New England's Evolving Grid

The 2024 Economic Study Report

SEPTEMBER 15, 2025

Introduction

ISO New England's economic studies explore possible evolutionary changes to the power grid, shaped by public policy, emerging technologies, and other factors. They identify key regional issues and inform stakeholders, policymakers, and the wider public of the potential economic and operational implications of policy decisions.[1]

Most New England states have set ambitious goals to reduce carbon dioxide (CO_2) emissions by at least 80% from 1990 levels by 2050, with some states adopting more aggressive targets of up to 100%, through a combination of electrified heating and transportation, zero-carbon electricity production, and other strategies. Recent economic studies, including this one, have explored how building out the future grid with new resources like **solar photovoltaics (PV)**, **offshore wind**, **land-based wind**, **small modular reactors (SMRs)**, and **energy storage (BESS),** or adopting demand-side strategies, might achieve these emissions goals reliably and cost-effectively. This report details key findings from the ISO's most recent economic study cycle, which began in 2024.

Two key themes offer a backdrop for the latest economic study's findings:

Emissions reductions before the 2040s are more cost-effective than later reductions

Emissions reductions beyond 85% of policy goals drive escalating costs.

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Demand growth also increases costs beyond the 2040s.

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Land-based wind is consistently economical from 2033 to 2050, while PV supports early decarbonization.

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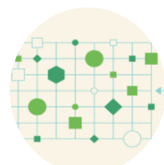

Reducing emissions for lowest cost requires the efficient use of a variety of technologies

Including more dispatchable technologies reduces needed capacity by over 15%.

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Shifting the hours of peak demand in winter reduces costs.

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Deep decarbonization in 2040s drives increased curtailment of renewables and reduces the economic viability of certain technologies.

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[1] Economic studies are conducted in accordance with Attachment K, Section 17 of the ISO's Open-Access Transmission Tariff (OATT). Not all these results are physically realizable plans, and they do not represent the ISO's vision of realistic future development, projections, and preferences.

New tools and broader scope allow better insight into likely trends.

This economic study cycle is the first conducted under recent changes to the study process and procedures, which include using capacity expansion tools to model the future grid. Originally piloted in the Economic Planning for the Clean Energy Transition (EPCET) study, capacity expansion modeling allows for greater customization of study inputs, such as CO_2 emissions constraints. Including these considerations better represents how state policies targeting deep reductions in emissions might affect the power grid in the coming decades. Capacity expansion modeling uses these emissions constraints, cost assumptions, and other inputs to simulate what the grid might look like, year by year, over the next 25 years, adding new resources as needed to serve increasing demand and to operate the grid in the most economical way possible.

Adjusting the carbon constraint or other inputs generates different versions of the 2033 to 2050 grid, referred to as either scenarios or sensitivities. Beginning in 2024, all ISO-NE economic studies include four repeatable reference scenarios: the Benchmark Scenario, Policy Scenario, System Efficiency Needs Scenario, and Stakeholder Scenario. Sensitivities explore modifications to the Policy Scenario and Stakeholder-Requested Scenario; they are either stakeholder-requested or developed internally.[2]

This economic study cycle examines almost 40 scenarios and sensitivities, compared to the 33 in EPCET and the 12 in the ISO's Future Grid Reliability Study (FGRS), which did not include capacity expansion modeling. Building upon prior work and modeling more possible trajectories than ever before makes it easier to identify consistent trends that may emerge in the decades ahead. Although technologies may advance at different paces, actual costs may vary from projections, and political factors may change, simulating many versions of the grid helps illustrate that these prevailing trends will hold across a range of future circumstances.

This cycle also provides more transparency and accessibility than ever before. For the first time, the public can access the economic study technical guide and download models from the ISO's website. This guide and models are the first stop for questions related to assumptions and modeling tools. More detailed results from the study can be found here.

The following page shows a sampling of scenarios and sensitivities from this economic study cycle, and what future assumptions they explore, along with a matrix of their relative costs and decarbonization levels. In general, costs increase with deeper decarbonization.

[2] A full list of scenarios and sensitivities for the 2024 Economic Study, and their results, can be found in presentations made to the Planning Advisory Committee.

Overview of Assumptions for Selected Sensitivities and Scenarios

1. **Economy-Wide Decarbonization Reduced to 75%** • Assumes both electric sector decarbonization and heating and transportation decarbonization at 75% of goals

2. **Blended Case** • Assumes heat pump adoption, but with fossil fuel heating below 20°, no new offshore wind, new additions of natural gas combined cycle, along with SMRs and synthetic natural gas

3. **Electrification Reduced to 75%** • Assumes electric sector decarbonization at 100% of goals; heating, transportation decarbonization at 75% of goals

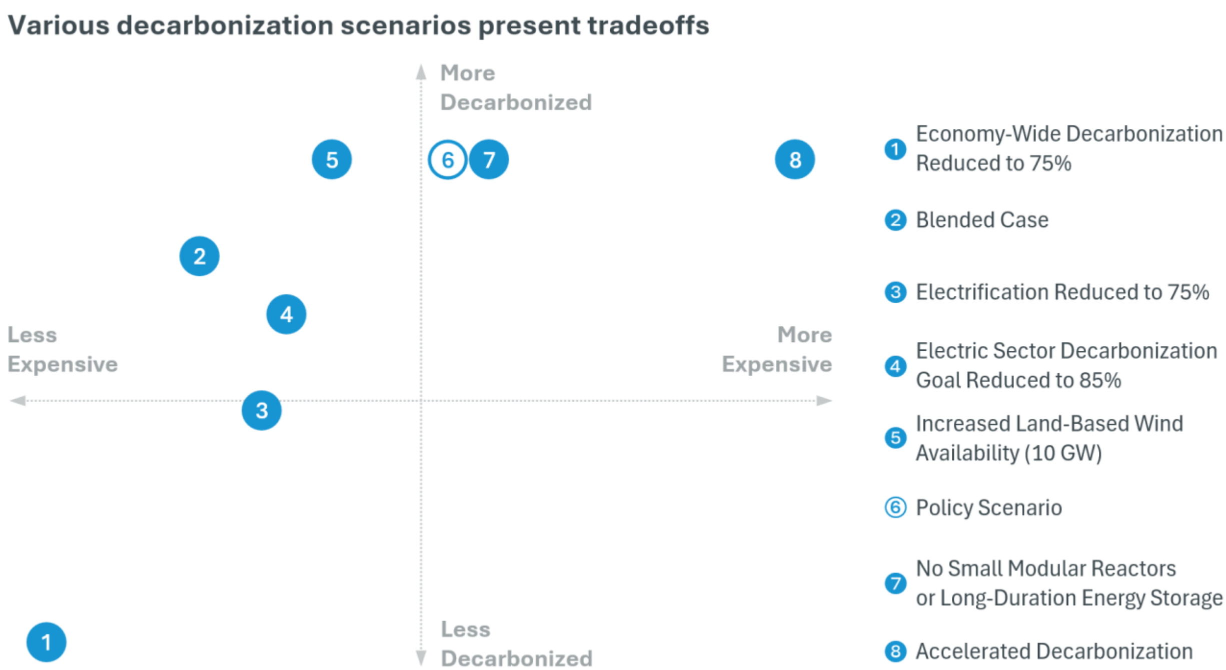
4. **Electric Sector Decarbonization Reduced to 85%** • Assumes electric sector decarbonization reduced to 85% of goals and heating and transportation decarbonization at 100% of goals

5. **Increased Land-Based Wind Availability** • Assumes enough land availability for 10 GW of land-based wind, and satisfies state emissions goals by **2050**

6. **Policy Scenario** • Satisfies state emissions goals of one million tons of CO_2 per year by **2050**

7. **No SMRs or Long-Duration Energy Storage** • Excludes SMRs and long-duration BESS from the model's technology options

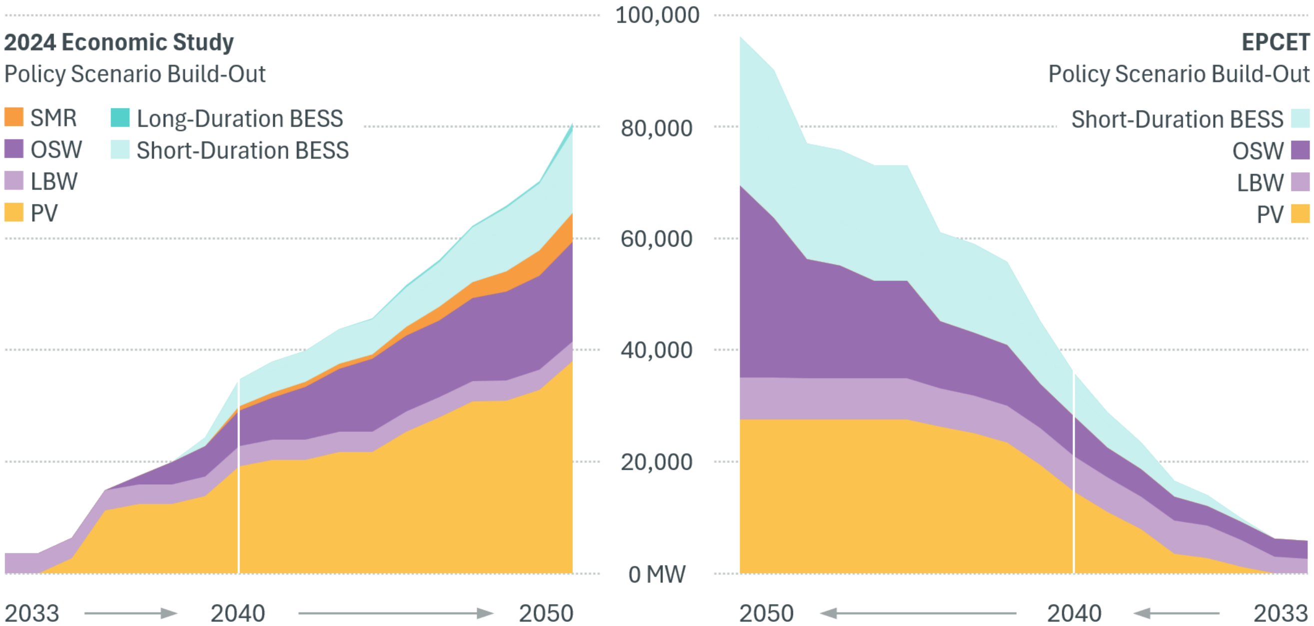
8. **Accelerated Decarbonization** • Achieves state emissions goals of one million tons of CO_2 per year by **2040,** and continues to constrain CO_2 to one million tons per year from **2040** to **2050**



Including more dispatchable technologies reduces needed capacity by over 15%.

Comparing this study's Policy Scenario results to those modeled in EPCET demonstrates that including a wider range of zero-carbon dispatchable technologies could reduce the capacity New England needs to achieve state policy goals and meet demand in 2050. The figure below illustrates this study's build-out and EPCET's build-out. EPCET's Policy Scenario technology options were limited to offshore wind, land-based wind, PV and short-duration BESS (4- and 8-hour).[3] This study expands that range to include SMRs and long-duration BESS (100-hour iron-air batteries).[4] Their inclusion lowers total necessary capacity from 96 GW to 80 GW. The primary driver of this reduction is the addition of SMRs—without them, EPCET's modeling required a vast battery and offshore wind build-out to decarbonize the winter months.

Inclusion of new technologies reduces the need for new capacity



Note: This new capacity is in addition to the roughly 49,000 MW of assumed 2033 capacity.

For this study, zero-carbon technology candidates must meet two criteria: 1) they have already been built, are under contract to be built, or have lease agreements in North America; and 2) they are suited to New England's geology. The first criterion excludes synthetic natural gas, which has no

[3] Two types of PV are included in this study—utility-scale PV and behind-the-meter (BTM) PV. Utility-scale PV is included as a build-out option in the capacity expansion model, while BTM PV is modeled as a reduction in demand. The study assumes significant growth in BTM PV over the next 10 years. Unless otherwise noted, "PV" in this report refers to utility-scale PV.
[4] One EPCET sensitivity (not the Policy Scenario) included SMRs as a build-out option, and one included 100-hour iron-air batteries, but no sensitivity included both.

current contracts in North America, while the second constraint excludes carbon-capture and hydrogen, because New England does not have the appropriate geology to store these gases.

Since capacity expansion simulates the most economical build-out possible under various constraints, these results are highly sensitive to cost assumptions.[5]

Shifting the hours of peak demand in winter reduces costs.

Daily and seasonal demand patterns in the future grid will look different from the demand patterns of today, which will have a large impact on system efficiency, and would likely increase costs. Strategies targeting shifted demand patterns may reduce those costs.

In today's grid, fuel-fired generators supply a large share of power, and the ISO's operators can quickly dispatch these resources up or down to balance the system. In the modeled future system, increasingly variable demand is met largely by renewable supply, which is itself highly variable and cannot be quickly dispatched up. Demand may often be high when renewable supply is low, and vice versa, creating the potential for mismatches that operators must quickly balance. Shifting some portion of consumption away from peak hours to times of lower demand and higher supply could increase overall system efficiency.

To explore this strategy, this study models various hypothetical types of shifted demand, which would encourage large groups of consumers to reduce and/or delay electricity consumption at peak times on a scheduled, widespread basis—and as a result, help lower those peaks.[6] Given that, after 2040, growth in peak demand drives a large part of the cost of the clean energy build-out, exploring several types and degrees of shifted demand illustrates how last-mile costs could decrease.

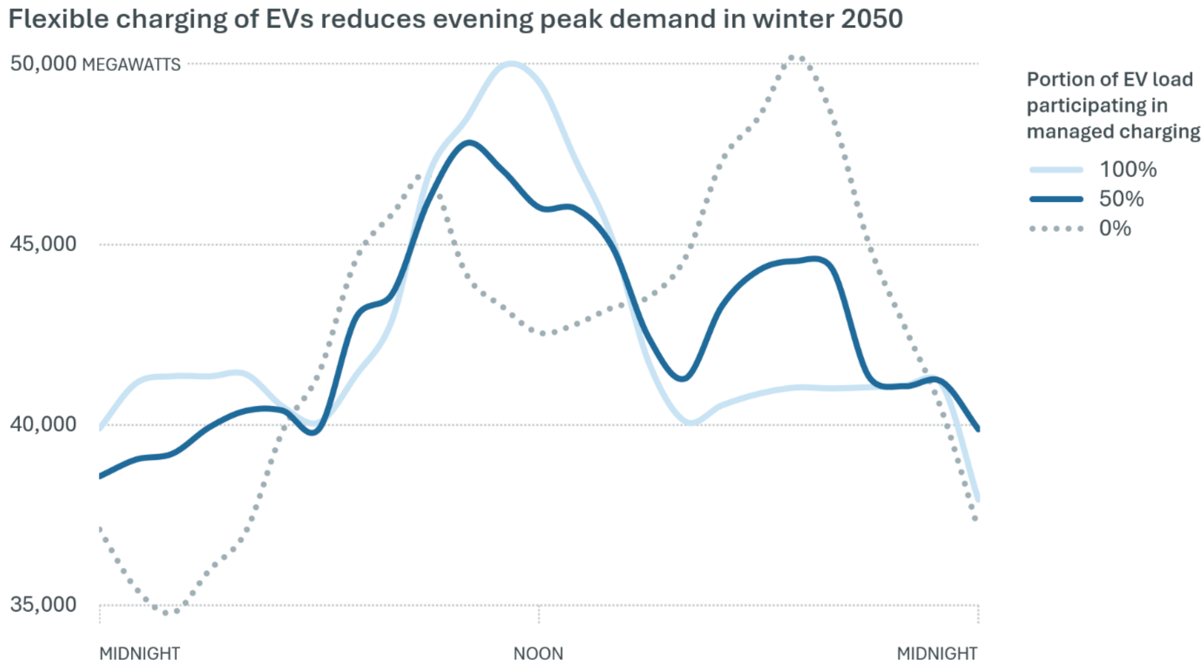
Some types of demand are easier to shift than others. Since heating demand is highly dependent on daily temperature patterns, shifting significant portions of electrified heat to other times of the day is typically difficult or impossible. However, shifting portions of electric vehicle (EV) charging is more feasible. In practical terms, this may include encouraging consumers to charge EVs during the day, when PV production is high, instead of in the evening.

The illustration below shows three demand curves for a winter day in 2050, in which 0%, 50% or 100% of New England's total EVs participate in managed charging. With no EVs participating in managed charging, the evening peak—a period of potential grid stress, with more electrified heating and low PV production—reaches over 50 GW. With 50% of EVs participating, the peak shifts to around 10AM, and the evening peak is reduced to ~44 GW. With 100% EVs participating, the

[5] EPCET's cost assumptions were taken from the [2023 Annual Energy Outlook] released by the US Energy Information Administration, while this study uses assumptions from [NREL Annual Technology Baseline], since there was no Annual Energy Outlook in 2024.

[6] In today's grid, operators can already dispatch what is known as *active demand response* (ADR) to quickly lower demand at times of grid stress. ADR is also included in economic study modeling, but it is different—and much smaller in magnitude—than shifted demand.

evening peak is reduced to ~41 GW. Notably, these demand curves *include* reductions from BTM PV, but *not* utility-scale PV. The large amount of utility-scale PV in the modeled 2050 system would help meet mid-morning peaks much more effectively than evening peaks.



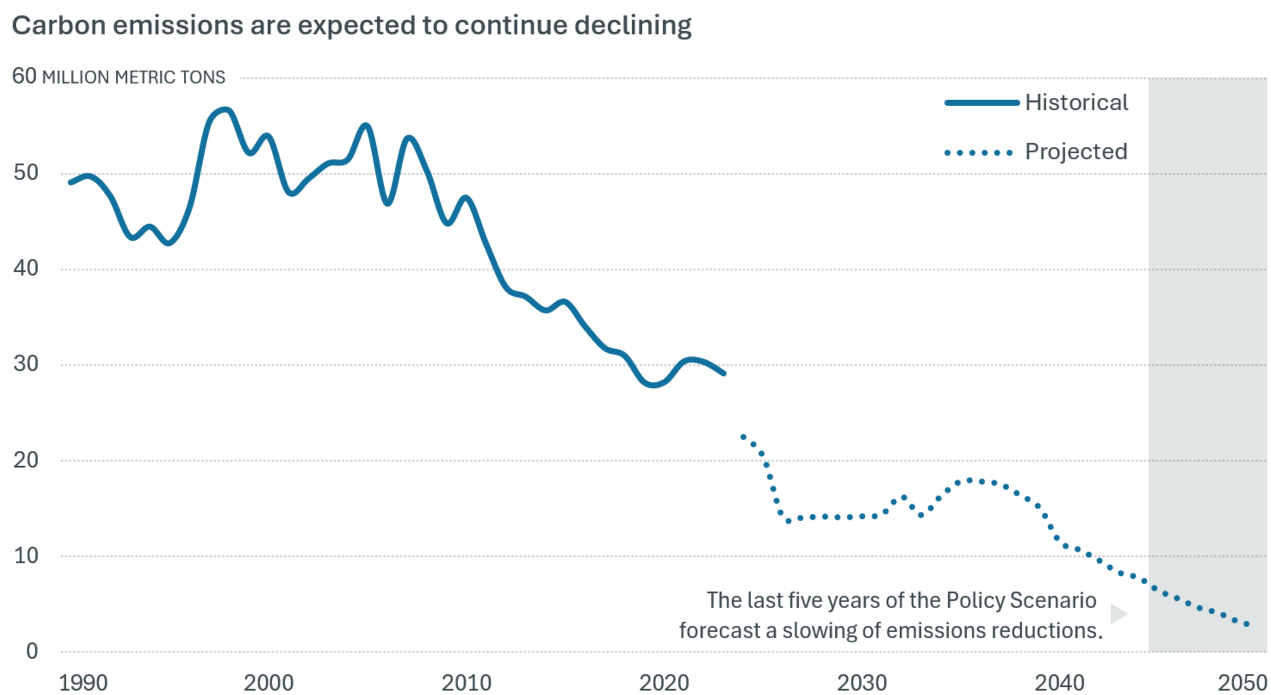
With reduced evening peaks, the modeled 2050 grid requires fewer dispatchable resources like SMRs and short- and long-duration BESS, and costs decrease. Results show that shifting *half* of the region's EV fleet to a managed charging pattern could reduce build-out costs by almost 8%, or $12 billion. Shifting *all* the region's EV fleet to managed charging would reduce resource build-out costs by 15%, or $22 billion. Using baseload appliances like dishwashers, washers, and dryers at non-peak times could have similar effects. Results show that shifting 50% of evening baseload to midday hours reduces build-out costs by 12%, or $18 billion. If a portion of both EV load *and* baseload were shifted, combined cost reductions could be significant.

The smaller-scale managed EV charging programs already in place in today's grid incentivize customers to charge overnight. But with higher penetrations of renewables, the optimal charging times will shift to midday hours, when PV produces more. And as heating electrification increases, winter peak demand hours may occur in the morning, while summer peak demand hours remain in the evening. Future managed charging programs could benefit from different hourly schedules for different seasons.

These results build on findings from the ISO's [2050 Transmission Study](), which explored how lowering peak winter loads could reduce transmission build-out costs. Results from that study showed that reducing 2050's peak winter load from the forecasted 57 GW to 51 GW would avoid roughly $9 billion in transmission upgrade costs.[7] The analysis in this economic study shows this margin of reduction is possible through shifted EV and baseload, and suggests that even lower peak winter peak loads may be possible. In short, shifting peak demand could significantly reduce both build-out and transmission upgrade costs.

Emissions reductions beyond 85% of policy goals drive rapidly escalating costs.

By 2045, the Policy Scenario build-out achieves an 85% reduction in carbon emissions from 1990 levels. After 2045, decarbonization continues, but slows, and costs begin to escalate. Placing projected emissions alongside historical emissions contextualizes the diminishing returns of investments to decarbonize post-2045. The chart below illustrates actual New England electric sector CO_2 emissions since 1990, those forecast between now and 2032, and those modeled by the Policy Scenario after 2033.[8]



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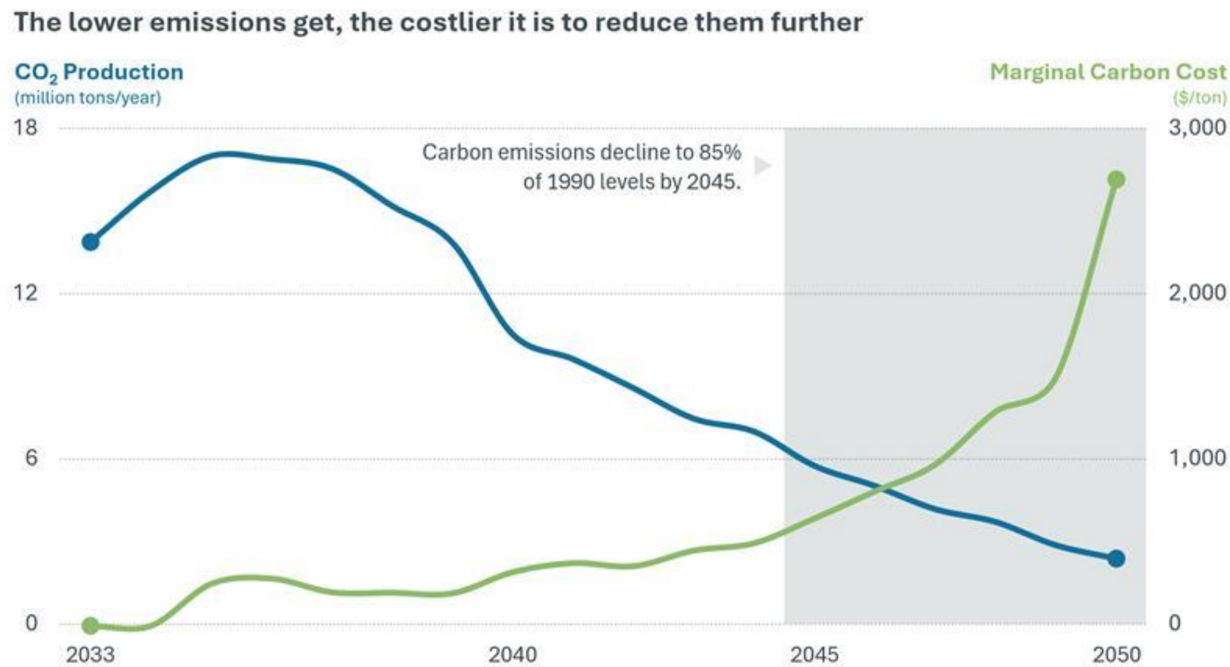
[7] The 57 GW peak winter load assumption used in the 2050 Transmission Study was taken from the All Options Pathway in Massachusetts' Deep Decarbonization Roadmap report, published in December 2020. Peak load assumptions used in the Policy Scenario of this study are from the ISO's own load forecasts.

[8] 1990-2023 emissions data is taken from the NEPOOL Emissions Reports and ISO's Air Emissions Reports. 2023-2032 emissions projections are taken from models of the assumed resource mix, and include NECEC, Vineyard Wind, and Revolution Wind all coming online by early 2026. 2033-2050 emissions projections are results of the capacity expansion modeling of the Policy Scenario. The slight increase in emissions shown in the mid-2030s is driven by the forecasted increase in demand from further heating and transportation electrification.

2033-2045 reductions are achieved through a combination of mostly PV (utility-scale and BTM), land-based wind, and short-duration BESS. This decarbonizes most spring and fall hours. Since cost assumptions for these technologies are relatively low compared to offshore wind, SMRs, and long-duration BESS, the marginal cost of carbon reduction stays below $500 per ton before 2045, as illustrated below.[9]



Beyond 2045, the model adds more zero-carbon dispatchable generation like SMRs and long-duration BESS to further decarbonize winter hours. Since cost assumptions for these technologies are higher, costs escalate. The marginal cost to decarbonize one ton of CO_2 rises to $1,000 by 2048, and to more than $2,500 by 2050.

Results initially [highlighted in EPCET](#) support this finding. The decarbonization of spring and fall hours, when wind and sunshine are abundant and temperatures are milder, far outpaces the decarbonization of winter hours. In 2045, spring and fall may be ~100% decarbonized, while winter is ~75% decarbonized. The escalation in costs after 2045 is driven by the deeper decarbonization of winter hours.

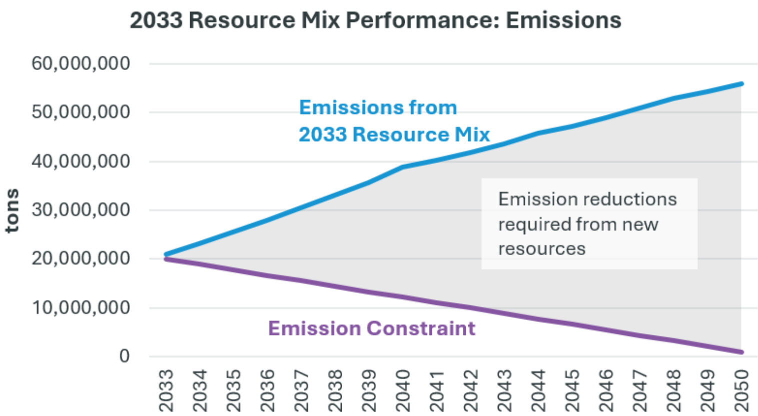
Demand growth also increases costs in the 2040s.

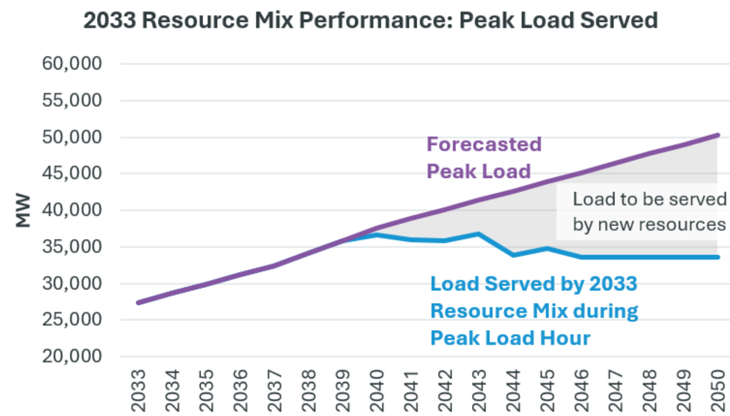
Two factors drive the build-out of additional resources over the study's 2033-2050 timeline: staying on target to accomplish state policy goals regarding emissions, and meeting increasing demand due to electrification. However, the impact of each factor is not always equal or constant, as

[9] The marginal cost of carbon is the cost of reducing the next increment of carbon emissions.

illustrated below. Before 2040, meeting emissions targets is the only driver of resource additions in the model. From 2040 onward, both factors play a part.[10]

Results show that for average weather, the projected 2033 resource mix could serve forecasted demand through 2039. But over the same timeframe, it cannot achieve the emissions reductions needed to stay on target for state policy goals without building out new resources.[11] Taken together, these results suggest that from 2033 to 2039, the model adds new zero-carbon resources primarily to satisfy regional emission reduction policies, not demand growth.[12] From 2040 onward, demand growth becomes a larger factor.





Before 2040, staying on target to meet decarbonization goals is possible through increases in BTM PV and a relatively inexpensive resource build-out of mostly utility-scale PV, land-based and offshore wind, and short-duration BESS, while the existing 2033 resource mix helps serve demand growth. From 2040 onward, with demand growth an increasing factor and decarbonization goals still in effect, costs escalate as the build-out requires more expensive resources like SMRs, long-duration BESS, and floating offshore wind. Once again, winter is the key season—growth in electrified heating increases winter demand when PV output is low, and the 2040s resource mix cannot rely on the large existing BTM PV and utility-scale PV mix to serve this specific type of demand. Reducing decarbonization goals or demand could decrease the “last-mile” build-out and its associated costs.

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[10] The study assumes significant growth in BTM PV through 2033, which reduces demand. Assumed BTM PV growth stops in 2033 as the ISO’s load forecast used in this study does not go beyond this year.
[11] The study’s assumed 2033 resource mix (~49,000 GW) is current resources plus those resources defined in Section 17.10 of Attachment K of the ISO New England Open Access Transmission Tariff.
[12] These results do not include a full resource adequacy screen, and do not consider adverse conditions such as unplanned outages or fuel shortages, or retirements that have not been announced. They include state-contracted resources, and are deterministic rather than probabilistic.

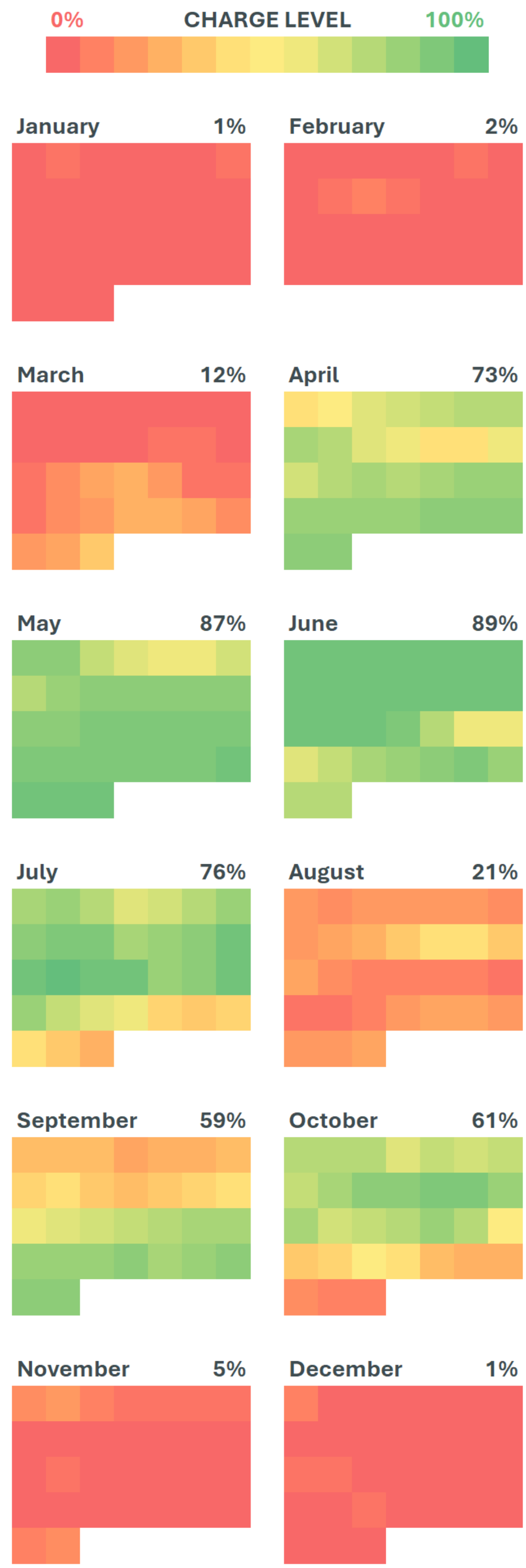
Deep decarbonization in 2040s drives increased curtailment of renewables and reduces the economic viability of certain technologies.

Curtailment is the reduction of output by a resource, usually a renewable, even when energy (sun or wind) is available to generate power. It is used to reduce supply when demand decreases, to maintain a balanced grid. Higher curtailment is a measure of system inefficiency, since available energy is not used. This inefficiency rises in the later years of the study's timeline, particularly after 2040.

By the 2040s, the model's high penetration of PV, land-based and offshore wind has decarbonized much of spring and fall, when sunshine and wind are more abundant, and temperatures are mild. The model continues to add utility-scale PV and offshore wind after 2040 at a slower rate. But since renewables added in these later years decarbonize smaller and smaller periods of time, each increment added is curtailed more than the last increment. Curtailment of utility-scale PV, land-based wind and offshore wind rises from just under 3% of the year in 2033 to almost 14% of the year in 2050.

The short- and long-duration BESS that form an increasing share of the 2040 to 2050 system reduce some of this inefficiency by storing renewable energy that would otherwise be curtailed, but this benefit is largely intra-seasonal rather than inter-seasonal. BESS stores the most energy and stays charged the most consistently in spring, fall and summer. But it stores much less energy in winter, when the 2050 system needs it most. Despite the 2050 build-out's significant quantities of long-duration BESS, it cannot shift enough excess energy from spring, summer and fall to winter to avoid the need for other dispatchable generation. The illustration at right shows how the 2050 system's long-duration BESS maintains its charge levels throughout the year, with the darkest green representing a full charge, and the darkest red representing an empty

Long-duration energy storage stays below 25% charged for half of modeled 2050



charge. BESS is often at or near depletion in winter months, which drives a need for fuel-reliant dispatchable energy.

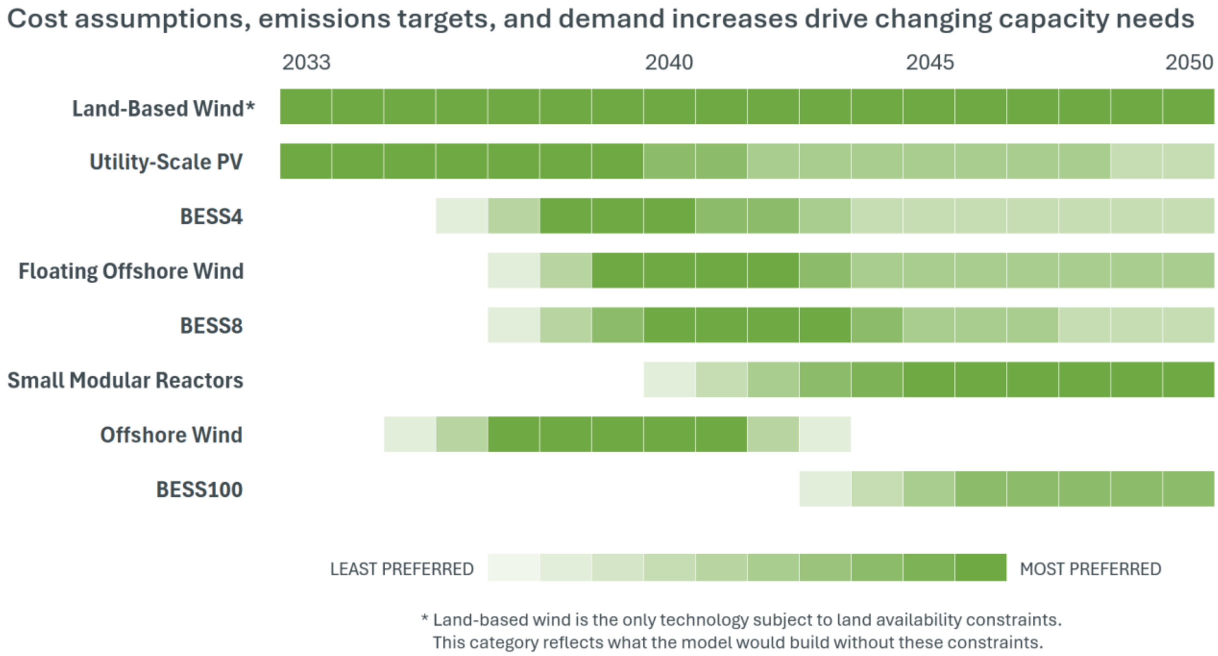
Resources such as SMRs could provide this crucial zero-carbon fuel-reliant dispatchable generation in the 2040s, and the study's Stakeholder Requested Scenario finds they are more cost-effective at decarbonization than long-duration BESS. Results are also highly dependent on conservative relative cost assumptions; if SMRs cost less than the study assumes, their economics increase rapidly. But challenges related to their revenue structure versus renewables remain.

Wind and PV resources rely on "free" fuel, and the study assumes they receive out-of-market contracts as compensation—so these renewables often bid into the 2033-2050 modeled market at zero or negative prices to fulfill must-run obligations associated with those contracts. SMR fuel, however, has an associated cost, which units must recoup exclusively in the market if they are to generate revenue, since the study assumes SMRs are not receiving out-of-market contracts. By 2050, under the Policy Scenario, SMRs bid into the market at an average of $12.48/MWh, which is higher than the bids offered by 2050's large renewable fleet. As a result, SMRs run less frequently when renewable production is high, and generate less revenue. By 2050, SMRs produce just 21% of their maximum possible output for the year, called capacity factor, which for current nuclear units is typically over 90%. However, this SMR production is vital during crucial winter hours when batteries are depleted. Since SMRs are the most expensive technology to build, but may not run for many hours of the year, developers may be less likely to invest in this technology without additional incentives. Different compensation strategies for SMRs could affect their capacity factor significantly.

The inefficiencies mentioned in this section could also be reduced by the shifted demand strategies discussed earlier, since "matching" supply to demand more efficiently would lessen the need for dispatchable resources.

Land-based wind is consistently economical from 2033 to 2050, while PV supports early decarbonization

As noted, a build-out with a wider variety of technologies overall helps reduce build-out costs. But *when* technologies are added is also an important factor in cost-efficiency and value for decarbonization. The illustration below shows the model's "preference" for when certain technologies might be built, depending on decarbonization targets, needs for meeting demand, and varying cost assumptions. Land-based wind and utility-scale PV play particularly important roles in reducing emissions in the earlier years of the study's timeline.



From 2033-2036, cost assumptions for utility-scale PV are significantly lower than most other technologies. Its role as an inexpensive decarbonizer—relative to other resources—is useful in these years. After 2036, however, additional PV provides diminishing returns for decarbonization, largely due to its generation patterns—it is most useful at reducing midday loads. To further decarbonize evening hours and winter and summer peaks, the model builds more offshore wind, SMRs and long-duration BESS. While still relatively expensive, their projected costs decline over the years, since the model assumes that technology becomes less expensive as it matures.

One study sensitivity also explored the benefits of using only single-axis bi-facial tracking PV, versus the fixed-tilt PV assumed in the Policy Scenario, and found a 2.5% reduction in build costs as a result.[13]

Land-based wind is even more economical than utility-scale PV, but it is the only resource in the model constrained by assumptions about land availability. The model maximizes the build-out of this technology in 2033, at 3.6 GW, once the land constraint has been reached.[14] Additional sensitivity results show that if land availability were not constrained, the model would build 44 GW of new land-based wind, demonstrating the consistent usefulness of this technology for reducing emissions for least cost. The illustrations on the following page show the total build-out costs for

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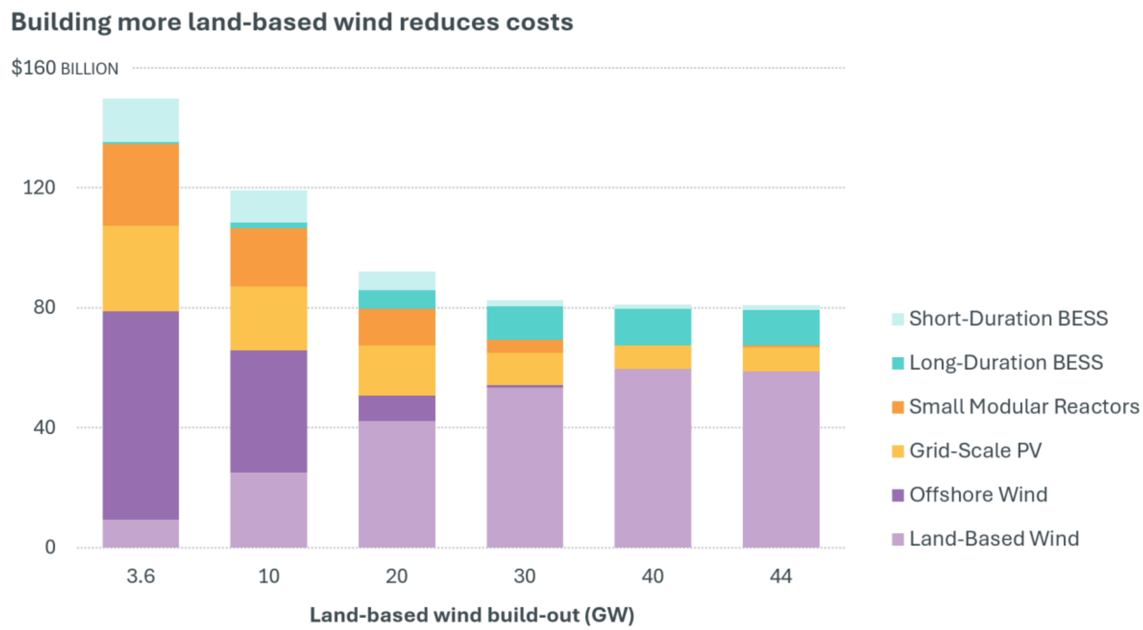
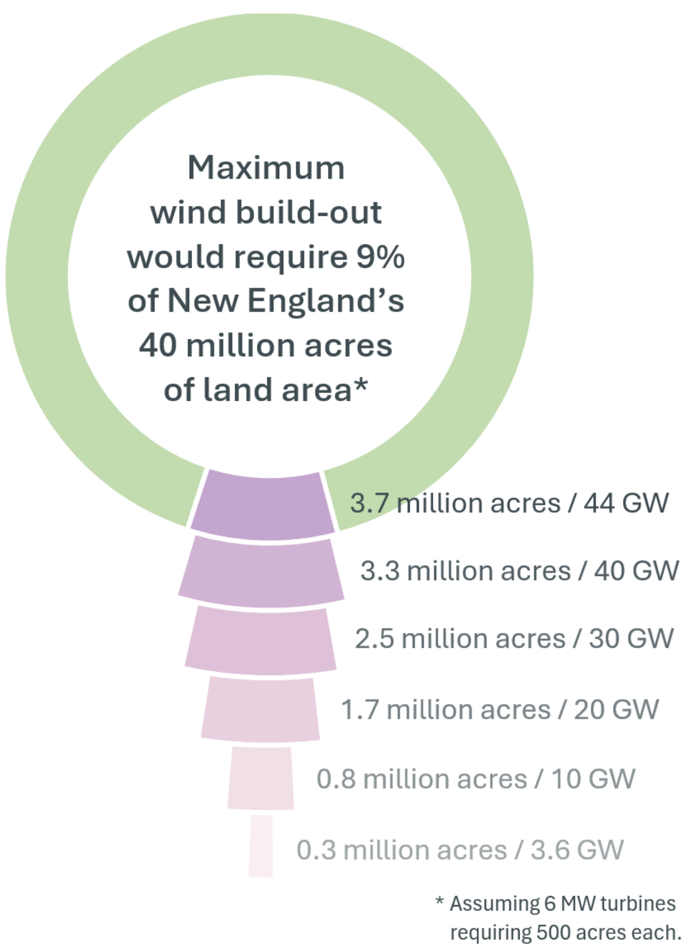
[13] Fixed-tilt PV is typically South-facing and can only generate from the front of the panel. Single-axis tracking bifacial PV is on a horizontal axis of rotation that orients from North to South and can generate from both the front and the back of the panel.

[14] Total land-based wind nameplate for the Policy Scenario is 5 GW; 1.4 GW of existing wind plus 3.6 GW of new land-based wind. Land availability constraints for the 3.6 GW build-out are based on acreage numbers for the current expected future size of New England's land-based wind build-out.

different levels of land-based wind, and the estimated acreage for these various levels, from 3.6 GW to 44 GW, with 44 GW offering the lowest-cost buildout.





These land-based wind results align with other priorities in regional power system planning, including New England's longer-term transmission process that began in 2021. One outcome of this process is the New England States Commission on Electricity's (NESCOE) recent directive for a request-for-proposals (RFP) to improve transmission between Maine and more southerly points of the region. One of NESCOE's key RFP objectives is to support delivering energy from land-based wind in Maine to load centers in southern New England.

Offshore wind is a key decarbonization tool in the model, but has higher cost assumptions than land-based wind. Still, annualized build-out costs rise 15% if offshore wind is excluded from consideration as a candidate for expansion. In this case, the model adds more SMRs and long-duration BESS, which are more expensive.

Conclusion

With over 2,500 simulations run of almost 40 scenarios and sensitivities, this study explores a broader range of possibilities for the regional grid than ever before, with a breadth of detailed supporting data.

Echoing results from EPCET, this study identifies themes that will hold for many future versions of the New England grid. Emissions reductions before the 2040s are more cost-effective than later reductions, and reducing emissions for least-cost requires the efficient use of a variety of technologies. The seasonality of emissions reductions drives a continued need for dispatchable fuel-reliant generation to meet demand.

When some of the various technologies and strategies discussed in this report are used together, cost savings are significant—combining reduced decarbonization and electrification, flexible demand, and bifacial tracking PV, for example, could reduce capital costs by up to 74%. Additionally, renewables like wind and PV provide the region with greater energy independence, and fixed fuel costs in an unpredictable world. The 2026 Economic Study will continue to explore these ideas and other possible trajectories for the regional power grid.

Not all these results are physically realizable plans, and they do not represent the ISO's vision of realistic future development, projections, and preferences. But they do provide tools to policymakers and stakeholders to evaluate tradeoffs, paths forward, and insights into practical, least-cost strategies for reducing power system emissions and meeting future power system needs. The ISO will continue to collaborate with stakeholders to refine economic study tools and approaches and provide the region with valuable insights into a clean energy future.