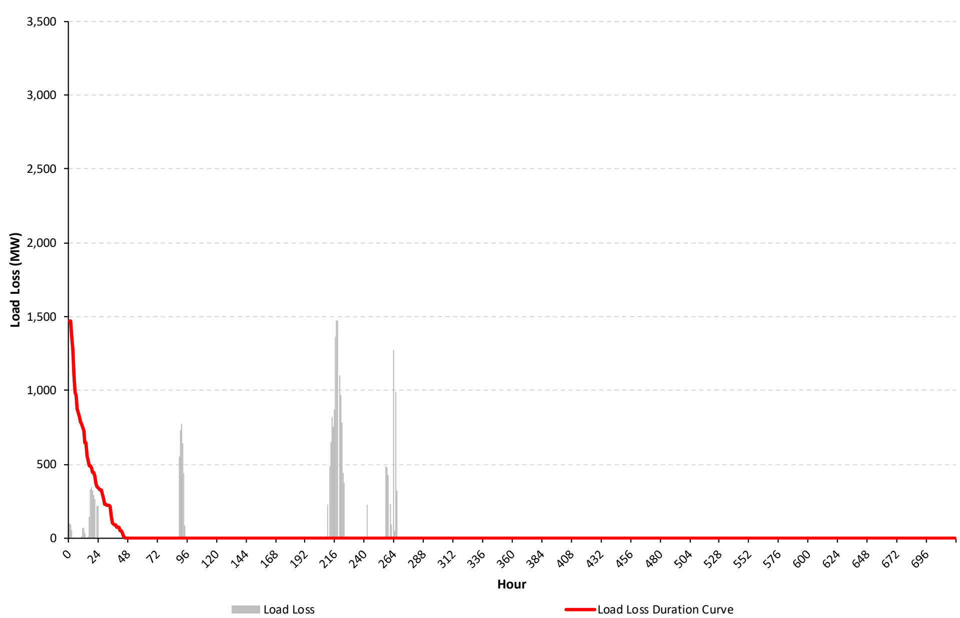


Figure 28: Example of NYCA Loss of Load Occurrences Duration



B. Analysis of Outcomes

The key focus of the analysis is on cases where there is a potential loss of load occurrence, or where leading indicators (PRD activations and/or use of DE resources) point to tight conditions and heighted reliability risks. Each combination case based on an initial load scenario and resource set is first reviewed and analyzed as a "baseline" case without additional physical disruptions factors that might influence system operations. Cases are analyzed based on usage of price responsive demand and DE resource activation, and potential load deficits. The severity of impact, meaning the magnitude, duration, and frequency of DE resource usage or loss of load, is informative to the properties of the DE resource needed to maintain system reliability. Aggregate energy balance patterns, peak hour patterns, and resource ramping requirements are all reviewed. Following the "baseline" cases, the physical disruption cases are analyzed using the same metrics to measure level of impact.

The model does not take into account other emergency actions such as voltage reduction, public appeals, or targeted load shedding, nor does it automatically consider that there may be other steps that could be taken to resolve any transient or minor potential outage (e.g., allowing assets to move to emergency operation ratings). In addition, the model does not take into account the probability that the combination of scenario definition and the physical disruptions identified in a particular case will come to fruition. The model output metrics quantify the potential reliability *consequences* of each case - that is, the magnitude and duration of potential LOLO (or for leading indicators) under the modeled combinations of system scenarios and physical disruptions, but it is not intended to replicate a probabilistic assessment of whether the conditions in question will or will not meet a standard such as loss of load no more frequent than once in ten years.[65] That type of assessment is not within the scope of this report.

The analysis of cases is summarized in Section V below, and Appendix B and Appendix C provide exhibits that show detailed diagnostic results across all combination cases run.

[65] NYISO is obligated to plan for a system that has the "probability (or risk) of disconnecting any firm load due to resource deficiencies, on average, not more than once in ten years." New York State Reliability Council, "Reliability Rules and Compliance Manual," February 9, 2018, page. 13, available at http://www.nysrc.org/pdf/Reliability%20Rules%20Manuals/RRC%20Manual%20V42_Final.pdf.

V. Results and Observations

A. Overview

The purpose of this report is to evaluate whether and how a changing climate and policies to mitigate its effects may place additional stresses on reliable power system operations in New York State. These stresses may range from changes to load due to increasing average temperatures to more frequent and/or severe storms and other weather events. The Phase I climate study identified the impact of increasing temperature on load. This analysis carries that review one step further, and postulates how the changing climate depicted in the Phase I study may affect power system operations and reliability.

Our analysis is complicated by the fact that in response to the realities and risks of climate change, New York State is embarking, through the CLCPA, on an ambitious and challenging period of transition -- one that will require an unprecedented level and pace of change in energy supply and use to achieve steep reductions in GHG emissions across all sectors of the economy. The electricity sector is expected to play an outsized role in this transition - both to enable reductions in other sectors through electrification, and through a rapid decarbonization of the power infrastructure relied on to reliably meet electricity demand. As a result, the electric system of 2040, which is the required year for no GHG emissions from the electric sector, will look fundamentally different from the current system. That system will need to meet growing electricity demand without any of the fossil-fueled resources relied upon to maintain reliability today.

Thus the context for our analysis is both an altered climate, with new and different challenges to system operations, and a completely altered set of demand, generating, fuel and transmission resources to reliably meet the system demand 8,760 hours each year.

In this section we review the results of our modeling of potential climate disruption scenarios in the year 2040. We discuss the results of our model in the context of the transition to a decarbonized economy and power system that meets the requirements of the CLCPA.

B. Baseline Scenario Results

1. A Note About Starting Point Resource Sets

As noted earlier, before evaluating the climate disruption scenarios we must establish a system that; (1) has demand consistent with the Climate Change Phase I Study, (2) has a set of resources that comply with the requirements of the CLCPA, and (3) that meets electricity demand in every hour all year.

Constructing a set of "starting point" resources is highly uncertain at this point, for a variety of reasons:

- The New York power system is currently heavily dependent on natural gas fired generating units to provide energy, to be available during high load hours, to provide critical reserves on the system, and to be able to ramp up and downs on timescales of seconds, minutes, hours, and days to manage net load[66] variability. At least as currently configured and fueled, these resources cannot operate in 2040;

- Even retaining existing zero-carbon (nuclear, hydro) resources, there is an enormous amount of energy and capacity needed to meet projected demand in 2040;
- Currently-available and reasonably economic resources available to make up the zonal and system-wide energy deficits include solar and wind resources, yet their availability is uncertain and somewhat unpredictable. In fact, data reviewed for this report reveal that there would be long (multi-day) "lulls" in production from these resources. This means that almost no quantity of nameplate capacity from these resources is sufficient to meet demand in all hours of the year;
- Energy storage resources that are currently and expected to be available can fill part, but not all of the gap needed to maintain system reliability;
- There is a void that will need to be filled with technologies and/or fuels that - at the scales that would be required - will need to developed, proven, and economic; and
- There is no doubt a major amount of technological change that will happen over the next twenty years, rendering it very difficult to forecast a future resource set with reasonable confidence.

Thus constructing a "starting point" resource set on which to model system reliability in 2040 is highly subjective. There are innumerable potential combinations of generating resources (current and future), storage resources, transmission expansions, distributed resources, and demand management practices that could evolve to meet future demand. Therefore, we construct a starting point resource set with a few core principles in mind:

(1) The state of New York has embarked on an aggressive path to facilitate the rapid development and siting of zero-carbon renewable energy resources to ensure reasonable progress towards the ultimate CLCPA requirements. Based on this, we focus as a first step on constructing a resource set that relies on the build out of solar and wind resources in all zones.

(2) The potential for development of substantial renewable resources exists somewhat distant - upstate and offshore - from the downstate region where load is concentrated in the state. Thus, relying on renewable resources to facilitate the transition of energy supply and demand in New York will require substantial increases in inter-zonal transfer capability through the development and construction of new high-voltage transmission capacity.

(3) Based on current technologies and the Phase I study assumptions about the shape of electricity demand in 2040, there could be periods of time when all of the retained resources and renewable generating output are not sufficient on their own to meet demand. While we cannot know what or which technologies may emerge to fill any gaps, we do include the DE resource to identify the nature and magnitude of residual need.

One point is worth repeating - this is but one approach to constructing a starting point resource set. The GIT resource set - which we also evaluate in the model - may be viewed as an alternative approach to the CCP2 resource set. The GIT resource set does not have increases to the transmission system and therefore results in a smaller set of renewable generation which is located closer to the downstate load and also results in relying more on the DE resource. Thus while there are many other ways in which the grid will evolve in the coming decades, the two resource sets we evaluate in this study may be viewed to some extent as bookends on potential outcomes.

[66] "Net load" is used to represent the varying second-by-second level of demand on the bulk power system, net of the impact of energy efficiency, demand response, and behind-the-meter generating resources (primarily solar photovoltaic).

Since the CCP2 resource set was designed to have sufficient capacity and transfer capability to meet peak demand in each case (reference and CLCPA), it is worth reviewing results of running the system for all hours in the modeling periods with this resource set in place. Primarily, this gives us a view into how much and how often the system requires the operation of the DE resource, but it also demonstrates quantitatively the challenges of reliable system operations with a system configured with existing zero-carbon resource and storage technologies.

While from an annual energy standpoint the DE resources provide only minor contributions, in both the summer and winter modeling periods, the DE resources are critical to maintaining system reliability during hours when the system is stressed, either from high loads, low renewable capacity factors, or both. This section will summarize the aggregate load/generation balance across the seasonal modeling periods, then discuss specific observations about DE resource generation in various cases.

2. Aggregate Load/Generation Balance

By construction, the total amount of baseload and renewable generation in each modeling period is sufficient to meet all load in that period if there were no deliverability or storage constraints. For example, in the CLCPA winter load scenario (as shown in Figure 30), in the peak load month, aggregate baseload and renewable generation is 28,493 GWh, more than the total load of 27,322 GWh. However, due to the existence of limits on inter-zonal transfer capability in certain hours (even with some expansion of the transmission system) and finite storage quantities, the realized resource mix used to meet load includes 12 percent DE resources and price responsive demand, meaning that renewables, either in terms of concurrent generation or stored energy), are not able to be used to provide 12 percent of load (see Figure 31).

Even assuming large increases in both transmission and storage capacity (as defined in Section II.D), sizable variance in renewable output and load means that there will not always be enough storage capacity to meet short-term load/generation deficits. For example, as seen in Figure 29, in the winter CLCPA Case, the wind capacity factor from hours 150-200 is 74.1 percent, which allows all storage units across the state to be charged to full capacity (138,840 MWh) by hour 173. During hours 174-200, an average of 18,121 MW per hour of excess renewable capacity is effectively curtailed due to lack of storage. This period is immediately followed by the hours of 200-288, where the wind capacity factor is 28.5 percent and load simultaneously increases. As a result, storage capability is completely used up by hour 226, and DE resource generation is needed to run. In other words, even though there is enough renewable generation to meet loads in winter, due to its intermittent nature, the energy is not always deliverable during the times and to the locations it is needed.

The CLCPA load scenario is winter-peaking, so the summer and shoulder modeling periods require less DE resource generation and PRD to fulfill demand. The summer modeling period has more than enough aggregate baseload and renewables generation of 27,760 GWh to meet load of 22,475 GWh (see Figure 32). Again, due to transmission and storage restrictions, the analysis finds that DE resource and PRD resources are needed to provide six percent of load (see Figure 33). The shoulder modeling period has even more surplus generation compared to load, with aggregate baseload and renewables generation of 35,688 GWh and load of only 12,496 GWh (see Figure 34). In this modeling period, no DE resource generation is needed at all to supply load (see Figure 35).

Figure 29: Battery and Pumped Storage Energy Level, CCP2-CLCPA Winter

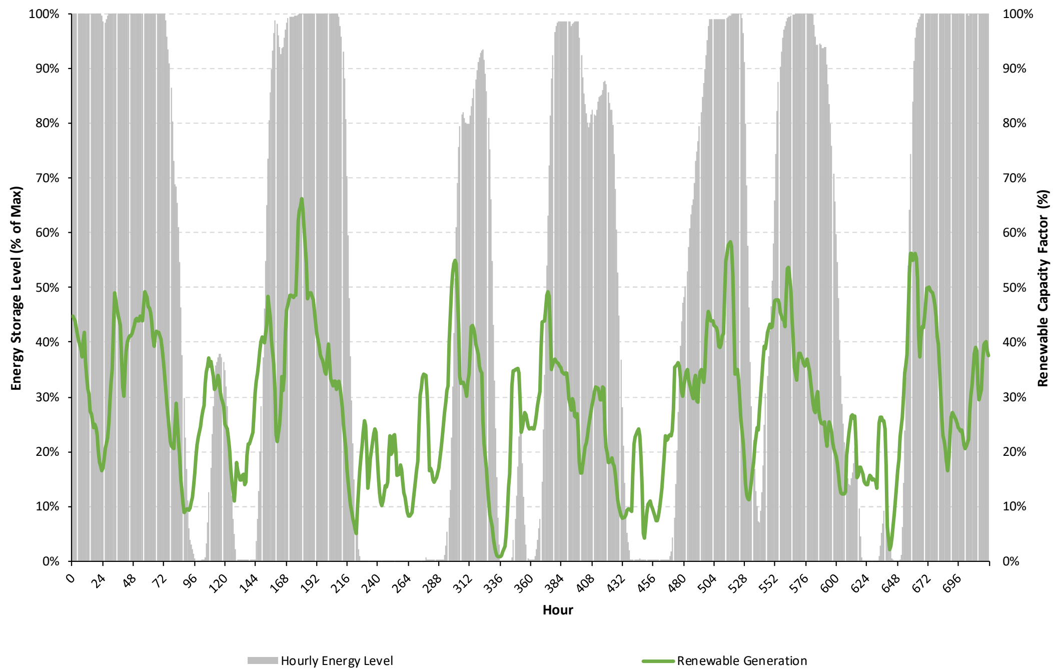


Figure 30: Hourly Load/Generation Balance, CCP2-CLCPA Winter

Aggregate Load in Period (MWh)	27,322,037
Aggregate Gen in Period (MWh)	32,894,710
Gen Surplus/Deficit (MWh)	5,572,673
Hours with Aggregate Gen Deficit	0
Hours with Load Loss in any Zone	0
Aggregate Zonal Load Loss (MWh)	0

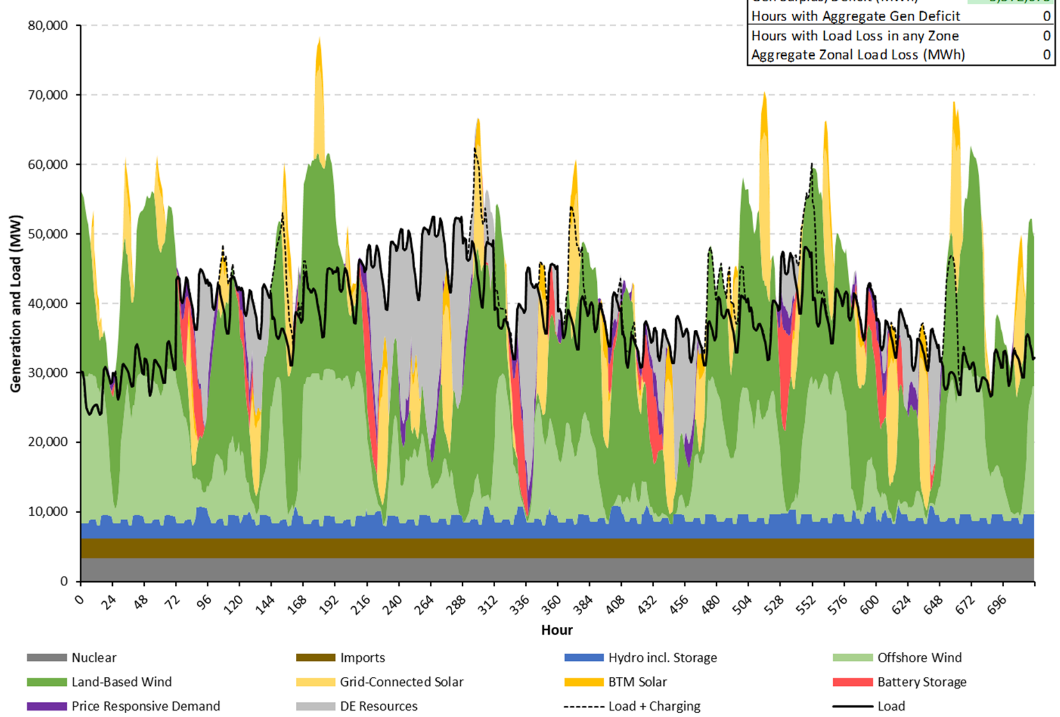


Figure 31: Generation by Resource Type, CCP2-CLCPA Winter

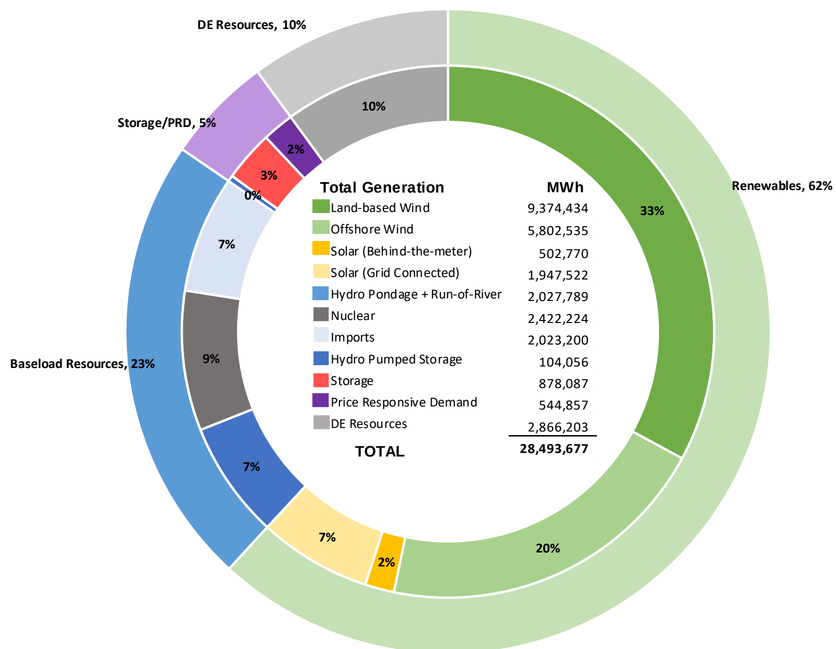


Figure 32: Hourly Load/Generation Balance, CCP2-CLCPA Summer

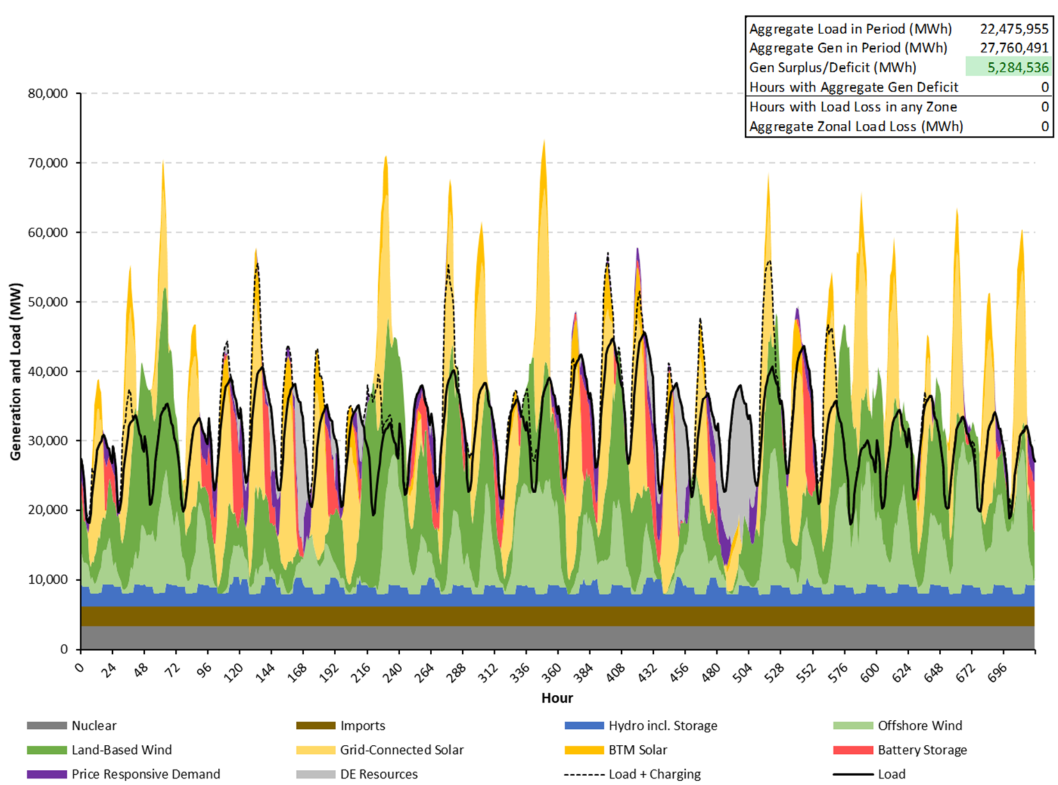


Figure 33: Generation by Resource Type, CCP2-CLCPA Summer

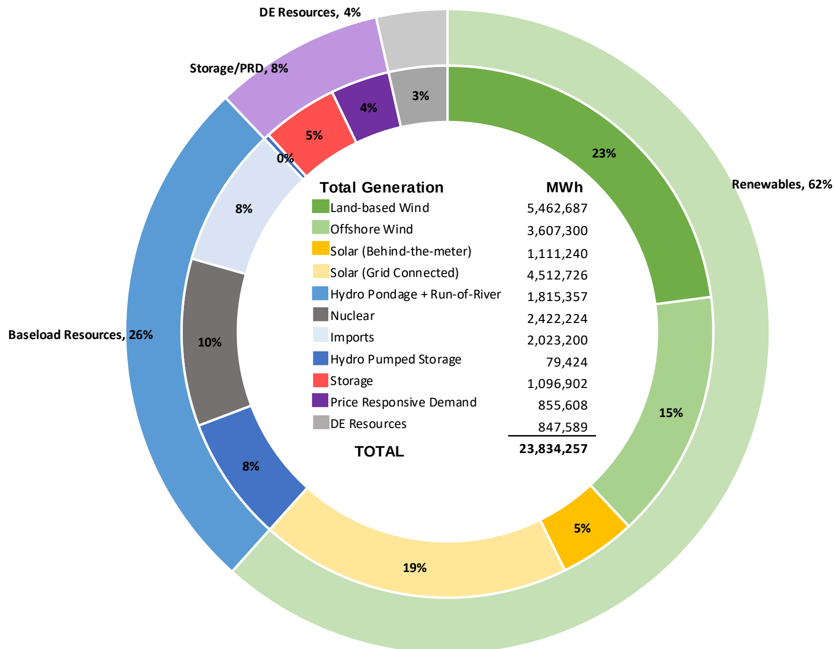
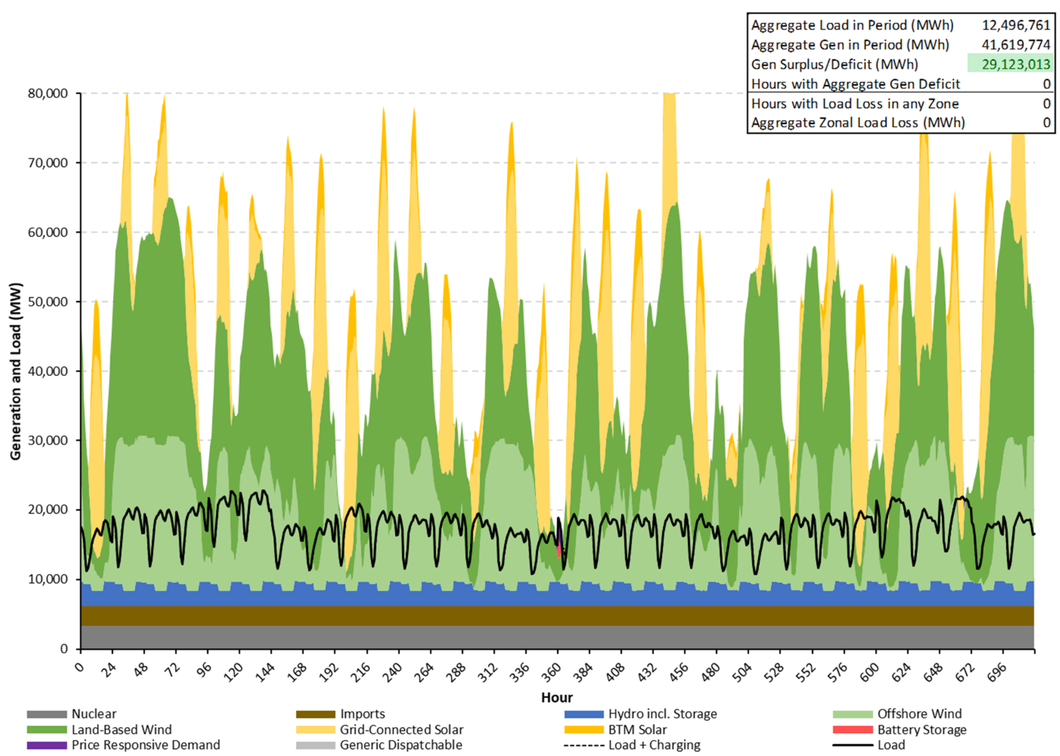
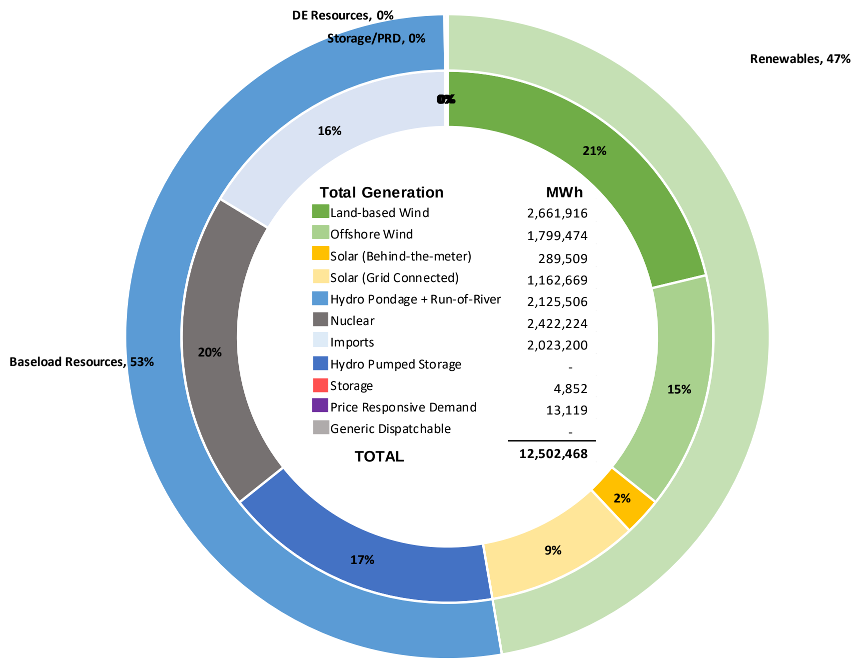


Figure 34: Hourly Load/Generation Balance, CCP2-CLCPA Shoulder



Note:
[1] Aggregate Generation in period includes curtailed renewable output not used to meet load or charge storage.

Figure 35: Generation by Resource Type, CCP2-CLCPA Shoulder

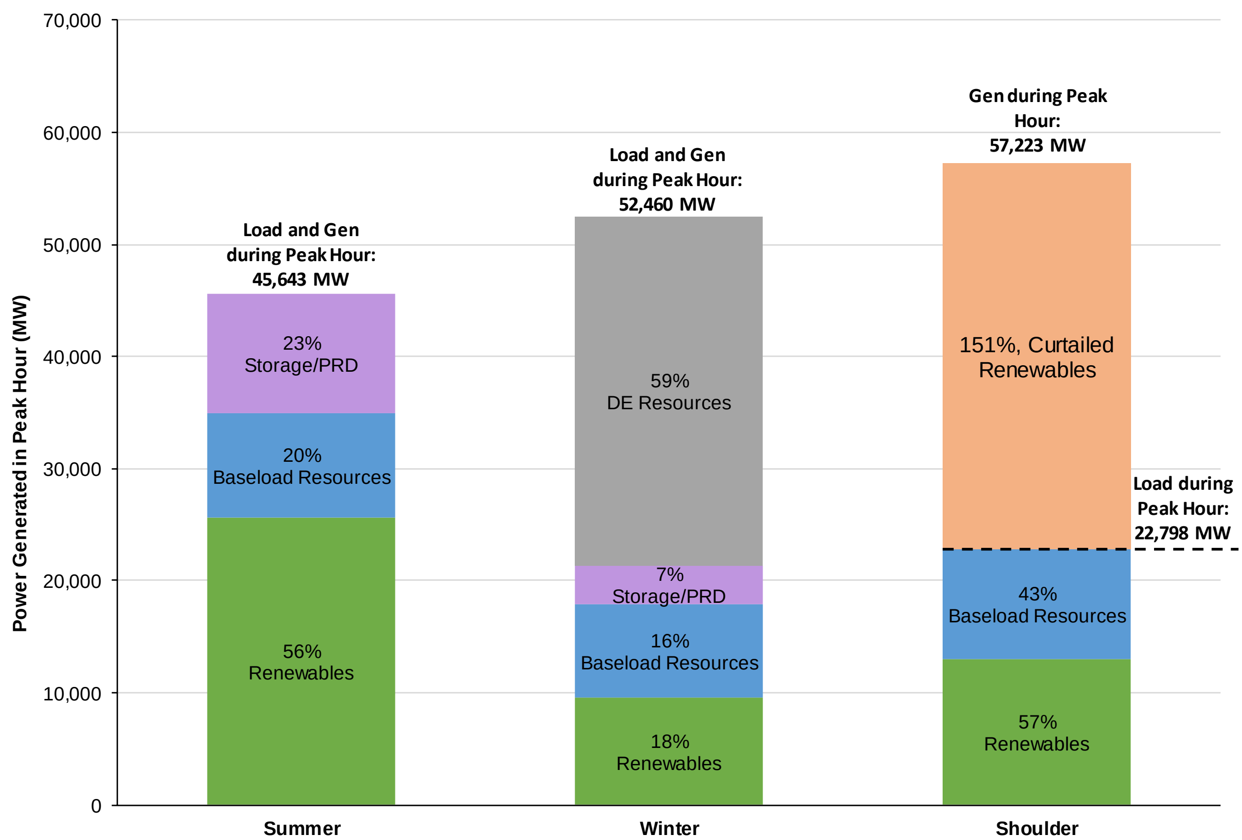


3. Peak Hour Patterns

DE resources have a particular role to play during the peak load hours of each modeling period. Figure 36 shows that during the peak hour in the winter CLCPA Case (Hour 2 of January 12, 2040), DE resources provide 59 percent of demand. It happens that in the winter peak hour, solar generators on aggregate have a 0 percent capacity factor, and wind generators have on aggregate a 17 percent capacity factor. As a result, DE resources provide the majority of energy on the peak winter hour.

By contrast, Figure 36 shows that during the peak load hour during the summer CLCPA Case (Hour 17 of July 18, 2040), the entirety of load is met by the ample amount of renewable resources, baseload resources, storage, and PRD, and no DE resource generation is required. In the summer peak hour, solar generators on aggregate have a 24.0 percent capacity factor, and wind generators have on aggregate a 24.2 percent capacity factor, enough to meet load needs. However, there are several hours in the summer that, due to reduced renewable output, that significant amounts of DE resources are required to serve load. Additionally, even though the results from this analysis did not show the need for DE resources during the shoulder season load levels, there is always the potential, given the nature of renewable resources, for the need for DE resources.

Figure 36: Resource Mix during Seasonal Peak Load Hours, CCP2-CLCPA Case



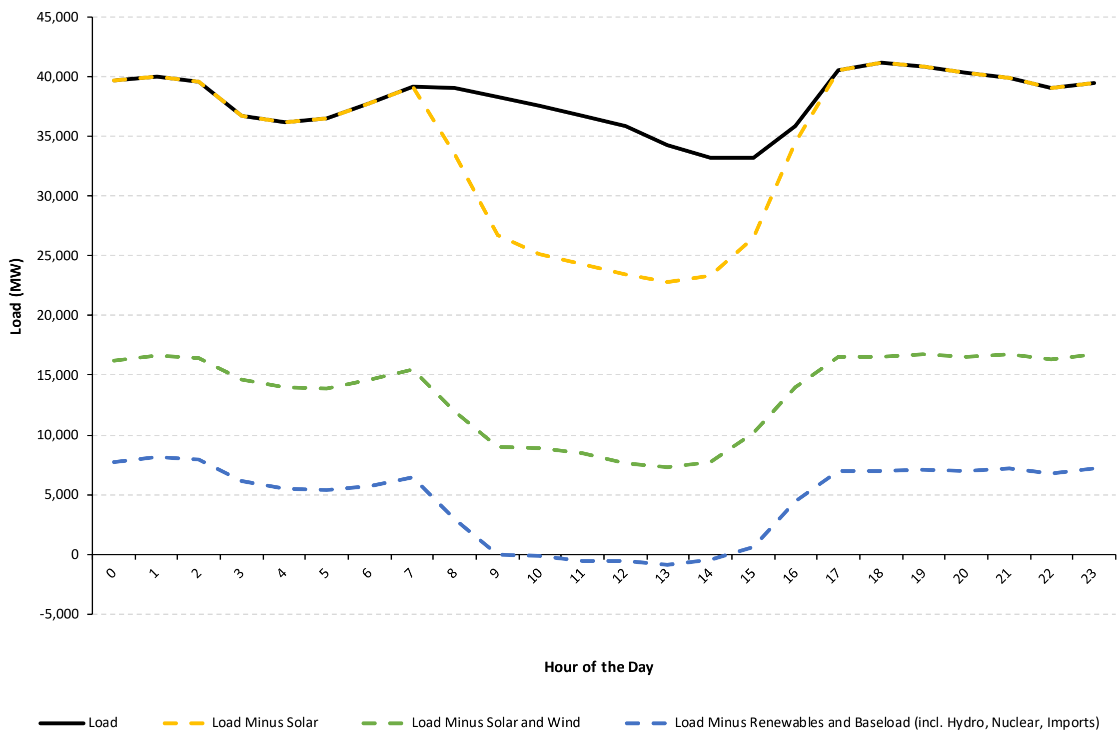
4. Ramping Patterns

Another important requirement for the DE resource is the ability to "ramp up" quickly, or increase generation over a short period of time during the course of an operating day. Due to the large reliance on renewable generation throughout each modeling period, there are certain hours and certain days in the modeling periods where a large quantity of DE resource output is needed to meet load needs.

Figure 37 shows the quantity of load that is needed to be met on average by hour for each day of the Winter CLCPA baseline case. The top black solid line shows average load over the course of the day. This load is met first by solar and wind resources, shown by the load reductions in the dashed yellow and green lines. The final average quantity to be met by storage, PRD, or DE resource generation is the quantity shown by the blue dashed line.

On average during the day, there is more generation than load, which means that storage capacity can be filled from generation and DE resources are not needed to operate. Even on days when there are short lulls in resource generation, if storage resources are filled to capacity in advance of the evening peak, storage output is sufficient to meet load needs without dispatch of DE resources.

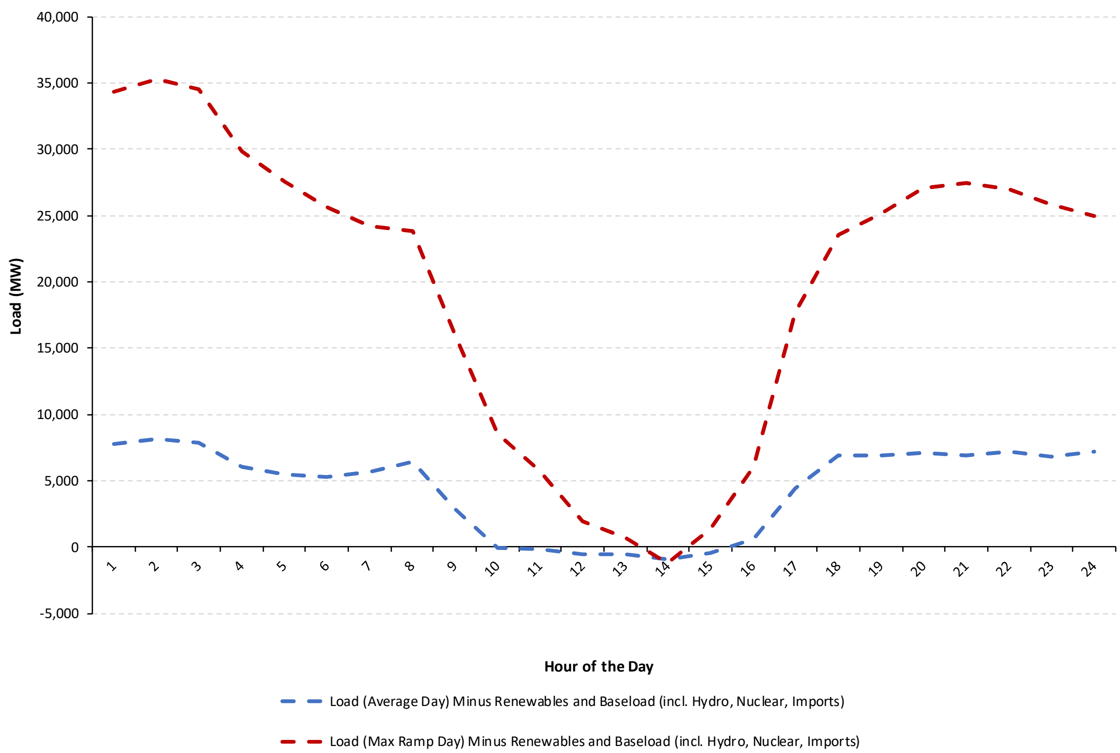
Figure 37: Average Load and Generation Requirements, CCP2-CLCPA Winter



Note:
[1] Renewable generation quantities offset from load do not include curtailed renewable generation.

However, there is also great variance between days within the modeling period. Based on model results, there also are short periods of less than 6 hours where output from the DE resource must be ramped from almost nothing to almost full capacity. Figure 38 shows an example of the single day in the CLCPA Winter baseline case where the most ramping capability is required. Between hours 14 and 20, DE resource output across the state must increase from 362 MW (or 1.1% of DE resource nameplate capacity) to 27,434 MW (or 85.4% of nameplate capacity). In the single hour between 15 and 16, DE resource output must increase 11,716 MW, which is the largest single-hour increase across the entire winter modeling period. Given the rapidity of decrease in solar generation when the sun sets, the DE resource must have fast ramping capability in order to meet requirements on days when other resources are not available to meet load.

Figure 38: Maximum Hourly Ramping Requirement, CCP2-CLCPA Winter



Note:

[1] Renewable generation quantities offset from load do not include curtailed renewable generation.

5. Aggregate Use of Dispatchable and Emissions-free Resources

Though DE resources provide an important function during peak hours, on average, they are rarely called upon to supply energy. As shown in Table 16, DE resource capacity factor is only 12.4 percent in winter, 3.7 percent in summer, and zero percent in the shoulder month for the CLCPA Case. In addition, as shown in Figure 39, the need for DE resources is most acute in a limited number of hours. In winter, when the system is most stressed, over 10,000 MW of DE resources are needed for 126 hours (or 17.5 percent of the 720 hour modeling period), but no DE resources are called upon for 465 hours (or 64.6 percent of modeled hours).

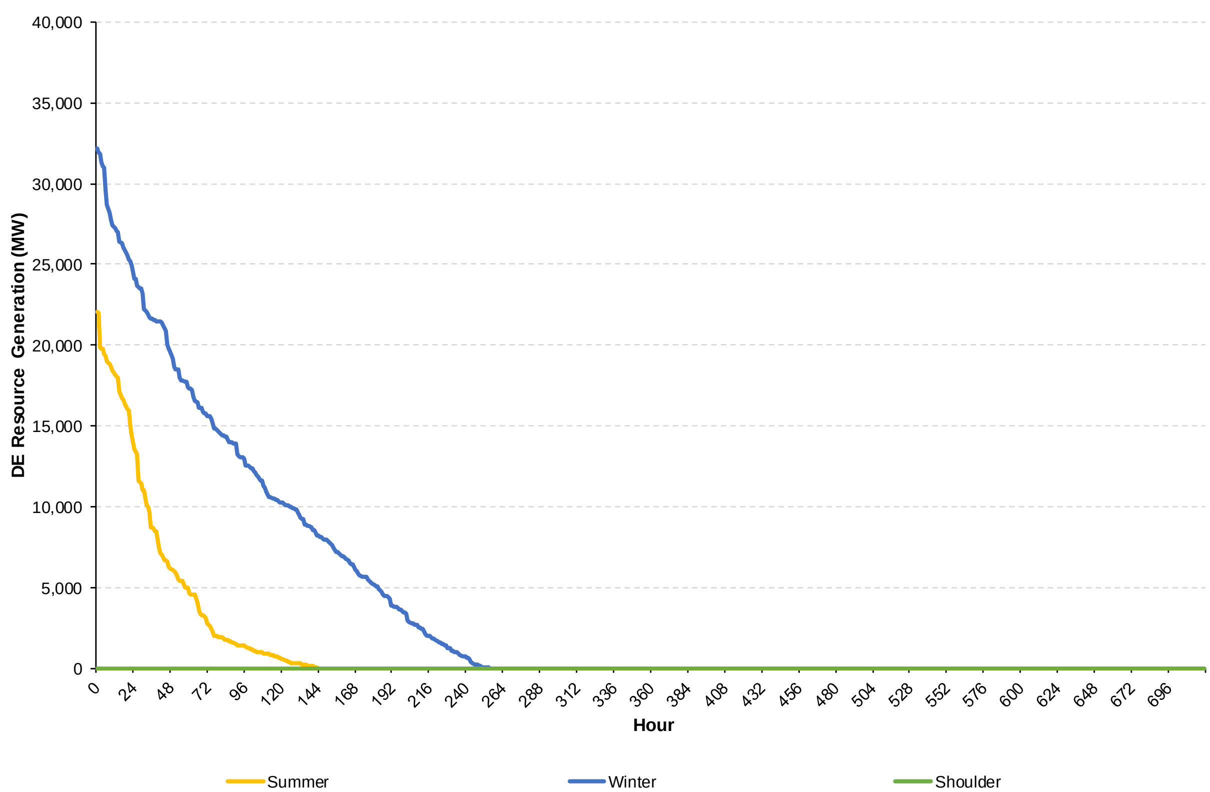
In this study, we provide results for two very different visions for the evolution of the power system - one that relies on renewables and transmission (the CCP2-CLCPA resource set), and one that places greater emphasis on the DE resource - that is, the potential emergence of a zero-carbon generation or fuel source (the GIT resource set). A key difference between them is that since the GIT resource sets do not include any transmission expansion, it results in a higher degree of reliance on the DE resource. This provides insight into the challenges New York State will face in guiding and managing what will likely be a rapid transition over the next two decades.

For example, if there is skepticism that an economic fuel or technology will emerge and be widely available, and that can deliver reliable capacity, energy, reserves, and flexible operating attributes with no emissions of GHGs, then the pathway may be more heavily tilted towards aggressive investment in and development of renewable and transmission infrastructure, such as in the CCP2 resource set. This approach would allow the system to operate with relatively low annual generation from the DE resource. Conversely, if such a fuel or technology were to emerge, be technologically and economically viable, and be widely available, then there is little need to invest the significant capital needed to build out renewable and transmission infrastructure to meet the CLCPA requirements. Thus, the degree of reliance on a DE resources under different scenarios and resource sets is evaluated in this report as an indication of the challenges New York will face to manage its energy systems transition in the coming decades.

Table 16: DE Resource Capacity Factor by Season

Season	Average Capacity Factor
Winter	12.39%
Summer	3.66%
Shoulder	0.00%

Figure 39**: Duration Curve of DE Resource Generation by Modeling Period**



C. Key Observations by Physical Disruption

1. Temperature Waves

For both the summer heat wave and winter cold wave scenarios, model results show no losses of load based on increased reliance on DE resources, as discussed below. The combination of transmission, PRD, and DE resource generation is sufficient to meet load in all hours. In the summer modeling period in particular, increases in solar output partially offset declines in wind production.

In both cases, there is an increase of the use of DE resources over the baseline case. This increase is more pronounced in the summer modeling period as compared to the winter. Based on the Phase I study temperature-load modeling, across all zones, higher temperatures during heat waves lead to steeper increases in load compared to lower temperatures during cold waves. That is, a one degree increase in temperature during a summer heat wave will lead to more *additional* MWs of load during the daily peak than a one degree decrease in temperature during a winter cold wave. As a result, the summer heat wave scenario requires more DE resource generation over the baseline scenario as compared to the winter cold wave.

Figure 40: Hourly Load/Generation Balance, CCP2-CLCPA Summer Heat Wave Case

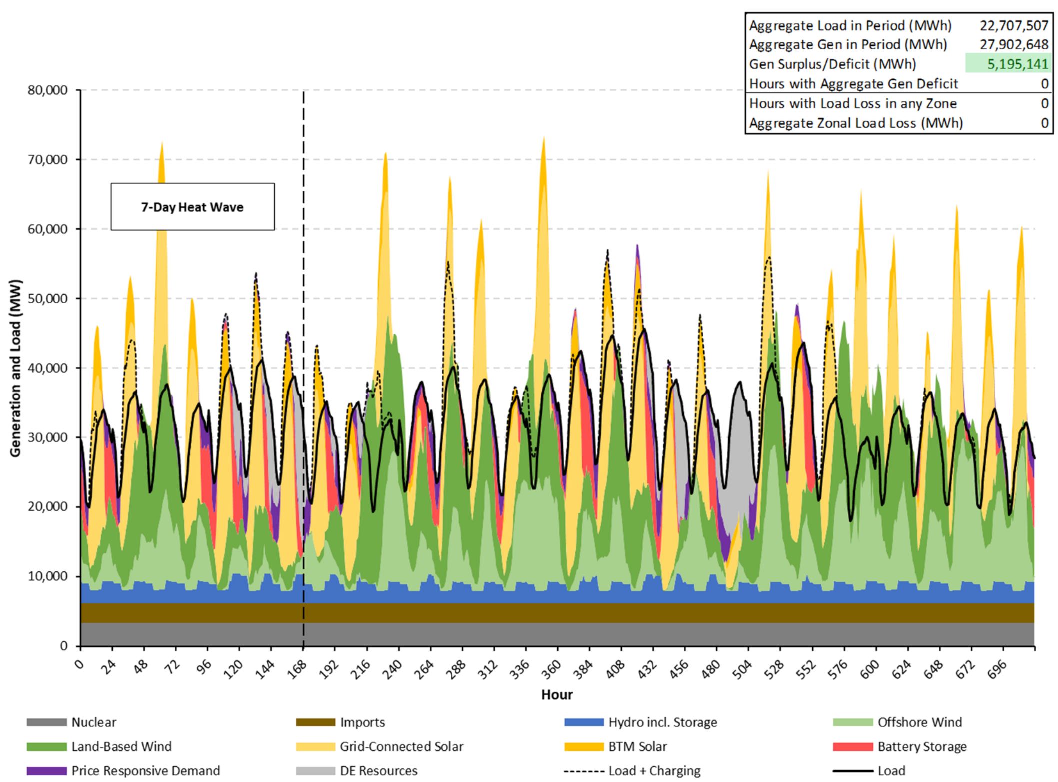
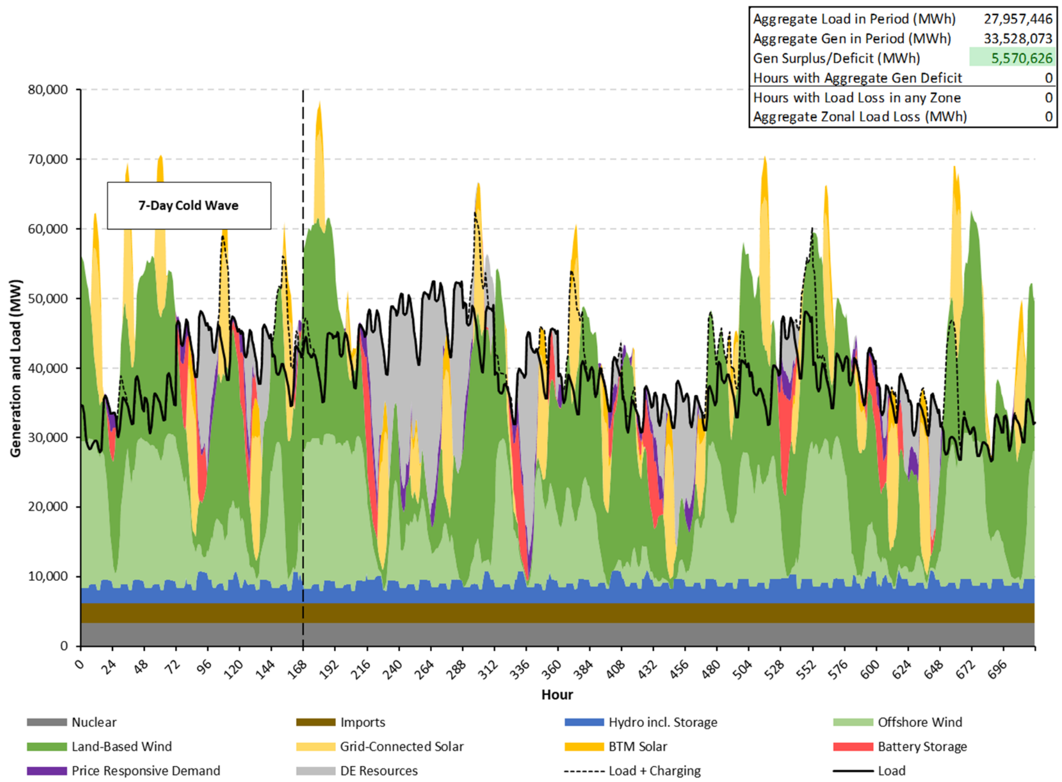


Figure 41: Hourly Load/Generation Balance, CCP2-CLCPA Winter Cold Wave Case



The heat and cold waves modeled in this study are meant to represent temperature waves that are consistent with historical record in terms of severity and duration. More severe modeled temperature waves, as may occur more frequently in a future with climate change, could result in increased stresses on the power system and/or greater reliance on the DE resource.

2. Wind Lulls

According to model results, multi-day wind lulls coincident with peak load hours can lead to significant increased use of DE generation and loss of load. This is particularly pronounced in the most stressed month for each load scenario, winter for the CLCPA Case, summer for the CCP2 Reference Case.

As shown in Figure 42, a winter wind lull that overlaps with the peak load period in the CLCPA load scenario would lead to a reliance on DE generation in order to meet demand, and 13 hours with some loss of load across all Zones. In Figure 43, solar generation during the 12-day summer wind lull offsets a significant portion of generation losses from wind, with the remaining demand met by price responsive demand and an increased amount of DE resource generation. Ultimately, there is no load loss in the summer load scenario even with the more severe wind lull than in winter.

Figure 42: Hourly Load/Generation Balance, CCP2-CLCPA Winter Wind Lull Case

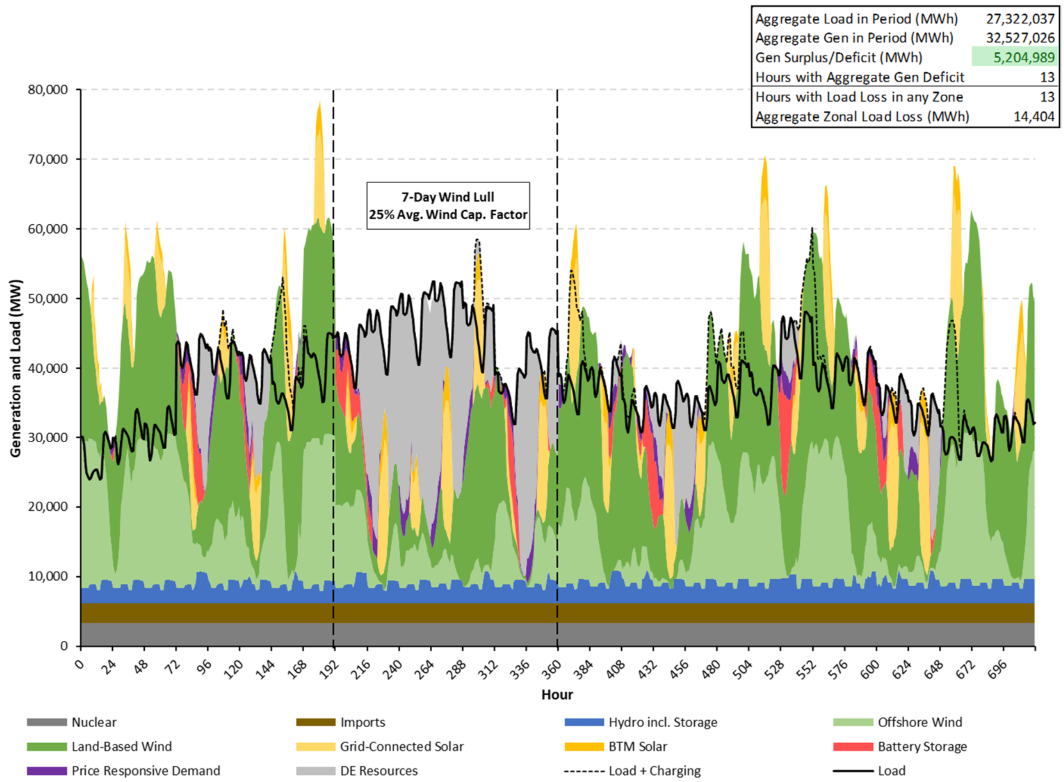
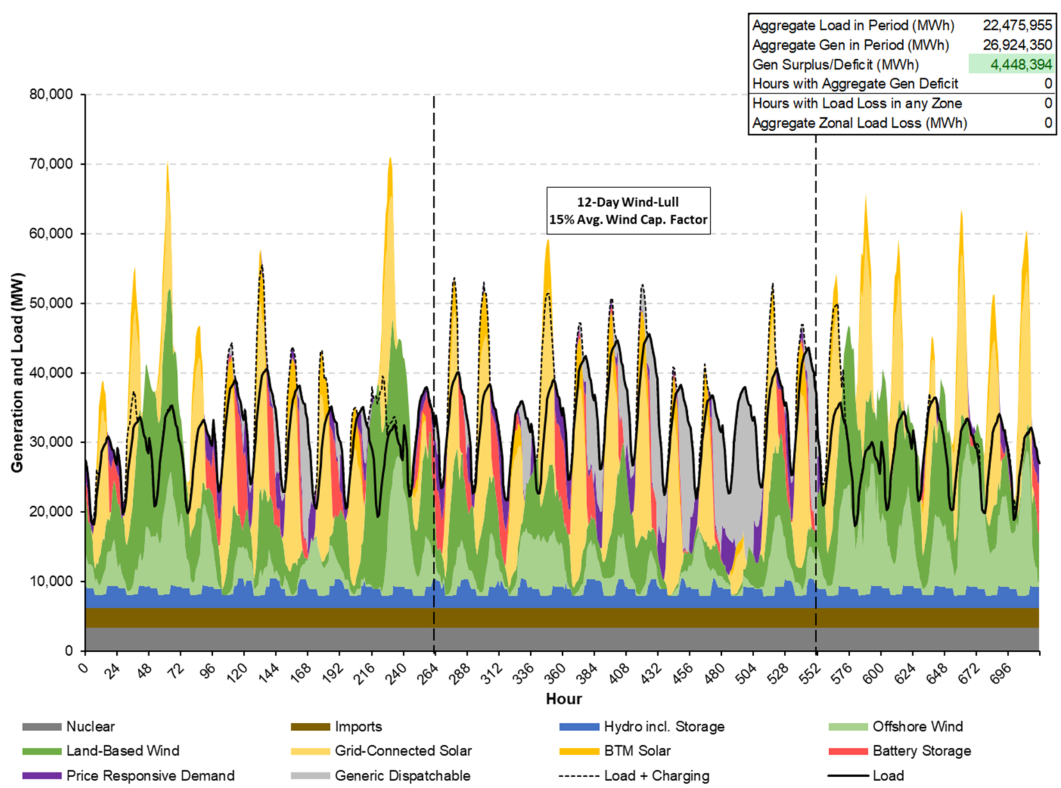


Figure 43: Hourly Load/Generation Balance, CCP2-CLCPA Summer Wind Lull Case

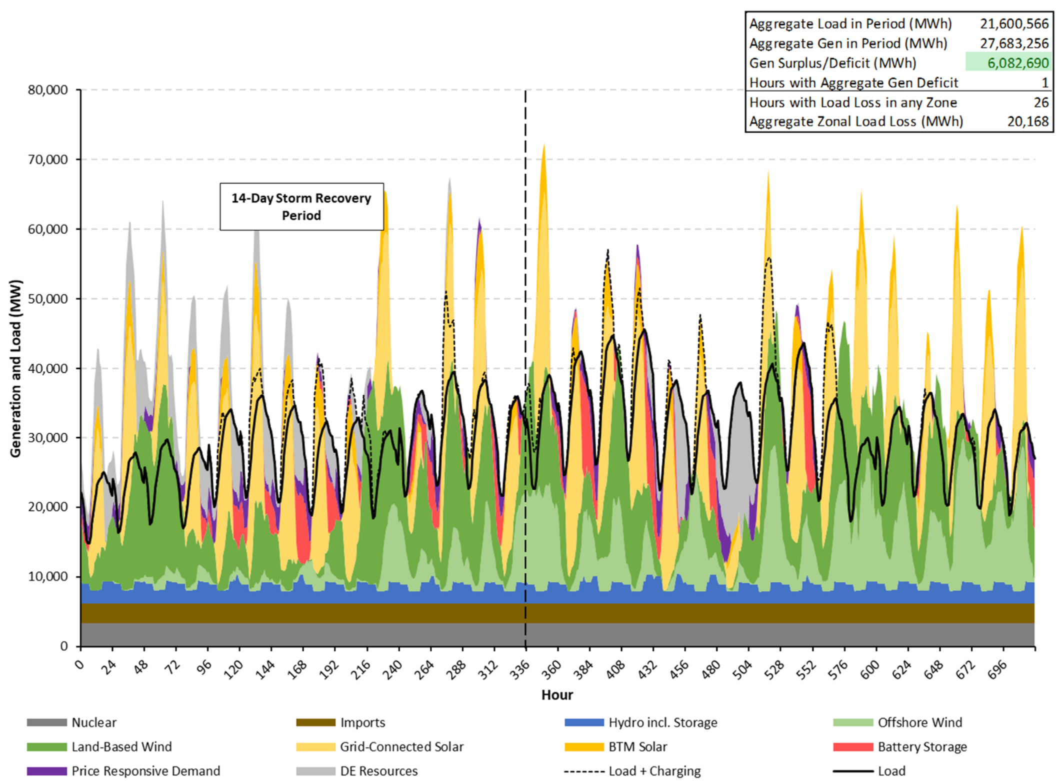


3. Storm Scenarios

The storm disruptions caused the most severe impacts to system reliability of all the cases run in the model. Based on model results, hurricane/major wind storms can cause loss of load at the transmission system level during the storm itself and the 14-day recovery period, but losses ease significantly once transmission is partially restored. Based on historical experience in Hurricane Sandy, generation, transmission, and load recover at similar paces, which means that generators would be back online to meet increased demand when storm damage is repaired and power is restored to end users. Quick recovery of transmission assets is vital to limiting load losses. Any loss of transmission in downstate zones prevents batteries, renewable resources, and DE resource generation in upstate Zones from relieving loss of load downstate.

The storm cases cause the greatest system disruption in seasons when load is highest; the winter upstate storm case under the CLCPA load scenario shows more losses of load than the summer hurricane case. In both seasons, the storm scenario affecting offshore wind availability shows only modest system impact - there are a handful of hours with potential for loss of load in winter and none in summer.

Figure 44: Hourly Load/Generation Balance, CCP2-CLCPA Summer Hurricane Case



The storm scenarios were all based on historical experience with Hurricane Sandy. While the impact of that storm was significant, the results here may understate system reliability challenges to the extent that climate change leads to more severe or more frequent storms, especially if multiple storms occur in rapid succession.

4. Other Climate Impacts

The drought event has a limited impact on DE resource generation usage during the CLCPA Case and no loss of load. The lower summer loads as compared to winter means that there is enough renewable and DE resource generation to compensate for the loss of hydroelectric capacity. The icing event leads to two hours with very small loss of load occurrences in the CLCPA winter load scenario. For the most part, other resources are able to compensate for losses of transmission and generation during the event.

5. Case Result Summaries:

	Loss of Load		DE Resource Generation				
	Total Hours with LOLO in at least one Load Zone	Aggregate LOLO (MWh)	Max Consecutive Hours with DE Resource Gen.	Total Hours with DE Resource Gen.	Aggregate DE Resource Gen. (MWh)	Max DE Resource Gen. (MW)	Max 1-hr. DE Resource Gen. Ramp (MW)
CLCPA Summer Scenario - Climate Impact Phase II Resource Set							
Baseline Summer	0	0	36	145	847,589	22,081	9,170
Heat Wave	0	0	36	147	964,668	22,081	8,642
Wind Lull - Upstate	0	0	37	179	1,171,656	23,361	9,447
Wind Lull - Off-Shore	0	0	40	196	1,116,165	23,170	9,170
Wind Lull - State-Wide	0	0	40	235	1,697,161	24,440	11,605
Hurricane/Coastal Wind Storm	26	20,168	171	322	1,892,046	22,081	8,642
Severe Wind Storm – Upstate	8	1,620	87	283	2,002,682	22,081	8,642
Severe Wind Storm – Offshore	0	0	36	167	1,079,462	22,163	10,015
Drought	0	0	36	166	1,148,649	23,595	10,610

	Loss of Load		DE Resource Generation				
	Total Hours with LOLO in at least one Load Zone	Aggregate LOLO (MWh)	Max Consecutive Hours with DE Resource Gen.	Total Hours with DE Resource Gen.	Aggregate DE Resource Gen. (MWh)	Max DE Resource Gen. (MW)	Max 1-hr. DE Resource Gen. Ramp (MW)
CLCPA Winter Scenario - Climate Impact Phase II Resource Set							
Baseline Winter	0	0	62	255	2,866,203	32,135	11,716
Cold Wave	0	0	62	259	2,879,947	32,135	11,716
Wind Lull - Upstate	5	2,373	62	259	3,076,530	32,135	12,707
Wind Lull - Off-Shore	10	7,184	104	274	3,350,666	32,135	11,715
Wind Lull - State-Wide	13	14,404	105	278	3,653,404	32,135	12,403
Severe Wind Storm – Upstate	45	22,146	81	369	3,822,059	31,419	12,850
Severe Wind Storm – Offshore	9	4,203	103	304	3,609,785	32,135	11,715
Icing Event	2	88	62	273	2,909,437	32,135	11,716

	Loss of Load		DE Resource Generation				
	Total Hours with LOLO in at least one Load Zone	Aggregate LOLO (MWh)	Max Consecutive Hours with DE Resource Gen.	Total Hours with DE Resource Gen.	Aggregate DE Resource Gen. (MWh)	Max DE Resource Gen. (MW)	Max 1-hr. DE Resource Gen. Ramp (MW)
Reference Summer Scenario - Climate Impact Phase II Resource Set							
Baseline Summer	0	0	36	183	972,444	17,059	6,520
Heat Wave	0	0	36	199	1,067,892	17,059	6,520
Wind Lull - Upstate	2	729	38	209	1,175,961	17,059	5,655
Wind Lull - Off-Shore	2	1,797	41	243	1,307,211	17,059	6,380
Wind Lull - State-Wide	4	3,149	42	283	1,697,728	17,059	10,929
Hurricane/Coastal Wind Storm	76	96,295	173	349	1,637,221	17,059	6,520
Severe Wind Storm – Upstate	18	4,470	106	330	1,975,003	17,059	6,520
Severe Wind Storm – Offshore	0	0	36	241	1,249,958	17,059	7,489
Drought	11	6,383	38	209	1,305,698	17,059	5,755

	Loss of Load		DE Resource Generation				
	Total Hours with LOLO in at least one Load Zone	Aggregate LOLO (MWh)	Max Consecutive Hours with DE Resource Gen.	Total Hours with DE Resource Gen.	Aggregate DE Resource Gen. (MWh)	Max DE Resource Gen. (MW)	Max 1-hr. DE Resource Gen. Ramp (MW)
Reference Winter Scenario - Climate Impact Phase II Resource Set							
Baseline Winter	0	0	4	6	9,316	3,762	2,479
Cold Wave	0	0	4	6	9,316	3,762	2,479
Wind Lull - Upstate	0	0	4	6	10,646	4,213	2,400
Wind Lull - Off-Shore	0	0	9	15	48,055	6,386	3,819
Wind Lull - State-Wide	0	0	13	32	90,238	8,219	4,127
Severe Wind Storm – Upstate	10	1,146	14	56	119,192	5,809	2,283
Severe Wind Storm – Offshore	0	0	8	20	31,311	4,677	3,809
Icing Event	3	157	6	14	9,886	3,762	2,479

D. Cross-Seasonal Effects

The resource sets evaluated in this study are designed to maintain sufficient resource availability to meet peak seasonal demand for electricity. Thus, due to the large differences in load and renewable generation across seasons, the modeled results show large surpluses of renewable generation during the shoulder seasons of spring and fall. As discussed in Section II.C.2 and Table 6 earlier, wind capacity factors are highest during the shoulder season modeling, with over 50 percent capacity factor for both land-based and offshore wind generation. At the same time, aggregate load is lowest in the shoulder month, with total energy demanded over the 30-day modeling period 54.3 percent lower than demand during the winter modeling period and 44.4 percent lower than demand during the summer modeling period for the CLCPA load scenario (see Table 5). As a result, during the shoulder month, there is on average 32,227 MW of "excess" potential renewable generation that is curtailed - or "spilled" - due to a lack of load or short-term storage capacity (see Table 17). In fact, for each of the resource sets and load scenarios developed for this study,[67] the majority of renewable generation during the shoulder month is excess, and is not needed to meet load or fill storage (see Table 18). The quantity of excess renewables is particularly pronounced when looking at peak load hours. For the hour with the highest load in the shoulder season modeling period, there is enough renewable generation to meet 208 percent of demand (see Figure 45).

Table 17: Curtailed "Excess" Renewable Generation by Seasonal Modeling Period, CLCPA Load Scenario, CCP2-CLCPA Resource Set

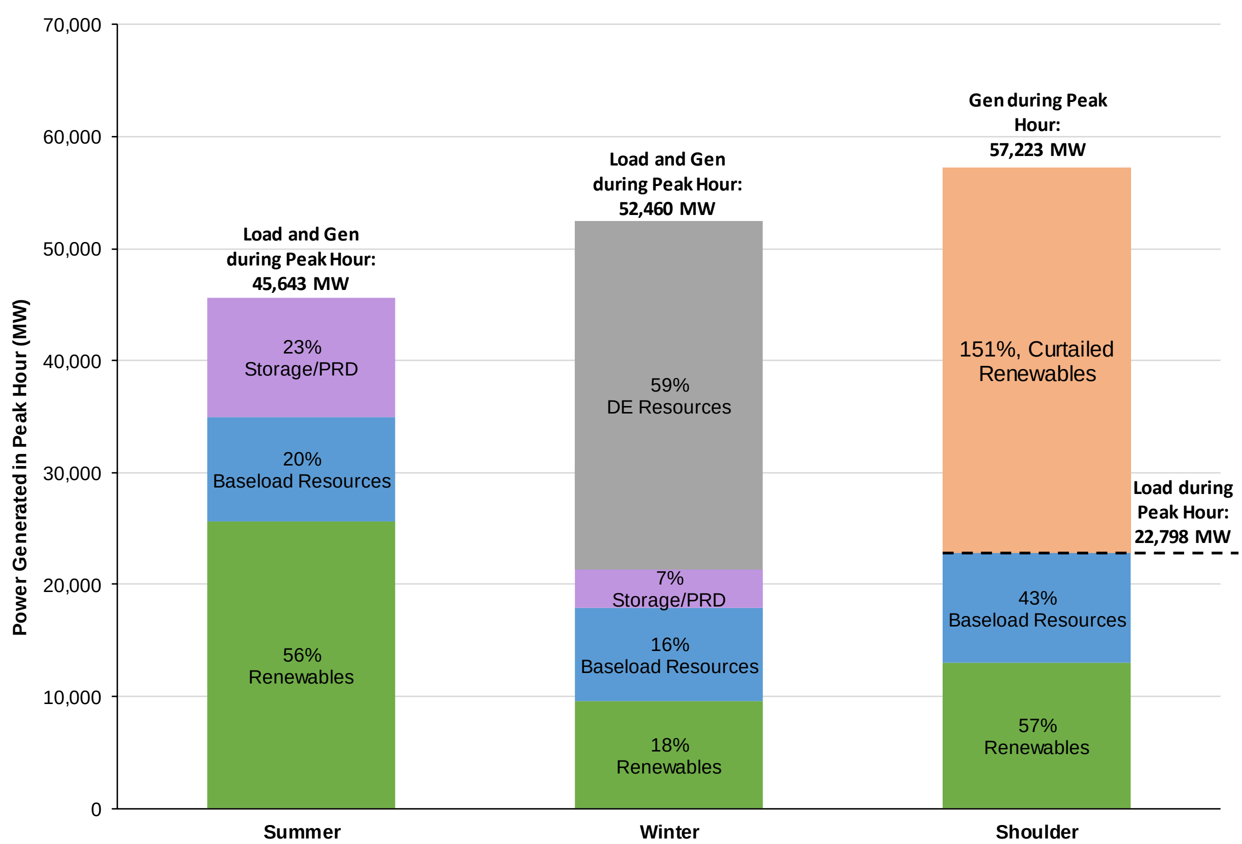
Season	Aggregate Excess Renewable Generation (GWh)	Average Hourly Excess Renewable Generation (MW)	Average Hourly Percentage of Excess Renewable Generation (%)
Winter	4,401	6,112	13.66%
Summer	3,926	5,453	13.95%
Shoulder	23,204	32,227	75.80%

Table 18: Curtailed "Excess" Shoulder Month Renewable Generation by Load Scenario and Resource Set

Resource Set - Load Case	Aggregate Excess Renewable Generation (GWh)	Average Hourly Excess Renewable Generation (MW)	Average Percentage of Hourly Excess of Total Renewable Generation (%)
Climate Impact Phase II			
CLCPA	23,204	32,227	75.80%
Reference	16,900	23,472	73.40%
Grid In Transition			
CLCPA	17,153	23,823	64.51%
Reference	8,162	11,336	47.30%

[67] As noted, this is a key difference between the renewables/transmission-focused resource set, and the GIT resource set. Since the GIT resource set relies far less on renewables to meet seasonal peak loads, there is less renewable generation spilled in shoulder season months (and across the year).

Figure 45: Resource Mix during Seasonal Peak Load Hours, CCP2-CLCPA



Given the large quantity of excess generation during the shoulder month, there is a potential for a seasonal storage technology to meet the energy needs of DE resource generation during the summer and winter. For example, as seen in Table 19, the excess renewable generation in the shoulder season modeling period under the CLCPA load scenario totaled to 23,204 GWh, and the DE resource use in the winter modeling period was just 4,401 MWh. Therefore, if a technology existed that allowed 12.4 percent of the excess renewable generation in the shoulder month to be stored until winter - e.g., through the production, processing and/or storing of renewable natural gas or hydrogen fuel for use in generation technology - then all of the winter DE resource fuel need could be met by excess renewable energy from the shoulder season.

Table 19: Shoulder Month Energy Potential as Compared to DE Resource Use, CCP2 Resource Set

		Shoulder	Summer	Winter
	Dates	4/1/2040 -4/30/2040	7/1/2040 -7/30/2040	1/1/2040 -1/30/2040
CLCPA Case	Total DE Resource Energy Used (GWh)	0 GWh	848 GWh	2,866 GWh
	Total Intermittent Renewable Energy Curtailed (GWh)	23,204 GWh	3,926 GWh	4,401 GWh
	Seasonal Storage Efficiency Needed to Meet DE Resource Energy Need with Shoulder Season Curtailed Energy	-	3.65%	12.35%
Reference Case	Total DE Resource Energy Used (GWh)	0 GWh	972 GWh	9 GWh
	Total Intermittent Renewable Energy Curtailed (GWh)	16,900 GWh	2,660 GWh	8,467 GWh
	Seasonal Storage Efficiency Needed to Meet DE Resource Energy Need with Shoulder Season Curtailed Energy	-	5.75%	0.06%

E. Comparisons of Results with Grid in Transition Resource Set

As described in Section II.F, the Grid in Transition study resource set includes considerably more DE resource capacity than in the resource sets developed for this study, which include more renewables and transmission. The differences in resource mix also lead to considerable differences in results. As seen in Figure 46 and Figure 47, in the baseline cases, the proportion of load met by DE resources in the CLCPA winter load scenario is roughly nine percent for the AG resource set but about 20 percent for the Grid in Transition resource set. One of the main difference between the two resource sets is the level of available transmission capacity, especially on the Total East and Total South interfaces constraints. As shown on Table 20, those constraints are binding in a larger percentage of hours under the Grid in Transition resource set, which means that DE resources downstate are dispatched to produce electricity in more hours.

Figure 46: Winter Generation by Resource Type – CCP2-CLCPA

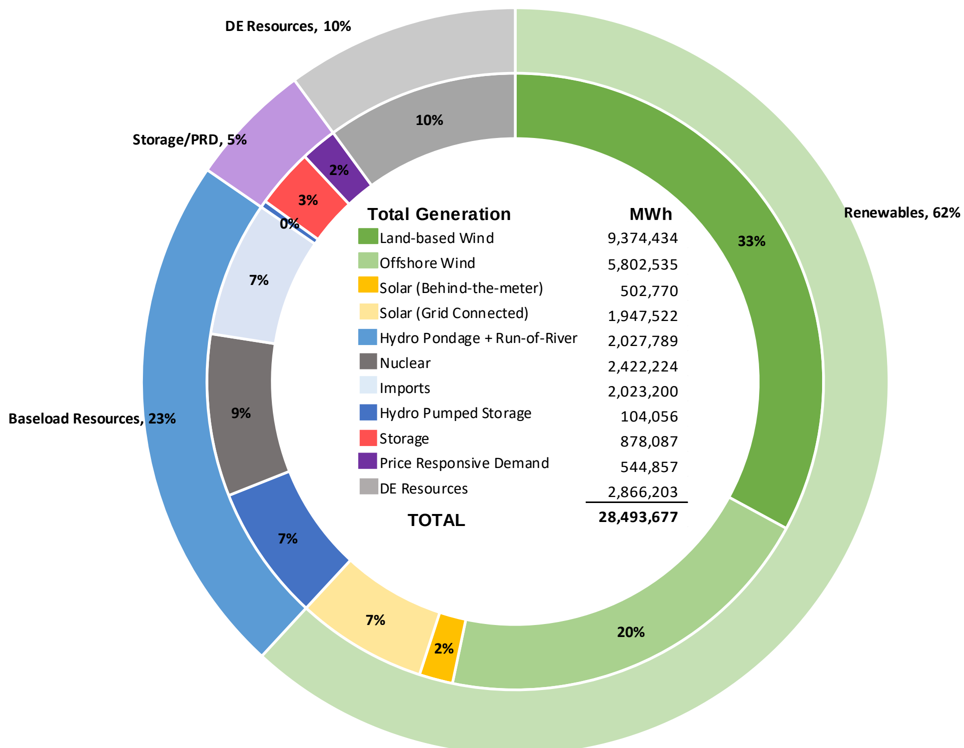


Figure 47: Winter Generation by Resource Type – GIT-CLCPA

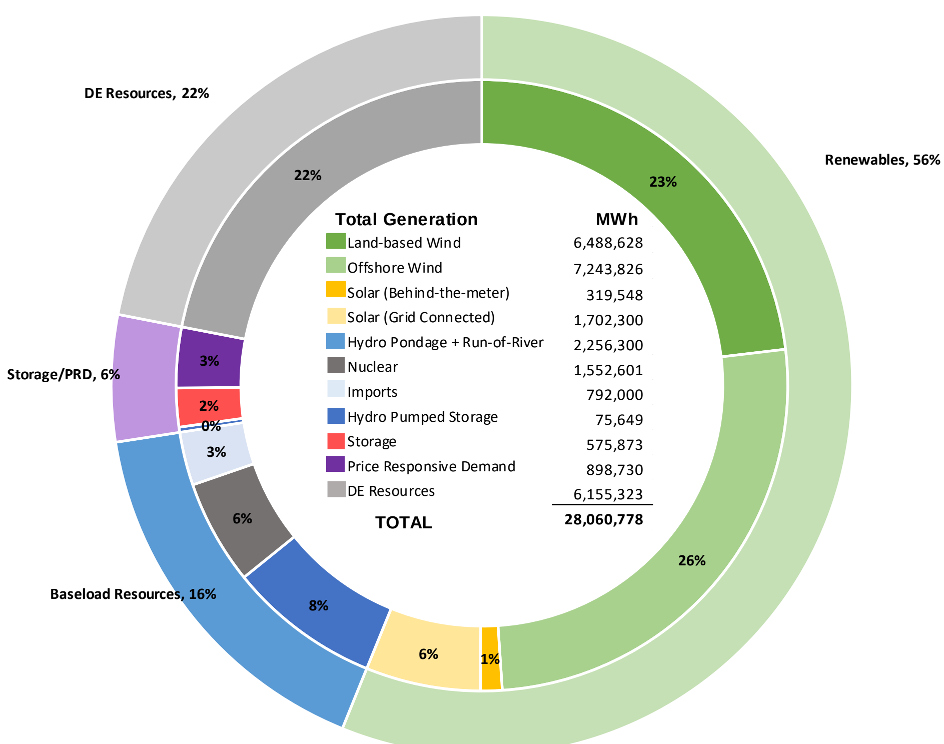


Table 20: Transmission Constrained Hours, CCP2-CLCPA Winter Baseline Case

	Total East		Total South	
Resource Set	**N**	**%**	**N**	**%**
Climate Impact Phase II	81	11%	1	0%
Grid In Transition	310	43%	82	11%

The differences in the baseline cases also produce changes in the physical disruption cases. As seen in Table 21, there are more hours with loss of load occurrences in the state-wide and offshore wind lull cases under the Climate Change Phase II resource set, given the smaller overall quantity of DE resources, and the far greater reliance on wind resources. On the other hand, reduced transmission under Grid in Transition resource set leads to more severe load losses during scenarios that affect upstate resources (Severe Wind Storm – Upstate and Icing Event).

Table 21: Comparison of Case Results by Resource Set, Winter CLCPA

	Climate Impact Phase II Resource Set					Grid in Transition Resource Set				
	Total Hours with LOLO in at least one Load Zone	Aggregate LOLO (MWh)	Total Hours with DE Resource Gen.	Aggregate DE Resource Gen. (MWh)	Diff. in DE Resource Gen. from Baseline (MWh)	Total Hours with LOLO in at least one Load Zone	Aggregate LOLO (MWh)	Total Hours with DE Resource Gen.	Aggregate DE Resource Gen. (MWh)	Diff. in DE Resource Gen. from Baseline (MWh)
CLCPA Winter Scenario										
Baseline Winter	0	0	255	2,866,203	+0	0	0	460	6,155,321	+0
Cold Wave	0	0	259	2,879,947	+13,744	0	0	466	6,272,961	+117,640
Wind Lull - Upstate	5	2,373	259	3,076,530	+210,327	8	7,090	469	6,309,711	+154,390
Wind Lull - Off-Shore	10	7,184	274	3,350,666	+484,463	6	1,378	487	6,836,558	+681,237
Wind Lull - State-Wide	13	14,404	278	3,653,404	+787,201	9	10,757	486	6,988,838	+833,517
Severe Wind Storm – Upstate	45	22,146	369	3,822,059	+955,856	51	57,457	551	6,707,765	+552,444
Severe Wind Storm – Offshore	9	4,203	304	3,609,785	+743,582	2	327	561	7,916,575	+1,761,254
Icing Event	2	88	273	2,909,437	+43,234	24	11,242	480	6,145,568	-9,753

The patterns of differences in DE resource generation between resources are repeated in the summer modeling period. As seen in Figure 48 and Figure 49, in the baseline cases, the proportion of load met by DE resource generation in the CLCPA winter load scenario is approximately three percent for the CCP2 resource set but about 16 percent for the Grid in Transition resource set. Again, the differences in transmission is one of the main contributing factors to differences in generation outcomes; Table 22 shows that the number of hours with constrained transmission under the Grid in Transition resource set is greater than that under the AG resource set.

Figure 48: Summer Generation by Resource Type – CCP2-CLCPA

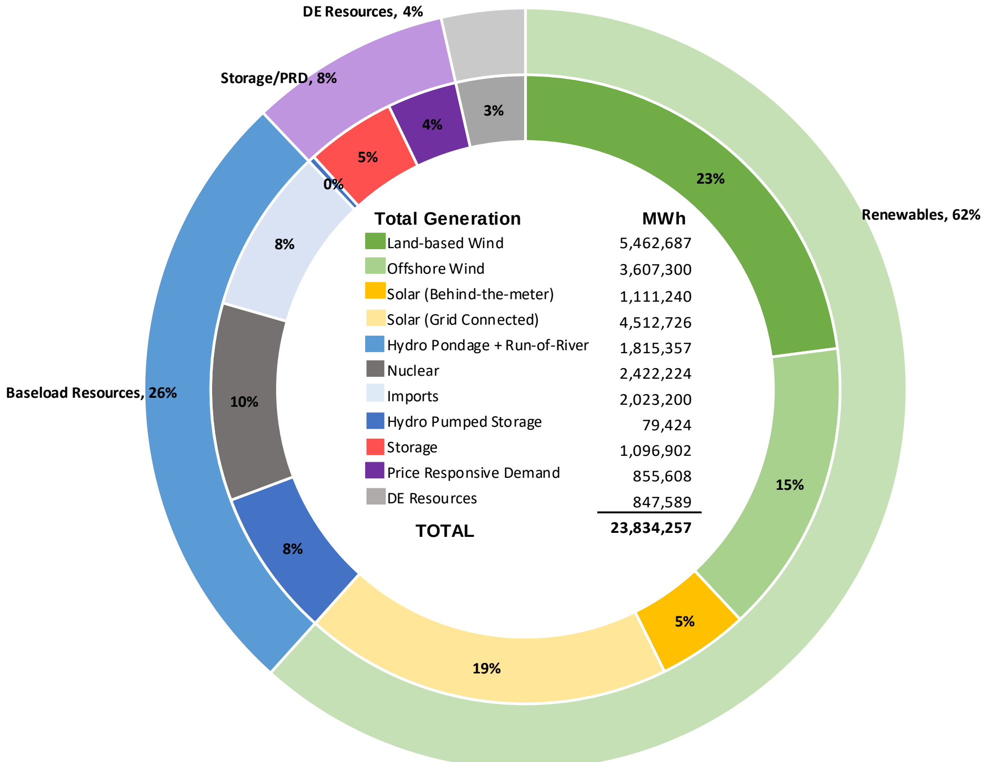


Figure 49: Summer Generation by Resource Type – GIT-CLCPA

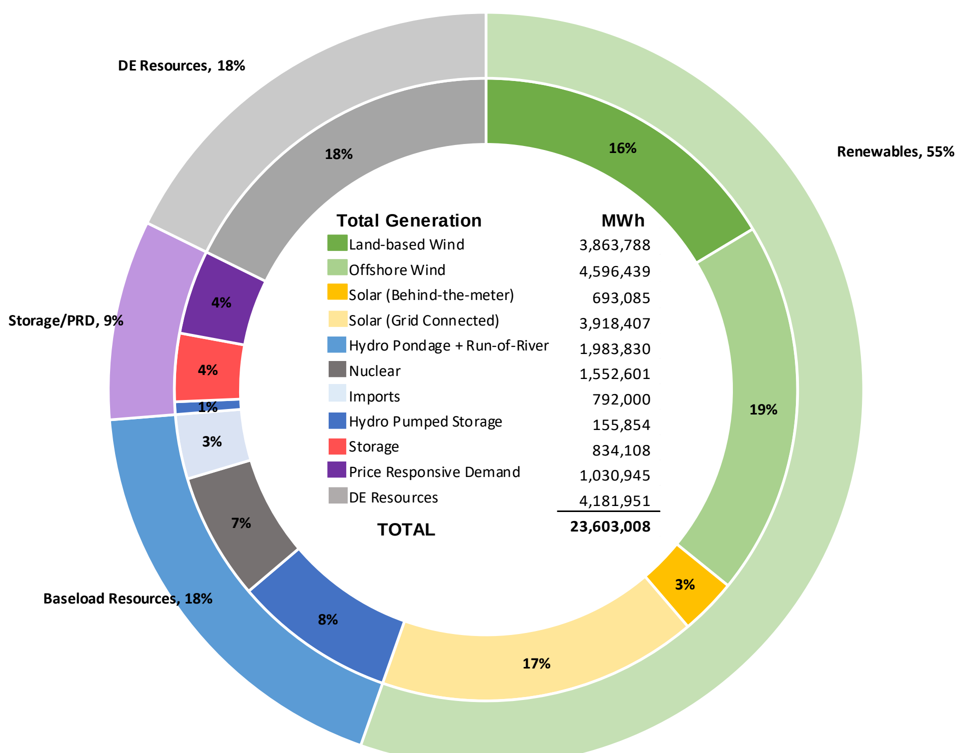


Table 22: Transmission Constrained Hours - Summer CLCPA Baseline Case

	Total East		Total South	
Resource Set	**N**	**%**	**N**	**%**
Climate Impact Phase II	12	2%	0	0%
Grid In Transition	229	32%	179	25%

The Severe Wind Storm - Upstate case also has greater losses of load under Grid in Transition resource set, due to more limited transmission during the storm recovery period.

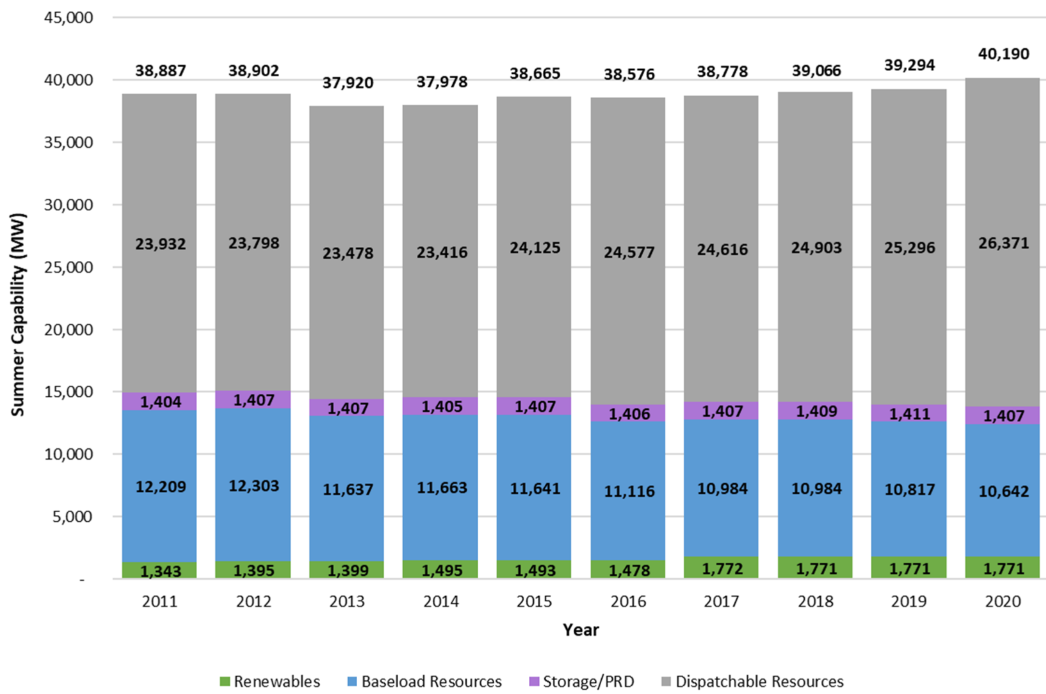
Table 23: Comparison of Case Results by Resource Set - Summer CLCPA

	Climate Impact Phase II Resource Set					Grid in Transition Resource Set				
	Total Hours with LOLO in at least one Load Zone	Aggregate LOLO (MWh)	Total Hours with DE Resource Gen.	Aggregate DE Resource Gen. (MWh)	Diff. in DE Resource Gen. from Baseline (MWh)	Total Hours with LOLO in at least one Load Zone	Aggregate LOLO (MWh)	Total Hours with DE Resource Gen.	Aggregate DE Resource Gen. (MWh)	Diff. in DE Resource Gen. from Baseline (MWh)
CLCPA Summer Scenario										
Baseline Summer	0	0	145	847,589	+0	0	0	512	4,181,951	+0
Heat Wave	0	0	147	964,668	+117,079	0	0	523	4,404,209	+222,258
Wind Lull - Upstate	0	0	179	1,171,656	+324,067	0	0	516	4,501,251	+319,300
Wind Lull - Off-Shore	0	0	196	1,116,165	+268,576	0	0	543	4,983,818	+801,867
Wind Lull - State-Wide	0	0	235	1,697,161	+849,572	0	0	543	5,322,997	+1,141,046
Hurricane/Coastal Wind Storm	26	20,168	322	1,892,046	+1,044,457	25	20,488	559	4,832,633	+650,682
Severe Wind Storm – Upstate	8	1,620	283	2,002,682	+1,155,093	24	18,963	549	4,998,149	+816,198
Severe Wind Storm – Offshore	0	0	167	1,079,462	+231,873	0	0	556	5,126,163	+944,212
Drought	0	0	166	1,148,649	+301,060	0	0	520	4,616,646	+434,695

F. Pace of Resource Change

The pace of development required to meet the capacity requirements for each resource set is historically unprecedented in New York. As seen in Figure 50, the resource mix within New York has not changed much from 2011 through 2020. According to the NYISO Gold Books, between 2011 and 2020, the total summer capability of grid-connected renewable generation increased from 1,342.5 MW to 1,770.5 MW (an increase of 47.6 MW/year on average). The only grid-connected Solar PV power plants in New York are the Long Island Solar and Shoreham Solar Farms, and wind generation has modestly increased from 2011 to 2020.

Figure 50: Historical Resource Mix in New York, 2011-2020



Notes:
[1] Dispatchable Resources include "Gas," "Oil," and "Gas & Oil."
[2] Baseload Resources include "Coal," "Nuclear," "Hydro," and "Other", with the exception of 31.5MW of grid-connected solar.
[3] Renewable Resources include "Wind."
[4] Storage/PRD Resources include "Pumped Storage."

Sources:
[1] 2012-2020 NYISO Gold Books.

As shown in Table 24, in order for the system to have the quantities of renewable generation in nameplate capacity developed for the CLCPA resource set (56,263 MW), wind nameplate capacity will need to grow by 2,714 MW per year for the next 20 years. This would be a thirty-fold increase in wind capacity. Solar capacity will need to grow by 1,960 MW per year to reach the CLCPA resource set quantity of 39,262 MW, for a more than thousand-fold increase in solar capacity. The pace of development is much the same for the other resource sets presented in this study, and each will require large sustained increases in renewable capacity through 2040.

Table 24: Required Pace of Development to Meet 2040 Resource Set Quantities

	Nameplate Capacity (MW)		Required 2020-2040 Nameplate Capacity Growth Rate (MW/yr)	
	Wind (Land-based and Offshore)	**Grid-Connected Solar**	**Wind (Land-based and Offshore)**	**Grid-Connected Solar**
Existing Resources (2020)	1,985	57		
Climate Phase II Reference Case Resource Set (2040)	39,962	34,354	1,899	1,715
Climate Phase II CLCPA Scenario Resource Set (2040)	56,263	39,262	2,714	1,960
Grid in Transition Reference Case Resource Set (2040)	23,522	30,043	1,077	1,499
Grid in Transition CLCPA Scenario Resource Set (2040)	48,357	31,669	2,319	1,581
Historical Nameplate Capacity Growth Rate (2012-2020, MW/yr)			**71.4**	**3.1**

G. Observations

In this report, we have evaluated a range of climate disruption scenarios in the year 2040, and under assumptions about the resources in place in that year. Based on our review of modeling results and the context for our analysis, we come to the following observations:

Climate disruption scenarios involving storms and/or reductions in renewable resource output (e.g., due to wind lulls) can lead to loss of load occurrences. Electrification, particularly in the building sector, transforms New York into a winter-peaking system. Thus loss of load occurrences due to climate disruptions in the winter are deeper and occur across more scenarios than in the summer (*See* Table ES-2). Specifically, in the winter severe wind storms, lulls in wind resource output (upstate or downstate), and icing events all lead to loss of load, as well as elevated reliance on the DE resource. In the summer, these events increase the system's reliance on the DE resource, but LOLOs are only triggered in the severe coastal (hurricane) and upstate wind storm events.

The variability of meteorological conditions that govern the output from wind and solar resources presents a fundamental challenge to relying on those resources to meet electricity demand. In scenarios involving LOLOs, or requiring substantial contributions from DE resources, periods of reduced output from wind and solar resources are the primary driver of challenging system reliability conditions, particularly during extended wind lull events. *See* Figure ES-2, showing results for the CCP2-CLCPA Case in the winter, including an extended wind lull. During the wind lull,[68] the state realizes losses of load in at least one zone for thirteen hours, with a total loss of over 14 gigawatt-hours (GWh). Moreover, during the wind lull the system relies *primarily* on the DE generating resource to avoid more severe LOLOs. Even outside the specific seven-day climate disruption wind lull period, one can see that base case reductions in wind output create periods of significant reliance on the DE resource to avoid losses of load.[69] Importantly, further increasing the nameplate capacity of such resources is of limited value, since when output is low, it is low for all similar resources across regions or the whole state.[70] As can also be seen across the full winter month, periods of solar output are not able to contribute during the early evening winter peak hours.

Battery storage resources help to fill in voids created by reduced output from renewable resources, but periods of reduced renewable generation rapidly deplete battery storage resource capabilities. As described in Section II, the CCP2-CLCPA resource set includes the development and operation of over 15,600 MW (124.8 GWh) of new storage resources, configured as eight-hour batteries, and distributed throughout the state to maximize their ability to time shift excess generation from renewable resources.[71] At this level of development, battery storage

[68] The wind lull is a seven-day period from hours 192-360 in Figure ES-2.

[69] *See* hours 72-144, and hours 408-480.

[70] As noted, the generation profiles used for the wind and solar resources are taken from NREL state-specific generation profiles, based on historical meteorological data. The resulting renewable resource output profile across each season's month affects both the amount of renewable capacity needed to meet 2040 peak demand, and the reliance on the DE Resource and occurrence of LOLOs across all hours of the month. Renewable generation technology development and/or the realization of meteorological conditions that are different than the underlying historical NREL profiles could result in fundamentally different contributions from such resources in 2040, and different levels and types of system impacts than those reported here. The significance of the modeled renewable generation technologies and profiles thus represents a key uncertainty in the analysis, and this should be considered in interpreting results.

[71] As noted earlier, the development of the CCP2 resource sets requires a vast buildout of carbon-free resources to meet elevated electricity demand and the absence of existing fossil-fueled generating resources. This need drives the assumed amount of battery storage resources included in the resource sets; that is, the amount of battery storage assumed reflects an assumption of continuous and significant growth in storage technology over the next twenty years, and is well in excess of any existing mandates or near-term development expectations.

makes significant contributions to avoiding loss of load and reliance on backstop generation for the immediate period following sharp declines in renewable resource output due to climate disruptions (and also due to normal wind/solar resource variability).[72] While this represents a substantial level of assumed growth in battery storage within New York, the contribution of storage is quickly overwhelmed by the depth of the gap left during periods of time with a drop off in renewable generating output over periods of a day or more. This is revealed by the fill in of the DE Resource (in grey) following depletion of the storage resources (in red) during various periods in Figure ES-2.

The DE resources needed to balance the system in many months must be significant in capacity, be able to come on line quickly, and be flexible enough to meet rapid, steep ramping needs. Our generic DE resource generates energy as needed to meet demand and avoid loss of load occurrences. This study does not make any assumptions about what technology or fuel source can fill this role twenty years hence. Instead, the model includes the DE Resource to identify the attributes required of whatever resource (or resources) emerges to fill this role. Based on a review of the frequency and circumstances of reliance on the DE Resource to maintain reliability in the model, we can identify the characteristics required of the resource. In this, certain observations stand out. First, even in the baseline cases (*i.e.,* before layering in climate disruption events), there are periods of very low output from the renewable resources during periods of demand when resources need to be available to meet the bulk of the system's annual energy requirements. During such periods, the need for the DE Resource climbs very high - at times more than 30,000 MW. This is true even though the DE Resource is not significantly utilized on an annual energy basis, and has a very low capacity factor, at or less than ten percent. Second, the DE Resource needs to be highly flexible - it needs to be able to come on quickly, and be able to meet rapid and sustained ramps in demand. The results in Table ES-2 show that the minimum one-hour ramp requirement, even in the baseline CCP2-CLCPA case, approaches 12 GW, and climbs to nearly 13 GW in multiple CLCPA climate disruption cases. Moreover, as can be seen in Figure ES-3, the ramping capability of the DE Resource is even larger when viewed across multiple hours. For example, the four-hour period of greatest ramp in the CCP2-CLCPA case in the winter exceeds 20,000 MW.

The assumed increase in inter-zonal transfer capability in the CCP2 resource sets enables a renewables-heavy resource mix and improves reliability, but also increases vulnerability to certain climate disruption scenarios. The CCP2 resource sets are designed to maximize the contribution of renewable resources which, due to available land area and ease of siting, are heavily weighted towards the upstate region. As a result, it is necessary to assume a major build out of the transmission system in New York, to enable the upstate renewable resources to contribute to meeting load in the downstate region. Across the climate disruption cases, the increased transfer capability improves the resilience of the power system to all events that are localized, such as offshore storms or wind lulls that only affect the upstate or downstate regions, as well as to some disruptions that affect load and generation across the state, such as heat waves and cold snaps. Conversely, the increased reliance on transmission increases the vulnerability of the system to climate disruption events that specifically impact transmission capability, including icing events or major storms that disable transmission capacity.

Cross-seasonal differences in load and renewable generation could provide opportunities for renewable fuel production. The CCP2 resource sets are constructed to be able to meet peak demand in the winter and summer seasons based primarily on production from renewable resources. However, this means that there is a substantial amount of renewable generation that is excess, or "spilled," in off-peak seasons and hours. This introduces the potential for a seasonal storage technology to help meet the needs represented in the analysis by DE Resource

[72] *See*, e.g., Figure ES-3, hours 72-96, 192-216, and 410-440.

generation during the summer and winter. Such potential assumes the emergence of economic technologies capable of converting excess renewable energy to a fuel and storing it for later use, or the development of other long term storage technologies. For example, as seen in Table ES-3, the excess renewable generation in the shoulder season modeling period under the CCP2-CLCPA case totaled roughly 23,204 GWh, while the DE Resource use in the winter modeling period was just 4,401 GWh. This raises the possibility that, should such technologies or capabilities emerge, excess off-peak renewable generation could help meet the peak-month energy requirements represented in the model by generation from the DE Resource.

The current system is heavily dependent on existing fossil-fueled resources to maintain reliability, and eliminating these resources from the mix will require an unprecedented level of investment in new and replacement infrastructure, and/or the emergence of a zero-carbon fuel source for thermal generating resources. A power system that is effectively free of GHG emissions in 2040 cannot include the continued operation of thermal units fueled by well-based natural gas. However, these are the very units that are currently vital to maintain power system reliability throughout the year. This is the fundamental challenge of the power system transition that will take place over the next two decades. Indeed, this transition must take place at the same time that electricity demand in the state will grow significantly if electrification of other economic sectors, such as transportation and heating, is needed to meet the economy-wide GHG emission reduction requirements. In all four cases studied, the required investment in and development of renewable resources is substantial, and far greater than anything previously experienced in New York. Table ES-4 shows the pace of development required for each case and resource set, compared to the historical capacity growth rate in New York.

Overall, the key reliability challenges identified in this study are associated with <u>both</u> how the resource mix evolves between now and 2040 in compliance with the CLCPA, and the impact of climate change on meteorological conditions and events that introduce additional reliability risks. The climate disruption events modeled in the EBM may be more frequent and/or more severe than in the past, and this increases NYISO's challenges in managing reliability risks over time. Nevertheless, such events do not appear to be *qualitatively* different than similar events experienced in the past, and present reliability challenges that may be considered similar to those faced today. With sufficient planning and preparation such events could be managed to maintain reliability in much the same way current weather-based disruptions are managed. However, on top of this the analysis demonstrates that, based on current information and technologies, the evolution of the system to one focused on zero-carbon resources and the infrastructure needed to support such a resource mix could introduce a number of key vulnerabilities to system reliability. These challenges include the variability of the meteorological conditions affecting renewable generation, the temporal limitations of existing battery storage technologies, and the increased dependence on resources distant from load centers. Based on our analysis, managing this transition seems to introduce reliability challenges that may be more difficult than those arising from the conditions of a changing climate. *Most importantly, this analysis suggests that establishing electricity market designs and energy policies to encourage innovation and accelerate advanced energy resource development will be key to reliably and economically managing the transition in the electric sector in New York*.

Comparing the CCP2 resource sets to the GIT resource sets reveals key differences in how the system makeup in 2040 can affect reliability outcomes. There are key differences between the Climate Change Phase II resource sets and those developed for the Grid in Transition study. First, given the different mixes of resources, the proportion of load met by DE Resources in the CLCPA winter load scenario is roughly nine percent for the CCP2-CLCPA resource set, but about 20 percent for the GIT-CLCPA resource set. In addition, given differences in the assumed level of transmission on the system (the GIT resource set does not include any expansion of the current transmission system), constraints on the Total East and Total South interfaces are binding in a larger percentage of hours under the GIT resource set, which means that DE Resources downstate are dispatched to provide electricity in more hours. The differences also lead to changes in vulnerability to climate disruptions. There are more hours with loss of load occurrences in the state-wide and offshore wind lull cases under the CCP2 resource sets, given the smaller overall quantity of DE Resources and greater reliance on wind resources. Conversely, the lower level of inter-zonal transfer capability in the Grid-in-Transition study resource set leads to more severe load losses during scenarios that affect upstate resources, such as severe windstorm and icing events.

In this study, we provide results for two very different visions for the evolution of the power system - one that relies on renewables and transmission (the CCP2 resource sets), and one that places greater emphasis on the backstop resource - that is, the potential emergence of a zero-carbon generation or fuel source (the GIT resource sets). These are only two of a wide range of potential outcomes as the system and technologies change over the next two decades, but they represent in some sense two bookends to potential system changes - one focused on aggressive system infrastructure development, and one that looks more like the current system, but is dependent on the development of zero-GHG fuel sources. The key differences between them are the relative levels of investment in system infrastructure, and the degree of reliance on the DE Resource.

For example, if there is skepticism that an economic fuel or technology will emerge and be widely available, and that can deliver reliable capacity, energy, reserves, and flexible operating attributes with little or no emissions of GHGs, then the pathway may be more heavily tilted towards aggressive investment in and development of renewable and transmission infrastructure, such as in the CCP2 resource sets. This approach would allow the system to operate with relatively low annual generation from the DE Resource. Conversely, if such a fuel or technology were to emerge, be technologically and economically viable, and be widely available, then there is less need to invest the significant capital needed to build out renewable and transmission infrastructure to meet the CLCPA requirements. These differences provide useful insight into the challenges New York State will face in guiding and managing what will likely be a rapid transition over the next two decades.

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VII. Glossary

C&I	Commercial and industrial
CARIS	Congestion Assessment and Resource Integration Study
CLCPA	Climate Leadership and Community Protection Act
EDD	Effective degree day
EDRP	Emergency Demand Response Program
EE	Energy efficiency
EFORd	Equivalent Forced Outage Rate on Demand
EIA	US Energy Information Administration
FERC	Federal Energy Regulatory Commission
GHG	Greenhouse gas
HQ	Hydro-Québec
ICAP	Installed capacity
ISO	Independent System Operator
ISO-NE	ISO New England Inc.
LI	Long Island (Zone K)
LOLO	Loss of load occurrences
MW	Megawatts
MWh	Megawatt hour
NYC	New York City (Zone J)
NYCA	New York Control Area
NYISO	New York Independent System Operator, Inc.
NYSERDA	New York State Energy Research and Development Authority
OSW	Offshore wind
PS	Pumped storage
PV	Photovoltaic
RTO	Regional Transmission Organization
SCR	Special Case Resource
SENY	Southeastern New York (Zones G-K)
SUN	Solar
UPNY	Upstate New York (Zones A-F)
WND	Wind
WT	Wind turbine