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Assessing new transmission and energy storage in achieving increasing renewable generation targets in a regional grid

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HIGHLIGHTS

- Realistically-priced transmission upgrades are evaluated for a regional grid.
- Infrastructure needs for renewable generation targets between 50 and 80% are presented.
- Cost-benefits of renewable generation and integration measures are compared.

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ABSTRACT

This study evaluates generation, transmission, and storage capacity needs to achieve deep renewable energy penetration in a regional electricity grid with an average load of approximately 20 GW. Increasing renewable energy targets are analyzed to evaluate the effects of realistic regional transmission upgrade and energy storage cost assumptions on the cost-optimal mix of generation, transmission, and storage capacity. Contextual data is used for New York State's grid to examine how electricity generation from renewable energy resources (wind, water, and solar power) can meet between 50% and 80% of electricity demand. A central finding of the study is that when realistic transmission upgrade costs are assumed, new interzonal transmission and battery storage are not needed to cost effectively meet near-term renewable energy goals. In fact, New York can achieve 50% renewable energy penetration with only a buildout of new generation capacity: Onshore wind (13.7 GW), offshore wind (4.1 GW), and solar photovoltaics (3 GW). The presence of grid-scale battery storage, electric vehicles, or additional behind-the-meter solar capacity does not markedly change the model-selected generation mix. To achieve the 50% target, we compute a $52/MWh levelized cost of electricity for new renewable energy, which is in line with current generation costs.

As the renewable generation target increases beyond 50%, the model begins to select transmission upgrades and new storage capacity, the latter particularly if battery costs continue to decline as anticipated. At deeper targets, marginal generation capacity would otherwise experience high curtailment primarily due to supply–-demand imbalances; we calculate the value of energy storage at a 65% renewable energy penetration level to be 2.5–3 times higher than its value at a 50% level. However, the additional storage and generation – and transmission, to a lesser degree – needed to achieve longer-term renewable energy goals lead to a substantial rise in total investment. Between 50% and 55% targets, the computed marginal levelized cost of electricity for new variable renewable energy is $94/MWh, compared to $592/MWh between 75% and 80%, suggesting alternative integration measures are likely necessary at such high penetration rates.

Nomenclature

Note: All variables indexed by r vary by region; all variables indexed by t vary by time-step.

Fixed Variables and Parameters

AP	capital annualization rate for annualization period P
C_{batt}	battery storage capital cost [$/MWh]
C_{on}	onshore wind power capital cost [$/MW]
C_{off}	offshore wind power capital cost [$/MW]
$C_{trans,rr'}$	capital cost of upgraded transmission from region r to adjacent region r' [$/MW-mi]
$D^{t}_{elec,r}$	existing hourly electricity demand [MW]
$D_{ev,r}$	average hourly electric vehicle demand [MW]

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$d_{rr'}$	distance between region r and adjacent region r' [mi]
$H^t_{fix,r}$	fixed hydropower electricity generation [MW]
$H^{monthly}_{tot,r}$	total monthly hydropower electricity generation (fixed plus flexible) [MW]
i	interest rate
J_r	set of all onshore wind sites in region r
$L_{rr'}$	existing transmission flow limit between region r and adjacent region r' [MW]
l	transmission loss rate (constant for all transmission interfaces)
N^t_r	nuclear-generated electricity [MW]
P	annualization period [years]
RGT	renewable electricity generation target: Fraction of total demand that must be met by renewable energy (combined wind, water, and solar power)
R	set of all regions in study area
S^t_r	solar photovoltaic-generated electricity [MW]
T	total number of hourly time steps in analysis (T = 52608 for 6-year period simulated)
$W^t_{off,r}$	potential offshore wind-generated electricity [dimensionless, $MW_{generation}/MW_{installed}$]
$W^t_{on,r}$	potential onshore wind-generated electricity [dimensionless, $MW_{generation}/MW_{installed}$]
$\varepsilon^t_{fix,r}$	electric vehicle charge rate under fixed charging constraints [MW]
η	efficiency (applies to battery storage and electric vehicle charging)
Decision Variables	
E^t_r	aggregate energy storage state of charge [MWh]
$H^t_{flex,r}$	flexible hydropower electricity generation [MW]
NL^t_r	net load [MW]
$U^t_{off,r}$	utilized offshore wind-generated electricity [MW]
$U^t_{on,r}$	utilized onshore wind-generated electricity [MW]
$x_{on,j}$	capacity of onshore wind at site j [MW]
$X_{batt,r}$	total capacity of battery storage installed in region r [MWh]
$X_{off,r}$	total capacity of offshore wind installed in region r [MW]
$X_{on,r}$	total capacity of onshore wind installed in region r [MW]
$X_{trans,rr'}$	total capacity of new transmission from region r to adjacent region r' [MW]
$Z_{rr'}$	energy transmitted from region r to adjacent region r' [MW]
γ^t_r	increase in battery storage state of charge [MW]
δ^t_r	decrease in battery storage state of charge [MW]
$\varepsilon^t_{flex,r}$	electric vehicle charge rate under flexible charging constraints [MW]
Subscripts and Superscripts	
batt	battery storage
daily	daily
j	individual onshore wind site index
m	day index (ranges between 0 and $\frac{T}{24}-1$)
max	maximum
monthly	monthly
off	offshore wind
on	onshore wind
r	region
r'	region adjacent to r
t	hourly time step
trans	transmission

1. Introduction

The use of variable renewable energy (VRE) technologies to decrease fossil fuel usage and greenhouse gas (GHG) emissions is widely accepted [e.g. [1,2]]. However, the stochastic and intermittent nature of VRE supply is expected to require some suite of system integration measures at large installed capacities [3]. Such measures can include advanced grid monitoring, communication, and control [4]; expanded transmission capacity [5]; electrification of transportation and heating [6]; increased energy storage capacity [7]; and further interconnection among regional systems [8]. Two integration measures that could be achieved at large scale are the primary focus of this paper: expanded transmission and grid-scale battery storage.

Researchers looking at transmission dynamics have shown that increased transmission is more effective than battery storage at lowering wind power curtailment [9]; curtailment is almost entirely due to transmission constraints in some studies [10]. However, to ease computational requirements or to standardize across large geographic regions, many energy system models do not account for the full set of constraints that face new transmission projects, instead assuming (a) costs below historical rates [5,11], (b) idealized network topologies [12], or (c) unlimited interregional transmission capacity [13,14].

Previous analyses have modeled the ability of battery storage to improve VRE integration [15]. Storage is shown to be a valuable balancing asset at high VRE penetration levels, but its deployment is often not a cost-effective method of reducing curtailment; system benefits diminish with increased adoption [16] and integration can become largely a seasonal issue with large VRE capacities, particularly in the case of wind power [17]. To date, energy storage has largely been used to provide energy system services other than VRE supply shifting (e.g. regulation services and peak load reduction) [18]. Evaluating storage adoption and transmission expansion together, researchers have found that in a transmission-constrained system, energy storage at generation sites allows for greater renewable power utilization compared to storage at load centers [19]. Yet while co-locating storage with transmission bottlenecks has shown to be an effective method of integrating VRE, such practice can also reduce the economic viability of the batteries [20]. A previous study by two of this paper's authors further identified that large-capacity VRE supply variability is likely to be highest distant from the VRE resource; this finding implies distributed energy storage will have value for reliability services that may not be captured in capacity expansion models [21].

In this study, we evaluate the cost-effectiveness of these two integration measures (energy storage and transmission) to achieve renewable generation targets (RGTs) in New York State's (NYS) regional grid; the NYS grid aligns with the New York Independent System Operator (NYISO) control area. We perform simulations with and without electric vehicle (EV) adoption, as the presence of a sizable electric transportation load can influence how a system decarbonizes [22]. While this paper uses the NYS system as a case study, many states across the US have adopted RGTs [23], and all include some common characteristics: Spatially heterogeneous electricity demands, transmission line limits, potential for battery storage, and existing fossil fuel-based transportation that may shift to some proportion of electric vehicles during a larger energy transition. Therefore, the approach described here can be applied to any regional electric grid after adjusting for domain-specific topologies.

Previous work by two of the authors showed that up to 10 GW of onshore wind can be added to the NYS grid with minimal curtailment; beyond this point, curtailment is largely a seasonal issue with higher wind output and lower demand in the winter [24]. While this prior work identified transmission bottlenecks, it did not evaluate whether upgrades would be economical. A NYISO study evaluated the ability for NYS to integrate 8 GW of wind, finding that this capacity would have no adverse reliability impacts, would decrease total system costs, would result in less than 2% curtailment, and would create congestion only at local transmission facilities [25]; it remains to be seen whether these results hold at higher renewable penetrations. Similarly, large NREL studies investigated the integration of high levels of VRE in NYS as a portion of the larger Eastern Interconnection [13,14]. Yet these studies ignored intra-NYS transmission and did not quantify the cost-effectiveness of various flexibility measures. [11] considered the possibility of 100% decarbonization of all NYS energy infrastructure; however, in modeling the state's electricity grid, this study both ignored intrastate transmission limits and underestimated the costs of state-specific transmission expansion. The current paper addresses the above-mentioned gaps in previous NYS-specific work, and in doing so, presents a modeling framework translatable to other grid topologies.

This paper makes two principal contributions to the literature on VRE integration. First, it examines the cost-effectiveness of transmission expansion in a regional grid with price assumptions based on historical projects. Related renewable penetration studies [5,11] have understated the cost of transmission expansion, especially near high-density load zones. Second, our work appraises the need for particular types of infrastructure along a pathway of near- to long-term RGTs. By evaluating cost-effective methods of meeting more immediate goals, and then by comparing these results to those for more distant renewable energy objectives, we investigate optimal energy planning decisions at various stages in the transition of an electricity grid. Other contributions include substantiating the value of offshore wind generation in a transmission-constrained system with coastal load pockets and quantifying the value of battery storage at increasing renewable targets.

The structure of the paper is as follows: *System Topology* (Section 2) discusses NYS RGTs and relevant characteristics of the NYS electricity grid. *Methodology* (Section 3) details the data sources utilized and the development of the Renewable Target Model, the study's primary analytical tool. *Results* (Section 4) presents relevant figures and findings. *Discussion* (Section 5) unpacks what the results mean for meeting RGTs and how policy can best support near- and long-term goals in NYS and other regional systems. *Conclusion* (Section 6) summarizes the most salient aspects of the study.

2. System topology

NYISO manages New York State's electricity grid. The NYISO control area shares boundaries with NYS and is divided into 11 load zones. For the purposes of the present study, we group these zones into the four regions shown in Fig. 1 based on major transmission interfaces.

Region 1 (NYISO Zones A-E) produces 91% of the state's hydropower electricity and 64% of its nuclear-generated electricity, while accounting for only 34% of statewide demand [26]; this region also contains 86% of the state's potential onshore wind power capacity [14]. Region 2 (NYISO Zones F and G) holds the remaining 9% of hydropower supply and 13% of the state's electricity demand [26]; this region contains 10% of the state's potential onshore wind capacity [14]. In contrast, the two remaining downstate regions (NYISO Zones H-J, designated Region 3, and Zone K, designated Region 4) account for 51% of NYS electricity demand [26] but offer little potential onshore renewable capacity [14]; however, there is abundant undeveloped offshore wind power potential adjacent to these areas, and NYS (and nearby states) has begun incentivizing its deployment [27]. Region 3, which includes the New York City metropolitan area plus Westchester County, does include one nuclear power plant; however, this plant is slated to be decommissioned in 2021, so we do not include it in this study.

Bulk transmission of electricity in NYS primarily follows a west-to-east pathway from Buffalo to Albany, and then changes to a north-to-south orientation, connecting Region 2 to Region 3. Approximately 1.4 GW of transmission capacity exists at the interface of Regions 3 and 4 [28]; however, because of high electricity demand in Region 3, these transmission lines are infrequently loaded. In 2016, NYS obtained 19% of its electricity from hydropower (86% from instate generation, 14% from imports from Quebec and Ontario), 31% from nuclear power, and 4% from wind and solar, resulting in one of the lowest carbon-intensity fuel mixes in the country [14,26,29]. The fossil fuel-based generation fleet in NYS is composed of primarily natural gas-fired plants that are well dispersed throughout the state, generally near the loads as required by NYISO [30]. Because of this distribution, in-region dispatchable generation generally satisfies loads not met by low-carbon resources (VRE, hydropower and nuclear power) [31].

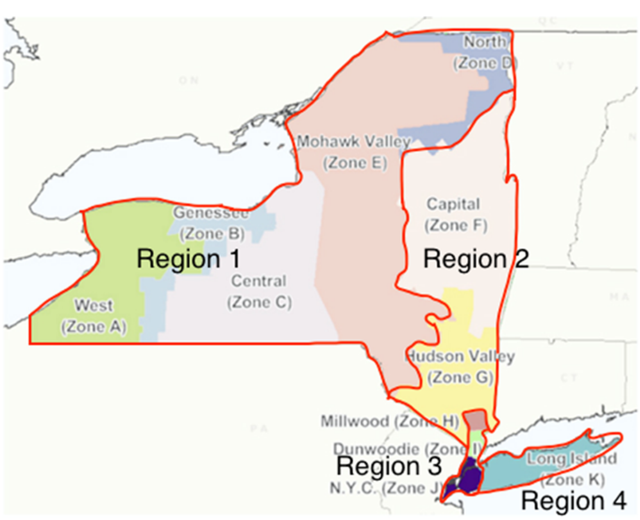

Fig. 1. NYISO control area load zones [26]. Region boundaries by authors.

Table 1 summarizes relevant regional data: Average demand, average generation from fixed capacity sources (i.e. nuclear, solar PV and hydropower), maximum potential wind capacity (see Section 3.3), and average EV load assuming 25% electric vehicle adoption (see Section 3.5). The processes for determining these quantities are detailed in *Methodology*.

To evaluate the effect of transmission prices on future energy scenarios, we reviewed the costs of recent and proposed transmission projects in NYS, as well as the cost assumptions used in other studies. The reported costs for recent NYS projects align with the high-cost estimates used in this study [32–35]. Low-cost estimates come from a combination of previous integration model assumptions and comparisons to the high-cost prices. [5] estimates a cost of \$1400/MW-mi for a line length of 300 miles; [13] assumes a cost of \$4173/MW-mi for 345 kV cables and supporting substation and transformer improvements. These references do not account for the unusually high costs of large-scale transmission in densely populate areas (e.g. Regions 3 and 4 in the present study). Table 2 summarizes the results of this process and shows transmission upgrade costs in \$/MW-mi for comparison.

In 2010, the NYS Public Service Commission established a 30% renewable energy (wind, water, and solar power; abbreviated as WWS) target to be met by 2015 [36]. While the state has not yet achieved the 30% RGT (28% of generation in 2017 [37]), [24] demonstrated that a build out of onshore wind power without additional integration measures would be sufficient to reach this level of renewable energy penetration. In 2016, NYS accelerated its clean energy goals, adopting a 50% RGT for 2030 [38].

3. Methodology

This section describes the formulation and assumptions of the Renewable Target Model (RTM), a mixed integer linear program (MILP) that minimizes the total system capital investment necessary to meet a RGT. The model is optimized over a 6-year time period (2007–2012) selected based on data availability; unless otherwise noted, all data described here applies to this time period. The RTM is formulated in Python [39] and solved in Gurobi [40] on a 16C GeForce GTX Titan Black GPU with 32 GB of RAM.

3.1. Objective function and net load constraints

The objective function for the RTM (Eq. (1)) minimizes total system investment based on the per-unit capacity cost, C, and installed capacity, X, of onshore wind generation ("on"), offshore wind generation ("off"), grid-scale battery storage ("batt"), and new interregional transmission capacity ("trans") between each region r and adjacent region r'. The distance between each region r and r' is defined by $d_{rr'}$. All costs, C, are annualized over with their respective capital annualization rates and then summed over the 6-year optimization period.

Table 1
Summary of relevant NYISO regional data and model parameters.

Region	Average Regional Electric Demand and Nuclear-Solar-Hydro Generation (MW)					Maximum Wind Capacity (MW)		Average EV Load (MW)
	Demand[1]	Nuclear[2]	Solar PV[3]	Hydro[4]		Onshore Wind[5]	Offshore Wind[6]	25% Adoption[7]
				Fixed	Flexible			
1	6382	3026	120	2395	328	32,406	0	519
2	2495	0	167	0	270	4376	0	249
3	7211	0	74	0	0	0	37,572	341
4	2566	0	85	0	0	0		292

[1] Average 2007–2012 electricity demand [26].
[2] Average 2016 nuclear generation, excluding soon-to-be decommissioned facility [26].
[3] 3 GW solar capacity distribution, per [62].
[4] See Section 3.2.
[5] Maximum potential onshore wind capacity, per [14].
[6] Maximum potential offshore wind capacity for installations at water depths < 60 m [45]; see Section 3.3.
[7] Average EV load given 25% electric vehicle adoption as described in Section 3.5.

Table 2
Summary of transmission interfaces.

Regional Interface	Distance[1] (miles)	Current Limits[2]		Low Cost Estimates $/MW-mi	High Cost Estimates $/MW-mi
		W→E (MW)	E→W (MW)		
1: Region 1 → 2 (Buffalo to Albany)	300	4925	3400	1600[3]	3200[4]
2: Region 2 → 3 (Albany to NYC)	150	5750	2000	3200[5]	6400[6]
3: Region 3 → 4 (NYC to Long Island)	60	1424	120	8000[7]	16,000[8]

[1] Interregional distance ($d_{rr'}$) calculated via Google Maps and rounded to the nearest 10 miles.
[2] Current line limits ($L_{rr'}$) ascertained from [63].
[3] From [5], for line length of 300 miles, approximately $1400/MW-mi (aboveground HVDC). After conversion, [11] assumes a cost of $2056/MW-mi for a 300-mile line.
[4] From [32], after subtracting upgraded substation costs, approximately $3614/MW-mi (underground HVDC).
[5] From [13], approximately $4173/MW-mi for overhead 345 kV and supporting transformer and substation reinforcements.
[6] From [33], approximately $6567/MW-mi (underground HVDC). Because of the unique challenges facing the referenced project, we assume ½ the cost of [33] for our low-cost scenario, a quantity more closely in line with the cost estimate from [13] after subtracting the latter estimate's transformer and substation reinforcement costs.
[7] Because of the unique challenges facing transmission projects in densely populated areas and the lack of low cost estimate for such projects, we assume ½ the cost for the Region 3–4 transmission high cost scenario
[8] From [34,35], approximately $13,986/MW-mi (underground HVDC).

$$\text{minimize} \sum_{r\in R}\left[C_{on} * X_{on,r} + C_{off} * X_{off,r} + C_{batt} * X_{batt,r} + \sum_{r'} C_{trans,rr'} * d_{rr'} * X_{trans,rr'}\right] \tag{1}$$

Model constraints for regional net load, onshore and offshore wind utilization, and interregional transmission are shown in Eqs. (2)–(10). Unless otherwise stated, all constraints apply for all time steps, t, in T and for all regions, r, in R.

The metric of "net load" is used throughout the analysis; the net load is the remaining electricity demand after using low-carbon resources (i.e. VRE, hydropower and nuclear power). Eq. (2), below, defines net load, NL_r^t, for each region, r, at each time step, t. Eq. (2) includes five exogenously-defined variables: Existing electricity demand, $D_{elec,r}^t$; nuclear generation, N_r^t; solar generation, S_r^t; fixed hydropower generation, $H_{fixed,r}^t$; and fixed electric vehicle charging, $\varepsilon_{fixed,r}^t$. The RTM also uses the following decision variables: Flexible hydropower generation, $H_{flex,r}^t$; utilized onshore wind energy, $U_{on,r}^t$; utilized offshore wind energy, $U_{off,r}^t$; increase in battery state of charge (i.e. battery charge), γ_r^t; decrease in battery state of charge (i.e. battery discharge), δ_r^t; flexible electric vehicle charging, $\varepsilon_{flex,r}^t$; electricity exported to an adjacent region, $Z_{rr'}^t$, and electricity imported from an adjacent region, $Z_{r'r}^t$. The model assumes transmission losses, l, of 3% between adjacent regions and applies them to the imports; this is not meant to provide a definitive transmission loss model, but it ensures that electricity is first used to meet demand nearest the region in which it is generated.

$$NL_r^t = D_{elec,r}^t - N_r^t - S_r^t - H_{fixed,r}^t + \varepsilon_{fixed,r}^t - H_{flex,r}^t - U_{on,r}^t - U_{off,r}^t + \gamma_r^t - \delta_r^t + \varepsilon_{flex,r}^t + \sum_{r'}\left[Z_{rr'}^t - (1-l) * Z_{r'r}^t\right] \tag{2}$$

Eqs. (3)–(5) impose electricity utilization limits and site capacity constraints for the onshore wind generation. Onshore wind power capacity, $x_{on,j}$, is installed at individual sites, j, selected from all sites within a region, J_r; the aggregate regional onshore wind power capacity is defined as $X_{on,r}$. Each onshore wind site is defined by a potential wind-generated electricity output at each time step, $W_{on,j}^t$.

$$U_{on,r}^t \le \sum_{j\in J_r} x_{on,j} * W_{on,j}^t \tag{3}$$

$$x_{on,j} \le x_{on,j}^{max} \tag{4}$$

$$\sum_{j\in J_r} x_{on,j} = X_{on,r} \tag{5}$$

Eqs. (6) and (7) similarly constrain offshore wind power. The regional offshore wind power utilization at each time step, $U_{off,r}^t$, is limited by the product of the region's installed capacity, $X_{off,r}$, and potential wind-generated electricity output, $W_{off,r}^t$. The total offshore wind power capacity across all regions is limited by the maximum potential offshore wind capacity for the state[1], X_{off}^{max}.

$$U_{off,r}^{t} \le X_{off,r} * W_{off,r}^{t} \tag{6}$$

$$\sum_{r \in R} X_{off,r} \le X_{off}^{max} \tag{7}$$

Eq. (8) restricts the amount of electricity transmitted between regions, $Z_{rr'}^{t}$, to the sum of existing transmission limits, $L_{rr'}$, and new transmission capacity, $X_{trans,rr'}$:

$$Z_{rr'}^{t} \le L_{rr'} + X_{trans,rr'} \tag{8}$$

Eq. (9) is the domain constraint:

$$All\ variables \ge 0 \tag{9}$$

The RTM characterizes renewable generation as that from wind, water, and solar (WWS), consistent with NYS policy targets as well as generally accepted definitions of renewable energy. For a given renewable generation share of statewide electricity (*RGT)*, the model requires that this fraction of the demand be met by WWS (accounting for transmission losses):

$$\sum_{t \in T}\sum_{r \in R}\left[S_r^t + H_{fixed,r}^t + H_{flex,r}^t + U_{on,r}^t + U_{off,r}^t - \sum_{r'} l * Z_{r'r}^{t}\right] \ge RGT * \sum_{t \in T}\sum_{r \in R}[D_{elec,r}^t + D_{ev,r}] \tag{10}$$

The model does not include capital and operational costs for fossil fuel-based electricity generation. While these costs may constitute a substantial portion of overall system expenditures, we do not expect that they would significantly affect the renewable energy generation mix for a particular RGT. There is a body of work, including by the present study's authors, that investigates reliability services in addition to energy services; for example, our earlier analysis of large capacities of wind power in NYS indicated that operating reserve and regulation requirements could increase in magnitude and become more concentrated near load centers where large dispatchable thermal generation capacity already exists [21]. By tailoring the focus of the RTM, we explore the primary costs and infrastructure planning challenges of renewable energy only, filtering out downstream concerns about how other grid actors will respond to system change. We therefore do not consider how the internal economics of individual market participants will influence future bids or retirements; we do not expect this to be significant for transmission or storage expansion in the context of deep VRE penetration.

3.2. Hydropower

We do not explicitly model hydropower reservoirs; NYS has over 300 individual hydropower stations. Instead, we rely on a method we investigated in detail in a previous study [41]. Actual monthly hydropower output by facility [42] is aggregated at the regional level to produce total regional monthly hydropower output, $H_{tot,r}^{monthly}$. As shown in Eq. (2), the RTM includes both fixed hydropower (defined exogenously, it varies in time and by region) and flexible hydropower (limited regional daily energy, but with intraday flexible output limited by regional maxima). This basic formulation is adaptable to many approaches to hydropower; here, we assume that in each region some fraction of the total regional hydropower output, is fixed, $H_{fix,r}^{monthly}$. In New York, the two largest hydroelectric plants (both in Region 1) operate near their maximum possible outputs given available stream flows. As such, we treat these facilities as fixed hydro. The resulting proportion of hydropower considered fixed is 88% of $H_{tot,1}^{monthly}$ (Region 1) and 0% of $H_{tot,2}^{monthly}$ (Region 2); Regions 3 and 4 contain no hydropower at all. We fit a cubic spline function to $H_{fix,r}^{monthly}$ to determine the regional hourly fixed hydropower output, $H_{fix,r}^{t}$. The cubic spline ensures continuity and smoothness between time steps.

As NYS hydropower exhibits a degree of load-following behavior that is generally diurnal with some additional storage capabilities, we designate the remaining portion of hydropower output as the total regional monthly flexible hydropower generation, $H_{flex,r}^{monthly}$. The resulting proportion of hydropower considered flexible is 12% of $H_{tot,1}^{monthly}$ (Region 1) and 100% of $H_{tot,2}^{monthly}$ (Region 2). We fit a cubic spline function to $H_{flex,r}^{monthly}$ to determine regional daily flexible hydropower, $H_{flex,r}^{daily}$. As above, the cubic spline ensures continuity and smoothness across the time series.

For the purposes of the present study – and as recently investigated by the authors in more detail in [41] – the hourly flexible hydropower output by region, $H_{flex,r}^{t}$, is subject to the constraint that it must meet a daily total regional flexible hydropower output, $H_{flex,r}^{daily}$, without exceeding aggregate regional flexible hydropower capacity, $H_{flex,r}^{max}$. Eqs. (11) and (12) impose these limitations.

$$\sum_{t=1+24m}^{24*(m+1)} H_{flex,r}^{t} = H_{flex,r}^{daily}, \quad \text{for } m = 0..\frac{T}{24} - 1 \tag{11}$$

$$H_{flex,r}^{t} \le H_{flex,r}^{max} \tag{12}$$

The resulting regional, fixed and flexible hydropower generation averages are shown in Table 1 (Section 2).

3.3. Variable renewable energy potentials

In simulating capacities of onshore wind power far exceeding current levels, the authors rely on model wind power data for 126,000 potential U.S. wind sites developed by National Renewable Energy Laboratory (NREL) [43,44]. In a previous study, two of the authors found the NREL model consistently to over-predict the electricity generation at existing onshore wind power sites in NYS and developed a procedure to adjust the time series to reflect actual output [24]; the resulting hourly potential onshore wind power output by site (normalized by installed capacity), $W_{on,s}^{t}$, is used in the current study.

The same NREL database provides hourly model offshore wind power outputs for sites near Regions 3 and 4. Because no method of independently verifying the offshore wind generation estimates exists and because the model capacity factors at those locations more closely reflect the performance of global offshore wind installations, we make no additional modifications to these time series for the hourly potential offshore wind power output by region, $W_{off,r}^{t}$. We assume that generation from the westernmost sites make landfall in Region 3 and that generation from the easternmost sites make landfall in Region 4. As existing literature has only placed an upper bound on the total potential offshore wind capacity in NYS waters, this paper limits the combined offshore capacity of both regions to 37.6 GW for water depths less than 60 m, per [45].

To determine the potential solar resource in each region, we first select a representative city for each NYISO zone from those in the NREL National Solar Radiation Database [46]. We then compute hourly potential solar PV output, normalized by capacity, using the NREL System Advisor Model (SAM) [47]. SAM simulates the performance of commercially available equipment and realistic system configurations; we select PV panels with 22% efficiency, installed with fixed tilt equal to location latitude and with an inverter with 95.3% weighted efficiency (as determined by the protocols of the California Energy Commission [48]). Because of its cost and potential production relative to wind power in NYS, model simulations do not select any solar PV capacity in cost-optimal infrastructure mixes for near- and medium-term RGTs.

To account for the reality that solar installations will almost

[1] For all potential installations at water depths less than 60 m [28]. Note that offshore wind power is only available for Regions 3 and 4; the total capacity is used here as it is not yet clear where offshore transmission lines will make landfall.

Table 3
Wind and Storage RTM Capital Costs.

	Unit Cost ($)		Unit	Capital Annualization Period (Years)
	High Cost Scen.	Low Cost Scen.		
Onshore Wind[1]	1588	1588	kW^{-1}	20
Offshore Wind[2]	4644	3754	kW^{-1}	20
Battery Storage[3]	250	100	kWh^{-1}	10

[1] Onshore wind costs assembled from [54,55].
[2] Offshore wind costs assembled from [45,54–56].
[3] Battery costs assembled from [57,58].

certainly continue to grow in NYS, we impose behind-the-meter solar PV capacities of either 3 GW or 6 GW in all model optimizations. These capacities are distributed to NYISO zones in proportion to projected zonal capacity distributions from a recent NYISO study [44]. The products of the non-dimensional hourly zonal potential solar-generated electricity and the zonal solar capacity are then aggregated at the regional level to produce the regional hourly solar-generated electricity output, S_r^t. Table 1 (Section 2) presents the average regional generation for 3 GW of installed capacity.

3.4. Battery storage treatment

Standalone battery storage in the RTM is assumed to have 95% efficiency in charging and discharging. The battery power-to-energy ratio is (1 kW):(4.2 kWh), a specification equivalent to that of an available commercial-scale battery storage product [49]. As this specification is based on usable storage capacity, we place no limitations on the battery depth of discharge; we also do not constrain cycling behavior aside from the charge/discharge limits imposed by the power-to-energy ratio and formalized in Eq. (13). The RTM treats regional storage as a lumped capacity, and at all times limits the energy stored in a standalone battery, E_r^t, to less than its capacity, $X_{batt,r}$. After accounting for battery efficiencies, the hourly change in battery energy level is equal to the battery charge or discharge. Eqs. (14) and (15) govern these relationships.

$$\gamma_r^t + \delta_r^t \le \frac{1}{4.2} * X_{batt,r} \tag{13}$$

$$E_r^t \le X_{batt,r} \tag{14}$$

$$\frac{\delta_r^t}{\eta} - \eta * \gamma_r^t = E_r^{t-1} - E_r^t \tag{15}$$

In addition to including battery storage capacity as a decision variable in the cost minimization, we also impose different amounts of battery storage capacity in certain model scenarios to investigate its distribution and value in reducing VRE capacity needs.

3.5. Electric vehicle charging constraints

In the RTM, EV load is specified as a percent of statewide automobile use, as determined by reported gasoline consumption quantities. We use 2015 NYS annual gasoline sales by county, aggregated by region, to determine the annual quantity of energy used for automobile transport [50]. After accounting for standard electric and gasoline-engine vehicle efficiencies (24.7 MPG [51], 0.36 kWh/mile [52]) and a charging efficiency (η = 95%), we convert the annual quantity of gasoline sold to average hourly regional electric loads, $D_{ev,r}$. $D_{ev,r}$ for the 25% EV adoption scenario is shown in Table 1 (Section 2).

Many studies have investigated the system benefits of flexible EV charging in a variety of domains, each with particular constraints [e.g. 20]. Here, we look at one fairly straightforward charging regime, in which we investigate both fixed and flexible charging. The purpose of the current study is not to determine an optimal EV charging strategy, but to evaluate how charging flexibility impacts VRE capacity selection and the value of other large-scale integration measures.

In fixed charging scenarios, the RTM distributes daily EV load, $D_{ev,r}^{daily}$ ($D_{ev,r}^{daily} = 24 * D_{ev,r}$), evenly over the hours between 7 pm and 6am (inclusive), leaving twice the hourly EV load at each. In flexible charging scenarios, the model meets the daily EV load over these same hours. By assuming that EV charging operates on a daily cycle, and that the model needs to meet charging requirements by 7 am, this methodology aligns with others found in the literature [e.g. [53]]. The RTM imposes fixed and flexible charging conditions through Eqs. (16)–(18), respectively. Maximum charging capacity is limited to one quarter the daily EV load.

$$\varepsilon_{fixed,r}^t = \frac{D_{ev,r}^{daily}}{12}, \text{ for } t = 19 + 24m \text{ to } 6 + 24(m+1), \text{ where } m = 0..\frac{T}{24} - 1 \tag{16}$$

$$\sum_{t=19+24m}^{6+24(m+1)} \varepsilon_{flex,r}^t = D_{ev,r}^{daily}, \quad \text{for } m = 0..\frac{T}{24} - 1 \tag{17}$$

$$\varepsilon_{flex,r}^t \le \frac{D_{ev,r}^{daily}}{4} \tag{18}$$

3.6. Capital cost assumptions

While renewable energy infrastructure cost projections abound, to limit computational requirements and the model solution set, we restrict the analysis to two capital cost scenarios. The high-cost scenario simulates prices similar to those currently available [54–58]. The low-cost scenario assumes the presence of an accelerated learning curve for offshore wind power and standalone battery storage. Cost assumptions for both scenarios are shown in Table 3.

In both cost scenarios, the price of onshore wind power remains constant; further cost declines in onshore wind power are likely to be less significant than those for offshore wind power and batteries [54,55]. We do not expect this assumption to alter our conclusions as these cost assumptions largely only influence tradeoffs between onshore and offshore wind (this may be analogous to onshore wind vs. solar tradeoffs in other regions of the United States). After first exploring optimization sensitivity to transmission costs (Section 4.1.1), we take the price of new transmission capacity to be the average of the low-cost and high-cost estimates presented in Table 2 with an annualization period of 20 years.

The RTM annualizes capital costs based on a capital annualization rate, A_P. A_P is computed as follows, with a 5% interest rate, i, over the equipment's annualization period, P:

$$A_P = i * (1 + i)^P / ((1 + i)^P - 1) \tag{19}$$

3.7. Treatment of system costs, savings, and marginal LCOEs

Total system costs are calculated over a 20-year period. For the types of infrastructure with a 20-year annualization period (wind generation and transmission), we multiply the costs given in Table 3 by the capacities returned by the model. For battery storage, with an assumed 10-year lifetime, we include twice the quantity of batteries selected by the optimization in order to calculate the storage costs over a 20-year horizon. To determine the marginal levelized cost of electricity (LCOE) for a given RGT, we take the marginal total system cost compared to the previous RGT and annualize this difference per Eq. (19). This annual value is then divided by the difference between the average annual renewable electricity generated at the given RGT and at the previous RGT to compute the marginal LCOE.

In certain simulations, we impose a no-cost, system-wide battery storage capacity and compare the computed total system cost to that computed for the same RGT without battery storage. The difference between the two quantities, the “avoided capital cost,” is considered the total battery storage value. However, the battery storage lifetime is shorter than that of other infrastructure investments considered. To determine the value of a unit of energy storage ($/kWh) for a given RGT, the avoided capital cost is standardized with the following equation:

$$Storage\ Value = \frac{Avoided\ Capital\ Cost}{Storage\ Capacity * \left(\frac{20\ years}{Storage\ Lifetime}\right)} \tag{20}$$

In addition to the 10-year battery lifetime described above, we also considered a battery lifetime based on 3000 cycles equivalent usage. We present system savings in both scenarios as future battery lifetimes are not yet known [59].

4. Results

This section begins with a detailed investigation of the computed mix of energy infrastructure to meet the 50% RGT (Section 4.1). We then extend the analysis to evaluate continuing trends up to an 80% RGT (Section 4.2), the upper limit of electricity sector decarbonization that researchers believe achievable in the US without notable increases in LCOE [5,12].

4.1. The 50% renewable generation target

Regional resource potentials and interregional transmission limits heavily influence the cost-optimal mix of energy infrastructure needed to meet the 50% RGT. As such, it is helpful first to understand regional generation and interregional flow dynamics under two divergent scenarios: (a) one with existing transmission limits, and (b) one with nearly-unlimited transmission. (Nearly unlimited transmission is simulated by solving the RTM with an assumed upgrade cost of 1/20th the low-cost transmission estimates.) Fig. 2 summarizes the average NYS electricity load, utilized low-carbon generation (WWS plus nuclear), and interregional electricity flow for these two cases.

Fig. 2 shows that, regardless of transmission assumptions, the bulk of NYS low-carbon energy generation occurs in Region 1. As presented in Table 1, Region 1 contains the entirety of the state's simulated nuclear generation, 91% of the state's hydropower generation, and 81% of the state's potential onshore wind power capacity. The model-selected onshore wind capacity in Region 2 is that region's total potential capacity and remains constant in both transmission scenarios. Two factors drive this result: (1) Potential wind power in Region 2 has a higher capacity factor than in Region 1, and (2) Region 2 is nearer to load centers in NYC and Long Island, so new generation does not congest the upstream Region 1–2 transmission interface.

The principal difference between scenarios is the tradeoff between Region 1 onshore wind and offshore wind in Regions 3 and 4. Without transmission upgrades, 5076 MW of offshore wind capacity is installed in Regions 3 and 4, providing 91% of aggregate low-carbon electricity generated in those two regions. Relaxing transmission constraints results in approximately double the total existing statewide transmission capacity, an additional 8486 MW onshore wind capacity in Region 1,

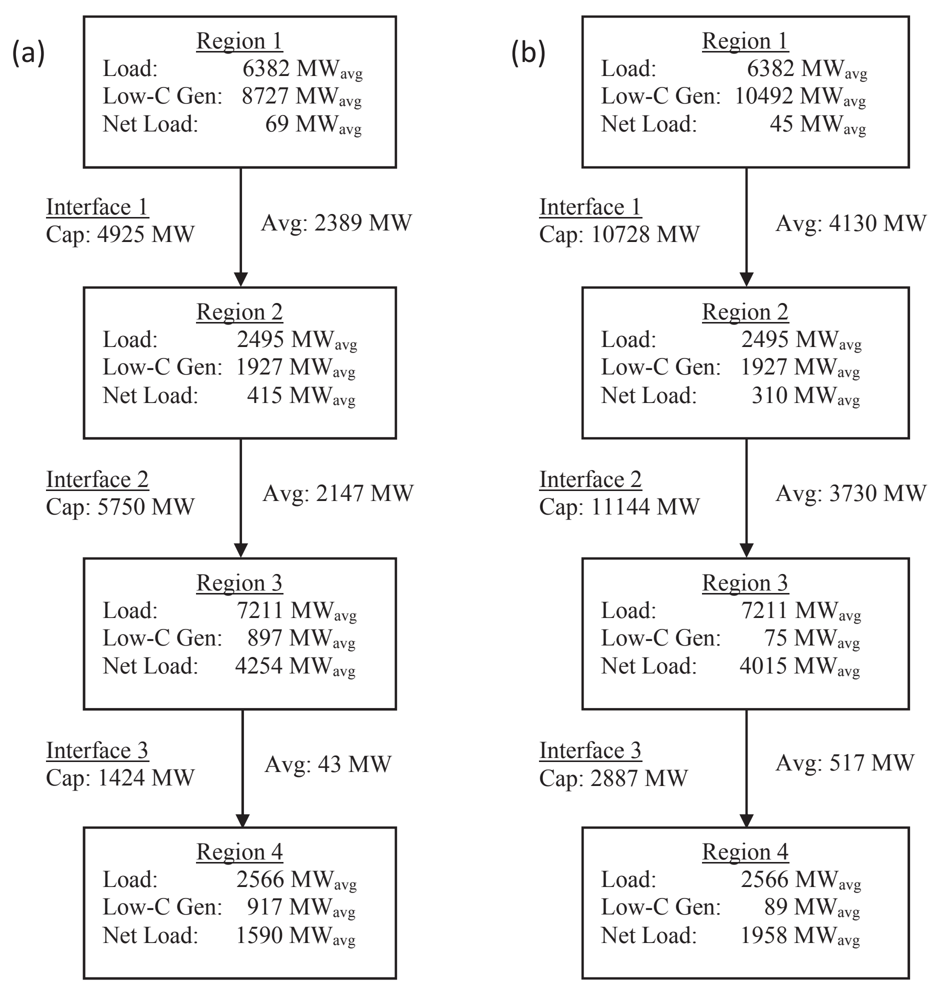

Fig. 2. Select simulated system characteristics under a 50% renewable generation target: (a) existing transmission limits; (b) nearly-unlimited transmission. Low-carbon generation averages include 3 GW of solar capacity. All values in regional boxes are averages.

and no offshore wind power. The sensitivity of the onshore vs. offshore wind capacity selection to transmission upgrades motivates a more detailed analysis of model cost assumptions.

4.1.1. Transmission expansion

Increasing transmission costs result in the model selecting less additional transmission capacity to accommodate (less expensive) onshore wind power, instead calling for increasing amounts of (more expensive) offshore wind power. Fig. 3 shows the computed optimal mix of offshore wind, onshore wind, and new transmission capacity for the 50% RGT for a range of transmission costs and two offshore wind cost scenarios. Transition capacity expansions at each interface are added (in MW) even though distances between regions vary. Although transmission costs are generally considered in units of $/MW-mi, the assumed values in Table 2 result in equivalent transmission cost upgrades in $/MW at each interface. Therefore, relative comparisons of new transmission capacities at different transmission cost estimates is equivalent to relative comparisons of total investment in transmission upgrades.

In all simulations, transmission capacity additions are selected only in the West-to-Southeast direction; specifically, this means transmission capacity additions are limited to (a) Region 1 to 2, (b) Region 2 to 3 and (c) Region 3 to 4. For comparison, we include very low transmission costs, shaded gray, which are not realistic in NYS but are on the order of assumptions used in other studies.

Fig. 3 shows that the cost-optimal generation mix is highly dependent on the price of transmission in the unrealistic cost range (until 1x the low-cost estimates). After this point, when transmission costs reach more realistic levels, the computed amounts of onshore and offshore wind capacity plateau, as new transmission is no longer selected as a cost-effective integration measure. Moreover, Fig. 3 demonstrates the influence of offshore wind costs on the mix of wind capacity selected to meet the 50% RGT. In the low offshore wind cost scenario, offshore wind capacity increases more quickly at lower transmission prices and levels out at a higher quantity than in the high-cost scenario. Here, an increase in offshore capacity displaces a larger capacity of onshore wind, due to the higher relative capacity factor of offshore wind turbines.

Given that (1) we estimate new transmission in NYS to cost *at least* 1x the low-cost estimates presented in Table 2 and (2) that offshore wind capacity costs will likely decrease to lower, internationally-competitive rates [60], the model behavior shown in Fig. 3 implies that the most cost-effective method of meeting the NYS 50% renewable generation target may include no new interregional transmission.

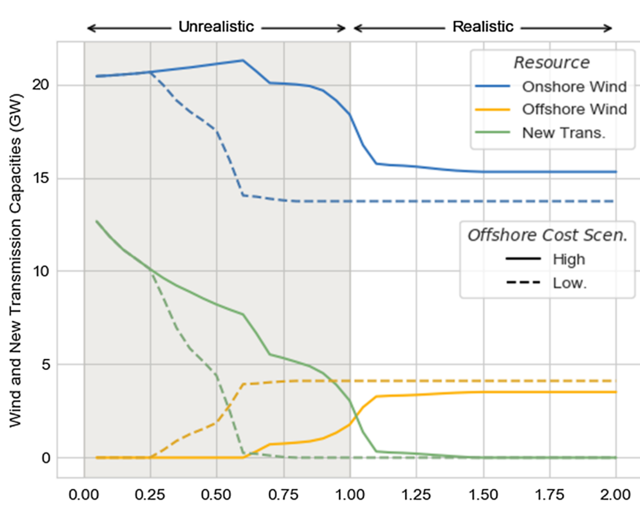

Fig. 3. Optimal wind power and new transmission capacities vs. transmission upgrade costs for the 50% RGT. All simulations include 3 GW of solar capacity. Transmission costs are presented as multiples of the low-cost estimates presented in Table 2.

The analyses described below investigate several model scenarios in detail. Having established the cost-sensitive behavior of new transmission, all following analyses assume transmission costs to be the average of the low and high transmission cost estimates; this is equivalent to a multiple of 1.5 of the low-cost estimates per Fig. 3.

4.1.2. Case-based optimal infrastructure mixes

To evaluate wind power capacity and transmission expansion sensitivity to other energy infrastructure measures, we exogenously impose battery storage, EV adoption, or increased solar PV capacity in certain model simulations, as shown in Table 4. These capacities would not be selected in the RTM to meet the 50% RGT due to limitations of the model's formulation as a capacity expansion model. Battery storage and solar PV have quantifiable local system benefits beyond the scope of the model, and EV adoption is not included as a system planning-level decision variable with an associated cost assumption. In all cases, more qualitative considerations of individuals or policymakers may also influence adoption and they are widely expected in future energy systems with deep VRE penetration. Table 4 presents a summary of results for relevant high and low-cost scenarios.

Simulation results indicate that energy storage reduces curtailment of onshore wind power, thus reducing the need for more expensive offshore wind capacity. Storage is most effective when co-located with low-carbon generation, as shown in Fig. 4. Co-located storage allows electricity to be stored either for later in-region use or for export when transmission lines out of the region are no longer congested. Because this behavior can be driven by both renewable energy and nuclear power, Fig. 4 presents the optimal distribution of this storage and how it relates to the mix of regional all low-carbon generation.

In Case 2, an EV adoption rate of 25% (flexible charging assumed) leads to computed capacities of onshore and offshore wind larger than those in the base case (see Table 4). This increase in electricity load also makes transmission upgrades cost-effective in the high-cost scenario. Installing another 3 GW of solar PV capacity (Case 3) reduces the total wind power capacity to meet the 50% RGT but affects onshore and offshore wind power differently. The computed decrease in offshore wind capacity is larger than the decrease in onshore wind capacity in both absolute and relative terms, as the added solar first displaces this more expensive generation.

Two key takeaways emerge from the results shown in Table 4: First, at realistic prices, transmission expansion will not play an important role in meeting the 50% RGT, even with additional EV load present. Second, the optimal generation mixes in all cases, regardless of what background energy infrastructure is imposed, share a common characteristic: a considerable buildout of onshore wind capacity and a multiple-GW installation of offshore wind power. Our analysis indicates that the pathways for meeting the 50% RGT vary little if storage, EVs, or additional solar generation is present at the scales modeled here.

4.2. Renewable generation growth beyond 50% energy penetration

To this point, our analysis has established that NYS may not need two planning-level actions to achieve a 50% RGT: Transmission capacity upgrades and standalone energy storage. This is largely driven by a more cost-effective strategy of utilizing local renewable generation (i.e. offshore wind near downstate load centers). In this section, we extend the model to deeper renewable energy penetration scenarios in order to investigate how longer-term considerations may affect planning decisions.

Fig. 5 presents the optimal capacities of wind power, new transmission, and battery storage under RGTs ranging from 50% to 80% for (a) the high-cost scenario and (b) the low-cost scenario; 0% and 25% EV adoption rates are considered. It is worth briefly noting that the 50% RGT points in Fig. 5 are consistent with the values presented for the

Table 4
Meeting the 50% RGT with different amounts of imposed energy infrastructure.

	Imposed Capacities[1]			High-Cost Scenario Results Optimal Cap. (GW)[2]			Low-Cost Scenario Results Optimal Cap. (GW)[2]		
Case	Batt. (GWh)	EVs (%)[3]	Solar (GW)	On.	Off.	Trans.	On.	Off.	Trans.
Base	0	0	3	15.31	3.52	0	13.74	4.11	0
1	33.6	0	3	15.93	2.72	0	14.22	3.37	0
2	0	25	3	16.94	3.93	0.26	14.87	4.79	0
3	0	0	6	14.73	2.76	0	13.21	3.33	0

Note: "On.", "Off.", and "Trans." correspond to the optimal computed amounts of onshore wind, offshore wind, and new transmission capacity, respectively.
[1] "Imposed Capacities" refers to capacities given as inputs to the RTM.
[2] "Optimal Cap." contains the quantities of energy infrastructure selected by the RTM.
[3] EV adoption rate refers to the percentage electrification of annual light-vehicle energy usage.

base and 25% EV cases in Table 4.

The initial observation is that, as the scenarios extend beyond the 50% target, some level of system flexibility in the form of storage or transmission buildout is necessary to meet RGTs cost-effectively. The interplay observed in Section 4.1 continues between (1) onshore wind with transmission upgrades and (2) offshore wind power: With an accelerated offshore wind learning curve leading to lower costs, more installed offshore wind power reduces the computed amounts of onshore wind power and new transmission capacity.

Comparing Fig. 5(a) and (b), up to approximately 70% renewable energy penetration, there is a tradeoff between investments in storage or transmission that appears highly dependent on the offshore wind and battery storage costs. Beyond 70%, the simulations predict sizable storage value regardless of the cost assumptions. For example, under the low-cost scenario, no storage is built to meet the 50% target; however, at the 65% target with 0% EV adoption, the model selects storage equivalent to 2.1 h average demand, a quantity that jumps to 15.7 h average demand to meet the 80% target. At the same time, transmission upgrades remain relatively flat, indicating limited additional cost-effectiveness at deep renewable energy penetrations.

The effect of EVs on the overall results is relatively small beyond requiring some additional generation to meet a portion of the new electricity demand. Electric vehicle adoption decreases the amount of storage needed to meet all renewable generation targets, a result which implies that battery storage and flexible EV charging provide a similar service to the system – time shifting demand in order to aid integration – and thus act somewhat competitively. However, the limited scale of this reduction in computed standalone storage indicates a significant role for batteries to play in shifting supply even with EV flexibility present. As a point of comparison, at the 65% RGT in the low-cost scenario, the addition of EVs with a daily load equivalent to 33.6 GWh reduces the cost-optimal standalone storage by 9.47 GWh (24.7% of battery capacity). These results motivate additional investigation of the energy storage value.

4.2.1. Value to system of standalone energy storage

To simplify the discussion of results in this section, we consider only the low offshore wind and battery cost scenario based on the following:

1. The analysis presented in Section 4.1 and corroborated in Section 4.2 indicates that, regardless of cost assumptions, some substantial buildout of offshore wind power capacity is needed to meet a 50% RGT, suggesting offshore wind costs are likely to decrease in that time period.
2. Battery storage costs have rapidly decreased in recent years with projections expecting further reduction, particularly if EV adoption accelerates.

The value of a range of storage capacities – defined here as the avoided capital costs of renewable generation capacity and transmission upgrades – is computed for two representative RGTs: 50% (NYS 2030 goal) and 64% (together with 16% nuclear generation by energy,

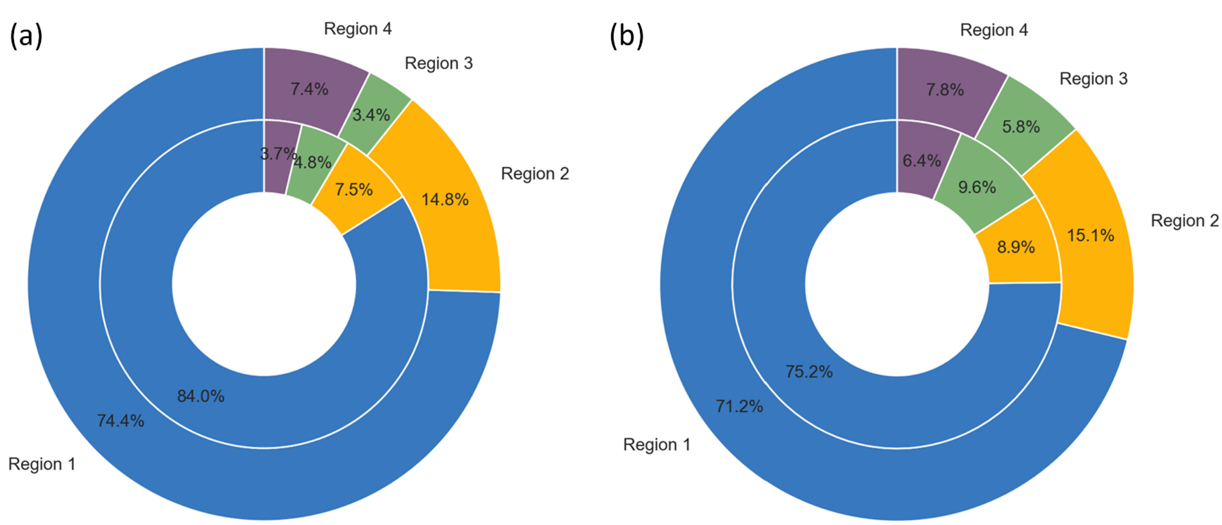

Fig. 4. Optimal standalone storage location and the regional, average low-carbon generation for the 50% RGT: (a) high-cost scenario; (b) low-cost scenario. The inner pie chart shows storage location (33.6 GWh total); the outer pie chart shows average uncurtailed low-carbon generation by region (13.03 GW in Fig. 4(a); 12.74 GW in Fig. 4(b)). Results include 3 GW of solar PV capacity present and no new transmission. In both cost scenarios, storage is most valuable when spatially paired with low-carbon generation.

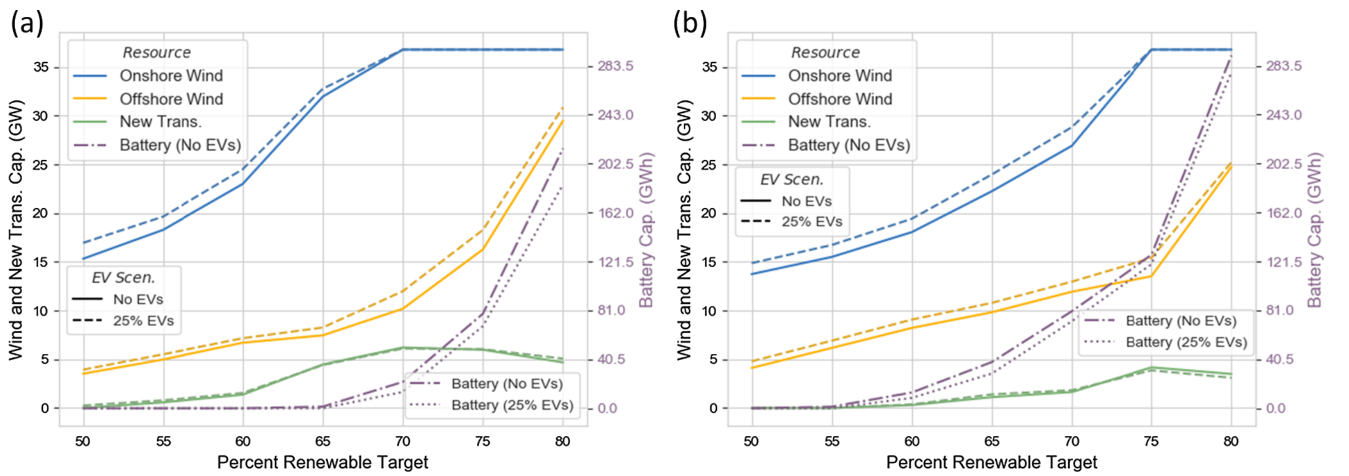

Fig. 5. Optimal mix of energy infrastructure for RGTs between 50% and 80% and for 0% and 25% EV adoption cases with flexible charging: (a) high-cost scenario; (b) low-cost scenario. Wind and new transmission capacities are shown in GW on left-hand axes; battery storage capacity is shown in GWh on right-hand axes. Results include 3 GW solar capacity.

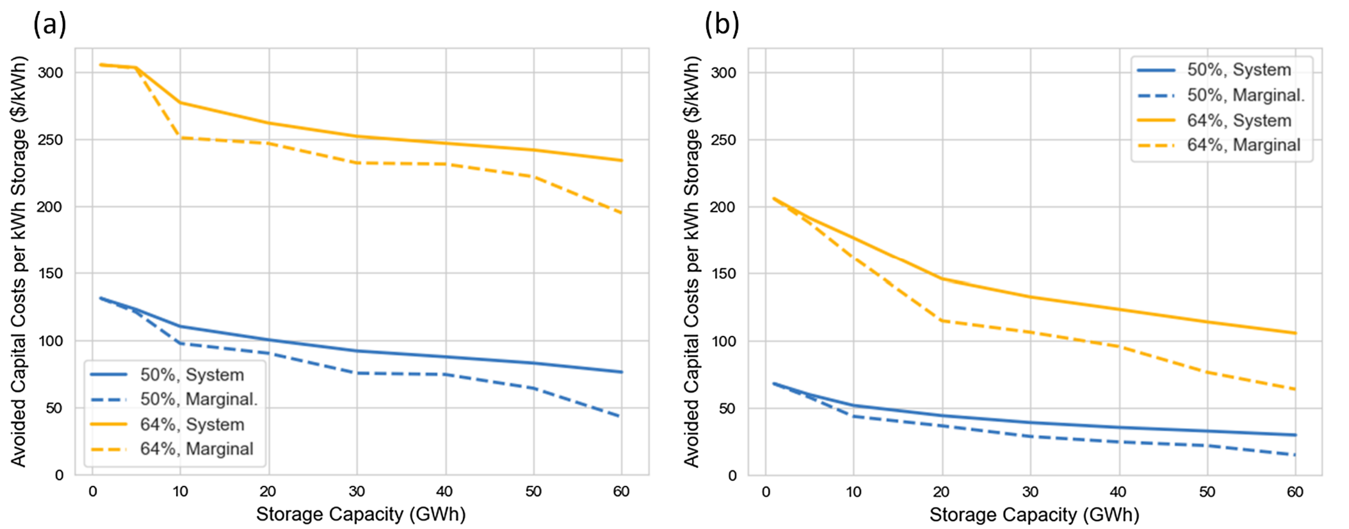

Fig. 6. Avoided capital costs per kWh storage ($/kWh) for storage capacities between 1 and 60 GWh. Results shown for 50% and 64% RGTs under the low-cost offshore wind assumption: (a) battery lifetime of 3000 cycles; (b) battery lifetime of 10 years. No electric vehicle adoption. Results include 3 GW of solar capacity.

this yields 80% low-carbon electricity generation). We consider two scenarios for computing the system's avoided capital cost per kWh of storage: An assumed 3000-cycle battery life (Fig. 6(a)) and an assumed 10-year battery life (Fig. 6(b)). We offer these comparisons as it is unclear, at present, how long such batteries will operate; this is not meant to be a detailed analysis of battery operational effects or chemistries.

In no simulations did a battery go through > 3000 cycles in a 10-year period; as such, all simulations indicate higher battery value over 3000 cycles than over 10 years. We note a general trend of the computed storage values in the 64% target scenario being 2.5–3 times the computed values in the 50% target scenario, a difference which explains the large-scale storage buildout observed at higher renewable energy targets: For a 10-year lifetime, the marginal value of energy storage exceeds its $100/kWh cost in the 64% target scenario up to approximately 35 GWh, whereas the energy storage value is less than its cost in the 50% target scenario. This general trend holds when EVs are introduced, but we can observe additional effects when including both EVs and 5 GWh of battery storage in our simulations, as shown in Fig. 7.

By comparing the results of flexible and inflexible EV charging for a 10-year standalone battery lifespan (Fig. 7), we note that flexible charging displaces some of the benefits from standalone storage for a 64% RGT, but there is a point of diminishing effect: The reduction in standalone storage value caused by flexible EV charging remains relatively stable beyond approximately 20% EV adoption. Perhaps counterintuitively, the value of standalone energy storage increases slightly in the 50% renewable target scenario. These effects imply that there is value in shifting supply to the time periods in which EV charging occurs *even if* that charging schedule is flexible.

4.2.2. *Total system cost breakdown*

Fig. 8 presents the total capital cost breakdown for a NYS electricity system that achieves 50–80% RGTs for (a) high-cost and (b) low-cost scenarios. Comparing the two figures side-by-side, it is helpful to divide the RGTs into two sections: medium-term goals, consisting of targets between 50% and 65%, and long-term goals, represented by targets between 65% and 80%. In meeting the medium-term goals, the scale and distribution of investments are similar regardless of the cost scenario. At these levels of VRE integration, the RTM selects simultaneous, near-equal investments in onshore and offshore wind power, investments which make up the bulk of all system costs; computed expenditures on new transmission and battery storage are minor. To achieve the 65% RGT under a low-cost scenario, the state needs $84.3B

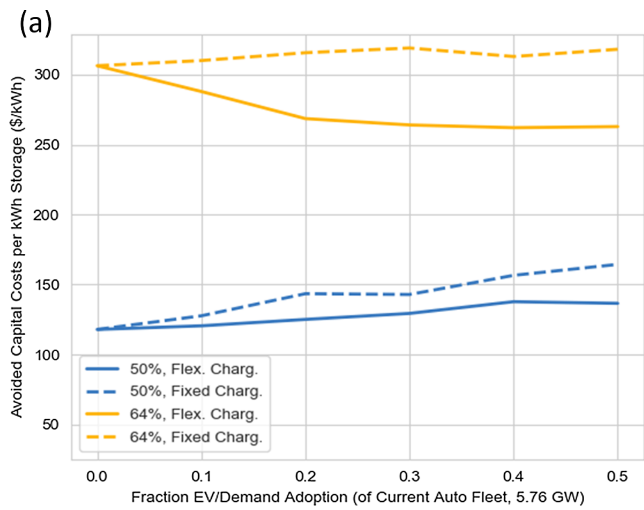

Fig. 7. Avoided capital costs per kWh storage ($/kWh) for EV adoption rates between 0% and 50% due to 5 GWh of storage. Results are shown for flexible and inflexible EV charging scenarios for 50% and 64% RGTs under the low-cost offshore wind assumption: (a) battery lifetime of 3000 cycles; (b) battery lifetime of 10 years. Results include 3 GW of solar capacity.

(annualized cost of $6.0B, 0.39% of NYS 2017 GDP [61]); high cost assumptions increase this quantity to $91.7B (annualized cost of 6.5B, 0.42% of NYS 2017 GDP).

In both cost scenarios, wind power capacity (both onshore and offshore) contributes the vast majority of the total system cost until the deepest penetration rates, when marginal investments in both offshore wind power and battery storage are similar (and all onshore wind power sites have already been utilized fully). By comparing the cost breakdown results in Fig. 8 to the capacity optimizations in Fig. 5, we can see that while more investment is made in batteries in the high-cost scenario, the state would install more battery capacity in the low cost-scenario. If battery prices reach the lower estimate of $100/kWh, the increased amount of storage present allows the system to install less offshore wind power capacity and new transmission at all RGTs modeled; the model also selects less onshore wind power capacity at RGTs less than 75%. To meet the 80% RGT under low cost assumptions, the state needs $209.5B (annualized cost of $14.9B, 0.96% of NYS 2017 GDP); high cost assumptions increase this quantity to $295.4B (annualized cost of $21.0B, 1.36% of NYS 2017 GDP).

By comparing the marginal LCOEs at a range of RGTs, we see that the price of additional utilized renewable energy accelerates as VRE penetration increases. For the low-cost scenario, our calculations indicate that a 50% RGT can be achieved with LCOE of $52/MWh for new VRE. Between the 50–55% RGTs, the marginal LCOE of utilized VRE increases to $94/MWh; between 75 and 80%, the marginal LCOE rises sharply to $592/MWh. For RGTs through 65%, the high-cost scenario marginal LCOE is computed to be less than 10% greater than the low-cost scenario marginal LCOE. Beyond this point, the computed marginal LCOE values diverge: The high-cost scenario LCOE is 27% higher at the 70% RGT and 70% higher at the 80% RGT.

5. Discussion

At different points along a pathway to deep energy decarbonization, the value of particular resources is likely to vary. This paper investigates several likely large-scale energy planning decisions in the context of near-to-long-term renewable generation targets (RGTs): Whether to build new intrastate transmission to connect high wind areas to load centers, whether to invest in dedicated energy storage to align supply and demand, and which generation resources to prioritize in a geographically heterogeneous region. The effects of wide-scale adoption of EVs on these decisions is also investigated. Electricity grid regions at the state or multiple-state level can generally contain large distances between the most economical variable renewable energy

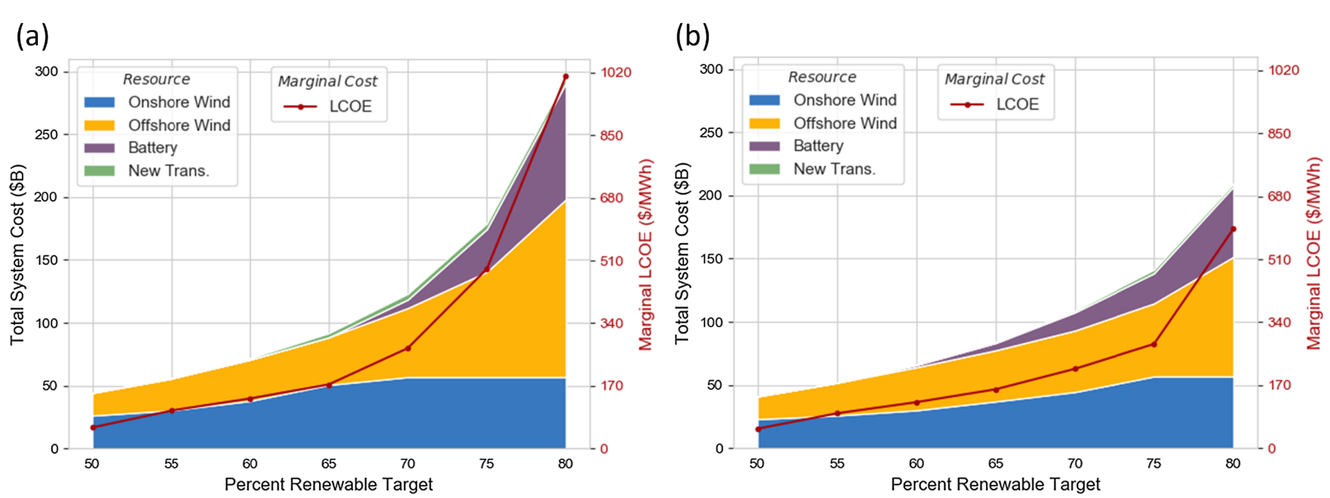

Fig. 8. Total system costs ($Billion) and marginal LCOEs ($/MWh) for RGTs between 50 and 80%: (a) high-cost scenario; (b) low-cost scenario. Both scenarios include 3 GW of solar PV capacity and 25% EV adoption with flexible charging. Total system costs are calculated over a 20-year lifespan; battery costs are accordingly adjusted based on an assumed 10-year lifespan.

(VRE) resources and the largest load centers; more expensive local or nearby resources may make up a sizable part of a pathway to deep VRE penetration. To complete an analysis at this scale, we simulate New York State's (NYS) regional electricity system, which is representative of regions with transmission-linked zones and heterogeneous demand and potential supply.

When we adopt existing interzonal transmission constraints and realistic transmission cost assumptions, we find that the computed cost-optimal buildout of new transmission capacity is less than what other analyses propose. In fact, we demonstrate that NYS can most cost-effectively meet a 50% renewable generation target (RGT) with no new interzonal transmission capacity. (We do not investigate smaller-scale transmission that may be needed to connect wind power sites themselves to the larger grid.) We attribute the difference between our results and those of other studies to the tendency for other models to underestimate transmission costs or assume deployment that does not consider that new infrastructure will handle only the marginal increases in transmission; if this new transmission comes solely at times of very high VRE production, the low utilization rate may render new capacity uneconomical even if it appears inexpensive compared to other renewable integration measures. It is not necessarily given that considerations of dispatchable generation to meet net loads would not affect the results of this type of analysis; however, NYS's existing regime of well-dispersed gas-fired generation is unlikely to transform into one in which net loads are met by distant fossil fuel-based generation.

A central result of the analysis is a cost-minimal solution to meeting a 50% renewable energy penetration level that includes only a large buildout of onshore wind generation (~15 GW) and a multi-GW expansion of offshore wind capacity; the inclusion of energy storage, electric vehicles, or additional solar capacity does not meaningfully change this infrastructure mix. At this renewable penetration level, the value of battery storage remains below even the most optimistic cost assumptions. Similarly, the scale of electric vehicles modelled here – 25% adoption – does not provide enough system flexibility to substantively change the computed optimal generation mix. Alongside our transmission findings, this suggests that a 50% RGT can be achieved solely through a cost-effective buildout of VRE generation capacity; further, our computed LCOE of new renewables to achieve this target ($52/MWh) is in line with reasonable current generation costs.

While co-locating dedicated energy storage with variable supply improves VRE integration, the computed optimal resource mix to achieve the 50% RGT includes no standalone energy storage, even with costs as low as $100/kWh. Though storage is already proving to have other value (e.g. grid frequency regulation services and peak demand reductions), it is unlikely to be cost-effective for shifting energy supply to times of higher demand in achieving near-term RGTs. Since battery storage capacities are aggregated at the regional level, we note that further study is needed to investigate how the intraregional distribution of these resources and local conditions would affect operation.

In exogenously doubling the amount of solar PV capacity in our model (6 GW vs. 3 GW), we find limited effects on our overall findings. The additional solar tends to displace local resources: Onshore wind power in less densely populated western regions and offshore wind power in high load centers along the coast. That said, even though the regional distribution of solar PV capacity is similar to the regional distribution of demand, the absolute and relative reductions of offshore wind power capacity are greater than the reductions of onshore wind power capacity.

These findings are likely generalizable to other regional grids, particularly those along the U.S. Atlantic coast that contain high population density areas with limited local or nearby VRE resources other than offshore wind power. Similar findings may also apply to inland areas with access to distant onshore wind resources and more expensive local solar potential. A useful metric from our analysis is that, although 3–4 times more onshore wind than offshore wind capacity is built to reach the 50% RGT, the total financial investments of onshore and offshore wind are roughly equal.

Moving next to RGTs in the 50–65% target range, we compute growth in both transmission and storage capacity, although the infrastructure mix is dependent on assumed offshore wind and battery costs. If battery and offshore wind costs remain high, additional transmission to better utilize onshore wind power will become necessary; however, if battery and offshore wind costs drop as predicted, battery storage will provide the system flexibility necessary to integrate additional VRE. The increased reliance on energy storage as NYS approaches the 65% target is primarily a result of the computed value of storage increasing to 2.5–3 times greater than its value at the 50% target. As near-term targets transition to longer-term goals, model-selected energy storage capacities increase from no storage at the 50% RGT to storage equivalent to approximately 2 h average demand at the 65% RGT, and finally to 16 h-equivalent storage at the 80% RGT. Such scales indicate that some portion of the storage requirement may be met by alternatives to batteries, a hypothesis that deserves further study.

At a 64% target (with 16% nuclear power, a total of 80% electricity generation by low-carbon sources), the value of dedicated energy storage holds relatively steady even with up to 50% adoption of flexible charging EVs. While flexible charging does decrease the value of the energy storage, all reduction in value occurs within the first 20% of EV adoption. These effects imply that there is value in shifting VRE supply to the time periods in which EV charging occurs even if that charging schedule is itself flexible. This explains why our analysis shows that large-scale adoption of EVs, even with flexible charging operation, is unlikely to alter the overall approach to meet RGTs, aside from the self-evident need for additional capacity to meet the demand.

Overall, our calculations indicate that a 50% RGT can be achieved with a LCOE largely in line with current reasonable generation prices that gradually increases at deeper penetration rates. Between the 50–55% RGTs, the marginal LCOE nearly doubles, but this reflects an increased share of offshore wind-generated electricity utilization and would not necessarily represent a large electricity price increase for the urban areas making most use of the offshore wind resource. Between the 75% and 80% RGTs, the marginal LCOE of utilized VRE rises sharply. This surge in price can be attributed to the large amounts of wind and storage capacity needed to meet long-term targets. As these cost estimates would prove prohibitive from an investment standpoint, NYS will likely turn to other integration measures or future technologies not analyzed in this paper to achieve long-term renewable energy goals. These measures could also include further connections to neighboring grids and large-scale electrification of heating.

In general, this study demonstrates that near-term renewable energy goals can be achieved most cost-effectively through VRE capacity buildout alone. Beyond this point, policy and investments that bring down the costs of nascent energy technologies – here, offshore wind and battery storage – will be particularly important. Even at high costs, significant shares of such technologies would be required to achieve deep energy decarbonization; an approach that incorporates them into near-term planning may make the longer-term transition more affordable.

6. Conclusion

This paper presents an optimization model for a regional electricity grid to assess cost-minimal generation, transmission, and storage capacities required to meet a series of renewable generation targets. We compare results for a range of transmission costs and for two broader technology cost assumption scenarios. Additional insight is gleaned from exogenously varying standalone energy storage capacity, adoption levels of electric vehicles, and solar photovoltaic capacities. The first half of this paper investigates a 50% target in detail; the second half extends the analysis to targets up to 80%.

The paper first demonstrates that New York can most cost-effectively realize a 50% renewable generation target with no new transmission or large-scale storage. Assuming offshore wind generation costs decrease to internationally-competitive levels, the optimal generation mix includes 13.7 GW of onshore and 4.1 GW of offshore wind power capacity; despite its high capital costs, offshore wind's high capacity factor, proximity to load centers and lack of reliance on long-distance transmission upgrades result in its selection. Here, the contribution of 4.1 GW of offshore wind represents 28% of new potential renewable energy production. Even with 33 GWh of storage or 6 GW of solar exogenously imposed, optimal offshore wind capacity does not fall below 3.3 GW.

As renewable energy penetration increases from 50% to 80%, the model builds out all of New York's available 37 GW of onshore wind capacity and dramatically increases offshore wind capacity to 25 GW. At the 80% target, offshore wind contributes 48% of new potential renewable energy generation in the state, and as this generation connects directly to downstate load centers, additional statewide transmission buildout is limited to 5 GW and 1% of the total financial investments in generation, storage and transmission. This overall picture is largely insensitive to the cost of offshore wind capacity, or the presence of electric vehicles.

Storage plays an increasingly important role at higher renewable energy targets. In our results, we compute no storage at the 50% target, storage equivalent to about 2 h average demand at the 65% target (7% of investment), and 16 h average demand at the 80% target (27% of investment). The rising value of storage drives this growth: the avoided capital cost per kWh of storage is nearly 3 times greater at 65% renewable penetration than at the 50% penetration level. At deeper renewable energy targets, large computed battery capacities with relatively low annual cycling suggest that some proportion of alternative forms of storage may be effective.

Evaluating the marginal costs of utilized renewable electricity between the 50% and 80% targets, we observe a marked increase in price as New York requires more capital to build out and integrate additional generation capacity. To achieve a 50% target, we compute a levelized cost of electricity of $52/MWh for new renewable energy, a quantity in line with current reasonable generation prices. Between 50 and 55%, the marginal cost of electricity nearly doubles to $94/MWh, which may be reasonable for the urban areas considered in this study. To reach the 80% target, this marginal cost increases sharply to $592/MWh. In the 70–80% target range, the rapidly increasing marginal costs are largely driven by energy storage and offshore wind capacity costs.

It is important to understand a couple limitations of the study. We have not modelled interconnections to adjacent grids in this paper, and these may play an important role in lowering costs at higher renewable energy penetration levels. We have also not simulated unit commitment or dispatch with deep penetration of renewables; transmission and storage may affect the internal economics of dispatchable generators, market prices, and dispatchable capacity needs, warranting further study. Lastly, we do not model anticipated heating electrification, which is likely to reduce wind power curtailment in winter months.

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