NYISO MMU REVIEW OF THE 2019 CARIS PHASE 1 STUDY

POTOMAC ECONOMICS

By:

David B. Patton, Ph.D.
Pallas LeeVanSchaick, Ph.D.

Market Monitoring Unit
for the New York ISO

June 2020

Table of Contents

EXECUTIVE SUMMARY

The Congestion Assessment and Resource Integration Study ("CARIS"), NYISO's economic planning process, identifies when investment in transmission would likely be economic compared to investments in generation, energy efficiency, and/or demand response.[1] In Phase 1 of CARIS, NYISO assesses historic and projected congestion patterns, estimates the costs and benefits of several generic solutions, and analyzes the results of scenarios with various changes in the base case assumptions.[2]

NYISO's 2019 CARIS Phase 1 study also focuses attention on high-renewable penetration scenarios that would achieve New York State goals in 2030. The study provides a wealth of information that is useful for: evaluating the transmission needs of the system with large-scale entry of renewable resources, providing prospective investors insight regarding potential future market conditions, and helping policymakers craft renewable development goals and conduct REC solicitations.

As the Market Monitoring Unit for the NYISO, Potomac Economics is obliged to review and comment on the CARIS report in accordance with Market Services Tariff 30.4.6.8.4. This report provides our comments on the CARIS Phase 1 report, focusing on the 70x30 scenario results. We discuss key findings of the study related to congestion management and market operations under high-renewable generation conditions, and we evaluate the implications for investment incentives for developers of policy resources. Section II of this report provides our supporting analysis of congestion patterns and investment incentives.

A. Key Findings of the 2019 CARIS Phase 1 Report

The 2019 CARIS Phase 1 study provides detailed information from its simulations of market outcomes for a range of "business as usual" cases and 2030 scenarios for a hypothetical resource mix that would satisfy the State's goal of serving 70 percent of demand with renewable generation. NYISO emphasizes that these simulations are not a forecast of future market outcomes, but simply a detailed assessment of one possible way that the 2030 goal could be met. Nevertheless, these simulation results can be used to assess how the current transmission system

1 Projects are eligible for cost recovery if they: (a) alleviate congestion, (b) have capital costs of at least $25 million, (c) result in production costs benefits that exceed the levelized costs over the first ten years of operation (i.e., an efficiency criterion), and (d) receive approval from at least 80 percent of the votes of the project's beneficiaries. The resulting costs are recovered from the project's beneficiaries.

2 In Phase 2 of CARIS, NYISO estimates the benefits of specific transmission projects that individual developers submit for cost recovery consideration. Additionally, in the CARIS process, any interested party can request an analysis of the economic effects on the New York bulk power transmission system of a particular transmission, generation, energy efficiency, and/or demand response project.

will integrate high levels of renewable generation and whether additional transmission could relieve bottlenecks and make more of this generation deliverable to consumers.

As required by the NYISO tariff, the "business as usual" cases evaluate the benefits of transmission on three corridors in each year from 2019 to 2028 under assumptions that do not include the anticipated build-out of renewable generation or battery storage. The study finds relatively low production cost savings for these projects under various gas price assumptions. It produces benefit-to-cost ratios mostly ranging from 0.1 to 0.4 (where values above 1.0 indicate that the benefits exceed the costs).

In the 70x30 scenarios, the CARIS study identifies five major generation pockets where the existing network would be overwhelmed by the volume of renewable generation at certain times and result in significant curtailment, especially upstate and for solar generation. NYISO concludes that additional transmission will be needed to deliver renewable power to consumers efficiently, although the study did not examine the benefits of specific projects in the 70x30 scenarios. Ultimately, the CARIS study results provide useful information about potential transmission bottlenecks and will stimulate further assessments of high-renewable penetration in the Reliability Needs Assessment, the Climate Change Impact & Resilience Study, and future Public Policy Transmission studies.

However, transmission congestion and the need for new transmission cannot be separated from the locational incentives to invest in generation resources. Therefore, we use the CARIS study results to evaluate the locational incentives that could emerge to invest in different types of renewable resources in various locations, as well as the incentives to invest in battery storage and flexible resources. Appropriate locational price signals will help to optimize investments in both resources and transmission in an economically efficient manner.

Finally, the study also shows that the fleet of conventional generators will produce less output but cycle on and off more often. This indicates the effects of renewable resources on the operation of conventional generation. These results are discussed in greater detail in Section I.A.

B. The Role of Markets in Facilitating State Policy Goals

New York State's ambitious clean energy targets will require large amounts of new intermittent renewable generation, as well as flexible resources and price-responsive demand to balance variations in intermittent renewable generation. Some question the value of competitive wholesale markets if so much investment will be driven by state policy initiatives. However, given the high levels of generation investment that are anticipated in the coming years, it is more important than ever to provide efficient investment incentives to developers of intermittent resources and battery storage.

Wholesale markets are highly effective in facilitating investment that provides value to the system. Policy makers should leverage markets to achieve their clean energy objectives more quickly and cost-effectively. Wholesale markets complement state policy by setting prices that:

- Reward flexible technologies as the penetration of renewables increases,
- Encourage renewable resources to locate where their output will be deliverable,
- Facilitate investment in renewables that produce electricity when it is most valuable, and
- Identify where additional transmission would provide an efficient way to deliver more renewable generation to consumers.

The CARIS Phase 1 report's 70x30 scenarios provide an opportunity to evaluate how the wholesale market is likely to influence the direction of investment in new renewable generation, battery storage resources, and transmission. This report evaluates these incentives.

C. Using Index RECs to Reduce Market Risk for Developers

One of New York State's preferred methods for contracting with renewable generators is to enter long-term (20 to 25 year) contracts for Index RECs.[3] These are designed to:

- Protect the developer from the market risk resulting from general fluctuations in average zone-level energy prices, and
- Expose the developer to the market risk resulting from curtailment and price differences between the generator's node and the zone where it is located.

Hence, the Index REC relies on the wholesale market to reduce market risk while still exposing developers to risks that will guide them away from locations where there is already an excess of a particular type of renewable generation. Although renewable generation developers entering the New York market by 2030 are likely to expect more than half of total net revenues to the project to come from Index REC contracts, they will still rely on the wholesale market for a large share. These incentives will be very important given the transmission bottlenecks and curtailments identified in the CARIS study's 70x30 scenarios.

Section II to this report provides our analysis of incentives for investment in renewable generation, which is based on the 70x30 scenario in the CARIS Phase 1 Report. In this evaluation, we focus on two categories of market risk to intermittent renewable generation investors that are not eliminated by Index RECs. These are:

- *Technology discount* – This is the difference between the simple average zonal LBMP in the day-ahead market and the generation-weighted average zonal LBMP in the real-time

3 An Index REC pays a price per MWh equal to a fixed strike price minus the index price for a nearby pricing hub over the life of the contract. For example, if the fixed strike price of the contract is $65 per MWh and the average day-ahead price for a nearby trading hub is $29 per MWh over a particular month, then the generator will receive $36 per MWh for its RECs for that month.

market by technology. This captures the revenue reduction for technologies that tend to produce electricity at times when zonal LBMPs are below the day-ahead average.[4]

- *Nodal discount* – This equals the generation-weighted average differential between the zone LBMP and the node LBMP for a particular technology and location in the real-time market. This captures the revenue reduction when localized transmission constraints further discount the energy revenue to a particular technology and location.[5]

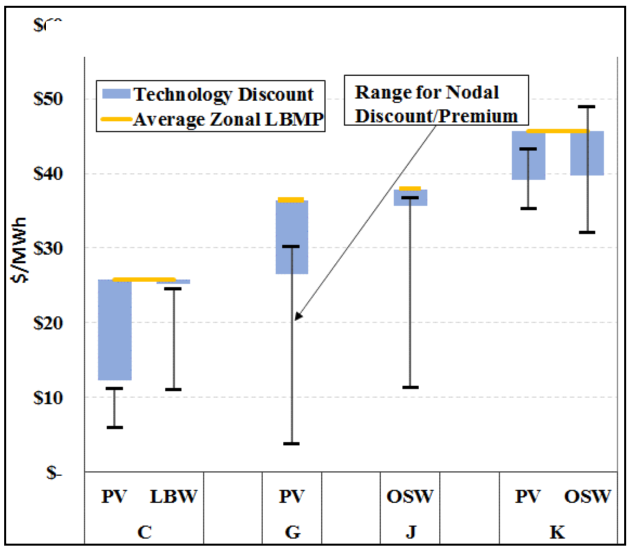
The evaluation of the technology discount and nodal discount provide insight about how renewable generation developers are likely to respond to wholesale market incentives.

D. Analysis of Incentives for Investment in Renewables

Our analysis of investment incentives in Section II of this report uses the NYISO's production cost modeling results to estimate day-ahead and real-time LBMPs at 30 nodes across eight zones, including simple average LBMPs and generation-weighted average LBMPs for each technology at each location. Our results in Figure 1 for selected locations show:

- Technology discounts of 27 to 87 percent of the average zonal LBMP for solar generation in Zones A to G;
- Modest technology discounts of 14 percent for solar generation in Zone K, 2 to 21 percent for land-based wind in Zones A to E, and 6 and 13 percent for offshore wind in Zones J and K;
- A wide range of nodal discounts for solar generation (79% discount to 29% premium), land-based wind (56% discount to 8% premium), and offshore wind (68% discount to 23% premium) for the location/technology combinations that we evaluated.

Figure 1: Technology and Nodal Discounts



These substantial technology discounts and nodal discounts are not observed in our analysis of 2019 market conditions.[6] Therefore, such

4 For example, if the simple average day-ahead LBMP for Zone E is $25/MWh and the solar-generation weighted average zone LBMP is $15/MWh in the real-time market, then solar generation exhibits a $10/MWh or 40 percent technology discount in Zone E.

5 For example, if the real-time solar-generation weighted average LBMP for Zone E is $15/MWh and the weighted average for a particular node in Zone E is $12/MWh, then solar generation exhibits a $3/MWh or 20 percent nodal discount at the node.

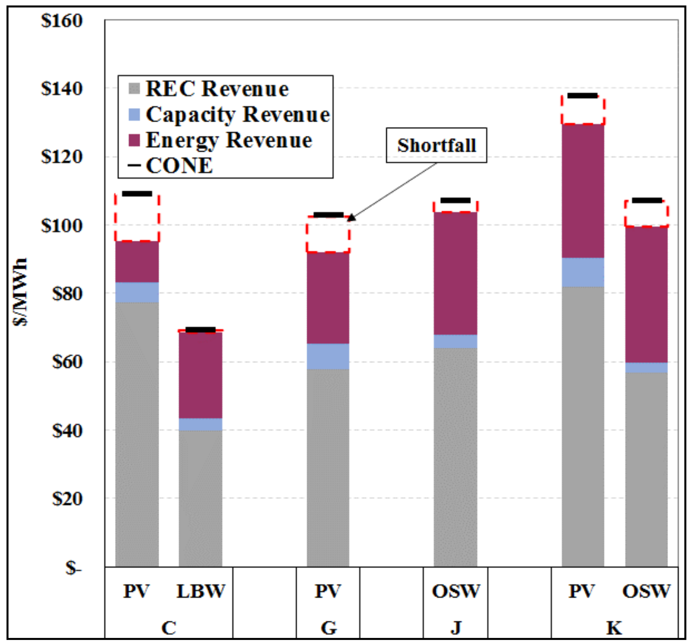
6 Figure 6 in Section II.B shows small (and sometimes negative) technology discounts and nodal discounts in 2019.

discounts will emerge during the coming decade if a given region becomes saturated with a particular type of renewable resources.

Renewable generation projects being built under current market conditions face the risk that too many future projects will be built in the same region. Although future project developers have an incentive to avoid areas that are already saturated with a particular technology, this incentive could be overcome if the State increases the prices of Index REC contracts in the future. Thus, the potential for future increases in Index REC prices is a significant risk for current projects, which may reduce their willingness to enter the market in the near-term (i.e., before a given area reaches the saturation point).

This concern is illustrated by the increase in the technology discount that we observe from our analysis of 2019 compared to our analysis of 2030. Figure 2 shows that the increase we estimate in the technology discount after 2019 would reduce revenues to wind and solar developers in Zones C, G, J, and K by up to $14 per MWh in the 2030 scenario. In addition, we identify many locations where the nodal discount would also increase significantly after 2019. This suggests that the Index REC prices would need to increase from current levels if New York State was to achieve its 70x30 goal using a resource mix similar to the one modeled in the CARIS study.

Figure 2: Net Revenue vs. CONE at Selected Locations



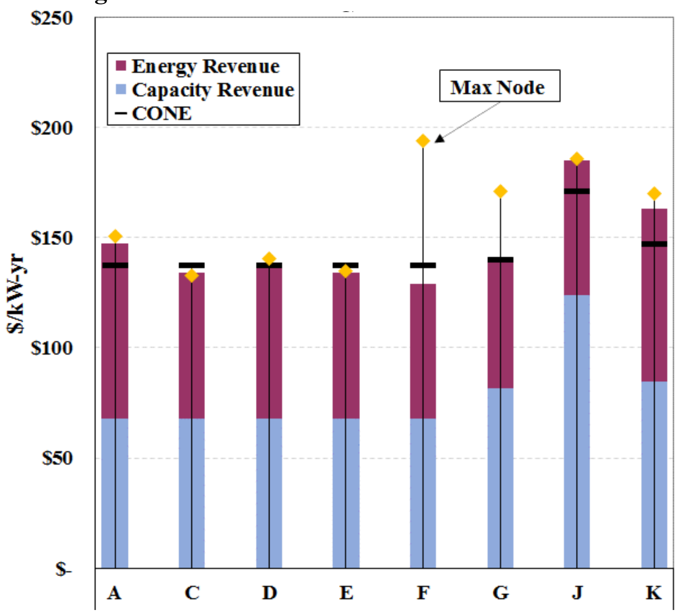
While use of long-term Index REC contracts reduces risk for renewable generation developers, they are still exposed to the risk that areas of New York may become saturated with certain types of renewable generation and that this will reduce revenues to the project. This risk is ameliorated by NYISO's planning processes which will continue to evaluate the potential benefits of new transmission. Another factor that could limit such risks is the potential for additional battery storage investment beyond NYISO's assumptions. Batteries would increase consumption during periods of excess renewable generation, especially at locations where there is a nodal discount. The next part of this section discusses our assessment of battery storage investment incentives based on the 70x30 simulations that the NYISO performed.

E. Analysis of Incentives for Investment in Battery Storage

The technology and nodal discounts discussed above are a significant source of risk for renewable developers, but these present an opportunity for battery storage developers that are located in areas where they can charge inexpensively when renewable generation is in surplus and discharge at much higher prices when renewable generation falls. In addition, increased intermittency may increase ancillary services prices and requirements, which will provide more revenue to flexible units in general. These market incentives will encourage additional entry of battery storage, which should moderate prices during periods of surplus renewable generation. Ultimately, this will ameliorate the risks faced by renewable generation developers and illustrates how the wholesale market can facilitate state policies.

In our analysis of the incentives in 2030, we find that battery storage projects would earn moderate returns (i.e., net revenues approximately equal to their levelized cost of new entry) without subsidies in most of the zones, and relatively high returns in Zones A, J, and K as well as parts of Zones F and G. This is summarized in Figure 3. Strong investment incentives are expected to motivate additional entry of battery storage. This should, in turn, moderate the returns to battery storage developers and reduce the risks for renewable generation investors.

Figure 3: Net Revenue vs. CONE for Selected Cases



Based on our analysis of the high renewable penetration simulations that the NYISO produced in the CARIS Phase 1 study, we find that 31 to 65 percent of the net revenue to battery storage resources is from energy and ancillary services sales, while the remainder is from capacity sales. In our evaluation, we assume that these resources sell capacity at 75 percent of the levelized cost of new entry under the proposed demand curves. This corresponds to the price level at which new subsidized resources will be able to sell capacity if the recently filed Part A test BSM enhancements are accepted by the FERC.

The reliance of future battery storage projects on capacity revenues highlights the importance of the BSM rules in supporting a robust wholesale market that will facilitate beneficial market responses to large-scale entry of renewable resources. If wholesale capacity prices are suppressed below competitive levels for extended periods, it will become challenging to motivate needed investment in flexible technologies.

F. Conclusions

The 2019 CARIS Phase 1 study provides a wealth of information from simulations of 2030 scenarios for a hypothetical resource mix that would satisfy the State's goal of serving 70 percent of demand with renewable generation. CARIS identifies five major generation pockets where the existing transmission system would be overwhelmed by the volume of renewable generation at certain times, resulting in significant curtailments and increased cycling of conventional generation. NYISO concludes that additional transmission will be needed to deliver renewable energy to consumers efficiently, although the study did not examine the benefits of specific projects in the 70x30 scenarios. Ultimately, the study will guide further assessments of how the power system can adapt to high renewable penetration.

However, the transmission congestion that indicates the potential need for transmission also substantially affects investment incentives for generation. Therefore, we used detailed information from the NYISO's simulations to evaluate implications for investment incentives of renewable generation and battery storage developers. The wholesale market will provide incentives that will encourage developers to place assets where they are likely to be most valuable—that is, where the transmission system is not already saturated with a particular renewable technology. If additional entry into saturated areas is motivated by raising Index REC prices in the future, it will result in large financial risks to renewable generation developers that invest sooner (i.e., before the area has become saturated with a particular intermittent generation technology). Thus, a stable and predictable policy regarding Index REC price levels may facilitate progress towards the State's goals.

Lastly, we find that the high renewable penetration modeled in the 2030 scenario would provide strong incentives for entry by unsubsidized battery storage developers. This market response would moderate energy prices and reduce market risks for renewable generation investors. Hence, a competitive wholesale market for energy, ancillary services, and capacity will ultimately facilitate State policy objectives.

I. DISCUSSION OF KEY FINDINGS IN THE CARIS REPORT

Phase 1 of the 2019 CARIS Study evaluated congestion on New York's bulk transmission system to provide information to market participants, policymakers, and other interested parties to be considered in evaluating transmission projects. The NYISO studied potential future congestion patterns using GE-MAPS production cost modeling software to simulate the NYISO bulk transmission system over a forecast period from 2019 to 2028. The standard CARIS Base Case used the NYISO's normal inclusion rules, reflecting only limited changes to the resource mix that have a high degree of certainty such as the retirement of Indian Point Energy Center and the completion of the Western New York and AC Public Policy Transmission projects that have previously been approved. It also examined standard alternative scenarios including higher or lower fuel prices and energy demand.

The NYISO also created the "70x30" Case, which is an alternative scenario that assumes the achievement of New York's Climate Leadership and Community Protection Act (CLCPA) goals of 70 percent of demand served by renewable sources by 2030, 9 GW of offshore wind by 2035, 6 GW of distributed solar by 2025, and 3 GW of energy storage by 2030. The 70x30 Case also considers other policy-driven resource changes including retirement of simple cycle combustion turbine plants affected by the recent "Peaker Rule" regulations issued by the NYDEC. For the 70x30 Case, NYISO combined production cost modeling in GE-MAPS with power flow modeling using TARA software to identify and include additional constraints and contingencies that would emerge given the drastically different resource mix. The 70x30 Case is of particular interest because it provides a glimpse of possible impacts on transmission congestion and other aspects of the NYISO system due to the significant and unprecedented resource mix changes that are anticipated in the coming years. Hence, a key question for this study is what challenges are likely to emerge as the state makes progress towards public policy goals and how NYISO markets can help to address those challenges.

The following summary statistics from the 2019 CARIS Phase 1 study and 70x30 Case illustrate the magnitude of change between the Base Case and 70x30 Case:

- The results of the CARIS Base Case are not supportive of including additional transmission solutions to relieve congestion based solely on production cost savings. The estimated benefit-cost ratio for a transmission solution in the 2024-2028 timeframe using mid-range cost assumptions is 0.12 for the Central East interface, 0.11 for the Central East-Knickerbocker interface, and 0.35 for the Volney-Scriba interface. The Base Case represents a 'status quo' scenario that includes the planned Western New York and AC Transmission projects, resulting in a reduction of congestion, but does not include most changes to the resource mix that would be required to comply with the CLCPA in 2030.
- The 70x30 Case includes very high penetrations of intermittent renewables by 2030. Table 1 below summarizes resources modeled in the 70x30 Case to comply with CLCPA targets in the Scenario Load case (which reflects the impact of CLCPA policies on the

demand side) and the Base Load Case (which does not). In the Scenario Load Case, 37.5 GW of new renewables are added by 2030, not including the assumption of 1.3 GW of additional hydropower imports from Quebec to New York City. While the assumed amounts and locations of renewables in the 70x30 Case are not intended as a roadmap for CLCPA compliance and are not derived from an optimized approach, NYISO notes that they are guided by the present locations of projects in the interconnection queue.

Table 1: New Intermittent Renewables Included in the CARIS 70x30 Case

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

There are significantly higher levels of congestion in the 70x30 Case compared to the Base Case. Notably, congestion (measured in Demand$ terms) on major bulk transmission system constraints increased significantly in the 70x30 Scenario Load Case relative to the Base Case for Central East, New Scotland – Knickerbocker, Princetown – New Scotland, Dunwoodie to Long Island, as well as on other interfaces. These results suggest a return of major congestion between upstate and eastern and southeast New York, which in the Base Case is substantially reduced by the completion of the Western New York and AC Public Policy Transmission projects.

In addition to major interfaces, significant congestion takes place in the 70x30 Case on local lower-voltage transmission constraints that are largely not binding today, as well as curtailment of renewable generation. In the Scenario Load HRM Method Case (which includes 3 GW of energy storage resources as required by the CLCPA), over 9 TWh of renewable generation, representing approximately 9 percent of total renewable output, is curtailed. Curtailment is concentrated in transmission-constrained generation pockets identified by NYISO throughout the state, with curtailment of wind or solar exceeding 50 percent in some pockets.

Overall, the CARIS study found that while the benefit-cost ratio of transmission solutions in a Status Quo case is low, in a case where the goals of the CLCPA are achieved additional transmission at the bulk and local levels will be necessary to efficiently deliver power to consumers. This conclusion is informed by the higher levels of congestion at the bulk and local levels in the 70x30 Case and by the high rates of curtailment of intermittent renewables in certain generation pockets. However, NYISO's specific results are illustrative and the CARIS report does not provide solutions for issues identified in the 70x30 Case. NYISO notes that local system constraints do not equate to the necessity of upgrading those constraints one by one and that there are multiple options to address congestion at the bulk and local levels. The results of the 70x30 Case are therefore useful for illustrating the types of challenges that may emerge as New York makes progress towards the CLCPA goals, which include increased congestion on the bulk transmission system and widely varying local congestion at specific locations where renewables are deployed, rather than for evaluating specific transmission solutions.

II. Incentives for Investors in New Renewable and Battery Storage Technologies

This section evaluates revenues of renewable and energy storage resources and incentives for investment based on the results of NYISO's 70x30 CARIS GE MAPS case. The CARIS study and the analysis presented in this section are not intended as a forecast of future market or investment conditions, which depend on many factors including commodity prices, technology costs, demand growth and others. Instead, we examine one possible future scenario satisfying CLCPA targets by 2030 and draw lessons for the role of NYISO markets in guiding investment in public policy resources. This section is structured as follows:

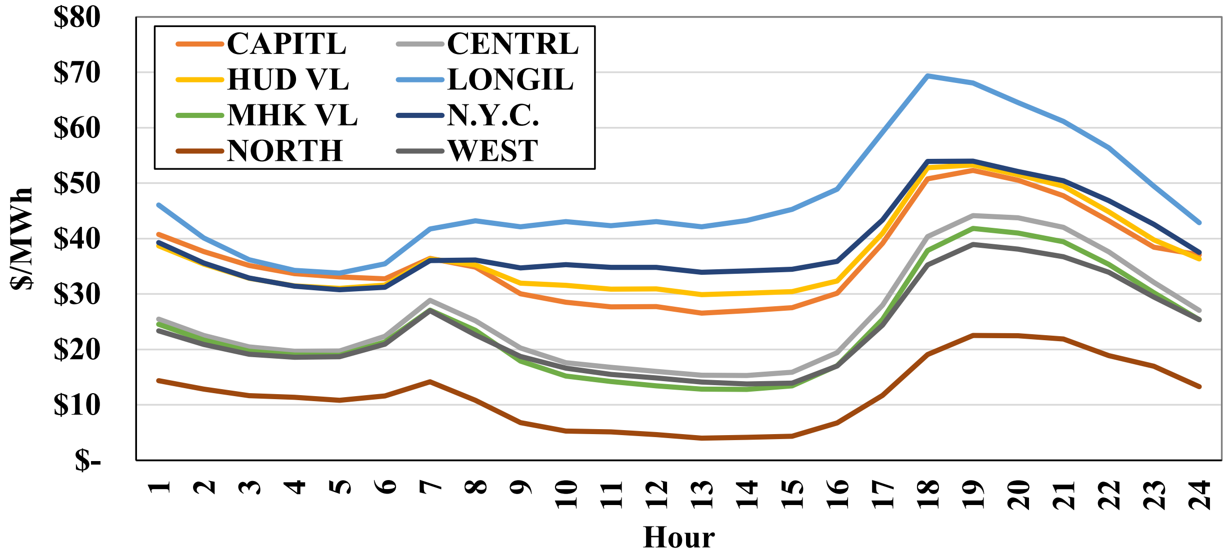
- Subsection A summarizes LBMPs produced in the NYISO's 70x30 case and how we used these to estimate day-ahead and real-time LBMPs for 2030. While these LBMPs exhibit familiar patterns of congestion from upstate areas to downstate areas, high levels of solar generation result in very low LBMPs in the late morning and early afternoon hours in most areas.
- Subsection B compares average LBMPs for a total of 30 pricing nodes and eight zones in 2030 to the generation weighted-average LBMPs at each location for hypothetical utility-scale solar, land-based wind, and/or offshore wind generators. This section also summarizes the corresponding net revenue and levelized cost of energy for each technology and location, assuming Index REC prices that would allow a generator receiving the simple average zone LBMP to break even. We find that the generation weighted-average nodal LBMPs in the real-time market are far below the simple average zone LBMPs in the day-ahead for many of the nodes and technologies evaluated, leading to net revenues being significantly lower than the levelized cost at many node-technology combinations.
- Subsection C estimates the net revenues that would accrue to a battery storage resource in the same 2030 scenario, finding that variations in LBMPs from increased intermittency would lead battery storage resources to receive net revenues in excess of levelized CONE at most locations.
- Subsections D & E discuss the implications of the analysis for investment in renewable generation, battery storage, and transmission.

A. Modeled Price Levels in the 70x30 Scenario Case

In order to model resources' prices and incentives, we developed a set of day-ahead and real-time LBMPs based on output from the GE MAPS CARIS 70x30 Scenario Load HRM Method case provided by NYISO and historical market data. Output data from CARIS for the 70x30 case was adjusted to resemble realistic day-ahead prices based on the relationship between the 2017 CARIS Benchmark MAPS case and historical 2017 price data. Further details of how GE MAPS data was used to develop price estimates can be found in the Technical Appendix (Section III). Prices were developed for various nodes across the NYISO market, including existing generation nodes and sites where new intermittent renewables were added in NYISO's 70x30 CARIS assumptions.

Figure 1 summarizes estimated day-ahead zonal prices as an average for each hour of the day over the course of one year. Figure 2 summarizes monthly average prices in Zone F in the GE-MAPS 70x30 and 2017 Benchmark cases, 2017 historical day-ahead price data, and our estimated 2030 day-ahead prices.

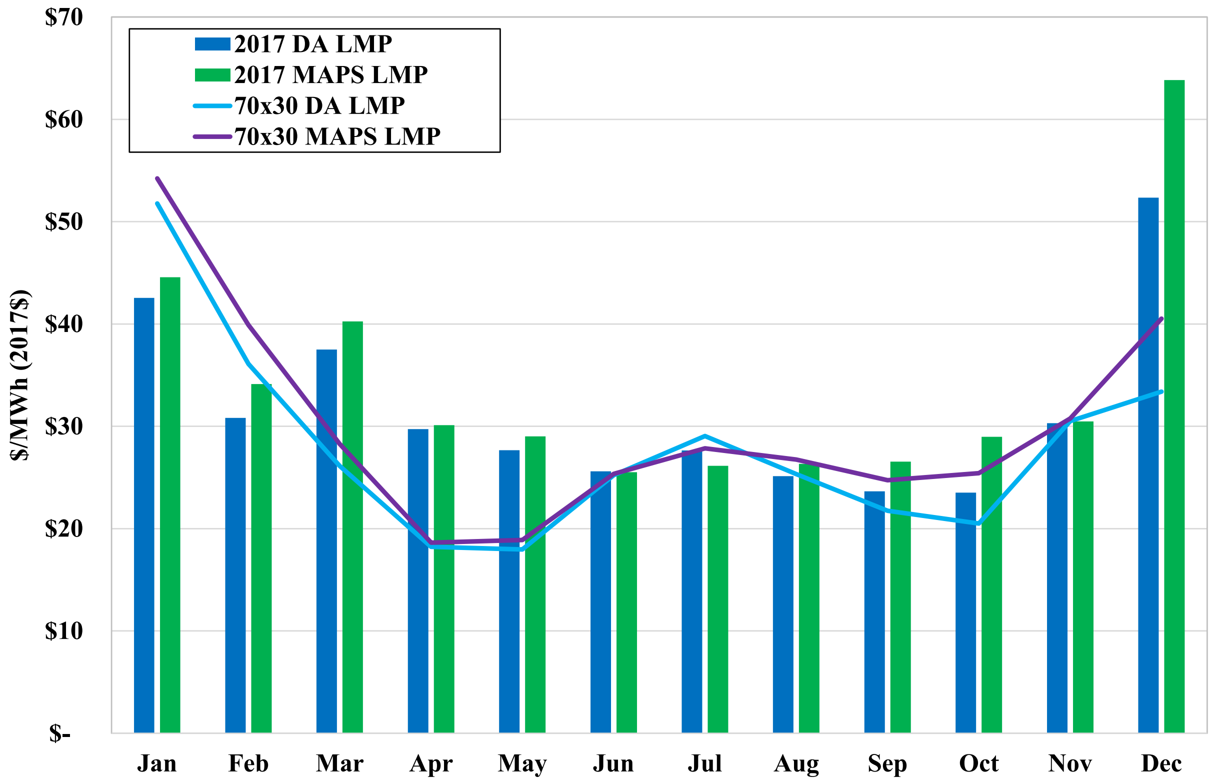
Figure 1: Average Price by Time of Day in 70x30 Case



These figures exhibit several interesting patterns in the 2030 scenario. Estimated prices in the 70x30 case show a pattern of low prices during the late morning to afternoon hours followed by rising prices in the late afternoon and evening. The emergence of this 'duck curve' pattern is related to a large assumed increase in solar generation. The downstate areas (i.e., Zones J and K) do not exhibit the duck curve pattern, which implies that transmission bottlenecks limit the amount of solar generation that can be delivered to downstate areas.

Overall price levels in the 70x30 Case are similar in real terms to recent historical price levels. Higher assumed fuel prices and RGGI carbon allowance prices by 2030 are offset by lower implied heat rates because of high penetration of renewables. Prices vary by region, reflecting significant congestion on interzonal transmission interfaces, especially the Moses South interface (from Zone D to E), the Central East interface (from Zone E to F), and the Dunwoodie-Shore Road interface (from Zone I to K). Areas in western and northern New York are deeply discounted relative to prices downstate.

Figure 2: Estimated Monthly Average Prices in Zone F



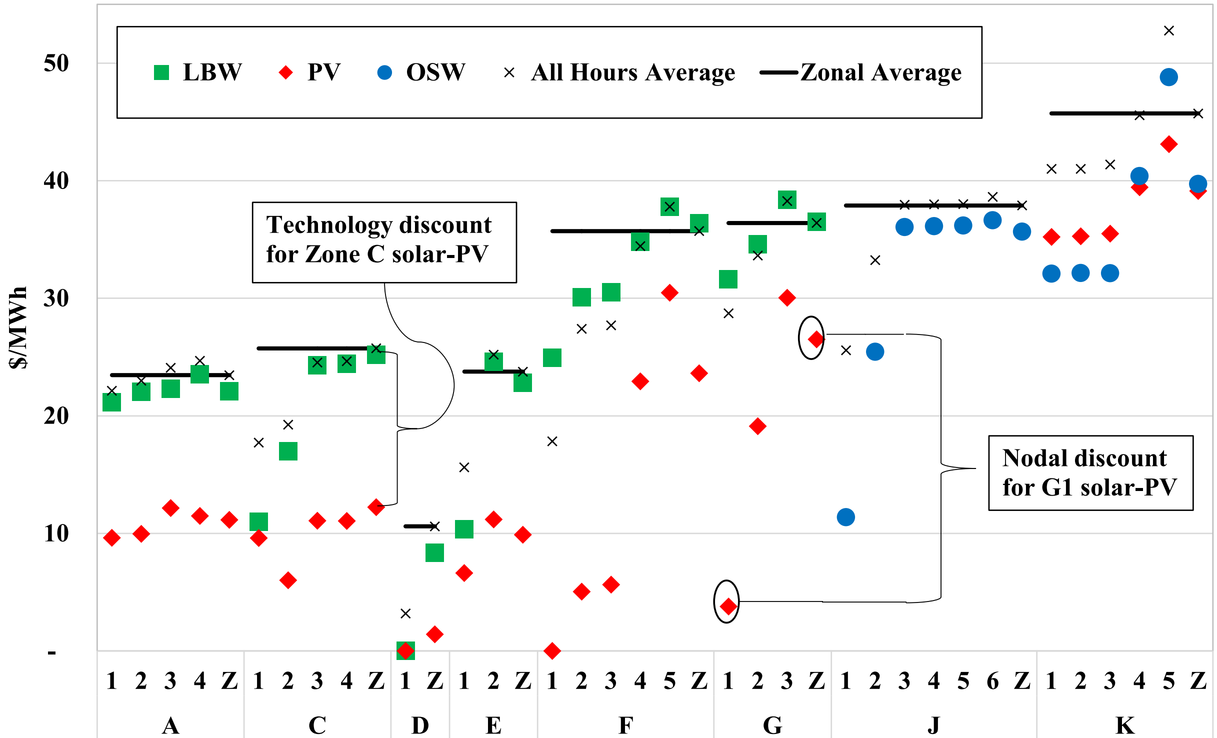
Average estimated day-ahead LBMPs in the 70x30 case are similar to LBMPs in the GE MAPS case output. Prices are adjusted based on the relationship between 2017 historical data and the 2017 Benchmark MAPS case to account for differences between price profiles generated by GE MAPS and realistic day-ahead price patterns.

B. Prices and Revenues for Intermittent Renewable Generators

Figure 3 compares generation-weighted real-time prices earned by hypothetical resources at several locations to simple average real-time prices across all hours at the same node and zone. Prices for land-based wind, solar PV and offshore wind are weighted by the resource's generation in each hour of the year, in order to show the average realized price in the hours in which it operates. Prices are shown for a hypothetical resource at various nodal locations, but they are not intended to represent specific suppliers. The horizontal axis indicates the node or zone location being modeled. (For example, under "A", "1" refers to a particular node in Zone A, while "Z" refers to our analysis of the Zone A price itself.) [7] All-hours average prices at each node and zonal average prices are calculated as a simple average across all hours of the year.

[7] Nodes that we analyzed are discussed throughout this section using generic labels. They represent a diverse set of locations both upstream and downstream of transmission constraints identified by NYISO in its 70x30 Case analysis. Some, but not all, of these sites included intermittent renewables modeled by NYISO in the 70x30 Case. A list of nodes by name and their locations relative to generation pockets identified by NYISO can be found in the Technical Appendix (Section III).

Figure 3: Generation-Weighted and Simple Average LBMPs for Intermittent Renewables



In Figures 4 through 7, we estimate net revenues in the 70x30 case for hypothetical new resources of various types, compared to the cost of new entry (CONE) for each resource and location. Figure 4 shows net revenues for hypothetical solar PV resources in zones A-G and K, while Figure 5 shows net revenues for a hypothetical land-based wind resource in zones A-G (although the NYISO's scenarios did not model land-based wind additions in Zones F and G) and offshore wind in zones J and K. Like Figure 3, Figures 4 and 5 have a horizontal axis indicating the node or zone location being modeled. (For example, under "A", "1" refers to a particular node in Zone A, while "Z" refers to our analysis of the Zone A price itself.) [8]

We estimate revenues using the following methodology. Energy revenues for renewables are generation-weighted average real-time prices as described above. Capacity revenues are estimated assuming prices at the Default Net CONE level (75 percent of the demand curve Net CONE value) by 2030. Capacity value of each intermittent renewable generation type is based on estimated by Brattle Group.[9] Summer capacity credit values are 18 percent for solar, 15 percent for land-based wind, and 14 percent for offshore wind.

8 *Ibid.*

9 The Brattle Group, "Quantitative Analysis of Resource Adequacy Structures", May 29, 2020, http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={1363C680-F134-41F4-809B-7CF65AF8AD71}

REC revenues are estimated using the Index REC approach recently approved by NYPSC for use in NYSERDA solicitations for large-scale renewables.[10] Index REC prices are equal to a strike price minus all-hours zonal day-ahead energy prices and capacity prices. We estimate a generic REC price for each resource type and zone assuming that the Index REC strike price is equal to the resource's CONE.[11]

In Figures 4 and 5, estimates of CONE for each resource and location are derived from the 2019 NREL ATB, using the mid-case projections for 2030, and financing parameters from the most recent NYISO Demand Curve Reset.[12]

The emergence of technology and nodal discounts as renewables enter the system in larger quantities may cause net revenues of renewables to fall below their Index REC strike price over time, even if revenues were equal to the strike price when the resource first entered the market. Figure 6 shows estimated net revenues by 2030 for a hypothetical resource entering the market today with an Index REC strike price equal to its CONE. Net revenues are lower than the strike price in some instances because the emergence of technology and nodal discounts causes energy market revenues to decline by more than REC revenues increase.

Figure 7 estimates the after-tax internal rate of return (IRR) for these resources over the project lifetime beginning in 2019. If Index RECs keep net revenues equal to the strike price over the project life, the resource's IRR will be equal to the weighted average cost of capital (WACC) needed to justify investment. If Index REC values do not keep pace with declining energy and capacity revenues, the IRR will be below the WACC needed to justify investment.[13]

[10] New York Public Service Commission, Order Modifying Tier 1 Renewable Energy procurements, Issued January 16, 2020, http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={1F9CA0EB-3968-41DB-BBE0-C251A3FE52DE}

[11] For a resource that expects to earn energy and capacity revenues approximately equal to the average prices in its zone, an Index REC strike price equal to the resource's CONE would provide sufficient REC revenues to encourage investment.

[12] Details of resource costs and other assumptions used in our analysis can be found in the Technical Appendix (Section III).

[13] WACC for Subsidized Resources is based on COE of 10.6 percent, and COD of 6.1 percent sourced from IHS Markit report on *The Cost of Capital for Renewable Generation Capacity Ownership,* available at: https://www.eia.gov/conference/2017/pdf/presentations/james_saeger.pdf. Debt to Equity ratio is assumed as 55/45 based on the NYISO ICAP DCR study.

Figure 4: Net Revenues vs CONE for a New Solar PV in 70x30 Case

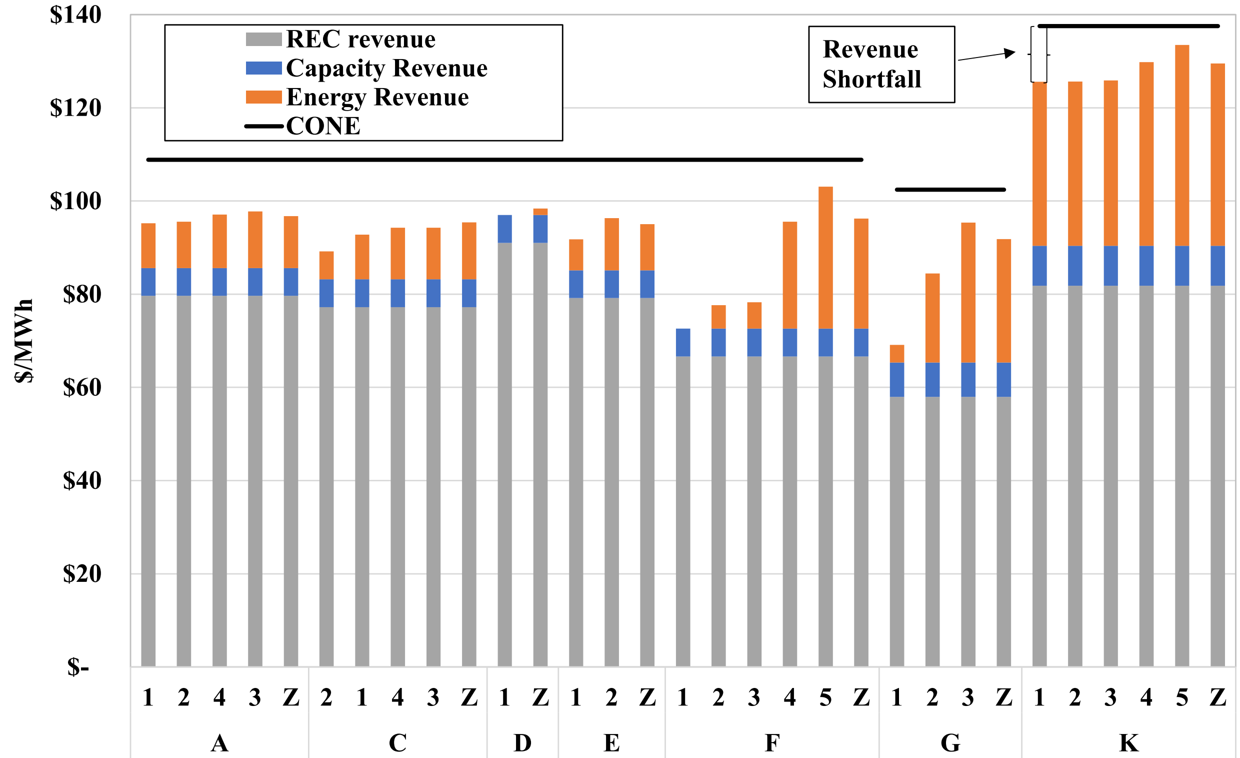


Figure 5: Net Revenues vs CONE for New Land-Based and Offshore Wind in 70x30 Case

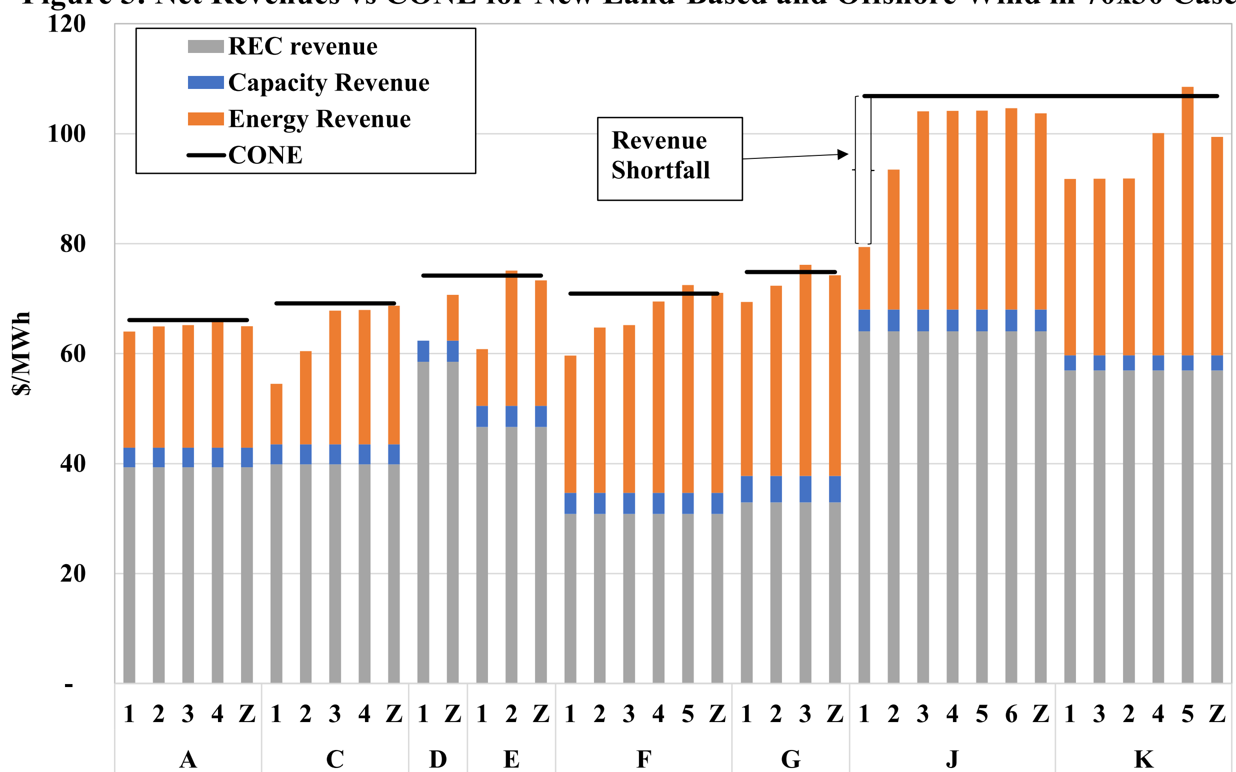


Figure 6: Net Revenues in 2019 vs. 2030 for Selected Cases in 70x30 Case

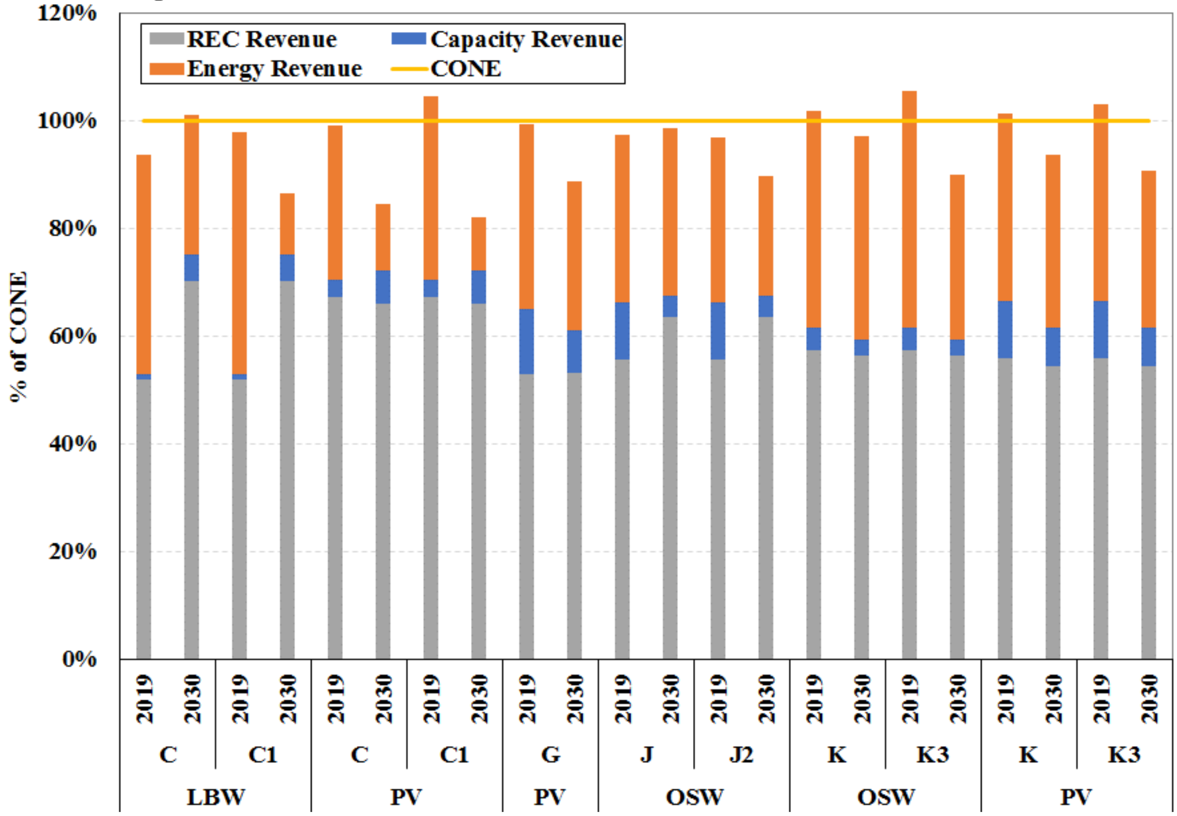
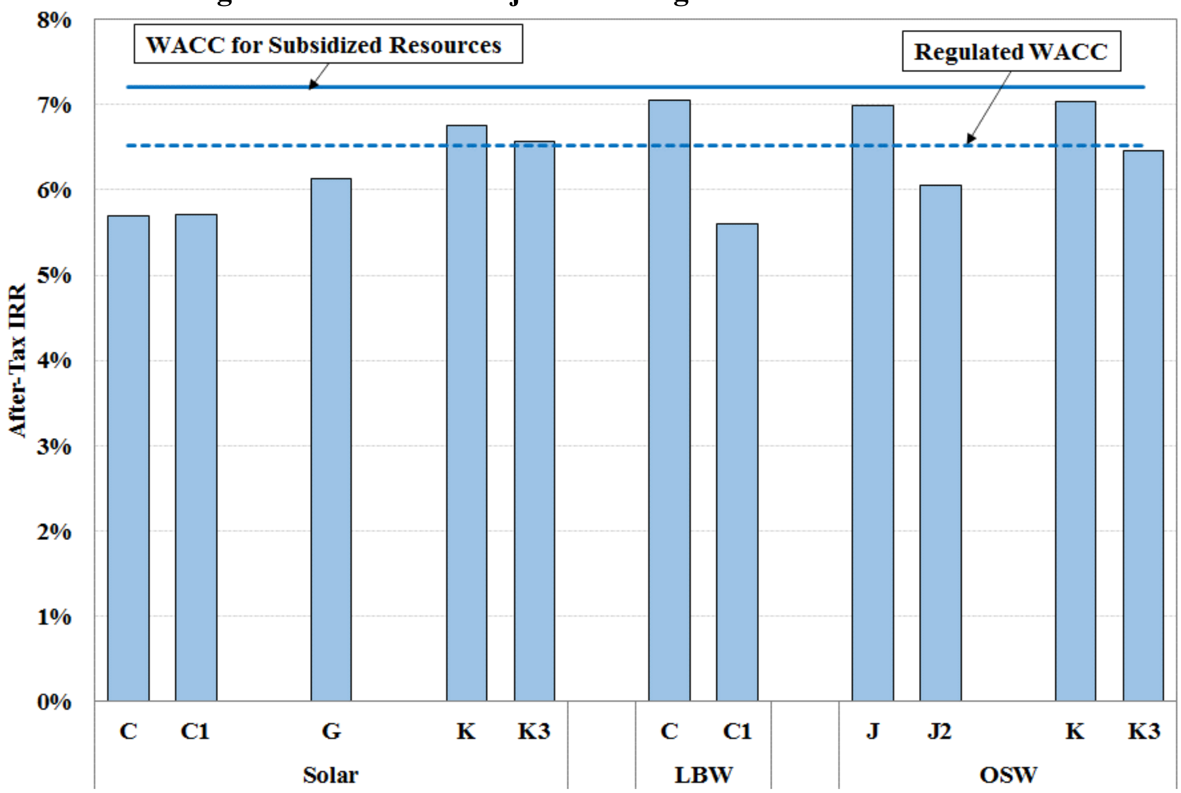


Figure 7: IRR for a Project Entering in 2019 for Selected Cases



Many key observations may be drawn from the figures in this subsection:

- *Generation-weighted vs. Average Prices* – Generation-weighted prices at many nodes differ significantly from the average price at the same location. For example, at the BENET115 node in Zone C (see "C1"), the annual average day-ahead price is $18/MWh while the realized price for a solar PV facility is $10/MWh and the realized price for a wind facility is $11/MWh. A generation-weighted price that is lower than the average price indicates that the resource tends to generate during relatively low-priced hours or seasons.
- *Prices Vary by Technology* – Generation-weighted prices for solar resources in the 70x30 case are systematically lower than for wind resources in most locations, often by a large margin. Prices for solar resources at many locations are lower even compared to wind resources at locations that are lower priced on average. For example, a solar resource at SHOEM138 in Zone G (see "G2") earns a lower price than a wind resource at EDIC 345kV in Zone E (see "E2"), even though the average price at Node G2 is higher than at Node E2. This result suggests that prices are suppressed during hours of solar generation relative to hours of wind generation across the market as a whole, resulting in a large discount in the value of solar generation. By contrast, in eastern Long Island (HOLBROOK, BRKHVN 3 and EHAMP, which are "K1", "K2" and "K3"), generation-weighted prices for offshore wind are lower than for solar, suggesting that in this location correlated offshore wind depresses energy prices during its hours of generation.
- *Prices Vary by Location* – There are large differences in price at different nodal locations within each zone due to the effects of transmission congestion. For example, within Zone J (New York City), an offshore wind facility interconnected to the FRESH KI node ("J1") would earn $11/MWh on average, compared to $25/MWh at the GOWANUS node ("J2") and $36/MWh at the Farragut node ("J3"). Transmission congestion is related to generation-weighted prices, as resources located behind bottlenecks tend to exacerbate congestion and reduce the price at their own location when they generate.
- *Technology Discounts versus Nodal Discounts* – Some of the differences between generation-weighted average prices and simple average zone prices are driven by localized transmission constraints, while other differences are driven by the timing and correlated nature of intermittent generation in a particular region.
- *Role of REC Revenues* – REC prices in this scenario make up the majority of total revenues for intermittent renewables. The value of RECs ultimately depends on many factors including future technology costs, commodity prices and others, and should not be viewed as a forecast. However, this result indicates the large role that REC revenues may play in a scenario in which high intermittent renewable penetration leads to low energy and capacity market prices for these resources.
- *Generic REC prices vary by resource and location* – Zonal REC prices for a new hypothetical resource range from $58/MWh to $91/MWh for solar, $57/MWh to $64/MWh for offshore wind, and $31/MWh to $59/MWh for land-based wind.
- *Generic RECs not sufficient for all resources* – at many locations, net revenues from energy, capacity and RECs are not enough to justify investment when assuming an Index REC strike price equal to the resource's CONE. This is because REC prices are indexed to simple average zonal prices, while the resource actually earns a generation-weighted

nodal price in the energy market. Hence, resources at locations with low generation-weighted prices do not earn total net revenues equal to CONE. Such resources would likely require an index REC strike price above their CONE.

- *REC Prices May Increase Over Time* – For nearly all locations, the spread between the generation-weighted average LBMP and the simple-average zone LBMP is much larger in the 70x30 scenario than in the 2019 market results. This ranges from 17 to 100 percent discount for solar, 6 percent premium to 100 percent discount for land-based wind, and 7 percent premium to 70 percent discount for offshore wind. Consequently, renewable generators entering the market under current conditions will demand Index REC prices that are higher than their LCOE (after considering offsets for capacity and federal incentives). Furthermore, uncertainty regarding the change in node/technology basis over the next two decades creates substantial risk for renewable developers considering entry in the near future.

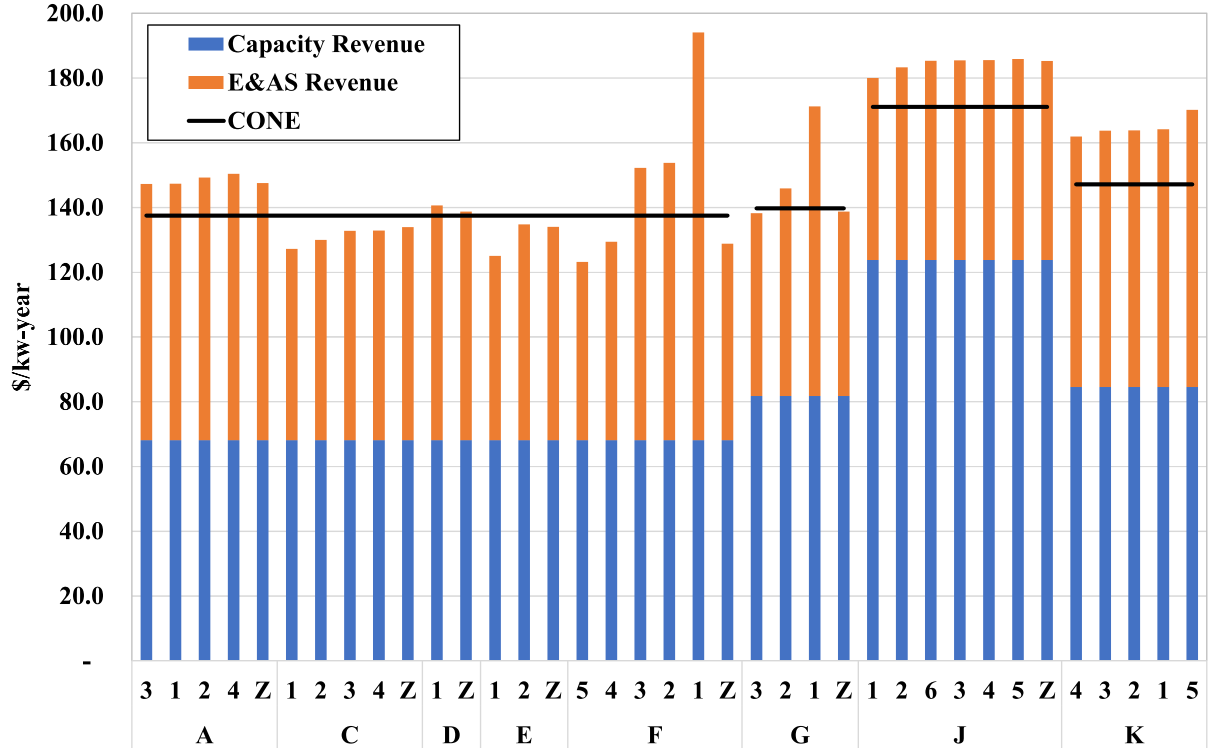
C. Prices and Revenues for Battery Storage Projects

Figure 8 shows estimated net revenues for a hypothetical new 4-hour energy storage resource compared to CONE at various locations in the 70x30 Case. The analysis assumes the resource sells a number of MWhs of operating reserves in the day-ahead market equal to its maximum state of charge which is evenly spread across peak hours (hours 10 to 17). Real-time energy and ancillary services revenues were modeled using a dispatch algorithm that optimizes charging, discharging and sale of operating reserves based on a bid/offer curve that is developed from information available before the real-time bid submission deadline. Hence, this model does not employ hindsight to develop inflated net revenue estimates. Capacity revenues are estimated assuming prices at the Default Net CONE level (75 percent of the demand curve Net CONE value) by 2030 and 90 percent capacity value for 4-hour energy storage.[14]

---

[14] NYISO has estimated in its Expanding Capacity Eligibility project that capacity value for four-hour storage will begin to decline from its starting value of 90% after 1,000 MW has been deployed. However, other factors such as penetration of intermittent renewables will also impact the future capacity value of ESRs. Recent estimates by Brattle group suggest that capacity value for ESRs will not decline in a 70x30 renewables case until penetrations larger than 3,000 MW are reached. For this analysis, we maintain the current 90% rating. See Brattle Group, "Quantitative Analysis of Resource Adequacy Structures", May 29, 2020, http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={1363C680-F134-41F4-809B-7CF65AF8AD71}

Figure 8: Net Revenues vs CONE for Battery Storage in 70x30 Case



Key Observations:

- Revenues from the energy, ancillary services and capacity markets are sufficient for a new energy storage resource to earn its levelized CONE at many locations in the 70x30 Case.
- Energy and capacity revenues at different nodes indicate the relative value of storage at those locations in this scenario. In many upstate areas, where a surplus of renewable generation contributes to large fluctuations in price throughout the day, net energy revenues make up a large share of total net revenues. In New York City, capacity revenue makes up a larger share of total net revenues but this is supplemented by additional energy and ancillary services revenues which are sufficient for the new resource to recover its levelized CONE in all areas.

D. Incentive Implications

These results show the importance of competitive investment signals in meeting state policy goals in a way that can attract the needed investment without excessive cost. The set of resources developed by NYISO for its 70x30 Case were not intended as a derivation of the optimal resource mix to meet state goals – rather, it is just one hypothetical resource mix that could possibly meet CLCPA goals by 2030. Analyzing revenues and investment incentives in such a case has value because it illustrates how a resource plan that is not guided by market signals could lead to inefficient outcomes where: (a) some projects are located in areas with an excess of generation of a particular technology, and (b) other projects earning higher-than-normal returns.

This situation would create incentives that would encourage investment decisions that would likely moderate these effects. For example, low net revenues for solar resources would lead to smaller amounts of investment or higher Index REC prices. Our results show much lower generation-weighted prices for solar compared to other resource types and deeply discounted solar revenues at many locations. This is likely to reduce the amount of solar entry in key areas and moderate this price impact.

Finally, our results indicate that energy storage resources would be economic in many locations and are therefore 'underbuilt', even after assuming the 3,000 MW deployment required by the CLCPA and modeled in the 70x30 HRM Method Case. Larger deployments of storage at key locations would likely dampen price volatility, increasing the net revenues of intermittent generators and reducing the net revenues of incremental energy storage resources. Although many factors in this analysis are highly uncertain, we note this scenario as an example of how NYISO markets are capable of guiding merchant storage investment in the amounts and at the locations where it would have value in a system characterized by high levels of policy-driven intermittent renewables.

The risk faced by solar generation developers would be reduced by the Index REC, however, solar generators would earn 27 to 87 percent less than the simple average LBMP, so they are exposed to large market risks. One factor that would help reduce these risks would be robust entry of battery storage projects, which appeared to be economic at most locations, because battery storage resources would increase consumption during hours of high solar generation.

E. Implications for Transmission Investment

Prices and incentives for renewable resources are affected by congestion on the transmission system. NYISO concludes from its 70x30 Scenario that transmission expansion at the bulk and local levels will be necessary to efficiently deliver renewable energy to consumers.[15] The NYPSC is currently overseeing a process to comprehensively study, identify and develop bulk and local transmission projects in order to facilitate the CLCPA as required by the Accelerated Renewable Energy Growth and Community Benefit Act.[16] It is therefore necessary to comment on how NYISO market signals facilitate the coordination of transmission planning and generation investment.

---

15 2019 CARIS Phase I Draft Report, p. 108.

16 New York Public Service Commission, "Order on Transmission Planning Pursuant to the Accelerated Renewable Energy Growth and Community Benefit Act", issued May 14, 2020, see http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={FF8A7989-D35E-4636-8A9A-F886808FD2F7}

The value of generation and transmission projects are interdependent, which can create coordination challenges. Generation owners will respond to planned transmission when selecting sites and investments, but the best mix and locations of generation is not known to transmission planners. Transmission plans based on specific assumptions of future resource locations run the risk that those resources will not actually materialize or that the combined generation and transmission will not be cost-effective compared to other possible alternatives.

The nature of the CARIS study underscores this challenge. The CARIS base case includes only generation projects that meet strict standards for likelihood to enter service in its assumptions. Consequently, it largely excludes future changes to the resource mix related to CLCPA goals and does not identify any economically viable transmission solutions (and historically has never done so). The CARIS 70x30 Case shows significantly greater congestion and our analysis indicates wide variations in nodal pricing. However, its assumptions of specific locations and amounts of each resource type are necessarily speculative and therefore may not serve as a reliable basis for evaluating specific transmission projects.

NYISO markets, combined with a planning process that leverages competitive incentives, can facilitate development of transmission that cost-effectively helps to meet state goals. Markets can help to guide transmission planning in the following ways:

- NYISO market prices provide signals for the value of transmission projects. Differences in LBMPs not only indicate the presence of congestion but quantify the benefits of relieving it at different locations, which can be compared to costs of proposed transmission projects. Where renewable energy faces the risk of curtailment, low or negative prices result in nodal pricing differentials that can help to value the tradeoff between investing in transmission and allowing a certain level of curtailment.
- We have previously recommended that transmission developers earn market revenues for the capacity value and congestion management benefits of their projects, in order to encourage developers to propose creative and cost-effective solutions to policy goals.[17] Such measures would encourage experienced developers to carefully consider where congestion will actually occur and where the value of relieving it will be greatest, and to take risks associated with an uncertain future resource mix that would otherwise be borne by ratepayers.
- Where transmission bottlenecks can be resolved by individual generation owners, NYISO markets signal the value of such investments. For example, a transmission upgrade that relieves local congestion for a single generator could be undertaken or paid for by the owner of that project, who can evaluate whether the value of enabling incremental output justifies the cost and risks. A generation owner may also choose to invest in energy storage as a lower-cost alternative to new transmission, or a storage developer may find it profitable to invest at locations where it can absorb otherwise-curtailed energy from multiple projects.

[17] See MMU Review of NYISO's 2017 CARIS Phase I and Recommendation 2012-1c of the 2019 State of the Market Report for the New York ISO Markets.

III. Technical Appendix

A. LBMP Adjustment

We estimated a series of hourly day-ahead and real-time market prices for the 70x30 Case, using GE-MAPS production cost modeling output provided by NYISO and historical market data. Production cost modeling software such as GE-MAPS simulates economic dispatch of the system on an hourly basis and produces nodal and zonal LMPs as an output, but does not explicitly represent either the DAM or RTM.[18] In estimating prices for use in evaluation of generators' revenues and incentives, we adopted a methodology that relies on price levels and patterns from the 70x30 Case with adjustments to simulate prices in the DAM and RTM. We relied on the CARIS 70x30 Scenario Load HRM Method Case for 70x30 case output. This case includes 3,000 MW of energy storage and the estimated impacts of CLCPA policies on net demand.[19] We also used data from the 2017 Benchmark GE-MAPS case conducted by NYISO as discussed below. We used the following approach to estimate prices:

- We calculated a series of adjustment factors for each hour of the day within each month on a zonal basis (e.g. 12x24 adjustment factors for each zone). Adjustment factors are calculated as the ratio of historical average DA zonal LMPs for that month to LMPs from the 2017 CARIS Benchmark Case for the same month. Figure A-1 compares historical and MAPS benchmark data to illustrate how MAPS output prices, because they are not intended as a complete simulation of the DAM, tend to under-estimate variability in DA price patterns.
- We estimated DA LMPs in the 70x30 Case by multiplying LMPs from the 70x30 GE-MAPS case by the adjustment factors matching the same month and hour of day. We applied the same adjustments to all nodes within the same zone, so that the relationship between nodes within a zone is consistent with the 70x30 CARIS case. Figure A-2 shows the resulting change in price shape for an example month and zone. Estimated DA prices exhibit more diurnal variability than the underlying GE-MAPS output data.
- We estimated RT LMPs in the 70x30 Case by adjusting the 70x30 DA LMPs for hourly differences between RT and DA prices derived from 2017 historical data, in order to preserve a realistic pattern of random variability in the RTM.

[18] The GE-MAPS simulation used for the CARIS study does not include certain aspects of the DAM such as virtual bidding, price-capped load, generation and demand bid price, and Bid Production Cost Guarantee payments, and does not consider unscheduled forced outages of generation and transmission.

[19] NYISO conducted multiple cases including 3,000 MW of energy storage using alternative storage dispatch methods. Although there are limitations on the ability of production cost modeling software to simulate optimal dispatch of batteries in each case, we selected the HRM Method case for this analysis so that our results would approximately reflect the impact of storage on market prices.

Figure A-1: June 2017 Zone G Historical DA and GE-MAPS Benchmark LMP

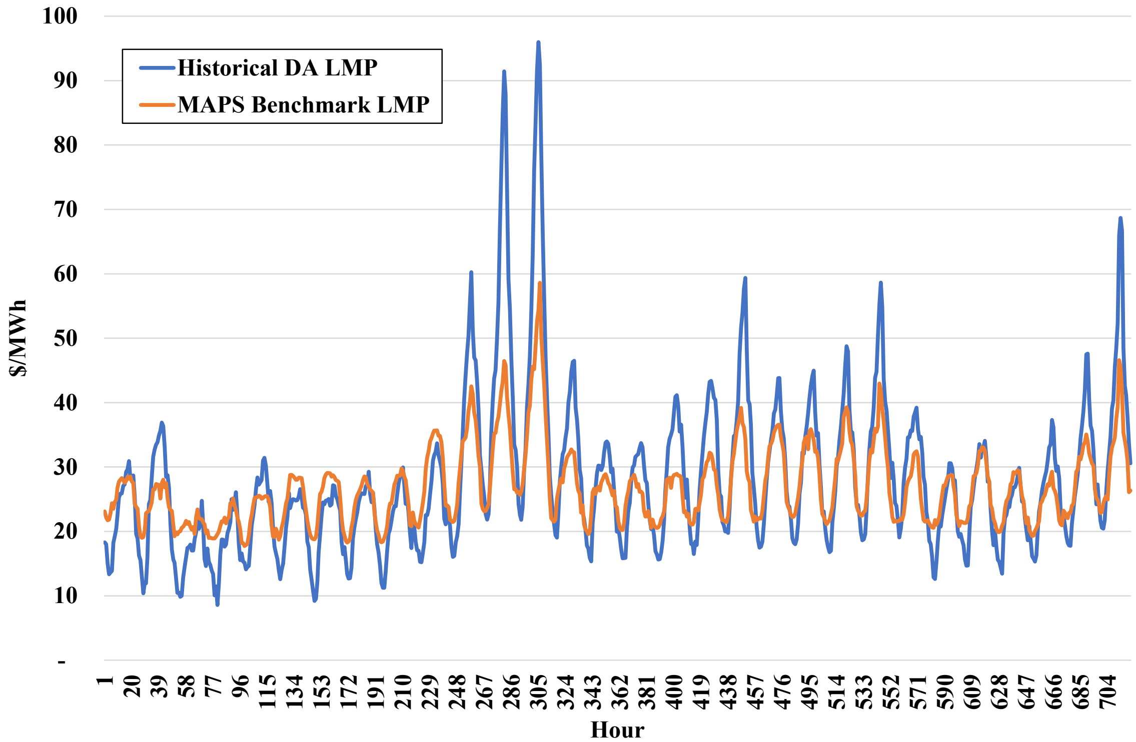
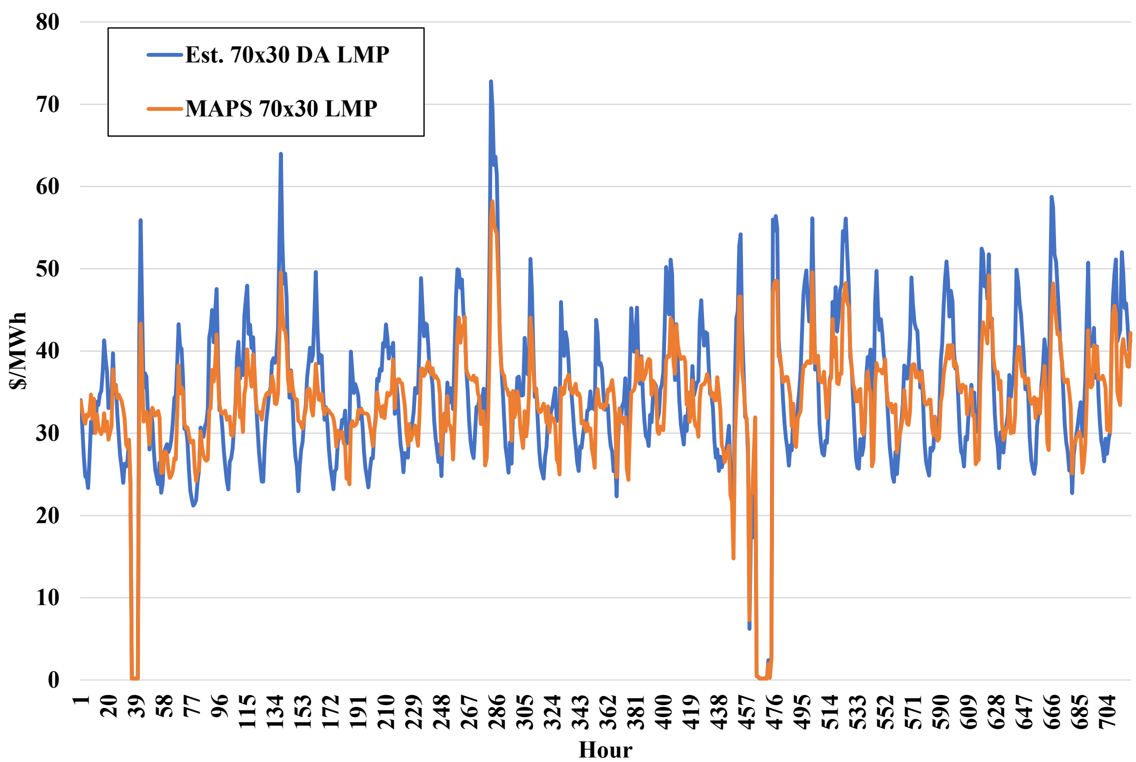


Figure A-2: June 2030 Zone G Estimated DA and GE-MAPS 70x30 Case LMP



B. List of Nodes Used in Analysis

We selected a subset of nodes throughout New York from the CARIS 70x30 Scenario Load case for our analysis. Nodes were chosen to represent a range of geographic locations and positions both upstream and downstream of constraints within generation pockets identified by NYISO in the CARIS study. Some are sites at which NYISO modeled additional intermittent renewables in the CARIS 70x30 Case, while others are existing generation bus sites. In Charts 3 through 8 of Section II, these locations are referred to by zone and ID number.

The table below shows details of nodal locations that were included in our study, including the zone and number by which the nodes are referred in other sections of this report, the identity of the node, and the amount intermittent renewable capacity that was added at that node in the CARIS 70x30 Scenario Load case. We also note location relative to generation pockets identified by NYISO in the CARIS 70x30 study.[20]

Table A-1: Locations Analyzed from 70x30 CARIS Case

Zone	Node Number	Location	Note	MW Added in 70x30 scenario Load Case		
				UPV	LBW	OSW
A	1	Niagara	Upstream of W1 constraints			
	2	Q545A_DY 345kV	Upstream of W1 constraints	1,105		
	3	DUNKIRK	Upstream of W3 constraints		256	
	4	STOLE345	Downstream of W1 constraints	483		
C	1	BENET115	Upstream of Z1 constraints	32	416	
	2	S.PER115	Upstream of Z1 constraints	71		
	3	Independence CC	Downstream of X3 constraints			
	4	Clay	Downstream of X3 constraints	349		
D	1	PATNODE	Upstream of X1 constraints.		436	
E	1	BLACK RV	Upstream of X3 constraints		488	
	2	EDIC 345kV	Downstream of X2 constraints	374		
F	1	STONER 115kV	Upstream of Y1 constraints	44		
	2	AMST 115	Upstream of Y1 constraints	239		
	3	MARSH115	Upstream of Y1 constraints	365		
	4	PRNCTWN	Downstream of Y1 constraints	653		
	5	Empire CC	Downstream of Y1 constraints			

[20] A map of generation pockets and constraints identified by NYISO in the 70x30 Case can be found here: https://www.nyiso.com/documents/20142/11738080/11_Preliminary_70x30_Scenario_Pocket_Map.pdf/af355880-a89c-68f5-1938-15409f73e0d8

Zone	Node Number	Location	Note	MW Added in 70x30 scenario Load Case		
				UPV	LBW	OSW
G	1	N.CAT. 1	Upstream of Y2 constraints	687		
	2	SHOEM138	Downstream of Y2 constraints	305		
	3	Cricket Valley	Downstream of Y2 constraints			
J	1	FRESH KI	Zone J wind interconnection			1,424
	2	GOWANUS	Zone J wind interconnection			1,456
	3	FARRAGUT	Zone J wind interconnection			1,440
	4	Ravenswood ST3	Existing NYC generator bus			
	5	Astoria GTs	Existing NYC generator bus			
	6	Gowanus 1-1	Existing NYC generator bus			
K	1	HOLBROOK	Zone K wind interconnection			880
	2	BRKHVEN3	Zone K wind interconnection			384
	3	EHAMP	Zone K wind interconnection			130
	4	RULND RD	Zone K wind interconnection			384
	5	Barrett GT1	Existing LI generator bus			

C. Renewable Units Net Revenues

Our methodology for estimating net revenues and the CONE for utility-scale solar PV and onshore wind units is based on the following assumptions:

- Net E&AS revenues are calculated using estimated real time energy prices.
- Technology and location-specific hourly capacity factors are derived from hourly energy production for the renewable units by location in the 2019 CARIS study.[21]
- The capacity revenues for solar PV, onshore wind, and offshore wind units are calculated assuming the capacity market clears at the Default Net CONE ("DNC") in 2030, equivalent to 75 percent of Net CONE. Net CONE values were taken from the preliminary 2019/20 ICAP demand curve reset study published by Analysis Group on June 4, 2020, adjusted for inflation through 2030.
    - The capacity values of renewable resources were assumed to be 20, 1, and 9 percent for Winter Capability Periods and 15, 18, and 14 percent for Summer Capability Periods for onshore wind, solar PV, and offshore wind, respectively.

[21] See, CARIS 70x30 Scenario Draft Report, available at: https://www.nyiso.com/documents/20142/12367529/09_2019_CARIS_DraftReport_70x30Section_ESPWG_TPAS_2020-05-01.pdf/664078c6-3d8d-8d72-753c-43a1152d7bd4. We scaled up the hourly capacity factors with the ratio of annual average capacity factor based on NREL ATB 2019 study and annual average capacity factor derived from CARIS 2019 study.

These values are based on estimates by the Brattle Group for a scenario with assumptions similar to the CARIS 70x30 scenarios.[22]

- We estimated the value of Index RECs using as a Strike Price (in $/MWh terms) minus the average monthly day-ahead LMP and the monthly spot capacity price (adjusted for resource capacity value and converted to $/MWh terms by dividing by monthly generation). Index REC values were calculated individually for each zone and resource type for utility-scale solar PV, onshore wind, and offshore wind units. We assumed a Strike Price equal to the CONE of each resource.
- Table A-2 shows cost estimates for solar PV, onshore wind and offshore wind units we used for a unit that commences operations in 2030. The data shown are largely based on NREL's 2019 Annual Technology Baseline.[23] The table also shows the capacity factor and capacity value assumptions we used for calculating net revenues for these renewable units. The CONE for renewable units was calculated using the financing parameters and tax rates specified in the preliminary 2020/21 ICAP demand curve reset study published by Analysis Group on June 4, 2020.

---

22 The Brattle Group, "Quantitative Analysis of Resource Adequacy Structures", May 29, 2020, http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={1363C680-F134-41F4-809B-7CF65AF8AD71}

23 See NREL, 2019, *Annual Technology Baseline and Standard Scenarios*, https://atb.nrel.gov/electricity/2019/index.html

The assumed investment costs and fixed O&M costs for solar PV, onshore wind and offshore wind are based on the 2019 NREL ATB (Mid) values. The DC investment cost for solar PV was converted to AC basis based on the assumed PV system characteristics as outlined in the CES Cost Study (see page 166 of the CES Cost Study). CONE calculation for offshore wind in NYC assumes zero city tax rate.

For onshore wind, US average investment costs were adjusted to New York conditions using technology-specific regional cost regional multipliers used in the EIA's AEO and the CES Cost Study. See "Capital Cost Estimates for Utility Scale Electricity Generating Plants", available at https://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capcost_assumption.pdf. Regional multiplier for solar PV was utilized from ReEDS input data used for the 2019 NREL ATB analysis.

The assumed investment cost trajectory over the years for onshore wind and solar PV units was assumed to follow the technology-specific CapEx trajectory specified in the 2019 NREL ATB.

The assumed investment cost estimates also include interconnection costs. Interconnections costs for wind and solar PV units can vary significantly from project to project. For upstate solar PV, onshore wind, and offshore wind the interconnection cost were sourced from NREL ATB 2019.

Table A-2: Cost and Performance Parameters of Renewable Units

Parameter	Utility-Scale Solar PV	Onshore Wind	Offshore Wind
Investment Cost (2030$/kW AC basis)	*Upstate NY*: $1437 *Long Island*: $1988	*Upstate NY*: $1778	*NYC/Long Island* : $4100
Fixed O&M (2030$/kW-yr)	$16	$50	$99
Federal Incentives	ITC (10%)	None	None
Project Life	20 years		25 years
Depreciation Schedule	5-years MACRS		
2030 Average Annual Capacity Factor	Upstate NY: 16% LI: 18%	Upstate NY: 40.0% LI: 44.0%	NYC/LI: 49%
Unforced Capacity Percentage	Summer: 18% Winter: 1%	Summer: 15% Winter: 20%	Summer: 14% Winter: 9%
Index Renewable Energy Credits	Calculated using CONE less energy and capacity prices.		

D. ESR Net Revenues

We estimated the net revenues for a 4-hour battery storage resource using the same estimated real time energy prices that were used to evaluate the renewable generators, so the LBMP-effects of the battery storage resources were not estimated. The battery storage dispatch model utilized the following assumptions:

- The hourly net revenues are determined using the real-time energy and ten-minute spin prices, and the resource's output as determined by its charge and discharge offers. The charge and discharge offers are strictly based on information that is publicly available 75 minutes before the scheduling hour (i.e., the development of offers does not assume perfect foresight). The method for setting offers is as follows:
    - The resource's hourly charge and discharge offers in the real-time market are each the product of two components: a) the minimum (for charging) or maximum (for discharging) of the DA prices for the remainder of the day, and b) an empirically estimated adjustment factor.
    - For all hours in a given month, we set the adjustment factors to equal the values that maximized profits in the prior month.[24] Our model uses separate adjustment factors for charge and discharge offers.
    - If the battery's state of charge as determined by the charge offers is not 100 percent by hour 17, we assume that the battery will start charging. Similarly, we assumed that if the battery's state of charge as determined by the discharge offers is not 100 percent by hour 21 then the battery will start discharging.
- We assumed that the battery would also earn additional revenues by selling 50 percent of its capacity as reserves in each hour from 10 to 17 in the Day Ahead market such that the

[24] For example, if the battery storage resource would have maximized EAS net revenues in the previous month by offering to sell energy at 130 percent of the forecasted maximum price, the resource will submit energy offers in the current month at 130 percent of the forecasted maximum price.

total quantity of reserve sales each day would be equal to its maximum potential state of charge (i.e., 4 MWhs per MW of capacity). The day-ahead and real-time reserve prices for 2030 were estimated as equal to 2017 prices plus inflation.

- The costs and operating characteristics of this unit are summarized in Table A-.

Table A-3: Operating Parameters and Cost of Storage Unit[25]

Characteristics	Storage
Capital Cost (2030$/kW)	*Upstate NY*: $1048
Fixed O&M (2030$/kW-yr)	*Upstate NY*: $26
Technology	Li-ion Battery
Service Life (Years)	20
Reserve Selling Capability	10-min spin
Roundtrip Efficiency	85%
EFORd	2%
Capacity Value	90%

25 Cost data for upstate region is sourced from 2019 NREL ATB. For regional adjustments to costs for other zones, we used the 2020/21 ICAP DCR zonal cost ratios.