ANALYSIS GROUP

Pathways Study

Evaluation of Pathways to a Future Grid

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Preface

ISO New England is pleased to present the *Pathways Study*, *Evaluation of Pathways to a Future Grid* by The Analysis Group, which provides important information to the region on potential pathways to meet the New England states' decarbonization goals. In early 2021, the ISO's Board of Directors directed the ISO management team to pursue an assessment of policy and market frameworks that could further advance the evolution of the regional power grid. The ISO retained the Analysis Group to conduct the study, which is part of New England's Future Grid Initiative to assist the region's transition to a future grid that is efficient, clean and reliable. The Analysis Group worked closely with ISO staff, regional stakeholders, and the New England states to gather input on the development of the assumptions, scenarios, and sensitivities, but it exercised its independent judgement in carrying out the modeling work and the production of study results.

This study is part of ISO New England's broader efforts to assist the region in evaluating the potential needs of a future grid that meets the states' climate and energy goals. The process leading to the final report of this study included numerous meetings with the New England states and the New England Power Pool (NEPOOL) participants to identify the potential approaches, including design concepts; to develop assumptions, scenarios and sensitivities; and to discuss the quantitative and qualitative analysis approach and findings. The ISO and the Analysis Group sought and received valuable feedback during the study process and on a draft version of this report.

The *Pathways Study* provides the region with significant data and analysis to evaluate four approaches that could meet the New England states' ambitious environmental goals. The objective of the study was not to determine a preferred approach, but rather to examine key differences and tradeoffs between the pathways. The findings indicate that all of the approaches considered can achieve substantial greenhouse gas emissions reductions; however, each approach has different implications for economic and market outcomes. Each approach also differs in the degree of coordination needed among the six New England states, as well as in the level of complexity in implementation. In addition, as detailed in the *Pathways Study*, certain approaches have greater implications for the sustainability of competitive wholesale electricity markets.

ISO New England appreciates the work of the Analysis Group and all of those who participated in the process. With this critical information in hand, the region can now seek to find consensus on a path forward and begin to discuss important related issues, such as legal and jurisdictional issues and market design requirements.

A lot of work remains, but the ISO looks forward to the continued collaboration with the states and regional stakeholders to find the most efficient way to meet New England's needs for a clean and reliable future grid.

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Glossary of Terms

Abbreviation	Definition
AEO	Annual Energy Outlook
ATB	Annual Technology Baseline
ATWACC	After-Tax Weighted Average Cost of Capital
BOEM	Bureau of Ocean Energy Management
BTM	Behind-the-meter
BTM PV	Behind-the-meter Photovoltaic
CEC	Clean Energy Certificate
CELT	Capacity, Energy, Loads, and Transmission Report
CEM	Capacity Expansion Model
CO_2	Carbon Dioxide
CO_2e	Carbon Dioxide Equivalent
EAS	Energy and Ancillary Services
EIA	Energy Information Administration
EMS	Energy Market Simulation
FCA	Forward Capacity Auction
FCEM	Forward Clean Energy Market
FCM	Forward Capacity Market
FERC	Federal Energy Regulatory Commission
FGRS	Future Grid Reliability Study
GHG	Greenhouse Gases
ICCM	Integrated Clean Capacity Market
ICR	Installed Capacity Requirement
LMP	Locational Marginal Price
MT	Metric Ton
MTCO2e	Metric Ton Carbon Equivalent
NA	Not Applicable
NCP	Net Carbon Pricing
NECEC	New England Clean Energy Connect
NEPOOL	New England Power Pool
NESCOE	New England States Committee on Electricity
NREL	National Renewable Energy Laboratory
O&M	Operations and Maintenance
PPA	Power Purchase Agreement

Abbreviation	Definition
PV	Photovoltaic
REC	Renewable Energy Certificate
RGGI	Regional Greenhouse Gas Initiative
RPS	Renewable Portfolio Standard(s)
SMART	Solar Massachusetts Renewable Target
SRMC	Short-Run Marginal Cost

Pathways Study: Evaluation of Pathways to a Future Grid

I. Executive Summary

To address global climate change arising from increasing concentrations of greenhouse gases ("**GHGs**"), the New England States have developed ambitious targets to reduce GHG emissions from economic activity throughout the economy. While the region's states have begun to implement policies to meet these environmental objectives, substantial reductions in GHG emissions will be needed in the coming decades to achieve them. Reducing GHG emissions from the electric power sector will be an important component in meeting these targets as plans to decarbonize other sectors of the economy – *e.g.*, transportation and space heating – depend heavily on these sectors switching to electricity. The Pathways Study evaluates which policy or regulatory approach is best suited to achieving these emission reductions in the New England's electric power sector.

In particular, the Pathways Study focuses on four potential approaches — one of these is a continuation of the current policy approach employed by the New England States, while the other three would involve a **"centralized" solution**, requiring some degree of coordination among the states:

- **Status Quo**, continuing current unilateral state policies, which incent the development of clean energy resources using bilateral power purchase agreements ("**PPAs**"), with the corresponding costs allocated to electricity consumers;
- **Forward Clean Energy Market ("FCEM")**, compensating non-emitting resources via the development of a centralized, forward market for clean energy, with the corresponding costs allocated to electricity consumers;
- **Net Carbon Pricing ("NCP")**, pricing carbon emissions from generators and returning the carbon price revenues to electricity consumers; and
- **Hybrid Approach ("Hybrid")**, combining a carbon price sufficient to provide revenue adequacy for existing clean energy resources with an FCEM that provides incremental compensation only to new clean energy resources.

We consider only the four policy approaches listed above, but recognize that other alternatives are possible, including combinations of these policies (*e.g.*, fixed carbon price with an FCEM for all clean energy) or transitions over time from one approach to another (*e.g.*, the Status Quo accompanied by gradually increasing carbon prices over time). While our study provides an overview of the key conceptual design elements and options for each approach (*see* **Section III**), its primary objective is to identify and assess the tradeoffs in economic and regulatory considerations between each of these approaches, accounting for the particular circumstances of New England's electricity grid, the multi-state region that it covers, and the region's natural resources, including the potential for variable renewable electric generation.

Our analysis does not consider in depth (but may inform) many other issues relevant to developing decarbonization policies for the region, including legal and regulatory considerations, reliability outcomes, and potential transmission system needs. Thus, the study is intended to provide information on the key economic and regulatory factors to help inform, along with information from other studies and initiatives, discussions within the region about potential future pathways for New England's climate policy. Further, our study does not provide an exhaustive assessment of design issues for any of the policy approaches; thus, further investigation and deliberation would be required if the region were to pursue any of these approaches given the complexity of developing these policies. All of the approaches would require meaningful time and effort to develop and some level of complexity to implement, though that may vary among the approaches.

Our analysis is informed by a quantitative analysis that evaluates each approach's performance in achieving aggressive decarbonization (carbon emissions at 80% below 1990 levels) by 2040. This analysis provides information helpful to assessing how the choice of a policy approach impacts market outcomes, social costs, customer payments and other economic metrics. Our modeling uses common assumptions about loads, supply options, and environmental (emission) targets, such that the only differentiating factor is the regulatory approach used to incent incremental emission reductions. However, our quantitative analysis is not a forecast of future market conditions, particularly because future market conditions, technological features, and market rules are likely to shift from those assumed. For example, under all of the approaches, the current wholesale market rules are presumed to remain intact, although in practice, we expect that market rules will likely change during the twenty years comprising the study period. Moreover, assumed state procurement outcomes could also differ from actual procurement outcomes, if states pick different resources to sponsor based on costs or other considerations. Given uncertainties, we consider the sensitivity of our general findings to changes in key assumptions.[1] While changes to key assumptions change the level of economic outcomes (*e.g.*, costs go up or down), the relative impacts across policy approaches are generally insensitive to these alternative assumptions.

Table ES-1 summarizes the key considerations differentiating the four policy approaches for decarbonization evaluated in the Pathways Study. Our findings reflect both analytic economic evaluation and the results of our quantitative analysis of each approach in achieving aggressive decarbonization. Below, we provide further detail on each of these factors and discuss the economic outcomes under each policy approach from our quantitative analysis.

[1] We analyze: an alternative, more stringent decarbonization target; alternative capital costs of renewable and fossil technologies; increased retirements (to approximately 12 GW); an alternative allocation of clean energy costs among states; alternative compensation to existing resources in the Status Quo approach; outcomes under alternative transmission infrastructure (congestion) costs; and alternative revenue (LMP) target for the Hybrid Approach.

Table ES-1. Summary of Key Factors Differentiating Decarbonization Pathways Policy Approaches

Policy Factor	Status Quo	FCEM	Net Carbon Pricing	Hybrid Approach
Policy Flexibility and Challenges				
Reliance on Regional Coordination and Consensus	• Low (unilateral state policies)	• Can coordinate state clean energy goals • Requires consensus on CEC product definition (and potentially CEC target and state allocations)	• Requires CO_2 price or target consensus	• Requires consensus on CO_2 price and CEC product
Cost Allocation Flexibility	Low (bound by unilateral policies)	High (through assignment of CEC obligations)	Moderate (through allocation of carbon revenues)	Moderate/High (through assignment of CEC obligations and allocation of carbon revenues)
Emission (and Cost) Uncertainty	Medium		Low-High (varies by design, with tradeoff between emission and cost uncertainty and need for forward policy commitment)	
Implementation Challenges (Examples)		• Determining CEC quantity needed to achieve GHG target • Integration of FCEM with FCM (if proposed)	• Determining carbon price needed to achieve GHG target (with a fixed carbon price)	• Risk of existing clean energy resource exit • Tension between retaining existing clean energy resources and potential customer savings from price discrimination • Complexity of administrative calculations of carbon price and CEC quantity
Other Policy Dimensions				
Legal	Pathways Study does not address legal and regulatory issues associated with alternative policy approaches, including jurisdictional issues and compliance with existing federal and state statues and policies, such as requirements not to create undue discrimination in competitive markets			
Reliability	Pathways Study does not address variable renewable integration, capacity market uncertainty, or other dimensions of reliability			
Transmission	The Pathways Study accounts for some (but not all) transmission costs and accounts for certain transmission constraints, but does not provide a thorough analysis of transmission needs of a decarbonized system			

Table ES-1. Summary of Key Factors Differentiating Decarbonization Pathways Policy Approaches

Policy Factor	Status Quo	FCEM	Net Carbon Pricing	Hybrid Approach
Economic and Market Outcomes				
Cost-effective CO_2 Emission Reduction	Low	Moderate/High	High	Moderate/High
Cost-effective incentives for reductions in carbon-intensity	No	No	Yes (efficient)	Yes (but less than efficient level)
Cost-effective incentives for clean energy investment	NA (no in-market incentive, depends on administrative planning)	Partial (Incents clean energy generation, but not necessarily cost-effective choice among clean energy resources)	Yes (efficient)	Yes (mix of FCEM and carbon price)
Cost-effective incentives for investment across time	No (no in-market incentive, depends on administrative planning)	Yes (for clean energy investment)	Yes (efficient)	Yes (mix of FCEM and carbon price)
Transparent Price Signals	No	Yes (creates carbon or CEC price signal)		
Negative LMPs	Yes (potential storage "churning", inefficient battery use/investment)	Yes (potential storage "churning", inefficient battery use/investment)	No	Yes (potential storage "churning", inefficient battery use/investment, less than Status Quo and FCEM)
Price Discrimination	Yes (risk of inefficient entry/exit, capital turnover; need for additional out-of-market contracts)	No	No	Yes (risk of inefficient entry/exit, capital turnover)
Potential Distortions in Market Offers	Yes (*e.g.*, curtailment based on PPA price, not costs)	No	No	No

Achieving Emission Reduction Targets (Section VI.A)

In principle, all four policy approaches are capable of achieving substantial levels of decarbonization, as each policy approach has sufficient policy "levers" to achieve any given emission target.

However, the policy approaches differ in the amount of cooperation among the six New England states is required for implementation. Because it is already the result of the unilateral actions of each of the six New England states, the Status Quo approach involves no coordination. While the centralized approaches require some degree of coordination, they differ in their ability to accommodate different ways in which the New England States may choose to cooperate. One path for cooperation is for the states to adopt a regional decarbonization target, developed through consensus among the New England States, and agree to pursue this target through a centralized policy approach. This "regional consensus" requires agreement by all New England States about the regional target (for emissions or CECs) and, in principle, represents the only approach likely to achieve a particular regional "consensus" decarbonization target that is any different from simply adding up of the six state's unilateral actions. All of the centralized policy approaches can accommodate this level of regional cooperation, although the scope of issues over which consensus is needed would differ.

Another path for cooperation is for the states to agree to coordinate their efforts to meet decarbonization goals without necessarily reaching consensus on a specific regional decarbonization target. This path, in effect, simply "adds up" the targets from individual, unilaterally adopted state policies (*e.g.*, state emission or clean energy targets), but does not expand on decarbonization goals beyond what each state is undertaking on its own but may allow state-level targets to be achieved in a more coordinated fashion. The FCEM offers an approach that can coordinate actions to achieve existing state-level targets through a centralized market for clean energy production, although such coordination would require consensus regarding certain market elements, such as product definitions (*e.g.*, definition of a CEC).[2] An FCEM also provides flexibility to allocate costs based on different criteria reflecting each state's "demand" for decarbonization. However, such flexibility may require negotiation over state-by-state cost allocation, which may impede rather than enhance coordination under some circumstances.

Carbon pricing can also attain such coordination through a cap-and-trade system, but only if all six states (or all states with fossil-fired generators) participate in translating individual state emission targets into a regional emission target. Like the existing Regional Greenhouse Gas Initiative, the revenues from carbon costs could be returned to customers in each state via various formulas, which would account for a portion of the distributional consequences of carbon pricing. However, cap-and-trade otherwise leads to allocation of payments according to customer load as the carbon price is included in the energy market prices ("**LMPs**").[3] A fixed, predetermined carbon price would be similarly challenging absent consensus, as common agreement would need to be reached on the level of the price.

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[2] Some have suggested that an FCEM could be limited to a subset of New England states, in the event that all states do not opt to participate in a centralized approach.

[3] LMPs refers to locational marginal prices.

The approaches also differ in the degree of certainty they provide about the emission (and cost) outcomes. The FCEM and Net Carbon Pricing via cap-and-trade fix environmental (clean energy or emission) targets, thus creating greater certainty that targets will be achieved. However, this environmental certainty is achieved at the expense of cost certainty, as the cost of achieving emission targets is unknown and could be much higher (or lower) than expected. By contrast, a fixed carbon price fixes costs in advance, but the price may be set either too low or too high to achieve any intended emission target. However, various market design features can be adopted to moderate these “stark” outcomes to achieve a balance between cost and emission uncertainty, such as price floors and price caps. Moreover, in practice, given the long time periods over which climate policy is made, key policy features affecting policy stringency — such as the level of carbon prices or emission targets for new compliance periods — may be set (or modified) over time to account for new information about the true costs and benefits.

Incentives for Reductions in GHG Emissions

Each of the policy approaches differ in how they incent changes in system resources and operations, and these differences, in turn, affect each approach’s cost-effectiveness in reducing carbon emissions. The incentives differ for two primary reasons. *First*, the approaches differ in the types of price signals used to incent decarbonization. *Second*, the approaches differ in whether incentives apply to all or only some resources. In each case, key differences in the approaches include whether they incent all ways (or only some ways) of reducing emissions, whether they target least-cost reduction approaches, and whether the incentives have unintended consequences for ISO-NE markets.

Incentives from In-Market Price Signals (Section VI.B)

Net Carbon Pricing achieves emission reductions cost-effectively, creating price signals that incent all substitutions that can reduce emissions. The other policy approaches fall short of this standard, failing to create efficient price signals to incent certain kinds of emission reductions or fail to create clear and transparent price signals to incent reductions. In particular:

- While the ***FCEM*** (with a uniform CECs)[4] incents the least-costly sources of “clean energy,” it fails to provide incentives for reductions in the carbon-intensity of fossil generation and fails to directly account for the carbon-intensity of the generation it displaces when rewarding clean energy (and thus provides no direct mechanism to ensure clean energy is rewarded only when it displaces fossil generation, rather than displacing other variable renewable generation).[5]

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[4] Some have discussed an FCEM with multiple types of CECs, representing different technologies or characteristics, rather than a single, uniform CEC definition. In general, an FCEM with multiple CEC products would be less cost-effective in reducing carbon emissions.

[5] Given bidding incentives in the ISO-NE energy markets, variable renewable resources may be indirectly incented to avoid supplying when there is an excess of clean energy supplies, leading to economic curtailments, as negative LMPs will diminish the margins earned during these periods.

- Incentives under the ***Hybrid Approach*** generally reflect a blend of the Net Carbon Pricing and the FCEM, although incentives are weaker for existing clean resources than new clean resources due to the absence of incremental revenues from CEC awards for existing resources.
- The ***Status Quo*** approach does not rely on transparent price signals to incent the right levels of clean energy investment at the right time (let alone incenting other ways of reducing carbon emissions, such as lower-emission fossil generation). Instead, it relies solely on the incentives created by resource procurements using long-term PPAs. Thus, the cost-effectiveness of the Status Quo in incenting the least-costly sources of clean energy and accounting for the carbon-intensity of generation being displaced depends on the outcome of the administrative processes used to develop and implement these procurements. These outcomes will depend on a host of factors, such as the effectiveness of administrators in designing and implementing efficient procurements, the criteria used in selecting among multi-attribute proposals, state and administrator preferences (*e.g.*, location, technology), and bidding behavior given pricing terms.

Policy approaches also differ in the extent to which they cost-effectively incent the timing of emission reductions. With the centralized approaches, carbon or CEC price signals incent cost-effective timing of investment to achieve cumulative decarbonization objectives. The Status Quo can only achieve such cost-effective investment timing through administrative analysis that determines when investments should be undertaken, rather than relying on the market response to price signals.

The policy approaches also differ in the distortions they may introduce to market outcomes. In particular, the Status Quo, FCEM and Hybrid could lead to frequent and large negative LMPs. For example, in the FCEM and Status Quo, we find that 28% to 33% of hours have negative LMPs in 2040. These negative prices are the result of the payments made to clean energy resources outside the energy markets (*e.g.*, PPA prices or CEC awards), which incent them to offer energy supply at a *negative* price. Thus, when the market clears at these offers (*e.g.*, when there is an excess supply of variable renewable energy), they set the market-clearing price. Because the region has not previously experienced negative LMPs with this frequency, the consequences to market operations (and reliability) are uncertain. In principle, such pricing could place greater pressure on other markets and revenues sources to cover costs. Specifically, negative pricing would be expected to increase energy uplift for resources with intertemporal operating constraints (*e.g.*, minimum runtimes) and could lead to inefficient operation of resources in the ISO-NE markets, particularly storage resources. The potential inefficient operation of storage resources due to negative pricing is explained further below.

These differences in incentives have important implications for the cost-effective development and efficient operation of various types of resources on the system and are illustrated by our quantitative analysis.

- ***Variable Renewable Resources***. The market-based incentives created by each of the centralized approaches are likely to lead to similar mixes of variable renewable resources, as all create similar transparent price signals to incent the lowest-cost clean energy, accounting for factors such as correlated output and economic curtailments (which could diminish potential supply). By contrast, while the Status Quo competitive procurements would introduce competition into the procurement process, the process may not identify or procure the lowest cost resources, as procurement outcomes would depend on many factors, some of which might cause selected resources to differ from a least-cost mix.

- ***Energy Storage***. Energy storage can help address the weather-dependence of solar and wind resources that are the primary means to generating clean energy given current commercially available technologies. Along with providing flexible supply to maintain reliability, energy storage can lower emissions by shifting variable renewable supply from periods when it would be curtailed to periods when it can displace fossil-fired resources. Each policy approach incents energy storage resources by increasing the spread in energy market LMPs (*i.e.*, the difference between on-peak and off-peak prices), thus allowing the battery to earn greater profits from shifting energy from lower-priced periods (with excess variable renewable energy) to higher-priced periods (when fossil resources set market-clearing prices). Our quantitative modeling confirms that all approaches can incent substantial supplies of new storage capacity.

  With Net Carbon Pricing the increase in the spread between on- and off-peak LMPs reflects the cost of carbon, thus providing efficient incentives for storage investment and operations. However, the spreads created by other policy approaches may not reflect this efficient incentive, potentially being too high or too low.

  More importantly, due to frequent and large negative prices, these approaches may incent inefficient battery storage "churning" of otherwise economically curtailed energy, in effect being paid to generate CECs for clean energy resources even though the generated energy does not displace carbon-intensive generation.[6] The potential for energy storage "churning" depends on multiple factors, but particularly the extent to which advanced technologies emerge that can profitably consume energy when LMPs are negative, such as expanded flexible demands that can shift load from high to low (or negative) LMP periods[7] or production of "green" hydrogen, and thus submit higher (less negatively) priced offers to buy energy than those submitted by battery storage.

- ***"Clean" Dispatchable Resources.*** At present, commercially-viable clean energy resources are largely limited to PV solar, onshore wind and offshore wind, all of which are included in the Pathways Study. While not yet commercially viable, dispatchable resources powered by "clean" fuels would contribute greatly (and be potentially necessary) to integrating renewables and maintaining reliable system operations in a highly decarbonized system, similar to the function currently played by gas-fired resources. The centralized approaches each provide a technology-neutral incentive, because they offer an in-market incentive reflecting the value of clean energy or emission reductions. However, structuring a PPA under the Status Quo approach for these resources could pose challenges because the amount of the needed subsidy (given the higher relative fuel costs) would not be known in advance, could vary over time and could require difficult-to-observe information. Moreover, contracts would

[6] When prices are negative, the battery is *paid* to charge with otherwise curtailed variable renewable energy and then pays to discharge a smaller quantity of energy (due to energy losses), resulting in a net positive payment. Such battery storage churning provides no social benefit, but increases social costs due to additional battery degradation. The higher returns from such churning could lead to greater, but inefficient, levels of battery storage investment.

[7] For example, space-heating electrification with thermal storage or electric vehicle charging.

likely need to span the plant's entire operational life to provide the on-going subsidy needed to make the more-costly fuel competitive, rather than be limited to a finite multi-year period to recover fixed capital costs.

- ***Fossil-fired Resources.*** Net Carbon Pricing, and to a lesser degree, the Hybrid Approach, would provide incentives to reduce the carbon-intensity of fossil-fuel generation when cost-effective to do so. The quantitative analysis shows that carbon pricing can lead to reductions in carbon-intensity and promote a more efficient, lower-emission gas-fired fleet (with more-efficient combined-cycle capacity compared to less-efficient combustion turbines). However, because New England's fossil fleet relies primarily on natural gas and is already relatively efficient, the scope for these cost-effective emission reductions through improved carbon-intensity is limited given current technologies. This conclusion could change, however, with significant improvements in gas-fired technology or low-carbon fuel blending (*e.g.*, natural gas and either green hydrogen or renewable natural gas) that would create the potential for substantial reductions in carbon-intensity, which could be most cost-effectively unlocked using carbon pricing. Such low-carbon technologies can have an important role in achieving decarbonization goals, as they may offer a cost-effective source in energy under declining emission targets and may provide operational flexibility not available from other clean energy technologies.

Price Discrimination (Section VI.C)

The policy approaches differ in whether they create incentives for all or only some sources of carbon emissions reduction or clean energy production. Both the FCEM and Net Carbon Pricing are technology- and vintage-neutral — that is, both create incentives reflecting environmental attributes (either carbon emissions or clean energy production) while not otherwise differentiating based on plant, technology, location or vintage characteristics. By contrast, the Status Quo and Hybrid Approaches would provide different compensation for resources providing otherwise similar services based on their characteristics or circumstances (*i.e.*, they "price discriminate"). Specifically, the compensation under the Status Quo and Hybrid Approach depends on a resource's vintage. Under the Status Quo, new resources can be awarded PPAs, with pricing terms potentially differing from contract to contract, while existing resources would not have the opportunity to enter into such contracts.[8] Under the Hybrid Approach, only new resources are awarded CECs for their clean energy, while existing resources receive no such awards. These differences may raise legal issues in the context of Federal Energy Regulatory Commission ("**FERC**") regulated wholesale markets[9] — we do not opine on these issues, other than noting the legal risks associated with pursuing this approach.

Given legal questions about whether the Hybrid Approach imposes undue discrimination on wholesale electricity markets, this approach may face uncertain regulatory risks. In addition, price discrimination can

[8] In principle, procurements could include new and existing resources, although, to date, most procurements have targeted new resources, though there have been certain notable exceptions (*e.g.*, nuclear facilities).

[9] FERC, "Technical Conference regarding Carbon Pricing in Organized Wholesale Electricity Markets," Docket No. AD20-14-000, available at https://www.ferc.gov/news-events/events/technical-conference-regarding-carbon-pricing-organized-wholesale-electricity.

have adverse economic consequences. *First*, more favorable compensation (and contractual terms) available to certain resources, but not others, can lead to inefficient outcomes, particularly the inefficient use of capital, with excess capital flowing to favored resources, to the detriment of less-favored resources. Specifically, favoring new resources over existing resources can lead to economically premature retirement, inefficient investment in facility maintenance, or exit from the system (*e.g.*, exporting supply to other systems). *Second*, under the Status Quo, variation in PPA prices would determine the order in which variable renewable resources are economically curtailed when there is excess supply of variable renewables (*i.e.*, “overgeneration”). Variable renewables with lower out-of-market payments (*e.g.*, no PPA or a lower-priced PPA) would be curtailed before resources with higher-price PPAs.[10] This outcome would exacerbate the new capital bias by paying higher compensation to new resources, compared to existing resources.

Total Social Costs (Section VI.D)

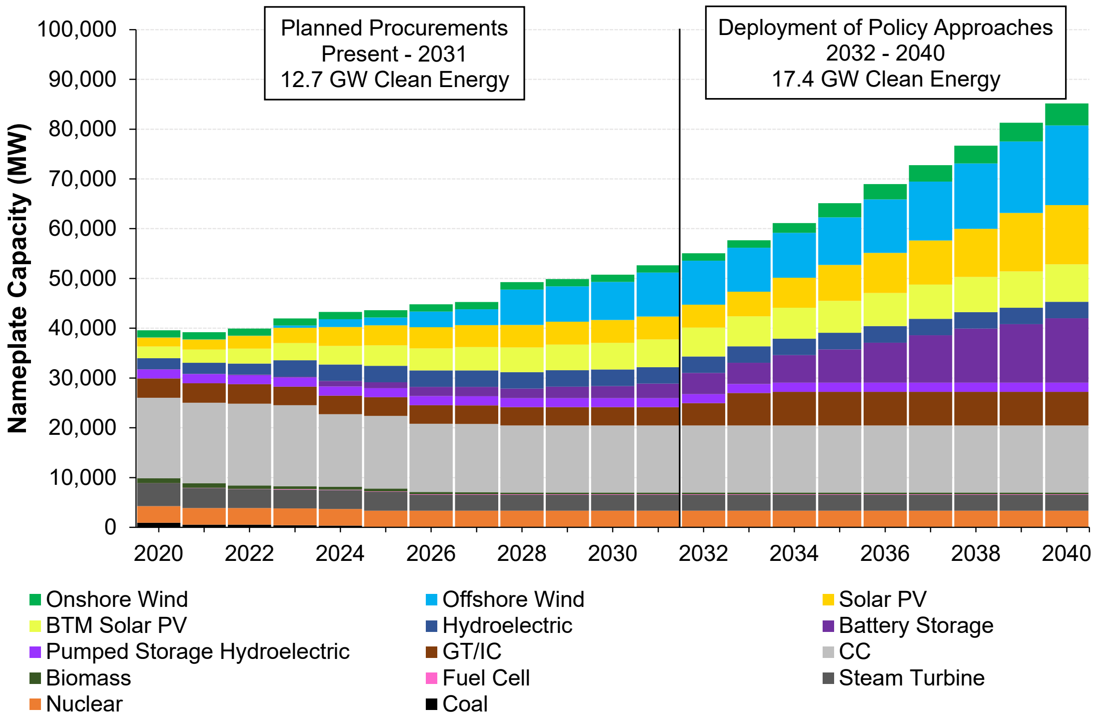
The quantitative analysis estimates the social costs of achieving decarbonization goals, accounting for capital, fixed, variable, fuel and other variable costs of developing and operating a decarbonized New England grid. We account for all costs associated with generation resources (including transmission needed to ensure delivery of new variable renewable resources), but do not consider transmission costs associated with system-wide upgrades that may be needed to reliably support the increased loads, new patterns of energy flows, and need to integrate more-variable resource supplies and loads. These estimates of social costs provide the best metric for evaluating each policy approach’s economic performance, as social costs reflect the true cost of using society’s resources to achieve public benefits, in this case, a decarbonized power grid.

Our study focuses on actions to decarbonize New England’s electricity sector in the second half of our study period, from 2030 to 2040, which reflects the *assumption* that the New England states continue to pursue various Status Quo near-term planned procurements that result in substantial buildout of variable renewable supplies, particularly offshore wind, during the 2020s[11] with alternative approaches being introduced to achieve further decarbonization (and meet increased loads from heating and transportation electrification) in the later years of the study period. **Figure ES-1** shows the evolution of the resource mix under the Status Quo approach reflecting existing state plans and studies. However, the New England states retain the flexibility to alter this sequence of procurements and regulatory approaches to, for example, reduce near-term procurements and accelerate reliance on the alternative regulatory approaches considered in this study.

[10] Resources with higher PPA prices would be expected to submit *lower* (more negative) energy market offers. Thus, when there is overgeneration, the resources with lower PPA prices and higher, less negative, offers would be curtailed before resources with higher PPA prices and lower, more negative offers.

[11] We refer to these procurements as “baseline state policies.” While our quantitative analysis assumes that baseline state procurements occur in all four policy approaches, the states still retain discretion to undertake or forgo these procurements, and thus they could pursue a policy path in which all emission reductions from this point forward occur through one of the alternative centralized policy approaches.

Figure ES-1. Resource Mix, Status Quo Policy Approach, 2020-2040 (MW)



Our quantitative analysis indicates that decarbonization will be costly, requiring the development of large amounts of higher-capital cost resources. Thus, if the choice policy approach can meaningfully lower social costs, it will produce important economic benefits. In fact, our quantitative results confirm this is the case, showing that the choice of policy can have important consequences for social costs.

Figure ES-2 shows the annual incremental social cost per MWh from 2021-2040 of meeting a more stringent carbon emission target with each of the four regulatory approaches considered in the study, while **Table ES-2** shows the incremental social costs in 2040 and cumulatively over the study period (in present value terms).[12] These incremental costs are measured relative to the costs in a Reference Case, which has the same assumptions as each policy approach except the region does not achieve any electricity sector carbon emissions reductions beyond those resulting from the assumed clean energy procurements already planned by the states. Thus, our analysis captures the incremental costs of the next phase of decarbonization in the region beyond these assumed planned procurements, which are substantial enough to meet our assumed GHG emission targets given load growth over this period.[13]

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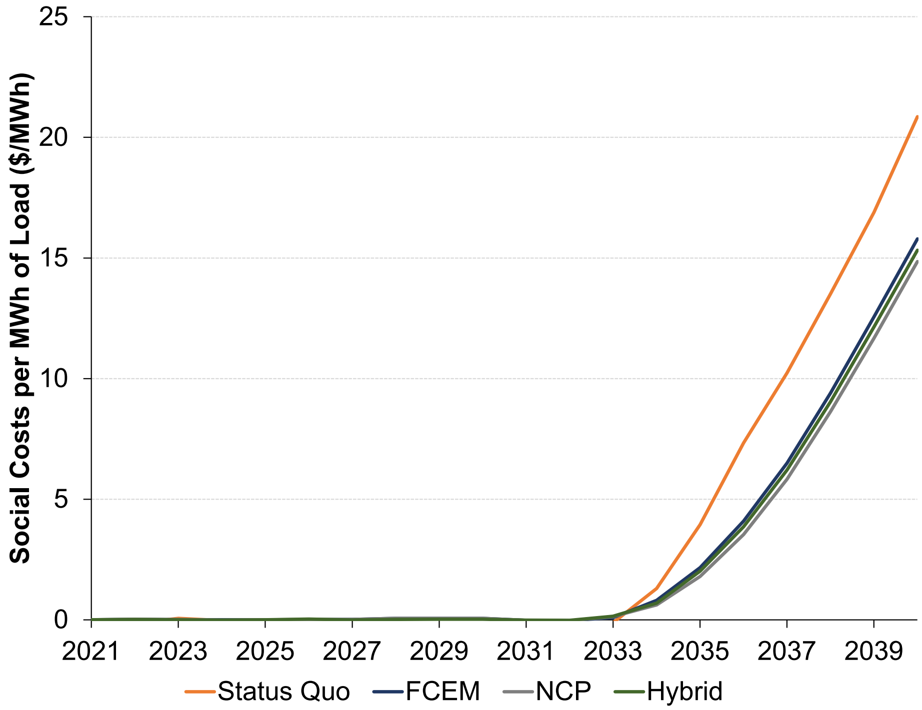
[12] Present value is calculated using a 5% real discount rate.

[13] Our model estimates this more stringent emission target would reduce carbon emissions by an additional 35 percentage points in 2040 relative to 1990 levels, from 45% below 1990 carbon emissions in the Reference Case to 80% below 1990 emissions in 2040. Our incremental cost estimates also reflect expanded electricity demand due

Figure ES-2. Average Incremental Social Costs by Policy Approach, 2021-2040 ($2020/MWh)



Note: Incremental social costs is the difference between social costs for each policy case and social costs in a baseline, Reference Case.

Incremental social costs (beyond the higher-emission Reference Case) start in 2033 and increase annually through 2040 to achieve the more ambitious regional 2040 emission target.[14] Consistent with providing cost-effective incentives for emission reductions, incremental social costs are lowest with Net Carbon Pricing, with a present value over the 2021-2040 study period of $3.9 billion in $2020[15] (and a nominal value of $3.0 billion in 2040, in $2020).[16] The incremental costs of the other centralized approaches, the FCEM and Hybrid Approach, are 9% and 5% higher, relative to the Net Carbon Pricing, in present value terms, respectively.[17]

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electrification of heating and transportation. However, our analysis only considers electricity sector outcomes, and thus capture the economy-wide impacts of decarbonization, which would reflect other incremental costs (*e.g.*, costs of new equipment) and savings (*e.g.*, reduced fuel consumption) in other sectors of the economy.

[14] Incremental abatement is not required until this year due to assumed clean energy procurements (the baseline state policies), common across all four policy approaches.

[15] Throughout the report, all dollar values reported from our quantitative modeling as in 2020 dollars (“$2020”).

[16] This social cost estimate includes variable costs and the amortized cost of incremental capital spent on new investment.

[17] The model does not assume CEC banking or allowance banking (if carbon pricing were implemented through cap-and-trade), which can lower costs of achieving cumulative emission reductions below the estimated costs.

Table ES-2. Incremental Social Costs by Policy Approach, 2040 and Present Value

	2040			2021-2040	
Policy Approach	Incremental Social Cost ($2020 M)	Incremental Social Cost ($2020/MWh)	Percent Change from Status Quo	Present Value of Incremental Social Cost ($2020 M)	Percent Change from Status Quo
Status Quo	4,256	20.86	-	6,027	-
FCEM	3,222	15.79	-24.3%	4,296	-28.7%
NCP	3,031	14.86	-28.8%	3,935	-34.7%
Hybrid	3,126	15.32	-26.5%	4,119	-31.7%

Note: Incremental social costs is the difference between social costs for each policy case and social costs in a baseline, Reference Case.

Estimated social costs are higher under the Status Quo compared to the centralized approaches. By 2040, the incremental social costs in the Status Quo are 40% higher compared to Net Carbon Pricing. This gap in costs widens over time, as loads increase due to electrification and environmental stringency increases due to declining emission targets. This outcome reflects several factors, including the absence of an in-market incentive for clean energy generation or GHG emission reductions, and the high cost of particular resources developed in the state climate roadmaps and plans. Our results, however, are not a forecast of the likely outcomes under the continuation of state policies represented in the Status Quo, but reflect one potential outcome of such a process and are indicative of the impacts associated with an administrative process that leads to resource outcomes that differ from the more cost-effective use of capital. In practice, there is uncertainty over the costs associated with the Status Quo, with actual costs that could be higher or lower than those estimated in our analysis.

Prices and Customer Payments (Section VI.E)

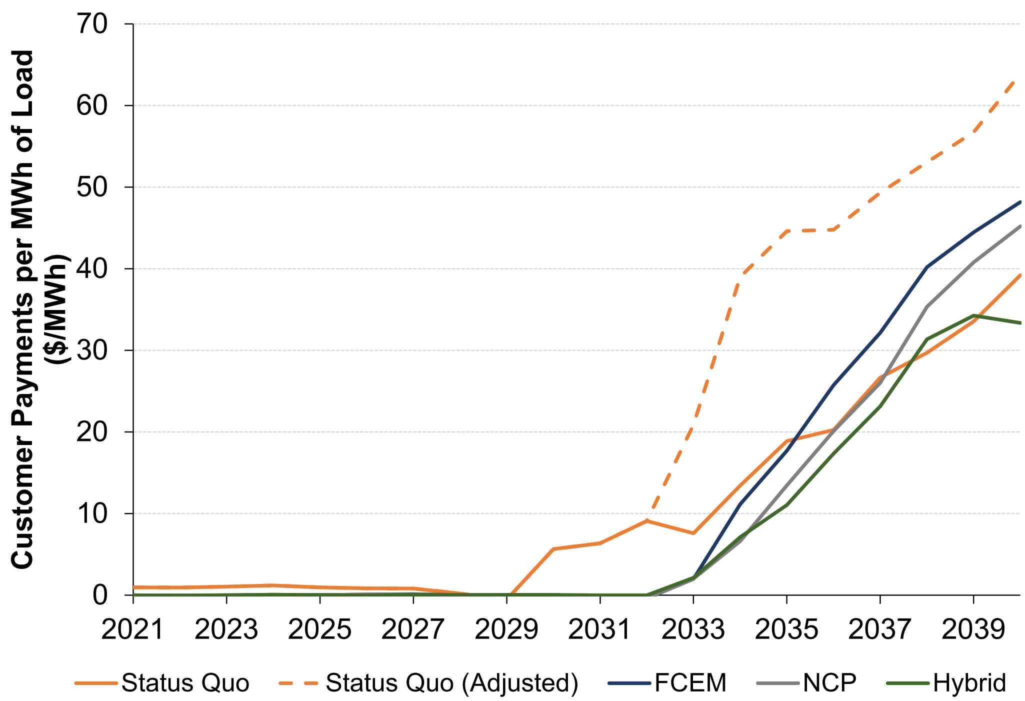
Total customer payments for wholesale energy include payments for energy, capacity and environmental attributes. Across the policy approaches in our study, the levels of payments in each category differ — thus, comparisons based on only one category may lead to incorrect conclusions about total costs. Moreover, in some cases, it is infeasible to unbundle payments into each category. For example, the PPAs relied on in the Status Quo bundle energy and environmental attributes into the PPA price, thus confounding the assignment of the payments to each category.

Compared to social costs, customer payments are a less-robust measure of economic outcomes, as they consider only the outcomes to customers (*i.e.*, “consumer surplus”), and do not account for producer outcomes (*i.e.*, “producer surplus”).

Figure ES-3 shows the annual incremental customer payments by policy approach from 2021-2040, while **Table ES-3** shows the incremental customer payments in 2040 and cumulatively over the study period (in present value terms). As with social costs, incremental payments reflect the increase in payments compared to the higher-emission Reference Case. Thus, the incremental payments are the additional payments needed to achieve the additional emission reductions associated with the more stringent decarbonization target. Total customer payments differ across policy approaches. Payments are lowest with the Hybrid, which achieves this result by price discriminating among different resources that provide the same environmental services. At the other extreme, the incremental payments under the Status Quo are nearly 40% greater than those under the Hybrid Approach (cumulatively over the study period), reflecting the particular mix of resources developed and differences in in-market incentives.

Estimated payments are particularly uncertain under the Status Quo, given uncertainty about both procurement outcomes and compensation to existing clean energy resources (*e.g.*, nuclear power and existing renewables) that are not awarded new resource PPAs. The central case (non-dashed line) for the Status Quo in **Figure ES-3** assumes some compensation to existing resources, toward the lower end of a reasonable range.[18] Some compensation would be expected due to retirement risks (due to declining financial viability from falling LMPs) and the potential to exit the system (*i.e.*, export energy to other regions). To bookend these results, compensation to these existing resources is increased to the same rate as new resources; under this assumption, total Status Quo payments increase substantially, such that they are 156% of payments with the Hybrid Approach across the study period. The sensitivity of total payments to this assumption illustrates the impact of the state's ability to differentiate levels of compensation between existing versus new resources.

Figure ES-3. Average Incremental Customer Payments by Policy Approach, 2021-2040 ($2020/MWh)



Note: Incremental payments is the difference between payments for each policy case and payments costs in a baseline, Reference Case.

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[18] Specifically, we assume the region's nuclear plants earn $41 per MWh on average for their energy supply and provide existing renewable resources with incremental revenues starting at $0/MWh in 2031 and rising to $60/MWh in 2040 for their clean energy supply.

Table ES-3. Incremental Customer Payments by Policy Approach, 2040 and Present Value, 2021-2040

	2040			2021-2040	
Policy Approach	Incremental Payments ($2020 M)	Incremental Payments ($2020/MWh)	Percent Change from Status Quo	Present Value of Incremental Payments ($2020 M)	Percent Change from Status Quo
Status Quo	7,997	39.20	-	18,692	-
Status Quo (Adjusted)	13,034	63.89	63.0%	34,368	83.9%
FCEM	9,828	48.18	22.9%	18,600	-0.5%
NCP	9,222	45.20	15.3%	15,872	-15.1%
Hybrid	6,806	33.36	-14.9%	13,442	-28.1%

Note: Incremental payments is the difference between payments for each policy case and payments costs in a baseline, Reference Case.

In general, while the level of social costs and payments changes in the scenarios we evaluate, which use alternative assumptions to the Central Case, the relative costs and payments do not change between policy approaches, indicating that findings based on the Central Case are generally robust to potential uncertainties. **Table ES-4** provides the range of social costs and customer payments across the scenarios, along with the Central Case results, reported in the tables above.

Table ES-4. Summary of Central Case and Scenario Estimated Social Costs and Payments

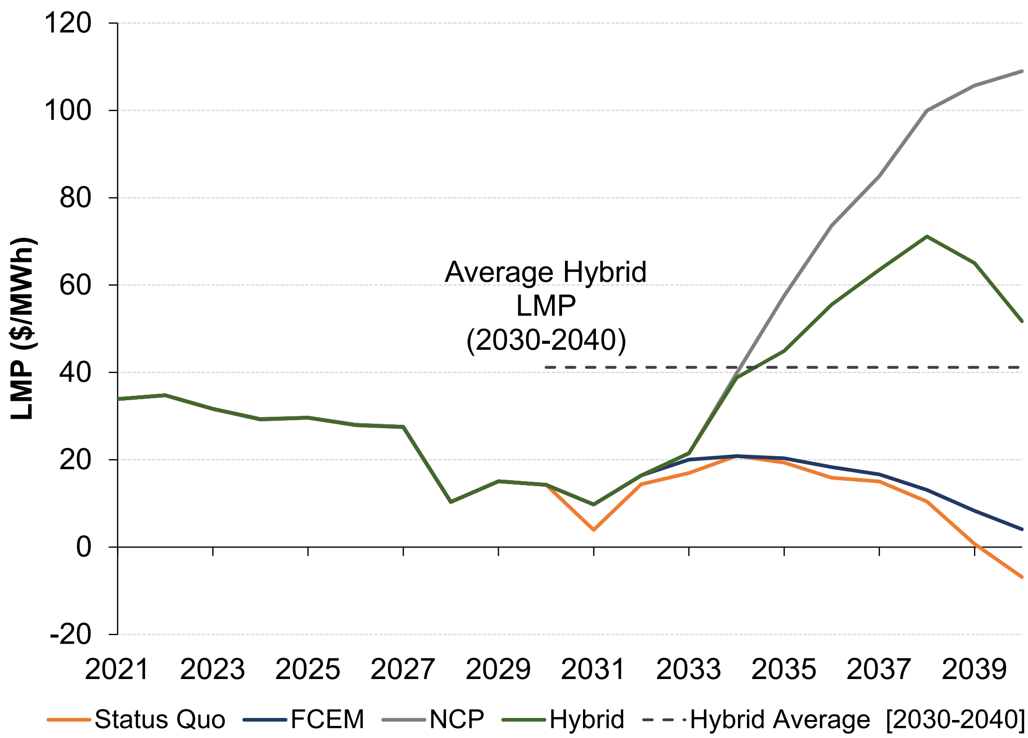
	Status Quo	Status Quo (Adjusted)	FCEM	Net Carbon Pricing	Hybrid Approach
Incremental Social Costs					
Central Case					
2021-2040 (PV)	6,027		4,296	3,935	4,119
2040	4,256		3,222	3,031	3,126
Scenarios					
2021-2040 (PV)	(4,125 - 9,249)		(3,148 - 5,798)	(2,922 - 5,613)	(3,026 - 5,888)
2040	(3,052 - 5,515)		(2,336 - 4,008)	(2,245 - 3,939)	(2,292 - 4,126)
Incremental Payments					
Central Case					
2021-2040 (PV)	18,692	34,368	18,600	15,872	13,442
2040	7,997	13,034	9,828	9,222	6,806
Scenarios					
2021-2040 (PV)	(16,984 - 19,865)	(25,868 - 39,514)	(14,030 - 21,420)	(11,892 - 20,133)	(10,945 - 15,573)
2040	(5,408 - 7,984)	(8,320 - 14,601)	(7,405 - 11,075)	(6,412 - 10,600)	(5,385 - 8,286)

Note: Incremental payments is the difference between payments for each policy case and payments costs in a baseline, Reference Case.

The energy market plays a critical role in determining the resource mix and the compensation to resources (and thus total consumer payments). LMPs differ dramatically under the four policy approaches. **Figure ES-4** shows annual average LMPs under each policy approach. Under Net Carbon Pricing, average LMPs increase to over $100/MWh in 2040 due to the addition of carbon prices. By contrast, under the Status Quo, average LMPs *decline* over time, and eventually become *negative* in 2040. These price declines occur because the energy market increasingly clears at variable renewable resource negative-priced offers because of the incentives offered through PPAs to deliver clean energy. By 2040, nearly one-third of hours experience negative pricing under the Status Quo. LMPs under the FCEM follow a similar trajectory to the Status Quo due to frequent negative-priced LMPs, because, like the incentives created by PPAs, CEC awards incent negative-priced offers for energy from clean energy resources. Hybrid Approach leads to LMPs intermediate to the other approaches.

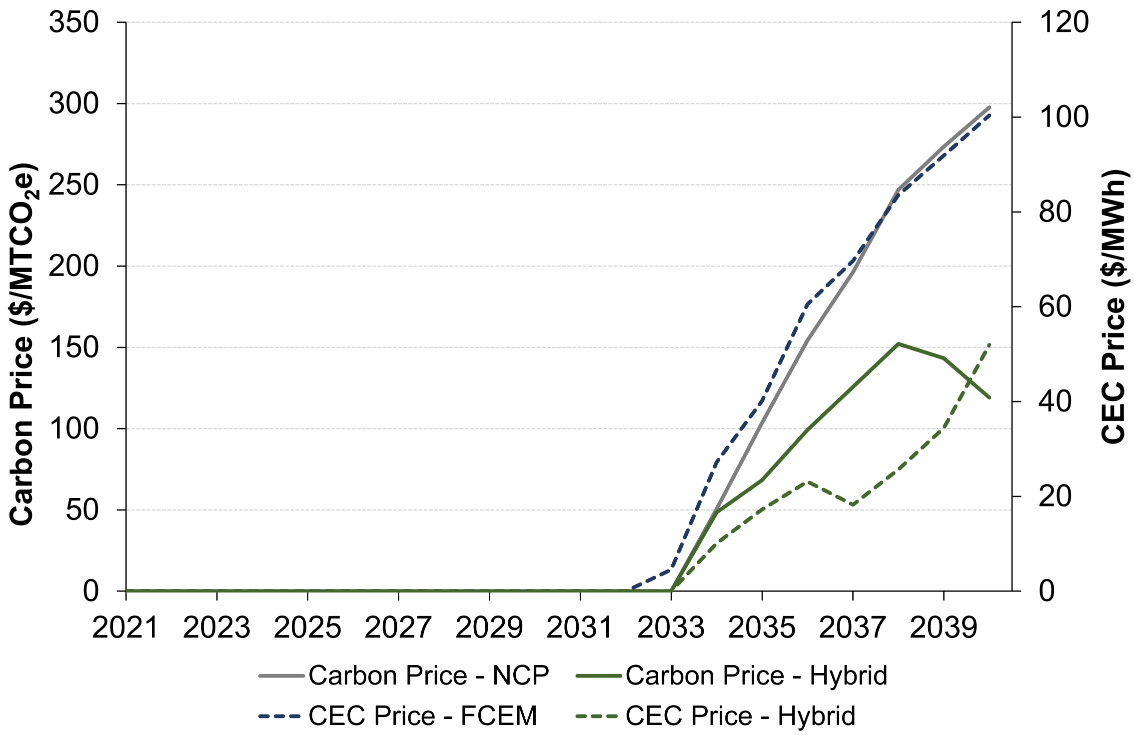
Across policy approaches, reliance on the wholesale energy market varies. In particular, the Status Quo procures an increasing quantity of energy over time through bilateral PPAs. Thus, the LMPs in **Figure ES-4** do not represent the price paid for energy through these PPAs, making the LMPs in this figure an inaccurate estimate of average energy cost (per MWh).

Figure ES-4. Annual LMP by Pathway, 2021-2040 ($2020/MWh)



Compensation (and consumer costs) must also consider payments for environmental attributes. **Figure ES-5** shows carbon prices and CEC prices under Net Carbon Pricing, the FCEM and the Hybrid Approach. Carbon prices and CEC prices rise steadily to nearly $300/metric ton carbon equivalent ("**$MTCO_2e$**") and $100/MWh in 2040, respectively. At high levels of decarbonization, carbon and CEC prices may rise steeply, as correlated output from weather-dependent renewable generators leads to increasing levels of economic curtailments, thus decreasing the effective supply new variable renewable can generate. With lower delivered energy, carbon prices (and thus LMPs) and CEC prices must rise to allow recovery of the fixed cost of capital.

Figure ES-5. Carbon and CEC Prices, 2021-2040 ($2020/MTCO₂e and $2020/MWh)



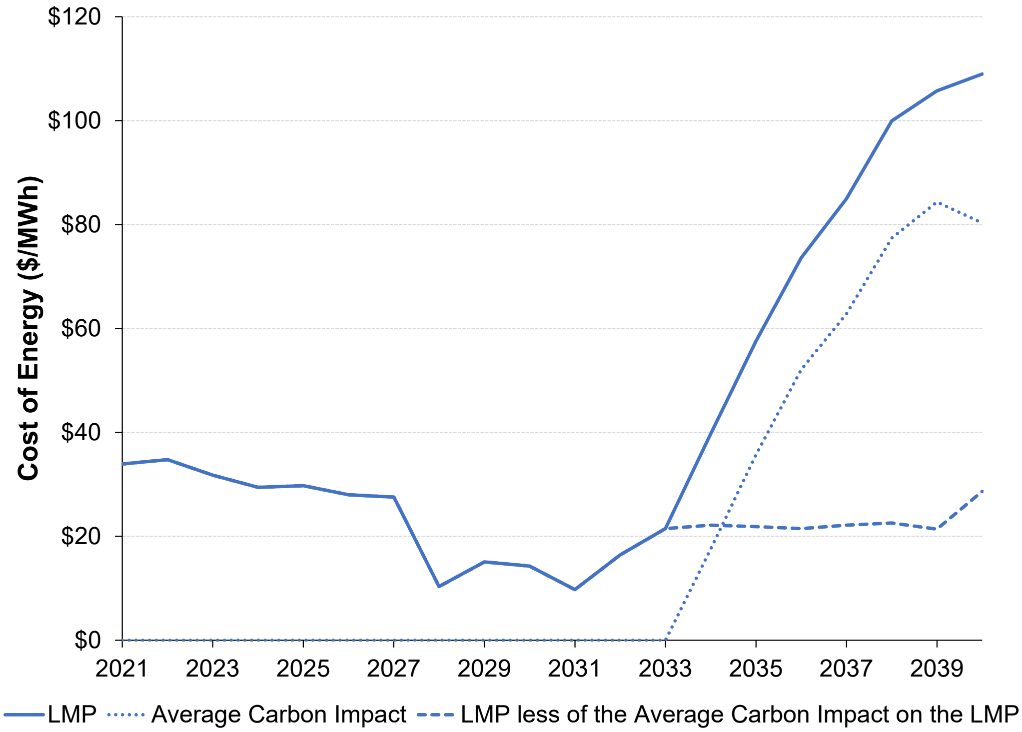
With CECs, the compensation for clean energy (and the payments by customers) is directly through the CEC price. However, with carbon pricing, there is no direct compensation for clean energy; rather, the "compensation" to clean energy (and lower emitting energy) is captured by the higher LMP, which reflects both generator costs (*i.e.*, fuel and operating costs) and the carbon costs from fossil plants. **Figure ES-6** illustrates the impact of carbon pricing on LMPs, decomposing average LMPs into the average variable costs and average impacts of carbon pricing.

Implications for ISO-NE Markets (Section VI.F.1)

The policy approaches have several other potentially important consequences for ISO-NE markets.

First, as we note above, the Status Quo, FCEM and Hybrid Approach would be expected to increase the frequency and magnitude of negative pricing. We show that negative pricing could exacerbate uplift and lead to inefficient plant operations, particularly for storage resources. Our study does not evaluate comprehensively the potential consequences of negative pricing for New England's electricity markets. However, given that the region has not previously experienced the frequent, large-magnitude negative pricing quantified in our study, further investigation of potential consequences may be warranted.

Figure ES-6. LMP and Average Impact of Carbon Price on LMP, 2021-2040 ($2020/MWh)



Second, the policy approaches could affect the region's resource adequacy outcomes. Under all policy approaches, energy market net revenues tend to decline for most fossil units in the ISO-NE system. Forward Capacity Market ("**FCM**") revenues may increase to offset these losses, shifting revenue recovery from the energy market to the capacity market. However, over time, as market conditions improve for new (non-fossil) technologies, such as battery storage, these new technologies may become the most cost-effective technology for supplying FCM qualified capacity, rather than gas-fired technology, thus reducing market-clearing capacity market prices (compared to prices needed to support gas-fired entry). This is the case in our analysis, which finds that battery storage technologies become the least-cost technology over the study period. This outcome would reduce FCM revenues paid to traditional fossil resources, thus increasing financial pressure for them to retire, and expanding the new technology's share of system resources. This shift in technology mix could have consequences for reliability particularly if the operational characteristics of these new technologies differ from traditional technologies. Such reliability issues must be carefully considered, but are outside the scope of this study. These effects would be expected to occur under all of the alternative policy approaches.

Under the Status Quo, however, resources procured through multi-year PPAs would not participate competitively in the FCM, as compared to the other policy approaches. In principle, market entry due to state procurements rather than transparent pricing could affect the market's performance, including diminished price discovery (*i.e.*, the market's ability to create price signals that reliably reflect the true cost of entry) and excess volatility. PPA procurement timing may be more uncertain than that arising from market-based approaches, particularly given the absence of transparent environmental price signals, creating uncertainty for going-forward revenue recovery for existing resources. Such impacts could lead to a more disorderly transition to a decarbonized grid, with potential interim impacts on reliability and market outcomes. More generally, continued reliance on multi-year PPAs for clean resources would likely crowd out any market-based entry for clean energy resources and could diminish the FCM's ability to incent development of other new resources through in-market price signals. Such outcomes would have implications for reliance on the FCM as the foundation of New England's resource adequacy construct. While our study touches on these issues, a full assessment of these issues is outside its scope.

Economic Consequences of Multi-Year Contracts (Section VI.F.2)

The Status Quo approach relies on procurement of clean energy through the award of multi-year contracts to new (and potentially existing) clean energy resources. The use of multi-year contracts introduces economic tradeoffs that we identify, but do not quantitatively assess. The use of multi-year PPAs would be expected to lower the cost of financing new clean energy projects, although we do not see PPAs as necessary to the development of new clean energy projects, assuming revenue increases needed to cover higher going-forward costs from CECs and/or carbon pricing. While potentially lowering financing costs, the use of multi-year PPAs could result in a countervailing increase in the cost to customers of the New England states, as these PPAs transfer risk from suppliers to customers. This transfer of risk grows as more contracts (representing larger commitments to purchase energy) are signed to incent increases in clean energy. Given the scale and pace of decarbonization contemplated by the region, the aggregate liability (whether on the books of the region's regulated utilities or implicitly held by the region's customers) represented by such commitments (and the associated consequences for creditworthiness) could be large. Thus, the use of multi-year PPAs creates a tradeoff between lower costs to suppliers, which in principle may be passed along to customers in the form of lower PPA prices, and an additional cost to customers given the transfer in risk. Available information, however, is insufficient to determine whether the tradeoff would be, on net, beneficial or detrimental to customers.

Challenges for Policy Implementation (Section VI.F.3)

If the New England region decides to pursue a centralized policy approach, development and implementation would require meaningful effort and time by ISO-NE, NEPOOL Stakeholders and the New England States, including further scoping of the policy design, analysis to ensure proposed designs are feasible, development of implementing rules and regulations, and development of supporting institutional capacity. Prior experience with a policy approach can reduce, but not eliminate, needed time and effort. There is substantial experience with carbon cap-and-trade, (fixed) carbon pricing and various types of market-based environmental standards (*e.g.*, RPS). This experience demonstrates the feasibility of many the policy approaches, such as Net Carbon Pricing and aspects of the FCEM, although this experience also shows that the time and effort required to develop effective policies and systems can be substantial.

However, there is less experience with certain aspects of some of the policy approaches. While there is experience with market-based systems for environmental attributes, such as RECs, the FCEM would involve certain policy design elements that have not been used previously, which may thus require substantial time and effort to scope, design and develop. These, include, but are not limited to, development of model rules to standardize state-level regulations creating demand for CECs (most policies have relied on compliance requirements from a single jurisdiction), a centralized forward market (as most of these markets have relied on bilateral markets), consideration of interactions with existing state environmental initiatives, and the potential integration of the FCEM with the existing Forward Capacity Auction used to procure capacity (referred to as the Integrated Clean Capacity Market or ICCM).

In some case the lack of experience and complexity of the proposed design raises questions of policy feasibility. For example, for the ICCM, the complexities involved in the joint forward procurement of CECs and Capacity Supply Obligations raise particularly complex questions with implications for both approach's feasibility and merit from an economic perspective (in light of the tradeoffs between costs of developing such a market and the benefits achieved through more efficient resource procurements).

Much like the Integrated Clean Capacity Market, the Hybrid Approach is a completely novel approach, which may raise questions concerning whether it can be designed to effectively meet its stated objectives. While there is much experience with carbon pricing and market-based policies like an FCEM (with the caveats noted above), we are unaware of any policy that attempts to combine these policies to obtain a particular outcome in a *different* market — *i.e.*, set the carbon price and CEC targets to achieve a particular energy market LMP level. Our quantitative analysis indicates that achieving this objective may be challenging because of the dynamic interactions between carbon prices, which increase LMPs, and CEC targets, which lower LMPs. Moreover, designing this policy to affect a particular market participant's resource decisions (*e.g.*, have the Millstone Plant remain economically viable) introduces additional challenges given uncertainty about their true costs and their risk tolerances (given uncertain LMPs under the Hybrid Approach). These issues raise questions about the Hybrid Approach's viability to the extent that these uncertainties undermine effectiveness.

II. Introduction

To address global climate change arising from increasing concentrations of greenhouse gases ("**GHGs**"), governments at the national and sub-national level have adopted targets to reduce GHG emissions throughout the economy and undertaken various policy and regulatory measures aimed at achieving those targets. Within the U.S., coordinated and comprehensive action has occurred largely at the state, rather than the federal, level, with many states establishing aggressive mandatory emission reductions targets. Targets set by some of the New England states are among the most aggressive, although substantial additional reductions in GHG emissions need to be made in the coming decades to achieve these long-run targets.

The Pathways Study is intended to inform the New England States, New England Power Pool ("**NEPOOL**") Stakeholders and the region about policy options to pursuing decarbonization within the New England electric power sector. While focused on the electric power sector, the policy approaches used to achieve electric power sector decarbonization have important implications for other sources of GHG emissions, such as transportation and building heating, because increased reliance on the electric power sector is seen as an important (if not the most likely) technical option to achieving reductions in these other sectors.

The Pathways Study considers several centralized policy approaches, which contrasts with the current policy approaches for achieving emission reductions that largely rely on state-by-state procurements of renewable energy, along with a suite of other policies targeting emission reductions through other measures. These centralized approaches would each require some degree of coordination between the New England states. The effort to achieve this coordination may produce important benefits, particularly achievement of decarbonization objectives at a lower social cost.

The Pathways Study differs from other studies of decarbonization in New England by focusing on differences in policy approaches to achieving an emission-reduction target. Other studies have focused on evaluating the technical options and the feasibility (and associated cost) of achieving particular emission or clean energy targets.[19] These other studies can provide valuable information to policy makers by, for example, assessing the consequences of alternative timing and stringency of climate policy targets. However, they generally do not evaluate tradeoffs among policy approaches to achieving a given decarbonization target in terms of economic costs and other market outcomes, which is the focus of this study.

[19] For example, Energy Futures Initiative and E3, "Net-Zero New England: Ensuring Electric Reliability in a Low-Carbon Future," November 2020; Evolved Energy Research, "Energy Pathways to Deep Decarbonization, A Technical Report of the Massachusetts 2050 Decarbonization Roadmap Study," December 2020; Connecticut Department of Energy and Environmental Protection, "Integrated Resources Plan, Pathways to achieve a 100% zero carbon electric sector by 2040," October 2021.

A. Assignment and Study Objectives

The Pathways Study compares the continuation of current policies and approaches, which we refer to as the ***Status Quo,*** to three alternative "**policy approaches.**" Thus, the Pathways Study will evaluate four policy approaches to achieving decarbonization:

- **Status Quo**, continuing current state policies which incent the development of clean energy resources using bilateral power purchase agreements ("**PPAs**"), with corresponding costs allocated to customers;
- **Forward Clean Energy Market ("FCEM")**, compensating non-emitting resources via the development of a centralized, forward market for clean energy certificates ("**CECs**"), with the corresponding costs allocated to electricity consumers;
- **Net Carbon Pricing ("NCP")**, pricing carbon emissions[20] from generators and returning the carbon price revenues to electricity consumers; and
- **Hybrid Approach ("Hybrid")**, combining a carbon price sufficient to provide revenue adequacy for existing clean energy resources with an FCEM that provides incremental compensation only to clean energy to "new" resources.[21]

The selection of policy approaches evaluated in the Pathway Study reflect a combination of factors, including input from NEPOOL Stakeholders and the New England States. Input was initiated in a Potential Pathways process undertaken by NEPOOL and the New England States[22] and continued in the early stages of this study. As we discuss in **Section II.C**, the Pathways Study evaluation is a holistic evaluation that includes an analytic economic assessment of alternative approaches, an evaluation of design elements for each policy approach (but not a full-scale market design assessment), and a quantitative analysis of each policy approach, along with qualitative consideration of other factors that may not be captured in the quantitative analysis.

The Pathways Study focuses on the analysis of the *differences* between each of the four policy approaches for achieving decarbonization in New England to help inform ISO-NE, the New England States, and NEPOOL Stakeholders about the tradeoffs offered by each policy approach to help determine which, if any, of the alternative policy approaches to pursue through a more-thorough market design process. Our analysis focuses on economic and regulatory issues and tradeoffs but does not consider reliability issues associated with decarbonization, which are being evaluated in a parallel process to this Pathways Study, the Future Grid

[20] Specifically, payments would reflect emissions of carbon dioxide ("**CO_2**"). Throughout the report, the term "carbon emissions" refers to CO_2 emissions.

[21] Eligibility to receive CEC awards would require specification of criteria to define "new" resources.

[22] This process included multiple meetings in 2020 that culminated in the "NEPOOL's Pathways to the Future Grid Process Project Report," January 6, 2021, available at https://nepool.com/wp-content/uploads/2021/01/NPC_20210107_Felder_Report_on_Pathways_rev1.pdf.

Reliability Study ("**FGRS**"), and does not consider legal and regulatory issues associated with the alternative approaches.[23]

Section III describes each of these policy approaches in further detail. While **Section III** discusses many of the design issues associated with each policy approach, the Pathways Study is not intended to provide a thorough analysis of the design issues relevant to each policy approach. Thus, if the region opts to pursue the development of one of the alternative policy approaches, substantial additional time and effort would be required to develop the design details, reflecting further analysis of the tradeoffs posed by various design elements, detailed specification of design elements, and input from NEPOOL Stakeholders and the New England States through the stakeholder process.

The Pathways Study also is not intended to evaluate preferred or desirable emission levels. In fact, to facilitate an "apples to apples" comparison of the policy approaches, our quantitative analysis holds emissions constant across policy approaches. Thus, our analysis does not consider the benefits-side of the climate policy equation as these benefits are held constant at assumed emission targets across the policy approaches.[24] In this regard, however, we note that economic analysis has developed estimates of the benefits of reducing in carbon emissions, as reflected in the "social cost of carbon" — *i.e.*, the dollar value of social damages from incremental carbon emissions. In principle, such damages include impacts such as changes in agricultural productivity, impacts to human health, costs associated with increased risk of flooding, and the value of ecosystem services.[25] For 2020, the federal government has estimated the social cost of carbon to be $51/metric ton ("**MT**"), increasing to $62/MT in 2030 and $73/MT in 2040.[26] These values provide one benchmark against which to compare the policies pursued in the Pathways Study.[27] Such a comparison would be relevant to

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[23] The analysis in this report is not a reliability study. The FGRS Study should be looked to instead for any technical analysis of reliability and reserve shortages.

[24] Our analysis does consider a scenario with lower emission targets.

[25] Greenstone, Michael, Elizabeth Kopits, and Ann Wolverton, "Developing a Social Cost of Carbon for US Regulatory Analysis: A Methodology and Interpretation," *Review of Environmental Economics and Policy*, Vol. 7, Issue 1, 2013, pp. 23-24.

[26] These estimates represent an average from a range of simulations that assume a 3% discount rate. Other estimates of the Social Cost of Carbon for 2020 are $14/MT, assuming a 5% discount rate, and $76/MT, assuming a 2.5% discount rate. There is much uncertainty around these estimates, however. For 2020, the simulation estimates range from less than $5/MT to over $152/MT. Estimates increase over time because CO_2 is a *stock* pollutant and incremental CO_2 emissions causes larger impacts as the stock increases over time. Interagency Working Group on Social Cost of Greenhouse Gases, United States Government, "Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide: Interim Estimates under Executive Order 13990," February 2021, pp. 5, 7, available at https://www.whitehouse.gov/wp-content/uploads/2021/02/TechnicalSupportDocument_SocialCostofCarbonMethaneNitrousOxide.pdf.

[27] From an economic perspective, net benefits are maximized when the cost of incremental (marginal) reductions equals the benefit gained from incremental reductions, as reflected by the social cost of carbon. The ease with which each policy approach can be assessed against this economic standard varies. Net Carbon Pricing is easily assessed using this standard, by comparing the social cost of carbon to the carbon price, which equals the marginal cost of emission reductions. Because other policy approaches do not provide comparable metrics, marginal emission reduction costs would need to be calculated to benchmark against the social cost of carbon.

assessment of appropriate stringency of decarbonization policy and relevant to the choice among policy approaches to the extent that policy approaches differed materially in the (marginal) costs of carbon.

B. Study Process

The Pathways Study is being undertaken through a multi-month process with Analysis Group, ISO-NE, the New England States, and NEPOOL Stakeholders. This process started in early 2021 with several meetings to obtain input on the different policy approaches to evaluate, consider preliminary design issues for each policy approach, specify the design of each approach for the quantitative analysis, and determine the parameters and specifications of the quantitative modeling analysis of each policy approach.

We provided NEPOOL Stakeholders and the New England States with preliminary results of the quantitative analysis, including results of the Central Case and Scenarios, in October and December 2021, and provided a draft Pathways Report in February 2022. Comments were provided by various entities in response to presentations of initial results and to the draft Pathways Report, and this final report reflects this feedback.

We appreciate the thoughtful feedback and comments provided by ISO-NE staff, the New England States and NEPOOL Stakeholders throughout the process. The report reflects the benefit of this input at various stages of the process, including the early stages of specifying the study scope and parameters, and the later stages of reporting preliminary results.

C. Approach to Assessment of Alternative Policy Approaches to Achieving Decarbonization

We undertake both qualitative and quantitative analysis with the goal of better understanding the differences between the four policy approaches to achieving decarbonization. While the analysis will reflect generalized economic and analytic principles that are broadly relevant to any circumstance, we also consider important differences that arise when deploying these policy approaches in the context of decarbonization of the New England electricity grid. These particular circumstances are accounted for, in part, through quantitative analysis of each policy approach.

Section IV summarizes our quantitative analysis methodology. The quantitative analysis was performed using market simulation models. We evaluate each policy approach under a common set of data and assumptions that we refer to as the "**Central Case."** This case assumes an aggressive decarbonization target — carbon emissions at 80% of 1990 emission levels by 2040 — but not 100% decarbonization. The incremental impact of the more aggressive decarbonization target achieved by each policy approach was measured relative to a Reference Case that assumes a less ambitious decarbonization, reflecting only certain planned procurements being undertaken by the New England states.

In **Section IV**, we provide a high-level description of the market simulation models, and the Central Case data and assumptions. **Appendix A** provides more granular detail on the quantitative analysis. Our study is based on plausible assumptions about future electricity demand, technologies, and costs, although we recognize that these outcomes are subject to substantial uncertainty particularly given the length of our study period. Thus, as with any decarbonization study evaluating outcomes far into the future, our analysis is not intended to be a "forecast" but an analysis of potential outcomes given reasonable assumptions about the future.

We expect that future market conditions, technologies, and market rules will differ from those assumed in this study, particularly as some of the assumptions we make, such as the methods for awarding operable capacity to system resources, are being actively discussed by ISO-NE, NEPOOL Stakeholders, and the New England States. To test the sensitivity of our results, we analyze outcomes under alternative assumptions, although these alternative scenarios are selected not only to capture areas of future uncertainty, but also to probe the sensitivity of conclusions regarding policy outcomes to changes to key assumptions.

Section V of the report discusses the consequences of decarbonization for market outcomes, including the mix of technologies in the system, energy market clearing, resource utilization, the impact of expanded variable renewable supplies on market clearing, and the growing role of energy storage technologies to complementing these new variable supplies.

Section VI provides our analysis of policy approaches, comparing all four approaches along key economic, environmental and policy dimensions, such as:

- the cost-effectiveness and other economic consequences associated with the mechanism by which each policy approach creates incentives to achieve decarbonization;
- the changes to ISO-NE market outcomes, particularly those with potential consequences for market clearing, settlements and resource use;
- the extent to which policy approaches offer different compensation for otherwise similar "services," produced by different energy resources, and the consequences of potential discrimination in compensation;
- potential limitations to each approach, such as required coordination among the New England states and practical hurdles to implementing each approach; and
- the implications of each approach for total social costs, customer payments and the distribution of these payments.

The results of the quantitative analysis provide context for comparing the performance of each policy approach by illustrating how economic effects occur, showing the direction of impacts, and providing information on the magnitude of each effect. Given the uncertainties inherent to our modeling, we complement the Central Case analysis with scenario analysis in which Central Case assumptions are varied to test the sensitivity of findings to key assumptions. **Section VII** of the report provides the results of this scenario analysis. Thus collectively, our quantitative analysis is designed to inform the comparison of policy approaches, by quantifying the impacts under each approach given one set of technology assumptions and assuming current market rules remain in place.

Throughout our study, we use term "**clean energy**" to generally refer to energy generated using technologies that do not produce net carbon emissions, which is consistent with the definition of "clean energy" in the FCEM, in that the FCEM is intended to award CECs to non-emitting energy resources. By contrast, we use the term "**renewable resources**" to refer to certain technologies, such as photovoltaic ("**PV**") solar and wind power, but not to other technologies, such as nuclear power, typically deemed not to be "renewable." Importantly, we use the term "**variable renewable resources**" to refer to technologies with output dependent on weather conditions.

D. Overview of State Policies Directly or Indirectly Decarbonizing New England's Electric Power Sector

New England states are individually — and to varying degrees — developing policies with the goal of reducing GHG emissions ("decarbonizing") from the electric power sector and the economy as a whole. While policy initiatives in recent years have begun the process of incenting the technology transformations needed to accomplish these goals, in many respects, the states are at an early stage of implementing the policies and initiatives needed to achieve these targets.

The decarbonization policy targets vary across the New England states. Many state legislatures have passed laws that impose legally binding decarbonization targets for the economy as a whole or for individual sectors, including the electric power sector. **Table II-1** below summarizes these legislated targets. Five of the six New England states have legislated aggressive long-run, economy-wide emission reduction targets, with all five requiring emissions to fall to 80% below historical emissions (either 1990 or 2001) by 2050.

These targets are likely to have substantial impact on the assets and operations in the electric power sector by both requiring direct GHG reductions within the electric power sector, and, in all likelihood, substantially increasing demand for electricity through "electrification" of heating and transportation. Thus, the electric power sector will likely need to reduce total carbon emissions while expanding output, if these decarbonization objectives are to be achieved.

Table II-1. New England States' Legislated Economywide GHG Emission Reductions Targets[28]

State	Legislated Emission Reduction Target(s)
Connecticut	45% below 2001 levels by 2030
	80% below 2001 levels by 2050
Maine	45% below 1990 levels by 2030
	80% below 1990 levels by 2050
Massachusetts	80% below 1990 levels by 2050
Rhode Island	45% below 1990 levels by 2035
	80% below 1990 levels by 2040
	100% below 1990 levels by 2050
Vermont	26% below 2005 levels by 2025
	40% below 1990 levels by 2030
	80% below 1990 levels by 2050

While the New England states have legislated aggressive GHG targets, they are still determining *how* — that is, through what policies and regulations — such carbon emission reductions will be achieved. Many states

[28] Connecticut: An Act Concerning Climate Change Planning and Resiliency (2018), Global Warming Solutions Act (2008); Maine: 38 MRSA §576-A (2019); Massachusetts: Global Warming Solutions Act (2008); Rhode Island: Resilient Rhode Island Act of 2014, 2021 Act on Climate; Vermont: Global Warming Solutions Act (2020).

have commissioned studies and "roadmaps" to evaluate "pathways" to meeting decarbonization targets, where "pathways" refers to a mix of technologies within and outside the electricity sector. For example, Connecticut's governor in 2019 commissioned a study of how to fully decarbonize the electric sector (*i.e.*, 100% carbon reduction) by 2040.[29] These studies provide much information on the potential transformations required to achieve reductions in the electric power sector and other sectors of the economy, but there are many open questions about how the states in the region (and the region as a whole) will pursue these objectives.

One important question is the timing of GHG reductions in the electric power sector compared to the rest of the states' economies. We do not analyze this question, but, for the purposes of the Pathways Study, chose an emissions reduction target for the electric power sector of 80% below 1990 levels by 2040. As described further below, achieving these goals will require that planners be mindful of the impact of the region's economy-wide goals, as efforts to decarbonize other sectors (such as transportation and heating) can lead to electrification and increased power sector demand. This target is chosen for use in the Pathways Study as it is broadly consistent with the stated goals of the New England states. It is important to note, however, that this choice is *not* intended to be a precise estimate of the cumulative requirement associated with existing state policies or a specific policy proposal for the New England states to pursue. Instead, the assumed emissions reduction target for the electric power sector of 80% below 1990 levels by 2040 was adopted as a vehicle for illustrating the differences between the policy approaches.

At present, the states are pursuing a variety of regulations, policies, and programs that can help achieve decarbonization goals. The New England states participate in the Regional Greenhouse Gas Initiative ("**RGGI**"), a coordinated emissions trading scheme between eleven states in the eastern U.S. that caps emissions from electric power generators in these states. The RGGI targets, however, are modest. By 2030, RGGI aims to reduce power-sector emissions by 30% relative to 2020 levels.[30] RGGI allowance prices have historically been low, below the levels required to incent significant emission reduction levels needed to achieve the decarbonization goals of the New England states. For example, in the December 2021 RGGI auction, allowances cleared at $13/short ton, the highest price to date,[31] yet, as we will show, this price is far below the levels needed to achieve meaningful emission reductions in the ISO-NE system. Moreover, RGGI spans states outside New England, and thus relying on RGGI to achieve deep decarbonization targets would not only

[29] Connecticut Office of the Governor, Executive Order No. 3, September 3, 2019, available at https://portal.ct.gov/-/media/Office-of-the-Governor/Executive-Orders/Lamont-Executive-Orders/Executive-Order-No-3.pdf.

[30] Regional Greenhouse Gas Initiative, Inc., "RGGI States Announce Proposed Program Changes: Additional 30% Emissions Cap Decline by 2030," August 23, 2017, available at https://www.rggi.org/sites/default/files/Uploads/Program-Review/8-23-2017/Announcement_Proposed_Program_Changes.pdf.

[31] The Regional Greenhouse Gas Initiative, "Auction Results", available at https://www.rggi.org/auctions/auction-results.

require consensus across all RGGI states, including those outside New England, but more importantly would be constrained by "emission leakage" from RGGI states in the PJM system.[32]

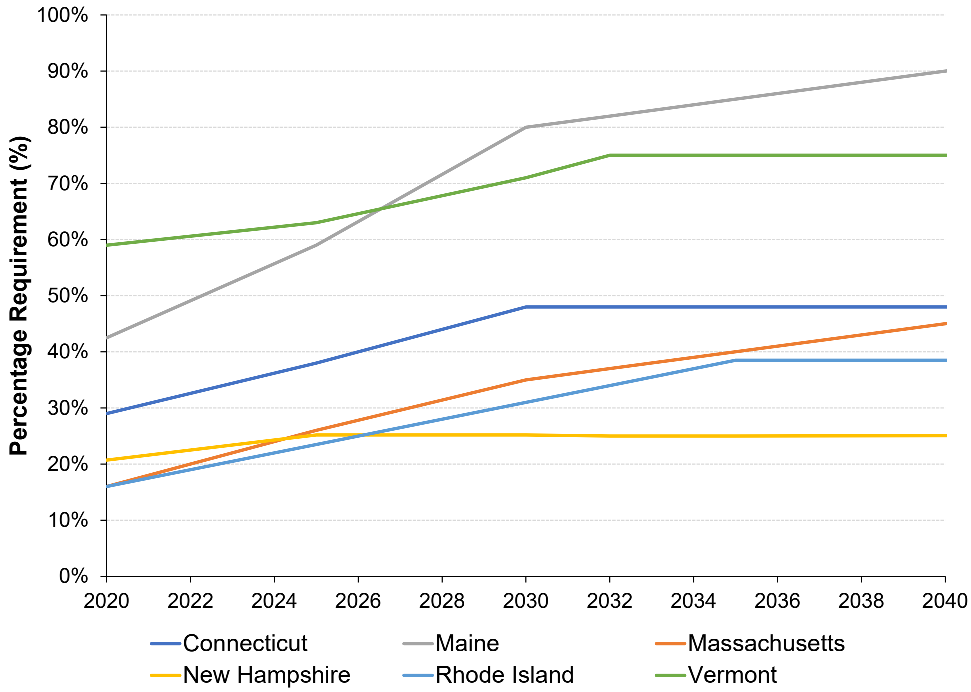
In the electricity sector, most states have undertaken a combination of energy policies that achieve GHG reductions, including renewable portfolio standards ("**RPS**"), net metering of behind-the-meter solar generation (and other subsidies) and energy efficiency. The RPS is an umbrella term for individual state policies which mandate that a certain percentage of retail electricity sales come from renewable energy. Individual states' RPS policies differ in terms of the targets (*i.e.*, what percent of load should come from renewable energy), and which technology types count as "renewable."[33] States track compliance with their RPS policies using Renewable Energy Certificates ("**REC**"), and define different classes of RECs, typically based on technology type, size of the generating facility, and/or whether a facility is "new" vs. existing.[34] In total, across the New England region, there are roughly 30 classes of REC products. **Figure II-1** shows the RPS targets for each New England state from 2020 to 2040.

[32] Emission leakage occurs when emission reductions in one location is offset by emission increases in another location, when economic activity shifts from the regulated to the unregulated region. Thus, reduced emissions from lower fossil generation in PJM's RGGI states may simply lead to increased generation and emissions from generators in other states in the PJM system.

[33] Generally, solar power, wind energy, and (small) hydroelectric plants qualify across all RPS programs in New England. However, the states differ in whether they consider other technology types such as "large" hydroelectric generation and fuel cells to be renewable. Notably, Vermont allows imported energy from HydroQuébec to qualify for RECs whereas other states do not. Fuel cells are considered renewable in all New England states except for New Hampshire and Vermont. *See* **Figure II-1**, footnote 36, and **Appendix A.C**.

[34] "New" is typically defined as having entered commercial operation after a certain date. All New England states except for Connecticut differentiate between new and existing resources in their Renewable Portfolio Standards. For example, in Rhode Island, "new" means after December 31, 1997; in Maine, "new" is defined as after September 1, 2005; and in Massachusetts, "new" is defined as after January 1, 1998. *See* Rhode Island Code of Regulations, Title 810, Chapter 40, Subchapter 05, Part 2, *available at* https://rules.sos.ri.gov/regulations/part/810-40-05-2; Maine Revised Statutes, Title 35-A, Part 3, Chapter 32, "Electric Industry Restructuring," §3210; Massachusetts 225 CMR 14.00 (RPS Class I); 225 CMR 15.00 (RPS Class II).

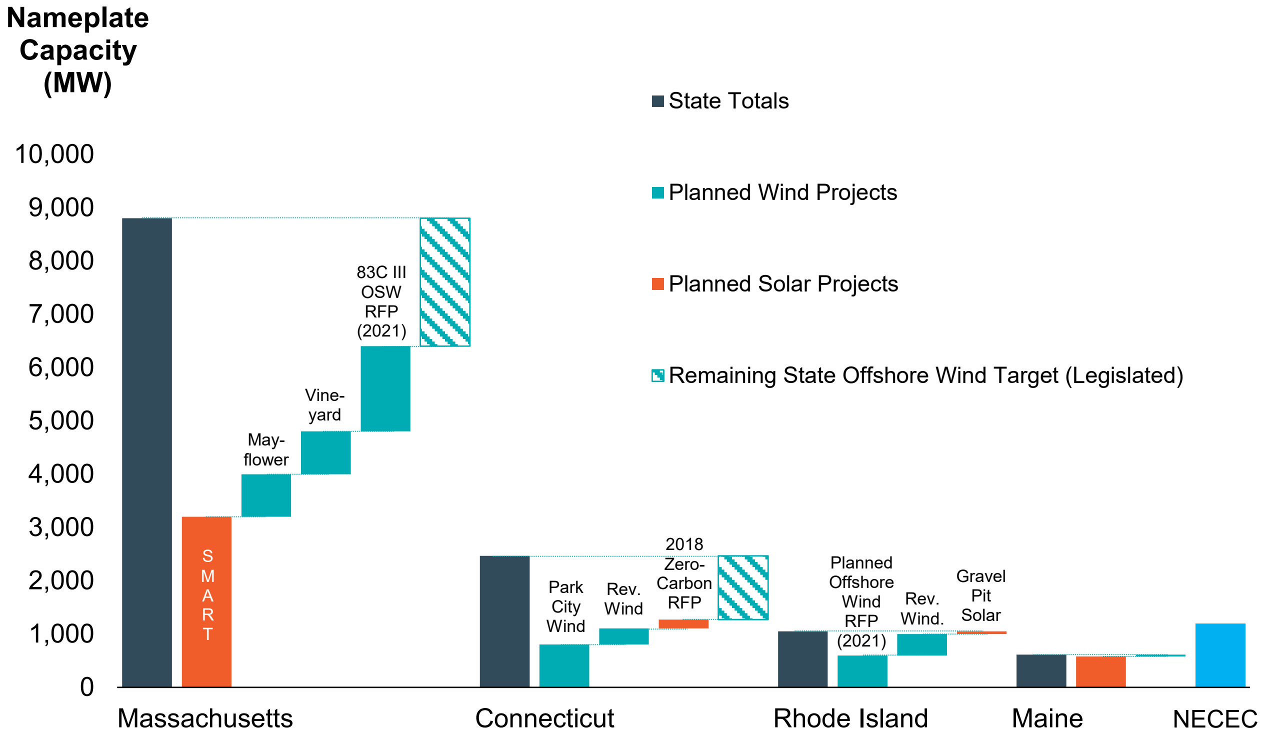
Figure II-1. New England States' Renewable Portfolio Standard Targets, 2020-2040[35]



Many states have also undertaken renewable energy procurements to support achievement of RPS targets. Most notably, the southern New England states (Massachusetts, Rhode Island, and Connecticut) have procured 3.1 GW of offshore wind and are planning to procure an additional 5.8 GW of offshore wind by 2030. Maine has recently begun two rounds of renewable energy procurements to satisfy its newly passed RPS target of 80% renewable energy by 2030, resulting in 770 MW of additional solar capacity and 150 MW of additional (onshore) wind capacity. In addition, it is pursuing an 11 MW floating offshore wind pilot project (the Aqua Ventus project). **Figure II-2** below summarizes some of the recent procurements for renewable energy that the states have undertaken.

[35] In Maine, RPS targets are legislated requirements through 2030. From 2030-2040, the *required* RPS target remains at 80%, but the state has also legislated a goal of 100% renewable energy by 2050. The increasing target for Maine beyond 2030 represents a linear interpolation of Maine's legislated goals of 80% renewable by 2030 and 100% renewable by 2050. General Statutes of Connecticut, Chapter 277, §§16-1(a)(20), 16-1(a)(21), 16-1(a)(38), 16-245(a); Maine Revised Statutes, Title 35-A, Part 3, Chapter 32, "Electric Industry Restructuring," §3210; Massachusetts Regulations: 225 CMR 14.00 (RPS Class I) ; 225 CMR 15.00 (RPS Class II); New Hampshire Statutes, Title XXXIV, Chapter 362-F, "Electric Renewable Portfolio Standard;" Rhode Island General Laws, Chapter 39, Section 26, "Renewable Energy Standard," §§39-26-2, 39-26-4, 39-26-5; Vermont Statutes Annotated, Title 30, Chapter 89, "Renewable Energy Programs," §§8002-8005.

Figure II-2. New England States' Renewable Energy Procurements and Legislated Targets[36,37,38,39,40,41]



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[36] Beiter, Philipp, Jenny Heeter, Paul Spitsen, and David Riley, "Comparing Offshore Wind Energy Procurement and Project Revenue Sources Across U.S. States," National Renewable Energy Laboratory, June 2020, available at https://www.nrel.gov/docs/fy20osti/76079.pdf.

[37] Massachusetts Governor's Press Office, "Governor Baker Signs Climate Legislation to Reduce Greenhouse Gas Emissions, Protect Environmental Justice Communities, March 26, 2021, available at https://www.mass.gov/news/governor-baker-signs-climate-legislation-to-reduce-greenhouse-gas-emissions-protect-environmental-justice-communities; Massachusetts Department of Energy Resources, "Solar Massachusetts Renewable Target (SMART) Program," 2021, available at https://www.mass.gov/info-details/solar-massachusetts-renewable-target-smart-program.

[38] Connecticut Office of Governor Dannel P. Malloy - Archive, "Gov. Malloy Announces Zero-Carbon Resource Selections," December 28, 2018, available at https://portal.ct.gov/Malloy-Archive/Press-Room/Press-Releases/2018/12-2018/Gov-Malloy-Announces-Zero-Carbon-Resource-Selections.

[39] RI.gov, "Raimondo calls for up to 600 MW of new offshore wind energy for Rhode Island," October 27, 2020, available at https://www.ri.gov/press/view/39674; Faulkner, Tim and ecoRI News staff, "Massive Solar Facility Would Displace Farmland, Forest," November 25, 2020, available at https://www.ecori.org/renewable-energy/2020/11/23/conn-solar-farm-criticized-for-displacing-farmland-and-woodlands.

Many New England states have also undertaken a variety of subsidy programs aimed at incenting the adoption of various technologies, particularly those that generate electricity using clean energy technologies. One prominent example is subsidies for the adoption of behind-the-meter ("**BTM**") technologies, such as PV panels, through policies such as Net Metering. Other subsidies, such as the Solar Massachusetts Renewable Target ("**SMART**") program, incent both BTM and grid-located PV systems.[42] Other subsidy programs target improvements in energy efficiency and energy management, with the goal of reducing the quantity of energy consumed. All New England states fund (passive) energy efficiency programs, largely through the regulated utilities that provide retail service to electricity customers.

Finally, decarbonization in non-electricity sectors, notably transportation and heating, may substantially increase demand for electricity, thus compounding challenges to reduce carbon emissions in the electrical system. Currently, the primary technological pathways to decarbonize transportation and heating rely on electrification. Moreover, while other technologies may rely on alternative fuels, such as hydrogen, these pathways may also increase electricity demand as they rely on electricity to produce the alternative fuel.

At present, there is limited coordination of decarbonization efforts across states. At prior times, the states have undertaken efforts to coordinate certain policies. The development of RGGI represents one example where the New England states (along with states outside New England) have successfully coordinated policies to achieve environmental objectives.

While the Status Quo approach evaluated in the Pathways Study largely relies on individual state policies, the Pathways Study considers three additional policy approaches that would require an increased level of coordination of policies across the New England states, similar to the coordination required to implement RGGI. The specifics of this coordination and the legal processes each state would need to undertake to authorize and implement this coordination (*e.g.*, would it require legislation or could it be pursued under existing statutes?) would depend on the particular policy approach pursued. The Pathways Study does not evaluate the legal requirements associated with pursuing each of the policy approaches. However, the importance of the interstate coordination required to pursue these policy approaches should not be diminished. For example, development of an FCEM would require that states commit to pursuing decarbonization through a coordinated FCEM system, rather than through clean energy procurements. Other approaches would require not only coordination (and discontinuation of current state procurement initiatives), but agreement on common policy

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[40] Maine Public Utilities Commission, "2020 Request for Proposals for the Sale of Energy or Renewable Energy Credits from Qualifying Renewable Resources," September 22, 2020, available at https://www.maine.gov/mpuc/electricity/rfps/class1a2020/index.shtml.

[41] Massachusetts Executive Office of Energy and Environmental Affairs, "Department of Public Utilities Approves Hydroelectricity Contracts," June 26, 2019, available at https://www.mass.gov/news/department-of-public-utilities-approves-hydroelectricity-contracts; State of Maine Office of Governor Janet T. Mills, "Governor Mills Secures Discounted Electricity for Maine from Hydro-Québec, July 10, 2020, available at https://www.maine.gov/governor/mills/news/governor-mills-secures-discounted-electricity-maine-hydro-quebec-2020-07-10.

[42] Massachusetts Department of Energy Resources, "Solar Massachusetts Renewable Target (SMART) Program," 2021, available at https://www.mass.gov/info-details/solar-massachusetts-renewable-target-smart-program.

parameters. For example, carbon pricing through a fixed fee would require that the states agree on the carbon price, while a cap-and-trade system would require agreement on emission targets. These coordination issues are addressed through analysis of the flexibility the policy approaches offer to accommodate varying degrees of state coordination and consensus, and through the analysis of the distribution of the costs of achieving decarbonization. More specifically, we expect that differences in this distribution would have consequences for the challenges to achieving coordination across the New England states. However, the coordination and consensus required of the New England states to pursue the centralized approaches raises many challenging issues, and our study does not assess their full scope and complexity.

III. Alternative Policy Approaches to Achieving Decarbonization

The Pathways Study considers four policy approaches to achieving decarbonization targets for the New England region. One approach is a continuation of current New England state policies, referred to as the ***Status Quo*** approach. As an alternative to the Status Quo approach, we consider **three alternative policy approaches** that create centralized market designs for the New England electric power system, including an **FCEM**, **Net Carbon Pricing**, and **Hybrid Approach**. Our quantitative analysis also includes a **Reference Case** in which the region achieves less ambitious decarbonization reflecting only certain planned procurements.[43] This Reference Case is *not* an alternative Pathway, but instead, as we discuss in **Section IV**, a benchmark against which to measure the incremental change in economic outcomes arising from the greater decarbonization. Thus, we do not discuss this case further in this section.

The four approaches we analyze do not necessarily represent the full scope of centralized approaches available to the region to pursue decarbonization. In particular, **policy approaches could be combined**, such as imposing a fixed carbon price on emissions, while also implementing an FCEM for all clean energy.[44] Alternatively, **policy designs could transition over time**, such that they start with one approach and transition over time to another, given political and other considerations. For example, under the Status Quo, carbon prices could be gradually increased over time.[45] We do not evaluate these "combined" approaches.

Our analysis also does not consider the potential for an **alternative policy approach to complement the Status Quo approach**. For example, carbon pricing could be introduced to current markets, with the states continuing multi-year clean energy procurements. While affecting energy market prices, carbon pricing would not otherwise affect state's ability to procure clean energy using PPAs. However, the introduction of carbon pricing would reduce developer's need for out-of-market revenues through those PPAs, potentially reducing the term of such agreements (or even diminishing the need for such agreement, depending on technological and other cost changes).

A. Status Quo

Under the Status Quo approach, the New England states expand the quantity of clean energy resources through periodic procurements in which the states award multi-year contracts for the production of clean energy

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[43] These procurements are the baseline state policies, a common assumption to each of the policy approaches. We discuss these baseline state policies further in **Section IV.B**, based on information summarized in **Section II.D**.

[44] Note that this policy differs from the Hybrid Approach, because all clean energy would be awarded CECs, rather than only energy from deemed eligible "new" resources.

[45] For further discussion of introducing dynamic adjustments to policy instruments over time, *see* Pahle, Michael, et al., "What Stands in the Way Becomes the Way, Sequencing in Climate Policy to Ratchet Up Stringency Over Time," Resources for the Future Report, June 2017; Stavins, Robert, Todd Schatzki, and Rebecca Scott, "Transitioning to Long-Run Effective and Efficient Climate Policies," Harvard Environmental Economics Program, Discussion Paper 19-80, April 2019.

with new (and potentially existing) resources. This approach represents a continuation of the states' current policies for decarbonizing the electric sector (as described in **Section II.D** above). This approach assumes that future energy resource procurements continue through the study period to meet decarbonization (and RPS) goals, and that these procurements resemble recent competitive procurements, such as those for offshore wind in southern New England, or for solar and wind resources in Maine. The process involves multiple steps, including planning stages to determine procurement timing and specifications (*e.g.*, technology eligibility, quantities, contract terms, need parameters), and procurement implementation, which involves RFP development, determination of selection criteria and processes, review and selection of offers to be awarded contracts, and contract negotiation and execution. We do not evaluate the many design issues and options available to the New England states to modify their current planning and procurement approaches to achieving decarbonization.[46]

In comparison to the alternative policy approaches evaluated, the Status Quo approach is not a formal "regulation," but the characterization of a general policy approach emerging from various statutory and regulatory decisions made in recent years in different states. These statutory and regulatory decisions do not, however, provide a clear path for *how* states will achieve the statutory targets they have adopted. Thus, as we discuss in **Section IV**, we assume, as a starting point, that the states' resource mixes under the Status Quo approach generally align with their recently published deep decarbonization studies or plans.[47] These studies and plans do not represent promulgated regulatory or policy decisions, but are the best publicly available articulation of the process the New England states envision to achieving the statutory decarbonization targets they have adopted.

From a regulatory standpoint, a feature of the Status Quo approach is that it is inherently focused on new resources, but does not specify a clear approach for compensating existing clean energy resources, including both renewable resources and nuclear power facilities. Current policies have addressed this gap through measures such as existing RPS carve-outs,[48] aimed to compensate certain older renewable resources, and Connecticut's "zero carbon" procurement, which allowed participation of nuclear power facilities. However, over time, as renewable resource PPAs expire, the quantity of renewable resources without any contractual support would be expected to grow absent new measures. The ongoing financial viability of these existing renewable resources without any contractual support could become questionable as new renewable resources (supported through PPAs) come into the system, further driving down market prices and revenues to existing resources. In principle, expanded RPS policies may help support these resources, although the viability of

[46] For more information on planning approaches to decarbonization, including assessment of experience with such approaches, particularly in European countries and California, *see* Cleary, Kathryne and Heidi Bishop Ratz, "Experience with Competitive Procurements and Centralized Resource Planning to Advance Clean Energy," Resources for the Future, Working Paper 21-01, January 2021, as well as materials associated with workshop conducted by Resources for the Future and World Resources Institute, "Market Design for the Clean Energy Transition: Advancing Long-Term Approaches," December 16-17, 2020.

[47] See **Section IV.B.4** for further discussion.

[48] Massachusetts Regulation 225 CMR 15.00; General Statutes of Connecticut, Chapter 277; Maine Revised Statutes, Title 35-A, Part 3, Chapter 32.

such an approach requires further examination. As we discuss below, the outcomes under the Status Quo depend on whether and how such existing resources receive ongoing out-of-market compensation in recognition of their continuing contributions to meeting decarbonization objectives.

B. Forward Clean Energy Market

The FCEM emerged as a potential policy approach during the Potential Pathways Process undertaken by the region during the second half of 2020. The group that brought this concept forward represents a range of companies and organizations.

The FCEM creates incentives for resources to generate "clean energy" by (1) imposing requirements on regulated utilities (or other entities) to procure specified quantities of CECs, and (2) awarding CECs to resources that generate clean energy, where one MWh of clean energy produced is awarded one CEC.[49] Thus, this compliance obligation would create the demand for CECs that would give them market value. In principle, "clean energy" would include energy generated by any resource that does not produce net carbon emissions.

CEC awards reward clean energy resources for producing "clean energy," rather than energy produced by fossil generation. In principle, the market value of CECs would cover the incremental costs of generating energy using clean technologies relative to the cost of generation using carbon-emitting technologies. Thus, in a sense, CECs provide the "missing clean energy money" associated with the higher cost of producing clean energy to meet a decarbonization target. By awarding CECs, the FCEM incents the development of clean energy sufficient to meet targeted levels by clean energy.

The cost of CEC awards would be borne by customers. To comply with CEC requirements, utilities (or other entities) would need to purchase CECs in sufficient quantities to meet the state-level (or regional-level) CEC obligation, where the costs associated with purchasing these CECs would then be passed along to end-use customers.

In many respects, the FCEM is similar in design to existing RPS. Under current RPS, utilities must surrender enough **RECs** to cover the mandated fraction of energy that must be generated by renewable energy. Thus, like RPS, the FCEM awards certificates with market value, although eligibility requirements for CECs would differ from those for RECs. Unlike current RPS, the FCEM would include a forward market run several years in advance of delivery, similar to the existing Forward Capacity Market ("**FCM**"). In principle, a forward market would allow clean energy resources to sell their clean energy supply forward, which may reduce financial risk to clean energy projects, particularly new resources seeking project financing.

The development of an FCEM would raise many design issues, some of which we list below. In general, our assessment is not intended to exhaustively review and assess all aspects of the design of an FCEM. While it

[49] The FCEM is, in effect, a modified Clean Energy Standard, which requires that a specified share of electricity be generated from eligible clean energy resources. *See* Cleary, Kathryne, Karen Palmer, and Kevin Rennert, "Clean Energy Standards," Resources for the Future, Issue Brief 19-01, January 2019. https://media.rff.org/documents/CleanEnergy-Issue20Brief_2.pdf.

was not necessary to fully resolve all of these design issues for our analysis, it would be necessary to address these issues to develop a full market design proposal. Thus, as discussed in Pathways Study meetings, there are many design issues that would require further detailed analysis and discussion if the region were to pursue the development of an FCEM.

- ***Forward, Centralized Auction.*** Similar to the FCM, an FCEM would establish a centralized market in which future commitments to supply CECs several years in advance of the CEC requirement by suppliers are cleared against demand for CECs from the New England states. Most proposals assume a forward auction three years in advance of the delivery period occurring near in time with (or integrated with, as discussed below) the FCM.[50] However, further analysis would be warranted regarding the optimal forward period and whether a centralized auction is warranted, as compared to continuous trading through bilateral trades and exchanges. Many auction design issues would need to be resolved, including whether new resources would be given the option to lock-in prices for a multi-year period (and if so, who bears the costs for future procurements). The design and implementation of a centralized FCEM auction is potentially complex, particularly to the extent that the auction permits "lumpy" (non-rationable) offers, in which offers reflect large quantities of CECs tied to the entry of new clean energy facilities that would supply these CECs. This complexity increases further if the auction integrates procurement of operable capacity and CECs (see discussion of an Integrated Clean Capacity Market, below).[51]
- ***CEC Product Definition***. In principle, a CEC represents one MWh of "clean" energy, where "clean" is defined as production from an eligible resource. While it is possible to design an FCEM with a single ("uniform") CEC product, it is also possible that the FCEM might involve different types of CECs differentiated by different standards. Designing the market to include multiple products would generally be less-cost effective than a design with a uniform CEC.[52] In addition, multiple CECs would likely add significant complexity to the market design and could limit the potential benefits of a centralized market by, for example, potentially reducing competition between resources to provide clean energy and spreading liquidity across multiple products.
- ***Resources Eligible for CECs***. The development of an FCEM would require rules to determine the criteria for awarding CECs. In principle, CECs would be awarded to resources that generate energy without net carbon emissions. From an economic perspective, CECs would not be awarded to energy

[50] ISO-NE, "Pathways to the Future Grid: Evaluating clean energy and carbon pricing frameworks as alternative market designs to advance the region's clean energy transition," NEPOOL Participants Committee Working Session, February 18, 2021, slide 13.

[51] The current FCM design allows for lumpy offers, in which the offer does not permit the rationing of a portion of the offer if it is the market-clearing offer. While there is experience with how to design and implement auctions that maximize social benefit under the non-linearities created by non-rationable offers, these are particularly complex issues that have required substantial effort to work through.

[52] With multiple CEC products, the CEC market would create a differentiated incentive for clean energy based on a criteria or characteristic that is unrelated to the emission reductions achieved by displacing fossil energy with clean energy.

from storage resources.[53] Storage resources do not generate electricity, but discharge previously charged energy.[54] Instead, as we show in **Section VI**, the FCEM increases compensation to storage resources by increasing LMPs spreads, which allow the storage resource to earn higher arbitrage profits. Developing these rules would likely require substantial involvement by NEPOOL Stakeholders and the New England States, and would bring in issues such as which technologies would be eligible for CEC awards and whether impacts from other systems would be eligible for awards (and whether the technology criteria for imports would differ from in-system resources). Technology criteria is the likely starting point for determining CEC awards. But determining the list of eligible technologies among the states is potentially complex considering that current REC criteria vary across states and do not include certain non-emitting resources, such as nuclear generation. In **Section IV**, we discuss the specific assumptions made in our assessment about which resources and sources are eligible for CEC awards.[55]

- ***CEC Demand***. Offers to supply CECs would be cleared against demand for CECs based on CEC requirements established by state regulators and/or legislators. Various proposals have been made regarding the mechanism by which CEC demand is formed, although it is most likely that forward CEC demand would be covered by regulated utilities.[56] Effective markets (and market-based systems for environmental attributes) rely on dependable future demand, as efficient outcomes in these markets can depend on large capital investments that require the recovery of returns over many future years. Thus, uncertainty about future demand can raise costs. Consequently, the development of an effective FCEM may greatly benefit from a mechanism, such as forward-looking statutory commitments, to provide sufficient certainty to the market about the sustainability of future demand for CECs. In light of the importance of certainty about future demand, our assessment assumes that (1) CEC demand derives from state requirements imposed on regulated utilities such that payment for CECs is proportional to state "commitments" (*i.e.*, demand) for CECs, and (2) total

[53] For more discussion, *see* ISO-NE Market Development, "Storage Resources and Pathways to a Future Grid," memorandum, April 8, 2021, available at https://nepool.com/wp-content/uploads/2021/04/NPC_FG_20210415_ISO_Mkt_Dev_Memo_Storage_Resources_and_Pathways_to_Future_Grid.pdf.

[54] Moreover, a method that relied on determining whether the battery was charged using clean energy or non-clean energy would face many conceptual and practical challenges to determining the marginal resource at any given point in time.

[55] For further discussion, *see* ISO New England, "Pathways to the Future Grid: Defining the Frameworks for the Modeling Efforts," July 14, 2021, pp. 7-9 (hereafter, "ISO-NE Pathways Scoping Document").

[56] There many issues associated with the formation of CEC demand, including: what types of commitments to CEC demand would be made by New England states, the future specification of legally binding state-level requirements (*e.g.*, similar to legislated RPS), and mechanisms for inclusion of non-state CEC demand (*e.g.*, corporate demand). *See*, Fuller, Pete, "A Forward Clean Energy Market for New England," January 18, 2021, available at https://nepool.com/wp-content/uploads/2021/02/FCEM-for-NEPOOL-Pathways-210218-Rev1.pdf; NEPOOL, "A Forward Clean Energy Market for New England – Design Specifications," December 2020, available at https://nepool.com/wp-content/uploads/2021/02/FCEM-design-parameters-20-12-29.pdf; Fuller, Pete and David O'Connor, "FCEM in New England: Feedback on ISO-NE Questions," March 18, 2021, available at https://nepool.com/wp-content/uploads/2021/03/FCEM-Feedback-on-ISO-Questions-Pathways-210318-FINAL.pdf.

CEC demand reflects *all* demand needed to meet emission targets. We assume that this demand is fixed in our modeling, but in theory, a priced demand curve for CECs could be considered. However, this would add further complexity to FCEM design.

- ***Participation of Supply in the FCEM***. Participation of physical clean energy supply in the FCEM could be either voluntary or mandatory (*i.e.*, must offer). In addition, entities without any physical assets capable of generating CECs (*i.e.*, virtual supply) could participate, with the benefits of such participation (*e.g.*, in improving market efficiency) being greater if physical supply does not have a "must offer" requirement.[57] If the market is limited to physical asset owners, rules would need to be developed to ensure sufficient supply-side participation, such as maximum and minimum offer quantities. However, with variable renewable resources, the "must offer" quantity would be subject to greater uncertainty than must offer requirements in other markets, such as the FCM, due to the variability in renewable output and the potential for economic curtailment of supply. Many other supply-side issues would need to be addressed, including: allowance of non-rationable offers (similar to the FCM, for new clean energy resources) and whether and how offers would need to be reviewed by the Internal Market Monitor (*e.g.*, what principles would dictate offer review, and how would this review interact with FCM offer review).

- ***Market Settlement***. In principle, the FCEM would likely operate like a standard two-settlement market, with forward commitments settled during the delivery period against actual performance, with a requirement that suppliers fulfill their forward sale with CECs generated by the specific asset making the commitment, transfer of CECs from other clean energy resources in the resource owner's portfolio, or market purchases of CECs generated by the assets of other suppliers. In addition, suppliers would have the opportunity to sell any surplus CECs generated in excess of the forward commitment. However, in principle, other settlement procedures could be adopted, such as the assignment of "penalties" for underperformance below committed quantities and exemptions from performance of forward commitments.[58] Rules for the timing and settlement of auctions and reconfiguration auctions (if any) would need to be studied and adopted.

- ***Integrated Clean Capacity Market***. The FCEM could be operated as a stand-alone forward market, or, potentially, it could be integrated into the existing FCM to form an Integrated Clean Capacity Market ("**ICCM**"). As an integrated market, the ICCM would simultaneously determine clearing awards and prices for both forward capacity and forward clean energy. Analysis to date by ISO-NE has reached several conclusions about the ICCM, including: (1) "the joint clearing of capacity and clean energy in a single auction is theoretically feasible," and (2) under this theoretically feasible

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[57] The participation of virtual supply (and demand) in forward markets can improve forward market efficiency by including market participants able and willing to bring forward markets into equilibrium with spot markets through arbitrage of forward and spot prices. ISO-NE's day-ahead energy market allows the participation of virtual offers to help the convergence of day-ahead and real-time energy prices.

[58] Under a two-settlement market, underperformance results in a charge incurred in the second settlement. When the prices during the delivery period exceed the prices received through the forward commitment, the market participant loses money, as they must pay the delivery period price to cover their commitment, while receiving the (lower) forward commitment price.

approach, resource offers would include a single price that would be associated with both a quantity of capacity (in MW) and a quantity of clean energy (in MWh).[59] In principle, the ICCM offers certain benefits compared to a stand-alone FCEM and FCM. In particular, integration may lower costs by accounting for complementarities in offers and allowing new resources to ensure they clear both the FCM and FCEM, rather than clearing one and not the other. However, such optimization can involve substantial complexity and cost, and further analysis would be required to assess feasibility of allowing non-rationable offers. Thus, to understand the practical feasibility of an ICCM and any implementation or market design challenges that it may introduce, a more thorough assessment would be necessary.

- ***Dynamic CECs***. In a basic clean energy market, one CEC is awarded for each MWh of clean energy generated. However, this approach does not account for the quantity of emission reductions achieved by additional clean energy, which would reflect the marginal emission rate at the time when the clean energy is generated (in other words, is this clean energy displacing another clean resource, or a "dirty" fossil resource?). To account for this variation, the quantity of CECs could be awarded dynamically based on a metric associated with the marginal emission rate at the time when the clean energy is generated. Implementing such a dynamic CEC scheme would require the development of a metric for awarding the quantity of CECs, which would raise many design issues, including several relating to how this metric is developed, and how a dynamic measure of CECs may impact supply and demand for certificates. **Appendix C** provides further discussion of Dynamic CECs.
- ***CEC Banking***. An FCEM can include rules to allow market participants to hold or "bank" allowances generated in one year to be used for compliance in later years. Banking offers many benefits and is included in nearly all market-based environmental programs:[60] (1) banking can lower economic costs by providing flexibility over "when" investments and actions occur, (2) banking can reduce price volatility by, for example, avoiding price spikes during compliance windows by ensuring that there is sufficient supply of allowances allowing in these periods, and (3) banking can provide environmental benefits by achieving desired environmental outcomes (*e.g.*, carbon emission reductions) earlier than they otherwise would have occurred. Our quantitative analysis does *not* assume banking, although the impacts of banking are discussed qualitatively.[61]
- ***Interactions with Existing State Policies***. In principle, the adoption of an FCEM would require specification of how the FCEM would interact with existing environmental regulations. In particular, it would need to be determined whether the environmental attribute associated with clean or renewable generation could be used to comply with *both* the FCEM and existing state policies, particularly the RPS, or whether the attribute could be used to comply with *either* the FCEM *or* the

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[59] ISO-NE Pathways Scoping Document, p. 12.

[60] For example, in Massachusetts up to 30% of the RPS quota for certain REC classes in a given year can be met by RECs generated in the prior two years. *See* Massachusetts Regulations: 225 CMR 14.08 (RPS Class I); 225 CMR 15.08 (RPS Class II).

[61] In particular, we discuss the potential for banking to lower costs by shifting the timing of when emissions reductions are made.

existing state policies. In principle either approach is feasible, although the choice has implications for how CEC (and REC) demand required to meet a particular environmental target is specified, whether changes to the existing state programs would be necessary to accommodate an FCEM, and whether existing contracts with renewable resources may need to be revised to account for changes in how environmental attributes are accounted for in renewable and clean energy products such as RECs and CECs. It also likely has implications for the potential treatment of energy imported from outside New England (if such energy is eligible to receive CECs).[62]

Below, in **Section IV**, where we describe the quantitative analysis, we identify assumptions we make in the modeling with respect to these design issues.

C. Net Carbon Pricing

Under Net Carbon Pricing, a price is imposed on carbon emissions. Generation resources with carbon emissions pay a cost equal to the carbon price for each unit (metric ton, or "**MT**") of CO_2 emissions.[63] At present, there are 65 carbon-pricing policies worldwide covering 22 percent of global GHG emissions.[64] Thus, the use of carbon-pricing policies is widespread. FERC has focussed some attention to the issue of carbon pricing in the FERC-regulate wholesale markets, including a technical conference dedicated to the issues.[65]

Faced with carbon pricing, generators with CO_2 emissions will include the cost of their carbon emissions in their energy market offers, as they would any other variable cost (*e.g.*, fuel costs). This cost per unit of energy (MWh) equals the carbon price multiplied by the quantity of emissions per MWh. Thus, the carbon cost per MWh depends on the resource's fuel efficiency in producing MWh (*i.e.*, its heat rate) and carbon intensity per MMBtu of the fuel used (*e.g.*, coal, oil or natural gas).

When fossil resources include the cost of their emissions in their energy market offers, market-clearing LMPs will increase by the carbon cost when the marginal generating unit reflects offers from these fossil resources. Thus, LMPs will increase in many hours, increasing the net revenues earned by resources that do not generate any emissions or that generate emissions at a lower rate than the marginal generating unit.

In general, carbon prices are paid to a centralized authority. In the Pathways Study, we assume carbon price proceeds are collected by the system operator (*i.e.*, ISO-NE). In our analysis, we assume that the system operator credits the revenues collected from carbon-emitting resources back to customers to reduce their net

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[62] ISO-NE Pathways Scoping Document, p. 12.

[63] Greenhouse gas (GHG) emissions are measured on a carbon dioxide equivalent ("**CO_2e**") basis. Here, we assume a metric ton unit (2,205 pounds) for carbon emissions and prices.

[64] World Bank, "Carbon Pricing Dashboard," accessed September 22, 2021 (data accessible from https://carbonpricingdashboard.worldbank.org/map_data); Stavins, Robert N., "The Future of U.S. Carbon-Pricing Policy," *Environmental and Energy Policy and the Economy*, Vol. 1, 2020, pp. 8-64, at p. 12.

[65] FERC, "Technical Conference regarding Carbon Pricing in Organized Wholesale Electricity Markets," Docket No. AD20-14-000, available at https://www.ferc.gov/news-events/events/technical-conference-regarding-carbon-pricing-organized-wholesale-electricity.

electricity bills. Specifically, we assume that these costs are netted off from customer (utility) payments in the energy market as a part of the energy market settlement process. Thus, the revenues collected from carbon prices are returned to customers in proportion to their energy (MWh) consumption. However, in principle, other approaches to allocating carbon revenues could be used, based on different allocation criteria, and for different purposes. For example, RGGI allocates revenues raised through the auction of RGGI cap-and-trade allowances to the individual RGGI states, which then use these revenues for a variety of programmatic objectives, such as expansion of energy efficiency programs.[66]

In principle, carbon pricing can be imposed by either price- or quantity-based approaches.[67] A price-based approach fixes the price of carbon and allows the resulting emissions to vary, while a quantity-based approach fixes total emissions and allows the resulting emission price to vary. Quantity-based approaches include cap-and-trade systems and emission intensity-based systems.[68] There is a vast literature on the trade-offs between these two approaches and which approach is more appropriate for reducing GHG emissions, with various economists favoring one approach over the other.[69] In principle, the Net Carbon Price approach evaluated in the Pathways Study could represent either a quantity- or price-based approach. While our quantitative analysis assumes a fixed decarbonization quantity target, this fixed target could be achieved through either a fixed, predetermined carbon price, set at a sufficient level to achieve the needed emission reductions, or through a cap-and-trade system, with the cap set at the quantity target assumed in our analysis.

D. Hybrid Approach

The Hybrid Approach combines net carbon pricing applied to all resources, and an FCEM for clean energy that only awards CECs to "new" facilities. The Hybrid Approach was put forth for further discussion and analysis by the New England States Committee on Electricity ("**NESCOE**"), which provided the details of how the Hybrid Approach would be specified. Specifically, the Hybrid Approach includes two key elements:

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[66] Hibbard, Paul, et al., "The Economic Impacts of the Regional Greenhouse Gas Initiative on Nine Northeast and Mid-Atlantic States, Review of RGGI's Third Three-Year Compliance Period (2015-2017)," April 17, 2018, available at https://www.analysisgroup.com/globalassets/uploadedfiles/content/insights/publishing/analysis_group_rggi_report_april_2018.pdf.

[67] Cleary, Kathryne, Karen Palmer and Dallas Burtraw, "Lessons from the Literature for State Carbon Pricing Policy Design," Resources for the Future, Report 22-01, January 2022; Stavins, Robert N., "A Meaningful U.S. Cap-and-Trade System to Address Climate Change," *Harvard Environmental Law Review*, Vol. 32, 2008, pp. 293-371.

[68] A cap-and-trade system limits total emissions to a fixed, pre-determined quantity, while an emission intensity-based system limits emissions to a quantity determined by a metric of total economic activity (*e.g.*, total economic production) and a fixed, pre-determined emission intensity standard, measured in total emissions per unit of total economic activity. Globally, both systems have been deployed in different jurisdictions. For example, California, the Regional Greenhouse Gas Initiative ("RGGI") states and the European Union have imposed cap-and-trade systems, while China has imposed an emission intensity-based system. *See* ICAP, "USA - California Cap-and-Trade Program," ETS Detailed Information, August 9, 2021; Potomac Economics, "Annual Report on the Market for RGGI CO_2 Allowances: 2020," May 2021; ICAP, "EU Emissions Trading System (EU ETS)," ETS Detailed Information, August 9, 2021; ICAP, "China National ETS," ETS Detailed Information, August 9, 2021.

[69] For a review of the literature, *see* Stavins, Robert N., "The Future of US Carbon-Pricing Policy," *Environmental and Energy Policy and the Economy*, Vol. 1, 2020, pp. 8-64.

1. A carbon price set at a level to ensure that all existing clean energy facilities have sufficient revenues to remain financially viable. In particular, NESCOE stated that the Hybrid Approach "is not intended on its own to provide revenue adequacy to meet the regional target, but rather to ensure that the average annual energy price (including the carbon adder) is at a level to ensure revenue adequacy for the largest existing clean energy resource."[70] In principle, this has implied that the carbon price would be set such that LMPs would rise sufficiently due to the carbon price to provide sufficient revenues for the Millstone Power Station, the largest existing clean energy resource in New England.

2. An FCEM with CEC awards limited to "new" resources, defined as resources that do not have a capacity supply obligation as of June 1, 2024.[71] Under this design, the FCEM would aim to incent new entry from clean energy resources by providing compensation via CECs, but not provide any revenue support to existing clean energy facilities. Rather, existing clean energy facilities would, in principle, receive revenue support through higher LMPs due to the carbon price.

As the Hybrid Approach includes both a carbon price and an FCEM (for "new" clean resources), implementing this approach would require addressing design issues and considerations associated with both methods (including those described above). Further, the Hybrid Approach design would require an administrative determination of both the carbon price and CEC demand to produce an average LMP that provides revenue adequacy for the largest clean energy plant in the region. As we discuss in **Section VI.F**, this requirement could add substantial complexity to the administrative process of setting carbon prices and CEC demand given interactions between LMPs, carbon prices and CEC awards.

IV. Approach to Quantitative Analysis of Alternative Policy Approaches for Achieving Decarbonization

We provide an overview of the methodology, assumptions and data used in the quantitative analysis of alternative policy approaches to achieving decarbonization. The overview starts by describing the market simulation software we use in our analysis. We then describe the data and assumptions used in our Central Case, including demand and supply. We also describe assumptions specific to each policy approach and to the Reference Case, which serves a benchmark for estimating certain incremental economic impacts of greater decarbonization. Finally, we describe the Scenarios we evaluate as alternatives to the Central Case. **Appendix A** provides further details on the models, data, and assumptions used in the quantitative analysis.

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[70] NESCOE, "Pathways Hybrid Model Scope Memo," June 22, 2021, available at https://nescoe.com/resource-center/hybrid_approach_memo/.

[71] Technically, the NESCOE proposal specifies the following criteria: "Resources that have cleared only a small portion of their eligible capacity (<30% of its available FCM qualified capacity) prior to the established cut-off date will be treated as having no CSO for purposes of this modeling and be fully eligible for the FCEM/ICCM. This includes resources that have contracts in place." NESCOE memo to ISO-NE/NEPOOL, "Pathways Hybrid Model Scope Document," June 22, 2021, p. 1, footnote 1, available at https://nescoe.com/wp-content/uploads/2021/06/Hybrid_Approach_Assumptions_6-22-21.pdf.

Our study makes reasonable assumptions about future loads, technologies and costs associated with a more decarbonized New England grid. These assumptions benefited from discussions with and input from NEPOOL Stakeholders and the New England States. However, these assumptions are subject to substantial uncertainty given the length (20 years) of our study period. Given this uncertainty, we undertake scenario analysis to test the robust of these assumptions to a range of alternative technological and cost outcomes. Key assumptions in our study include:

- **Customer demand.** We assume increasing aggregate wholesale electricity demand, driven in large part by electrification of heating and transportation.

- **Generation and storage technologies.** We assume technology costs and operating efficiencies from reliable, independent sources (U.S. Energy Information Agency), but do not assume the availability of any technologies that are not currently commercially viable (*e.g.*, flow batteries, combustion turbines or combined-cycle resources powered by "green" hydrogen or "renewable" natural gas). Thus, our study assumes battery storage is the only dispatchable technology that does not emit carbon. We also do not assume any clean energy sources from outside the New England system (*e.g.*, Hydro-Quebec), aside from those already planned or in development (in particular, the New England Clean Energy Connect or "NECEC").[72]

- **Transmission.** Our Central Case assumes no transmission constraints (*i.e.*, no congestion), but we evaluate outcomes with transmission in a scenario.[73] The Central Case assumes costs associated with ensuring the deliverability of supply from variable renewable resources. However, we do not estimate costs of new transmission across the system needed to meet increasing electricity demand and achieve regional decarbonization. The upgrades needed to achieve decarbonization could be substantial, given the need to accommodate both variable renewable supplies interconnecting to parts of the system remote from loads and increasing loads, particularly from electrification of heating and transportation. However, it is not clear if these transmission costs are likely to differ materially across

[72] In particular, we do not consider the potential for additional hydropower resources from Canada beyond the NECEC project to enter the market under any policy approach. This decision does not reflect an assessment that such resources would not be cost-effective to achieving decarbonization targets or could not be developed given siting challenges, but the view that uncertainty about siting challenges and costs is particularly large for these resources, creating uncertainty about whether they would supply energy into New England. Including these resources in the assessment could lower the cost of achieving decarbonization (if their costs are lower than those of other clean resources) and would diminish the challenges and prevalence of market outcomes (*e.g.*, negative pricing) associated with variable renewable resources, as a smaller fraction of clean energy would be supplied by variable resources that may offer energy at negative prices. However, including Canadian hydropower resources in the quantitative analysis would not be expected to alter the overall findings of the study with respect to the policy approaches. In particular, there is nothing unique about these resources that would alter conclusions about the incentives for clean energy created by each policy approach.

[73] Our Central Case assumes no transmission constraints given uncertainty about the transmission investment that may occur over the next 20 years to accompany decarbonization efforts. ISO-NE is currently undertaking on long-term study of transmission for 2050. For example, ***see*** "2050 Transmission Study," Planning Advisory Committee, November 17, 2021.

policy approaches. ISO-NE is currently undertaking a transmission study for 2050 that will provide information about these potential upgrades and costs.[74]

Our analysis compares outcomes between alternative policy approaches to achieving decarbonization to assess the impact of policy design choice on economic and market outcomes. Specifically, we analyze economic outcomes of four different policy approaches — the Status Quo, FCEM, Net Carbon Pricing, and the Hybrid Approach — to reducing carbon emissions to 80% below 1990 levels by 2040. To evaluate economic outcomes of each approach to achieving this more stringent carbon target, we compare the outcomes for each policy approach to a "baseline" without any incremental decarbonization. This baseline is a **Reference Case,** in which the region achieves less ambitious decarbonization reflecting only certain planned procurements.[75] By comparing outcomes in each case to outcomes in the Reference Case, we can measure the incremental change in economic outcomes arising from the incremental decarbonization (*i.e.*, reduced carbon emissions) achieved with each Pathway relative to the baseline with no incremental decarbonization in the Reference Case. This comparison of multiple alternative policy approaches to achieving a regulatory objective (*i.e.*, the 2040 emission targets) to a "baseline" that does not achieve this regulatory objective is the standard approach to regulatory analysis used by regulatory agencies.[76]

A. Modeling Framework

Quantitative impacts of decarbonization under each of the four policy approaches are estimated using a market simulation model. We use two simulation models to capture different market outcomes:

- A **Capacity Expansion Model ("CEM")** determines long-run market outcomes by simulating outcomes in energy and capacity markets over an extended time horizon (*e.g.*, 2021-2040), along with the entry and exit of resources. The timing of new resource entry and resource exit estimated by the model reflects multiple model inputs including loads (levels and profiles), costs (*e.g.*, new technology improvements) and environmental requirements that change across the study period. The CEM also

[74] "2050 Transmission Study," Planning Advisory Committee, November 17, 2021.

[75] These procurements are the "baseline state policies," a common assumption to each of the policy approaches. We discuss these baseline state policies further in **Section IV.B**, based on information summarized in **Section II.D**. These "baseline state policies" are separate from the procurements assumed in the Status Quo.

[76] For example, the US Environmental Protection Agency guidelines state "The baseline serves as a primary point of comparison for an analysis of a proposed policy action. An economic analysis of a policy or regulation compares the current state of the world, the baseline scenario, to the expected state of the world with the proposed policy or regulation in effect, the policy scenario. Economic and other impacts of policies or regulations are measured as the differences between these two scenarios." US Environmental Protection Agency, "Guidelines for Preparing Economic Analysis", National Center for Environmental Economics, Office of Policy, updated May 2014, p. 5-1. Similarly, the U.S. Office of Management and Budget (OMB) guidelines state that regulatory analysis needs to "Identify a baseline: Benefits and costs are defined in comparison with a clearly stated alternative. This normally will be a "no action" baseline: what the world will be like if the proposed rule is not adopted" and continues "A good regulatory analysis should include the following three basic elements … (2) an examination of alternative approaches, and (3) an evaluation of the benefits and costs—quantitative and qualitative—of the proposed action and the main alternatives identified by the analysis." U.S. OMB, Circular A-4, September 17, 2003, available at https://obamawhitehouse.archives.gov/omb/circulars_a004_a-4/#c.

estimates environmental prices, including CEC prices for the FCEM and carbon price for the Net Carbon Pricing.

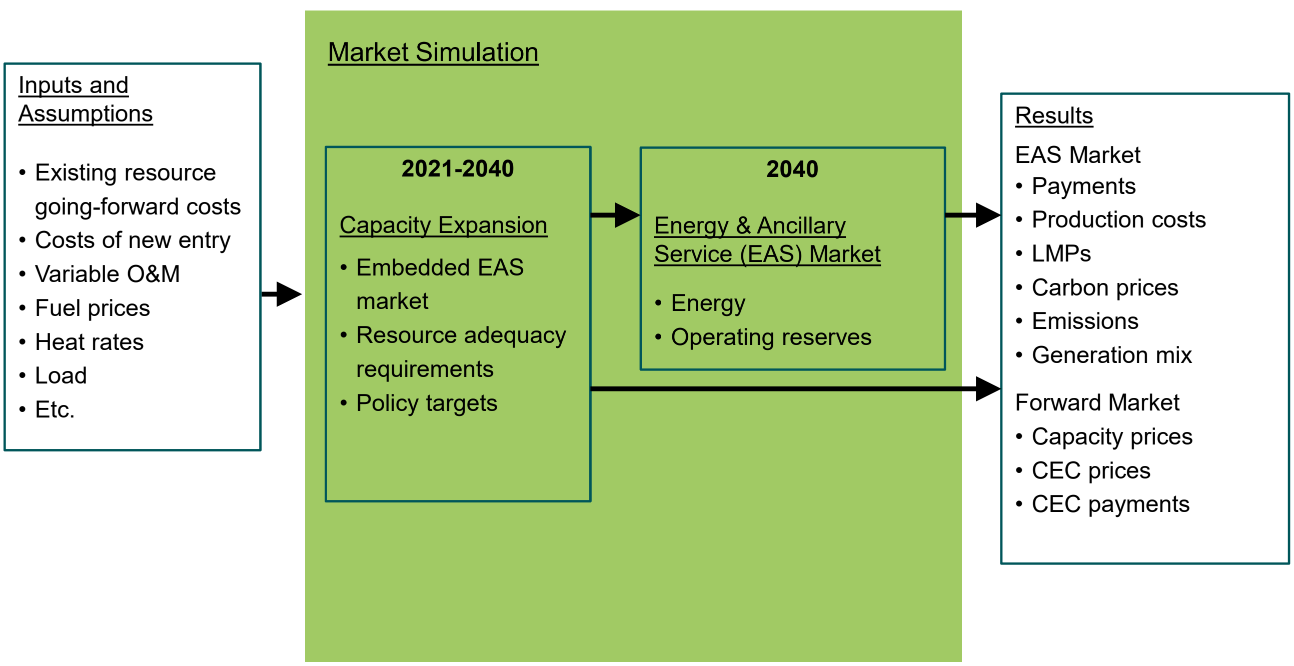
- An **Energy Market Simulation Model ("EMS")** simulates the energy (and ancillary service) market in one calendar year, with hourly simulation granularity. This simulation does not solve for resource entry and exit, and instead assumes the resource mix from the CEM simulation. Given this assumed resource fleet, the model chronologically simulates energy and ancillary services dispatch and calculates hourly production costs and location-specific market clearing prices, while simultaneously adhering to a variety of operating constraints.

  The EMS complements the CEM by providing more detailed information about energy market outcomes, as it models hourly energy market-clearing (*i.e.*, 8,760 hours per year). By accounting for greater temporal resolution, the EMS provides a more precise representation of certain aspects of energy market operations, LMPs, and production costs.

Both models rely on dynamic multi-period optimization using a Mixed Integer Programming (MIP) optimization solver to minimize the net present value of total costs for the generation fleet within ISO-NE.

Figure IV-1 shows the sequence of module interactions. First, the CEM determines the optimal capacity expansion plan for 2021-2040 and the prices for capacity, energy, CECs and carbon. Certain information from the CEM (*e.g.*, the resource fleet) is then used as key inputs for the EMS, which models chronological unit commitment and dispatch.

Figure IV-1. Overview of Modeling Components and Process



B. Central Case Assumptions

We analyze each policy approach under a common set of "Central Case" assumptions. By using common assumptions, we can ensure that the differences in results observed between the policy approaches are driven solely by differences in the incentives created by the policy approaches and are not due to differences in other modeling assumptions. When possible, we use assumptions consistent with the FGRS; however, because the FGRS is evaluating different issues than the Pathways Study, differences in simulation results may arise due to a variety of differences in model and analysis structure. Unless noted, the analysis herein assumes that current market rules remain in place; while market rules may change over time, it would be speculative to make assumptions about which rules will change, and how they will modified over the coming 20 years. Below, we describe these Central Case assumptions and provide more details on these assumptions in **Appendix A**.

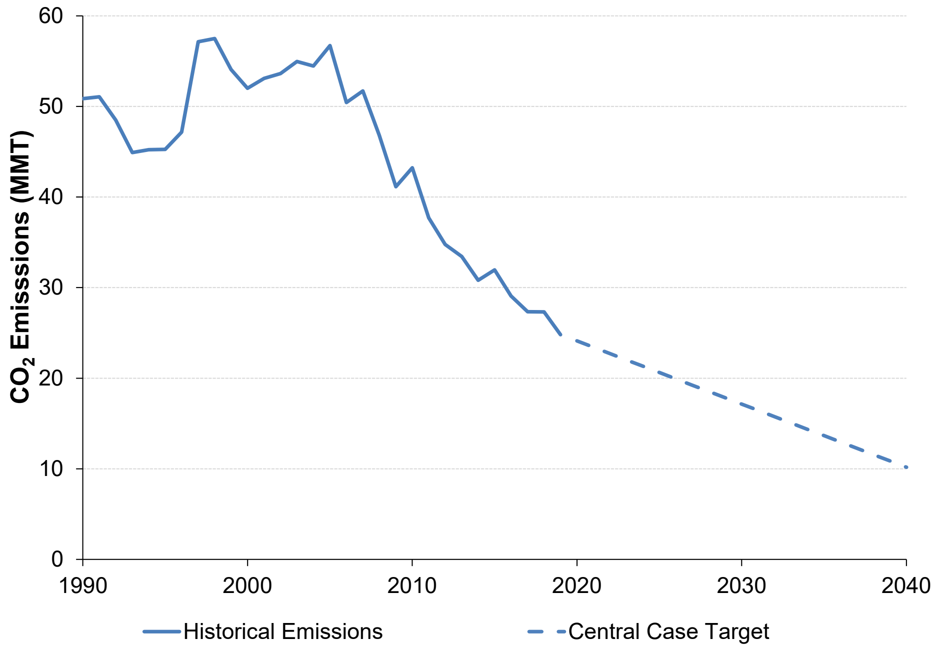
1. Time Period, Market Geography and Emission Target Assumptions

We model the time period 2021 to 2040. For each policy approach, we assume that the annual maximum allowable electricity sector emissions linearly decline from current levels to a target level of 80% below 1990 levels in the year 2040. **Figure IV-2** shows the emissions from the electricity sector in New England since 1990, as well as the assumed path of emissions to achieve the assumed decarbonization level.[77] This level is chosen to be consistent with the stated goals of the New England states, as described in **Section II.D**, which is intended to be neither a precise estimate of the cumulative requirement associated with existing state policies nor a specific policy proposal for the New England states to pursue. Instead, the assumed emission levels are adopted solely for the purposes of illustrating the differences between the policy approaches as the region pursues decarbonization in the coming decades.

The geographic scope of the modeling includes the ISO-NE system, with assumed import quantities from NYISO and Hydro-Quebec based on historical 2019 imports and exports. We do not model these neighboring regions separately in this study.

[77] This assumption is modified in scenario analysis, as described in **Section IV.C**.

Figure IV-2. Historical and Assumed Electricity Sector Emissions (Maximum Allowable) for the New England Region[78]



2. *Demand Assumptions*

Our analysis assumes that demand grows substantially due to extensive electrification of heating and transportation. Specifically, we rely on estimated load developed initially in the Massachusetts 80x50 decarbonization study.[79] This estimated load is also being used in the load scenario from the FGRS with high levels of electric vehicle penetration, substantial growth in electrification of residential and commercial building heating, and increasing energy-efficiency.[80] Thus, when reviewing social and consumer costs, it is important to recall that the high levels of electricity demand assumed may correspond with cost savings for other products and services that are now electrified, such as natural gas for heating and gasoline for automobiles.

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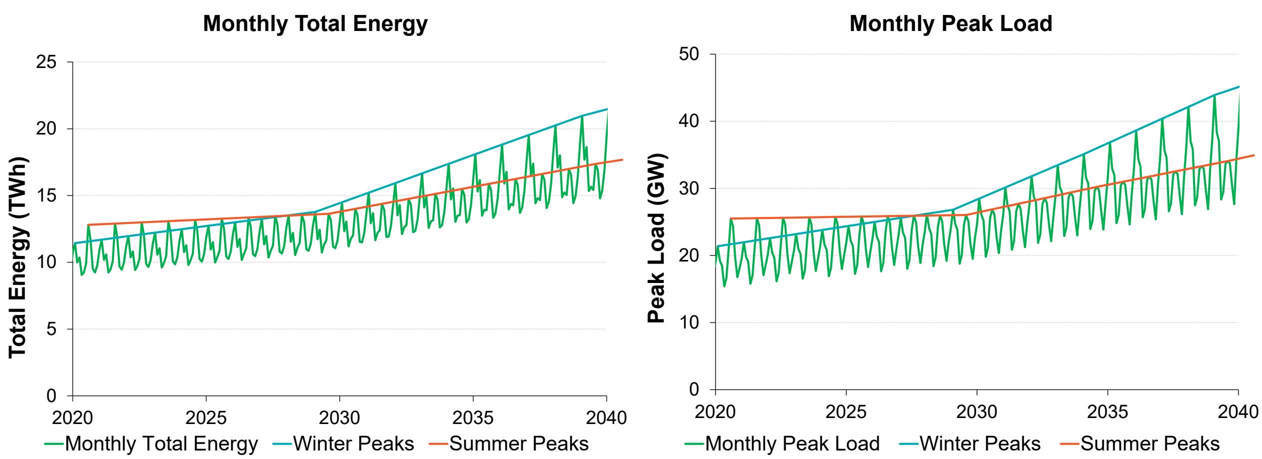
[78] EIA, Electricity, Detailed State Data, available at https://www.eia.gov/electricity/data/state/.

[79] Evolved Energy Research, "Energy Pathways to Deep Decarbonization: A Technical Report of the Massachusetts 2050 Decarbonization Roadmap Study," December 2020, available at https://www.mass.gov/doc/energy-pathways-for-deep-decarbonization-report/download.

[80] ISO-NE, "2021 Economic Study: Future Grid Reliability Study Phase 1 Overview of Assumptions – Part 1," April 14, 2021, available at https://www.iso-ne.com/static-assets/documents/2021/04/a8_2021_economic_study_request_assumptions_part_1_rev2_redline.pdf.

A key implication of this assumed demand is that the ISO-NE system shifts from summer peaking, as it is today, to winter peaking, starting in 2029.[81] **Figure IV-3** shows the monthly energy and peak load over the modeled time period, where this energy and peak load is net of energy efficiency. Supply from behind-the-meter PV ("**BTM PV**") is based on forecasts from ISO-NE, reported in its Forecast Report of Capacity, Energy, Loads, and Transmission (the "**CELT Report**").[82]

Figure IV-3. Modeled Monthly Total Energy and Monthly Peak Load, 2020-2040 (TWh and GW)



To represent a resource adequacy constraint, the CEM operates a capacity market to procure resources sufficient to meet an annual installed capacity requirement ("**ICR**"). The ICR in future years is calculated as the peak load (measured by gross summer peak load, net of energy efficiency) multiplied by the average historical ratio of ICR to peak load (as described above) from 2020 to 2024, as specified by the 2021 CELT report. We simulate the ancillary services markets, including regulation and reserve requirements, consistent with ISO-NE market rules.[83]

Existing state RPS requirements are assumed to remain in effect under all policy approaches.[84] RPS program designs are simplified by having a single REC product, with annual requirements equal to the sum of the New

[81] In reality, the change from a summer to winter peaking system will have implications for ISO-NE market processes, such as the process for establishing qualified capacity for resources in capacity markets. For the purposes of our analyses, we made simplifying assumptions to account for the winter peaking system. These assumptions are described in more detail in **Appendix A**.

[82] ISO New England, "2021 CELT Report: 2021-2030 Forecast Report of Capacity, Energy, Loads, and Transmission," May 1, 2021.

[83] The analysis in this report is not a reliability study. The FGRS Study should be looked to instead for any technical analysis of reliability and reserve shortages.

[84] In the FCEM and Hybrid Approach, renewable resources are assumed to generate both RECs and CECs that can be used to comply with RPS and FCEM requirements, respectively. However, certificates designed for one requirement cannot be used to satisfy the other environmental requirement (*i.e.*, a REC cannot be used to comply with the FCEM, and a CEC cannot be used to comply with an RPS.)

England states' RPS requirements as currently legislated.[85] Resources eligible to meet RPS requirements include onshore wind, offshore wind, utility scale PV, BTM PV, imports from Hydro-Quebec, run-of-river hydro, pondage hydro, solar plus storage, municipal solid waste, and other biomass generators.

3. Supply Assumptions

On the supply side, the existing resource mix that is assumed to be in operation at the start of the study period includes the generator list in ISO New England's CELT Report, as shown in **Table IV-1**.[86] In addition, we assume the following changes to the resource fleet, with further details provided in **Appendix A**:

- entry by resources that cleared capacity in the 2024-2025 Forward Capacity Auction ("FCA 15"),
- scheduled retirements, reflecting the ISO-NE list of retirements as well as other publicly announced retirements,[87]
- retirement of all coal resources in the region by June 1, 2025, and
- renewable entry from "baseline state policies," reflecting announced contracts, state legislated procurements, and state legislated goals, which we discuss in more detail in **Section II.D**.

The CEM determines optimal resource entry and exit for each year of the study period based on the costs and operational specifications of new and existing resources, and the market incentives created by each policy approach. The key factors determining entry and exit decisions include fixed operations and maintenance ("O&M") costs, capital and financing costs (from new resources only), net energy and ancillary service ("**EAS**") revenues, emissions costs or clean energy compensation, and eligible capacity to meet resource adequacy requirements.

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[85] The current New England states' RPS and CES programs are discussed in **Appendix A**.

[86] ISO New England, "2021 CELT Report: 2021-2030 Forecast Report of Capacity, Energy, Loads, and Transmission," May 1, 2021.

[87] ISO New England, "ISO New England Status of Non-Price Retirement Requests, Retirement De-list Bids and Substitution Auction Demand Bids," March 2, 2021. In addition, we assume Mystic 8 & 9 retires on May 31, 2024, *see* Exelon, "Statement regarding the retirement of Mystic Generating Station in 2024," August 21, 2020, available at https://www.exeloncorp.com/newsroom/statement-regarding-the-retirement-of-mystic-generating-station-in-2024.

Table IV-1. Assumed ISO-NE Resource Mix by Technology Type as of December 31, 2020 (MW)[88]

Unit Type	Nameplate Capacity (MW)
Fossil	
Combined Cycle	16,158
Steam Turbine	4,591
Gas Turbine	3,893
Coal	917
Fuel Cell	30
Fossil Total	**25,590**
Variable Renewable	
BTM PV	2,363
Hydro	2,234
Photovoltaic Solar	1,807
Land Based Wind	1,424
Offshore Wind	29
Variable Renewable Total	**7,857**
Other	
Nuclear	3,349
Pumped Storage Hydro	1,826
Biomass	972
Battery Energy Storage	8
Other Total	**6,155**
Total	**39,603**

Potential new resources include onshore wind, offshore wind, utility-scale solar, battery storage, natural gas combined cycle, and natural gas combustion turbines. Operation of storage resources reflects a simplification of charging and discharging decision-making, which is inherent to any quantitative modeling of storage operations, given the complex intertemporal dependence of these decisions. This simplified storage operation logic is more consistent with likely actual operations in the EMS, as compared to the CEM. Nonetheless, care should be exercised in interpreting certain quantitative results heavily dependent on these storage operations.

Our analysis assumes only technologies that are currently commercially viable, and thus does not consider any zero-carbon "backstop" dispatchable technologies, such as combustion turbines powered with "green" hydrogen or "renewable" natural gas, or fossil-fired generation with carbon capture technology.[89] Thus, while our analysis includes only one technology — 4-hour lithium ion batteries — able to complement non-dispatchable variable renewable output, in practice, other technologies could emerge (including other battery

[88] Hydro includes run of river, weekly, and pondage hydro.

[89] Carbon capture and sequestration technology is not commercially used at present, and New England lacks the geological features required to sequester captured carbon.

technologies, such as flow batteries) that could compete with 4-hour lithium ion batteries to more cost-effectively maintain resource adequacy while complementing the renewable variable output.

New entry capital costs for each of the modeled technologies are based on the Energy Information Administration ("**EIA**") Annual Energy Outlook ("**AEO**") 2021.[90] The EIA AEO is chosen because it is a publicly available, independent, bottom-up engineering analysis of costs that incorporates region-specific factors. The EIA provides this assessment of costs in the context of its Annual Energy Outlook, which is a forecast of future U.S. energy market outcomes. Fixed O&M for new-entry resources is based on national EIA AEO 2021 estimates. All new entry is assumed to have a 20-year financing period and a 6.1% after-tax weighted average cost of capital ("**ATWACC**").[91] We assume the same ATWACC in all policy approaches, including the Status Quo. **Section VI.F.2** discusses this decision and the tradeoffs between potential reductions in financing costs when projects are financed with a multi-year PPA in the Status Quo and the transfers in risk from suppliers to consumers (and utilities) associated with these contracts.

Capital costs vary to account for two key factors, which are partially offsetting over the study period. First, capital costs decrease over time to account for technological change.[92] **Figure IV-4** shows the reductions in new entry capital costs over time due to technological improvements, based on information developed by EIA for the AEO.

Second, capacity costs increase as more cumulative capacity of a given technology is developed. These increasing costs reflect variation in transmission and siting costs across projects and the assumption that the lowest-cost projects are developed first and subsequent projects are more costly. Thus, as more cumulative capacity in New England increases, capital costs increase over time. However, EIA AEO capital costs do not account for this variation in costs across projects and thus do not account for the full social costs of new entry capital resources such as transmission infrastructure costs or costs associated with resource siting. Full analysis of the challenges of resource siting for new resources, particularly onshore and offshore wind, is beyond the scope of our study. However, we do explicitly account for certain infrastructure costs and make assumptions to account for certain constraints associated with siting challenges and limitations. Thus, for each renewable technology, costs increase as cumulative capacity increases. In particular, for onshore and offshore wind resources, we account for transmission upgrade costs needed to ensure that renewable energy supply is deliverable to the system. Thus, for remote projects, cost estimates include transmission needed to interconnect the project to the transmission system, and potentially transmission system upgrade costs to ensure deliverability. Our estimates are based on resource location and the sequence of resource

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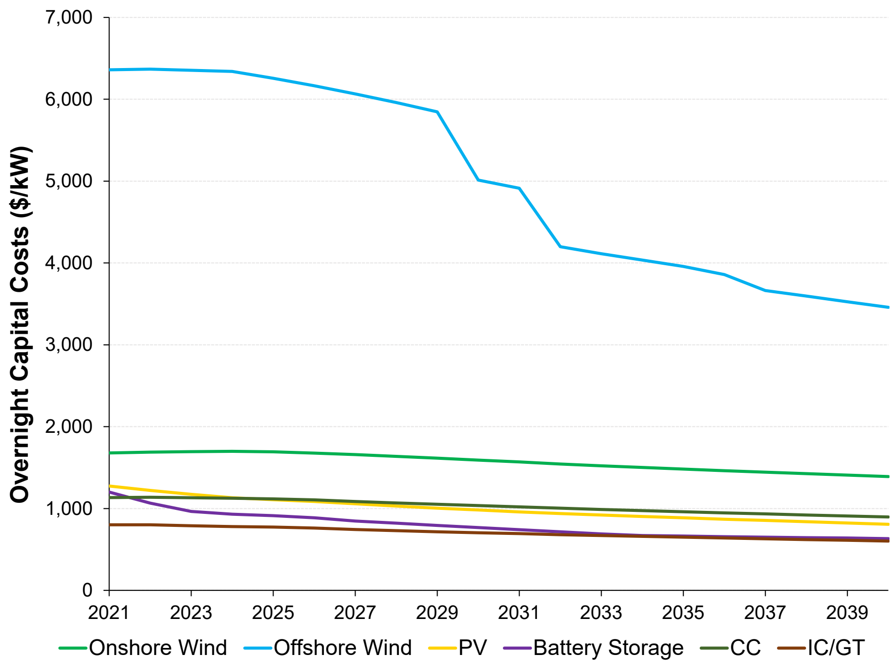
[90] In order to assess the sensitivity of the results to this assumption, **Section IV.C** describes a scenario using an alternative source for overnight capital costs.

[91] This ATWACC is based on Concentric Energy Advisors, Inc. and Mott MacDonald, "ISO-NE Net Cone and ORTP Analysis, An Evaluation of the Net Cost of New Entry and Offer Review Trigger Price Parameters to be Used in the Forward Capacity Auction, FCA-16 and Forward," December 2020, p. 10, more details in **Appendix A**.

[92] Much of this technological change likely occurs due to cumulative ("learning by doing") gains from deployment of advanced technologies through the U.S. and the world. Thus, the improvements are expected to be largely independent of cumulative technology development within New England.

development (given limits to the system's ability to accommodate new resources without upgrades), following recent publicly available ISO-NE studies.[93] For example, **Figure IV-5** shows the assumed capital costs for offshore wind in 2020. As more offshore wind is developed, costs increase as the lowest cost sites have already been taken. The figure illustrates several factors that we account for that increase costs: (1) the need to system upgrades at interconnection points (or the need for incremental transmission to interconnect at unconstrained hubs), (2) increases in upgrade costs and/or longer transmission routes for incremental projects, and (3) finite opportunities for fixed offshore wind platforms, which may necessitate development of more costly floating wind platforms to achieve higher levels of cumulative capacity.

Figure IV-4. Overnight Capital Costs by Technology Type ($2020/kW)[94]



Similarly, solar and battery resources include a cost adder that increases with total cumulative resource capacity developed to account for similar increases in siting costs as more solar and battery resources are developed. However, adders for solar and battery resources increase at a slower rate to reflect these

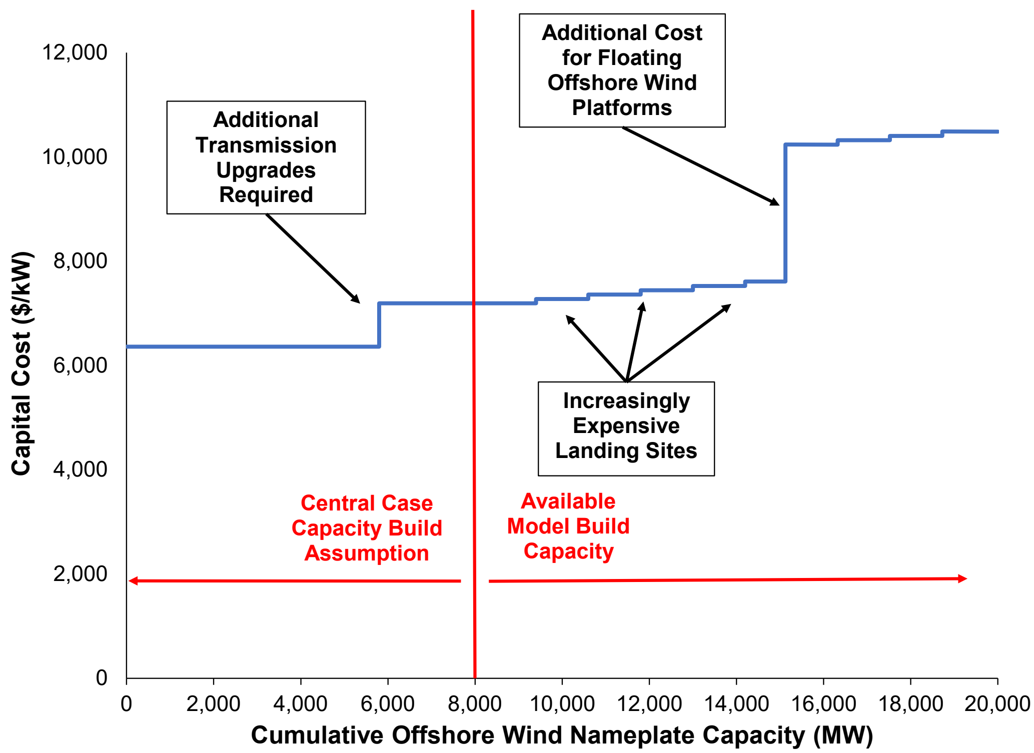
93 ISO-NE, "Final Second Maine Resource Integration Study," October 30, 2020, available at https://www.iso-ne.com/static-assets/documents/2021/01/second-maine-resource-integration-study-report-non-ceii-final.pdf; ISO-NE, "2019 Economic Study Offshore Wind Transmission Interconnection Analysis," June 17, 2020, available at https://www.iso-ne.com/static-assets/documents/2020/06/a4_2019_economic_study_offshore_wind_transmission_interconnection_analysis.pdf.

94 EIA, "Assumptions to the Annual Energy Outlook 2021: Electricity Market Module," Table 4, p. 7; EIA, "Annual Energy Outlook 2021," Table 55. Overnight Capital Costs for New Electricity Generating Plants, available at https://www.eia.gov/outlooks/aeo/data/browser/#/?id=123-AEO2021&cases=ref2021&sourcekey=0.

resources' greater flexibility in siting and smaller physical footprint per unit of capacity. More detail is provided in **Appendix A**.

Energy market offers reflect short-run marginal costs ("**SRMC**"), including variable O&M costs, fuel costs (reflecting plant-specific heat rates) and plant-specific intertemporal constraints (*e.g.*, minimum run times, startup costs, and energy limits for storage resources). Natural gas, oil and coal prices are based on forwards and futures data. RGGI is assumed to continue and have a price equal to that from the last three years. In **Section V.B.1** and **Section VI.B.3**, we provide further detail regarding offers from variable renewable resources under each policy approach.

Figure IV-5. Offshore Wind Capital Costs in 2020 ($2020)



Capacity market outcomes ensure that the total qualified capacity is at least equal to the ICR. Under current market rules, each resource's qualified capacity for the forward capacity auction reflects its capacity in the season that contains the annual system peak.[95] Currently, the system peak in New England is in the summer season. For purposes of this analysis, however, a resource's qualified capacity, which will be used to meet

[95] Under current market rules, a resource's qualified capacity is based on the resource's average seasonal claimed capability rating for the most recent five periods during summer and winter. The FCA uses the seasonal qualified capacity associated with the annual system peak. ISO New England, "Glossary and Acronyms," "qualified capacity," available at https://www.iso-ne.com/participate/support/glossary-acronyms/; ISO New England, "FCA Results," available at https://www.iso-ne.com/static-assets/documents/2018/02/fca_obligations.xlsx.

the ICR, is set at the average of their winter and summer qualified capacities. Estimates of summer and winter qualified capacity are based on current market rules and standard sources, such as the CELT Report.

We make this change from current market rules as a simple way to account for the projected future system moving from summer to winter peaking during the study period. Future changes to the market rules to determine appropriate resource contributions to resource adequacy have not yet been established and are an on-going issue being discussed among ISO-NE, NEPOOL Stakeholders, and the New England States at this time. This assumption is not intended to be a proposed approach to determining appropriate resource contributions to resource adequacy.

Output from certain resources is based on generation profiles that vary from hour-to-hour but are constant across years. Output from new and existing BTM Solar, utility scale solar, onshore wind, and offshore wind generators is based on hourly generation profiles using data compiled by DNV GL.[96] The profiles vary by location and are based on 2019 weather patterns. Hydropower output profiles are based on actual 2019 generation data provided by ISO-NE. Net energy flows across NYISO and Hydro Quebec interties are also based on 2019 flows.

4. Policy Approach Assumptions

The policy approaches modeled each have their own mechanisms to reach future climate goals. Below, we describe the assumptions made in modeling each policy approach:

- ***Status Quo***. Under the Status Quo approach, the New England states meet an emissions reduction target of 80% below 1990 levels by 2040 via competitive procurements. We assume that the resource mix procured aligns with state decarbonization studies and plans. **Table IV-2** provides the state-level resource mix arising from these studies and plans, as well as the resulting aggregate resource mix across New England. In each state's study, we chose scenarios with assumptions that most closely aligned with the Pathway Study's modeling assumptions. To meet emission targets, if additional resources beyond those shown in **Table IV-2** are needed, these resources are determined by the CEM. For each type of technology, we assume the state procurements award contracts to the least-cost resources, which may understate costs to the extent that state "pay-as-bid" procurements fail to select the least-cost resources. We discuss factors that may lead to this outcome in **Section VI.B**.
  Table IV-3 provides state-by-state decarbonization targets for the electricity sector based on statutory requirements and other commitments.[97] These targets are used as the basis for allocating the costs of PPAs in the Status Quo and the cost of CECs in the FCEM.

[96] DNV-GL, "Analysis of Stochastic Dataset for ISO-NE," February 24, 2021, available at https://www.iso-ne.com/static-assets/documents/2021/03/a9_dnv_gl_report_analysis_of_stochastic_dataset_for_iso_ne_rev1.pdf.

[97] See **Appendix A.C** for further details of these requirements.

Table IV-2. Status Quo Resource Mix Incremental Build by State (GW)[98]

	2020-2040 Incremental Build (GW)					
State	**Offshore Wind**	**Onshore Wind**	**Solar**	**Storage**	**NECEC**	**Total**
Connecticut	4.7	0.4	2.3	2.2	-	9.7
Maine	-	2.0	0.7	0.5	-	3.2
Massachusetts	9.2	0.4	5.5	0.4	1.2	16.6
New Hampshire	-	-	-	-	-	--
Rhode Island	2.0	-	1.4	1.0	-	4.4
Vermont	-	0.2	0.8	-	-	1.0
Total	16.0	3.0	10.7	4.1	1.2	35.0

Note: Specifically, we chose the following scenarios: (1) Connecticut - Electrification / Millstone, (2) Maine - Base (High) Load / Central Case, (3) Massachusetts - "All Options" Pathway, (4) Rhode Island - GRIDSIM Results, and (5) Vermont: TREES-HiBio. New Hampshire's most recent energy strategy report noted a "priority…to organize goals around cost-effective energy policies," so we allow the Capacity Expansion Model to select the optimal mix of resources to meet New Hampshire's electricity demand.

Table IV-3. New England States' Decarbonization Commitments by 2040

	2040 Quantities			
State	**Load (MWh)**	**RPS**	**RPS + CES + Other**	**All State Policies**
Connecticut	47,546,699	48%	100%	100%
Maine	22,542,752	80%	80%	90%
Massachusetts	92,638,082	57%	74%	95%
New Hampshire	19,225,387	25%	25%	25%
Rhode Island	12,255,921	39%	100%	100%
Vermont	10,359,234	75%	75%	99%
Total (load weighted)	204,568,075	54%	77%	89%

Note: CES + Other includes Massachusetts Clean Energy Standard, Massachusetts Alternative Energy Portfolio Standard, and Executive Orders in both Connecticut and Rhode Island. All State Policies represents the estimated clean energy required for each state to meet their decarbonization targets.

[98] Connecticut Department of Energy and Environmental Protection, "Integrated Resources Plan: Pathways to Achieve a 100% Zero-Carbon Electric Sector by 2040," Appendix A3, October 2021, available at https://portal.ct.gov/-/media/DEEP/energy/IRP/2020-IRP/Appendix-A3--Modeling-Results.pdf, p. 85 (Table 28); Energy+Environmental Economics and Applied Economics Clinic, "State of Maine Renewable Energy Goals Market Assessment," February 2021, available at https://www.maine.gov/energy/sites/maine.gov.energy/files/inline-files/GEO_Renewable%20Energy%20Goals%20Market%20Assessment_Feb%202021_1.pdf, p. 42 (Figure 27); Evolved Energy Research, "Energy Pathways to Deep Decarbonization: A Technical Report of the Massachusetts 2050 Decarbonization Roadmap Study," December 2020, available at https://www.mass.gov/doc/energy-pathways-for-deep-decarbonization-report/download, p. 89 (Figure 40); New Hampshire Office of Strategic Initiatives, "New Hampshire 10-Year State Energy Strategy," April 2018, available at https://www.nh.gov/osi/energy/programs/documents/2018-10-year-state-energy-strategy.pdf, p. 5; The Brattle Group, "The Road to 100% Renewable Electricity by 2030 in Rhode Island: Technical Support Document," March 2021, available at http://www.energy.ri.gov/documents/renewable/The%20Road%20to%20100%20Renewable%20Electricity%20-%20Technical%20Document.pdf, p. 36; Dunsky Energy Consulting, "Energy Policy Options for Vermont: Technologies and Policies to Achieve Vermont's Greenhouse Gas and Renewable Energy Goals," June 23, 2014, available at https://publicservice.vermont.gov/sites/dps/files/documents/Pubs_Plans_Reports/TES/C.%20Dunsky%20Final%20Report%20-%20Vermont%202050%20Energy%20Study.pdf, p. 65 (Figure 24).

- ***FCEM***. Under the FCEM, eligibility for CEC awards is based on plant technology, such that resources with no emissions and resources deemed to have no net emission impact (*e.g.*, certain biomass) receive CECs. **Table IV-4** shows these technology eligibility criteria used in this analysis. The quantity of CEC demand in each year is chosen to produce a generation mix that meets the applicable emissions target. The state-by-state decarbonization targets in **Table IV-3** are used to allocate the CEC costs among the New England states.

  Our analysis does not model the forward structure of the FCEM, but only models a spot market for CECs. Thus, in effect, the model assumes that forward market expectations reflect spot market outcomes. In addition, the structure of the CEM simulations solve for all markets simultaneously. Thus, in effect, the simulations are generally consistent with an ICCM, where the FCEM and FCM are integrated into a single, joint procurement that simultaneously determines clearing awards and prices for both forward clean energy and capacity.[99] Our analysis is also consistent with a stand-alone FCEM that is run separately from the FCM, assuming perfect foresight in market-clearing between the two auctions.

- ***Net Carbon Pricing***. Under Net Carbon Pricing, carbon emissions from facilities burning natural gas, oil, or coal are assessed a charge equal to the carbon price for each MT of CO_2 emissions. Certain biomass facilities and facilities that generate electric energy from fuel generated from landfill emissions are not subject to the carbon price (**Table IV-4**). The model determines the level of the carbon price needed to achieve the applicable emission target in each year.

- ***Hybrid Approach.*** Under the Hybrid Approach, certain new facilities are eligible for CEC awards and a price is imposed on carbon emissions. Eligibility for CEC awards is based on the same eligibility criteria for the FCEM *plus* the facility must not have cleared 30% or more of its qualified capacity in the primary forward capacity auction for the period starting June 1, 2024. Thus, by 2040, resources eligible for CECs under the Hybrid Approach include only resources completed after June 1, 2025 (with the exception of a small quantity of in-service resources that have not to date cleared more than 30% of their capacity). Facilities subject to the carbon tax are the same facilities as under the Net Carbon Price approach with no distinction made for vintage. **Table IV-4** shows the technologies eligible for CECs and the technologies subject to the carbon tax under the Hybrid Approach. The model chooses both a quantity of CEC demand and carbon price in each year needed to simultaneously achieve the emission target in each year and achieve an average annual LMP of $41/MWh over the time period 2030-2040.[100]

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[99] ISO-NE Market Development, "Modelling Equivalence of FCEM and ICCM," Memo to NEPOOL Participants Committee Working Session, May 6, 2021, available at https://nepool.com/wp-content/uploads/2021/05/4-ICCM-FCEM-Equivalence-Memo-vfinal.pdf.

[100] The LMP target of $41/MWh was chosen by NESCOE with the stated aim to "ensure that the average annual energy price (including the carbon adder) is at a level to ensure revenue adequacy for the largest existing clean energy resource." The time period 2030-2040 is chosen because Millstone currently has a contract in place with

Table IV-4. Technologies Eligible for CECs in the FCEM and Hybrid Approach or Subject to the Carbon Tax in the Net Carbon Price and Hybrid Approach

Technology	Eligible for CECs?	Subject to Carbon Tax?
Onshore wind	✓	✗
Offshore wind	✓	✗
Utility-scale solar	✓	✗
BTM solar	✓	✗
Canadian hydro	✓	✗
Run-of-river hydro	✓	✗
Pondage hydro	✓	✗
Pumped storage	✗	✗
Nuclear	✓	✗
Battery storage	✗	✗
Municipal solid waste	✓	✗
Other biomass	✓	✗
Natural gas combined cycle	✗	✓
Fuel cells	✗	✓
Coal	✗	✓
Steam Turbine	✗	✓
Gas Turbine	✗	✓

- ***Reference Case.*** To benchmark certain outcomes, we also model a Reference Case that includes no policies that would reduce emissions beyond the baseline state policy resources common to all of the policy approaches (shown in **Figure II-2**). This results in less decarbonization (higher carbon emissions) than under each of the four policy approaches, allowing us to evaluate the incremental economic cost and impact of achieving the more stringent target. Specifically, carbon emissions are 45% below 1990 levels in 2040 in the Reference Case, compared to 80% below 1990 levels for the policy approaches. However, all other assumptions otherwise remain the same, including total load

regulated Connecticut utilities that provides a fixed price for a portion of its energy output through 2029. Importantly, this analysis does not assess the energy market compensation needed to support the continued operation of Millstone, and instead simply assumes this level of compensation will allow Millstone to remain in the market going forward for this analysis. NESCOE, Memo to ISO-NE/NEPOOL, "Pathways Hybrid Model Scope Document," June 22, 2021, p. 2, available at https://nescoe.com/wp-content/uploads/2021/06/Hybrid_Approach_Assumptions_6-22-21.pdf.

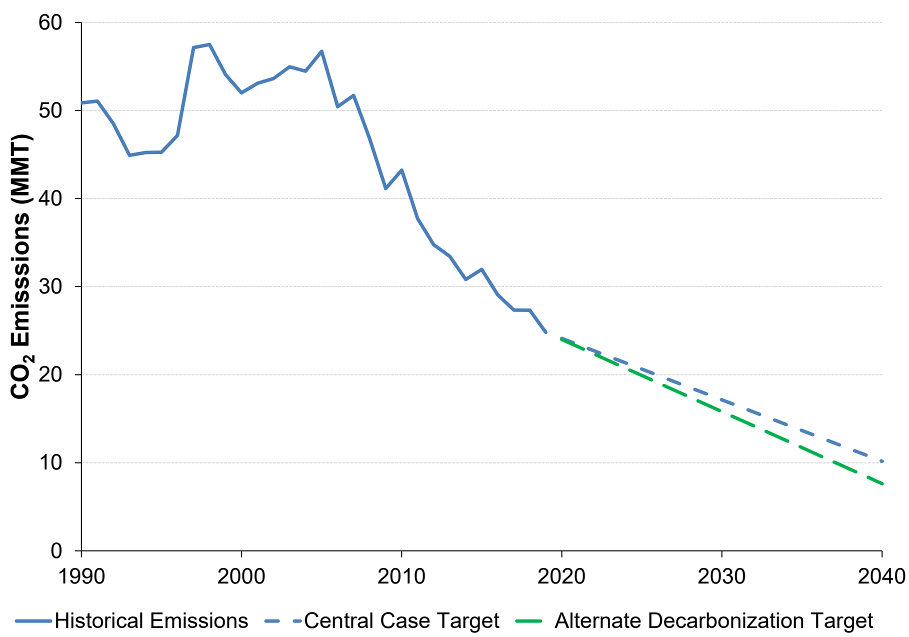
consistent with electrification of heating and transportation. Thus, comparisons of economic costs and payments between each policy approach and the Reference Case will capture the incremental impact of achieving the incremental emission reductions needed to meet the 80% below 1990 emissions target, rather than a lower emission reduction value of 45%.

C. Scenario Assumptions

To evaluate the sensitivity of quantitative outcomes to alternative assumptions about market conditions and model input assumptions, we consider different sensitivity analyses. The selection of scenarios reflects multiple considerations, including responsiveness to requests and feedback from the New England States and NEPOOL Stakeholders, expectations about which scenarios would provide the most valuable information in testing the robustness of Central Case findings, and time and/or model limitations. The sensitivity analyses vary certain key assumptions in the Central Case across all policy approaches. In particular, we consider the following scenarios and alternative assumptions:

- ***Alternative regional decarbonization carbon target***. We test the sensitivity of the Central Case results to a more aggressive decarbonization target — 85% below 1990 levels by 2040, rather than the 80% reduction assumed in the Central Case. **Figure IV-6** shows the targeted path relative to the Central Case assumption. Under this scenario, by 2040, annual electricity sector emissions will be 25% lower than in the central case.

Figure IV-6. Alternative Decarbonization Target[101]



[101] EIA, Electricity, Detailed State Data, available at https://www.eia.gov/electricity/data/state/.

- ***Alternative capital costs.*** We test the sensitivity of the Central Case results to different assumptions about the cost of new entry. Under this scenario, we use alternative capital costs from the 2021 National Renewable Energy Laboratory ("NREL") Annual Technology Baseline ("ATB").[102] **Table IV-5** compares the assumed overnight capital costs in this scenario (NREL ATB) with the Central Cases (EIA AEO). **Figure IV-7** shows the trajectory of the NREL ATB capital costs given technological improvements. For renewable resources, the NREL ATB cost estimates are lower than or approximately equal to the EIA AEO costs. In some cases, costs are significantly lower, such as for offshore wind. For gas-fired and battery resources, costs are similar, with the exception of combustion turbines in 2040, where NREL ATB costs are higher. The scenario produces the same total carbon emission reduction as the Central Case.

Table IV-5. Comparison of Overnight Capital Cost Assumptions, Central Cases (EIA) vs. Alternative Capital Costs Scenario (NREL)

	Overnight Capital Cost ($/kW)			
	2021		2040	
Resource Type	**EIA AEO**	**NREL ATB**	**EIA AEO**	**NREL ATB**
CT F-Class	801	838	603	730
CC H-Class (2 x 1)	1,134	952	897	871
Battery Energy Storage	1,201	1,282	633	686
Solar	1,276	1,288	808	692
Wind Onshore	1,680	1,291	1,391	819
Wind Offshore	6,360	3,446	3,458	2,112

Note: EIA AEO refers to the Energy Information Administration Annual Energy Outlook 2021, available at https://www.eia.gov/outlooks/aeo/. NREL ATB refers to the 2021 National Renewable Energy Laboratory Electricity Annual Technology Baseline, available at https://atb.nrel.gov/electricity/2021/data.

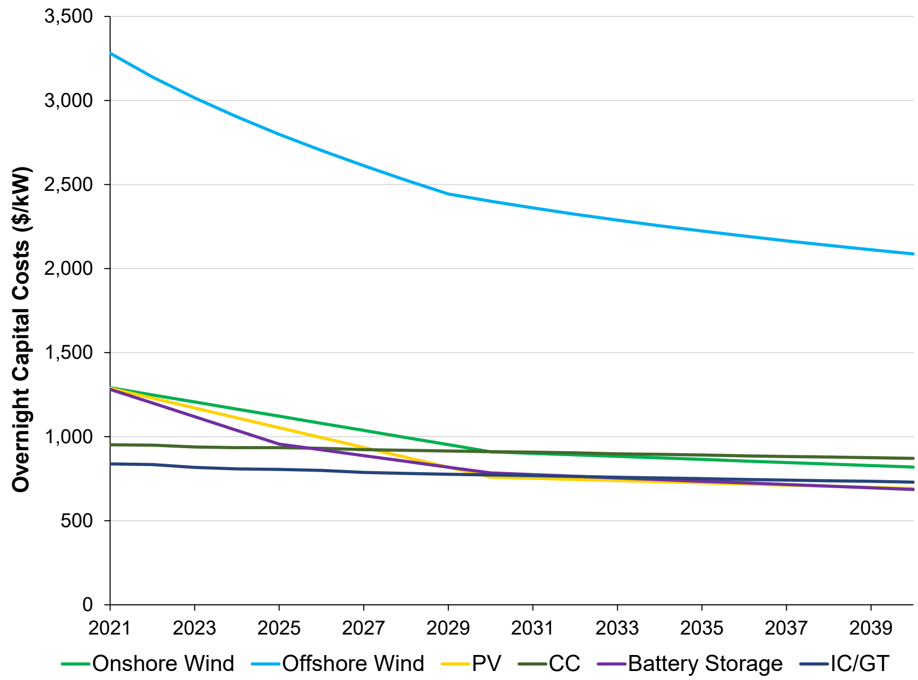
- ***Additional retirements scenario***. The model may not accurately capture all factors relevant to determining generating unit retirements, such as (1) large and relatively unpredictable forced maintenance events requiring large capital costs to repair that can result in an older unit retiring, and (2) uncertainty and heterogeneity in costs across the existing fossil resource fleet, such that certain plants have higher costs than assumed (*e.g.*, higher than average values across all plants), making them more likely to retire. Thus, our analysis may understate actual retirements that would be expected to occur with greater decarbonization. For that reason, we test the impact on the Central Case results of assuming additional retirements. Specifically, while only a portion of "at risk" generators identified by ISO-NE retire in each policy approach in the Central Case, in the additional retirements scenario, we assume all of these "at risk" resources retire.[103] Approximately 3,800-4,700 MW of additional capacity retires from 2021-2040 in the additional retirements scenario compared to the Central Case, for a total of over 11,500 MW of assumed retired capacity under this scenario. The

[102] NREL (National Renewable Energy Laboratory). 2021. "2021 Annual Technology Baseline." Golden, CO: National Renewable Energy Laboratory, available at https://atb.nrel.gov/.

[103] ISO-NE, "Power Plant Retirements," accessed on November 1, 2021, available at https://www.iso-ne.com/about/what-we-do/in-depth/power-plant-retirements.

additional units retired under this scenario are primarily steam turbine units. The scenario produces the same total carbon emission reduction as the Central Case.

Figure IV-7. Alternative Capital Costs Based on NREL ATB ($2020/kW)[104]



- ***Transmission scenario***. The central case results assume a "copper-plate" representation of New England's power system — power is able to flow unconstrained from any generation site to any demand site. In the transmission scenario, we relax this assumption by modeling a simplified transmission network. **Figure IV-8** provides a diagram of the individual interfaces comprising the transmission system. Individual transfer limits are based on those used for ISO-NE's sixteenth Forward Capacity Auction.[105] Transfer limits reflect all accepted, certified, and approved transmission upgrades according to their expected in-service dates. All import/export lines to areas outside of New England are assigned power flows according to a set schedule rather than solved by the model. We do not model any additional transmission upgrades. For the Hybrid case, the model chooses both a

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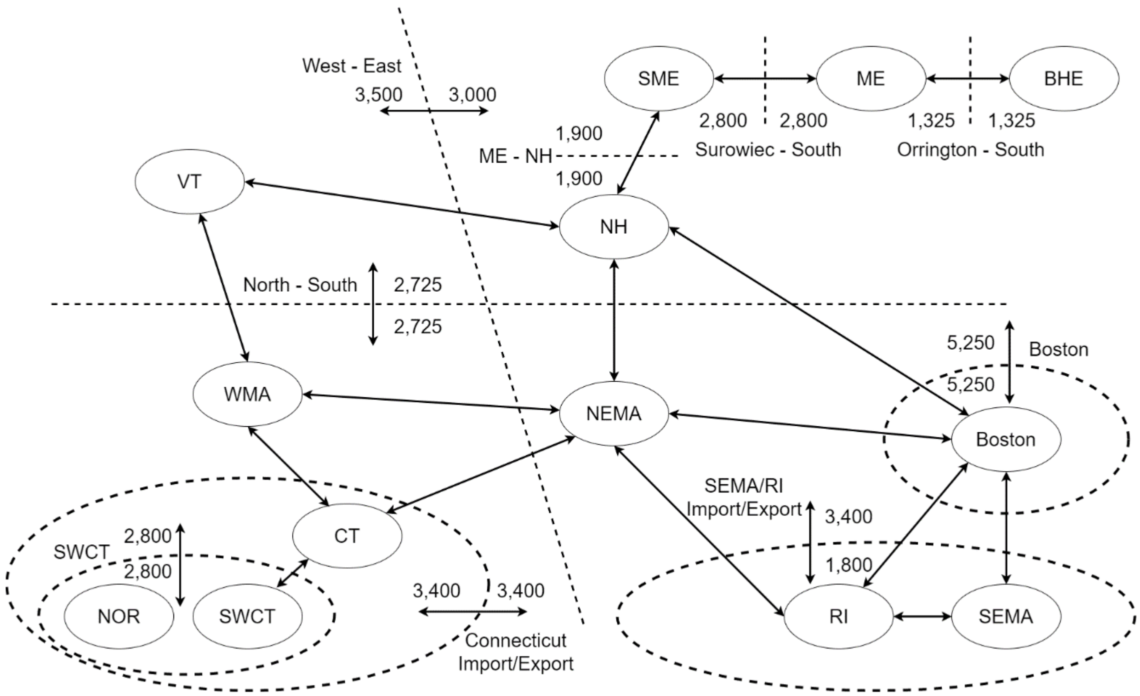
[104] NREL (National Renewable Energy Laboratory). 2021. "2021 Annual Technology Baseline." Golden, CO: National Renewable Energy Laboratory, available at https://atb.nrel.gov/.

[105] ISO-NE, "Forward Capacity Auction 16 Transmission Transfer Capabilities & Capacity Zone Development," March 17, 2021, p. 6, accessed on January 25, 2022, available at https://www.iso-ne.com/static-assets/documents/2021/03/a8_fca_16_transmission_transfer_capability_and_capacity_zonal_development.pdf. The FGRS also bases their transmission limits on FCA 16, but makes some modifications that are not included in our analysis, *see* ISO-NE, "2021 Economic Study: Future Grid Reliability Study Phase 1, High-Level Transmission Analysis - Part 2," December 15, 2021, available at https://www.iso-ne.com/static-assets/documents/2021/12/a7_2021_economic_study_phase_1_fgrs_high_level_transmission_analysis_part_2.pdf.

quantity of CEC demand and carbon price in each year needed to simultaneously achieve the emission target in each year and achieve an average annual LMP of $41/MWh at Millstone's location. The scenario produces the same total carbon emission reduction as the Central Case.

Figure IV-8. Modeled Transmission Network for Transmission Scenario



- ***Alternative LMP target for the Hybrid scenario***. We test the sensitivity of the Hybrid model results to the choice of LMP target. In this scenario, the average LMP from 2030-2040 is 25% higher than in the central case. The higher LMP is achieved through a lower average quantity of CEC demand and a higher average carbon price. The scenario produces the same total carbon emission reduction as the Central Case.

- ***Distribution of costs of carbon commitments across New England States.*** As an alternative to relying on state-level decarbonization targets to allocate the costs of PPA procurements under the Status Quo and CEC costs under the FCEM, we assume that these costs are spread equally across the New England states, in proportion to their annual loads. This scenario is not a proposed allocation, but simply an alternative benchmark to assess the sensitivity of customer payments to these allocations. This scenario does not result in changes to the resource mix or dispatch, but does yield different costs for consumers across the New England states.

V. Results of Quantitative Analysis: Decarbonization of the New England Electric Power Sector

The focus of the Pathways Study is on tradeoffs between alternative policy approaches to achieving decarbonization of the New England electric power system. However, before evaluating these tradeoffs, we first provide an overview of the quantitative modeling results with the goal of giving the reader background and intuition for key market and system changes arising from the transition to a more decarbonized grid. This background is valuable in its own right, given the challenges the region will face to making this transition, but also important background for the comparison of policy approaches we undertake in **Section VI**.

This section presents a description of several key mechanisms by which the power system evolves to drive emissions down to the target of 80% below 1990 emissions by 2040. The discussion focuses on results from the Status Quo approach, in part because this is the pathway the region is currently moving along, in which states achieve this decarbonization target via bilateral power purchase agreements rather than a centralized market mechanism. However, the issues and concepts discussed in this section are common across policy approaches, and thus we could have reviewed any approach to illustrate these issues. If readers are interested in the corresponding figures for other policy approaches, these are provided in **Appendix B**.

A. Resource Mix

Decarbonization of the New England electric power system is accomplished largely through changing the mix of physical assets in the system. **Figure V-1** shows the annual resource mix over the study period under the Status Quo approach. The changes in resource mix over the study period reflect the entry of new capacity, as well as the retirement of older fossil-fired resources, although the quantity of retirements is small in comparison to new entry. **Figure V-2** shows the incremental entry of new capacity by year over the study period, while incremental retirements are show below, in **Figure V-3**.

The specific change in the resource mix shown in **Figure V-1** reflects many factors, including increasing loads (due to heating and transportation electrification), baseline state policies, and achievement of the 2040 emission target. To better understand the incremental changes in the resource mix needed to achieve decarbonization in New England, **Table V-1** shows the change in the resource mix from 2020 to 2040 under the Status Quo:

- ***Clean Energy Resources.*** The largest system change is the significant expansion of clean energy resources to achieve decarbonization. Clean energy resource capacity increases by 35.3 GW across many technologies, including solar (BTM and utility scale PV), wind (offshore and onshore), and hydroelectric (NECEC).
- ***Storage Resources.*** To complement the variable output of solar and wind resources, 12.9 GW of battery storage is developed.
- ***Fossil Resources.*** While clean energy and storage resources increase, on net fossil resource capacity declines by 2.1 GW, reflecting an increase of 3.1 GW of combustion turbine capacity, 1.4 GW of efficient combined cycle capacity, and the retirements of 6.6 GW of existing combined cycle, existing combustion turbines, coal, and steam capacity. Thus, fossil resources are retired on net to meet the

increasingly stringent carbon target, but the mix of resources shifts toward lower capital cost-higher operating cost combustion turbines that can more cost-effectively supply resource adequacy.

Figure V-1. Resource Mix, Status Quo Policy Approach, 2020-2040 (MW)

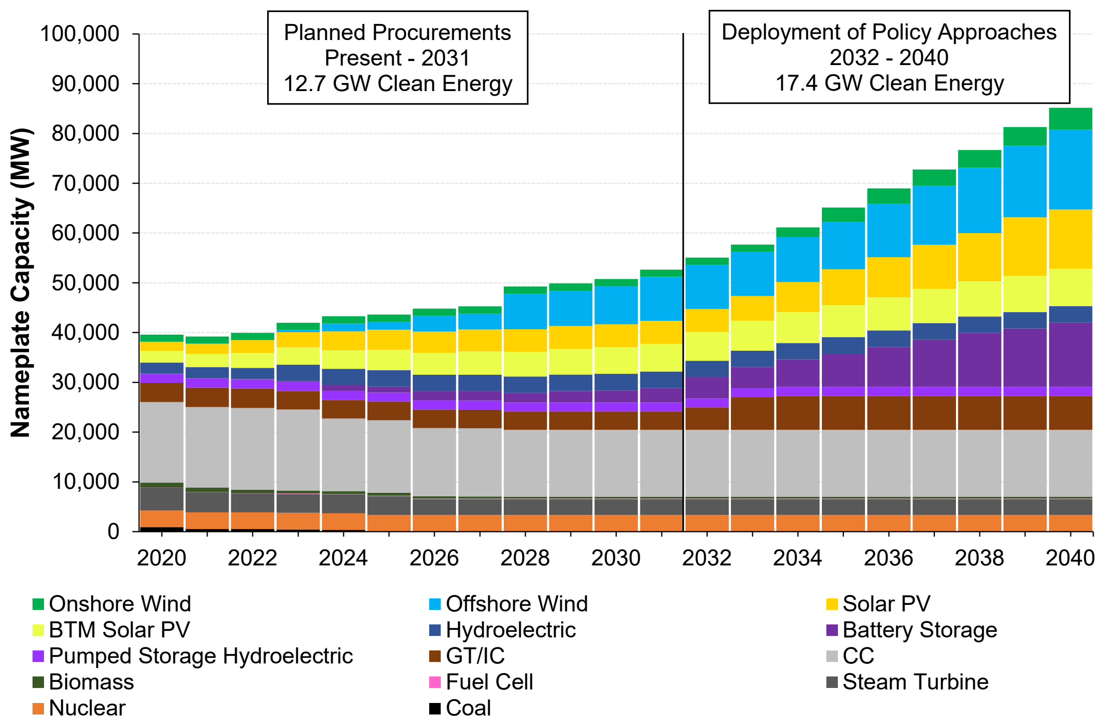


Figure V-2. Capacity Additions, Status Quo Policy Approach, 2021-2040 (MW)

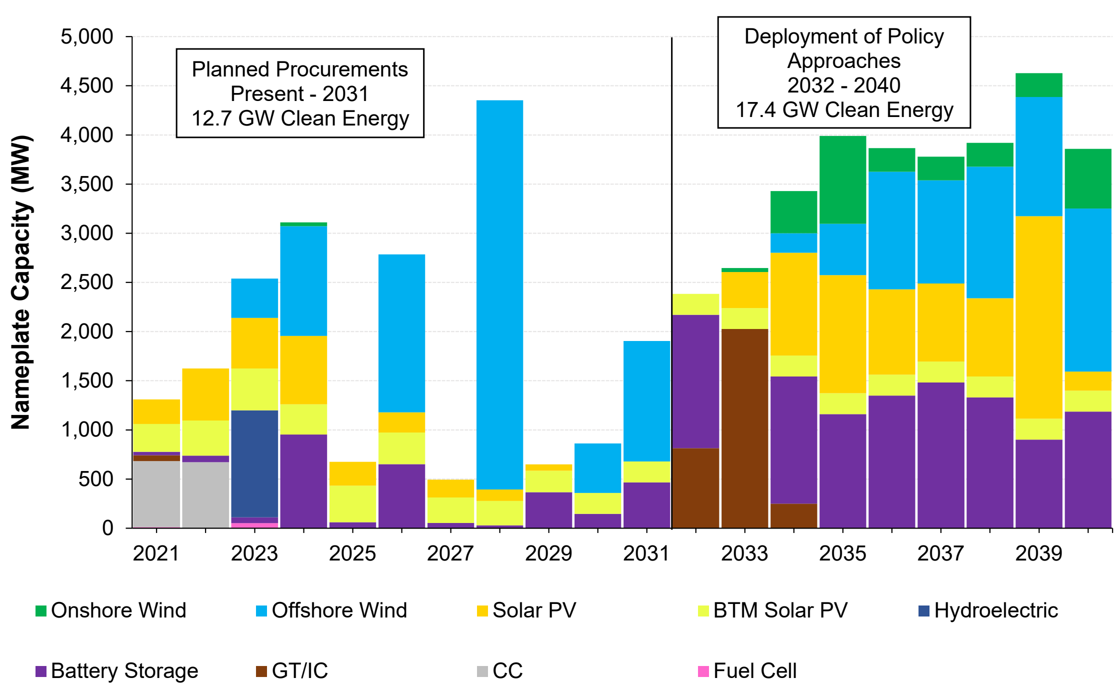


Table V-1. Change in Resource Mix from 2020 to 2040, Status Quo Policy Approach (MW)

Unit Type	2020 Baseline	Capacity in 2040 (MW)	Change in Capacity: 2020 to 2040 (MW)
Biomass	972	361	-612
BTM Solar PV	2,363	7,500	5,137
CC	16,158	13,474	-2,684
Coal	917	0	-917
Battery Storage	8	12,953	12,945
Fuel Cell	30	94	64
Hydroelectric	2,234	3,311	1,077
GT/IC	3,893	6,765	2,873
Nuclear	3,349	3,349	0
Offshore Wind	29	16,014	15,985
Pumped Storage	1,826	1,826	0
Solar PV	1,807	11,928	10,121
Steam Turbine	4,591	3,188	-1,403
Onshore Wind	1,424	4,401	2,977

As we discuss in **Section VI**, the mix of substitutions that occurs to achieve decarbonization varies across policy approaches given differences in incentives created by each policy. However, the general pattern of changes in resource mix — more renewables and storage and less fossil generation — is the same across all policy approaches.

Below, we provide further discussion of the changes in resource mix by technology type:

- ***Deployment of new clean energy resources*.** The starting point for decarbonization is the deployment of new, clean energy capacity that can supply energy to displace energy generated from fossil resources. Under the Status Quo, solar, offshore wind, and onshore wind are the primary new forms of clean energy generation, reflecting current commercially viable technologies.

  In the 2020s, new renewable resources enter largely as a result of the baseline state policies, common to all four policy approaches. Much of this new renewable capacity is offshore wind, reflecting planned procurements, largely comprised of projects in Bureau of Ocean Energy Management ("BOEM") lease areas off the coast of Southern New England.

  In the 2030s, new renewable capacity is mostly offshore wind and solar. In the Status Quo, these resource decisions reflect state roadmaps and plans. In the other policy approaches, the mix of resources reflects economic factors, with the model determining resource outcomes based on the financial incentives created by each approach with the goal of minimizing social costs. In these cases, the resulting resource mix reflects a combination of factors, particularly new build (capital) costs. These costs change over time due to multiple factors, particularly technological improvements (which lower costs and occur independent of resources developed in New England) and transmission and siting considerations (which increase costs as earlier projects exploit the most favorable (lowest cost) transmission and siting resource opportunities).

Under the Status Quo, expanded clean energy supplies are the result of expanded state procurements throughout the study period. While the analysis includes state RPS at existing statutory levels, the RPS targets are not binding, and thus REC prices fall to zero, during the study period because the supplies procured through the state sponsored PPAs to meet the 80 percent regional decarbonization objective exceed the quantity of clean energy that would be incented by the RPS alone.[106]

Another important factor is the interaction of supply from renewable resources with correlated output. These interactions have an important — but complex — impact on outcomes. Output from correlated renewables can lead to "economic curtailment" of supply because there is insufficient demand to consume all renewable output in some hours, particularly when demand is low but available renewable supply is high. This correlation in resource output, in turn, can diminish a resource's competitiveness by reducing its effective supply (given the curtailments). Thus, a higher-cost renewable resource with output that is less correlated with other existing renewable resources may be more competitive than a less-costly resource with more-highly-correlated output, because its output is less likely to be economically curtailed or earn lower revenues for its energy, because of negative LMPs. We discuss economic curtailments in further detail, below in **Section V.B.3**.

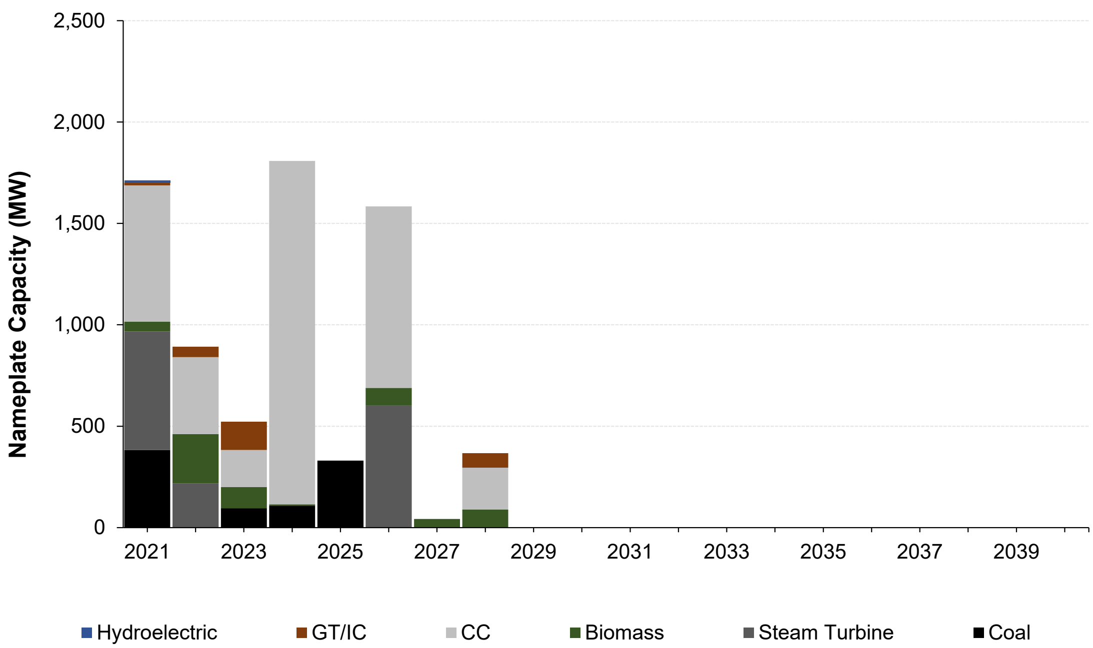
- ***Entry, retention and retirement of fossil dispatchable resources***. From 2020 to 2040, dispatchable fossil capacity falls from 25.6 GW to 23.5 GW, reflecting both resource retirements and new entry. Although new renewable capacity is needed to achieve decarbonization targets, dispatchable fossil-fuel generation like natural gas fired combined cycle and combustion turbines is still needed to meet demand during periods of low variable renewable output (recall, the Central Cases assume the region targets an 80% reduction in carbon emissions, which still allow some carbon emissions to occur in 2040). In the Status Quo, as additional variable renewable resources come online and displace output from fossil fuel generation, total (net) energy market revenues for existing generators decline due to reduced capacity factors and lower hourly LMPs. However, until new technologies emerge that can cost-effectively offer long-term storage or zero-emissions dispatchable generation, fossil fuel generation appears likely to be needed to ensure resource adequacy.

  Although some dispatchable technology is required to meet resource adequacy requirements, the transition to a low-carbon power system, along with other market forces, will lead to retirements of existing generators. Retirements are most likely for generators that are costly to operate (*i.e.*, high on-going fixed operation costs), are less efficient (*i.e.*, have higher heat rates), and are less able to quickly ramp up or down to meet load as variable renewable energy generation fluctuates. **Figure V-3** shows retirements under the Status Quo, which includes 6.6 GW of fossil fuel and 620 MW of biomass that retires before 2030. Most of this retired capacity reflects announced retirements, rather than

[106] When the supply of RECs created by state clean energy procurements exceeds regulatory requirements from state RPS, we expect the price of RECs to fall to zero in a competitive market.

"economic" retirement decisions by units within the model. Economic retirements are limited, as the model finds that it is generally more cost-effective to retain existing capacity to meet the increasing resource adequacy requirements from electrification of other sectors of the economy (heating, transportation) than to retire this capacity and replace it with new capacity to meet the growing resource adequacy needs. In fact, under the Status Quo policy approach, 3.1 GW of new gas turbines are installed between 2032 and 2034 to help meet resource adequacy. However, on net, total retirements exceed new entry of fossil resources, reducing the total quantity of fossil-fired resources in the system, despite the total increases in peak loads across the study period.

Figure V-3. Capacity Retirements, Status Quo Policy Approach, 2021-2040 (MW)



- ***Development of storage resources.*** Over the study period, there is substantial development of storage resources, which play an important role in maintaining resource adequacy in the modeled decarbonized system. Due to the expansion of variable renewable resources that may not provide energy supply during certain weather conditions (*e.g.*, when the sun is not shining or the wind is not blowing), meeting customer loads in all hours requires dispatchable resources that can deliver supply to meet energy demand and reserve requirements, independent of weather conditions. As the emission target becomes more stringent, there is a need for a zero (or low) emission source of dispatchable electricity to maintain resource adequacy. Within our analysis, storage resources play this role, as we assume no backstop dispatchable zero-carbon technology, given their current lack of commercially viability. Moreover, the entry of 12.9 GW of new battery storage more than offsets the loss of 2.1 GW of fossil generation, allowing the system to maintain resource adequacy despite the increased loads from electrification of heating and transportation. In fact, by the end of the study period, battery storage more cost-effectively provides resource adequacy than gas-fired technologies.

Storage resources also complement variable renewable resource deployment in a low-carbon power system by providing the capability to shift energy production from periods of excess renewable generation to periods when renewable generation is in shorter supply. Storage resources accomplish this shift in energy by charging in hours of excess supply (and low prices) and discharging in hours of tight supply (and high prices). In this sense, storage can economically "arbitrage" market conditions, charging when prices are low and discharging when prices are high.

In the 2030s, new battery storage enters the market economically, reflecting both (1) the increased output from variable renewables which causes larger intra-day (and inter-day) price spreads (which we discuss in greater detail, below) and (2) decreases in the cost of battery storage, given assumed technology improvement. Our analysis assumes 4-hour batteries, as these are a commercially available and prevalent technology in today's markets. However, because battery storage is an emerging technology and the technologies frequently used at present reflect current market opportunities, other battery profiles, including longer-duration batteries, may be commercially available and viable in the future.[107]

- ***Financial viability of existing clean resources.*** Along with newly built variable renewable capacity, the mix of installed capacity includes existing clean energy resources including nuclear, hydropower, wind and solar. In the Status Quo, these resources face declining average energy market revenues as increases in variable renewable generation reduce LMPs.

  These declines in revenues have different implications for different facilities. Some existing clean resources have high fixed costs of operation and thus the reduction in revenues from energy generation may adversely affect their continued financial viability. Thus, in the Status Quo approach, some of these existing clean resources require additional out-of-market payments to remain in operation. Nationally and in New England, nuclear power facilities have been financially challenged as LMPs have declined (due in large part to lower natural gas prices) and, in many cases, these resources are not compensated for their environmental attributes (*e.g.*, they do not receive RECs for their energy production). Some states, however, have developed compensation measures, such as Connecticut's zero carbon procurement, which compensates New England's nuclear facilities. Other clean energy facilities may face similar financial challenges, may seek to export energy to regions offering better compensation, or may undertake retrofits or re-powerings, if such actions provide alternative compensation options (such as allowing the resource to qualify as "new"). At present, existing clean generation resources, including solar, wind, hydroelectric, and biomass, are awarded RECs with market values that depend on resource characteristics and the complex RPS requirements specific to each New England state. For example, RPS carve out requirements for older (*e.g.*, pre-1998) facilities result in different REC prices for energy from these older resources than is received by

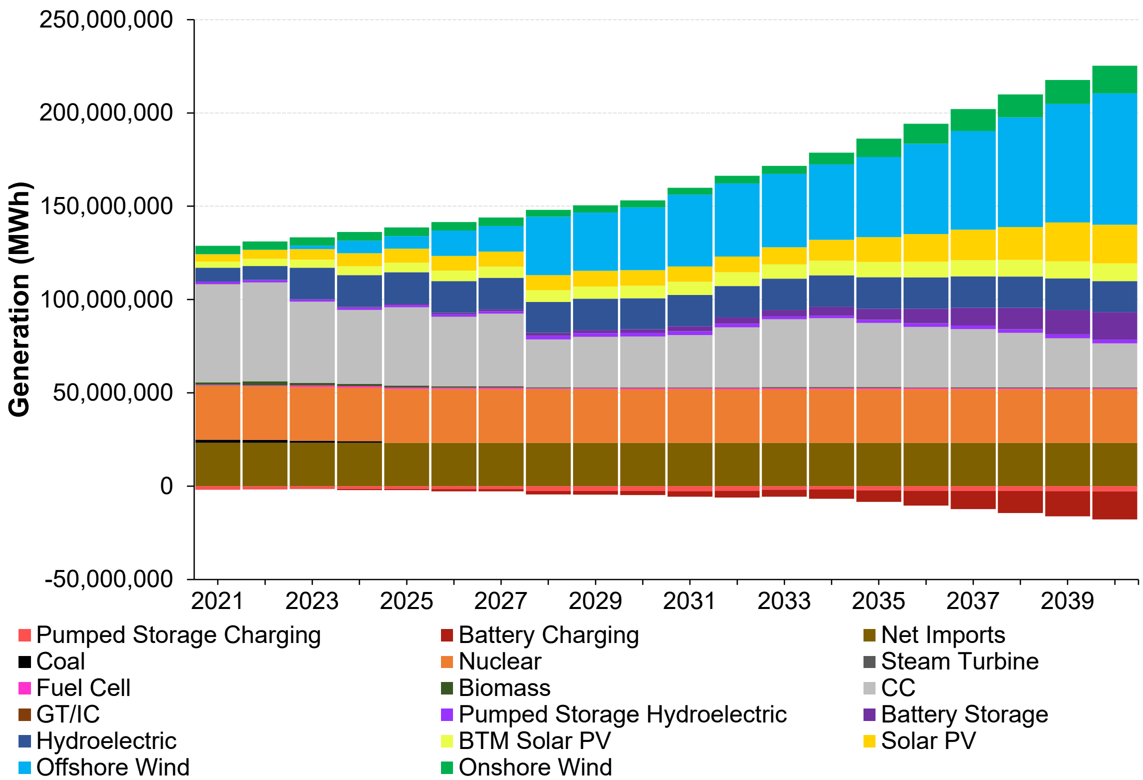
[107] We assume new battery units with the same operating characteristics as batteries in the FGRS. **Appendix A** provides additional information regarding the characteristics of our modeled storage technologies.

new resources.[108] In 2021, the price of 2020 vintage REC from such older, existing resources varied from approximately \$2.16/MWh to \$34.70/MWh.[109]

B. Energy Market Outcomes

Figure V-4 shows the generation mix under the Status Quo approach. As shown in **Figure V-4**, with increased decarbonization, the mix of resources used to meet customer loads shifts, with increasing shares of energy from variable renewable and storage resources, and decreasing shares of energy from gas-fired resources, particularly combined cycle resources. This outcome is not surprising given decarbonization emission targets. In effect, the output of traditional fossil technologies declines as variable renewable generation crowds out generators with positive fuel costs.

Figure V-4. Generation Mix, Status Quo Policy Approach, 2021-2040 (MWh)



[108] See, *e.g.*, the RPS Class II Renewable program in Massachusetts, available at https://www.mass.gov/service-details/program-summaries.

[109] Data from S&P Capital IQ Pro's REC Index as of December 14, 2021, with source data from Evolution Markets: http://new.evomarkets.com/, Tradition Financial Services: http://www.tfsbrokers.com/, Clear Energy Brokerage and Consulting: http://www.clearenergybrokerage.com/, and Karbone: http://www.karbone.com/.

Figure V-4 also shows that the timing and magnitude of on-going procurements has consequences for the operation of other resources in the system. For example, with the introduction of clean energy supplies from the baseline state policies through 2028, output from combined cycle resources declines by 51% from 2021 to 2028. However, after 2028, the introduction of new clean energy supplies slows because actual emissions are below the emission target, resulting in an increase (of 35%) in output from combined cycle resources from 2029 through 2034, as demand grows due to electrification of heating and transportation. However, starting in 2034, substantial quantities of clean energy supplies are added to meet emission targets, which displaces supplies from combined cycle resources and diminishes their output from that point forward. Thus, the particular assumptions about clean energy procurements, energy demand and emission targets create several sub-periods with different outcomes and market conditions across our study period. As we show below, these assumptions also have implications for other resources, such as variable renewable resources as shown through "curtailment" of energy supplies, which we discuss below.

Market clearing in a low-carbon power system with high levels of installed variable renewable capacity has important implications for which resources supply energy, market-clearing prices and the resulting net revenues earned by different resources in the system. Given their differing costs and operating capabilities, this transition has different consequences for traditional resources, such as gas-fired and nuclear resources, and for variable renewable and energy storage technologies important to making the decarbonization transition. We discuss these below.

1. Implications for Prices: Increasing Variable Renewable Output Lowers Average LMPs and Increases LMP Spreads

Competitive wholesale markets are intended to provide price signals reflecting the **SRMC** of resources in the system. In today's power systems, these SRMC typically reflect the fuel and variable costs associated with traditional fossil-fuel generation. Because these SRMC are positive, wholesale electricity prices are typically positive,

However, with higher shares of variable renewables in the system, the market will increasingly clear at prices set not by traditional fossil resources, but by either variable renewable resources or non-traditional dispatchable resources, such as battery storage. Thus, it is important to understand the pricing of competitive offers from these resources.[110]

Variable renewable resources generally have (approximately) zero marginal costs, which would imply economic offers at $0/MWh. However, many variable renewable facilities have out-of-market arrangements that provide revenues when they generate energy, and thus have an incentive to offer their energy into wholesale markets at *negative* prices. One type of arrangement is a subsidy or credit award, such as federal

[110] Storage resource offers reflect the opportunity cost of discharging (or charging) at a different point in time, subject to physical limits on power flows (to and from the battery) at any given moment. Thus, when discharging, offers from battery storage are generally affected by offers from fossil resources because they represent the storage resource's opportunity cost, even if storage resources are the market-clearing resources in a given hour. Offers from fossil resources represent the storage resource's opportunity costs because the most profitable intervals during which to discharge stored energy are when higher-cost fossil resources are on the margin setting the price.

tax credits or the award of RECs, and another type of arrangement is a PPA that pays the resources a fixed price irrespective of wholesale market prices. In both cases, resources have the incentive to submit energy offers equal to the *negative* of their out-of-market revenues. Consider two examples:

1. **A wind farm facing a market price for RECs of $40/MWh.** Because the wind plant earns $40/MWh through the REC price, it will earn positive profits from providing energy so long as the LMP does not fall *below* -$40/MWh. Thus, its competitive market offer is -$40/MWh.
2. **A wind farm with a PPA** that pays $80/MWh. With a PPA, the wind project owner operates the plant, offers the energy into ISO-NE energy market, and is paid $80/MWh by the PPA counterparty for energy produced. The PPA counterparty, now the owner of the energy, settles with ISO-NE at the market-clearing LMP. Given this structure, the wind project owner would bid in the plant's energy at the market price floor (*e.g.*, - $150/MWh),[111] because its compensation is independent of the LMP, in the absence of any contractual provisions designed to avoid this behavior.

Given the undesirable outcome of the second example for the party buying the energy, many PPAs, including the multi-year contracts signed in New England, include so-called "clawback" provisions to mitigate the incentive to offer at the market price floor. Under these clawback provisions, the resource's compensation is scaled down when LMPs are negative. Specifically, when LMPs are *negative*, the compensation is equal to the sum of (1) the PPA price and (2) the LMP. For example, in example 2 above:

2. If the LMP were -$50/MWh for the above wind project with a PPA paying $80/MWh, the project would be paid: $30/MWh = $80/MWh + (-$50/MWh). Moreover, the plant continues to earn a positive net revenue so long as LMP remains above -$80/MWh.

With the clawback provision, the plant now has the incentive to offer its energy at the *negative* of its PPA price (*i.e.*, - $80/MWh in the above example), because it will continue to earn a positive net revenue on output so long as the LMP remains above this offer.

An immediate implication of negative-priced offers from variable renewables is that market-clearing LMPs will be negative whenever the market clears at variable renewable resource offers. Such negative pricing is not a new phenomenon, particularly in systems with higher proportions of variable renewable resources or in areas of an electric system with transmission constraints within which variable renewable resources locate. However, with increasing decarbonization, the frequency of negative pricing increases.

Figure V-5 depicts the distribution of LMPs by year under the Status Quo approach.[112] Over time, as renewable generation increases, the number of hours with negative prices increases as well. By 2040,

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[111] ISO New England, Inc., "ISO New England Inc. Transmission, Markets, and Services Tariff, Section I," accessed on April 6, 2022, available at https://www.iso-ne.com/static-assets/documents/regulatory/tariff/sect_1/sect_i.pdf.

[112] To simplify the modeling, our analysis assumes that variable renewable resources offer at fixed price levels, rather than reflecting the full heterogeneity of offers that would be more likely in reality given variation in PPA terms, REC market price expectations, and other factors that vary across the system. Specifically, variable renewable resources with long-term PPAs offer their energy at -$100 per MWh and existing variable renewable resources offer

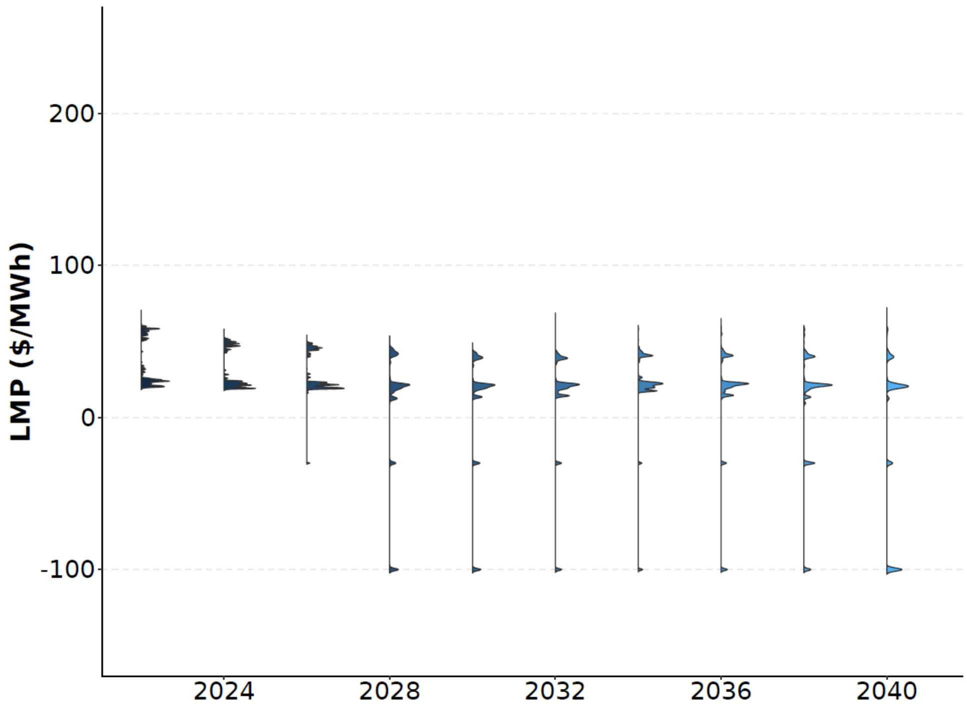
negative prices are common, occurring in 33% of all hours. Interestingly, the shape of the LMP distribution changes over time as well. In 2021, the distribution is bimodal with frequent periods of peak pricing and off-peak pricing. In 2040, with large amounts of battery storage deployed, peak prices are lower and less frequent, a large fraction of hours clear at negative LMPs, and the intraday pattern of LMP prices may differ from present pattern, which are largely driven by load variation.

Negative pricing has potential adverse consequences for system operations and the operation of fossil resources. In particular, more frequent negative pricing can increase uplift (*i.e.*, Net Commitment Period Compensation) and lead to inefficient battery investment and operations. We describe each of these effects below. As we discuss in **Section VI**, the policy approaches differ in the frequency and magnitude of negative pricing, and thus would differ in the incidence of these adverse market consequences.

Negative LMPs also reduce net revenues earned by variable renewable resources, due to the clawback provisions. For example, in the example above (a wind plant with an $80/MWh PPA and clawback provision), the plant earns $30/MWh, when LMPs are -$50/MWh, rather than $80/MWh, the PPA's "nominal" value. The same is true of variable renewables earning RECs, as the negative LMP offsets the positive REC value. Thus, while some variable renewable resources may supply energy when on the margin, the returns earned will be lower, potentially substantially so (and zero for the marginal resource). These negative impacts to energy payments, in turn, have implications for PPA contract pricing terms resource developers are willing to accept. Because resources would not earn the full PPA price on all energy sold under the PPA, project developers would be expected to require that the nominal price in the PPA increase to account for this clawback in contract revenues. Further, because the frequency and magnitude of negative pricing is uncertain, this adds uncertainty to revenue streams for new variable renewable resources, thus increasing financial risk faced by the resource under the PPA contract (compared to revenue streams based on margins assuming revenues at the full PPA price). Thus, resource developers may require risk premiums to their PPA offers.

their energy at -$30 per MWh. As a result, the realized LMPs in **Figure V-5** cluster around -$30 and -$100 per MWh. In reality, we would expect negative-price LMPs to be distributed more evenly across the negative domain given differences in PPA contract terms and other resource-specific factors.

Figure V-5. Distribution of LMPs by Year, Status Quo Policy Approach, 2022-2040 ($2020/MWh)

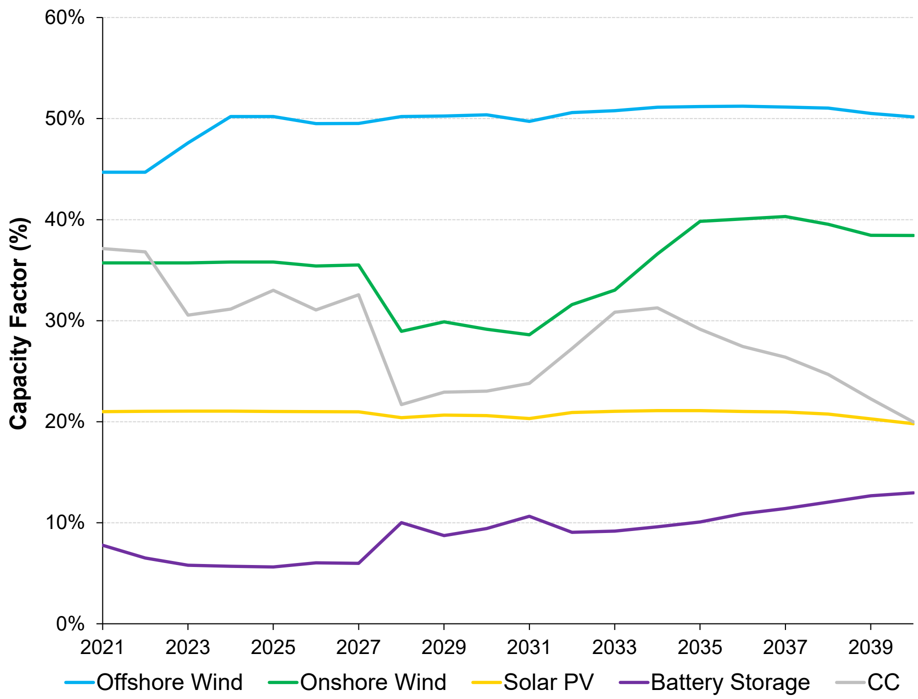


2. Implications for Gas-Fired Resources

For gas-fired resources, particularly combined cycle resources, total output declines across the gas-fired fleet, as much of their production is displaced by that from renewable resources with zero or very low operating costs. This decline in total output reflects both a decline in capacity and a decline in output per unit of capacity ("capacity factor"). **Figure V-6** shows the annual capacity factors for certain technologies over the period 2021 to 2040. Reduced capacity factors are consistent with declining prices over time — that is, with lower prices less efficient gas-fired capacity becomes less competitive.[113] In effect, over time, energy from gas-fired resources is increasingly needed for load-following or peaking supply, rather than as a source of baseload energy. These changes reflect reductions in total energy supplied and increased volatility in load net of variable renewable generation.

[113] We do not include combustion turbines in **Figure V-6** because energy supply from combustion turbines is limited and episodic in our analysis, due to, among other things, the model representing less real-time operational variability (*e.g.*, plant and transmission outages) than what might occur in the real world.

Figure V-6. Capacity Factors for Combined Cycle, Battery Storage, Offshore Wind, Onshore Wind, and Solar PV, Status Quo Policy Approach, 2021-2040 (%)



3. *Implications for Variable Renewable and Storage Operations*

As variable renewable and storage resources become a larger fraction of system resources, interactions between these resources have important consequences for their operations and the output they supply.

a) "Economic Curtailment" of variable renewable generation

"Economic curtailment" refers to a reduction in the output of a generator relative to what it could have otherwise produced. Generally, curtailment can occur due to transmission congestion, lack of firm transmission access, or excess generation ("overgeneration") during low load periods.[114] Here, we focus on curtailment due to overgeneration,[115] and refer to this as "economic curtailment" under the assumption that output is "economically" curtailed because the offer price exceeds the (potentially negative) LMP, rather than because of specific actions from ISO operators due to an imbalance between electricity supply and demand, and/or a physical constraint in the transmission system.

[114] NREL (National Renewable Energy Laboratory). 2014. "Wind and Solar Energy Curtailment: Experience and Practices in the United States." Golden, CO: National Renewable Energy Laboratory, available at https://www.nrel.gov/docs/fy14osti/60983.pdf.

[115] Our quantitative model does not capture other forms of curtailment.

Variable renewable energy generation is particularly susceptible to economic curtailment because output from solar, onshore wind and offshore wind is highly variable, given its weather-dependence, and highly correlated. This high correlation in output occurs because resources of a given technology in the same region are likely to all produce energy at the same time because they face the same weather conditions. Curtailments occur more frequently when larger amounts of the same variable renewable energy technology are installed in the same locations. For example, output from solar is highly correlated from moment to moment across plants at the same location. As solar capacity grows, output can be so large in daytime hours it exceeds total load, while providing no supply at nighttime, leading to the so-called "duck curve." The same correlations occur for wind resources, particularly when located in similar areas, such as the offshore wind lease areas off Cape Cod.

Figure V-7 illustrates a period with economic curtailment due to overgeneration. From the hours 7:00 to 16:00, as solar generation increases with the daylight hours, total generation exceeds load even after backing down nearly all natural gas-fired generation. To balance supply and demand, a portion of the renewable supply must be economically curtailed and LMPs become negative. Below, we will discuss further the factors that determine which renewable resources are curtailed (given the out-of-market revenues they receive if producing energy).

Figure V-7. Illustration of Excess Generation from Variable Renewable Resources

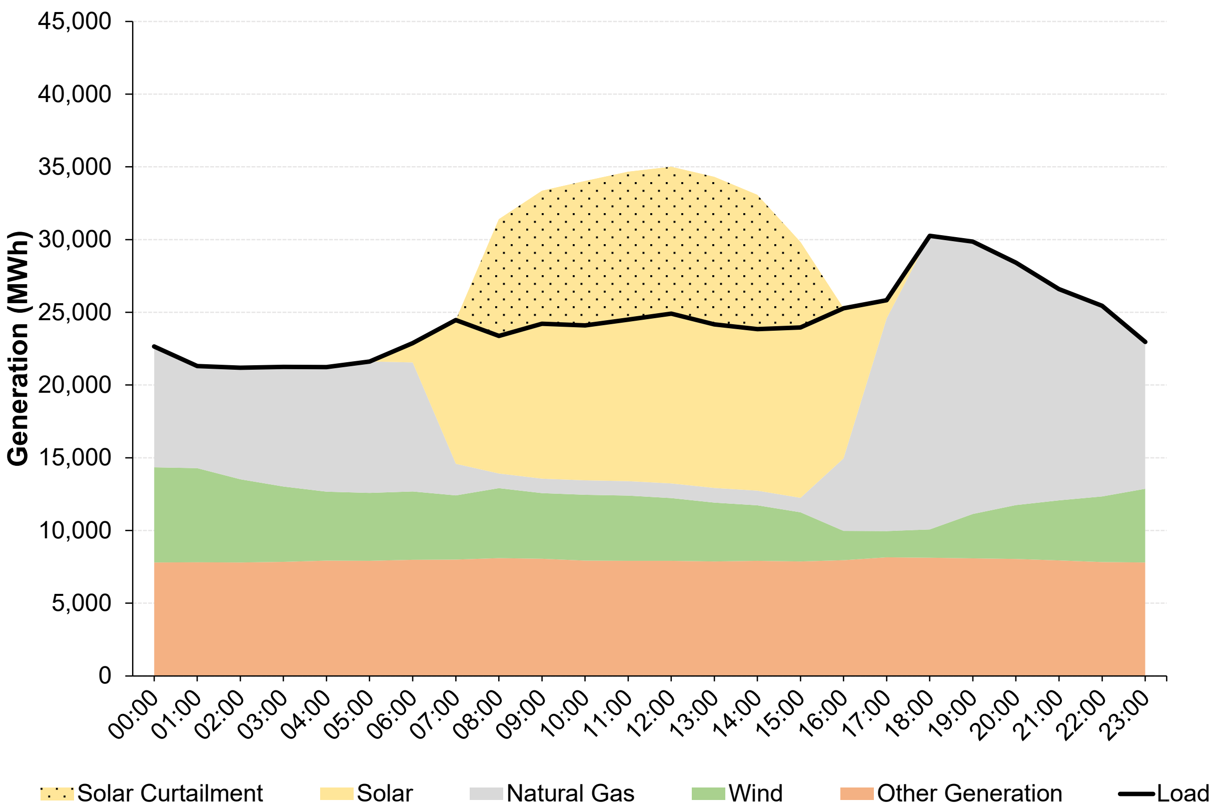
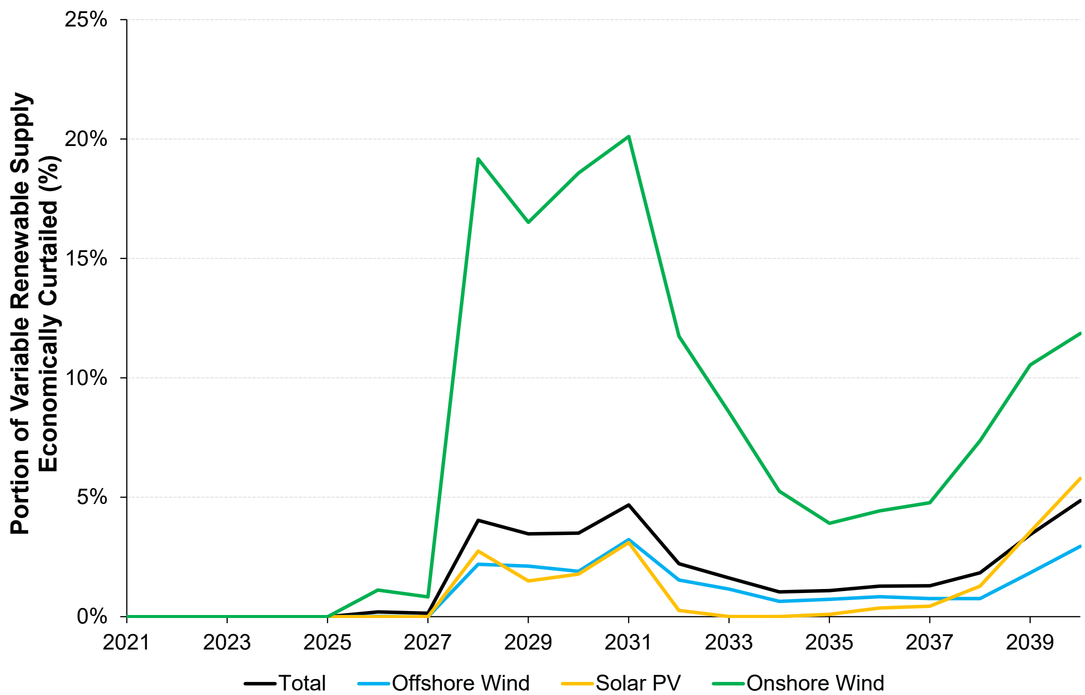


Figure V-8 shows economic curtailments by technology under the Status Quo approach. Curtailments are driven by the correlation in output from variable renewable resources but are also mitigated by storage resources, which can shift excess generation to periods when discharged energy can displace fossil generation. In the late 2020s, curtailments rise due to the high levels of offshore and onshore wind capacity being brought online. As load increases over time, curtailments decline in the mid-2030s. However, as the power system approaches the 2040 emissions target, curtailments rise again across all technologies as new variable renewable supply (developed to meet the increasingly stringent emission targets) increasingly occurs during hours when existing variable renewable generation is already high. Research has shown that as electric power systems attempt to attain even higher levels of decarbonization than assumed in our study (*e.g.*, 100% decarbonization), the level of economic curtailments can rise steeply in the absence of additional deployment of storage technologies.[116]

Figure V-8. Annual Curtailments by Technology Type for Variable Renewable Generation, Status Quo Policy Approach, 2021-2040 (%)



[116] de Sisternes, Fernando J., Jesse D. Jenkins, and Audun Botterud. 2016. "The value of energy storage in decarbonizing the electricity sector," *Applied Energy*, Vol. 175, pp. 368-379; Frew, Bethany, et al. 2021. "The curtailment paradox in the transition to high solar power systems." *Joule*, Vol. 5, pp. 1143-1167.

b) *The role of battery storage in mitigating curtailments* [117]

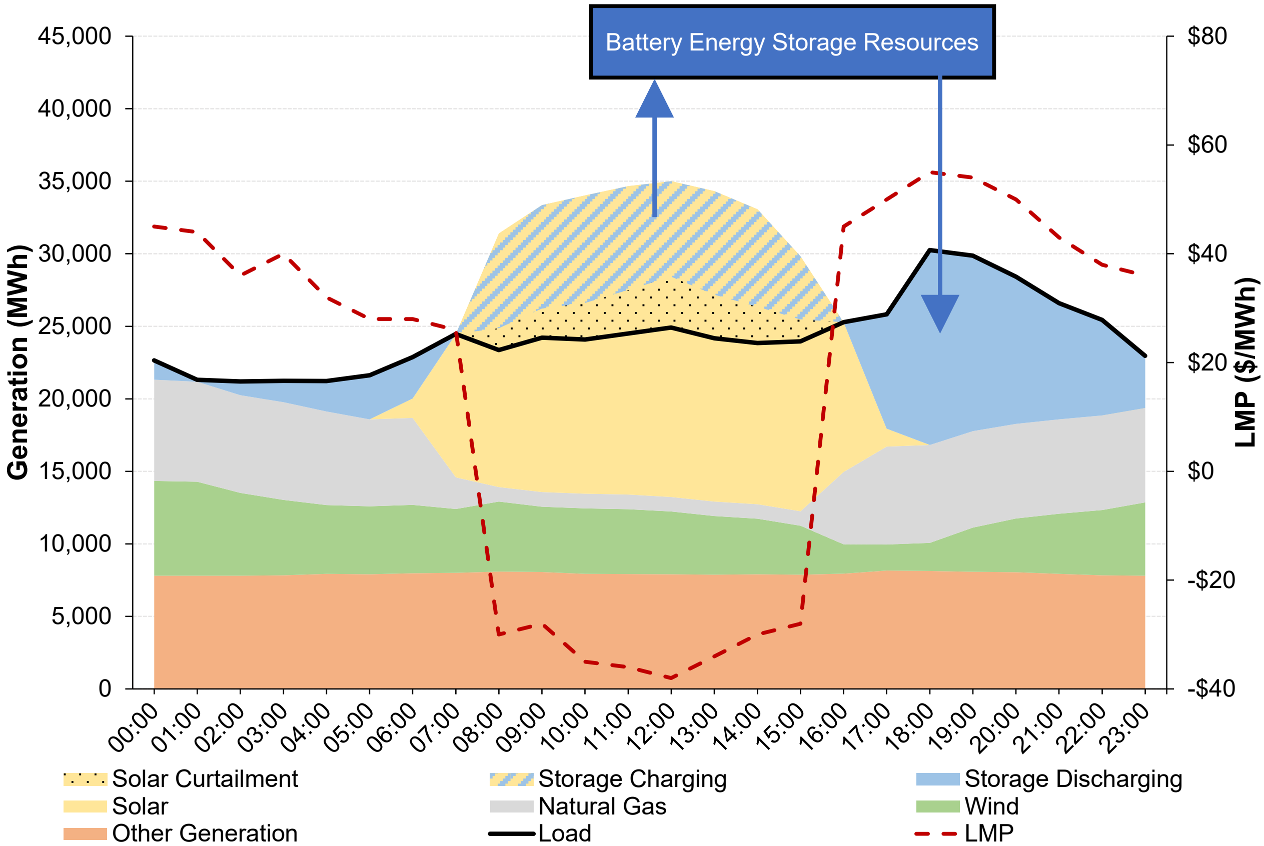
Energy storage can mitigate economic curtailments for variable renewable generators by shifting energy from periods of high renewable output to periods of low renewable output. **Figure V-9** provides an illustrative example of how battery storage lowers the amount of economically curtailed renewable generation. This example builds off of that presented in **Figure V-7** where, without battery storage, total generation, including nuclear, renewables, and sufficient gas-fired resources to maintain reliability, exceeds load during the daytime (*e.g.*, 12:00 noon). Thus, without battery storage, to avoid overgeneration some renewable output must be economically curtailed. Moreover, when the sun sets, solar output falls to zero and dispatchable technologies, like gas-fired combustion turbines must increase generation to meet load.

Faced with these curtailments, battery storage can provide two benefits. *First*, the battery can charge during the daytime, using the excess available renewable supply (overgeneration) and thus reducing economic curtailments. *Second*, the battery can discharge during the evening, thus displacing natural gas generation and reducing the associated emissions. Thus, in effect, battery storage can shift the variable renewable supply from periods when it is in excess supply to periods when there is too little supply. The battery reduces aggregate emissions by moving renewable energy generated at one point in time and displacing the fossil energy generation at a different point in time.

Figure V-9 shows that market price signals incent this behavior by energy storage. Prices are low when the battery charges — in fact, in the figure, prices are negative, and thus the battery is *paid* to charge. Then, prices are high when the battery discharges, allowing the battery storage owner to earn the difference in LMPs (net of the cost of energy losses).

[117] The performance of storage resources is important to our analysis, as it is to the analysis of any decarbonized energy system. However, the operation of storage resources is particularly complex given their inter-temporal physical constraints (*i.e.*, their finite energy storage, finite charging and discharging rates, etc.), the complexities of wholesale electricity markets (given real-time and day-ahead markets with particular participation rules and structures), and the future dynamics and uncertainties of decarbonized systems with many variable energy resources. As with any quantitative model, our model makes reasonable simplifications of battery operations, particularly in the CEM given its multi-year horizon. However, we caution against overinterpretation of certain findings regarding battery storage resources. We call attention to such instances in certain contexts, as appropriate.

Figure V-9. Illustration of the Role of Battery Storage in Mitigating Curtailments



While batteries and other storage resources can mitigate economic curtailments, it is not necessarily economically efficient for storage resources to mitigate all economic curtailments given that it is costly both to build and to operate storage facilities. As shown **Figure V-8**, in the Status Quo, economic curtailments remain even after the development of nearly 13 GW of battery storage. Thus, it is not economically efficient to mitigate all economic curtailment. The analysis indicates that development of additional battery storage, which would mitigate these economic curtailments, is not cost-effective given other options for reducing emissions (*e.g.*, developing additional renewable resources) or other options for achieving resource adequacy (*e.g.*, gas-fired generation).

c) **The role of a diverse portfolio of variable clean energy resources in mitigating curtailments**

Economic curtailments are also reduced by a more diverse portfolio of clean energy resources. This diversity includes both diversity of technology and diversity of location, which reduce the likelihood that output from renewable facilities is highly correlated because it is in the same location and relies on the same weather-dependent technology. Wholesale markets provide price signals consistent with greater portfolio diversity, because curtailments lead to lower LMPs. Thus, LMPs send price signals for developers to implement projects in locations using technologies that will earn the greatest revenues, rather than simply adopting the technologies with the lowest capital costs. As a result, for example, new offshore or onshore wind generation may be built in regions with higher transmission costs if resource output in those regions will be less correlated with (and therefore reduce competition from) output from other renewable resources.

d) ***The role of existing (or new) non-variable clean energy resources in mitigating curtailments***

Maintaining existing, or developing new, clean baseload or dispatchable generation such as hydroelectric, nuclear, and clean imports can reduce economic curtailments. "Baseload" resources, such as nuclear power, can reduce the extent to which the system must rely on variable renewables to achieve emission reductions, while dispatchable clean energy resources, such as reservoir hydropower, can supply energy during periods when output from variable renewables is low.

e) **Competition Among Renewable Resources**

In a competitive wholesale market in which the offer price floor does not bind, variable renewables are economically curtailed, because their market-based offers, rather than curtailed based on operator criteria or preferences.[118] As a result, variable renewables that offer at higher (less negative) prices are more likely to be curtailed than those with lower prices. Because negative-priced offers are driven by out-of-market payments, this implies that supply from resources with the largest out-of-market payments is more likely to clear than supply from resources with smaller (or no) out-of-market payments. Thus, we expect curtailment levels to vary across variable renewable resources in the fleet depending on the level of their out-of-market payments, thereby rewarding higher-cost units with higher margins than lower-cost units.

The dependence of economic curtailments on PPA prices would be expected to affect the bidding behavior in PPA procurements. Given the potential that energy curtailments (and margins earned if supplying) are dependent on PPA prices, low-cost resources would have the incentive to offer energy at a lower (more negative) nominal PPA price to reduce curtailment risk (and increase margins) when they participate in the energy market.[119] Thus, the dependence of energy curtailments on nominal PPA prices further complicates bidding strategies for project owners pursuing contracts, as they need to consider not only the project's true costs but the PPA offers from competing projects (as these would affect their resource's competitiveness in the energy market). These strategic considerations (made under uncertainty about competing PPA offers) could lead resources to submit offers that differ from their underlying costs, which could result in inefficient project awards, with higher-cost projects selected in place of lower-cost projects.[120]

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[118] Curtailment based on non-offer criteria may occur if there is excess supply, relative to load, from resources offering supply at the price floor.

[119] The clawback provisions reduce this incentive, because they diminish the returns to supplying energy when LMPs are negative.

[120] In **Section VI**, we also discuss the potential for auction structure to cause differences between resource costs and PPA price offers, such that auctions do not procure the least cost set of resources.

f) The impact of curtailments on the marginal cost of emission reductions

The economic curtailments in **Figure V-8** are costly, particularly at higher levels of decarbonization. In effect, a larger quantity of variable renewable plant must be developed to displace a given quantity of fossil generation, because growing curtailments (at higher levels of variable renewables) results in larger quantities of "lost" (curtailed) energy that cannot displace fossil generation. Put differently, the marginal cost of emission reductions increases with higher curtailments because the capital costs for new renewable plant remains fixed, but the energy produced (per unit of capacity) to displace fossil generation decreases due the curtailments.[121] Thus, at high levels of variable renewable capacity, each additional MW of installed variable renewable capacity will displace a smaller amount of fossil fuel generation because any incremental variable renewable generation is likely to be highly correlated with existing variable renewable generation. Prior research shows that this effect leads to very sharp increases in curtailments at high levels of decarbonization in the power sector, which in turn leads to sharp increases in marginal emission reduction costs.[122]

Energy storage offers one way to reduce emissions by shifting otherwise curtailed energy to periods when it can displace fossil generation. However, these reductions are costly, because they require investment in battery storage capacity that otherwise would not be developed as well as the costs associated with operating this storage. Thus, while energy storage can mitigate the costs associated with economic curtailments, they do not eliminate these costs.

These increases in marginal costs have implications for the alternative policy approaches because, directly or indirectly, the environmental prices in these approaches (*i.e.*, CEC and carbon prices) depend on marginal emission reduction costs. Under all policy approaches, prices that affect compensation to clean energy resources, including PPA prices, CEC prices and carbon prices, will tend to increase with curtailments because net generation of new variable renewable technologies will decline as the average level of curtailments increase. As such, CEC and PPA prices will rise so new generators can recover their lifetime costs over fewer hours of non-curtailed generation. Similarly, carbon prices will need to increase to increase the LMPs earned over non-curtailed generation hours.

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[121] The marginal cost of emissions reduction is the incremental system costs incurred per unit of avoided emissions, in this case CO_2 emissions.

[122] Sepulveda, Nestor A., et al. 2018. "The Role of Firm Low-Carbon Electricity Resources in Deep Decarbonization of Power Generation." *Joule*, Vol. 2, pp. 2403-2420; Cole, Wesley J., et al. 2021. "Quantifying the challenge of reaching a 100% renewable energy power system for the United States." *Joule*, Vol. 5, pp. 1732-1748.

VI. Assessment of Alternative Policy Approaches to Achieving Increased Decarbonization

A. Achieving Emission Reduction Targets

In principle, all four policy approaches are capable of achieving substantial levels of decarbonization. Each can impose requirements or provide incentives that produce the investment in clean energy resources (and other complementary assets, such as energy storage) needed to achieve increased levels of decarbonization. However, there are two issues worthy of further discussion related to the potential for each approach to achieve decarbonization in New England. The first is the extent to which the policy approaches can accommodate varying degrees of coordination and consensus among the New England states. The second is uncertainty in the emission or clean energy levels achieved by each approach.

1. Accommodating Various Degrees of Regional Coordination and Consensus

The policy approaches differ in how readily they can accommodate different levels of cooperation and coordination among the New England states. Under the Status Quo, by design, each New England state pursues decarbonization through independent policies — that is, it is the policy outcome absent regional cooperation and coordination. By contrast, the centralized approaches all envision and require some degree of coordination. However, the policy approaches differ in their compatibility to different types of cooperation and coordination. One potential outcome of coordination efforts is that the states adopt a regional decarbonization target, reflecting a consensus among the New England states and an agreement about how to allocate the costs. Such consensus may lead to a more aggressive and stringent target than the simple adding up of the current individual targets of the six New England states. All of the policy approaches can accommodate this outcome, although the scope of issues over which consensus is needed would differ.

However, if the states fail to a agree on a single, consensus regional target, a second form of coordination could occur in which each state develops its own state-level "demand" for emission reductions or clean energy, and then all six states (or a sub-set of states) develop a more centralized approach to achieving these state-level targets. This outcome may not expand the ambition of the region's aggregate target, but it may facilitate greater coordination in achieving emission reductions. The FCEM, in particular, can accommodate such a coordination role, by centralizing current Status Quo clean energy procurements through a market mechanism, rather than through sequential and decentralized procurements of multi-year contracts. The FCEM also provides flexibility to allocate costs, as CEC payments can be allocated in accordance to, for example, each state's emission or clean energy target (or, in principle, by some other approach). While each state could develop its own "demand' for clean energy, this approach would still require coordination among the states on the definition of the clean energy product.[123] An FCEM also provides flexibility to allocate costs based on

[123] Some have suggested that an FCEM could be limited to a subset of New England states, in the event that all states do not opt to participate in a centralized approach.

different criteria reflecting each state's "demand" for decarbonization. However, such flexibility may require negotiation over state-by-state cost allocation, which may impede rather than enhance coordination under some circumstances.

Carbon pricing could also accommodate various forms of coordination among the New England states, with such coordination requiring agreement on the carbon price level with a fixed carbon price and an aggregate emission cap with cap-and-trade, with such an emission cap potentially reflecting an aggregation of state-level emission caps.[124] With carbon pricing, because the impact of carbon pricing is accounted for in LMPs, a portion of its cost impact will be borne according to customer loads, rather than each state's decarbonization targets. However, the allocation of carbon pricing revenues collected from generators provides some discretion to affect the final allocation of net payments across states.[125] These payments could be distributed using different metrics, including customer loads or the difference between state targets and the region's aggregated target. Moreover, revenues collected could be used for different purposes and returned to states using different means. One approach would simply credit customers for these costs, while an alternative would return these revenues to the states to be used for various fiscal and policy purposes. For example, revenues collected by RGGI auctions are used by the RGGI states for a variety of programmatic objectives.[126]

2. *Uncertainty in Emission (and Cost) Outcomes*

The approaches differ in the degree of certainty they provide in whether a particular desired emission target will be achieved.[127] So-called "quantity-based" approaches, such as the FCEM and Net Carbon Pricing via cap-and-trade, for example, fix environmental targets, thus creating greater certainty that chosen targets will be achieved. However, with an FCEM, selecting a target for clean energy (*i.e.*, the quantity of CECs to procure)

[124] While a cap-and-trade system could be developed for a sub-set of New England states, such a system would likely have poor environmental and economic efficacy. In particular, such a system could produce uncertain emission benefits, and potentially lead to higher emissions due to emission leakage, in which generation shifts from resources under the cap to resources outside the cap (*e.g.*, imports from outside of New England).

[125] For more discussion on the tradeoffs from alternative uses of allowance revenues, *see* Schatzki, Todd and Robert N. Stavins, "Using the Value of Allowances from California's GHG Cap-and-Trade System," Regulatory Policy Program, Mossavar-Rahmani Center for Business and Government, Harvard Kennedy School, August 27, 2012.

[126] Regional Greenhouse Gas Initiative, Inc., "Elements of RGGI," accessed on April 6, 2022, available at https://www.rggi.org/program-overview-and-design/elements

[127] There is a vast literature analyzing uncertainty in market-based environmental policies and thus we provide only a cursory treatment of the topic. For more discussion, *see* Weitzman, Martin. 1974. "Prices vs. Quantities." *The Review of Economic Studies*. 41 (4): pp. 477-491; Roberts, Marc and Michael Spence. 1976. "Effluent Charges and Licenses Under Uncertainty." *Journal of Public Economics*. 5 (3-4): pp. 193-208; Pizer, William. 2002. "Combining price and quantity controls to mitigate global climate change." *Journal of Public Economics*. 85 (3): pp. 409-434.

will not necessarily lead to a particular level of emissions, as uncertainty will remain about many factors that may affect carbon emissions, including the quantity and carbon-intensity of non-clean energy.[128]

With quantity-based approaches, any environmental certainty is achieved at the expense of cost certainty, as the cost of achieving emission targets is unknown and, as a result, costs may be higher (or lower) than expected. By contrast, so-called “price-based” approaches, such as a fixed carbon price, fix in advance the unit cost or payment associated with emissions. Thus, while this approach reduces cost uncertainty, the price may be set either too low or too high to achieve any specific emission target.

These options appear to provide a stark dichotomy between environmental and cost uncertainty. However, various design features can moderate these outcomes to balance cost and emission uncertainty.[129] One option is to cap prices to prevent them from rising above a predetermined cap level.[130] Price caps can be set for either carbon prices, within a cap-and-trade system, or for CEC prices, within an FCEM. Price caps ensure the prices do not exceed a threshold amount that, in general terms, reflects a maximum willingness to pay for the environmental benefit (*e.g.*, additional emission reductions or clean energy). While mitigating cost uncertainty, a consequence of effective price caps is that emissions increase because, at the margin, the cap relaxes the policy’s stringency.

Another approach to mitigating emission and cost uncertainty is to, over time, adjust key policy features affecting policy stringency — such as the level of carbon prices or emission targets — as new information is gained about the true costs and benefits. While the potential for such adjustments can introduce uncertainty for investors, which may raise costs, such adjustments can also act as implicit “guardrails” for policy targets or prices that turn out, *ex post*, to be excessively or insufficiently stringent.[131] For example, recently, the emission targets in the RGGI program were modified because the policy’s initial targets were insufficiently stringent in light of unanticipated reductions in natural gas prices that caused substantial emission reductions from

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[128] In particular, the quantity of non-clean energy will depend on how CEC targets are defined. For example, if CEC targets are specified as a fraction of total load, the absolute quantity of non-clean energy (and thus potentially emissions) will vary with the quantity of total load.

[129] A cap on prices can be achieved through a variety of mechanisms, and includes both “soft” and “hard” caps, which differ in the extent to which they curtail the frequency and magnitude of prices above desired threshold prices. *See* Congressional Budget Office, “Managing Allowance Prices in a Cap-and-Trade Program,” Congress of the United States, November 2010; Murray, Brian, et al., “Balancing Cost and Emissions Certainty: An Allowance Reserve for Cap-and-Trade,” *Review of Environmental Economics and Policy* 3(1): 84-103, Winter 2009. For discussion of the complications created by soft-cap approaches, *see* Schatzki, Todd and Robert N. Stavins, “Three Lingering Design Issues Affecting Market Performance in California’s GHG Cap-and-Trade Program,” Regulatory Policy Program, Mossavar-Rahmani Center for Business and Government, Harvard Kennedy School, January 2013.

[130] Policies can also include price floors, which aim to constrain environmental instrument prices from falling below a predetermined floor. Price floors can provide investors with greater assurance regarding revenue streams from generation of environmental benefits, thus supporting investments to achieve environmental targets.

[131] For discussion of related issues, *see* Pahle, Michael, et al., “What Stands in the Way Becomes the Way, Sequencing in Climate Policy to Ratchet Up Stringency Over Time,” Resources for the Future, June 2017.

substitution toward lower-emission gas-fired energy.[132] Many market-based policies set targets over finite horizons (*e.g.*, 10-15 years), thus providing a degree of flexibility to adjust stringency over time by adjusting the targets over successive time periods.

B. Incentives for Clean Energy and GHG Emission Reductions

1. Comparison of the Cost-Effectiveness of Incentives for Decarbonization Created by Alternative Policy Approaches

Each policy approach achieves emission reductions through different types of incentives for clean energy. These incentives, however, differ in the extent to which each achieves emission reductions cost-effectively. Cost-effectiveness occurs when a policy or regulation achieves its regulatory target, such as reducing emissions to a particular level, at the lowest possible economic cost. As is well-known, carbon pricing achieves cost-effective carbon emission reductions, while other approaches deviate from this ideal – that is, they result in greater costs to achieve the same level of carbon emission reductions as carbon pricing. Thus, we start our discussion of the cost-effectiveness of the policy approaches with Net Carbon Pricing, and then discuss alternatives and the ways in which they deviate from this benchmark.

Table VI-1 compares the cost-effectiveness of the incentives created by each policy approach with respect to different resource decisions that can reduce emissions.[133] As shown, all approaches create incentives to substitute fossil resources for clean resources. However, the policy approaches differ in whether (and to what extent) they incent development of clean energy projects that most cost-effectively reduce emissions and whether (and to what extent) they incent lower-emission fossil generation. Market-based prices for environmental attributes can also lower emissions if they cause customers to reduce their consumption of energy, an issue we discuss further in **Section VI.F.4**.

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[132] US Energy Information Administration, "Regional Greenhouse Gas Initiative auction prices are the lowest since 2014," May 31, 2017, available at https://www.eia.gov/todayinenergy/detail.php?id=31432. *See also* Regional Greenhouse Gas Initiative, Inc., "RGGI States Announce Proposed Program Changes: Additional 30% Emissions Cap Decline by 2030," August 23, 2017, available at https://www.rggi.org/sites/default/files/Uploads/Program-Review/8-23-2017/Announcement_Proposed_Program_Changes.pdf.

[133] The Status Quo approach does not achieve emission reductions through in-market incentives for clean energy, and thus we indicate that the incentives are not applicable ("**NA**") for these dimensions of cost-effectiveness.

Table VI-1. Cost-Effectiveness of Incentives for Emission Reductions Under Alternative Policy Approaches

Cost-Effectiveness of Key Resource Decisions	*Status Quo*	*FCEM*	*FCEM w/ Dynamic CECs*	*Net Carbon Pricing*	*Hybrid Approach*
Substitution of Clean for Fossil-Fuel Resources	*NA*	High	High	High	High
Choice Among Clean Energy Resources	*NA*	Low-Medium	Medium	High	Medium
Choice Among Fossil-Fuel Resources	Low	Low	Low	High	Medium

a) **Net Carbon Pricing**

Net Carbon Pricing incents emission reductions by internalizing the economic costs associated with carbon emissions. With carbon pricing, resources that generate carbon emissions incur a cost for these emissions and include these costs into their competitive offers for energy supply. As a result, market-clearing LMPs increase, which benefits resources with lower- or no-emissions, as they receive a higher price for their energy, but no cost (or a cost less than the increase in revenue). The carbon price can also incent the substitution of lower-emitting fossil generation for higher-emitting fossil generation, as the carbon cost faced by these lower-emission facilities can make them more competitive than facilities with higher emissions.

By directly internalizing the carbon emission externality, carbon pricing is the most cost-effective approach to reducing GHG emissions, as the decisions by all market participants include the direct costs of their emissions in their offers to deliver energy. As a result, carbon pricing (cost-effectively) incents all potential substitutions that reduce emissions, including substitution of clean energy for fossil energy, substitutions of lower-emission fossil energy for higher-emission fossil energy, and reductions in energy use.

Along with providing price signals to cost-effectively incent all substitutions that can reduce emissions, carbon pricing can also lower costs by creating incentives to reduce emissions *when* it is least costly to do so. With cap-and-trade, allowance banking provides covered sources with the flexibility to adjust the timing of when emission reductions occur, by allowing them to accelerate investment in emission reductions compared to what is required to achieve annual emission targets, and bank the allowances not used in complying with annual targets. These banked allowances can then be used to comply with emission targets in later years. This use of banking can lower costs when (marginal) emission reduction costs rise steeply from year-to-year, because lower cost emission reductions displace higher cost emission reductions that would have occurred later in time.[134] In effect, banking shifts emission reductions earlier in time while still achieving cumulative emission reduction targets.

Carbon pricing with fixed carbon prices can also create incentives to reduce emissions when it is least costly to do so. This can be accomplished by adjusting carbon prices from year-to-year to reflect the appropriate discount rate, such that the market is indifferent to reducing emissions from one year to the next.[135]

b) Forward Clean Energy Market

The ***FCEM*** approach creates incentives for clean energy generation through the introduction of a market for CECs. Supplying CECs to entities that require them to comply with state-imposed CEC requirements (*e.g.*, utilities) creates an incremental revenue stream for eligible clean-energy resources that incents the development and operation of these resources.

In principle, the FCEM (with a uniform CEC) creates incentives to cost-effectively produce "clean" energy (MWh). Market prices for CECs will reflect the marginal cost of incremental clean energy, reflecting either the cost of new sources of clean energy supply (to incent entry) or the going-forward cost of existing clean energy supply (to avoid retirement).[136] While incenting cost-effective generation of clean energy, the FCEM may not cost-effectively reduce carbon emissions for two reasons:

- ***Choice Among Clean Energy Resources.*** The emission reductions achieved by incremental clean energy depends on the carbon-intensity of fossil generation resources displaced by the clean energy. These marginal emission rates, reflecting the emission rate of the marginal fossil generation unit displaced by clean energy, vary from one hour to the next, and thus the emission reductions achieved by clean energy will vary over time. However, because the FCEM creates a uniform commodity — the CEC — that does not vary with marginal emission rates, the FCEM rewards all clean energy equally, irrespective of the emission reductions achieved. Thus, the FCEM will not necessarily incent the clean energy resources that will displace generation with the highest emissions.[137]

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[134] Absent banking, the model finds that allowance prices would rise steeply over time, consistent with the marginal cost of emission reductions. With banking, market participants instead bank allowances in earlier years that are then saved for future use, thus avoiding the cost of higher price allowances in future years. Thus, in equilibrium with banking, expected allowance prices grow by the cost of capital, so long as the expected marginal costs of achieving annual emission targets grows at or above cost of capital.

[135] To create the appropriate market incentive, the prices should adjust at the market's cost of capital, so that there is no perceived benefit to accelerating or delaying investment more than is economically appropriate.

[136] An FCEM with multiple CEC products would no longer be cost-effective with respect to clean energy, generally, although it would, in principle, provide cost-effective incentives for each type of CEC. Such fragmentation of the CEC product, however, would generally raise costs of incenting clean energy and carbon emission reductions.

[137] However, an FCEM with static CECs (*i.e.*, uniform CEC awards per MWh of clean energy) does not incent production of clean energy from variable renewable resources during periods with economic curtailments. Because variable renewable resources are incented to offer their energy supply at negative prices, negative LMPs erode any economic gains from CEC awards during periods of excess variable renewable supplies, when additional variable

To mitigate the insensitivity of a uniform CEC to variations in marginal emissions, the CEC may be assigned a dynamic CEC value that varies with the marginal emission rate. While a dynamic CEC reflecting actual marginal emissions rates might better internalize this variation in (marginal) emissions reductions into decisions, such a mechanism may provide limited improvement in cost-effectiveness, may have unintended adverse consequences for other emission reduction opportunities (*e.g.*, use of battery storage) and raises a number of practical questions and is likely more difficult to implement. **Appendix C** provides further discussion of dynamic CECs and the tradeoffs that would need to be evaluated to determine whether it would provide net benefits.

- ***Choice Among Fossil Fuel Resources.*** While the FCEM subsidizes the generation of clean energy, it does not create any incentives for substitution of generation from more efficient, lower-emission facilities for generation from less efficient, higher-emission facilities. For example, under the FCEM, more efficient combined-cycle facilities receive the same compensation as less efficient combustion turbines even though the more efficient combined-cycle facilities generate fewer carbon emissions per unit (MWh) of energy generated. Thus, the FCEM will not provide incentives to reduce emissions through substitution of higher-emission fossil generation for lower-emission fossil generation, as discussed further in **Section VI.B.2.d)**.

Like carbon pricing with cap-and-trade, CEC price signals can also lower costs through incentives regarding the timing of emission reductions. With cap-and-trade with allowance banking, price levels vary over time such that incentives are created to accelerate (or decelerate) investment as is most cost-effective given multi-year CEC targets.

c) **Hybrid Approach**

Compared to the other approaches, the **Hybrid Approach** creates a relatively complex set of incentives for emission reductions. The carbon price will raise LMPs, thus providing incremental revenues for clean energy resources, while imposing a cost on fossil resources. Thus, the carbon price affects the incentives for entry/exit and operations of all resources in the system:

- First, it incents operation and development of more efficient fossil resources.
- Second, it provides existing clean energy resources with additional revenues that are sufficiently high (or at least intended to be sufficiently high) to ensure continued operations. Thus, in principle, this approach avoids costly retirement of existing clean energy resources.
- Third, while we would not expect the carbon price needed to financially sustain existing clean energy resources would be adequate to incent sufficient new clean energy resources to meet decarbonization targets, it may reduce the "missing clean energy money" needed to incent new development and do

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renewables provide no emission reduction benefit. Thus, although CECs are awarded during periods of economic curtailment, resource developers are not incented to produce clean energy during these periods because it offers low (or no) net return.

so through a carbon price that creates an incentive for the new project to consider the carbon intensity of energy displaced by the new project's output.

In addition to the carbon price, the Hybrid Approach also awards CECs to provide additional revenue to cover any remaining "missing clean energy money" for clean energy from "new" facilities. Thus, new clean energy resources can receive even greater incremental revenues due to the award of CECs, sufficient to incent new entry of clean energy resources. This award of CECs would have the same incentive properties described above for FCEM. Moreover, as we show in **Section VI.C**, with the Hybrid Approach, the difference in compensation to existing and new clean energy resources has consequences for efficient capital use between new and existing assets.

d) Status Quo

The ***Status Quo*** incents new clean energy resources to enter the market by awarding out-of-market multi-year contracts for the supply of clean energy supply. The analysis assumes that these contracts are developed through competitive procurements undertaken by the state or utility administrators, with the specific contract and price terms each negotiated bilaterally. Thus, in contrast to the centralized approaches, the Status Quo approach creates no market-wide price signal or mechanism to incent new resource development (or maintain existing clean energy resources).

While outcomes in the centralized approaches are largely proscribed through design specifications, outcomes under the Status Quo approach depend on implementation decisions by administrators and regulators, such as when to hold procurements, the quantity of resources to procure, geographic preferences, and whether to run technology-specific or technology-neutral procurements. A procurement's design can also affect outcomes, such as whether contract awards lead to realized clean energy capacity. Past economic literature and the growing literature evaluating renewable procurement design and outcomes identifies many factors that potentially affect procurement outcomes, such as which proposals are selected and the structure and pricing contract terms:[138]

- ***Evaluation criteria, including geographic and/or technology preferences and other non-price factors***. PPA procurements typically reflect a combination of quantitative and qualitative criteria, reflecting policy preferences (*e.g.*, geographic or technology preferences), other metrics of policy or economic benefits (*e.g.*, tax benefits, local employment benefits and transmission requirements and risks) or other contracting issues (*e.g.*, financing, creditworthiness, siting risks and project development

[138] Regarding procurements generally, *see* Tierney, Susan F., and Todd Schatzki, "Competitive Procurement of Retail Electricity Supply: Recent Trends in State Policies and Utility Practices," *The Electricity Journal*, March 2009; Tierney, Susan F., and Todd Schatzki, "Competitive Procurement of Retail Electricity Supply: Recent Trends in State Policies and Utility Practices," prepared for the National Association of Regulatory Utility Commissioners in collaboration with the Federal Energy Regulatory Commission, July 2008. Regarding renewable procurements, *see* Cleary, Kathryne and Heidi Bishop Ratz, "Experience with Competitive Procurements and Centralized Resource Planning to Advance Clean Energy," Resources for the Future, Working Paper 21-01, January 2021; Haufe, M.C. and K.M. Ehrhard, "Auctions for renewable energy support-suitability, design and first lessons learned," *Energy Policy* 121:217-224, 2018; Mathhaus, David, "Designing Effective Auctions for Renewable Energy Support," *Energy Policy* 142, July 2020.

risks).[139] These non-price factors create administrative challenges for offer review and selection, and potentially create challenges for apples-to-apples comparison of pricing terms.[140]

Preferences for resources constructed in particular locations or with particular technologies may raise costs compared to markets or procurements that reflect only cost criteria. In principle, such preferences may provide other policy benefits deemed more beneficial by legislators, regulators or administrators. Whether or not, in fact, procurements exhibiting preferences by location or technology achieve such net benefits is an empirical question, outside the scope of this report.

- ***Contract structure***. Contract structure can be both beneficial and detrimental from an economic standpoint. While the contract guarantee may lower finance costs for project developers, these guarantees may raise costs and shift risk to utilities underwriting the contracts and/or customers that bear the shift in risk associated with the contracts. We discuss these issues in further detail in **Section VI.F.2**. Further, to standardize contract terms, the procurement may limit the scope of financial arrangements and thus reduce opportunities for alternative contract structures to support project financing and management of risk to emerge, which may reduce innovation in financing, risk management and financial markets for clean energy projects. Pricing terms for energy are generally based on a fixed-price schedule that specifies payments per MWh in each year; while providing a fixed-price schedule, clawback provisions introduce uncertainty for realized prices that would expose the project owner to price risk.[141]
- ***Pay-As-Bid structure****.* Most procurements in New England have used a pay-as-bid structure, in which prices for awarded contracts reflect each bidder's offer prices, rather than a single market-clearing price, in which all awarded contracts receive the same price. In principal, procurement structure can affect economic outcomes by affecting the pricing terms offered for new clean energy supply, particularly for auctions of standardized products in which multiple contracts are being awarded. Theory supports the conclusion that single-priced auctions, in which all supply clears at the same market-clearing price, create incentives for resources to offer supply at their true costs, while in pay-as-bid auctions, bidder have a stronger incentive to offer supply at the price at which they expect the market to clear.[142] These differences have potential implications for procurement outcomes,

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[139] For example, *see* "Request for Proposals for Long-Term Contracts for Offshore Wind Energy Projects," May 7, 2021, Massachusetts Distribution Companies, Massachusetts Depart of Energy resources, available at https://macleanenergy.files.wordpress.com/2021/05/83c3-rfp-and-appendices-final.pdf.

[140] Tierney, Susan F., and Todd Schatzki, "Competitive Procurement of Retail Electricity Supply: Recent Trends in State Policies and Utility Practices," *The Electricity Journal*, March 2009; Tierney, Susan F., and Todd Schatzki, Competitive Procurement of Retail Electricity Supply: Recent Trends in State Policies and Utility Practices," prepared for the National Association of Regulatory Utility Commissioners in collaboration with the Federal Energy Regulatory Commission, July 2008.

[141] As we show in **Section V**, the fixed-price structure would be expected to promote negative LMPs, which would trigger the clawback provisions.

[142] For illustrations of differences between pay-as-bid and uniform price auctions, *see* Tierney, Susan F., Rana Mukerji, and Todd Schatzki, "Pay-as-Bid vs. Uniform Pricing: Discriminatory Auctions Promote Strategic Bidding and

although there is on-going discussion in the economic literature about how these incentives are realized in practice.[143] With the pay-as-bid structure, offers reflect, in part, market participants' expectation of the market clearing prices, not only their true costs. Thus, pay-as-bid auctions are unlikely to fully price discriminate among offers from resources with different underlying costs because bidders will tend to raise their offer price to increase profits (*i.e.*, avoid losing returns because their offers were below the price of the highest offer that cleared the market). Moreover, to the extent that the pay-as-bid structure leads to offers that differ from a resource's underlying costs, it is possible that the least-costly resources are not selected, because the rank ordering of market's participants' offers may differ from the rank ordering of resources by costs (*e.g.*, some low-cost resources may bid "too high" and inadvertently fail to clear the auction).

- ***Price discovery.*** Procurements offer relatively limited opportunity for price discovery as procurements occur intermittently, the reporting on awarded prices is delayed, and only the prices for offers awarded contracts are reported. Thus, the procurements offer less transparent price signals in comparison to market-based approaches. Moreover, the structure of these agreements diminish the need for (and thus likely the development of) forward markets (*i.e.*, financial derivatives) that can be used to hedge risks and aggregate market information about price expectations.

Thus, the Status Quo approach relies on various administrative and regulatory processes to achieve outcomes that are satisfied through in-market incentives with the three centralized policy approaches. The effectiveness of relying on these administrative processes can be evaluated given the growing experience with such resource procurements. But the conduct of such evaluations, by their very nature, will always depend to some degree on the particular institutions tasked with responsibility for overseeing the resource procurement processes.[144]

The approach taken in the Status Quo has several important implications. *First*, the Status Quo approach is, in effect, a decision to forgo development of clean energy resources through market incentives — thus, going forward, *all* new clean energy would be developed through bilateral contract procurements. This is the case not only for the variable renewable contracts that have been the current focus of state procurements, but also any other clean energy facilities that require some form of economic support, including dispatchable clean energy sources that are not currently commercially viable.

Market Manipulation," *Public Utilities Fortnightly*, March 2008. While discussing energy markets, the concepts are generalizable.

[143] Anatolitis, V., Welisch, M., "Putting renewable energy auctions into action -- An agent-based model of onshore wind power auctions in Germany," *Energy Policy* ,110: 394-402, 2017; Haufe, M.C. and K.M. Ehrhard, "Auctions for renewable energy support-suitability, design and first lessons learned," *Energy Policy* 121: 217-224, 2018; Matthaus, David, Sebastian Schwenen and David Wozabal, "Renewable auctions: Bidding for real options," *European Journal of Operational Research* 291(3): 1091-1105, June 2021.

[144] Tierney, Susan F., and Todd Schatzki, "Competitive Procurement of Retail Electricity Supply: Recent Trends in State Policies and Utility Practices," *The Electricity Journal*, March 2009; Tierney, Susan F., and Todd Schatzki, Competitive Procurement of Retail Electricity Supply: Recent Trends in State Policies and Utility Practices," prepared for the National Association of Regulatory Utility Commissioners in collaboration with the Federal Energy Regulatory Commission, July 2008.

Second, the Status Quo approach does not directly address the going-forward financial viability of existing clean energy facilities. At present, the primary sources of revenue for existing clean energy resources without a multi-year, fixed price PPA is REC awards. In the future, the quantity of resources without PPAs is expected to grow as the initial PPAs of existing resources expire, including the zero carbon PPAs held by the region's nuclear plants. While these resources currently rely on REC demand to provide these additional revenues, the question is what policies would be used in the future to provide compensation (if any) to these "off-PPA" resources in the future that can continue producing clean energy to help meet decarbonization goals. Potential options include (1) offering follow-on PPAs (thus placing all clean energy resources, new and old, under contract), (2) an RPS that awards RECs to "off-PPA" facilities, or (3) doing nothing. Further analysis is required to determine the tradeoffs between these approaches and the consequences of providing no incremental compensation. In particular, further analysis of an RPS that targets existing facilities would be warranted. In particular, such an RPS may not create a workably competitive market for RECs, particularly because price formation in this market would be unlikely to reflect the true cost of clean energy.[145]

2. Implications of Structure of Incentives Under Alternative Policy Approaches for Resource Investment and Operation

Differences in the incentives created by each policy approach has consequences for efficient investment and operation of system resources. Below we discuss these implications by focusing on different types of resources and describing how each approach leads to different investment or operational outcomes.

a) **Investment and Operation of Variable Renewable Resources, Including Economic Curtailment**

The market-based incentives created by each of the centralized approaches are likely to lead to similar mixes of variable renewable resources. Each approach provides for the lowest cost clean energy resources to enter the market, accounting for factors such as correlated outputs and curtailments (which would diminish potential supply). By contrast, incentives from the Status Quo approach would encourage lower cost clean energy resources, but not necessarily identify the lowest cost resources, as procurement outcomes would depend on many factors, some of which might cause selected resources to differ from a least-cost mix.

Our quantitative results are consistent with this theoretical expectation. **Figure VI-1** shows the mix of resources in 2040 under each of the policy approaches as solved by our model, while **Figure VI-2** shows the capacity additions from 2021-2040 (capacity that is incremental to the baseline state policy resources that we

[145] Price formation in workably competitive markets requires that there be sufficient supply and demand transacting on a regular basis, where the supply faces the full opportunity cost of producing a REC. In the long run, under the Status Quo, much of the supply will reflect either (1) existing resources with high sunk capital cost and low- to no-short run marginal costs of generating RECs, or (2) new resources compensated for their RECs through their out-of-market PPAs. Because neither of these resources faces the true long-run opportunity cost of developing RECs, REC prices are unlikely to reflect the true "missing clean energy money" needed to incent clean energy (rather than "unlabeled" energy). Instead, REC market prices may reflect arbitrary factors such as the short run marginal cost of renewable resources with fuel costs, such as biomass facilities, which does not provide any price signal related to the "missing money" needed to incent clean energy.

assume in each case). The renewable resource mix across the Net Carbon Pricing, FCEM, and Hybrid Approach are similar, with 4,465 MW of on-shore wind, 11,526 to 12,133 MW of off-shore wind and 16,341 to 16,998 MW of solar. By contrast, the Status Quo mix differs, as it reflects the portfolios represented in the current state roadmaps and studies. In particular, the Status Quo has a higher share of offshore wind and lower share of solar compared to the centralized approaches.

Figure VI-1. Resource Mix by Policy Approach, 2040 (MW)

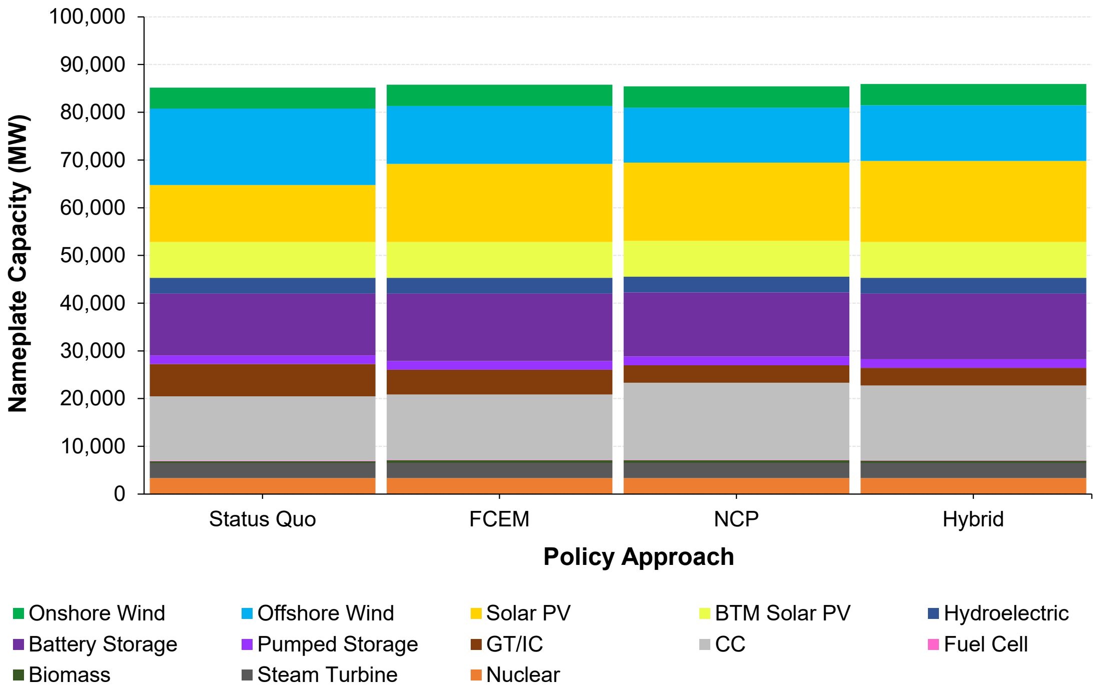
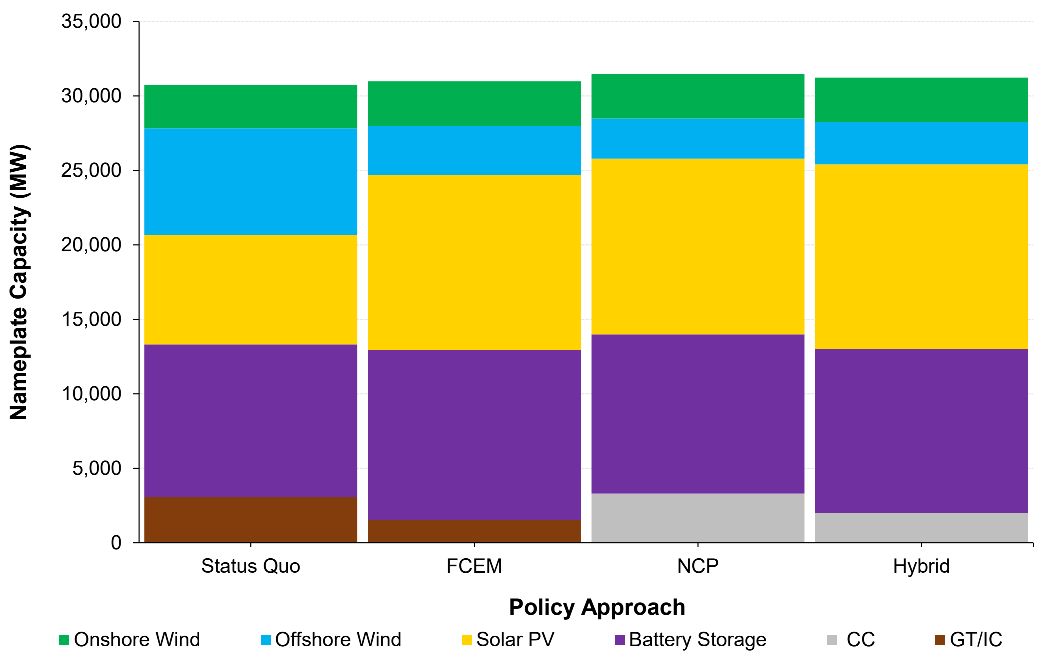


Figure VI-2. New Resources (Incremental to Baseline State Policies) by Policy Approach, 2040 (MW)



The differences in mix of renewable resources between Status Quo and centralized approaches shown in **Figure VI-1** do not represent a "forecast" of such differences. By nature, the fleet of renewables emerging from procurements used under the Status Quo is uncertain and will reflect the specific ways in which those procurements are designed and implemented across the six New England states. Thus, while it is reasonable to assume that this approach will not lead to the most cost-effective mix of clean energy resources (including both the mix of technologies and their locations), the differences in resource mix and resulting costs between the Status Quo and the other approaches cannot be ascertained, in advance. Consequently, a range of potential outcomes is possible, with costs lower or higher than those we estimate for the Status Quo approach. Nonetheless, our analysis provides an indication of the potential scope of these differences given reasonable assumptions about an alternative future mix of resources under the Status Quo (based on the state's current analyses and preferences), in contrast to the cost-effective mix of resources.

b) Investment and Operation of Storage Resources and Consequences for Economic Curtailment

In a decarbonized grid, energy storage can contribute to both resource adequacy and to achieving emission targets. As we show in **Section V.B.3**, storage can reduce emissions by shifting the delivery of variable renewable energy from periods when it is in excess supply to periods when it is in shortage, relative to load, although such emission reductions are costly, as they require investment of capital into new batteries.

Each of the approaches creates incentives for storage through different mechanisms. As described in **Section V.B.3**, competitive wholesale markets provide incentives for energy storage to reduce economic curtailment of variable renewables by providing price signals consistent with shifting energy from periods of excess clean energy supply, when prices are low due to high levels of renewable generation, to periods of clean energy shortage, when prices are high, clearing at fossil generation. Each policy approach increases the price spreads that incents this charging/discharging behavior and the associated shifts in the delivery of otherwise curtailed variable renewable generation.

Under each approach, the spread in market LMPs between periods when renewable resources are economically curtailed (at the margin) and periods when the marginal supplier is a fossil resource will increase. Thus, economic incentives for battery storage increase as the result of each policy approach. However, as we describe below, the cause of these increases varies across approaches and, in the case of the Status Quo, is an inadvertent outcome of guaranteeing payments for delivered energy through PPA contracts. The increase in LMP spreads can be observed in **Figure VI-3**, which shows the current (2021) distribution of LMPs and the distribution of LMPs for each policy approach for the year 2040.[146] **Figure VI-4** provides similar distributions bi-annually for each policy approach and **Figure VI-5** shows an alternative representation of the distribution in each year. **Table VI-2** provides energy market LMP summary statistics.

[146] The current distribution of prices is based on LMPs in the year 2021 of our Status Quo model, not the actual distribution of LMPs from ISO-NE's markets.

Figure VI-3. LMP Distribution by Policy Approach, 2040 ($2020/MWh)[147]

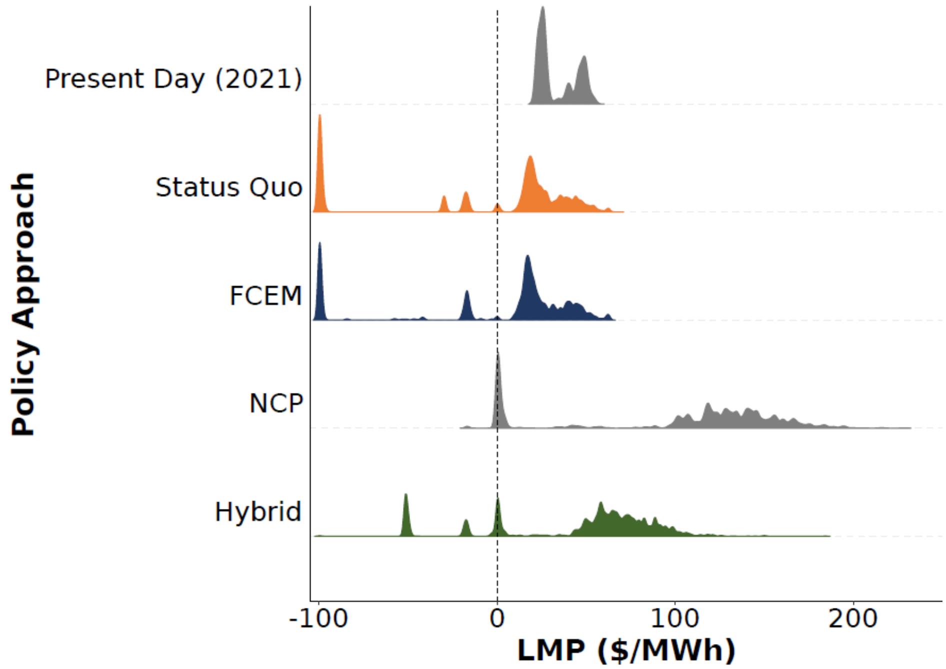
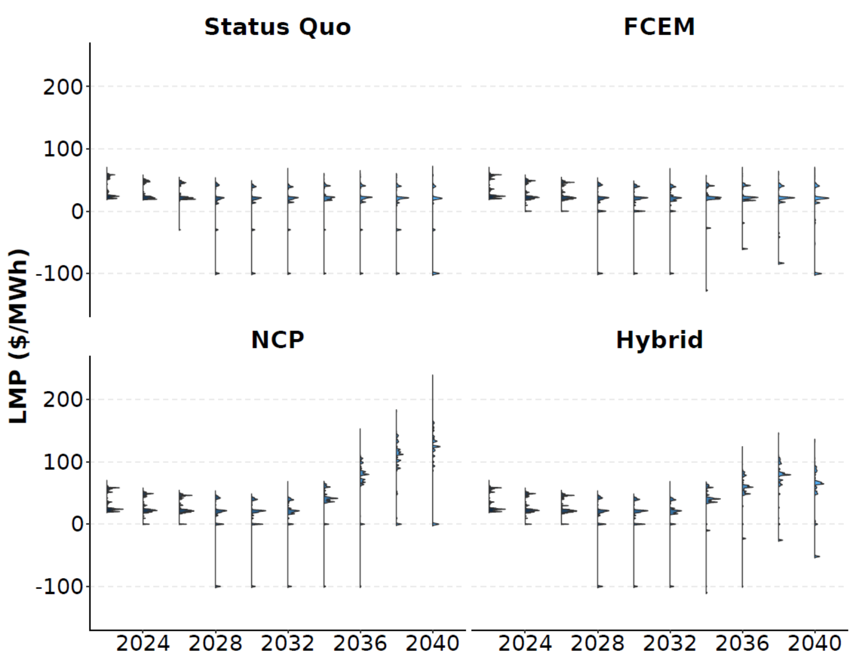
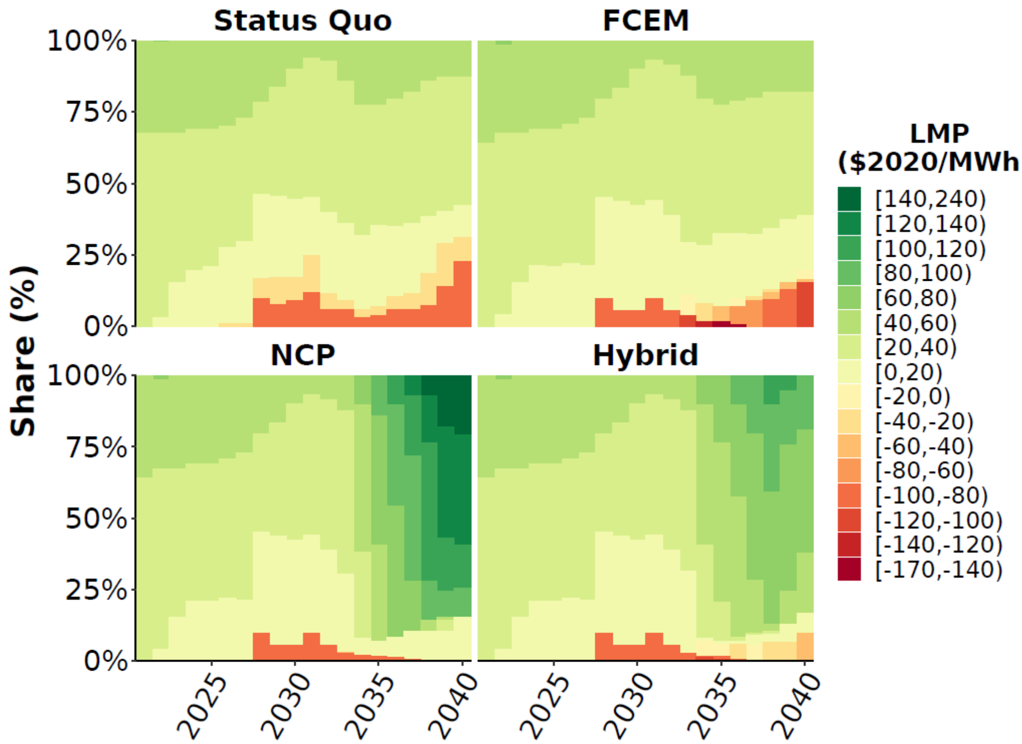


Figure VI-4. LMP Distribution by Policy Approach, 2022-2040 ($2020/MWh)



[147] The plots trim one hour in the FCEM with an LMP of $359 and one hour in Net Carbon Pricing with an LMP of $325.

Figure VI-5. LMP Distribution by Policy Approach, 2021-2040 (Share of All Hours, $2020/MWh)



- With Net Carbon Pricing, the spread in LMPs increases because the carbon price increases LMPs when fossil generation is on the margin, but does not affect LMPs when variable renewables are on the margin. Because the increase in LMPs due to the carbon price varies with carbon intensity, this contributes to wider LMPs spreads. As shown in **Table VI-2**, LMP spreads, as reflected by the standard deviation, are largest under Net Carbon Pricing. Net Carbon Pricing provides the economically efficient incentive for battery storage operations. In effect, carbon pricing sets equal (1) the (marginal) cost of reducing emissions through additional variable renewables and (2) the (marginal) cost of avoiding curtailment of variable renewable energy through charging the battery storage and then displacing fossil generation through discharging the stored energy.

Table VI-2. Summary Statistics for Energy Market LMPs by Policy Approach, 2040

LMP ($2020/MWh)	Status Quo	FCEM	NCP	Hybrid
Load-Weighted LMP	-2	4	106	51
Standard Deviation	54	49	60	45
Maximum LMP	68	359	325	184
Minimum LMP	-100	-100	-17	-100
% Hours with $0 LMP	0%	0%	7%	1%
% Hours with Negative LMP	33%	28%	1%	17%

- With the FCEM, clean energy resources are awarded CECs, which creates incentives for them to offer their clean energy at a negative price.[148] Thus, the LMP spread increases because market-clearing prices are reduced (more negative) when variable renewables are the marginal, price-setting resource, while LMPs when fossil resources are the marginal, price-setting resource remain unchanged.
- With the Hybrid Approach, the LMP spread increases due to (1) the addition of the carbon prices, which increases LMPs when fossil resources are on the margin, and (2) the addition of CEC awards for new variable renewable resources, which reduces LMPs when variable renewable resources are on the margin.
- With the Status Quo, new variable renewables are compensated for their energy supply regardless of the market clearing LMP, subject to "clawback" provisions, as discussed in **Section V**. Thus, the LMP spread increases because LMPs are lower when the market clears at offers from these PPA resources but is unaffected when fossil resources are on the margin.

Net Carbon Pricing provides cost-effective incentives for storage resources because the price signals reflect the (marginal) cost of reducing emissions by using otherwise curtailed clean energy to displace fossil-energy. While the Status Quo, FCEM and Hybrid Approaches all increase incentives for energy storage compared to current markets by expanding the LMP spreads, the magnitude and timing of these increases in spreads is not necessarily cost-effective, but may be higher or lower than the cost-effective incentive, thus leading potentially too much or too little storage investment relative to the cost-effective quantity. In our quantitative analysis, however, the quantities of investment in storage are relatively comparable across policy approaches, suggesting that the differences in incentives would not necessarily lead to material differences for storage resource investments.

Another important factor differentiating the approaches is that the Status Quo, FCEM and Hybrid Approach all increase LMP spreads by creating incentives for variable renewable resources to offer energy at *negative* prices, rather than increasing LMPs through higher offers from fossil resources. Thus, these approaches each increase the frequency and magnitude of negative pricing, although, as shown in **Table VI-2** to varying degrees.

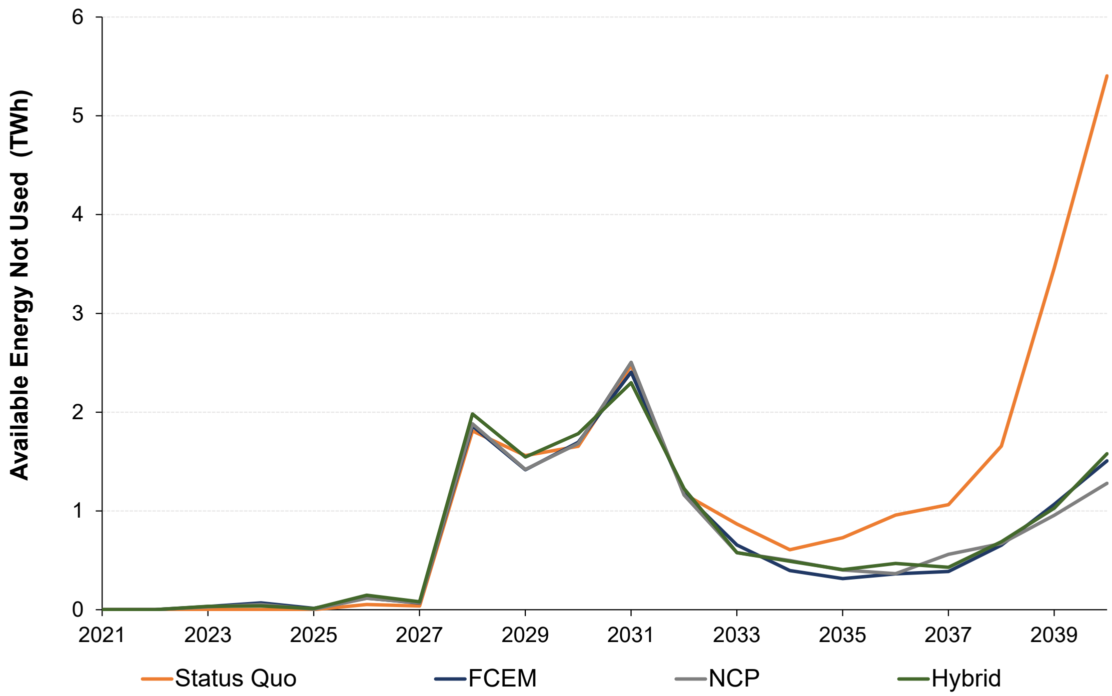
i. Economic Curtailment and Energy Storage Utilization

Differences in the operation of batteries and the level of economic curtailments vary across policy approaches. **Figure VI-6** shows total economic curtailments by year from 2020-2040 for each policy approach, while **Figure**

[148] The incremental impact of CEC awards on LMP spreads depends on the extent to which variable renewables currently receive out-of-market compensation that would be diminished (or replaced) by CEC awards. In particular, some variable renewables currently receive REC awards or, as we discuss below, guaranteed prices through PPAs. Given these existing out-of-market payments, variable renewable may already have the incentive to offer energy at negative prices. The incremental impact of the CEC awards for LMP spreads reflects their impact relative to spreads given these pre-existing out-of-market payments. For example, if variable renewables already receive REC awards at a value of $40/MWh and the FCEM policy leads to CEC awards valued at $100/MWh, then the incremental impact of the FCEM on LMP spreads reflects the impact of the difference between $100/MWh and $40/MWh (*i.e.*, $60/MWh), not the $100/MWh price created by the CEC market.

VI-7 provides greater detail on curtailments in 2040, showing how curtailments levels for each type of renewable resource.[149] The differences in the level of economic curtailments across technologies in these figures reflect the correlation of output for each type of technology, and the extent to which periods of highly correlated output occur when customers loads are low, thus increasing economic curtailment risk.[150]

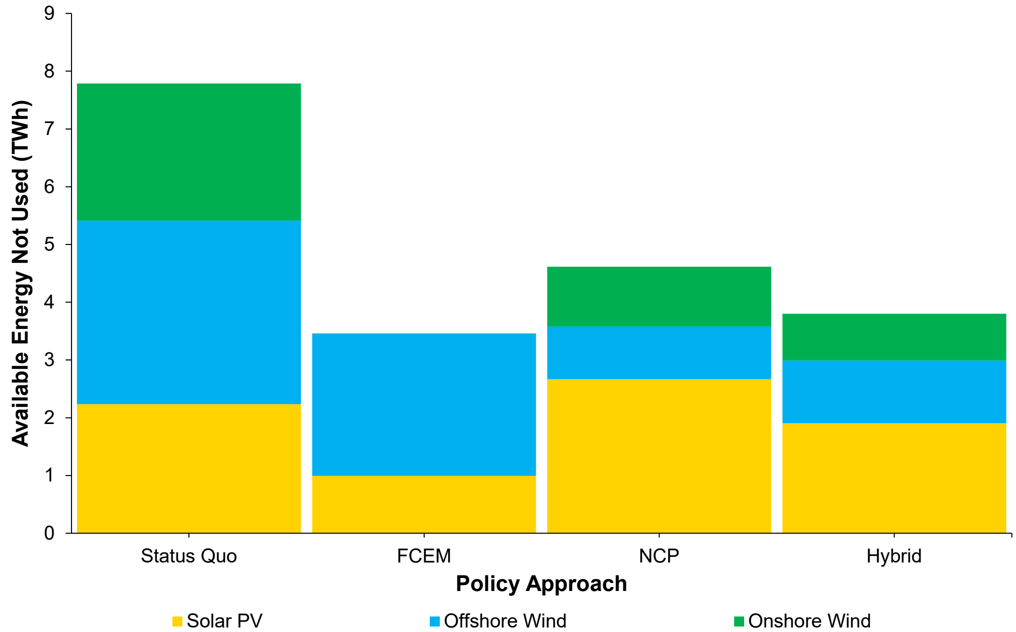
Figure VI-6. Economic Curtailments of Variable Renewable Generation by Policy Approach, 2021-2040 (TWh)



[149] Curtailment levels in **Figure VI-6** are from the CEM, while those in **Figure VI-7** are from the EMS. As we note earlier, behavior of battery storage resources differs somewhat between these models, leading to the observed differences in curtailment levels in 2040 between these figures.

[150] The quantitative analysis does not account for the impact the differences in PPA prices across resources could have on the incidence of economic curtailments in the Status Quo approach.

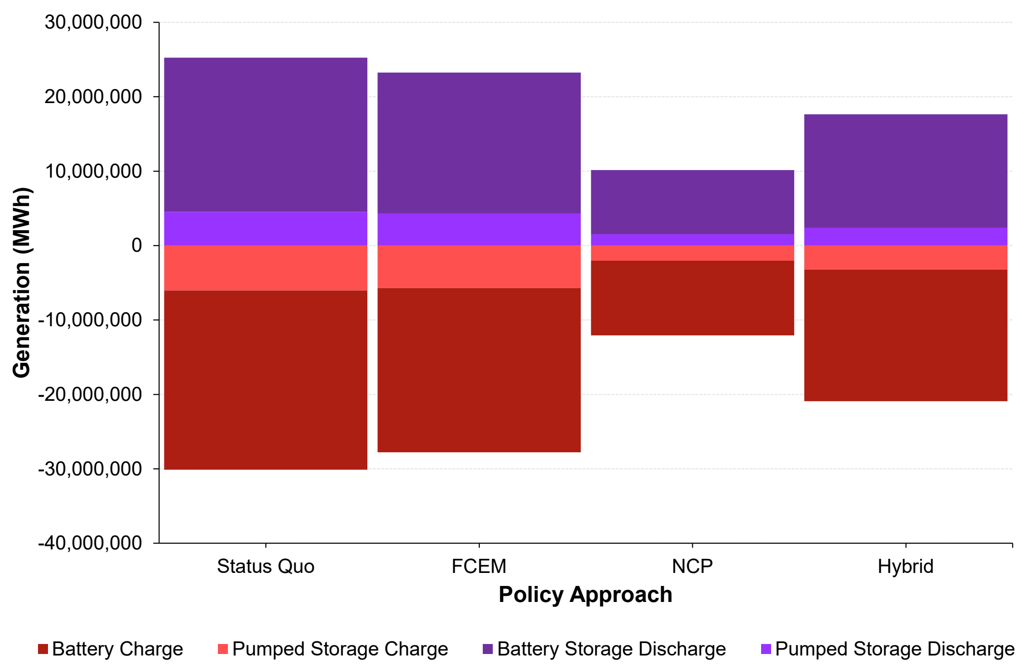
Figure VI-7. Economic Curtailments of Variable Renewable Generation by Policy Approach and Technology Type, 2040 (TWh)



Note: Economic curtailments arise from the EMS model, and thus may differ from the curtailments in the CEM model.

Figure VI-8 shows the operation (charging and discharging) of energy storage units in each policy approach. These outcomes differ across policy approaches due to many factors, including the mix of variable renewable resources (and the extent to which their output is correlated), the quantity of energy storage capacity developed, and the extent of negative-priced LMPs.

Figure VI-8. Storage Resource Charging and Discharging by Policy Approach, 2040 (MWh)



ii. Storage "churning": unintended consequence of negative prices

A potential unintended consequence of the increase in the frequency and magnitude of **negative energy pricing "churning" behavior**, in which battery owners consume otherwise-curtailed variable renewable energy and earn net revenues through energy losses. Such churning could occur because, with negative prices, the battery is *paid* to consume energy and then *pays* to discharge the energy, but revenues received exceed payments made because the quantity of energy discharged is smaller due to energy losses.[151]

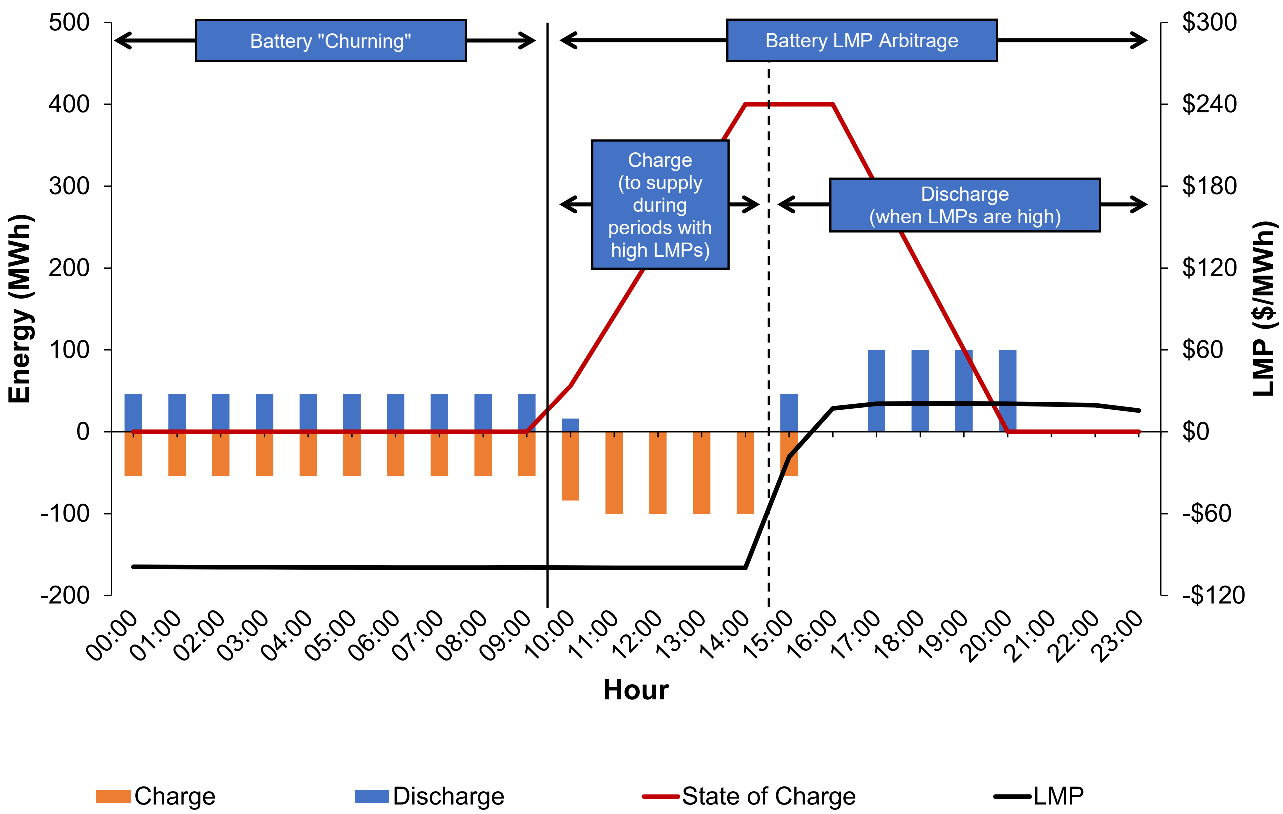
Our quantitative analysis indicates that future market conditions in a decarbonized power system can be conducive to frequent "churning" as a profitable operational strategy for storage resources. For example, in 2040, the proportion of total battery discharge energy due to churning is: 57% for the Status Quo, 45% for the FCEM, and 30% for the Hybrid Approach. By contrast, with limited negative pricing, only 1% of discharge energy is associated with churning under Net Carbon Pricing.

Figure VI-9 illustrates storage "churning" behavior using a stylized example of a 100 MW battery with a four-hour storage duration. The first hours of the day (*i.e.*, hour 0:00 to 14:00) contains a stretch of consecutive, negatively priced hours, with prices at -$100/MWh. Such stretches occur with some frequency when roughly a third of all hours during the year have negatively priced hours. These stretches may be somewhat predictable – a stretch of sunny weather with PV generation exceeding end-use load, or a stretch of windy weather during nighttime hours with wind generation exceeding end-use load. During the first portion of this period (hour 0:00 to 9:00), the storage resource "churns" by simultaneously charging and discharging, earning net revenues through losses. In this example:

- the storage resource is paid $100/MWh to charge the battery with 54 MWh of energy in each hour, earning $5,400 per hour, and then
- the storage resource pays $100/MWh to discharge 46 MWh of energy (lower than amount charged, due to losses), paying $4,600 per hour, such that,
- the storage resource earns a net revenue of $800 by "consuming" 8 MWh of energy through energy losses, and in the process creating 8 MWh of CECs that are earned by variable renewable resources.

[151] The extent to which storage resources can exploit the economic opportunity offered by battery churning will depend on many factors, including market rules, battery operational capabilities, physical (wear and tear) costs of churning on batteries, and the financial risks of executing such strategies given uncertain market prices.

Figure VI-9. Illustrative Example of Storage Resource Churning During Negative-Priced Hours



While "churning," the storage resource does not store any energy that could be sold at later points in time a positive price. The storage resource then alters its behavior towards the end of this stretch of negatively priced hours to ensure that it is fully charged at the end of this period of negative prices. Once prices become positive again, the storage resource then discharges to fully exploit the arbitrage opportunity available. In the illustrative example, the storage resource fully charges when prices are $-100/MWh and discharges when prices are $20/MWh, earning net revenues both when it charges and when it discharges. Thus, the storage resource is able to both exploit the opportunity to earn net revenues through "churning" energy losses that do not lead to emission reductions or otherwise provide value to consumers, and exploit arbitrage opportunities when prices rise and its operation displaces energy production from fossil resources with supply from (otherwise curtailed) renewable resources.

Storage churning would result in some economically inefficient behavior. *First*, storage resources are operated to store and then discharge energy, being paid a positive return for consuming the curtailed renewables through storage energy losses — that is, the storage resource is not storing energy across periods to allow more renewable energy to be used to meet demand in high energy periods, and instead is acting more like traditional energy demand. For battery resources, these energy losses and the associated storage cycling contribute to physical degradation of the battery, which imposes an economic (opportunity) cost.[152] Other storage resources incur similar opportunity costs, such as the efficiency losses associated with pumped storage resources. *Second*, the additional return may incent the development of excess storage resources compared to the economically efficient level.[153]

In principle, if storage churning were deemed to be an "undesirable" activity due to these inefficiencies, regulators or lawmakers could respond by adopting new regulations or changing market rules in an attempt to prevent or deter this behavior. We do not consider whether it would be possible to design regulations or rule changes that are successful at deterring churning behavior without imposing other costs or leading to other unintended consequences that outweigh any benefit achieved. However, we note that the need to consider regulatory actions to mitigate undesirable behavior, such as "churning", suggests a shortcoming in market design, particularly when alternatives approaches are available to avoid creating such undesirable incentives.

This behavior, however, is not necessarily inconsistent with the intent of either the Status Quo or FCEM approaches, which are both designed to incent the production of clean energy. Consistent with these incentives, "churning" behavior creates additional CECs through a transaction in which the variable renewable submits offers reflecting their willingness to pay to generate energy, so they can be awarded the CECs, while the storage resource simply responds to this price signal by "generating" CECs by churning energy through the resource to generate CECs. However, from a policy standpoint, these CECs provide no environmental benefit, as they do not displace any fossil generation and thus do not reduce emissions, but generating these CECs increases social costs through increased battery degradation and potentially increased storage investment.

Thus, policy approaches that incent the generation of a policy "good" can have unintended consequences, particularly when that "good" is not fully aligned with the environmental "bad" (*i.e.*, carbon emissions) that is being targeted. In this case, the positive incentive to generate the "good" leads to behavior that produces no environmental benefit but may raise costs. By contrast, approaches that directly discourage the "bad," such as imposing a cost on carbon emissions, avoid this problem.

Given the potential for inefficient storage churning, it is important to consider whether it is likely that batteries and other storage resources would actually operate in a manner consistent with churning given real-world factors. Faced with the opportunity presented by long, extended periods with negative pricing, the extent to which battery or other storage resource owners "churn" in practice will likely depend on multiple factors.

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[152] Economic losses associated with churning are $70.8, $50.6, $0.3 and $24.8 million for the Status Quo, FCEM, Net Carbon Pricing and Hybrid Approach, respectively, reflecting a variable O&M cost of $6/MWh.

[153] Our modeling framework does not provide a means for us to easily quantity the magnitude of the inefficiencies that would be created by storage churning or to evaluate outcomes absent storage churning. Absent storage churning, we would expect some diminishment of the inefficiencies that it causes, including excessive variable costs (largely battery degradation) and excessive capital investment, although, as discussed above, we do not know whether such gains could be achieved through modifications to market rules or regulations or whether such modifications would lead to additional costs or unintended consequences.

One factor relates to whether battery and storage resource have the physical capability to sustain churning. For battery resources, they appear to have this technical capability. Operationally, because batteries can shift power flows on very short time frames, the pattern of charging and discharging over short time frames needed to execute churning is technically feasible.[154] However, because charging and discharging leads to battery degradation, one question is whether a battery could sustain churning operations. In fact, it happens that the partial (or "shallow") battery charging/discharging used in churning operations causes less degradation than the "full" charge and discharge of the battery when arbitraging prices between peak and off-peak periods.[155] Thus, current battery technologies appear well suited to churning.[156] Another potential issue is the utilization of the battery, captured by the number of "cycles". In principle, high battery utilization could lead to a higher degradation rate. However, as shown in **Table VI-3**, average cycling is at most 1.1 cycles per day and less than one cycle per day in three of four policy approaches. This cycling rate is within the range of expected utilization for current lithium-ion battery designs and within the range of expected usage assumed in current battery warranties.[157] Thus, the current battery technology assumed in this study appear well-suited to responding to the incentives created by extended negative pricing with battery churning.

Table VI-3. Average Battery Cycling by Policy Approach, 2040

	Status Quo	FCEM	NCP	HYB
Total Discharge (MWh)	24,063,288	22,141,310	9,317,670	16,633,661
Capacity (MW)	14,752	15,933	15,203	15,546
Annual Cycles (N)	407.8	347.4	153.2	267.5
Daily Cycles (N)	1.11	0.95	0.42	0.73

Another factor relates to whether the ISO-NE energy markets provide sufficient offer flexibility for storage resources to clear offers to charge and discharge in the coordinated fashion needed to execute churning operations. Such market clearing might be impractical given limitations to the structure of offers (*e.g.*, hourly offers) or might impose excess risk on storage owners. While these factors could limit churning over short periods of negative pricing, over longer periods they would be less likely to impose a barrier. For example, **Figure VI-10** shows a 42-hour spell with negative prices caused by substantial overgeneration. Over this spell, there are two long periods of substantial overgeneration that would facilitate churning of energy within ISO-NE's current offer structure, while imposing limited pricing risk.

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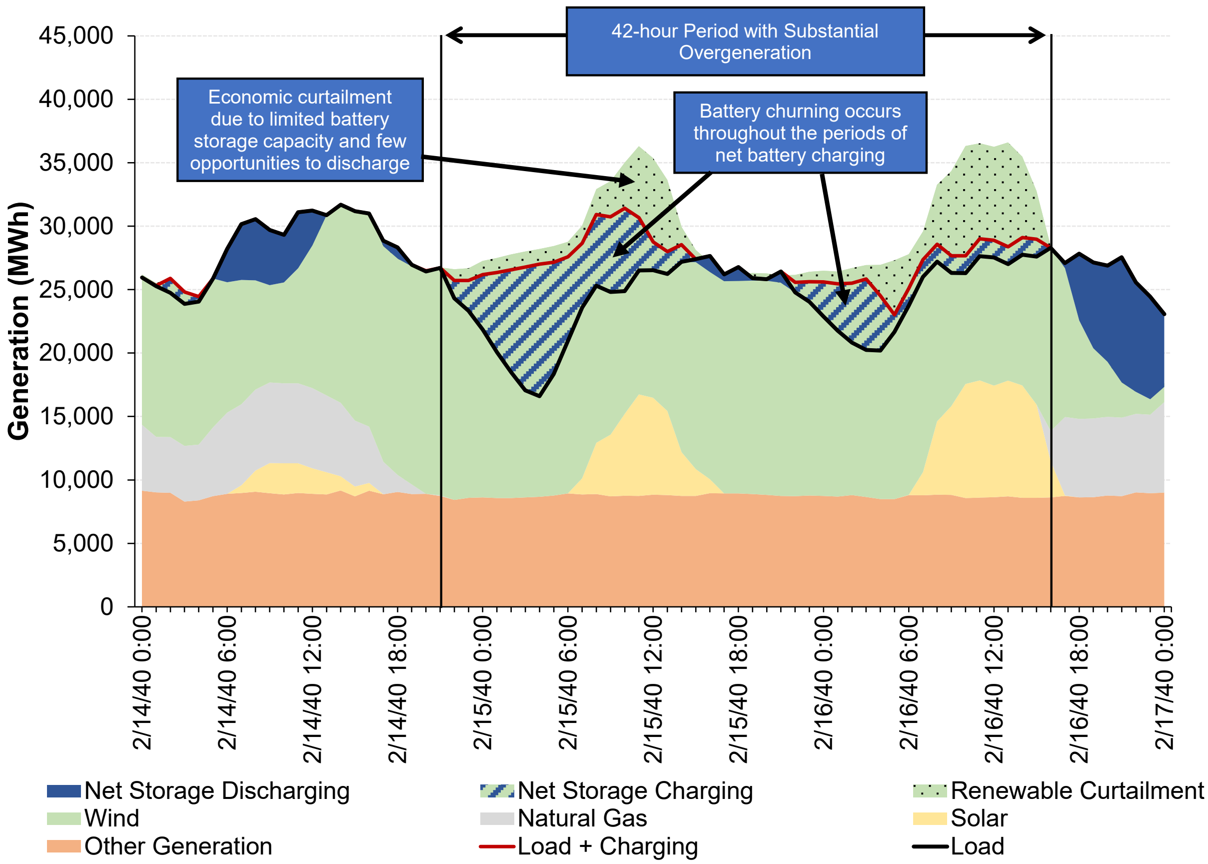
[154] NREL, "Grid-Scale Battery Storage: Frequently Asked Questions," September 2019, pp. 2-3, available at https://www.nrel.gov/docs/fy19osti/74426.pdf.

[155] Preger, Yuliya, et al. 2020. "Degradation of Commercial Lithium-Ion Cells as a Function of Chemistry and Cycling Conditions." *Journal of The Electrochemical Society*, Vol. 167, p. 120532.

[156] In principle, the incremental degradation from shallow rather than full charging could differ for alternative battery technologies that are under development, such as flow batteries.

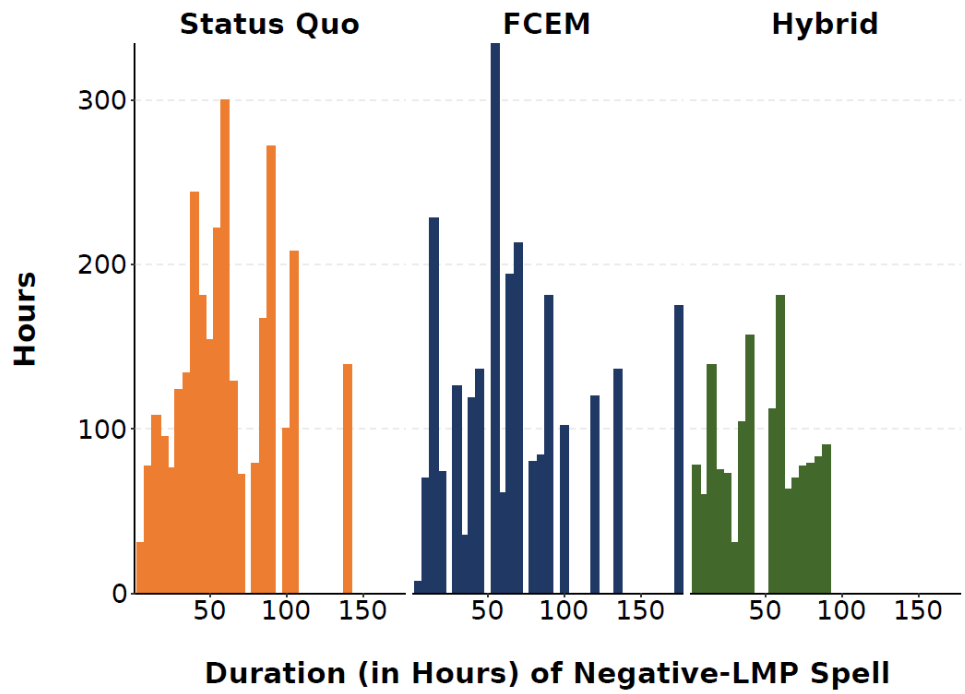
[157] The cycling limits in many battery warranties reflect the average cycling rate, calculated as the total charge/discharge divided by the battery's capacity. By calculating the number of cycles in this manner, the warranty does not distinguish between shallow and full charge-discharge.

Figure VI-10. Illustration of Long-Duration Spell of Overgeneration Leading to Negative Prices



To examine this question, we calculate the length (in hours) of each "spell" of negative prices, where more frequent and longer negative price spells are more likely to facilitate churning behavior from storage resources. **Figure VI-11** shows the count of negative-priced hours by the length (in hours) of the negative-priced LMP spell. For example, in the Status Quo, there was exactly one 100-hour spell of negative prices; thus, the figure shows that exactly 100 hours (y-axis) occurred during negative-priced LMP spells with exactly 100 hours long (along the x-axis). The figure illustrates that a large fraction of the hours with negative prices occur during long spells of negative prices. For example, 96% of hours with negative prices in the Status Quo occurred in spells of 12 hours of greater. Similarly, in the FCEM and Hybrid, 98% and 88% of negative-priced hours occurred in spells of 12 of greater hours, respectively. Thus, even after the operation of storage resources, the majority of hours with negative prices occur during long spells of negative prices, providing substantial opportunities for storage churning.

Figure VI-11. Distribution of Hours with Negative-LMPs by Duration of Negative-LMP Spell (Number of Hours)



Note: The Duration of Negative-LMP Spell is the number of consecutive hours in which LMPs are negative. For example, if LMPs were negative for 100 consecutive hours, this is a Negative-LMP Spell with a duration of 100 hours.

Finally, and most importantly, storage churning may be limited by competition from other advanced technologies. Churning is prevalent in our analysis because storage is the most cost-effective technology able to take advantage of the opportunity presented by negative prices. However, in principle, other technologies could similarly benefit from the opportunity to consume electricity at negative prices and frequent negative pricing may lead to innovations to take advantage of these opportunities. For example, "green" hydrogen could be produced by using excess variable renewable electricity to power the chemical process (electrolysis) needed to transform water into hydrogen.[158]

These advanced technologies could include longer-duration battery storage or technologies that store electricity in other energy forms, such "green" hydrogen or advanced demand-management technologies (that shift load to periods with negative prices). Our analysis does not consider such technologies, as they are not commercially viable at present, or data on their viability are not presently available. However, in the future

[158] The potential for green hydrogen production to mitigate negative prices will depend on many factors, including the extent to which green hydrogen production facilities are financially viable if they rely only on production in periods with negative prices (when curtailment occurs) or they require higher utilization, including operations during periods without curtailments. If the latter is true, the expanded demand hydrogen facilities may cause a growth in variable renewable resources that may itself exacerbate the curtailment problems. For a related discussion, *see* International Renewable Energy Agency, "Hydrogen: A Renewable Energy Perspective," prepared for the 2nd Hydrogen Energy Ministerial Meeting, Tokyo, Japan, September 2019.

given technological developments, these technologies may compete with the 4-hour battery storage resources assumed in our analysis to consume excess variable renewable supplies.

c) **Investment and Operation of Zero-carbon, Dispatchable Resources**

At present, commercially viable clean energy resources are largely limited to the variable renewable resources analyzed in the Pathways Study, including PV solar, onshore wind and offshore wind. With certain exceptions, these technologies represent the vast majority of clean energy resources being developed within the U.S. and globally.[159] However, the volatile and uncertain output from variable renewable resources poses substantial challenges to operating a highly decarbonized system.[160]

Given these challenges, there is an obvious need for dispatchable resources powered by "clean" (low- or no-carbon) fuels to provide the dispatchable supply needed to maintain reliable system operations in a highly decarbonized system, similar to the role currently played by gas-fired resources. Potential technologies include combustion turbines or combined cycle units fueled with hydrogen, "renewable" natural gas (created using renewable energy), or an alternative low- or no-carbon fuel. While these technologies are not commercially viable at present, it is important to consider whether each policy approach would efficiently incent these technologies.

In principle, each of the centralized policy approaches easily provides incentives to build dispatchable clean resources — both carbon prices and CECs incent a dispatchable clean technology, so long as these facilities are eligible for CEC awards. Under the Status Quo, however, there is no in-market incentive for clean energy generation. As a result, the market may provide insufficient revenues to recover the fuel (and operations) costs for these clean energy plants, as these costs are expected to be substantially higher than current SRMCs of gas-fired plants. For example, if the cost of clean or renewable fuels needed to power a combustion turbine are $15/MMBtu, this could result in costs of $150 per MWh of energy produced.[161]

In practice, there is nothing to prevent the expansion of state procurements to include dispatchable clean energy resources, in addition to variable renewable resources. However, the structure of PPAs for dispatchable clean resources would need to differ in several important ways from current variable renewable PPAs. *First*, the PPA would need to incent economically efficient plant operations, not only plant investment. With low (or no) SRMC, there is no need to incent plant operations for variable renewable resources, once constructed. However, with a dispatchable clean energy resource, developing effective PPA pricing terms would be more complex. In particular, the payments would need to be high enough to incent operation but not so high to provide a windfall. However, determining the plant's true cost of production may be challenging,

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[159] For example, certain resources are geographically limited, such as geothermal and hydro, and other resources may not economically or politically viable within the U.S., such as nuclear power.

[160] Hibbard, Paul, et al. 2020. "Climate Change Impact and Resilience Study - Phase II: An Assessment of Climate Change Impacts on Power System Reliability in New York State"; Sepulveda, Nestor A., et al. 2018. "The Role of Firm Low-Carbon Electricity Resources in Deep Decarbonization of Power Generation." *Joule*, Vol. 2, pp. 2403-2420.

[161] This assumes a heat rate of 10 MMBtu/MWh and no other variable costs.

particularly because fuel costs may be constantly changing and difficult to observe. Thus, establishing a mechanism to determine the right level of payment (or subsidy) within a commercial contract would be complex, particularly for newer, evolving technologies, and adds financial risk. *Second*, the plant would require such a contract for its entire commercial lifetime, because it requires a subsidy not just to finance construction, but also to incent each MWh of energy since its marginal costs will likely exceed LMPs. Thus, while discontinuation of PPAs with variable renewables would not be expected to affect the competitiveness of their energy supply (assuming they remain in operation), the financial support required for dispatchable facilities is needed on an on-going basis.

d) **Investment and Operation of More-efficient, Lower-emission Fossil Resources**

Along with substitution of fossil fuel-generated energy for clean energy, emission reductions can also be achieved by reducing the carbon-intensity of energy generated from fossil fuels. As we describe in **Section VI.B.1**, neither the Status Quo nor FCEM approaches provide any incentive for reductions in the carbon-intensity of fossil generation. By contrast, both Net Carbon Pricing and the Hybrid Approach incent the development of less carbon-intensive fossil resources by placing a cost on carbon that increases the cost of energy from more carbon-intensive resources compared to less carbon-intensive resources. However, the carbon prices in the Hybrid Approach are too low to incent all cost-effective emission reductions through investments in more efficient fossil generation and retirements of inefficient fossil generation, which decrease the carbon intensity of fossil generation.

The potential to reduce emissions through entry and exit of fossil generation that decrease the carbon-intensity of the fleet depends on the particular resources within a system. In a system with many older, less-efficient, coal-fired resources, this potential may be substantial, because of the potential emission reductions from switching to more efficient gas-fired resources can be large, while entailing modest costs. By contrast, given current technology opportunities, potential reductions in the New England system will be smaller, and the costs higher, because the New England system has relatively little fuel diversity, relying almost exclusively on natural gas, and most of the resources are relatively efficient. As a result, (1) there is little scope for emissions abatement through fuel-switching from oil or coal to natural gas and (2) emission reductions through more efficient gas-fired generation would require investment in new, more-efficient combined-cycle units to displace energy from less-efficient, marginal gas-fired resources, which could be very costly.

These conclusions about the limited scope for emission reductions within the New England gas fleet and our quantitative analysis of emission reduction potential reflects currently available technologies. However, these conclusions could change if technological changes create opportunities for reductions in the carbon-intensity of emitting resources at reasonable costs. Potential technology changes to reduce carbon-intensity include significant improvements in gas-fired generation efficiency and improved commercial viability of lower-carbon fuel blending (*e.g.*, blending natural gas with either green hydrogen or renewable natural gas). Such developments could expand the scope of cost-effective emissions reductions that would be incented by Net Carbon Pricing but would not be incented by the other policy approaches evaluated.

Moreover, carbon pricing would create incentives to undertake the research and development needed to develop these new advanced technologies. Lacking a price signal for carbon, the FCEM and Status Quo, which incent only zero-carbon energy, provide no economic inducement for companies to invest in research and development of new technologies that lower carbon-intensity, because these approaches provide no incentives for reductions in carbon-intensity. Thus, if these approaches were deployed widely, investment funds would flow into research on zero-carbon technologies, but not technologies to lower carbon-intensity.

Table VI-4 shows estimated marginal abatement costs associated with fuel-switching opportunities currently available given current technologies nationally and in New England: (1) existing coal-fired units to existing natural gas combined cycle units (*i.e.*, changes in merit order dispatch rather than new entry), (2) existing coal-fired units to new natural gas combined cycle units, and (3) existing natural gas generation to new natural gas combined cycle generation.[162] The estimate of marginal abatement cost for New England reflects the "average" (marginal) abatement costs across all hours in which the new resources operate across the entire study period (assuming the new resource become operational in 2021). The first two options are relevant nationally, as many U.S. regions still have substantial amounts of coal-fired generation, while third option is the most relevant option to New England, given the region's heavy reliance on gas-fired generation.[163] While coal to natural gas switching is relatively cost-effective (marginal abatement costs below $25/metric ton of avoided CO_2), existing natural gas to new natural gas substitution is eight times as expensive (*i.e.*, the current marginal abatement costs is $190 per metric ton of avoided CO_2). Thus, while fuel substitution may provide a relatively low-cost way to reduce carbon emissions in regions with substantial opportunities for coal-to-gas substitution, the gas-to-gas substitutions available in New England are substantially more costly, and thus represent a small share of emission reductions in our analyses.

[162] This calculation reflects changes in system costs and emissions due to hypothetical forms of fossil fuel switching. The national estimates rely on EIA AEO (2021) estimates for capital costs and EPA (2018) estimates for technology-specific emissions rates. The New England estimates calculate the average marginal cost of generation and average marginal emissions rate from the existing fossil fuel fleet under the Status Quo policy approach. The marginal abatement cost reflects the hypothetical entry of a new natural gas combined cycle unit in 2021, assuming fossil fuel retirements are the same as the Status Quo. As such, the marginal abatement cost can be thought of as an average abatement cost incremental to resource outcomes under the Status Quo. *See* EPA, "Emission Factors for Greenhouse Gas Inventories," 2018, available at https://www.epa.gov/sites/default/files/2018-03/documents/emission-factors_mar_2018_0.pdf.

[163] New England relies on some coal- and oil-fired generation, although increasingly small fractions. In 2020, oil- and coal-fired generation each accounted for 0.15% of MWh generated in the ISO-NE system. Nonetheless, the calculations in **Table VI-4** reflect potential substitutions with coal, oil, and gas, weighted by their capacity factors. *See* ISO-NE, "Resource Mix," available at https://www.iso-ne.com/about/key-stats/resource-mix/, accessed November 17, 2021.

Table VI-4. Marginal Abatement Costs, Alternative Forms of Fossil Fuel Switching[164]

	National		New England
	Existing Coal to Existing Natural Gas	**Existing Coal to New Natural Gas**	**Existing Fossil Fuel Fleet to New Natural Gas**
Marginal Abatement Cost ($/Metric Ton CO_2):	7.69	24.06	189.9

Note: "Existing Fossil Fuel Fleet" refers to the existing fleet of oil-fired plants, gas-fired combustion turbines, and gas-fired combined cycle plants, and coal-fired plants in New England from 2021-2040, weighted by capacity factor.

In contrast, in areas of the country with high levels of coal generation, fuel-switching from coal to natural gas can yield large amounts of emissions abatement because the average emissions intensity of coal-fired generation is 2.5 times the average emission intensity of natural gas-fired generation. For example, a $20 carbon tax will lead to an $8/MWh increase in variable costs for the average natural gas-fired unit and a $20/MWh increase in variable costs for the average coal plant.[165]

It is worth elaborating on the challenges to reducing carbon-intensity within a system relying primarily on one fuel. Within New England's gas-fired fleet, which accounts for the vast majority of fossil energy generation, the merit dispatch order already dispatches resources from least-carbon-intensive to most-carbon-intensive because both emissions and fuel costs depend on the unit's heat rate. Thus, increasing carbon prices (or gas prices) will not lead to a meaningful change in the dispatch order among gas-fired resources and thus would produce no emission reductions. As a result, the primary way that the carbon-intensity of emissions can be reduced from the gas-fired fleet is to replace output from a less-efficient, higher emitting plant with output from a more-efficient, lower emission plant. However, the cost of achieving emission reductions through such substitutions are generally high because the capital costs for new gas-fired plants are high and the reductions achieved by such substitutions tend to be modest, because they reflect only the reductions from switching the marginal plant to a more efficient (infra-marginal) plant. In an already efficient system such as New England's, these differences in heat rates tend to be small, and thus reflect a costly way to reduce the region's carbon emissions.

The quantitative analysis shows that, despite these limitations on the potential for reducing carbon-intensity, carbon prices can lead to differences in the new fossil resources developed in the region, and the existing fossil resources that choose to retire because this policy creates an incentive to have a lower heat rate, thereby reduce the plant's carbon-intensity. For example, as seen in **Figure VI-2**, Net Carbon Pricing supports the development of a more efficient gas-fired fleet, incenting the development of more efficient combined cycle units rather than less efficient combustion turbines. By comparison, the Status Quo and FCEM, which both

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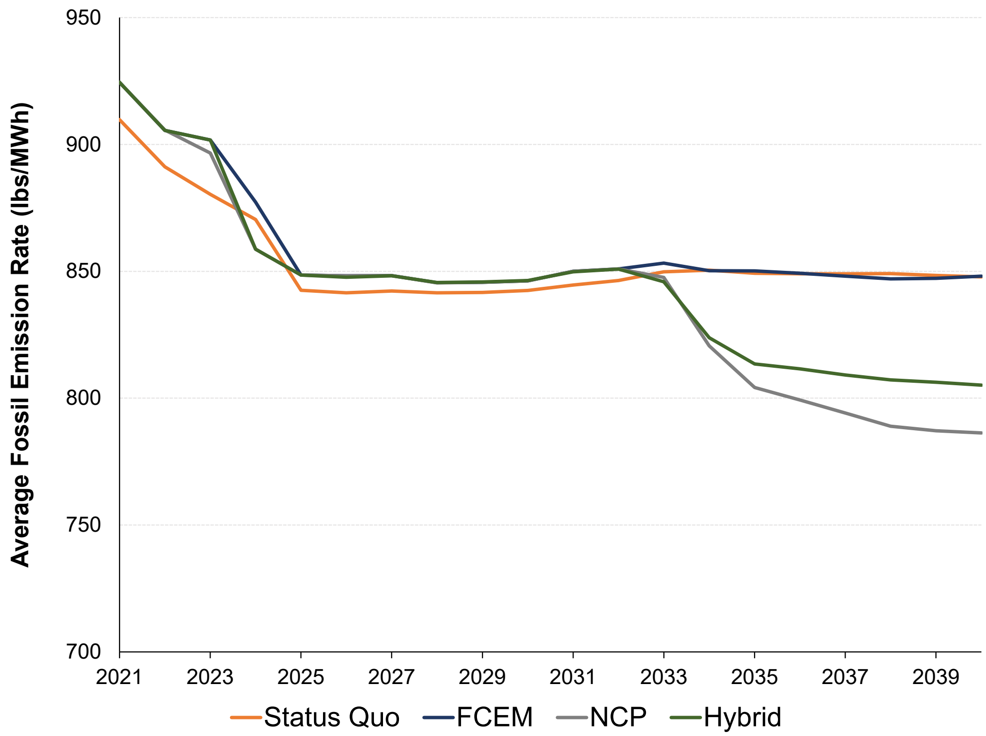
[164] Sources used in these calculations include model results, EIA AEO 2021, and EPA, "Emission Factors for Greenhouse Gas Inventories," available at https://www.epa.gov/sites/default/files/2018-03/documents/emission-factors_mar_2018_0.pdf.

[165] Cleary, Kathryne and Karen Palmer. 2021. "Carbon Pricing 201: Pricing Carbon in the Electricity Sector," Resources for the Future, available at https://www.rff.org/publications/explainers/carbon-pricing-201-pricing-carbon-electricity-sector/.

provide no incentives for reduced carbon-intensity, have the least efficient gas-fired fleet, incenting investment in combustion turbines rather than more efficient, combined cycle capacity.

The reduction in carbon-intensity from carbon pricing is illustrated by the reductions in average emissions (heat rates) for gas-fired resources. **Figure VI-12** shows the average emissions rate of fossil-fired generation under each scenario. The improvement in average emission rates illustrate the improvements in generation efficiency — and corresponding reductions in carbon-intensity — achieved by carbon pricing. In addition, it is important to note that these improvements in efficiency occur despite higher levels of total energy supplied by gas-fired resources under Net Carbon Pricing and the Hybrid Approach compared to the Status Quo and the FCEM.

Figure VI-12. Average Fossil-Fired Emissions Rates by Policy Approach, 2021-2040 (lbs. CO_2/MWh)



C. Discrimination in Pricing Between Resources

The policy approaches differ in whether there is price discrimination — that is, whether they uniformly incent and compensate resources for providing otherwise similar services independent from the resource's characteristics (*e.g.*, its technology) or circumstances (*e.g.*, its vintage), or whether compensation depends on these characteristics and circumstances.

Both the FCEM and Net Carbon Pricing offer uniform compensation. The FCEM awards CECs to *all* clean energy producers, and the Net Carbon Pricing compensates through higher LMPs paid to *all* resources supplying energy by imposing a cost on *all* resources that emit carbon. Although these incentives may vary over time and depend on location (*e.g.*, given geographic and temporal variation on LMPs), they are uniform across resources in the market that produce comparable "environmental" services — that is, resources that emit the same amount of carbon (whether zero or positive) per MWh of electric energy.

By contrast, the Status Quo and Hybrid Approach do not uniformly compensate resources that provide otherwise comparable environmental services. Instead, the incentives these approaches provide to reduce emissions depends on the resource's characteristics and circumstances:

- Under the ***Status Quo***, compensation for clean energy varies across *all* resources. New clean energy resources are awarded a PPA, but that price can vary from contract to contract. However, existing resources without a PPA contract (including resources with expired PPAs), receive no incremental payments for their clean energy unless there are separate measures through which compensation is provided.[166]
- Under the ***Hybrid Approach***, compensation for clean energy differs between new and existing resources. Existing resources are compensated through higher LMPs caused by the carbon prices, while new clean energy resources are compensated by both the increase in LMPs and the award of CECs that are then purchased by utilities (or other entities) to satisfy CEC requirements.

These types of differences in compensation between resources providing clean energy can have several unintended consequences.

First, compensating new resources more than existing resources can lead to ***economically inefficient capital decisions***, with more funds directed toward new, higher-compensated facilities relative to older, lower-compensated facilities. For existing plants, these inefficient capital decisions can manifest as either economically premature retirement or inefficiently low investment in plant maintenance***.*** This principle is well understood and is a foundation in market design, providing the rationale for paying new and existing capacity the same clearing price.[167]

Equal compensation ensures that entry and exit decisions for clean energy facilities reflect the same cost at the margin, meaning a new resource will replace a comparable existing resource only if it can provide the same services at lower cost. Paying equal compensation avoids the inefficient outcome, in which a retiring (or exiting) clean energy resource's going forward cost is less than the cost of developing a new clean energy resource. By contrast, providing new resources with higher compensation (compared to existing resources) can lead a new resource to replace a comparable existing resource even if the new resource has higher costs. This can result in inefficient capital turnover, with capital turning over too quickly and plant economic lifetimes that are shorter than is economically efficient. For example, an older, non-emitting resource receiving lower compensation for clean energy may retire prematurely if it is unable to cover fixed operating costs or if it is

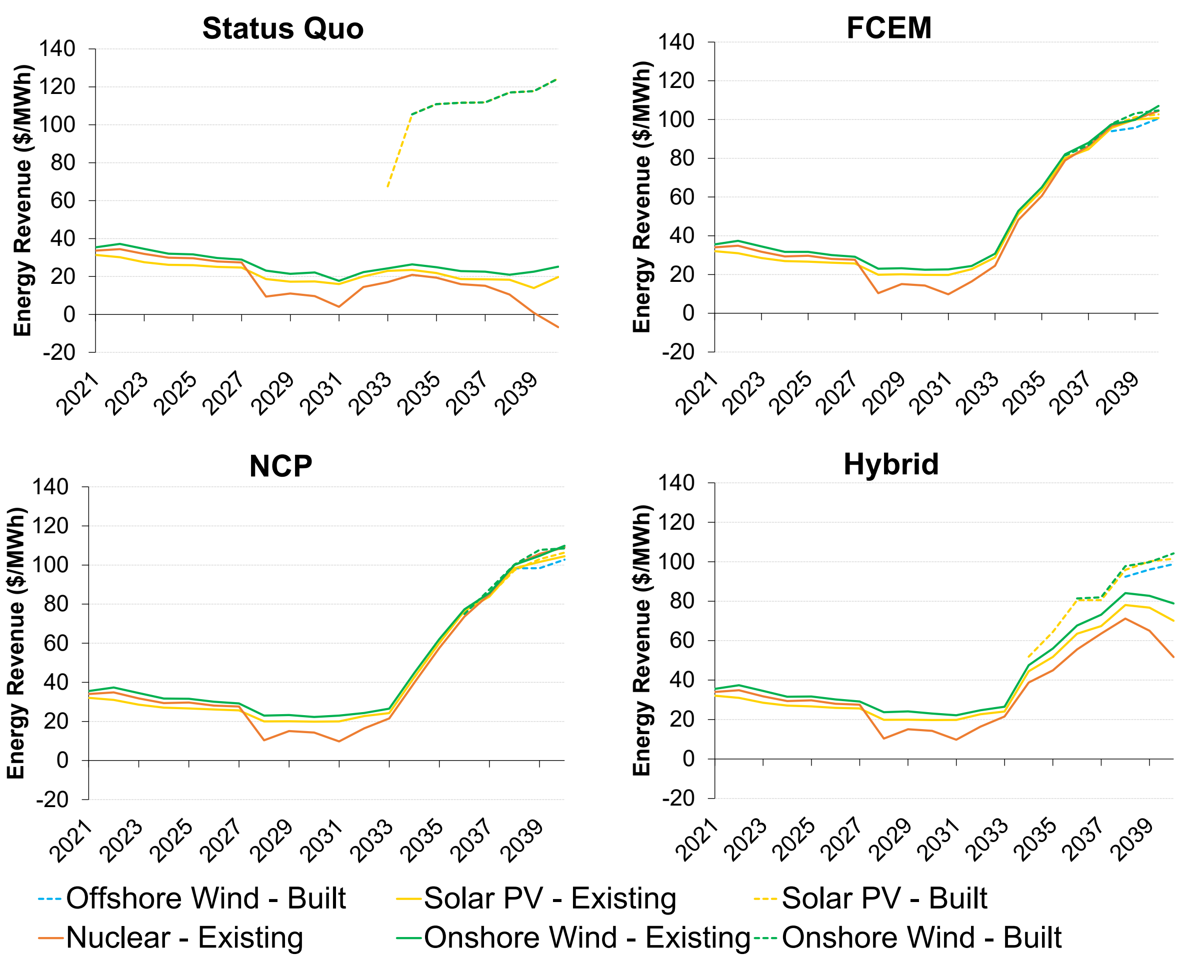
[166] States may make exceptions to this general approach of awarding PPAs to only new resources. For example, the state of Connecticut has awarded PPAs for "zero carbon" energy to Millstone Power Station and Seabrook Power station, the two existing nuclear plants in New England. *See* S&P Global, "Conn. Agency picks 2 nukes, offshore wind projects for power contracts," December 28, 2018, available at https://www.spglobal.com/marketintelligence/en/news-insights/trending/vrAiKSOzmpxuz3yuBq6XQw2.

[167] Testimony of Robert Ethier, FERC, Docket No. ER14-1639-000, April 1, 2014.

more profitable to repower the facility with new plant that is eligible for more preferable contract terms. This new capital bias is a well-known unintended consequence of relying on PPAs to maintain resource adequacy or, in the context of decarbonization, achieving a clean energy transition.

The scope of price discrimination is captured by differences in average revenue (per unit of capacity) under each policy approach. **Figure VI-13** compares the average revenue to clean energy resources under each policy approach. Under Net Carbon Pricing and the FCEM, compensation tracks closely across different clean resources, irrespective of whether they are new or existing plants. Under the Status Quo, compensation is substantially higher for new resources in comparison to existing resources, absent measures to provide additional compensation to existing resources. Under the Hybrid Approach, existing resources are compensated at a lower level — the gap in average revenues is largest in the last few years of the study period, although this is an artifact of the model's optimization of annual carbon prices and CEC quantities (as we discuss in further detail in **Section VI.D**).

Figure VI-13. Comparison of Energy Revenues for Clean Energy Resources by Policy Approach, 2021-2040 ($2020/MWh)



Note: In this figure, energy revenues reflect LMPs (which reflect carbon prices in Net Carbon Pricing and the Hybrid Approach), PPA prices in the Status Quo for new resources, and CEC revenues for the FCEM and Hybrid Approach. They do not include capacity revenues.

The Pathways Study does not attempt to capture the costs associated with economically premature retirement and inefficient use of capital. Instead, for the Status Quo approach, we consider alternative levels of compensation for existing clean energy resources required to avoid potential exits of existing resources.

Second, under the Status Quo, different PPA prices can lead to ***differences in market outcomes, particularly economic curtailments, across variable renewables***. Specifically, resources with higher PPAs will be more likely to clear the market, and less likely to be economically curtailed, as their energy market offers will be lower than resources with lower PPA prices (or those without a PPA). For example, assume there are two resources, one with a PPA price of $100/MWh and the other with a PPA price of $50/MWh. If market has excess renewables, it will economically curtail supply from the $50/MWh resource first (which will generally offer its energy at -$50/MWh), and then curtail the supply from the $100/MWh resource (which will generally offer at -$100/MWh) only after fully curtailing supply from the $50/MWh resource. This same sequence of economic curtailment will occur every time there would otherwise be overgeneration — that is, supply from the resource with the lowest out-of-market payments is always curtailed first. Note that, given reliance on these out-of-market payments, this criteria for economic curtailment has no relationship to resource costs (whether average or short-run marginal), but instead reflects the particular PPA pricing terms negotiated by the resource owners.

Because the Status Quo would lead to resource-to-resource variation in out-of-market payments, economic curtailments (and margins earned) would be unequally distributed across resources. Resources with lower out-of-market payments would experience higher levels of curtailments and earn lower margins, while resources with higher out-of-market payments would be curtailed less frequently and continue to earn some margins (reduced due to clawback provisions) in hours when variable renewables are on the margin. This skew in the distribution of curtailments (and margins) is an unintended consequence of the out-of-market PPAs under the Status Quo approach. This outcome has several potential unintended consequences. *First*, resources without PPAs will experience the highest curtailments and lowest margins, as these resources will have the lowest out-of-market payments. Existing renewables will not only receive limited (to no) incremental compensation for their environmental attributes, but their supply will be curtailed more frequently (and margins lower) than other resources in the market. Thus, the inadvertent process by which curtailments are allocated among variable renewables will further bias the market toward new rather than existing resources.

Second, as discussed in **Section V.B.3.f**, clean energy resource developers would be expected to adjust the PPA offers to try to account for the adverse impact of curtailments on revenues earned under the contract. The magnitude of the optimal adjustment to PPA offers would be difficult to quantity, *ex ante*, because of uncertainty about curtailment frequency, other market participants' PPA prices (which would affect their offers into the energy market), and the resulting LMP levels when prices are negative. However, this adjustment would be expected to be larger for resources with comparatively low costs, all else equal.

Because negative pricing in New England has been uncommon to date, the market has not directed much attention to these unintended consequences of differences in out-of-market offers. However, our analysis shows that these consequences will grow over time if the growth in variable renewables continues as assumed in our study. As we show in **Table VI-2** by 2040, the energy market may clear at negative prices in nearly one-third of hours, whereas negative prices are uncommon in today's markets. Thus, we would expect that developers would account for the effect of negative LMPs in the pricing terms they offer, to account for the reduction in revenue below the PPA's nominal price and may account for the uncertainty that negative pricing (and economic curtailments) creates in a project's revenue streams, potentially including risk premiums into offers. This artifact of negative pricing would thus be another factor developers would need to account for when preparing PPA offer pricing terms, along with accounting for the pay-as-bid structure of the procurement.

D. Economic Welfare: Social Costs

From an economic perspective, social welfare captures the net economic gain (or loss) arising from undertaking a new regulation or policy. Policies that generate greater social benefits than social costs are said to generate "net benefits" and a policy that generates the largest net benefits (among alternatives) is said to be "economically efficient," as it achieves the largest social benefit/welfare from the undertaking the policy.[168]

When benefits are difficult to measure (or are determined through alternative policy criteria), policy makers often compare the "cost-effectiveness" of alternative policy approaches to achieving a given policy target. A policy approach is more cost-effective than another if it achieves a given policy target at a lower social cost. The Pathways Study considers the cost-effectiveness of alternative policy approaches by comparing the estimated social costs of achieving an assumed decarbonization target through each policy approach.

1. Cost-effectiveness of Alternative Policy Approaches

To measure cost-effectiveness, each policy approach is evaluated under the assumption that it generates the same level of goods and services to consumers. Thus, along with assuming the same environmental target, reducing carbon emissions to 80% below 1990 emission levels by 2040, we also assume the same level of other energy services, including total energy supply and resource adequacy (by procuring the same quantity of operable capacity in each case). Because the social benefits are assumed to be the same in each case, social costs capture all differences in social welfare between policy approaches.

Social costs reflect the economic costs of the resources used to produce a good or service. In the context of producing electric energy services, social costs include capital costs to build new (or maintain existing) infrastructure, fixed O&M costs to operate facilities, and fuel costs and variable O&M costs to produce electric energy.

In principle, differences in the cost-effectiveness of alternative policy approaches reflect the differences in the incentives and mechanisms used to reduce emissions. With certain exceptions, these differences were reviewed in **Sections VI.A** and **VI.B**, but we summarize key differences below:

- **Status Quo**
    1. Status Quo approach provides no in-market incentives to reduce emissions or generate clean energy, but instead procures clean energy through competitive procurements for multi-year, fixed price contracts;

[168] An analysis of the economic efficiency of decarbonization policies for New England would aim to identify the point at which the marginal costs and marginal benefits of emission reductions are equal.

2. The cost-effectiveness of emission reductions reflects the specific resources selected to supply clean energy, and thus depends on the design and implementation of procurements;

3. Absent subsidies for existing resources, the Status Quo will favor new resources over existing resources, which may lead to economically premature retirements of or insufficient investment in existing clean energy resources; and

4. Status Quo approach subsidizes energy consumption, and thus may increase energy consumption, thereby raising costs.

- **FCEM**

  1. FCEM (with a single, uniform CEC) provides cost-effective incentives for the development of clean energy;

  2. The FCEM does not account for differences in the carbon-intensity of fossil generation displaced by clean energy and does not provide incentives for other means of reducing emissions, such as substitution of higher- for lower-emitting fossil-fired resources; and

  3. FCEM subsidizes energy consumption, and thus may increase energy consumption, thus raising costs.

- **Net Carbon Pricing**

  1. Provides cost-effective incentives to reduce carbon emissions; and

  2. Provides incentives for demand to reduce energy consumption.

- **Hybrid Approach**

  1. Carbon price provides a price signal to incent all types of substitutions that can reduce emissions, although the price signal is below the level needed to achieve all reductions needed to meet the target;

  2. The CEC cost-effectively incents sufficient "new" clean energy to meet carbon targets, but will not exhaust all cost-effective opportunities to reduce emissions.

  3. By providing higher compensation for "new" clean energy resources relative to existing clean energy resources, the Hybrid Approach may lead to economically premature retirements of or insufficient investment in existing clean energy resources; and

  4. On net, may subsidize energy consumption, and thus may increase energy consumption, thus raising costs.

The quantitative analysis captures some, but not all of these effects. For example, it does not capture the potential premature retirement or exit of existing clean energy resources that are not compensated at the same rate under the Status Quo or Hybrid Approach.[169] In addition, it does not consider the potential for allowance or CEC banking to reduce costs. Further, it does not consider the potential benefits created when demand sees a price signal that internalizes the cost of emissions, thus potentially causing consumers to reduce their energy consumption. We discuss this effect in **Section VI.F**.

2. Quantitative Analysis of Social Costs

Figure VI-14 shows annual social costs for 2021-2040 for the four policy approaches and the Reference Case, while **Figure VI-15** shows annual social costs per MWh over the same period. The quantitative analysis confirms that decarbonization will be costly under any policy approach. With decarbonization, total social costs increase substantially, more than four-fold, over time study period in the policy cases. This increase in costs reflects two effects.

First, **costs increase because of increasing loads over time** due to heating and transportation electrification. Thus, costs increase in part due to the broader, economy-wide decarbonization that increases reliance on the electricity sector. In this regard, it is important to remember that the shift in energy consumption from gasoline and natural gas to electricity results in cost savings, such as reduced fuel costs.[170]

Second, the **average unit cost of energy supply increases** under the policy approaches, as shown **Figure VI-15**. However, per unit energy costs increase less dramatically over time than total energy costs. Costs start at $26/MWh in 2021 and rise to between $71 and $77/MWh in 2040, depending on the policy approach. These costs include all costs associated with supplying wholesale energy, including short-run operating costs and long-run incremental capital costs, but not transmission costs, other than costs to ensure delivery of new resource supplies. The large cost per MWh increases over the study period reflect, in large part, the need to deploy more costly clean energy resources to achieve more stringent decarbonization targets, but also reflect the need to develop new generation capacity to meet the higher loads and resource adequacy needs.

The total costs in **Figure VI-14** or average costs in **Figure VI-15** include all costs needed to supply customers with all energy services, including energy and capacity, as well as the costs associated with carbon reductions achieved by the policy approaches. However, an assessment of the cost of each policy approach should reflect only the incremental costs needed to achieve the incremental reductions in carbon emissions. To estimate these incremental costs, we calculate the difference in total social costs for each policy approach relative to the total social costs of the Reference Case. As discussed earlier, this Reference Case has the same Central Case assumptions as each policy approach except that it does not assume the more stringent carbon target (*i.e.*, 80% below 1990 carbon emissions by 2040). Thus, the differences in costs between each policy approach and the Reference Case reflects the incremental costs of achieving the more stringent carbon

[169] Our analysis does not consider the potential retirement of any clean energy resources. An exception is that certain biomass facilities that could be awarded CECs or would not be subject to carbon prices have the potential to retire.

[170] A full analysis that extends beyond the electricity sector would also consider changes in capital stock, such as vehicles and heating/cooling systems.

target. This difference in costs is illustrated by the area between the Reference case line in **Figure VI-14** and the corresponding cost line for each policy approach.

Figure VI-14. Annual Social Costs by Policy Approach, 2021-2040 ($2020 Million)

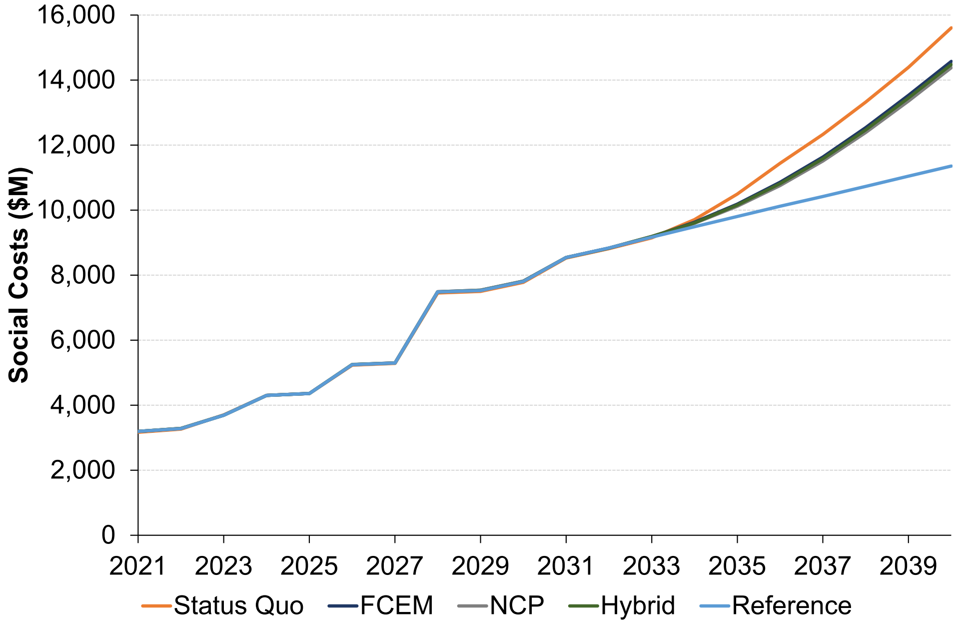


Figure VI-15. Average Social Costs by Policy Approach, 2021-2040 ($2020/MWh)

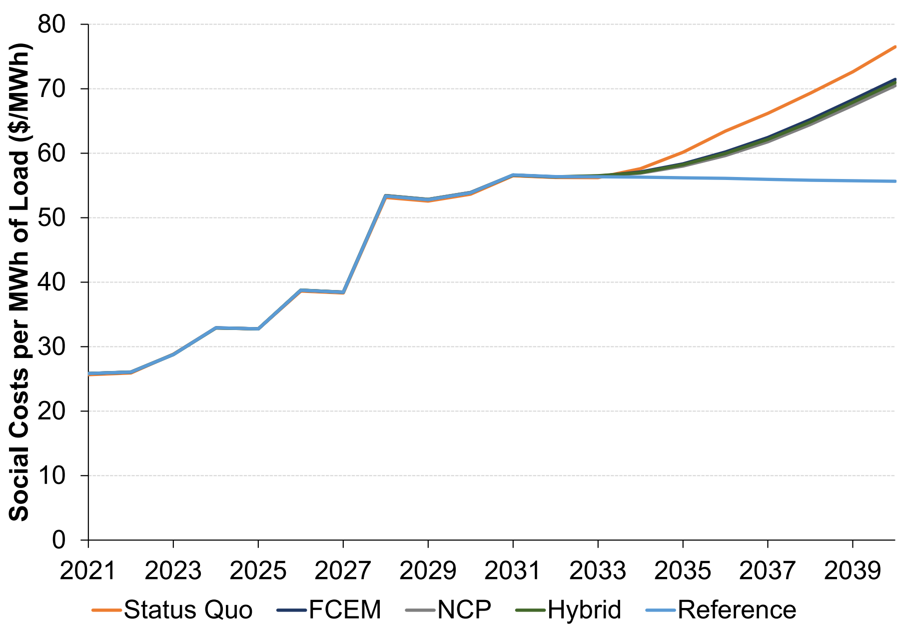


Figure VI-16 shows the incremental costs for each policy approach (relative to the Reference Case), while **Figure VI-17** shows the average incremental cost per MWh. **Table VI-5** shows the total social costs for the year 2040, as well as the present value of costs over the study period, as of the present (*i.e.*, 2021) calculated assuming a 5% discount rate. However, note that most of these incremental costs occur over a decade into the future (*i.e.*, after 2032), after the clean energy procurements associated with the baseline state policies are completed. Thus, while these present value calculations provide a useful metric for comparing incremental social costs of each policy approach across the study period, this delay in incremental costs should be considered when interpreting these present values.

The results show that the choice of policy approach can have important consequences for the total social costs. The Status Quo has the highest costs reflecting, in part, the mix of resources arising from the state roadmaps and studies. At the other extreme, incremental social costs are lowest with Net Carbon Pricing, which are 29% (and $6 per MWh) lower than the Status Quo. The other centralized approaches have higher costs than Net Carbon Pricing, though this difference is less significant than with the Status Quo. The FCEM incremental cost is 24% ($5 per MWh) lower than the Status Quo and the Hybrid Approach incremental cost is 27% ($5.5 per MWh) lower than the Status Quo. As our analysis assumes a single, uniform CEC in both the FCEM and Hybrid approach, designs with multiple CEC products would likely lead to higher costs.

Figure VI-16. Annual Incremental Social Costs by Policy Approach (Relative to the Reference Case), 2021-2040 ($2020 Million)

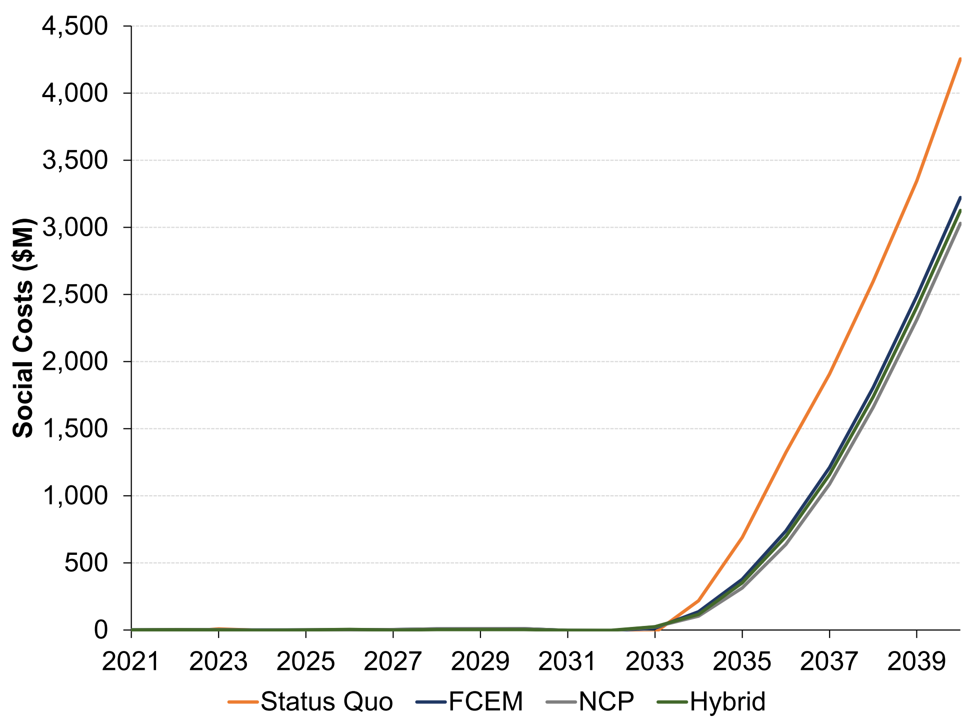


Figure VI-17. Average Incremental Social Costs by Policy Approach (Relative to the Reference Case), 2021-2040 ($2020/MWh)

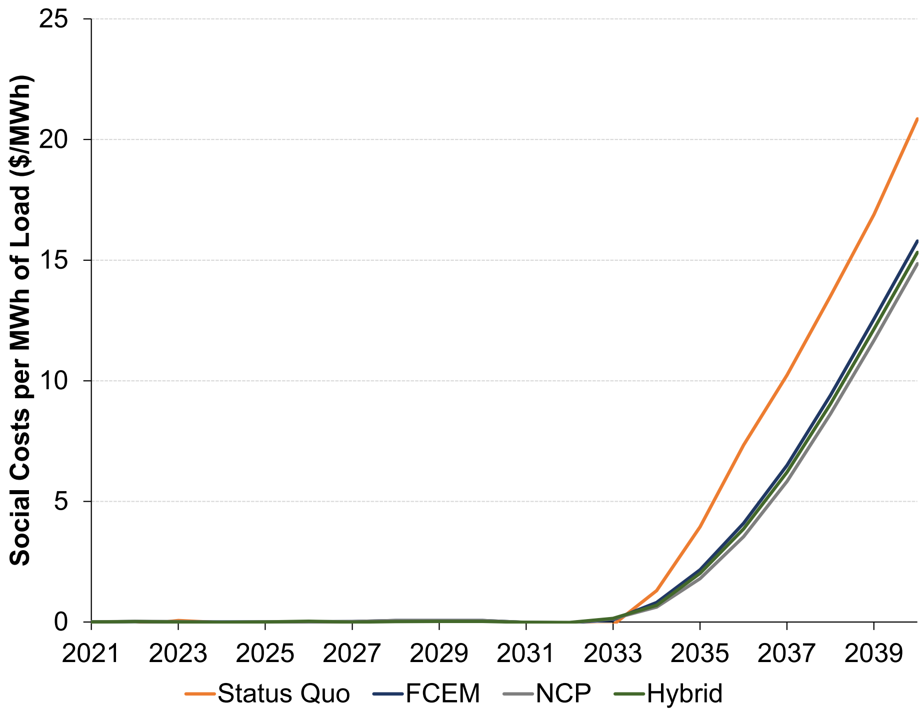


Table VI-5. Incremental Social Costs by Policy Approach, 2040 and Present Value (Relative to the Reference Case)

	2040			2021-2040	
Policy Approach	Incremental Social Cost ($2020 M)	Incremental Social Cost ($2020/MWh)	Percent Change from Status Quo	Present Value of Incremental Social Cost ($2020 M)	Percent Change from Status Quo
Status Quo	4,256	20.86	-	6,027	-
FCEM	3,222	15.79	-24.3%	4,296	-28.7%
NCP	3,031	14.86	-28.8%	3,935	-34.7%
Hybrid	3,126	15.32	-26.5%	4,119	-31.7%

The analysis of the centralized approaches assumes no banking of CECs or banking of emission allowances if Net Carbon Pricing is implemented as a cap-and-trade system. However, banking has been shown to provide important benefits to the performance of market-based policies and is commonly permitted (when environmentally appropriate).[171] Thus, development of either an FCEM or carbon pricing using cap-and-trade

[171] Fell, Harrison, Ian A. MacKenzie, and William A. Pizer. 2012. "Prices versus quantities versus bankable quantities." *Resource and Energy Economics*, 34 (4): pp. 607-623.

should allow CEC or emission allowance banking to take advantage of these benefits. Our analysis shows that banking would likely lower costs by over-complying with CEC and emission caps earlier in the study period when marginal reduction costs are lower, banking extra CEC credits or emission allowances (created by overcompliance), and then using banked credits to meet emission caps later in the study period, when the marginal reduction costs are higher. These marginal costs are captured by the carbon and CEC prices estimated by the model (*see* **Figure VI-19** and **Figure VI-20)**. Both carbon and CEC prices rise steeply once the environmental policy target is binding, indicating costs of achieving an aggregate emission target across the study period could be reduced by increasing emission reductions or clean energy earlier in the study period, and decreasing emission reductions or clean energy later in the period.[172] We do not quantify the potential cost savings from banking, but note that it suggests that our analysis may overestimate the true costs of these policies.

By contrast, the Status Quo approach does not include a banking mechanism that can provide price signals to shift the timing of emission reductions or clean energy generation to lower costs. In principle, administrators could perform analysis to determine the expected trajectory of marginal costs and adjust procurement timing to lower total social costs. However, such an analysis would be speculative and subject to substantial uncertainty. By contrast, with allowance or CEC banking, these adjustments occur automatically reflecting market expectations and, with fixed carbon prices (adjusted annually to reflect the cost of capital), the price signal incents investment in clean energy when it is most cost effective. Moreover, such forecasting under the Status Quo would not have the benefit of the forward price signals created by financial derivatives for emission allowances and CECs (*e.g.*, futures). Price discovery for such financial products aggregate the market's collective information about the future value of underlying commodities (in this case, emission allowances and CECs) to provide an estimate of future prices. However, under the Status Quo, there is no centralized market product that could support such financial products.

These estimates of total social cost are not intended as a forecast of the likely outcome of the continuation of state policies. As we discuss above, for the Status Quo, there is substantial uncertainty about the resources — and the resulting social costs — that would be developed through the administrative procurements implemented by states under the Status Quo, given uncertainty about the effectiveness of states in implementing procurements, approaches for addressing multi-attribute offers, selection criteria, including locational and technology preferences, and bidder behavior. Instead, we use the resource mix assumed in the Status Quo to reflect one potential outcome of such a process. As such, it provides an indication of potential impacts associated with an administrative process that leads to resource outcomes that differ from the more cost-effective use of capital. While actual outcomes of the administrative procurement process could result in social costs that are higher or lower than those in our analysis, we would nonetheless expect the resulting

[172] In principle, with banking, allowance or CEC prices will grow at market participant's weighted average cost of capital, which reflects the opportunity cost of shifting cost from one year to the next. In our analysis, carbon and CEC prices increase at an average annual rate of 29% and 53%, respectively, which far exceeds the cost of capital and implies that banking would lower social costs.

costs of this process to exceed the social costs achieving decarbonization targets from the centralized, market-based policy approaches.

E. Economic Impacts

Total customer payments for wholesale energy include payments for energy, capacity and environmental attributes. Across the policy approaches in our study, the levels of payments in each category differ — thus, comparisons based on only one category may lead to misleading conclusions. Moreover, in some cases, it is infeasible to unbundle payments into each category. For example, the PPAs relied on in the Status Quo bundle energy and environmental attributes into the PPA price, thus confounding the assignment of the payments to each category.

Similarly, within competitive wholesale markets, market prices provide incentives for efficient investment of capital in new facilities and maintenance of existing facilities, and the efficient, least-cost production of energy supply to meet customer loads. Because such decisions account for multiple forms of compensation in multiple ISO-NE markets (and potentially compensation through other arrangements), evaluation of incentives for development must consider all sources of compensation and not examine individual prices in isolation, which could lead to incorrect conclusions. In this section, we first discuss prices and then discuss total payments.

1. Prices

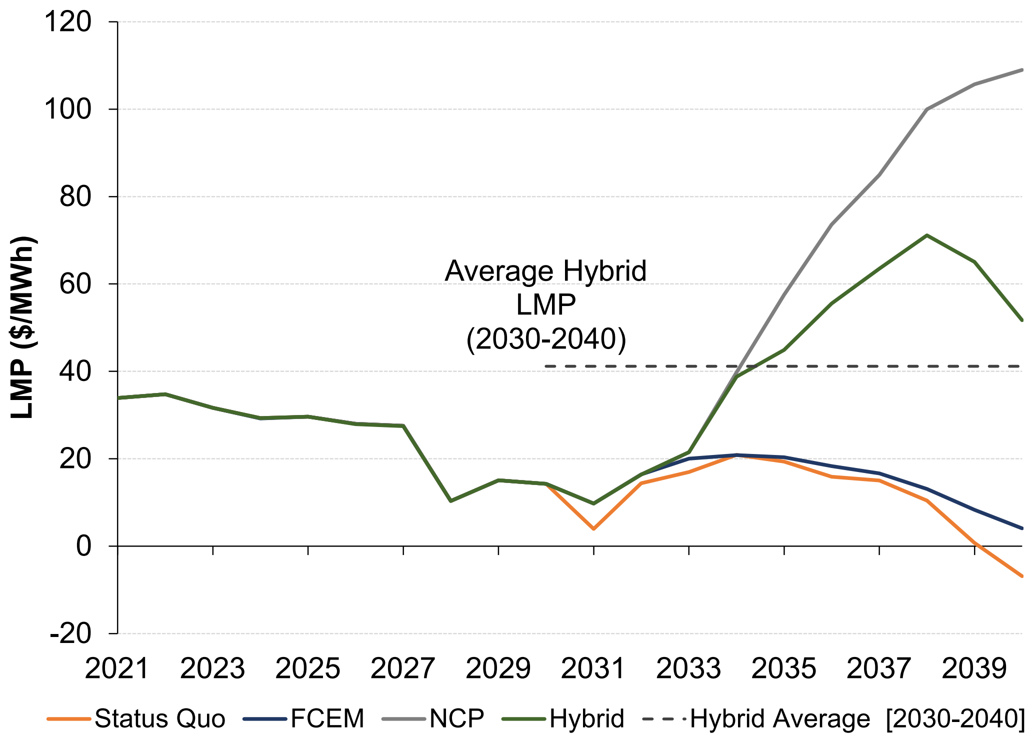
LMPs differ dramatically under the four policy approaches. **Figure VI-18** shows annual average LMPs under each policy approach.[173] Under Net Carbon Pricing, average LMPs increase to over $100/MWh in 2040 due to the addition of carbon prices. By contrast, under the Status Quo, average LMPs *decline* over time, and eventually become *negative* in 2040. These price declines occur because the energy market increasingly clears at variable renewable resource offers that are negative because of the incentives offered to deliver clean energy. By 2040, nearly one-third of hours experience negative pricing under the Status Quo. The Hybrid Approach leads to LMPs intermediate to the other approaches. The observed inter-annual pattern of LMPs for the Hybrid Approach reflects the particular combination of carbon prices and new CEC quantities estimated as least-cost to exactly meet annual emission targets. In practice, implementation of a Hybrid Approach may necessitate a more intuitive pattern of interannual prices (*e.g.*, carbon prices that increase consistently from year-to-year), which would imply a less cost-effective (*i.e.*, higher cost and payment) resource mix than is estimated in our analysis.

Across policy approaches, reliance on the wholesale market varies. In particular, the Status Quo procures an increasing quantity of energy over time through bilateral PPAs. Thus, the LMPs in **Figure VI-18** do not

[173] In 2021, average LMPs are $34/MWh, somewhat higher than current than prices in recent years (*e.g.*, $26 in 2020) driven largely by differences in assumed versus historical natural gas prices. *See* ISO-NE Internal Market Monitor, "2020 Annual Markets Report," June 9, 2021, p. 19, available at https://www.iso-ne.com/static-assets/documents/2021/06/2020-annual-markets-report.pdf.

represent the price paid for energy through these PPAs, making the LMPs in this figure an inaccurate estimate of average energy cost (per MWh).

Figure VI-18. Annual Average LMP by Policy Approach, 2021-2040 ($2020/MWh)



While LMPs differ across approaches, these differences reflect, in part, payments for environmental attributes. **Figure VI-19** shows carbon prices and CEC prices under Net Carbon Pricing, the FCEM and the Hybrid Approach. Carbon prices and CEC prices rise steadily to nearly $300 per metric ton carbon equivalent ("**$MTCO_2e$**") and $100 per MWh in 2040, respectively.[174] At high levels of decarbonization, carbon and CEC prices may rise steeply, as correlated output from weather-dependent renewable generators leads to increasing levels of economic curtailments, thus decreasing the effective supply new variable renewable can generate. With lower delivered energy, LMPs and carbon prices must rise to allow recovery of the fixed cost of capital. With CECs, the direct compensation to clean energy (and the payments by customers) can be directly identified; however, with carbon pricing, there is no direct compensation for clean energy; rather the "compensation" to clean energy (and lower emitting resources) is provided by the higher LMP, which reflects both generator costs (*i.e.*, fuel and operating costs) and the carbon costs from fossil plant. REC prices, for compliance with state RPS, fall to zero in all approaches, because REC supplies created as a result of

[174] The type of resource in each year that is the marginal unit for CECs in the FCEM and Hybrid Approach will be one of the clean energy resources that enters in each year. Resource entry in each year for each policy approach is presented in **Appendix B**.

implementing each policy approach exceed assumed RPS requirements. **Figure VI-20** illustrates the impact of carbon pricing on LMPs, decomposing average LMPs into the average variable costs and average impacts of carbon pricing.

Figure VI-19. Annual Carbon and CEC Prices, 2021-2040 ($2020/MTCO$_2$e and $2020/MWh)

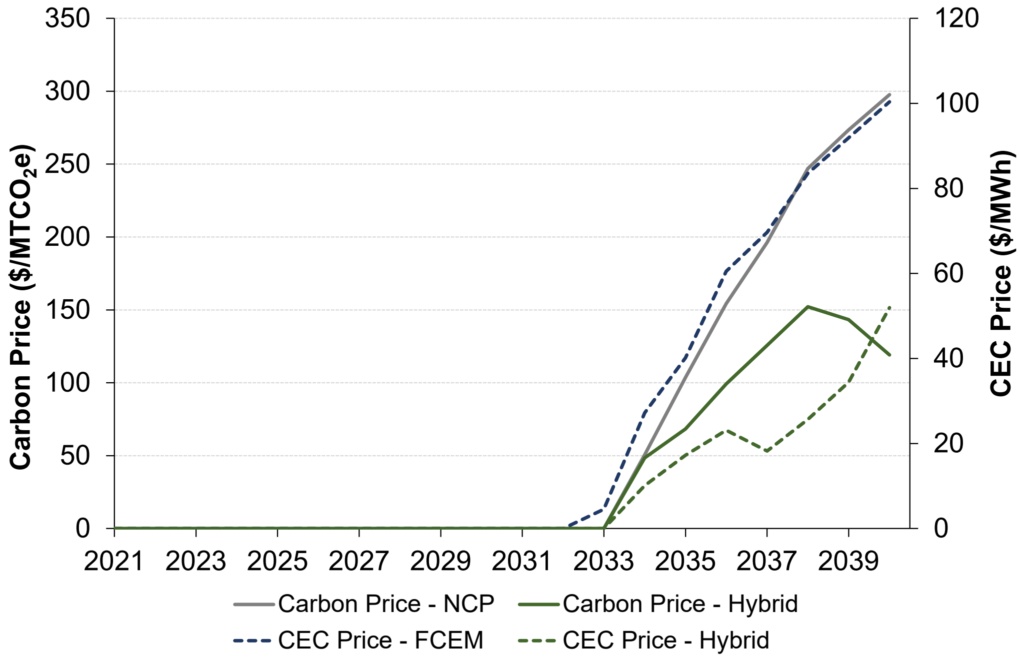
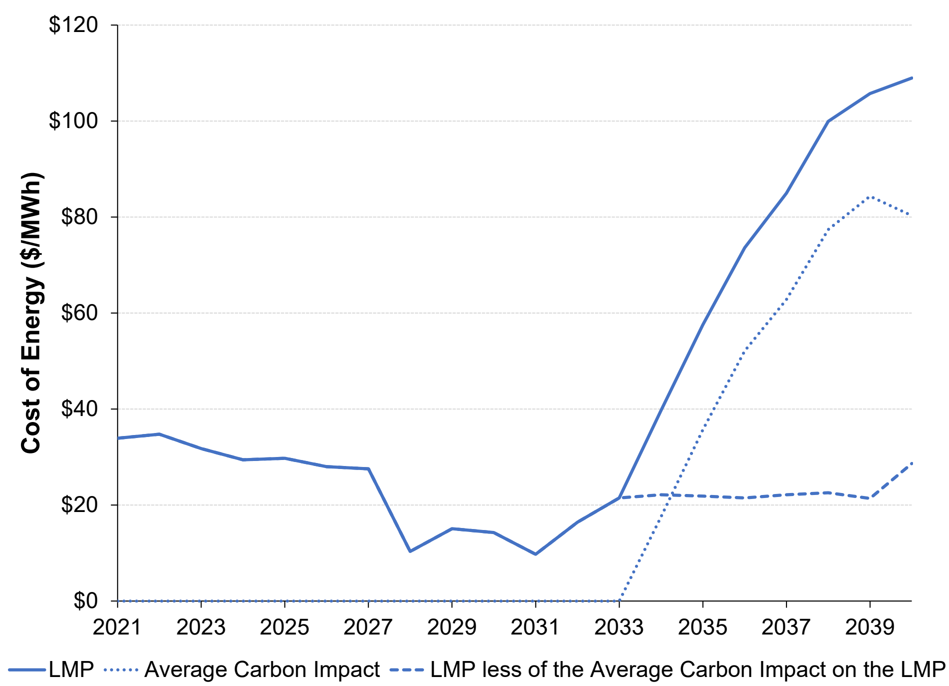


Figure VI-20. Net Carbon Price, 2021-2040 ($2020/MWh)



With the FCEM, CEC awards directly provide an incremental revenue stream to eligible clean energy resources, but not emitting resources, to support their development. By contrast, carbon pricing does not explicitly target particular types of resources for incremental revenues, but instead increases market revenues for all resources, while imposing costs on emitting resources that fully (or partially) reduce any gain from the higher LMPs. Thus, as with the FCEM, most if not all of the increase in market compensation paid by load due to carbon prices goes to clean, rather than emitting, resources.

Figure VI-21 illustrates this point, showing how the increase in payments due to carbon pricing from 2033 to 2040 is distributed across different types of resources in the market, including renewable (solar, onshore wind, offshore wind, biomass, and hydro), storage, nuclear and fossil resources. **Figure VI-22** shows each technology's share of total payments in each year. Initially, in 2033, increase in payments from carbon pricing is less than $1 billion, with 5% of net revenues received by fossil resources. However, by 2040, while carbon pricing increases payments by nearly $9 billion, over 97% of those payments are directed to clean, storage and nuclear resources, and less than 3% to fossil resources.

Figure VI-21. Total Impact of Carbon Pricing on Net Energy Market Revenues by Technology Type ($2020 Billion)

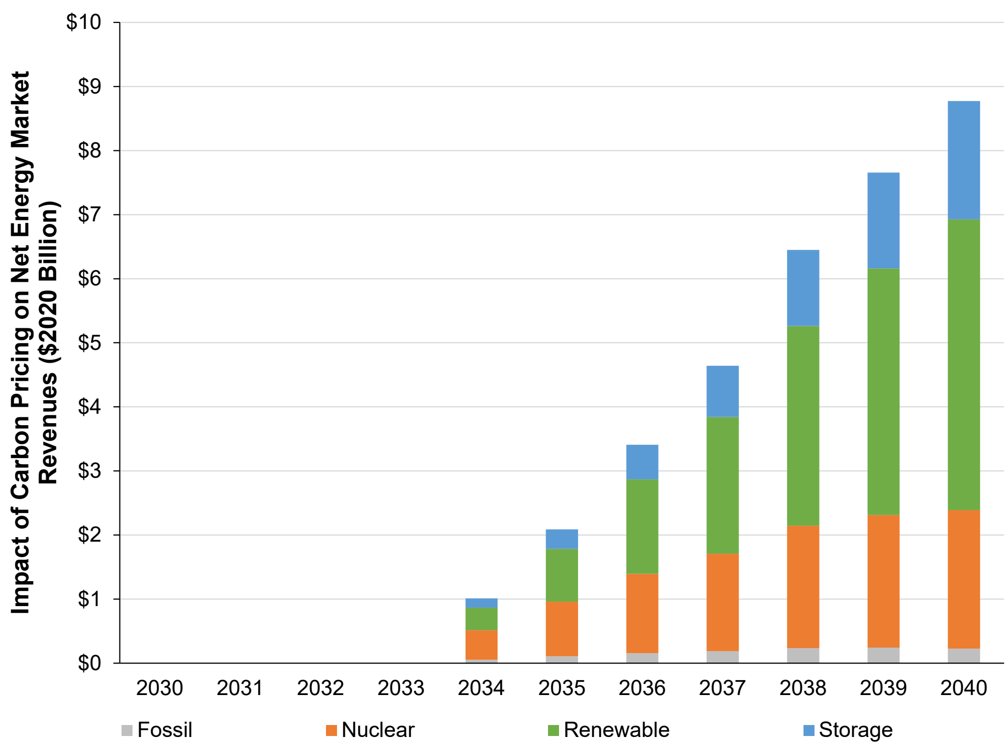


Figure VI-22. Share of Total Impact of Carbon Pricing on Net Energy Market Revenues by Technology Type

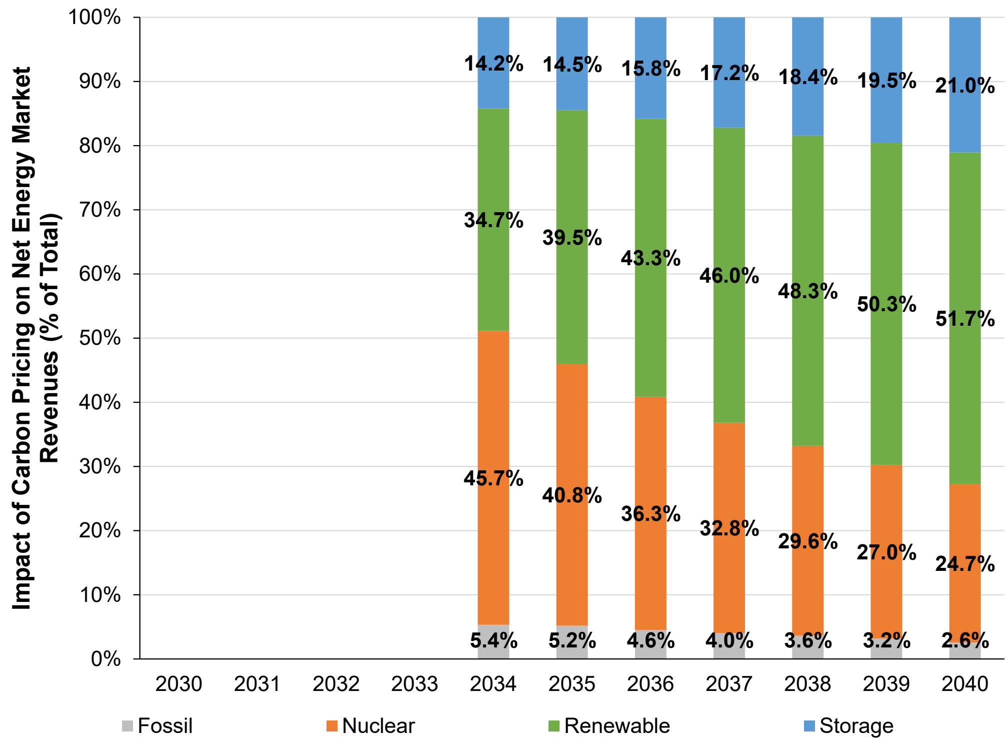


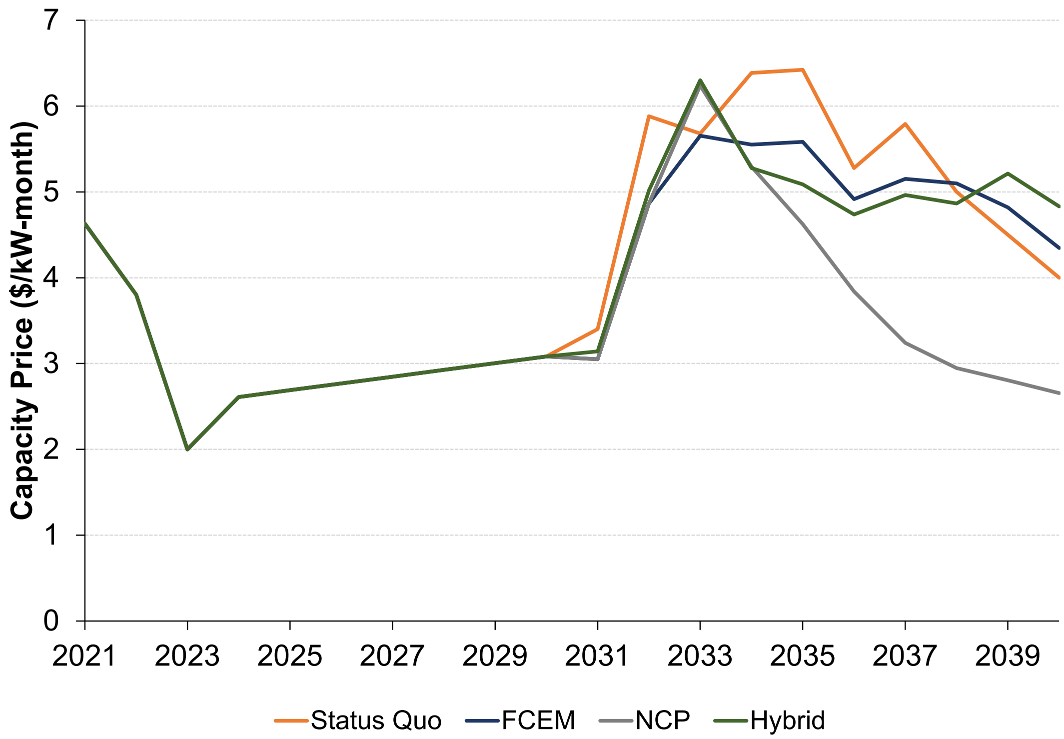
Figure VI-23 shows annual capacity market prices by policy approach from 2021-2040. Capacity market prices reflect the cost of meeting an incremental increase in the resource adequacy objective. In years when new entry is needed for resource adequacy, this cost reflects the incremental cost of capacity in the year of entry and all subsequent years (because the entrant recovers its costs over its economic lifetime).

Prior to 2031, capacity prices are low because the resource adequacy constraint is not binding.[175] Starting in 2031, the resource adequacy constraint binds, requiring the entry of new capacity to maintain resource adequacy. From this time forward, new capacity is required to maintain resource adequacy given the steady increase in peak demand over the study period. Thus, from 2031 forward, capacity prices reflect (but are not exactly equal to) the going forward costs for new entry, including capital costs (amortized to provide recovery over the plant's economic life) less net revenues, including net EAS revenues and other payments (*e.g.*, CEC revenues). In our analysis, given assumptions about technology costs, battery storage resources become the

[175] While the resource adequacy constraint is not binding, existing resources do not retire because they are a cost-effective supply of capacity later in the study period. That is, costs are reduced by keeping existing resources in the market rather than retiring them and later replacing them with new capacity. In years when the resource adequacy constraint is not binding, we assume a capacity price that increases at a constant rate starting from the capacity price in 2024, from FCA 15, to the capacity price estimated by the model in 2031. This assumption is consistent the current FCM's sloped demand curve, which causes prices to clear at positive levels when capacity supply exceeds ICR.

least-cost technology for meeting resource adequacy and thus generally set capacity prices in the latter part of the study. In the Central Case (and in the scenarios, which we discuss in **Section VII**), many factors affect the net cost of new entry for storage resources, such that it hard to identify the specific factors affecting the relative magnitude of capacity prices (from high to low) across policy approaches. Moreover, the rank order of capacity prices across policy approaches (*i.e.*, which approaches have the lowest or highest prices) differs across all scenarios (including the Central Case), suggesting that the choice of policy approach, on its own, cannot necessarily be expected to result in higher or lower capacity prices.

Figure VI-23. Annual Forward Capacity Market Prices by Policy Approach, 2021-2040 ($2020/kW-month)

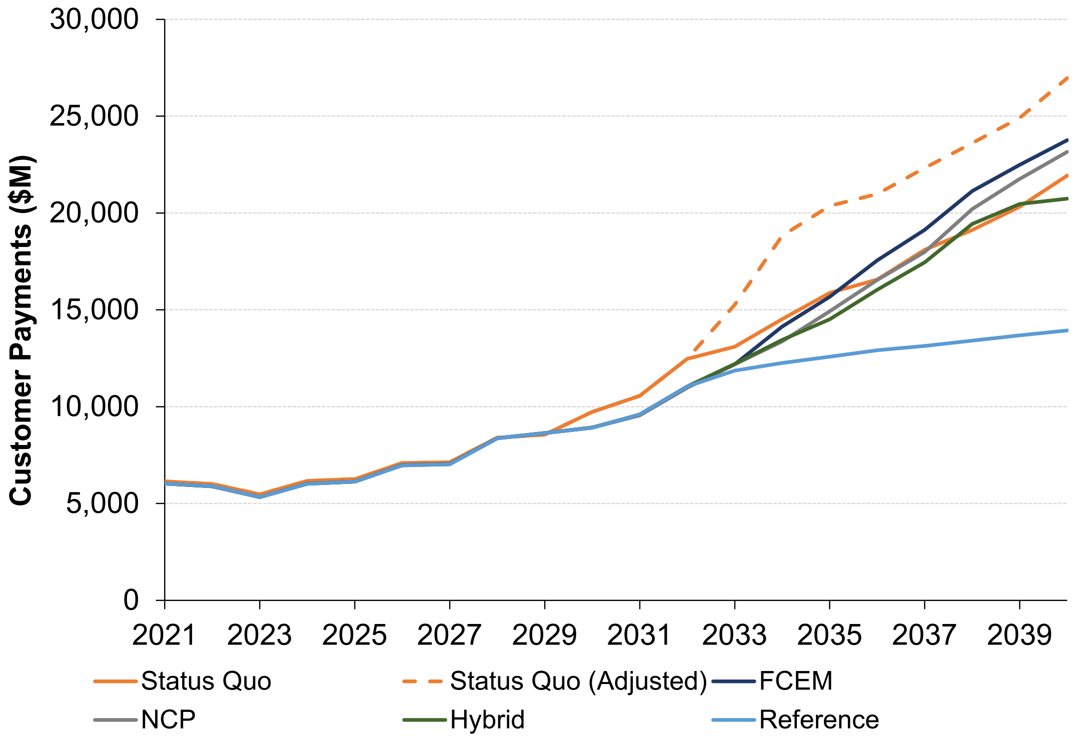


2. *Total Payments*

Total customer payments reflect the payments made by customers for energy services, including energy, reliability and (potentially) environmental attributes. Compared to social costs, customer payments are a less-robust measure of economic outcomes, as they only consider the outcomes to customers (*i.e.*, "consumer surplus"), and do not account for gains and losses to producers (*i.e.*, "producer surplus"). Thus, customer payments fail to account for the true cost to society of providing energy services.

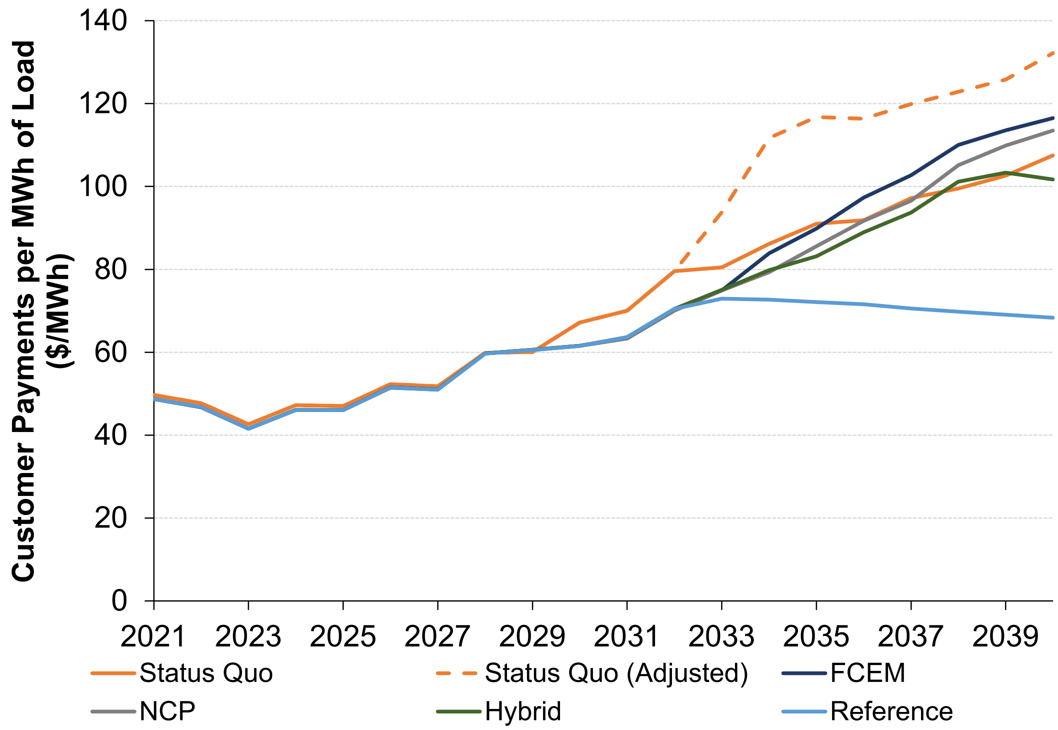
Figure VI-24 shows the total customer payments by policy approach, while **Figure VI-25** shows the average customer payment (per MWh) by policy approach.[176] Total and average payments are increasing over time in the policy approach cases, and flatten in the Reference Case, even declining on a per MWh basis. The increase in total payments reflects, in part, increased heating and transportation electrification, which would lead to other changes in expenditures that are not included in this study, including savings from fuel (gasoline and natural gas) consumption and changes in capital expenditures (on vehicles and heating and cooling systems).

Figure VI-24. Annual Customer Payments by Policy Approach, 2021-2040 ($2020 Million)



[176] Average payments are $49 / MWh in 2021. This is similar to costs in 2020, equal to approximately $49 per MWh, including energy ($26 / MWh) and capacity ($23 / MWh) payments. Our analysis does not consider regional network load costs. *See* ISO-NE Internal Market Monitor, "2020 Annual Markets Report," June 9, 2021, p. 19, available at https://www.iso-ne.com/static-assets/documents/2021/06/2020-annual-markets-report.pdf.

Figure VI-25. Average Customer Payments by Policy Approach, 2021-2040 ($2020/MWh)



As with the social costs, we estimate the incremental payments associated with achieving the incremental emission reductions for each policy approach (relative to the Reference Case). **Figure VI-26** shows the annual incremental payments associated with each policy approach from 2021 to 2040, while **Figure VI-27** shows the average incremental cost over this period. **Table VI-6** provides for each policy approach the incremental payments in 2040 and the present value of cumulative incremental payments over the study period, assuming a 5% discount rate. As with the social costs, note that most of these incremental payments occur over a decade into the future (*i.e.*, after 2032), after the clean energy procurements associated with the baseline state policies are complete. Thus, while these present value calculations provide a useful metric for comparing incremental payments of each policy approach across the study period, this delay in incremental payments should be considered when interpreting these present values, particularly in light of the increase in payments associated with the baseline state policies. **Figure VI-28** breaks down the total payments into categories, by type of payment.

Payments are lowest with the Hybrid Approach, which combines the use of price instrument with price discrimination in payments for environmental services. At the other extreme, the incremental net present value payments under the Status Quo, relative to the Reference Case, are nearly 40% greater than for the Hybrid Approach, reflecting the particular mix of resources developed and differences in in-market incentives.

Figure VI-26. Annual Incremental Customer Payments by Policy Approach (Relative to the Reference Case), 2021-2040 ($2020 Million)

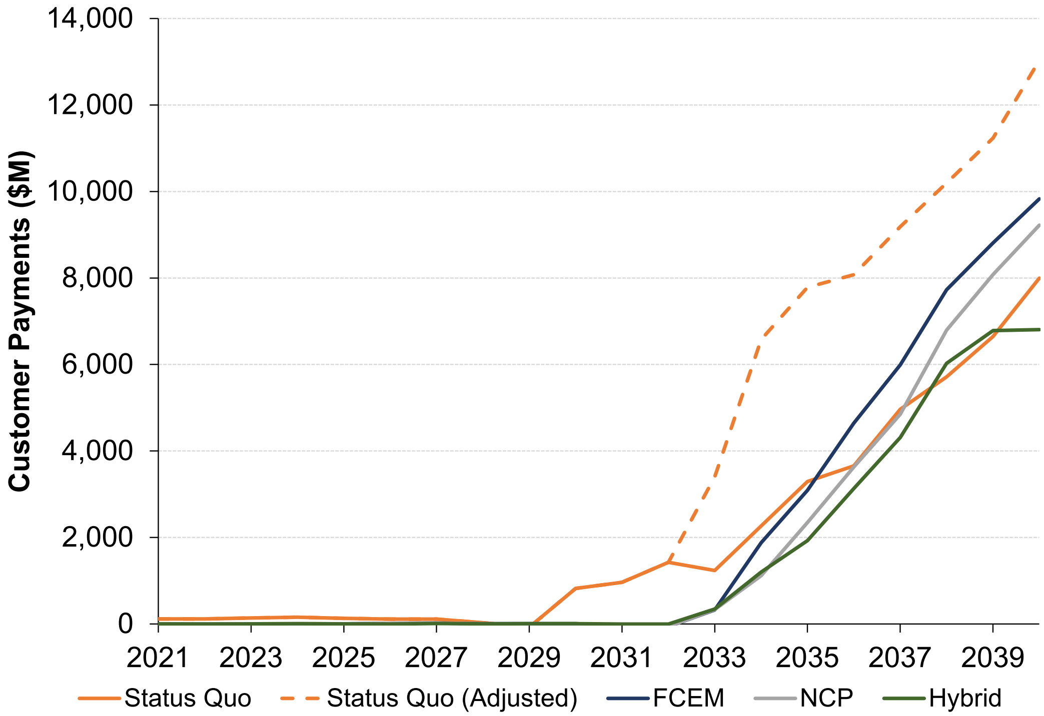


Figure VI-27. Average Incremental Customer Payments by Policy Approach (Relative to the Reference Case), 2021-2040 ($2020/MWh)

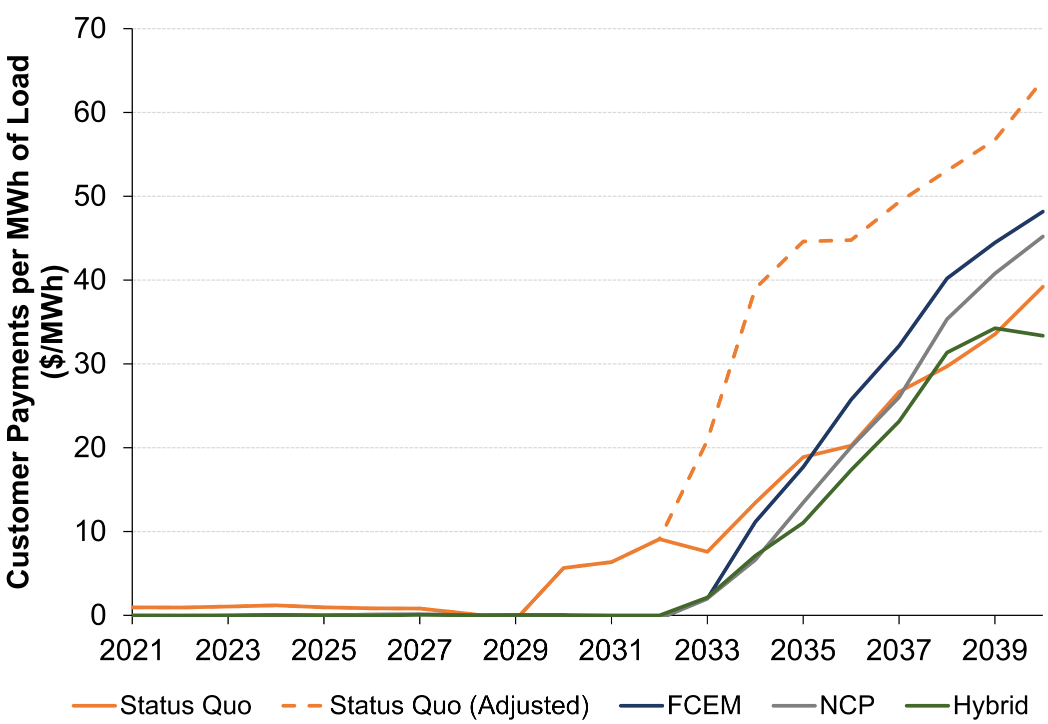
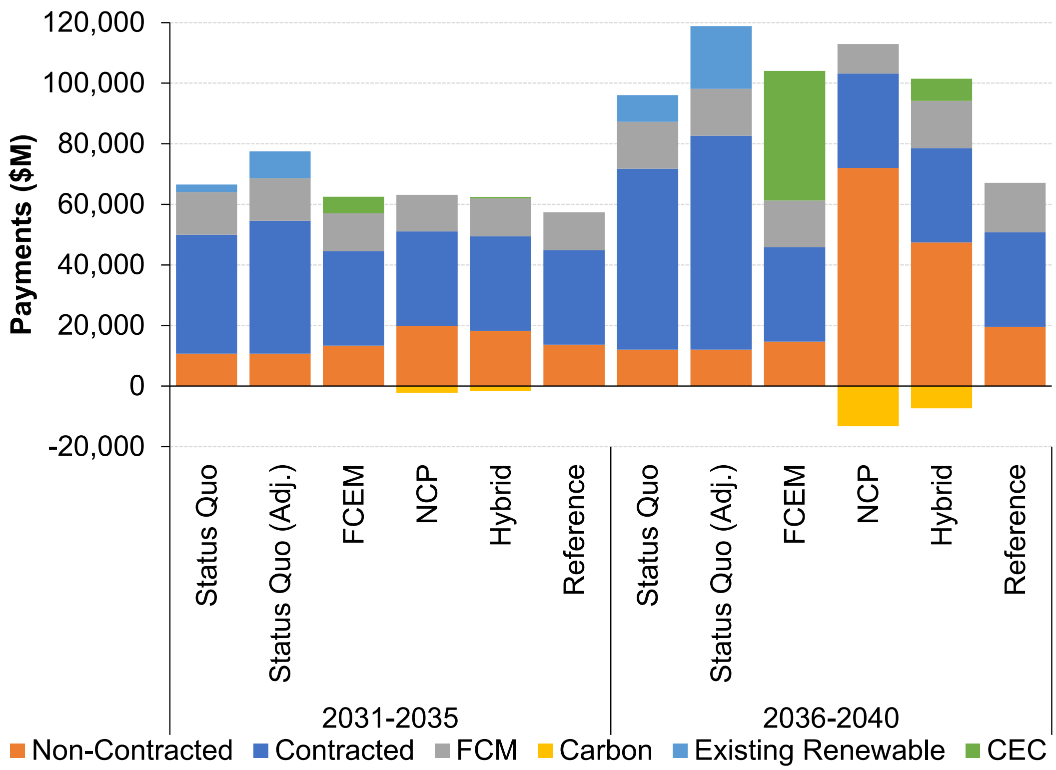


Table VI-6. Incremental Customer Payments by Policy Approach, 2040 and Present Value, 2021-2040 (Relative to the Reference Case)

	2040			2021-2040	
Policy Approach	Incremental Payments ($2020 M)	Incremental Payments ($2020/MWh)	Percent Change from Status Quo	Present Value of Incremental Payments ($2020 M)	Percent Change from Status Quo
Status Quo	7,997	39.20	-	18,692	-
Status Quo (Adjusted)	13,034	63.89	63.0%	34,368	83.9%
FCEM	9,828	48.18	22.9%	18,600	-0.5%
NCP	9,222	45.20	15.3%	15,872	-15.1%
Hybrid	6,806	33.36	-14.9%	13,442	-28.1%

Figure VI-28. Customer Payments by Category, 2031-2040 ($2020 Million)



While prices are all determined by the model for the three centralized approaches, there are certain aspects of the pricing under the Status Quo that are not completely specified by current state policies. In particular, current state policies do not specify a clear approach for whether and how they will compensate existing clean energy resources, including nuclear power plants and existing variable renewables. As we discuss in **Section V**, failure to compensate these resources could lead to retirement or exit of this supply from the system. In the Central Case, we assume that the region's two nuclear plants receive a PPA providing $41/MWh and existing renewables are awarded incremental payments (*e.g.*, through a targeted program) that result in incremental revenues starting at $0/MWh in 2031 and rising to $60/MWh in 2040.

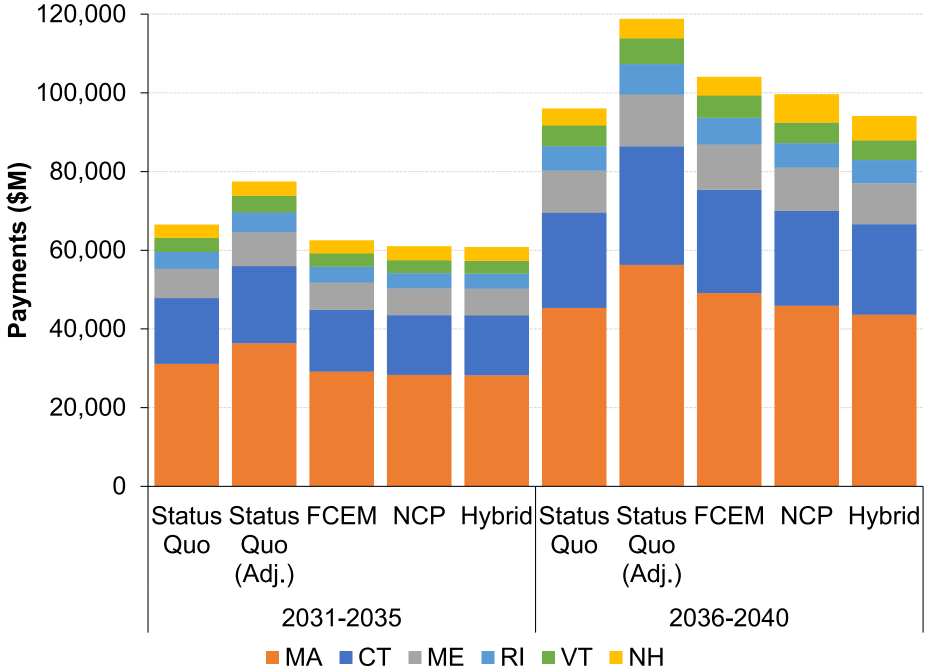
The level of compensation for these existing clean energy resources is an important unknown in evaluating total payments under the Status Quo. The assumptions in the Central Case described above are toward the lower end of the likely level of compensation — nuclear compensation is set at one estimate of their going-forward costs and the compensation for renewables is set at about half the compensation provided to new variable renewable sources. However, these payments could be higher under the Status Quo depending on future market conditions and other considerations. To evaluate the upper range of potential payments, we assume that the existing nuclear facilities and existing renewable resources receive the same level of compensation as new variable renewable resources through PPAs. These assumptions are not intended as either a forecast of future compensation or a reasoned policy proposal, but as a bookend of potential compensation. The "adjusted" line in **Figure VI-24** and **Figure VI-25** shows the result of this assumption — total payments are substantially higher when it is assumed that existing clean energy resources are compensated equally to new clean energy resources.

Providing compensation for existing clean energy resources on par with new clean energy resources results in substantial increases in payments. Compared to the (unadjusted) Status Quo approach, incremental payments are 63% greater in 2040 and 84% greater over the study period (in present value terms). Similarly, with the higher compensation, payments under the Status Quo are even greater when compared to the other centralized policy approaches. For example, in present value terms, this adjusted Status Quo results in incremental payments that are 85%, 116% and 156% greater than the FCEM, Net Carbon Pricing and the Hybrid Approach, respectively.

3. Distribution of Total Payments

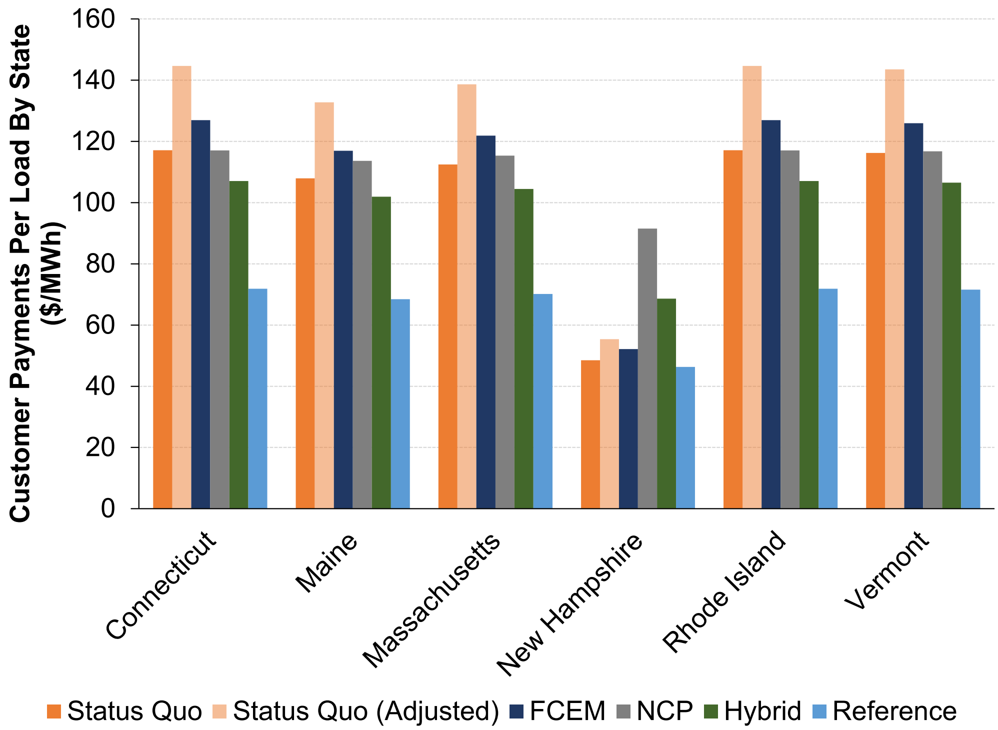
Along with the level of payments, the distribution of payments across the New England states may differ between the policy approaches. This distribution of costs has important implications for state-level economic impacts, particularly as each state's "demand" for decarbonization may differ and the policy approaches may vary in their ability to accommodate such differences. **Figure VI-29** shows total payments by state under each policy approach from 2031-2040, while **Figure VI-30** shows the average payment per MWh by state for each policy approach for 2040. We include the Reference Case in **Figure VI-30** to provide a benchmark for measuring incremental increases in payments by each state. Differences in payments between policy approaches are largely driven by differences in how each approach allocates the costs of achieving decarbonization. In the Status Quo and FCEM, these costs are allocated according to each state's demand for decarbonization, as reflected in statutory requirements and other commitments, which vary from state to state. Our results reflect the state-level allocations shown in **Table IV-3**. By contrast, under Net Carbon Pricing, the increase in payments from higher LMPs (net of credits for generators' carbon costs) are allocated across states based on their energy consumption.

Figure VI-29. Allocation of Total Payments by State and Policy Approach, 2031-2040 ($2020 Million)



Note: The allocation of payments associated with baseline state policies reflect each state's demand for decarbonization, which may differ from the distribution of baseline state procurements, as shown in Figure II-2.

Figure VI-30. Average Payments by State and Policy Approach, 2040 ($2020/MWh)



Note: The allocation of payments associated with baseline state policies reflect each state's demand for decarbonization, which may differ from the distribution of baseline state procurements, as shown in Figure II-2.

As an alternative to the Central Case allocation of decarbonization commitments, we consider a scenario in which the costs associated with carbon commitments are spread equally across the New England states, on the basis of each state's load. This scenario is not intended as a policy proposal, but as a means to illustrate the implications of our assumptions about cost sharing. **Figure VI-31** and **Figure VI-32** show the total change in cost, by state, from load-weighted sharing of costs. Total payments increase to New Hampshire, reflecting the comparatively low demand for clean energy assumed for New Hampshire in the Central Case. By contrast, total payments decrease for all other states, indicating that their assumed demand for clean energy was greater than the region-wide average. The change in payments for Maine, however, are particularly small, indicating that is Central Case commitment was very close to this region-wide average.

Figure VI-31. Change in Total Payments from Alternative Payment Allocation (Proportional to Load) for Each State by Policy Approach, 2031-2040 ($2020 Million)

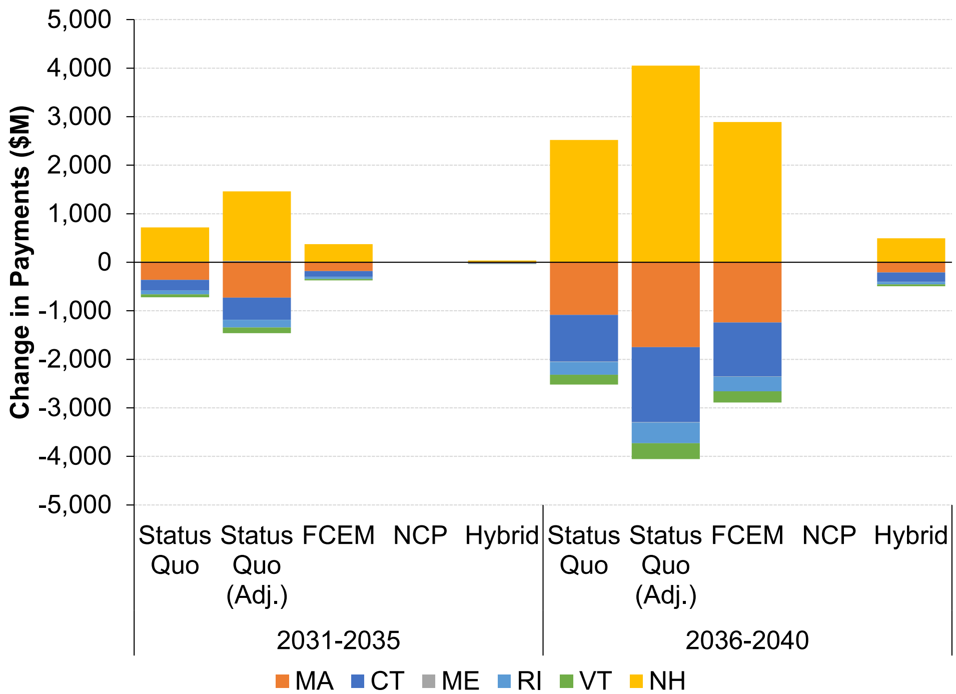
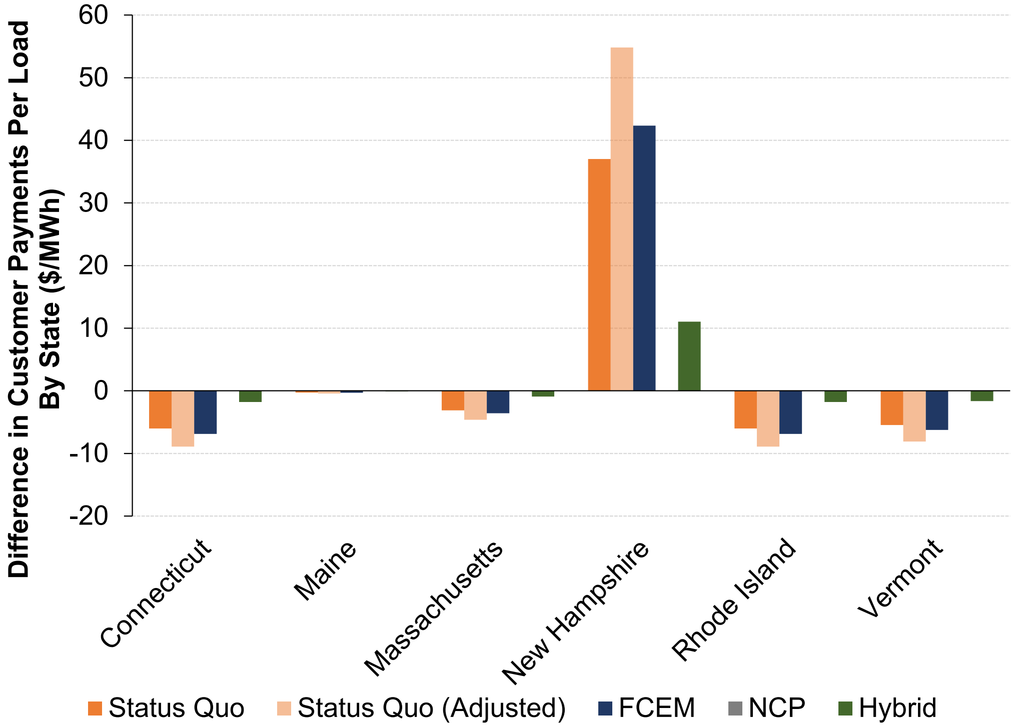


Figure VI-32. Change in Total Payments from Alternative Payment Allocation (Proportional to Load) for Each State by Policy Approach, 2040 ($2020/MWh)



F. Other Environmental, Economic and Market Consequences

1. Consequences for ISO-NE Markets

Decarbonization of the New England grid has many important implications for the ISO-NE markets related to the integration of variable renewable resources and storage resources, operation of the system (and markets) with few dispatchable fossil resources, and maintaining resource adequacy with a diverse mix of variable renewable resources. While the Pathways Study does not generally consider these issues, we note several differences between the policy approaches that have potential consequences for these broader set of issues.

First, the policy approaches differ in the frequency and magnitude of negative LMPs. We point out several potential consequences of negative LMPs, including potentially inefficient "churning" of storage resources (particularly battery resources), as we show in **Section VI.B**, and potential increases in energy uplift, which we describe below. However, there may be other adverse consequences that have not been identified by our work — thus, further research may be warranted.

Second, negative pricing could exacerbate uplift payments (*i.e.*, Net Commitment Period Compensation). Uplift payments are made to ensure that resources are "no worse off" for following system operator dispatch instructions, in effect, making the generator whole for any financial losses incurred over run-intervals. The risk of uplift payments is greatest for plants with larger intertemporal operational constraints (*i.e.*, minimum run times, startup costs, etc.), because these plants may operate over periods of fluctuating LMPs, including periods when LMPs clear below their offers for incremental energy. Negative pricing may increase the frequency and magnitude of uplift payments because they decrease a generator's net revenues over the run-interval (used to calculate NCPC). With negative pricing, a dispatchable generator can earn positive revenues to cover its offers when prices clear at positive levels, but net revenues are *reduced* if LMPs become negative for intervals over the plant's run cycle. By contrast, under Net Carbon Pricing, as with current markets, losses during periods when variable renewables are on the margin would be smaller because of less frequent and lower magnitude negative pricing.[177] Thus, the Status Quo, FCEM and, to a lesser degree, Hybrid Approach, may exacerbate uplift payments, where such outcomes may increase customer payments. Our quantitative analysis currently does not quantify the effect of increased uplift.

Third, the approaches may differ in their consequences for ISO-NE's resource adequacy construct and the viability of the FCM. While the centralized approaches all incent new plant development through market price signals, the Status Quo approach incents new clean energy plant development through procurement of multi-year, fixed price PPA contracts. As we discuss, such contracts would be required for not only variable renewable resources, but also for any dispatchable clean energy units that may develop with emerging technologies. Thus, the FCM would include a growing fraction of resources that do not participate in the market competitively, which has potential consequences for the market's ability to create reliable price signals reflecting the true cost of new entry.

The region is currently considering the potential impact of allowing resources with a multi-year PPA to offer capacity supply obligations without price mitigation on price formation in the FCM.[178] Related, our analysis finds the structure of supply in the FCM could change dramatically from the present market, with little (to no) market entry from traditional gas-fired resources, potentially large competitive entry from battery storage (assuming our cost assumptions are a reasonable representation of actual costs), declining supply from existing fossil resources, and a growing fraction of operable capacity met with clean resources entering the region through non-market mechanisms. Given these conditions, an important question to address is whether the growing fraction of noncompetitive offers from clean energy resources under the Status Quo reduce the likelihood of effective price formation in the FCM. This question is outside the scope of our analysis but may represent an important difference between the policy approaches.

2. Economic Consequences of Multi-year Contracts: Tradeoffs Between Impacts to Project Financing Costs and Utility and Customer Financial Risk

Under the Status Quo, developers of new clean energy resources are awarded multi-year PPAs in which plant output (energy) is sold according to fixed-price schedules (with clawback provisions). By comparison, the

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[177] With carbon pricing, the margins earned by inframarginal plants increase, but so do the startup costs, which would also reflect the cost of carbon.

[178] ISO Newswire, "ISO-NE to file stakeholder-supported plan for MOPR removal, renewable technology exemption," February 4, 2022, available at https://isonewswire.com/2022/02/04/iso-ne-to-file-stakeholder-supported-plan-for-mopr-removal-renewable-technology-exemption/.

centralized policy approaches create forward and spot price signals, thus allowing market participants to enter into contracts at their discretion to hedge financial risks.

This difference in contract structure represents an important difference between the Status Quo and the three centralized policy approaches. The PPAs offered under the Status Quo provide suppliers a means to shift certain market price risks to load and, in principle, supports the financing of variable renewable resource projects. Evaluating the tradeoffs to suppliers and loads from these multi-year PPA's is complex, as the reduction and transfers of risk are difficult to quantity. However, we reach four general conclusions about the use of PPAs in comparison to other market-based approaches that do not include these PPAs as a required element of the policy approach:

- The use of multi-year PPAs would lower the cost of financing new clean energy projects, although the magnitude of this reduction in costs is uncertain, in part due to limited public information about private financings;
- The absence of multi-year PPAs is unlikely to be a barrier to the development of new clean energy projects assuming revenue increases from CECs and/or carbon pricing. Stronger pricing diminishes the need for pricing support from a PPA. While price and volume risk remains, there are ways to help mitigate these financial risks through counter-party arrangements and/or financial products, although financing costs would likely be higher;
- The use of multi-year PPAs results in a countervailing increase in the cost to customers of the New England states, as these PPAs transfer risk from suppliers to customers, although measuring the magnitude of this cost is challenging. This transfer of risk grows as more contracts (representing larger commitments to purchase energy) are signed to incent increases in clean energy. Given the scale and pace of decarbonization contemplated by the region, the aggregate liability (whether on the books of the region's regulated utilities or implicitly held by the region's customers) represented by such commitments (and the associated consequences for creditworthiness) could be large; and
- The use of multi-year PPAs creates a tradeoff between lower costs to suppliers, which in principle may be passed along to customers in the form of lower PPA prices, and an additional cost to customers given the transfer in risk, although available information is insufficient to determine whether the tradeoff would be, on net, beneficial or detrimental to customers.[179]

We address each of these points, in turn.

First, the use of multi-year PPAs would likely lower the cost of financing new clean energy projects. A long-term PPA provides more certain revenues streams, which can reduce the costs of obtaining financing, particularly debt. Debt costs, particularly the non-recourse debt used in project financing, are generally lower with some demonstration of certainty in revenue streams, at least over the initial debt financing periods. Projects without a multi-year PPA have various options to provide greater surety regarding revenue streams. For gas-fired plants developed in systems with competitive capacity markets, such as ISO-NE, NYISO, and

[179] These tradeoffs are distinct from other consequences of reliance on multi-year contracts, particularly the efficient use of capital given differences in cost-effectiveness of incentives and differences in incentives for new and existing resources.

PJM, generators have used various financial hedges, such as revenue puts or heat rate call options to hedge these risks.[180] The market for similar financial products for variable renewable hedges is developing.[181] However, quantitative information on the financial risk mitigation benefits of multi-year PPAs for renewable projects is limited.[182]

Second, financing of clean energy projects would likely be feasible in the absence of a multi-year PPA assuming revenue increases from CECs and/or carbon pricing. Compared to earlier periods, clean energy technologies, such as solar and wind, are now commercially proven technologies. And, with stronger pricing from CECs and/or carbon pricing, the PPA structure would not be needed to supply out-of-market revenues to the extent there is "missing money" for clean energy resources needed to meet environmental targets. However, to provide sufficient certainty about the incremental revenue streams from CEC and/or carbon pricing from a financing perspective, it is important under any centralized policy approach for regulators and legislators to demonstrate credible commitment to policy targets. Moreover, even with these incremental revenues, financial risks remain and will differ from existing merchant projects, which are largely gas-fired resources. With these merchant projects, financial markets have been able to develop products to help hedge financial risks, and, more generally, the financial markets have been able to support many types of investment risks when there is a demand for these services.[183] As noted, products to mitigate renewable project financial risk are developing, and will need to reflect and take advantage of the particular characteristics of renewable projects. While such hedges or tools to mitigate risks may impose costs on developers not incurred with a PPA, they would not be expected to impose an immoveable barrier to project development.

Third, multi-year PPAs would transfer risk from suppliers to customers of regulated utilities or the citizens of states, as a counterparty to these contracts. The financial cost of these contracts is recognized by the financial

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[180] *See*, *e.g.*, Pillsbury Law, "Financial Hedges for United States Gas-Fired Power Generation Facilities," June 5, 2017, available at https://www.pillsburylaw.com/en/news-and-insights/financial-hedges-for-us-gas-fired-power-generation-facilities.html. *See also* Norton Rose Fulbright, "Energy Hedges: What To Look For," November 12, 2015, available at https://www.projectfinance.law/publications/2015/november/energy-hedges-what-to-look-for/.

[181] Bartlett, Jay. 2019. "Reducing Risk in Merchant Wind and Solar Projects through Financial Hedges." Resources for the Future. Working Paper 19-06, available at https://media.rff.org/documents/WP_19-06_Bartlett.pdf. Feldman, David, Mark Bolinger and Paul Schwabe, "Current and Future Costs of Renewable Energy Project Finance Across Technologies," National Renewable Energy Laboratory, Technical Report, NREL/TP-6A20-76881, July 2020. Norton Rose Fulbright, "Financing in an Era of Shorter PPAs," Project Finance NewsWire, August 2019, available at https://www.projectfinance.law/media/5470/pfnw-august-2019-v3.pdf.

[182] In prior work, Analysis Group evaluated the reduction in financial costs associated with a 7-year price-lock in a forward capacity market for gas-fired resources, finding that, compared to a market with a one-year commitment, the 7-year commitment could lower debt costs by approximately 50 to 175 basis points. Hibbard, Paul, Todd Schatzki, Craig Aubuchon and Charles Wu, "NYISO Capacity Market, Evaluation of Options," May 2015, Table 3.

[183] *See, e.g.*, Jay Bartlett, Resources for the Future, "Reducing Risk in Merchant Wind and Solar Projects through Financial Hedges," February 22, 2019, available at https://www.rff.org/publications/working-papers/reducing-risk-merchant-wind-and-solar-projects-through-financial-hedges.

community as "debt equivalency."[184] Debt equivalency recognizes that the legal contractual obligation to execute under a contract imposes a financial obligation, similar to debt. Ratings agencies, such as Standard & Poor's, recognize this cost when performing financial analysis to develop credit ratings for regulated utilities.[185] Thus, a utility that backs multi-year PPAs may be assessed a larger implied debt, which could result in a lower credit rating. If this were to occur, the utility would face higher costs of borrowing, which would increase customer rates.

However, debt equivalency assessed by ratings agencies may not be material if the ratings agency assumes limited risk that a utility's regulators will not allow recovery of contract costs. This does not, however, mean that there is no transfer of risk (and associated financial cost) associated with the PPA, but simply implies a transfer of risk to the regulated utility's customers (who pay the contracts costs in the form of regulated retail rates), rather than to the utility, itself. Thus, whether borne by the utility or the customer, the transfer of risk imposes a cost. One aspect of this risk is technological change in which significantly lower cost alternatives become available during a PPA's term, but the utility or its customers remain contractually obligated to continue buying power under the higher cost PPA. However, measuring the impact of this transfer of risk would be complex and no analyses we are aware of have attempted such quantification.

Fourth, the use of multi-year PPAs creates a tradeoff between the lower costs to suppliers, which in principle may be passed along to customers in the form of lower PPA prices, and higher costs to customers given the transfer in risk as the counterparty to the PPA. While these issues have garnered much attention, we are not aware of any analysis that attempt to quantitatively evaluate this tradeoff from a customer standpoint. We are also unaware of any analysis to evaluate this tradeoff from the standpoint of social costs.

Given these considerations, we use the same financing costs for all policy approaches. Differentiating financing costs for the use of multi-year PPAs would require that a corresponding cost be assigned to customers and/or the utility associated with the transfer of risk. Given the uncertainty and limited information about these adjustments and costs, we do not quantify these effects in our analysis.

3. *Challenges for Policy Implementation*

If the New England region decides to pursue a centralized policy approach, development and implementation would require meaningful effort and time by ISO-NE, NEPOOL Stakeholders and the New England States, including further scoping of the policy design, analysis to ensure proposed designs are feasible, development of implementing rules and regulations, and development of supporting institutional capacity. While the Pathways Study does not evaluate the steps required to implement each policy, we make several observations based on our economic analysis of the approaches.

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[184] California Public Utility Commission, "An Introduction to Debt Equivalency," Planning and Policy Division, August 4, 2017; Vilbert, Michael and Bente Villadsen, "Understanding Debt Imputation Issues," prepared for the Edison Electric Institute, June 2008.

[185] S&P Global, "Key Credit Factors For The Regulated Utilities Industry," November 19, 2013.

An important factor affecting the effort required at this stage is prior experience with a policy approach. There is substantial experience with carbon cap-and-trade, (fixed) carbon pricing and various types of market-based environmental standards (*e.g.*, RPS). This experience would inform and lower the effort required to pursue certain policy approaches, particularly Net Carbon Pricing and certain aspects of the FCEM. However, these experiences nonetheless show that the time and effort required to develop effective policies and systems can be substantial. Thus, meaningful time and effort by ISO-NE, the New England States and NEPOOL Stakeholders would be required if the region were to pursue any of the centralized policy approaches.

However, there is less experience with certain aspects of some of the policy approaches. While there is experience with market-based systems for environmental attributes, such as a CEC, the FCEM would involve certain policy design elements that have not been used previously and would likely require significant time and effort to develop. These, include, but are not limited to:

- Development of model rules to standardize state-level regulations creating demand for CECs, as RPS policies generally rely on compliance requirements from a single jurisdiction and thus do not have to harmonize REC standards across states;
- Defining the manner in which CECs interact with RECs used for compliance with existing RPS;
- Design of a centralized forward market, as RPS and environmental attribute programs have generally relied on bilateral transactions with no centralized auction (let alone a forward centralized auction) to transact forward CEC positions, and
- An ICCM, a novel framework introduced by certain stakeholders that would integrate the FCEM with the existing forward market used to procure capacity – that is, the Forward Capacity Auction.

In some cases the lack of experience and complexity of the proposed design raises questions of policy feasibility. For example, for the ICCM, the complexities involved in the joint forward procurement of CECs and Capacity Supply Obligations raise particularly complex questions with implications for both feasibility and merit from an economic perspective (in light of the tradeoffs between costs of developing such a market and the benefits achieved through more efficient resource procurements).

Much like the ICCM, the Hybrid Approach is a completely novel approach. While there is much experience with carbon pricing and market-based policies like an FCEM (with the caveats noted above), we are unaware of any policy that attempts to combine these policies to obtain a particular outcome in a *different* market — *i.e.*, set the carbon price and CEC targets to achieve a particular energy market LMP level.

Our analysis of the Hybrid Approach indicates that effectively achieving all the desired design elements may be administratively and analytically challenging. The Hybrid Approach differs from any prior market-based environmental policy. While prior market-based policies have used both price-based instruments (*e.g.*, carbon fees) and quantity-based instruments (*e.g.*, cap-and-trade), they have not attempted to combine the two into one integrated policy.[186] More importantly, the Hybrid Approach aims to "tune" the carbon price and CEC quantities to achieve a particular market-clearing LMP.

Our work shows that determining the level of the carbon price and the quantity of the CEC target needed to achieve the desired LMP would be challenging. In part, this challenge reflects the fact that these two adjustments have opposite effects on LMPs. While carbon prices increase LMPs, a more stringent "new" CEC target increases CEC prices, which in turn decreases LMPs. Thus, calibrating the carbon price and CEC quantities to achieve a particular LMP is challenging, as the relationship between these parameters and LMPs is, based on our modeling experience, nonlinear, complex and sensitive. This complexity and sensitivity has many implications.

First, the New England states would need to task an agency or consultant to develop Hybrid Approach policy parameters (*i.e.*, the carbon price and "new" CEC target) which would vary from year to year over the policy horizon. *Second*, the states would need to develop a target LMP, which would require data collection and need to address asymmetric information issues common in utility regulation. *Third,* despite whatever analytic precision is brought to bear, uncertainty in future LMPs would prevail under any choice of parameters, which would create uncertainty for existing clean energy resources regarding future returns.

Thus, there could be a meaningful risk of retirements even if the Hybrid Approach is designed to provide revenue adequacy for existing nuclear plants. Several factors create such risk. *First*, revenue streams expected by plants owners may be below their actual going-forward costs, in spite of the administrator's efforts to ensure adequate cost recovery. This could occur because the administrator underestimates the plant's true going-forward cost or because the plant owner's expectations of future revenues are below those of the administrator. *Second*, expected revenue streams would be more volatile than the revenue streams provided under current arrangements. At present, for example, the recent Connecticut zero-carbon procurement provides the region's two nuclear facilities with PPAs for $50/MWh for (approximately) one-half of their output, thus providing compensation with greater certainty than would occur under the Hybrid Approach.[187] In practice, this price risk would depend on the frequency and magnitude of negative pricing under the Hybrid Approach, which our analysis shows increases assuming high levels of system decarbonization. Thus, plant owners may require a risk premium due to this financial risk.[188]

[186] Many jurisdictions include both price-based and quantity-based policies targeting the same activity.

[187] Zero Carbon Emissions Generation Unit Power Purchase Agreement between the Connecticut Light and Power Company d/b/a Eversource Energy [Buyer] and Dominion Energy Nuclear Connecticut, Inc. [Seller], March 15, 2019, Exhibit B, available at http://www.dpuc.state.ct.us/dockcurr.nsf/8e6fc37a54110e3e852576190052b64d/b5d8d1ec76a368ad852584d6006996b9/$FILE/Dominion%20-%20Millstone%20PPA%20Eversource%20(Executed).pdf.

[188] As New England's nuclear fleet ages, these plants will likely require periodic and significant infusions of capital – *e.g.*, to replace a degrading turbine or steam generator – requiring multiple future years of sufficiently high prices to justify the investment. Thus, the decision to make such investments, or to instead retire the plant, will be based in large part on expected future price streams.

Given these factors, the exercise of specifying the parameters for the Hybrid Approach will not be a question of identifying the carbon prices and CEC quantities that ensure revenue adequacy, but an analysis in which higher carbon prices (and higher expected LMPs) reduces but does not eliminate the possibility that existing clean resource owners opt to retire their facilities, in spite of the intent of the Hybrid Approach. To minimize this risk, the administrator may need to offer a set of parameters that produces expected LMPs well above the resource's going-forward cost.[189]

4. Incentives for Efficient Energy Use

Each policy approach will create different incentives for efficient energy use by customers due to differences in variable electricity prices. As shown in **Figure VI-18**, average LMPs vary substantially across policy approaches. There are large differences in annual wholesale electricity prices by policy approach, with Net Carbon Pricing resulting in the largest average prices ($109/MWh in 2040) and the Status Quo resulting in the lowest average prices (-$7/MWh in 2040). In theory, policy approaches with higher wholesale prices will lead to lower levels of electricity consumption and associated emissions if end-users decrease their consumption in response to higher variable prices.[190] This reduced consumption is another potential source of emissions reductions that can vary across policy approaches. For example, Net Carbon Pricing would encourage reduced electricity consumption due to the high wholesale prices, while the Status Quo policy approach could actually encourage increased electricity consumption, due to negative wholesale prices.[191]

However, in practice, differences in electricity usage arising from each policy approach may be relatively modest. Retail electricity rates bundle generation, transmission and distribution components into an average rate, with fixed and variable components.[192] The relationship between this variable component and the LMPs in **Figure VI-18,** however, is very tenuous, and certainly does not reflect time-varying LMPs in the ISO-NE markets. Thus, under current retail ratemaking practices, retail consumers never observe the price signal represented in **Figure VI-18***.* Rather, as shown in **Figure VI-24**, total customer payments for wholesale energy

[189] For example, assume an administrator's analysis shows that a given combination of carbon price and "new" CEC target will produce LMPs of $41/MWh, the clean resource's true going forward cost. If the resource owner's assessment of the market is more pessimistic, $10/MWh lower than the administrator's, leading to an expectation that the actual LMP will be $31/MWh, then it will retire (or exit) when faced with the policy incentives, because he/she believes the market will provide insufficient revenues. Given this risk, the administrator may need to account for a "band of uncertainty" around its estimate by setting parameters that produce much higher expected LMPs, for example, at $51/MWh.

[190] Under classic economic theory, "efficient energy use" refers to the level of energy consumption resulting when consumers face the full social costs of electricity consumption. Pricing designed to include both the private costs of consumption and any external costs of consumption is typically referred to as "Pigouvian pricing." *See* Banzhaf, H. Spencer, "A History of Pricing Pollution (Or, Why Pigouvian Taxes are not Necessarily Pigouvian)," 2020, NBER Working Paper No. 27683, available at https://www.nber.org/papers/w27683.

[191] The impact on emissions would depend on the marginal emission rates corresponding to periods with high and lower LMPs, and the nature of the energy substitutions that consumers make (*e.g.*, are they reducing absolute use, or shifting use from one time period to another).

[192] ISO New England Inc., "Wholesale vs. Retail Electricity Costs," accessed on April 6, 2022, available at https://www.iso-ne.com/about/what-we-do/in-depth/wholesale-vs-retail-electricity-costs.

are relatively similar across policy approaches. This suggests that average retail electricity rates will be similar across policy approaches, thus leading to no real change in incentives for many (or even most) consumers under the different policy approaches.[193]

Of course, retail rate structures and customer interest in time-varying rates along with the influx of new technologies that can moderate consumption in response to time-varying rates (*e.g.*, managed EV charging) may evolve over time with greater decarbonization, particularly if LMP spreads increase, which occurs under all policy approaches. Larger price spreads would create opportunities for greater savings from shifting the timing of energy use, even if there is no reduction in total energy use. Thus, in principle, new rates structures and demand-side technologies to take advantage of expanded wholesale LMP spreads could represent another "technology" that could reduce the frequency of negative pricing and shift load to periods with negative pricing, similar to the operations of storage resources.

VII.Scenarios

We evaluate six scenarios, described in **Section IV.C.**, to test the sensitivity of certain Central Case assumptions. Specifically, we consider five scenarios that alter a key modeling input assumption: (1) an alternative regional decarbonization target of 85% below 1990 levels, as opposed to 80% below 1990 levels, (2) an alternative source for the capital costs of new entry, using NREL ATB as opposed to EIA AEO, (3) a scenario that assumes retirements beyond the resulting retirements from the Central Case, (4) a scenario that imposes simple transmission constraints, and (5) a scenario specific to the hybrid case with higher carbon prices and a lower quantity of CEC demand such that LMPs are 25% higher than the central case. The sixth scenario does not require altering key modeling input assumptions, but rather considers an analysis of alternative customer payment distributions which are discussed in **Section VI.E**.

In general, the qualitative conclusions we draw in **Section VI** about the differences in the policy approaches for resource, market and economic outcomes in the Central Case do not change materially in any of the Scenarios.

A. Resource Investment and Operation

System changes in each scenario reflect adjustments to a more stringent carbon target, lower costs (with varying relative costs across technologies), more retirements, transmission congestion, and an alternative LMP

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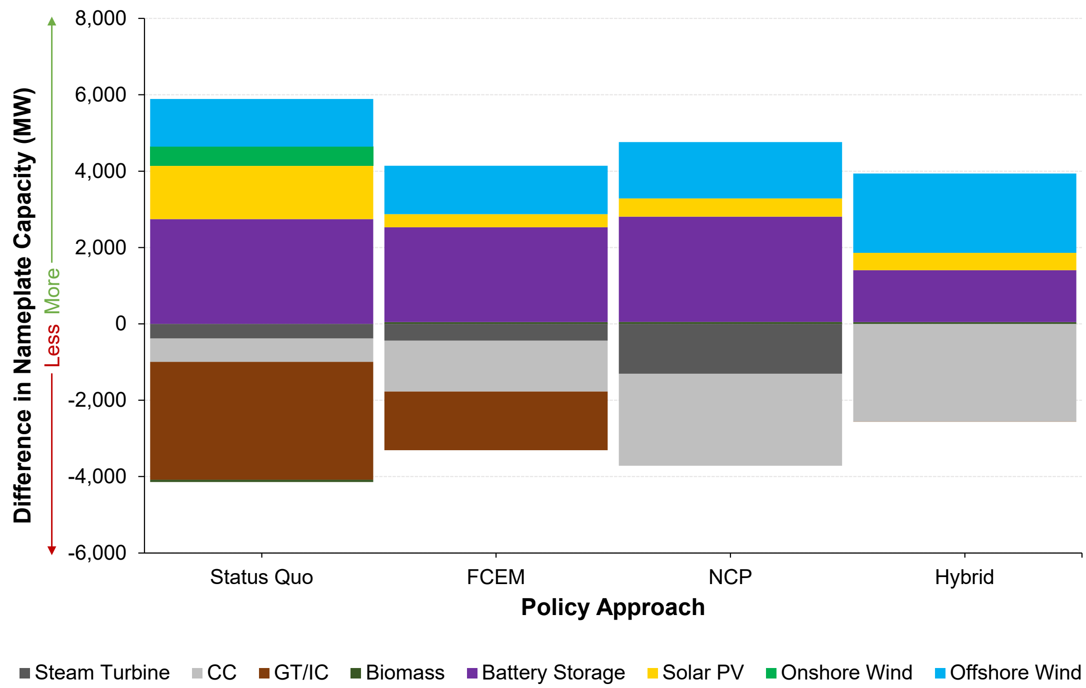
[193] Moreover, economic research suggests that many customers' consumption is relatively unresponsive to price (*i.e.*, their consumption is inelastic). *See*, Ito, Koichiro, "Do Consumers Respond to Marginal or Average Price? Evidence from Nonlinear Electricity Pricing," 2014, *American Economic Review*, 104(2): 537-63. Larger customers (*e.g.*, industrial customers) may be responsive to changes in volumetric electricity prices, although industrial demand in New England is limited. However, empirical research shows that households and smaller consumers are relatively insensitive to changes in volumetric rates. For example, Ito (2014) finds that consumers in California respond to changes in average electricity rates rather than non-linear increases in volumetric rates over a four-month period. In our setting, if consumers respond to changes in average retail rates rather than volumetric rates, energy consumption will be similar across policy approaches.

target in the Hybrid Approach. These scenarios lead to changes in resource, market and economic outcomes that are consistent with expectations. Below, we provide a brief overview of these changes, with selected figures, and provide additional results in **Appendix B**.

- **Decarbonization target of 85% below 1990 levels**. A more stringent decarbonization target results in an increase in clean energy and battery storage to achieve the lower emission target, increases in environmental (carbon and CEC) prices, and increases in social costs and total payments.

  For example, **Figure VII-1** shows the change in nameplate capacity for the higher decarbonization scenario relative to the Central Case. In all cases for this scenario, fossil-fired generation capacity is reduced, while variable renewable and battery storage capacity increases. The reductions in the capacity of fossil-fired resources reflects additional retirements and reduced new entry compared to the Central Case. The increase in battery storage reflects the continued need to maintain resource adequacy, while also meeting the decarbonization target, which can be met by moving greater quantities of renewable energy from periods with surplus renewable generation to peak load periods when renewable generation is scarce.

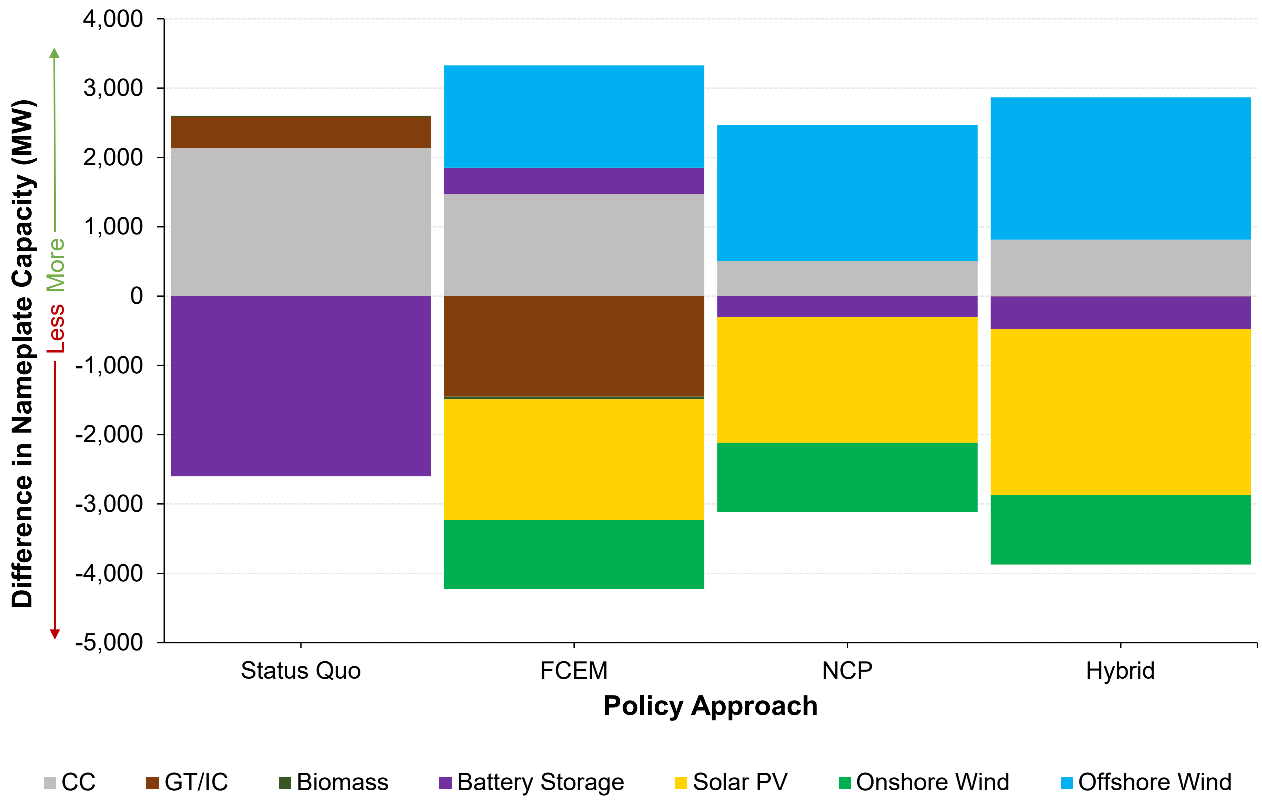
Figure VII-1. Difference in Resource Mix by Policy Approach for Alternative Regional Decarbonization Target Scenario Compared to Central Case, 2040 (MW)



- **Alternative Capital Costs**. The future costs of alternative generation are uncertain, particularly for clean energy technologies that continue to undergo technological changes that can lower costs and improve operating efficiencies. The NREL costs in the alternative capital cost scenario assume different relative costs among technologies and somewhat lower cost levels across technologies (**Table IV-5**). As a result, assuming these alternative costs results in a shift in the resource mix.

Figure VII-2 shows the change in nameplate capacity for the alternative capital cost scenario relative to the Central Case. For all of the centralized policy approaches, there is a shift in the mix of variable renewable resources, with increased offshore wind capacity and decreased solar and onshore wind capacity. The amount of fossil (gas-fired) capacity increases in each scenario, with combined cycle favored over combustion turbines. While gas-fired capacity increases, this comes at the expense of battery storage or combustion turbines. These changes reflect, for the most part, changes in the relative capital cost across technologies. For example, more combined cycle capacity is developed than in the Central Case, because under the alternative assumptions its capital costs are lower (in relative terms) than combustion turbines and battery storage.

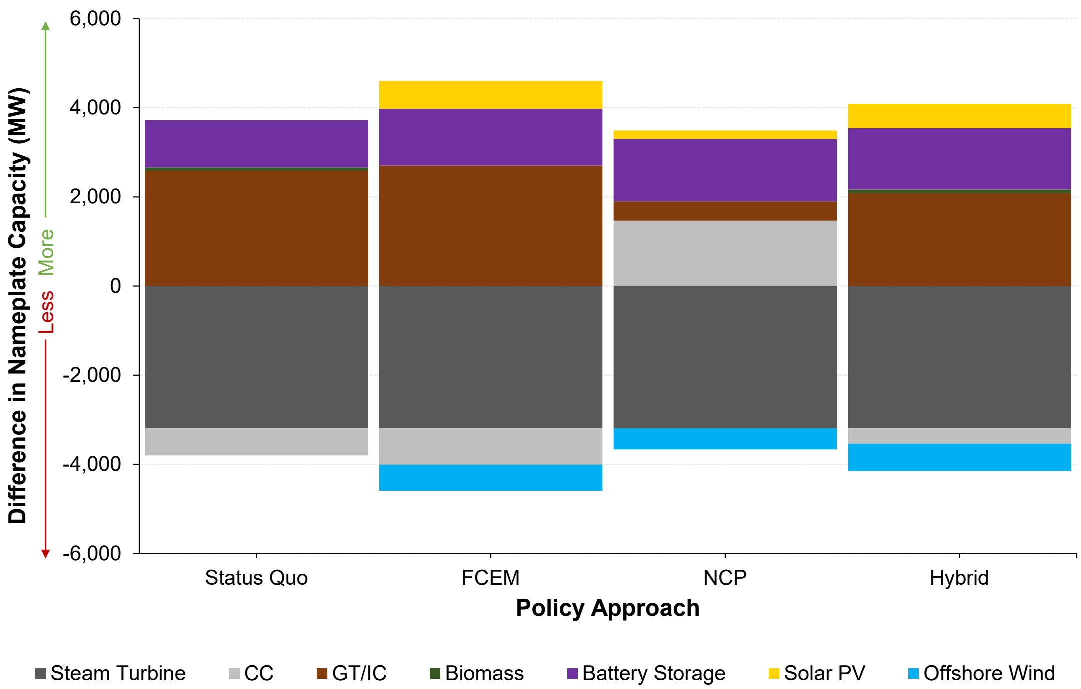
Figure VII-2. Difference in Resource Mix by Policy Approach for Alternative Capital Cost Scenario Compared to Central Case, 2040 (MW)



- **Additional Retirements**. Forcing the retirement of a larger quantity of fossil resource capacity require additional resources to enter the market to provide resource adequacy. **Figure VII-3** shows the increase in retirements and the new capacity developed to replace the retiring capacity. The retiring capacity is replaced by different mixes of gas-fired generation, largely combustion turbines, and smaller quantities of battery storage. These capacity changes lead to slightly lower environmental prices, because the more-efficient, lower-emission capacity enters the market in place of the less-efficient, higher-emission capacity that was retired. Our model had determined in the Central Case that it was least cost to keep these resources operational rather than retire them, so social costs increase when the retirements are assumed for all of the policy approaches, although the increase is not large.

In this scenario, differences in the incentives created by each policy approach are evident in the mix of resources replacing the retired resources. In particular, Net Carbon Pricing results in greater quantities of more-efficient, lower-emission combined cycle capacity, while the quantity of combined cycle capacity decreases in the Status Quo, FCEM, and, to a lesser extent, the Hybrid Approach, which lack the same incentive for reduced carbon-intensity amongst carbon-emitting resources. Less-efficient, higher emitting gas turbine capacity is installed under the Status Quo, FCEM, and to a lesser extent, the Hybrid Approach to replace this combined cycle capacity in order to maintain resource adequacy. There is a slight decrease in offshore wind capacity and an increase in solar PV capacity with the FCEM, Net Carbon Pricing, and Hybrid Approach. These changes occur because retiring the higher-emission units for lower-emission units reduces the quantity of clean energy needed to achieve decarbonization targets.

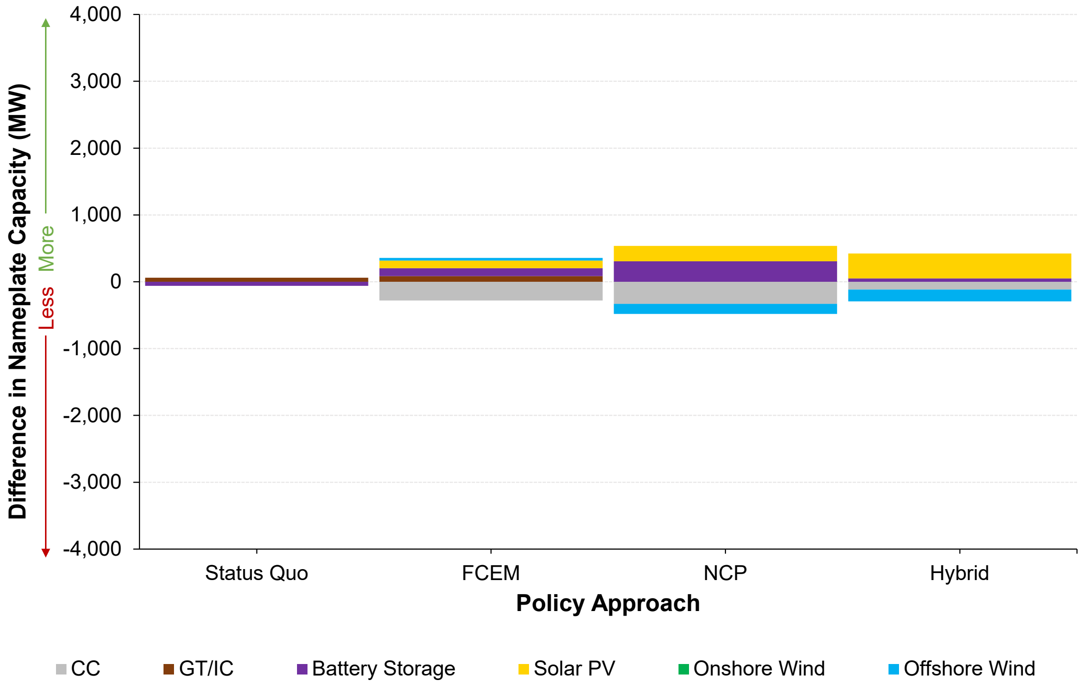
Figure VII-3. Difference in Resource Mix by Policy Approach for Additional Retirements Scenario Compared to Central Case, 2040 (MW)



- **Transmission**. Enforcing a set of simplified transmission constraints in the model affects the resource mix by shifting to renewable resources with more siting flexibility (*e.g.*, solar PV), which are favored compared to resources that have less flexibility (*e.g.*, offshore wind).

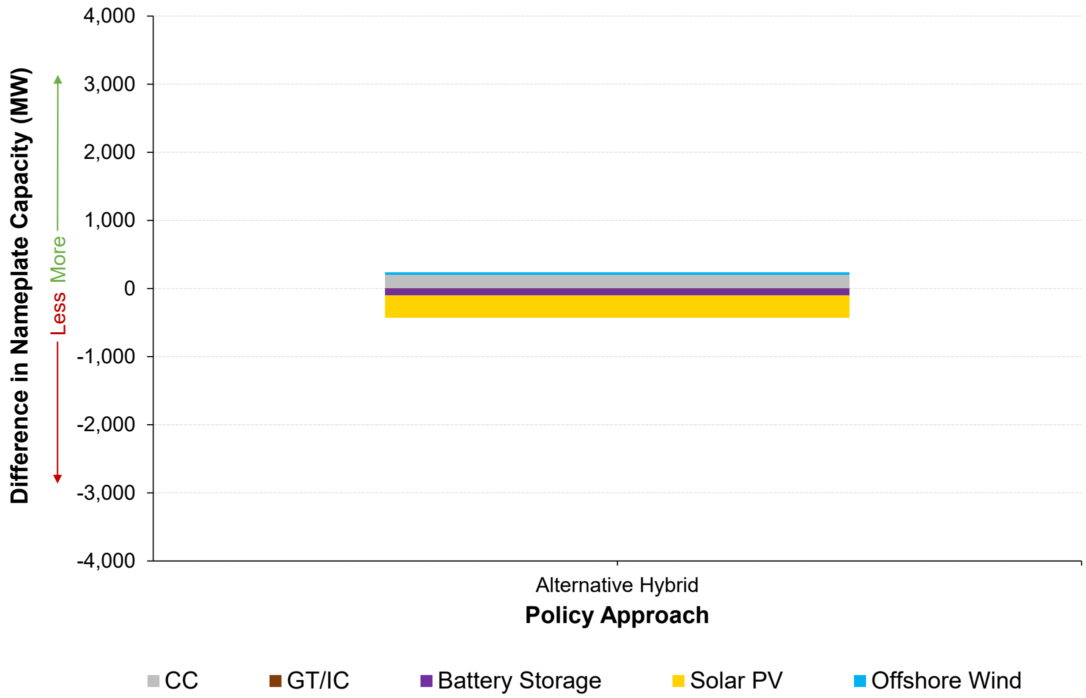
However, compared to the Central Case, the change in the resource mix for the Transmission scenario is modest, with no more than 1,000 MW of total change in nameplate capacity for each policy approach (**Figure VII-4**). Our analysis finds that 6% to 33% of hours in 2040 experience congestion coming out of RI and SEMA into the rest of the system across policy approaches. Because most of the offshore wind interconnects to those two regions, this congestion causes some substitution with solar PV, which can be placed anywhere in New England. Thus, solar PV capacity increases while offshore wind capacity decreases with Net Carbon Pricing and the Hybrid Approach. In addition, battery capacity increases while fossil capacity decreases. However, these shifts are small, and do not meaningfully change the qualitative differences in outcomes across the four cases discussed in **Section VI**.

Figure VII-4. Difference in Resource Mix by Policy Approach for Transmission Scenario Compared to Central Case, 2040 (MW)



- **Alternative Target LMP in the Hybrid Approach**. With a higher targeted LMP, the Alternative Hybrid Approach scenario leads to higher carbon prices, lower CEC demand, and higher LMPs. Increasing the target LMP by $10/MWh results in a relatively small change in total nameplate capacity. The adjustments in incentives are complex. The higher carbon price incents development/retention of more efficient combined cycle fossil units, which leads to some emission reductions and increases operable capacity. The decrease in carbon-intensity of fossil emissions reduces the need for variable renewables — thus, solar PV declined by 325 MW. In addition, the additional operable capacity from combined cycle generation displaces the need for some battery storage capacity.

Figure VII-5. Difference in Resource Mix for Alternative Hybrid Approach LMP Scenario Compared to Central Case Hybrid Approach, 2040 (MW)



B. Economic Welfare: Social Costs

Each scenario leads to changes in the magnitudes of the social costs that are consistent with expectations. Across scenarios, the relative costs of each policy approach generally remain consistent. That is, in each scenario, Net Carbon Pricing has the lowest cost, followed by the Hybrid Approach, FCEM and the Status Quo, with the Status Quo costs substantially higher than costs of the centralized policy alternatives.

Table VII-1 shows the net present value of total social costs for each case in each scenario over the entire modeling period (2021-2040). Relative to the Central Case, social costs increase with a more stringent decarbonization target, decrease with alternative cost assumptions (that reflect lower assumed costs across technologies), increase with additional assumed retirements (as this scenario forces additional units into retirement that would otherwise be cost-effective to maintain and use), and increase with the transmission scenario (because the scenario accounts for congestion costs).

Table VII-1. Present Value of Incremental Social Costs by Policy Approach and Scenario (Relative to the Reference Case), 2021-2040 ($2020 Million)

	Central Case		Alternative Emissions		Alternative Costs		Additional Retirements		Transmission	
Policy Approach	Present Value of Incremental Social Cost ($2020 M)	Percent Change from Status Quo	Present Value of Incremental Social Cost ($2020 M)	Percent Change from Status Quo	Present Value of Incremental Social Cost ($2020 M)	Percent Change from Status Quo	Present Value of Incremental Social Cost ($2020 M)	Percent Change from Status Quo	Present Value of Incremental Social Cost ($2020 M)	Percent Change from Status Quo
Status Quo	6,027	-	9,249	-	4,125	-	5,983	-	5,993	-
FCEM	4,296	-28.7%	5,798	-37.3%	3,148	-23.7%	4,296	-28.2%	4,333	-27.7%
NCP	3,935	-34.7%	5,613	-39.3%	2,922	-29.2%	3,900	-34.8%	3,938	-34.3%
Hybrid	4,119	-31.7%	5,888	-36.3%	3,026	-26.6%	4,018	-32.9%	4,145	-30.8%

Table VII-2. Incremental Social Costs by Policy Approach and Scenario (Relative to the Reference Case), 2040 ($2020 Million)

	Central Case		Alternative Emissions		Alternative Costs		Additional Retirements		Transmission	
Policy Approach	Incremental Social Cost in 2040 ($2020 M)	Percent Change from Status Quo	Incremental Social Cost in 2040 ($2020 M)	Percent Change from Status Quo	Incremental Social Cost in 2040 ($2020 M)	Percent Change from Status Quo	Incremental Social Cost in 2040 ($2020 M)	Percent Change from Status Quo	Incremental Social Cost in 2040 ($2020 M)	Percent Change from Status Quo
Status Quo	4,256	-	5,515	-	3,052	-	4,309	-	4,262	-
FCEM	3,222	-24.3%	4,008	-27.3%	2,336	-23.5%	3,181	-26.2%	3,268	-23.3%
NCP	3,031	-28.8%	3,939	-28.6%	2,245	-26.4%	2,975	-30.9%	3,029	-28.9%
Hybrid	3,126	-26.5%	4,126	-25.2%	2,292	-24.9%	3,064	-28.9%	3,124	-26.7%

Table VII-3. Average Incremental Social Costs by Policy Approach and Scenario (Relative to the Reference Case), 2040 ($2020/MWh)

	Central Case		Alternative Emissions		Alternative Costs		Additional Retirements		Transmission	
Policy Approach	Incremental Social Cost in 2040 ($2020/MWh)	Percent Change from Status Quo	Incremental Social Cost in 2040 ($2020/MWh)	Percent Change from Status Quo	Incremental Social Cost in 2040 ($2020/MWh)	Percent Change from Status Quo	Incremental Social Cost in 2040 ($2020/MWh)	Percent Change from Status Quo	Incremental Social Cost in 2040 ($2020/MWh)	Percent Change from Status Quo
Status Quo	20.86	-	27.03	-	14.96	-	21.12	-	20.89	-
FCEM	15.79	-24.3%	19.65	-27.3%	11.45	-23.5%	15.59	-26.2%	16.02	-23.3%
NCP	14.86	-28.8%	19.31	-28.6%	11.00	-26.4%	14.58	-30.9%	14.85	-28.9%
Hybrid	15.32	-26.5%	20.22	-25.2%	11.23	-24.9%	15.02	-28.9%	15.31	-26.7%

The general conclusions reached in **Section VI.D** about the relative social costs between the different policy approaches holds in each of the scenarios. Specifically, across scenarios, social costs of achieving incremental emission reductions are lowest with Net Carbon Pricing, somewhat higher with the FCEM (3-10%) and Hybrid Approach (3-5%), and substantially higher with the Status Quo.

The alternative LMP Hybrid Approach scenario, which targets an LMP 25% higher than in the Central Case, resulted in a modest reduction (less than 1%) in social costs of $22 million in 2040 (**Table VII-4**). By relying more on the carbon price and less on the new CEC quantity to achieve emissions reductions,[194] the alternative Hybrid Approach is more similar to Net Carbon Pricing (the most cost-effective approach) than the Hybrid Approach in the Central Case, and is thus less costly.

Table VII-4. Incremental Social Costs by Policy Approach (Relative to the Reference Case), Central Case and Hybrid Approach Alternative LMP Scenario

	2040			2021-2040	
Policy Approach	**Incremental Social Cost ($2020 M)**	**Incremental Social Cost ($2020/MWh)**	**Percent Change from Status Quo**	**Present Value of Incremental Social Cost ($2020 M)**	**Percent Change from Status Quo**
Status Quo	4,256	20.86	-	6,027	-
FCEM	3,222	15.79	-24.3%	4,296	-28.7%
NCP	3,031	14.86	-28.8%	3,935	-34.7%
Hybrid	3,126	15.32	-26.5%	4,119	-31.7%
Hybrid Alternative LMP	3,104	15.22	-27.1%	4,099	-32.0%

C. Total Customer Payments

As in the Central Case, total customer payments for wholesale energy in each scenario include payments for energy, capacity, and environmental attributes. **Table VII-5** provides the present value of total incremental customer payments for each policy approach in each scenario over the entire modeling period (2021-2040). **Table VII-6** and **Table VII-7** provide the total incremental payments (in $ Million and $/MWh, respectively) in 2040.

[194] Annual average LMPs, annual carbon prices, and CEC prices for the alternative Hybrid LMP target are presented in **Appendix B**.

Table VII-5. Present Value of Incremental Customer Payments by Policy Approach and Scenario (Relative to the Reference Case), 2021-2040 ($2020 Million)

	Central Case		Alternative Emissions		Alternative Costs		Additional Retirements		Transmission	
Policy Approach	Present Value of Incremental Payments ($2020 M)	Percent Change from Status Quo	Present Value of Incremental Payments ($2020 M)	Percent Change from Status Quo	Present Value of Incremental Payments ($2020 M)	Percent Change from Status Quo	Present Value of Incremental Payments ($2020 M)	Percent Change from Status Quo	Present Value of Incremental Payments ($2020 M)	Percent Change from Status Quo
Status Quo	18,692	-	17,681	-	16,984	-	18,424	-	19,865	-
Status Quo (Adjusted)	34,368	83.9%	39,514	123.5%	25,868	52.3%	33,898	84.0%	36,033	81.4%
FCEM	18,600	-0.5%	21,420	21.2%	14,030	-17.4%	19,329	4.9%	19,179	-3.5%
NCP	15,872	-15.1%	20,133	13.9%	11,892	-30.0%	17,014	-7.7%	16,792	-15.5%
Hybrid	13,442	-28.1%	13,961	-21.0%	10,945	-35.6%	14,031	-23.8%	13,980	-29.6%

Table VII-6. Incremental Customer Payments by Policy Approach and Scenario (Relative to the Reference Case), 2040 ($2020 Million)

	Central Case		Alternative Emissions		Alternative Costs		Additional Retirements		Transmission	
Policy Approach	Incremental Payments in 2040 ($2020 M)	Percent Change from Status Quo	Incremental Payments in 2040 ($2020 M)	Percent Change from Status Quo	Incremental Payments in 2040 ($2020 M)	Percent Change from Status Quo	Incremental Payments in 2040 ($2020 M)	Percent Change from Status Quo	Incremental Payments in 2040 ($2020 M)	Percent Change from Status Quo
Status Quo	7,997	-	7,900	-	5,408	-	7,594	-	7,984	-
Status Quo (Adjusted)	13,034	63.0%	14,601	84.8%	8,320	53.9%	12,420	63.5%	13,151	64.7%
FCEM	9,828	22.9%	11,075	40.2%	7,405	36.9%	10,592	39.5%	9,806	22.8%
NCP	9,222	15.3%	10,600	34.2%	6,412	18.6%	9,822	29.3%	9,425	18.1%
Hybrid	6,806	-14.9%	6,046	-23.5%	5,385	-0.4%	7,781	2.5%	6,953	-12.9%

Table VII-7. Average Incremental Customer Payments by Policy Approach and Scenario (Relative to the Reference Case), 2040 ($2020/MWh)

	Central Case		Alternative Emissions		Alternative Costs		Additional Retirements		Transmission	
Policy Approach	Incremental Payments in 2040 ($2020/MWh)	Percent Change from Status Quo	Incremental Payments in 2040 ($2020/MWh)	Percent Change from Status Quo	Incremental Payments in 2040 ($2020/MWh)	Percent Change from Status Quo	Incremental Payments in 2040 ($2020/MWh)	Percent Change from Status Quo	Incremental Payments in 2040 ($2020/MWh)	Percent Change from Status Quo
Status Quo	39.20	-	38.73	-	26.51	-	37.22	-	39.13	-
Status Quo (Adjusted)	63.89	63.0%	71.57	84.8%	40.78	53.9%	60.88	63.5%	64.46	64.7%
FCEM	48.18	22.9%	54.29	40.2%	36.30	36.9%	51.92	39.5%	48.07	22.8%
NCP	45.20	15.3%	51.96	34.2%	31.43	18.6%	48.15	29.3%	46.20	18.1%
Hybrid	33.36	-14.9%	29.64	-23.5%	26.40	-0.4%	38.14	2.5%	34.08	-12.9%

Across scenarios, total customers payments change consistent with expectations given the change in costs associated with each scenario. For example, relative to the Central Case, payments increase with a more stringent decarbonization target and additional assumed retirements, but decrease with alternative cost assumptions, reflecting lower assumed costs across technologies.

However, while the ranking of policy approaches based on social costs remained consistent across scenarios, the relative ranking with respect to payments varies across scenarios. For example, in the Central Case, the Status Quo had the highest total payments (based on the present value of payments across the study period), followed by the FCEM, Net Carbon Pricing and Hybrid Approach. While this relative ranking of policy approaches remains the same as the Central Case in the scenarios with alternative costs and transmission congestion, the ranking changes with the more stringent emission target and the retirements.

This variation in the rank ordering of total payments across policy approaches likely reflects multiple factors.[195] A key factor is differences in the impact of price discrimination on payments in the Status Quo and Hybrid Approach. While the economic cost of achieving emission targets varies across scenarios (given differences in emission stringency and abatement costs), we hold constant the additional payments made to existing clean energy resources in the Status Quo and Hybrid Approach. Thus, the reduction in payments associated with price discrimination varies depending on the magnitude of costs required to achieve decarbonization targets.

This effect is seen most easily through a simple example. Across scenarios, we hold constant the additional payment to existing renewable resources in the Status Quo for the environmental attribute of their energy at $60/MWh (in 2040).[196] If the existing resources would otherwise be paid $100/MWh for their environmental attribute (with either Net Carbon Pricing or the FCEM), then the price discrimination results in a reduction in payments of $40/MWh for energy from these existing resources. Suppose, however, that this payment increases to $125/MWh because the emission target is more stringent or abatement costs are higher. In this case, the reduction in customer payments would be $65/MWh (= $125/MWh – $60/MWh), which would make the policy approach employing the price discrimination (*i.e.*, the Status Quo in this case) appear more favorable (in relative terms).

We see this effect across the scenarios. For example, compared to the Central Case, customer payments under the Status Quo decrease with the more stringent emission target, but increases with the alternative (lower) cost assumptions relative to Net Carbon Pricing and the FCEM. Similar effects occur for the Hybrid Approach, with customers payments decreasing with the more stringent emission target and increasing with the alternative (lower) cost assumptions relative to Net Carbon Pricing and the FCEM. These results confirm

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[195] The calculation of payments is particularly sensitive to assumptions and interactions between the various components of payments, particularly energy market outcomes, environmental prices, and capacity market prices. Because battery storage resources are the market-clearing resources in the capacity market, these outcomes reflect the complex interactions between variable renewables and battery resources in the energy markets. Given the simplified representation of battery resource operations in our analysis, these outcomes provide a reasonable estimate of the resulting payments but are sensitive to the assumptions and methods used within the model.

[196] As noted earlier, these payments increase from $0 / MWh in 2031 to $60 / MWh in 2040. In addition, we provide additional revenues to nuclear plants to ensure average energy market payments of $41 / MWh.

the expectation that the reduction in payments associated with price discrimination is sensitive to the degree to which price discrimination lowers compensation to resources not receiving the market-clearing prices for their energy services.

The Hybrid Approach alternative LMP scenario, which has a $51 average LMP from 2030-2040 as opposed to $41 in the Central Case, results in higher payments, as shown in **Table VII-8**. The higher average LMP more than offsets lower capacity prices in this scenario. The results demonstrate that in the Hybrid Approach, payments potentially increase with the choice of a higher LMP, although the social costs were lower with the higher LMP.

Thus, overall, the major conclusions discussed in **Section V** and **Section VI** are largely the same conclusions as those reached in each scenario.

Table VII-8. Incremental Customer Payments by Policy Approach (Relative to the Reference Case), Central Case and Hybrid Approach Alternative LMP Scenario

	2040			2021-2040	
Policy Approach	**Incremental Payments ($2020 M)**	**Incremental Payments ($2020/MWh)**	**Percent Change from Status Quo**	**Present Value of Incremental Payments ($2020 M)**	**Percent Change from Status Quo**
Status Quo	7,997	39.20	-	18,692	-
Status Quo (Adjusted)	13,034	63.89	63.0%	34,368	83.9%
FCEM	9,828	48.18	22.9%	18,600	-0.5%
NCP	9,222	45.20	15.3%	15,872	-15.1%
Hybrid	6,806	33.36	-14.9%	13,442	-28.1%
Hybrid Alternative LMP	8,286	40.62	3.6%	15,573	-16.7%

ANALYSIS GROUP

Pathways Study

Evaluation of Pathways to a Future Grid

Appendices

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Appendix A Additional Technical Modeling Details

A. Energy Market Simulations

A **Capacity Expansion Model ("CEM")** determines long-run market outcomes, particularly regarding generating capacity, by simulating outcomes in energy and capacity markets over an extended time horizon (*e.g.*, 2021-2040). The CEM estimates the least-cost resource mix, which is consistent with the outcomes of the ISO-NE capacity and energy markets. The timing of new resource entry and resource exit estimated by the model reflects multiple factors including evolving loads (levels and profiles), evolving costs (*e.g.*, new technology improvements) and evolving environmental requirements. Furthermore, it calculates a price for any environmental constraints (such as a carbon price).[1] The CEM simplifies the representation of the energy market to achieve reasonable runtimes over a 20-year period.

An **Energy Market Simulation Model ("EMS")** is used to forecast day-to-day operations and decision making. The model chronologically optimizes energy and ancillary services dispatch and calculates hourly production costs and location-specific market clearing prices while simultaneously adhering to a variety of operating constraints. It determines the least cost dispatch of a system of interconnected generators to meet load in every hour of the day within a specific region.

The EMS model does not optimize additions and retirements. All changes to the resource mixture must be defined prior to running the optimization. For this reason, the EMS model is used in conjunction with the CEM, which informs decisions about capacity builds and retirements. While the CEM optimizes *annually* for a multi-year period, the EMS uses a finer time resolution, modeling all 8,760 hours of a year. It provides details including locational marginal prices, unit generation by technology type, fuel consumption, ramp rates, maintenance schedules, costs, and more. The EMS also allows for random variation in unknown variables such as fuel prices and weather patterns to reflect market uncertainty.

Given that the EMS optimizes *hourly*, the model faces run-time constraints. Our study operates the EMS in 2040, but not intermediate years. This approach, in conjunction with operating the CEM, allows for modeling accuracy in the year 2040, while limiting model run-times.

B. Central Case Data and Assumptions

This section details the data sources, model assumptions, and methodology used to evaluate proposed market designs and the status quo. Where sensible and feasible, assumptions have been aligned with the ISO-NE Future Grid Reliability Study (FGRS).[2]

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[1] Prices for environmental constraints are calculated as the shadow price of the constraint. This corresponds with the change in total system costs from an infinitesimal change in the constraint.

[2] The Future Grid Reliability Study (FGRS) is part of ISO New England's future grid initiative key project, alongside this study. Detail from both studies can be found at, ISO-NE, "New England's Future Grid Initiative Key Project," available at https://www.iso-ne.com/committees/key-projects/new-englands-future-grid-initiative-key-project/.

1. *Demand*

a) Load Forecast

For each year and month between 2020 and 2040, an hourly load forecast is determined. The forecast is determined in three steps. First, we obtained monthly peak load and total energy forecasts for certain years from other sources. For 2020, our forecast is based on the ISO-NE 2021-2030 Capacity, Energy, Loads, and Transmission Report ("2021 CELT") report, while for 2030, 2035, and 2040 it is based on "Load Scenario 3" from the Future Grid Reliability Study.[3] The FGRS Load Scenario 3 includes normal economic growth and high electrification of transportation and heating, as well as increased energy efficiency.[4]

Second, for intermediate years (between these certain years), we linearly interpolated loads at the state-month level.

Third, the hourly profile for each year is calculated based on the 2040 profile from "Load Scenario 3" of the FGRS study. The 2021 to 2040 profiles are shaped for each year using the monthly peak and total energy from the load forecast. All features of the load forecasts — peak monthly load, peak monthly energy, and hourly load profiles — are based on 2019 weather patterns.[5]

b) Capacity Market and ICR

We model the forward capacity market as a single ISO-NE wide zone for each year between 2021 and 2040, with no sub-system capacity zones. The targeted level of resource adequacy (*i.e.*, ICR) is calculated by multiplying the annual ISO-NE wide peak load net of energy efficiency (but not net of BTM PV solar) by the current ratio of ICR to peak load. The ICR in future years is calculated as the average historical ratio of ICR to gross summer peak load (net of energy efficiency) from 2020 to 2024, as specified by the 2021 CELT report.

c) Ancillary Services

We model four separate ancillary services products, consistent with ISO-NE market rules, in the energy market simulation. These rules include the cascading nature of the current ISO-NE reserve product requirements. The products include 600 MW of Ten-Minute Spinning Reserve (TMSR), 1,600 MW of Ten-Minute Non-

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[3] ISO-NE, "2021 Economic Study: Future Grid Reliability Study Phase 1 Overview of Assumptions – Part 1," April 14, 2021, p. 6, available at https://www.iso-ne.com/static-assets/documents/2021/04/a8_2021_economic_study_request_assumptions_part_1_rev2_redline.pdf.

[4] The FGRS loads are based on the loads developed for the Massachusetts "80X50" study, which uses a 2012 weather year. However, because the FGRS study is based on a 2019 weather year, ISO-NE System Planning adjusted the hourly load forecasts to align with the 2019 weather year. *See* Evolved Energy Research, "Energy Pathways to Deep Decarbonization: A Technical Report of the Massachusetts 2050 Decarbonization Roadmap Study," December 2020, available at https://www.mass.gov/doc/energy-pathways-for-deep-decarbonization-report/download.

[5] The FGRS Load Scenario 3 load profile adjusted for the 2019 weather year was provided by ISO-NE. We made two modifications to the load profile. First, FGRS adjusted baseload for daylight savings time but did not adjust electric vehicle time of use. In order to align the two time-series, we removed the daylight savings time adjustment for baseload. Second, FGRS has the same electric vehicle time of use profile on weekdays and weekends. We allow for a different electric vehicle time of use profile on weekends.

Spinning Reserve (TMNSR), and 2,400 MW of Thirty-Minute Operating Reserve (TMOR).[6] We also model a regulation product (REG) that is based on ISO's 2021 Daily Regulation Requirement.[7] This requirement varies from 50 MW to 190 MW, depending on the hour, day, and month. We do not model ancillary services in the CEM.[8]

d) **REC Demand**

We model the Renewable Portfolio Standards as a single product, with annual requirements equal to the sum of the New England states' RPS requirements as currently legislated.[9]

2. Supply: Existing Resources, Entry and Exit

a) **Baseline Resource Mix**

The baseline resource mix includes generators in ISO-NE's 2021 CELT Report and those that cleared ISO-NE's fifteenth Forward Capacity Auction (FCA 15) for the Capacity Commitment Period June 2024 to May 2025.[10] These data are then adjusted for other expected generation resource additions and known retirements.[11] Additionally, we assume the Merrimack 1 and Merrimack 2 coal plants will retire on June 1, 2025.[12]

b) **Baseline State Policies**

We assume that the Renewable Portfolio Standards continue to remain in place, and that currently legislated procurement targets will be met by the dates set forth in the legislation. We also assume that all renewable energy projects that have been procured will come online according to announced dates. If states have announced plans to procure a target amount of offshore wind, we assume that these projects will come online

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[6] These values are roughly in line with ISO-NE's 2019 requirements, see *Compliance Filing of Energy Security Improvements Addressing New England's Energy Security Problems*, April 15, 2020, Table 7-5, available at https://www.iso-ne.com/static-assets/documents/2020/04/energy_security_improvements_filing.pdf.

[7] ISO-NE, "Daily Regulation Requirements," February 10, 2021, available at https://www.iso-ne.com/static-assets/documents/sys_ops/op_frcstng/dlyreg_req/daily_regulation_requirement.xlsx.

[8] We would not expect modeling ancillary services to materially impact the results, since prices for these services tend to be very low or $0 in the energy market simulations.

[9] See **Figure II-1** and **Section A.C** of this appendix for more details of the current RPS policies.

[10] ISO-NE, "Forward Capacity Auction Obligations," accessed May 3, 2021, available at https://www.iso-ne.com/static-assets/documents/2018/02/fca_obligations.xlsx.

[11] ISO New England Status of Non-Price Retirement Requests, Retirement De-list Bids and Substitution Auction Demand Bids, accessed July 23, 2021, available at https://www.iso-ne.com/static-assets/documents/2016/08/retirement_tracker_external.xlsx.

[12] Merrimack Station has committed to providing capacity through mid-2025. *See* NHPR, "N.H. Coal Plant Will Run Through At Least 2025 After Latest Grid Auction," March 1, 2021, available at https://www.nhpr.org/climate-change/2021-03-01/n-h-coal-plant-will-run-through-at-least-2025-after-latest-grid-auction. We assume that the units retire after fulfilling this commitment. This assumption does not reflect any privately held knowledge, belief or prediction by us or ISO-NE that this retirement should or will occur at that date.

according to dates set forth in the announcements. **Table A-1** provides a summary of these assumed new resources due to state policies.[13]

Table A-1. Announced State Procurements

Announced Procurements	Nameplate Capacity (MW)
Massachusetts	
SMART - Solar	3,200
Planned Offshore Wind RFP	1,600
Mayflower Wind	804
Vineyard Wind	800
Remaining Offshore Wind	2,400
Total	*8,804*
Connecticut	
Park City Wind	804
Revolution Wind	304
CT Zero-Carbon 2018 RFP	165
Remaining Offshore Wind	1,196
Total	*2,469*
Rhode Island	
RI Planned Offshore Wind RFP	600
Revolution Wind	400
Gravel Pit Solar	50
Total	*1,050*
Maine	
Various Solar	583
Various Onshore Wind	32
Total	*615*
New England Clean Energy Connect	1,200

c) Behind-the-Meter Solar

Behind-the-meter solar resources are assumed to grow over the next ten years according to the 2021 CELT forecast. We assume much of this growth is driven by state policies that will be phased out over the next ten years. Beyond 2030, we assume constant growth of behind-the-meter solar, with the annual incremental increase in capacity set to the forecast level for 2030 in the 2021 CELT forecast. We model BTM PV as a resource.

d) Modeled Entry and Exit

For the central cases, new entry capital costs are based on EIA's Annual Energy Outlook (AEO) 2021. Overnight costs by technology type, in 2020 dollars per kilowatt, are based on values specific to New England.[14] Overnight costs are projected to change over time from these region-specific values based on national EIA trends, in terms of a year-on-year percentage change, by technology type.[15] EIA AEO includes

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[13] For more details, see **Figure II-2** and associated references.

[14] EIA, "Assumptions to the Annual Energy Outlook 2021: Electricity Market Module," Table 4, p. 7.

[15] EIA, "Annual Energy Outlook 2021," Table 55. Overnight Capital Costs for New Electricity Generating Plants, available at https://www.eia.gov/outlooks/aeo/data/browser/#/?id=123-AEO2021&cases=ref2021&sourcekey=0.

overnight costs for fixed-bottom offshore wind generators, but not for floating offshore wind. We assume that the overnight costs for floating offshore wind are 38% more, based on the difference in overnight costs between floating and fixed-bottom offshore wind in the NREL 2021 Annual Technology Baseline.[16]

In order to account for the total costs of new entry, the model also takes into account resource siting costs and transmission upgrade cost for onshore wind, offshore wind, and utility scale PV. Battery storage will not include these costs, because they have more flexibility in terms of siting as well as have a much smaller physical footprint. Similarly, new build fossil units do not include these costs because of the smaller number of additional units developed over the study period.

For onshore wind, we assume that new entry will be located in Maine. This assumption is driven by two factors. First, the majority of the wind in the ISO-NE interconnection queue in recent years has been located in Maine. Second, costs are relatively higher of building at scale outside of Maine, in part reflecting potential siting and land availability challenges. At present, transmission from Southern Maine to Southern New England has no incremental headroom. This means that all new onshore wind resources will include the costs of transmission expansion. For onshore wind in Maine, the cost of new transmission is based on the Second Maine Resource Integration Study (SMRIS), which estimated the cost at $1,498/kW.[17] In addition, the model assumes that transmission and siting for new onshore wind resources will become increasingly more expensive due to challenges associated with permitting, right of way, and land costs. Specifically, the model assumes that the cost of new onshore wind will increase by an additional $749/kW - 50% of the cost estimated in the SMRIS - for each additional 1,000 MW of capacity. These cost increases are illustrated in **Figure A-1**. The cost increases shown are relative to the base 2021 EIA overnight costs. The base costs decrease over time depending on the year of construction.

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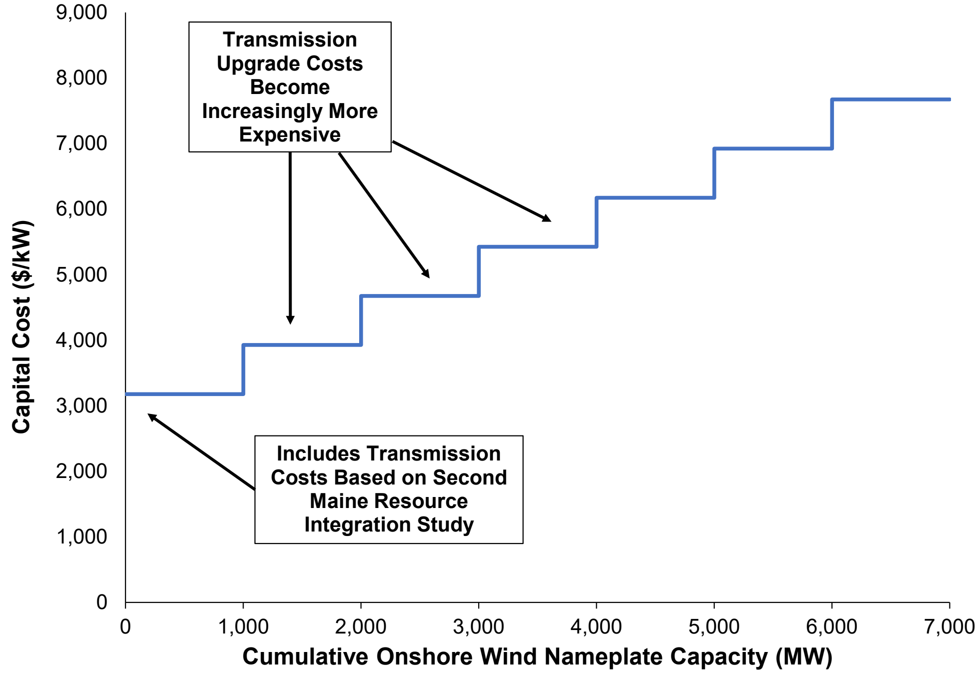
[16] NREL (National Renewable Energy Laboratory). 2021. "2021 Annual Technology Baseline." Golden, CO: National Renewable Energy Laboratory, available at https://atb.nrel.gov/.

[17] Total upgrade costs to interconnect 520 MW of onshore wind was estimated to be $779.1M, or $1,498/kW. *See* ISO-NE, "Final Second Maine Resource Integration Study," October 30, 2020, Table 6-1, available at https://www.iso-ne.com/static-assets/documents/2021/01/second-maine-resource-integration-study-report-non-ceii-final.pdf.

Figure A-1. Overnight Capital Costs for Onshore Wind Before EIA Time Trends Applied



Offshore wind similarly accounts for the costs of new transmission, when necessary. According to a recent ISO-NE study, approximately 6,000 MW of nameplate capacity offshore wind off the coast of southern New England could be interconnected without significant onshore transmission upgrades.[18] Beyond this, additional offshore wind build will require either significant onshore transmission upgrades or offshore HVDC connections that bypass the onshore grid, which will be reflected in the modeled costs. After the US Bureau of Ocean Energy Management (BOEM) lease areas have been exhausted (**Figure A-2**),[19] costs are assumed to increase reflecting onshore siting challenges and the need to build further from shore. As offshore transmission does not encounter the same challenges as onshore transmission, these costs are assumed to increase by 10% of the base assumed transmission costs for every 1,200 MW once the BOEM lease areas are exhausted. These cost increases are illustrated in **Figure A-3**. The cost increases shown are relative to the base 2021 EIA overnight costs. The base costs decrease over time depending on the year of construction.

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[18] ISO-NE, "2019 Economic Study Offshore Wind Transmission Interconnection Analysis," June 17, 2020, available at https://www.iso-ne.com/static-assets/documents/2020/06/a4_2019_economic_study_offshore_wind_transmission_interconnection_analysis.pdf.

[19] Bureau of Ocean Energy Management, "Commercial Leases OCS-A 0520, 0521, And 0511," available at https://www.boem.gov/renewable-energy/state-activities/commercial-leases-ocs-0520-0521-and-0522.

Figure A-2. Location of BOEM Lease Areas

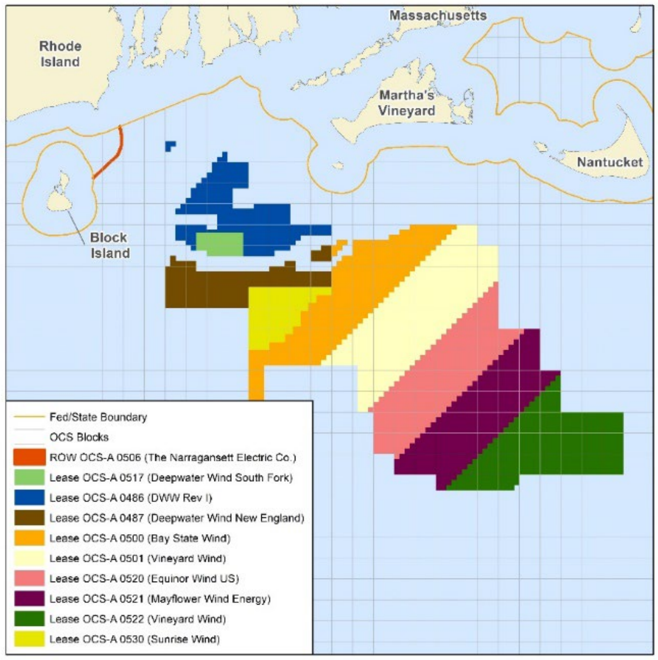
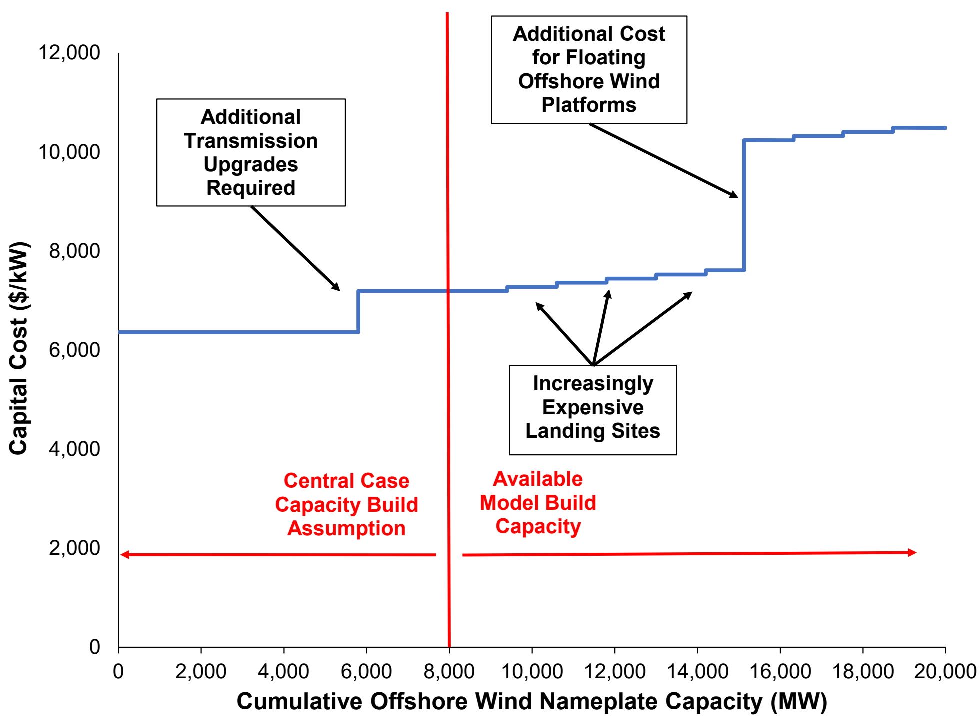


Figure A-3. Offshore Wind Capital Costs



Utility scale solar will also account for increasing costs reflecting land costs and siting challenges, similar to onshore wind. However, since utility scale solar is more flexible in terms of where it can be located, and has a smaller footprint per MW, each 1,000 MW will include an additional cost adder equivalent to 10% of the base EIA overnight costs.

Fixed O&M costs for new entry units are based EIA's AEO 2021 which are national projections.[20] For existing units, fixed costs are based on S&P Global Market Intelligence's regression model or S&P Global Market Intelligence's unit type default.[21] Older combined cycle, coal-fired, and steam turbine generators also include a fixed annual capital cost based on estimates from Sargent and Lundy.[22] The modeling assumes that fixed costs are constant over the modeling period.

All new entry units have identical financing terms, including a 20-year amortization period and a 6.1% After Tax Weighted Average Cost of Capital ("ATWACC") rate. The 6.1% ATWACC rate is based on what was used in the most recent New England Net CONE values.[23]

The CEM model takes into account the costs described above, expected net EAS revenues, and the environmental constraints to solve for the least cost resource mix, including generator entry and exit, over a rolling 10-year horizon.

3. *Supply: Resource Adequacy*

a) **Qualified Capacity**

To account for the fact that our model is simulating a summer peaking system prior to 2029 and a winter peaking system thereafter, we applied a simple rule for our Qualified Capacity determination that differs from current market rules. Summer and winter qualified capacity for existing non-intermittent resources (*e.g.*, combined cycle or battery storage) is assigned based on each individual unit's seasonal claimed capacity for summer and winter in the CELT Report. For resources that are not included in the CELT Report but did sell capacity in the Forward Capacity Auction 15, the summer and winter qualified capacity sold in that auction is used. The qualified capacity available to meet the model's ICR is the average of the summer and winter qualified capacity. The qualified capacity for new non-intermittent resources is equivalent to their nameplate capacity.

Summer and winter qualified capacity for intermittent resources (*e.g.*, wind or solar) follows the current ISO-NE Tariff.[24] For these resources, summer and winter qualified capacity is determined by the median output during certain "reliability hours" during the year. Reliability hours for summer qualified capacity are the hours

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[20] EIA, "Assumptions to the Annual Energy Outlook 2021: Electricity Market Module," Table 3, p. 6.

[21] S&P Global Market Intelligence, "Fixed O&M Cost per kW-Year ($/kW-year)".

[22] Sargent & Lundy, "Generating Unit Annual Capital and Life Extension Costs Analysis: Final Report on Modeling Aging-Related Capital and O&M Cost," SL-014201, Prepared for U.S. Energy Information Administration, May 2018.

[23] Concentric Energy Advisors, Inc. and Mott MacDonald, "ISO-NE Net Cone and ORTP Analysis, An Evaluation of the Net Cost of New Entry and Offer Review Trigger Price Parameters to be Used in the Forward Capacity Auction, FCA-16 and Forward," December 2020, p. 10.

[24] This is consistent with current ISO-NE Tariff III.13.1.2.2.2.1 and III.13.1.2.2.2.2, available at https://www.iso-ne.com/static-assets/documents/regulatory/tariff/sect_3/mr1_sec_13_14.pdf.

ending in 1400 through 1800, June through September. For winter qualified capacity, the reliability hours are hours ending 1800 and 1900.

b) MOPR

ISO-NE currently has a Minimum Offer Price Rule (MOPR) in the Forward Capacity Markets that establishes offer price floors (potentially subject to exemptions) for resources based on estimates of their competitive offer prices (Offer Reserve Threshold Prices). As ISO-NE has proposed to remove the MOPR and the New England States and the NEPOOL Stakeholders are considering this proposal, we assume the market does not include the MOPR.[25]

c) Generating Unit Characteristics

Energy suppliers are modeled either as individual (discrete) resources to be optimized by the capacity expansion model and the energy market simulation model, or profiles that are netted off from load. This section outlines how the resource characteristics and supply amounts (for profiled resources) are determined.

We consider resource entry by commercially available technologies with costs that potentially support economic entry and with meaningful resource potential in the region. Certain technologies were not evaluated because they were deemed too costly (*e.g.*, fuel cells) or had limited resource potential (*e.g.*, non-Canadian hydro). The resources we model for potential new entry are: onshore wind, offshore wind, utility-scale solar, battery storage, natural gas combined cycle units, and natural gas turbines.

d) Hourly Profiled Resource Characteristics

i. Solar, Hydroelectric, and Import/Exports

Utility-scale solar profiles are based on 2019 generation data at hypothetical locations in each state calculated by DNV GL. These profiles are for ground-mounted PV with a single axis tracker. Behind-the-meter solar generation is assumed to follow an hourly profile based on DNV GL's 2019 generation data, which differs by load zone.[26]

Hydroelectric and import/export profiles are based on 2019 generation data provided by ISO-NE. The exception is the New England Clean Energy Connect (NECEC), which is assumed to supply its contracted annual amount of 9,554,940 MWh of qualified clean energy generation at a constant hourly level.[27] No imports from or exports to New Brunswick are assumed.

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[25] ISO-NE, "Updated 2021 Annual Work Plan", May 6, 2021, slide 4, available at https://www.iso-ne.com/static-assets/documents/2021/04/2021_awp_update_05_06_21_pc.pdf.

[26] Data by DNV GL was provided by ISO-NE. For further description of the data, *see* ISO-NE, "Stochastic Time Series Modeling for ISO-NE," February 26, 2021, available at https://nepool.com/wp-content/uploads/2021/02/FG_20200226_a03b_stochastic_time_series_modeling_overview_2021-02-26.pdf.

[27] Re: Massachusetts Electric Company and Nantucket Electric Company d/b/a National Grid, Section 83D Long-term Contracts for Clean Energy; D.P.U. 18-65, July 23, 2018.

ii. Onshore Wind

Existing onshore wind profiles are matched to their unique 2019 generation profiles based on DNV GL's data. Any existing resources that do not have a match are assigned a profile that reflects the average of all the existing onshore wind within their state.

All new onshore wind will be assumed to be sited in Maine. The wind profile assumed will be the hourly average of the four hypothetical wind locations in the DNV GL data for Maine, reflecting four locations in the upper part of the state. The four locations are shown below in **Figure A-4**.[28]

Figure A-4. Location of Hypothetical Offshore Wind Locations (Green)

iii. Offshore Wind

The possible siting locations of new build offshore wind will include the existing BOEM lease areas, which reflects a total available capacity of approximately 12,000 MW of fixed bottom offshore wind. Each lease area has a unique offshore wind profile in the DNV GL data.[29]

In addition to the BOEM lease areas, we assume an additional 3,000 MW of fixed bottom offshore wind can be built in waters surrounding the BOEM lease areas. These lease areas are assigned a generation profile that is the average of the profiles for the BOEM lease areas. After this, we assume an unlimited amount of

[28] ISO-NE, "Stochastic Time Series Modeling for ISO-NE," February 17, 2021, p. 61, available at https://www.iso-ne.com/static-assets/documents/2021/03/a9_stochastic_time_series_modeling_for_isone_rev_2.pdf.

[29] Data by DNV GL was provided by ISO-NE. For further description of the data, *see* ISO-NE, "Stochastic Time Series Modeling for ISO-NE," February 26, 2021, available at https://nepool.com/wp-content/uploads/2021/02/FG_20200226_a03b_stochastic_time_series_modeling_overview_2021-02-26.pdf.

floating offshore wind can be built in deeper waters off the coast of Cape Cod and Southern Maine, using a hypothetical generation profile for each of these locations from the DNV GL data.

iv. Battery Storage and Pumped Storage

We aligned our assumptions for Battery and Pumped Storage resources with the FGRS. The Battery Storage resources have a roundtrip charging and discharging efficiency of 86% and a variable operating and maintenance cost of $6/MWh. The Pumped Storage resources have a roundtrip charging and discharging efficiency of 75% and a variable operating and maintenance cost of $0/MWh. Both resource types can provide all modeled ancillary services. Co-located solar and battery resources are modeled as separate solar and battery resources.

e) Discretely Modeled Resource Characteristics

We model fossil units (combine-cycles, gas turbine, internal combustion, steam, biomass, and coal units) as dispatchable units. The heat rates vary by unit and were developed based on S&P Global[30] and forced outage rates are based on the North American Electric Reliability Corporation (NERC) Generating Availability Report.[31]

Nuclear units are modeled as profiles. The hourly profile assumes generation at 97% of nameplate capacity in the summer (June 1st to September 31st) and in the winter (December 1st to March 31st) and at 92% of nameplate capacity in the shoulder season.

4. Supply: Energy Market Costs & Generating Unit Characteristics

a) Fuel costs

We rely on forwards and futures data to model oil, natural gas, and coal prices for fossil generating facilities.[32]

- ***Natural Gas:*** Natural gas prices are based on Algonquin City Gates OTC Global Holdings Futures provided by S&P Global Market Intelligence.[33] For years beyond 2031, the natural gas price is adjusted annually using the expected growth rate from the EIA Annual Energy Outlook for natural gas (**Figure A-5**).[34]

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[30] S&P Global Market Intelligence, "Heat Rate (Btu/kWh)".

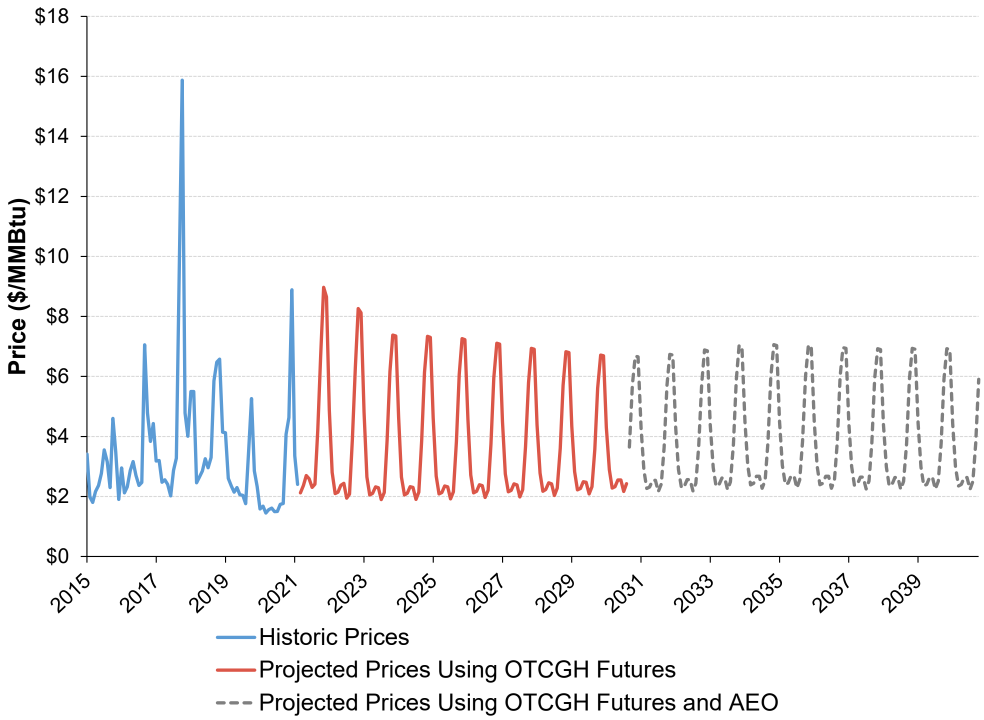
[31] North American Electric Reliability Corporation, "Forced Outage Hours", see https://gadsopensource.com/NERCRpts.aspx

[32] Oil and natural gas prices used in our modeling are adjusted to 2020 dollars assuming a 2% inflation rate.

[33] S&P Global Market Intelligence, "Natural Gas Forwards & Futures (Data)", as of 04/30/2021.

[34] Annual Energy Outlook 2020, "Table 3. Energy Prices by Sector and Source" (Natural Gas), U.S. Energy Information Administration.

Figure A-5. Historic and Projected Natural Gas Prices for New England



- ***Fuel Oil:*** Prices for No. 2 and No. 6 Fuel Oil are based on New York Harbor Heating Oil Futures and New York Harbor Residual Fuel Oil 1% Sulfur Futures, respectively, from S&P Global Market Intelligence. For years beyond 2024, the oil price is adjusted using the annual expected growth rate for fuel oil from the EIA Annual Outlook.[35]
- ***Coal***: Coal prices are derived by dividing S&P Global reported 2015-2017 annual prices of coal delivered ($/ton) by annual average heat content of coal burned (Btu/lbs).[36]
- ***Uranium***: The uranium prices are based on the 2020 price reported by the EIA and assumed to be fixed at $0.63/MMBtu.[37]

b) **Non-fuel energy costs**

- ***Variable O&M***: Variable O&M costs are based on a 2010-2011 Charles River Associates study on behalf of the Eastern Interconnection Planning Collaborative (EIPC).

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[35] Annual Energy Outlook 2020, "Table 3. Energy Prices by Sector and Source" (Natural Gas), U.S. Energy Information Administration.

[36] For plants without sufficient data, Newton Energy Group assumed the average price from other coal plants in the same area and/or state. Coal prices in our study range from $1.78/MMBtu to $2.02/MMBtu.

[37] EIA, "Nuclear fuel average price, all sectors, United States," available at https://www.eia.gov/opendata/qb.php?category=40290&sdid=SEDS.NUETD.US.A.

- ***RGGI***: RGGI allowance price is assumed constant across the study period at the average price in recent auctions (Q2 2019 to Q1 2021), equal to $6.21/Short Ton.[38]

c) **Energy market offers of units with PPAs and/or are CEC-eligible**

- ***Units eligible for CECs***: In the FCEM and Hybrid approach, generating units that are eligible for CECs offer into the energy market at their variable costs minus the CEC price.
- ***Units with PPAs***: Generating units with PPA contracts will offer into the energy market at -$100. The one exception is in the Status Quo case, where nuclear units, starting in 2030, offer at -$41.

5. Supply: RPS

Eligibility for REC awards reflects a facility's technology type. We assume a given technology type is eligible to receive RECs if a majority of the New England states consider the technology to be eligible for RECs. In our study, the following technology types are eligible for RECs: Onshore wind, offshore wind, utility-scale solar, behind-the-meter solar, run-of-the-river hydro, pondage hydro, solar + storage (solar generation only), municipal solid waste, and other biomass.

C. Further Detail on State Renewable and Clean Energy Standards

In this section, we provide further details on existing state renewable energy and clean energy standards. These standards require that a specified fraction of energy procured by regulated utilities meet certain renewable or clean standards. The quantitative analysis assumes that these policies remain in place, but that the targets are not modified in the future.

1. Connecticut

Connecticut's Renewable Portfolio Standard (RPS) consists of three classes.[39] Class I, which comprises the bulk of Connecticut's standard, includes both zero-carbon resources such as solar and wind as well as low-carbon resources such as landfill methane gas and biomass. Class II, which is supplementary to Class I, can be additionally met using generation from waste-to-energy facilities. Class III resources can broadly be grouped as "efficiency savings," and include combined heat and power systems with at least 50% efficiency, waste heat recovery systems, and savings from conservation and load management programs. By 2040, 40% of Connecticut's load must be met with Class I RPS eligible generation, with 4% being met with either Class I or Class II resources, and another 4% met with Class III resources.

2. Maine

Maine has a relatively ambitious Renewable Portfolio Standard compared with other New England states, requiring 80% of its electricity come from renewable resources by 2030.[40] Like Rhode Island and Massachusetts, Maine's Renewable Portfolio Standard consists (largely) of two classes, where the primary distinction is between "new" and existing resources. ("New" is defined as having an in-service date of after

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[38] RGGI, "Auction Results", available at https://www.rggi.org/auctions/auction-results.

[39] Connecticut Department of Energy and Environmental Protection, "Connecticut Renewable Portfolio Standard," October 2021, available at https://portal.ct.gov/PURA/RPS/Renewable-Portfolio-Standards-Overview.

[40] Maine Revised Statutes, Title 35-A, Part 3, Chapter 32, "Electric Industry Restructuring," §3210.

September 1, 2005.) Where Maine differs from other states, though, is that all resources except Class I/IA solar and wind must be less than 100 MW. RPS-eligible resources in Maine include wind, solar, (small) hydro, and landfill gas and biomass/biogas. Class II-eligible resources additionally include waste-to-energy and combined heat and power with at least 60% operating efficiency. Of the 2030 80% RPS target, 50% must come from Class I/IA resources and 30% must come from Class II resources.

3. Massachusetts

Massachusetts has a Renewable Energy Portfolio Standard (RPS) consisting of two classes.[41] The difference between the two classes is date of operation - resources eligible for Class I were in operation on or after January 1, 1998. Wind, solar, small hydro, landfill gas, and certain eligible biomass are eligible for the RPS program. By 2040, 45% of the load must be met with Class I RPS eligible generation, with up to 3.6% being met with Class II. Massachusetts' RPS program has an additional 3.5% carve out for waste to energy generation that is considered Class II - that is, in operation prior to January 1, 1998. On top of the RPS requirements, Massachusetts has a clean energy standard (CES).[42] The CES is not explicitly legislated but was instituted by the MA DEEP in response to the requirements of the Global Warming Solutions Act. By 2040, the CES will require an additional 15% of load being met by clean energy, inclusive of any remaining Class II eligible generation. The main difference between RPS and CES eligibility is that Nuclear and Large Hydro is eligible under CES.

Currently, Massachusetts has a Solar Carve-out (SREC) program that is a part of the RPS Class I standard. As of 2021, 5.59% of the load must be met with SREC eligible generation.[43] As of 2018, the SREC program is being phased out in favor of the Solar Massachusetts Renewable Target (SMART), which provides incentives for 3,200 MW of solar and solar plus storage that is a requirement not explicitly tied to a percentage of load like the RPS program.[44]

In addition to the RPS and CES requirements, Massachusetts also has a legislated alternative energy portfolio standard (APS) to complement the RPS program and contribute to the Commonwealth's clean energy goals.[45] By 2040, 12.5% of the Commonwealth's goals are to be met by APS eligible generation. Types of generation eligible include Combined Heat and Power and flywheel storage.

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[41] Massachusetts Electric Utility Restructuring Act of 1997; Green Communities Act of 2008 amended RPS; An Act Creating a Next Generation Roadmap for Massachusetts Climate Policy of 2021 amended the RPS further; Massachusetts Regulations: 225 CMR 14.00 (RPS Class I); 225 CMR 15.00 (RPS Class II).

[42] CES established in response to the Global Warming Solutions Act of 2016; Massachusetts Regulation: 310 CMR 7.75 (CES).

[43] Commonwealth of Massachusetts, “Solar Carve-out and Solar Carve-out II Minimum Standards and Market Information,” available at https://www.mass.gov/service-details/solar-carve-out-and-solar-carve-out-ii-minimum-standards-and-market-information.

[44] Commonwealth of Massachusetts, “Solar Massachusetts Renewable Target (SMART),” available at https://www.mass.gov/solar-massachusetts-renewable-target-smart.

[45] Green Communities Act of 2008; Massachusetts Regulation: 225 CMR 16.00 (APS).

4. New Hampshire

New Hampshire has a Renewable Portfolio Standard (RPS) that consists of five categories, with Class I ("New Renewable Energy") comprising the bulk of the standard.[46] Class I-eligible resources must be "new" (*i.e.*, in operation after January 1, 2006) and include wind, solar, and biomass/biogas. The other four categories are carve-outs for specific generation types. Class I Thermal include only thermal generation, such as geothermal and solar thermal. Class II is for new solar, Class III is for existing biomass/methane, and class IV is for existing small hydroelectric (<5 MW). By 2040, New Hampshire must have 12.8% of load come from Class I resources, 2.2% from Class I Thermal, 0.7% from Class II (new solar), 8% from Class III (existing biomass/methane), and 1.5% from Class IV (existing small hydroelectric).

5. Rhode Island

Rhode Island's Renewable Portfolio Standard consists of two classes, which is differentiated by whether generation is existing or new.[47] "New" is defined as having first entered commercial operation after December 31, 1997. RPS-eligible resources in Rhode Island include wind, solar, small hydro (defined as <30 MW), landfill gas, and biogas. By 2040, 38.5% of Rhode Island's electricity generation must come from renewable resources, with 36.5% coming from new resources and 2% from existing resources.

6. Vermont

Vermont's Renewable Portfolio Standard (RPS) consists of three tiers, which differ slightly from other states.[48] Vermont's Tier II is more like other states' Class I resources in that Tier II resources must be new. (Vermont's Tier I is more like other states' Class II.) Tier I/II RPS-eligible resources in Vermont include solar, wind, hydro, and landfill gas and biomass/biogas. One notable distinction between Vermont and other states is that Vermont allows imported hydroelectricity from Hydro-Québec to count towards RPS compliance. Vermont's Tier III generation includes behind-the-meter generation, combined heat and power, waste heat recovery. By 2040, 87% of Vermont's generation must be from renewable resources, with 75% from Tier I, 10% from Tier II (which counts toward the Tier I requirement), and 12% from Tier III.

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[46] New Hampshire Statutes, Title XXXIV, Chapter 362-F, "Electric Renewable Portfolio Standard."

[47] Rhode Island General Laws, Chapter 39, Section 26, "Renewable Energy Standard," §§39-26-2, 39-26-4, 39-26-5.

[48] Vermont Statutes Annotated, Title 30, Chapter 89, "Renewable Energy Programs," §§8002-8005.

Appendix B Additional Modeling Results

A. Central Case Results

Figure B-1. Central Case Emissions by Policy Approach, 2021-2040 ($MTCO_2e$)

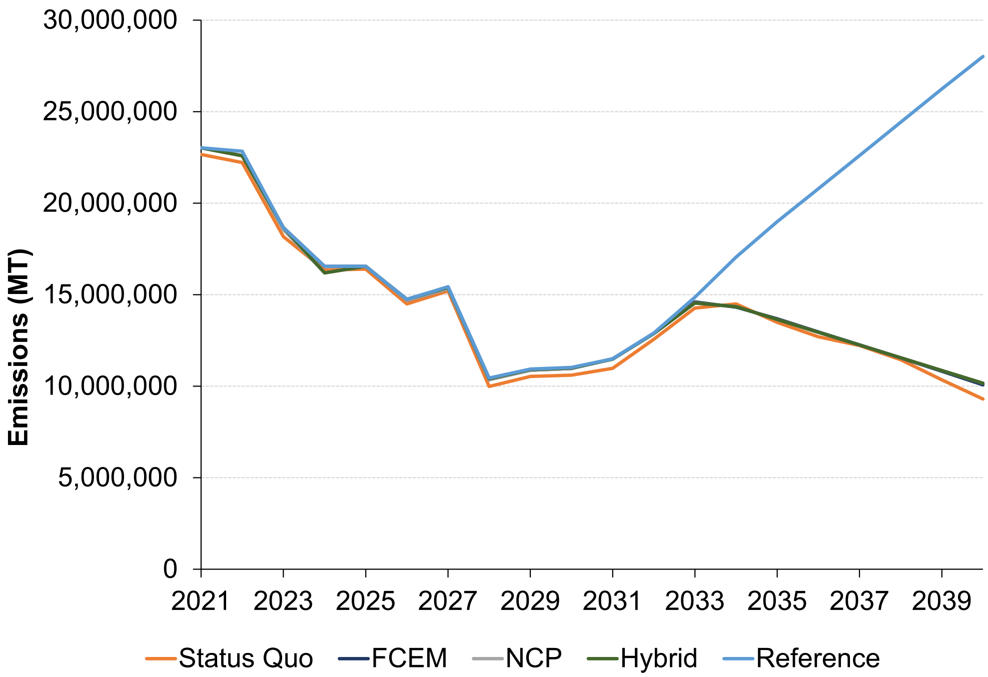


Figure B-2. Generation by Technology Type Across Policy Approaches, 2040 (MWh)

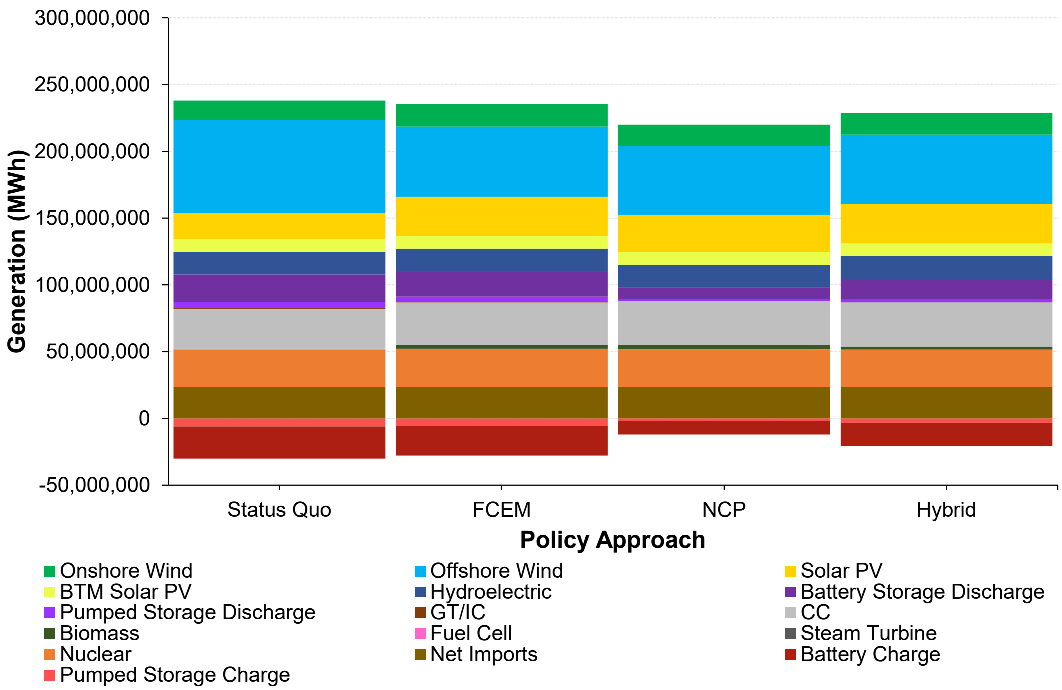


Figure B-3. Generation for Existing and New Fossil Resources Across Policy Approaches, 2021-2040 (MWh)

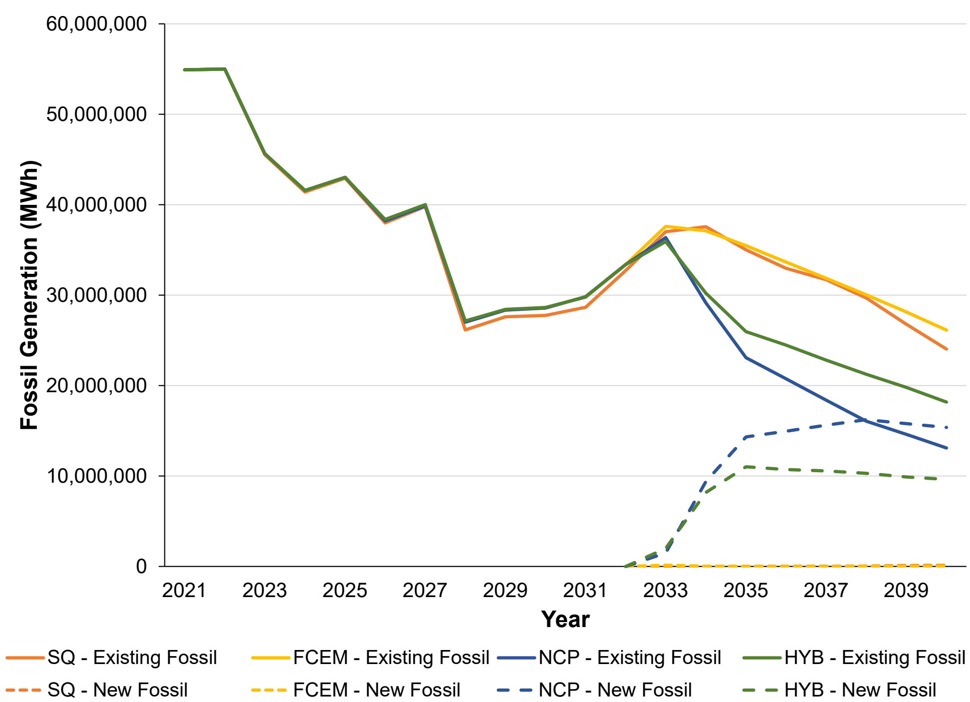
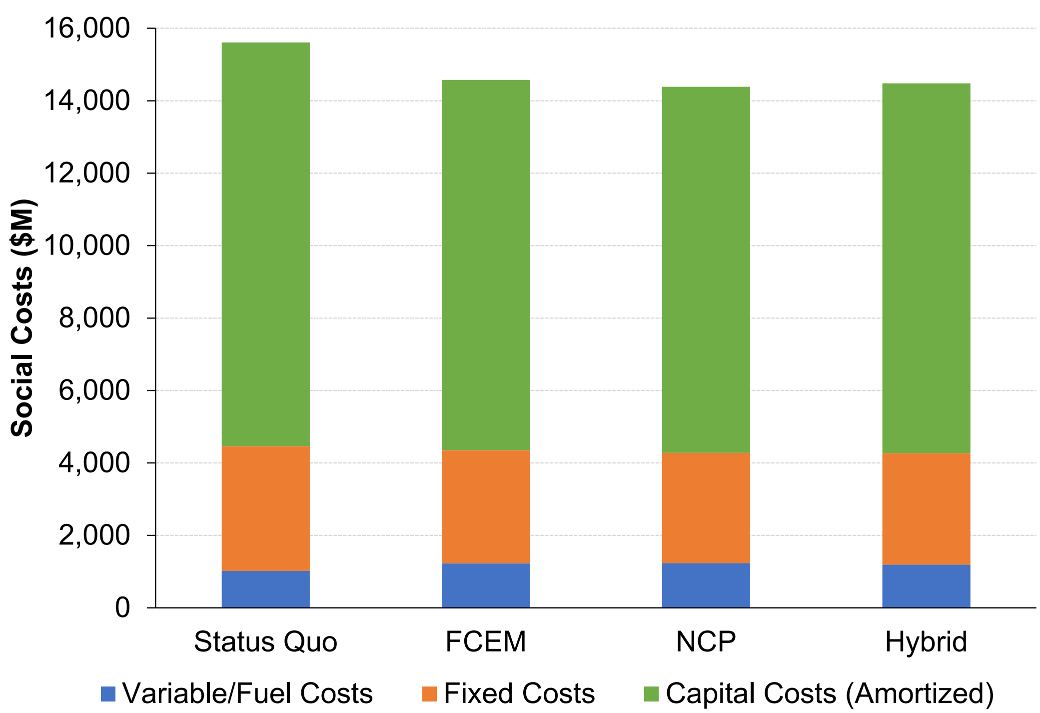


Table B-1. PPA Prices Over Time ($2020/MWh)

PPA Price	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Incremental to State Policies - Status Quo	None	None	None	None	None	None	None	None	None	None
Baseline State Policies - Status Quo	69.76	63.73	67.72	87.22	86.57	102.54	101.98	118.01	117.01	117.48
Baseline State Policies - FCEM	69.76	63.73	67.77	87.28	86.62	103.14	102.38	121.43	119.87	120.24
Baseline State Policies - NCP	69.76	63.73	67.78	87.36	86.66	103.14	102.36	121.35	119.85	120.26
Baseline State Policies - Hybrid	69.76	63.73	67.76	87.43	86.63	103.04	102.35	121.16	119.58	120.07
Baseline State Policies - Reference	69.76	63.73	67.74	87.33	86.58	103.22	102.35	121.37	119.91	120.37

PPA Price	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Incremental to State Policies - Status Quo	None	None	67.55	105.48	110.86	111.59	111.79	117.02	117.70	124.36
Baseline State Policies - Status Quo	118.68	116.96	116.63	116.15	116.12	116.45	116.39	116.24	117.28	118.71
Baseline State Policies - FCEM	122.17	119.03	117.33	116.76	116.38	116.04	115.99	115.81	115.84	116.15
Baseline State Policies - NCP	121.92	119.07	117.29	116.83	116.62	116.49	116.16	115.94	115.86	116.16
Baseline State Policies - Hybrid	122.23	118.82	117.28	116.74	116.37	115.92	115.92	115.70	115.78	115.81
Baseline State Policies - Reference	121.82	118.96	117.78	117.36	117.10	116.85	116.62	116.45	116.25	116.08

Figure B-4. Social Costs by Policy Approach, 2040 ($2020 Millions)



1. FCEM

Figure B-5. Resource Mix, FCEM, 2020-2040 (MW)

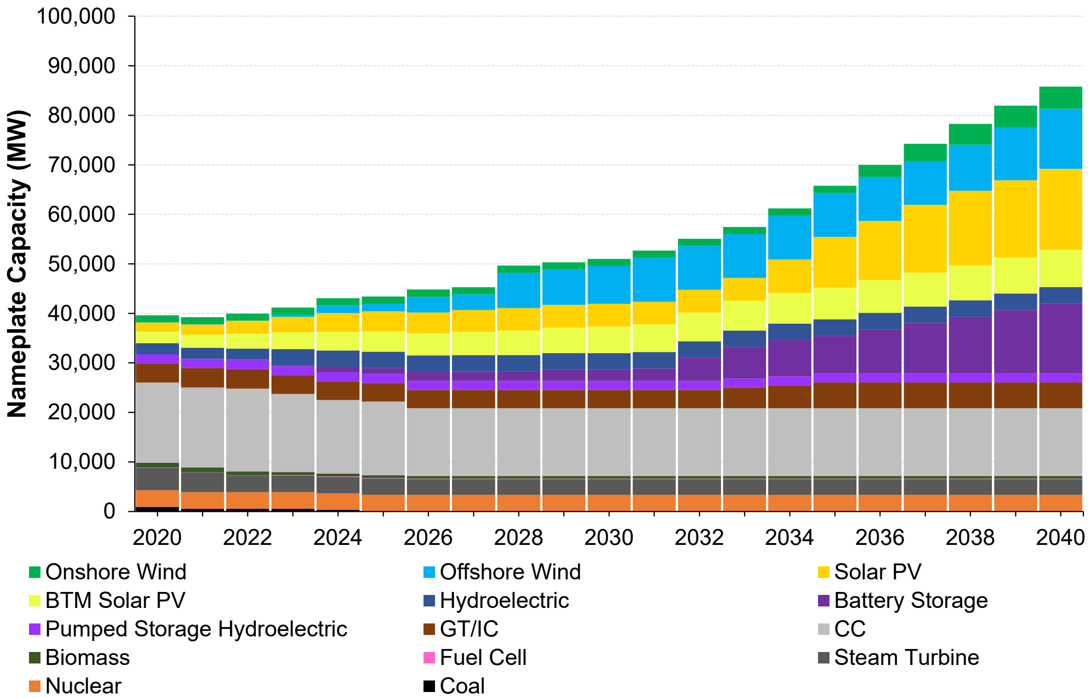


Figure B-6. Capacity Additions, FCEM, 2021-2040 (MW)

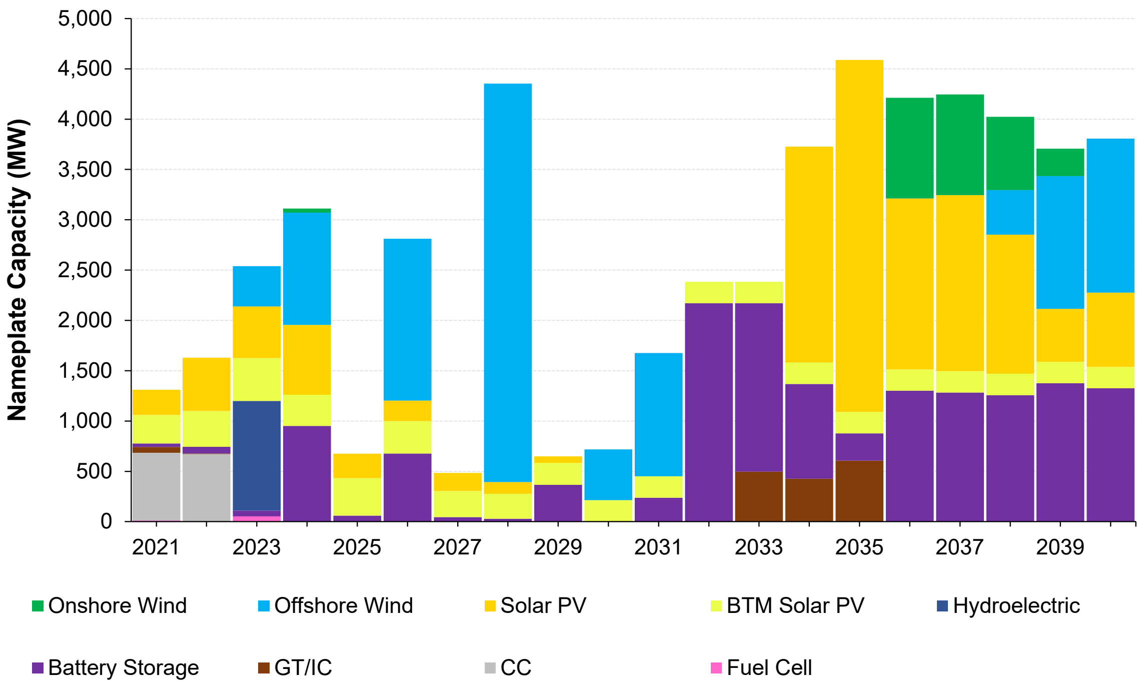


Figure B-7. Capacity Retirements, FCEM, 2021-2040 (MW)

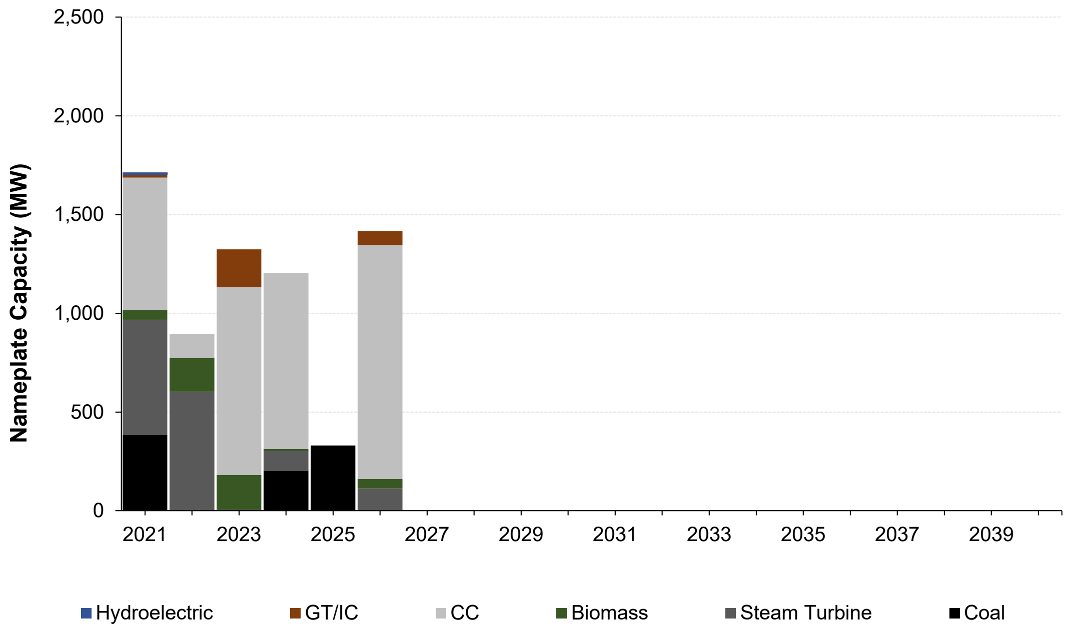


Figure B-8. Generation Mix, FCEM, 2021-2040 (MWh)

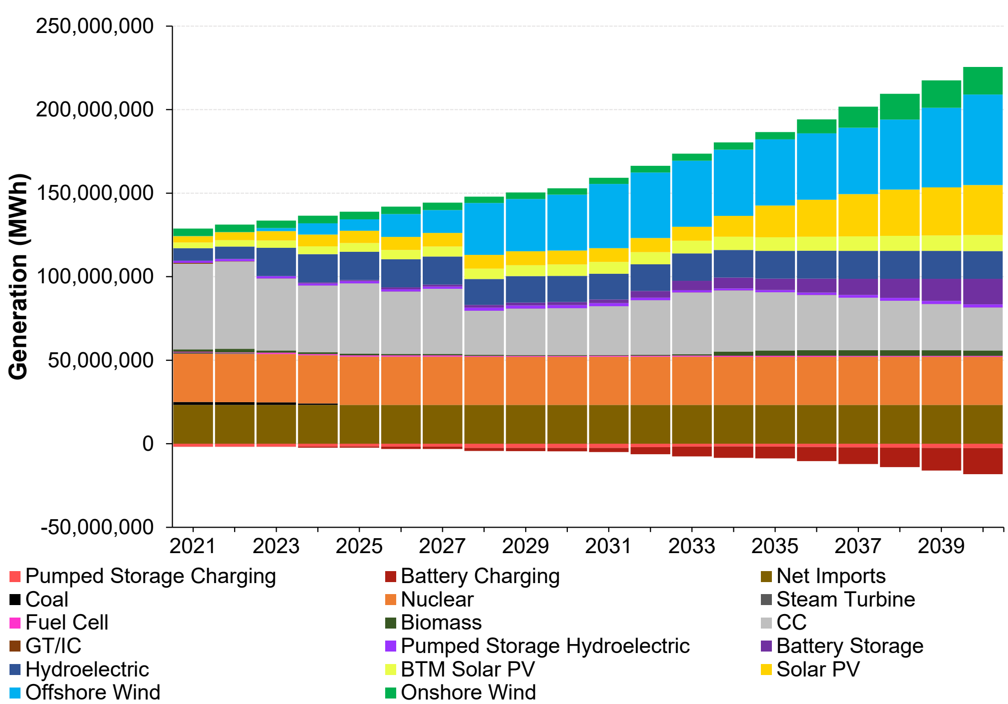


Figure B-9. Capacity Factors for Combined Cycle, Battery Storage, Offshore Wind, Onshore Wind, and Solar PV, FCEM, 2021-2040 (%)

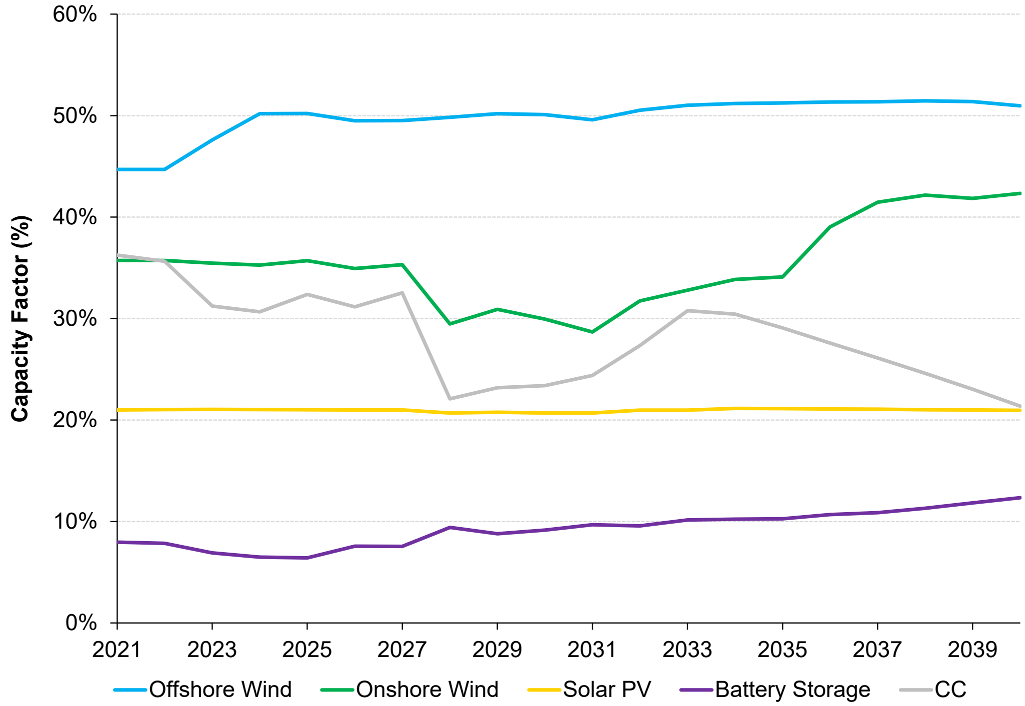
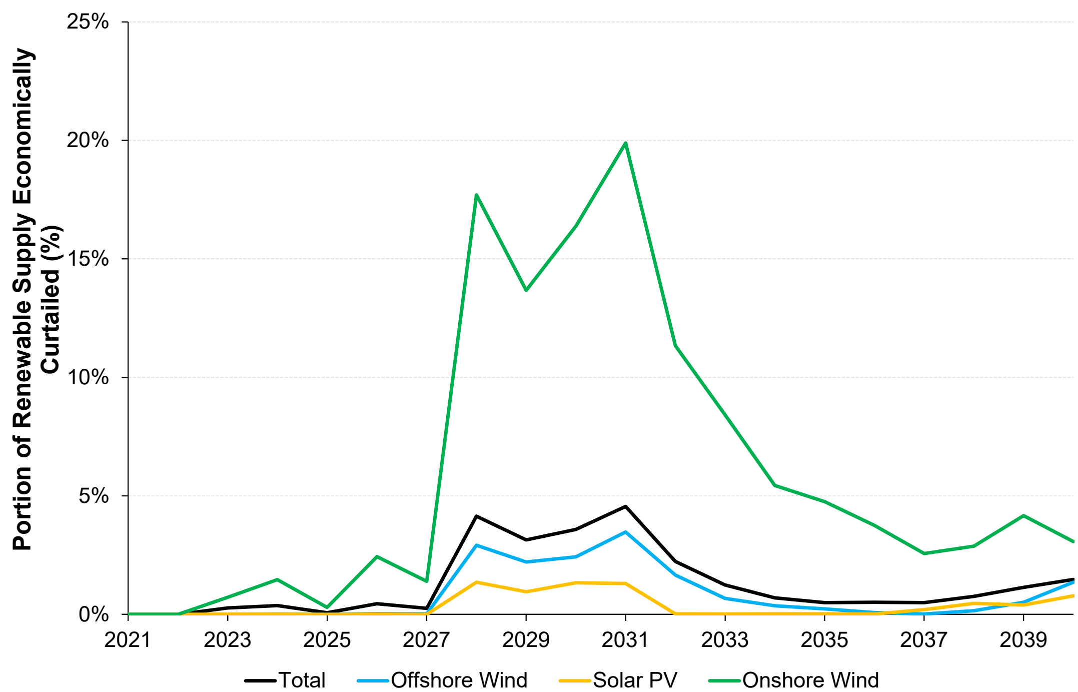


Figure B-10. Annual Curtailments by Technology, Variable Renewable Generation, FCEM, 2021-2040 (%)



2. *Net Carbon Pricing*

Figure B-11. Resource Mix, Net Carbon Pricing, 2020-2040 (MW)

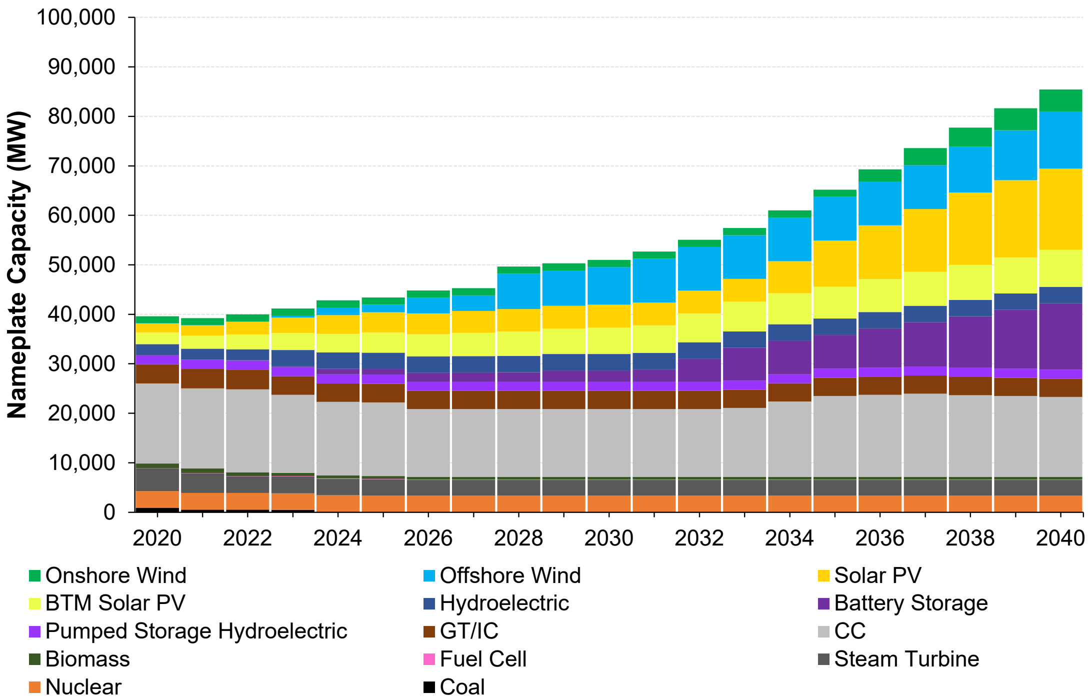


Figure B-12. Capacity Additions, Net Carbon Pricing, 2021-2040 (MW)

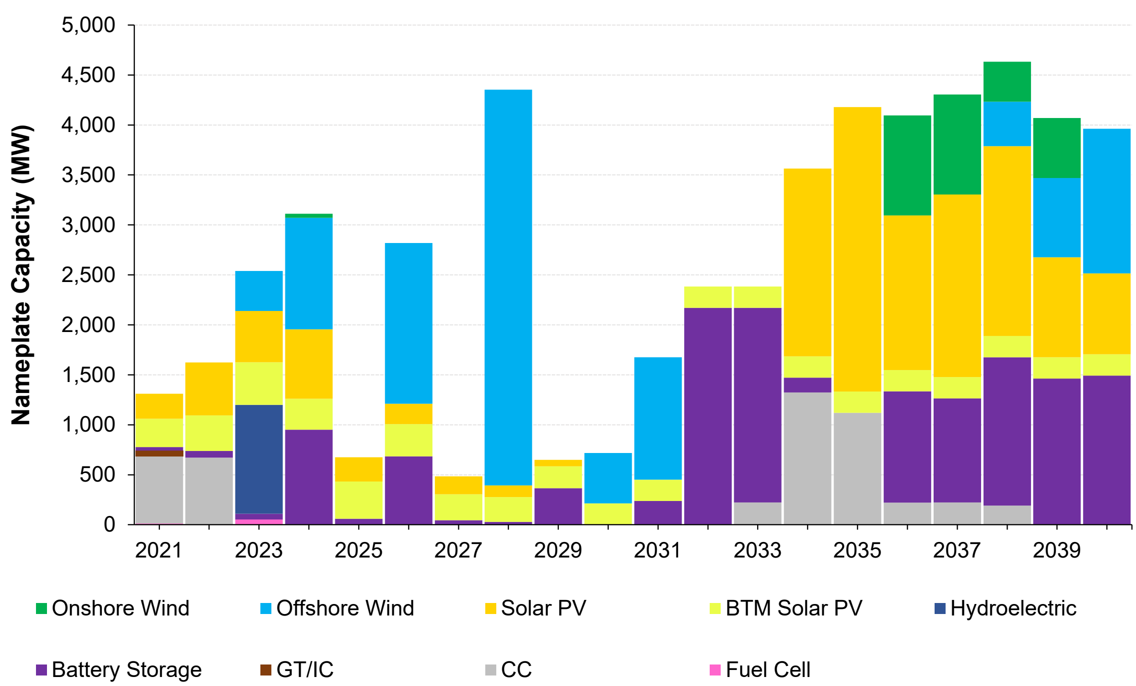


Figure B-13. Capacity Retirements, Net Carbon Pricing, 2021-2040 (MW)

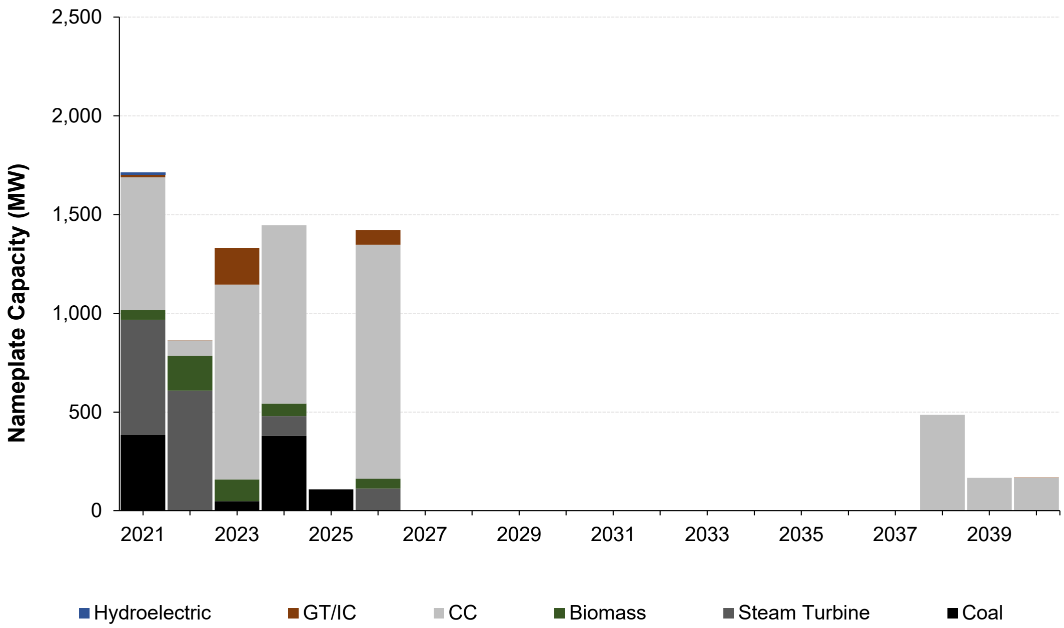


Figure B-14. Generation Mix, Net Carbon Pricing, 2021-2040 (MWh)

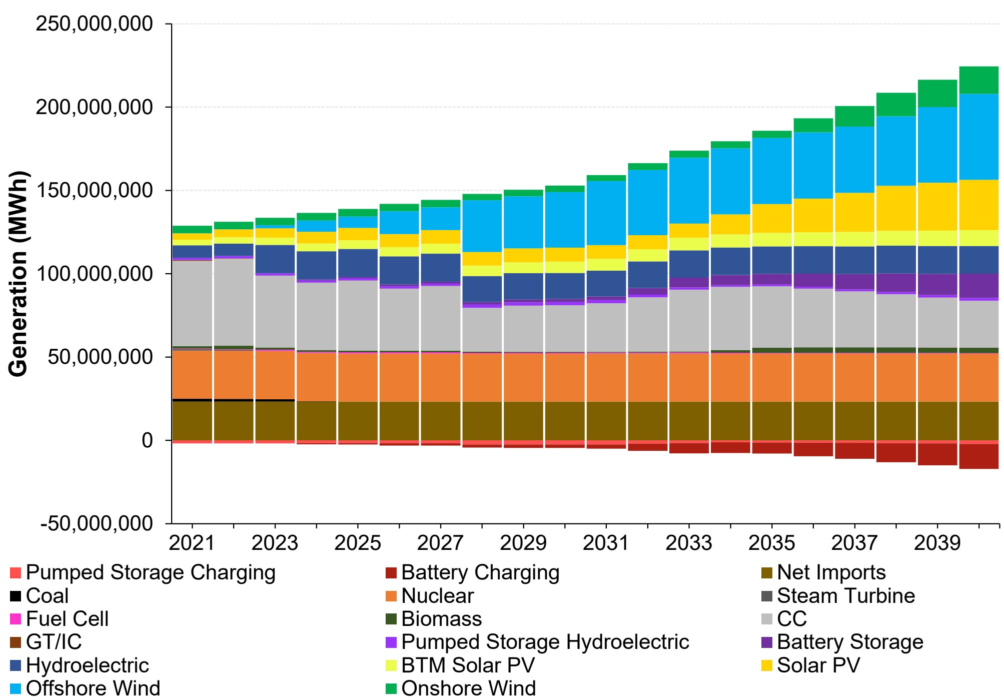


Figure B-15. Capacity Factors for Combined Cycle, Battery Storage, Offshore Wind, Onshore Wind, and Solar PV, Net Carbon Pricing, 2021-2040 (MW)

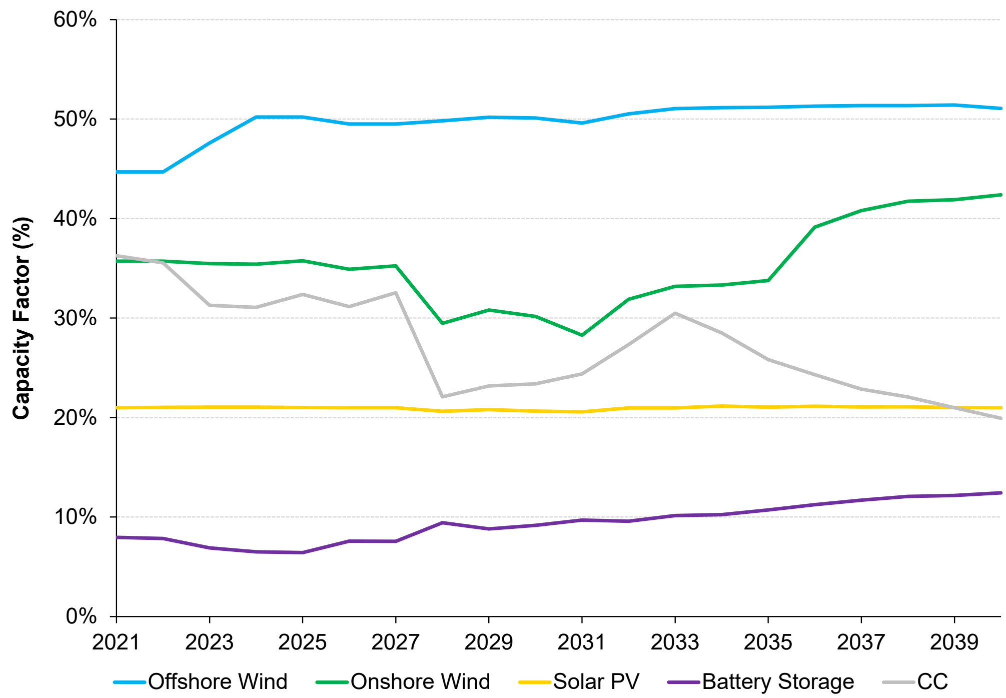
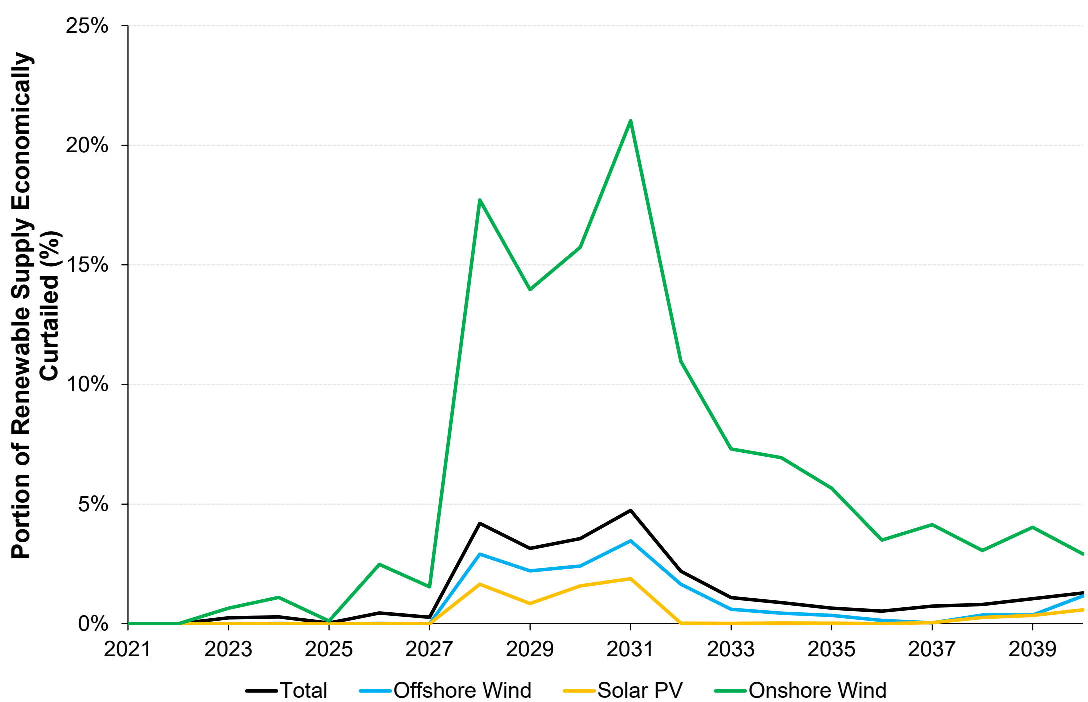


Figure B-16. Annual Curtailments by Technology Type, Variable Renewable Generation, Net Carbon Pricing, 2021-2040 (%)



3. Hybrid

Figure B-17. Resource Mix, Hybrid Approach, 2020-2040 (MW)

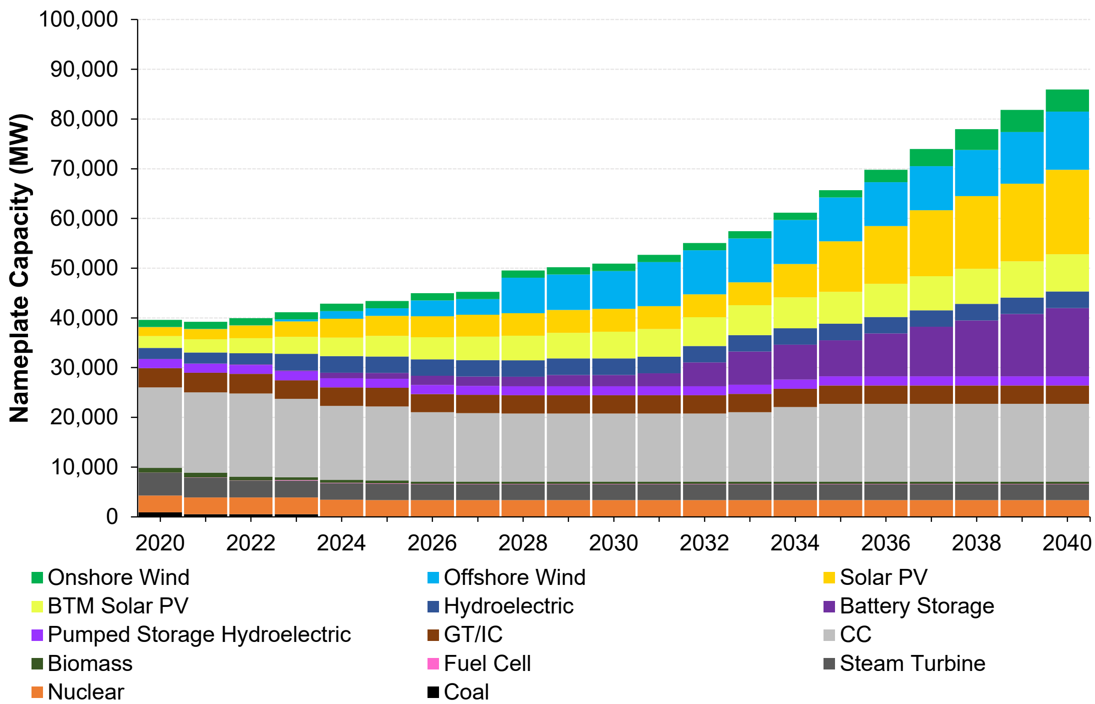


Figure B-18. Capacity Additions, Hybrid Approach, 2021-2040 (MW)

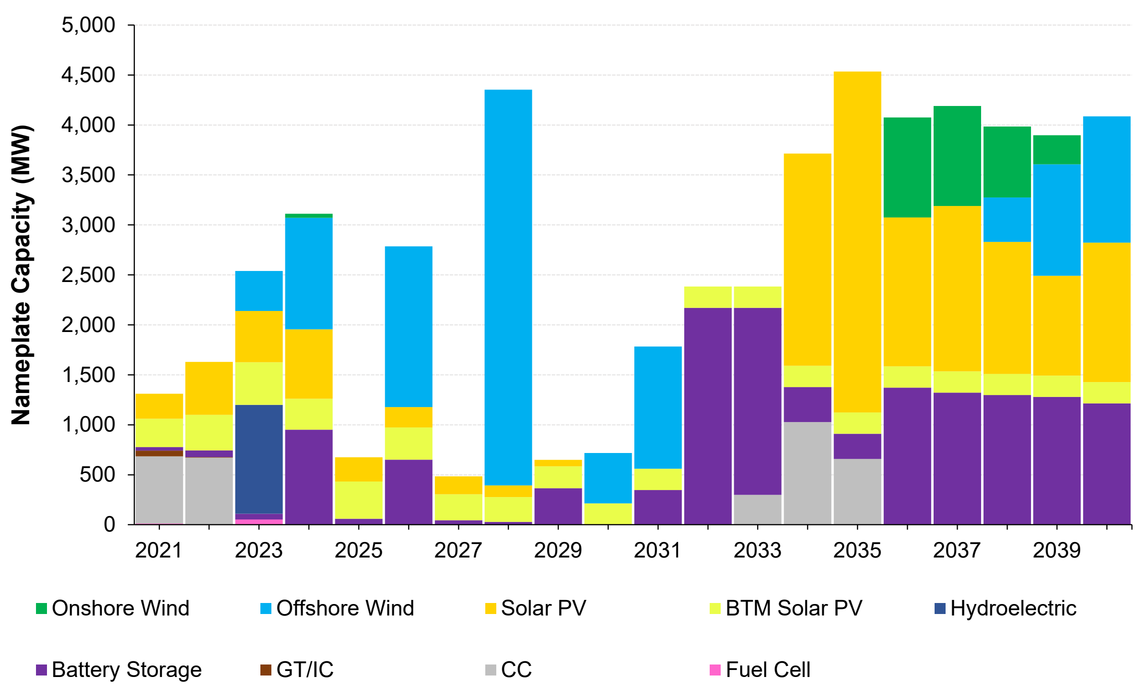


Figure B-19. Capacity Retirements, Hybrid Approach, 2021-2040 (MW)

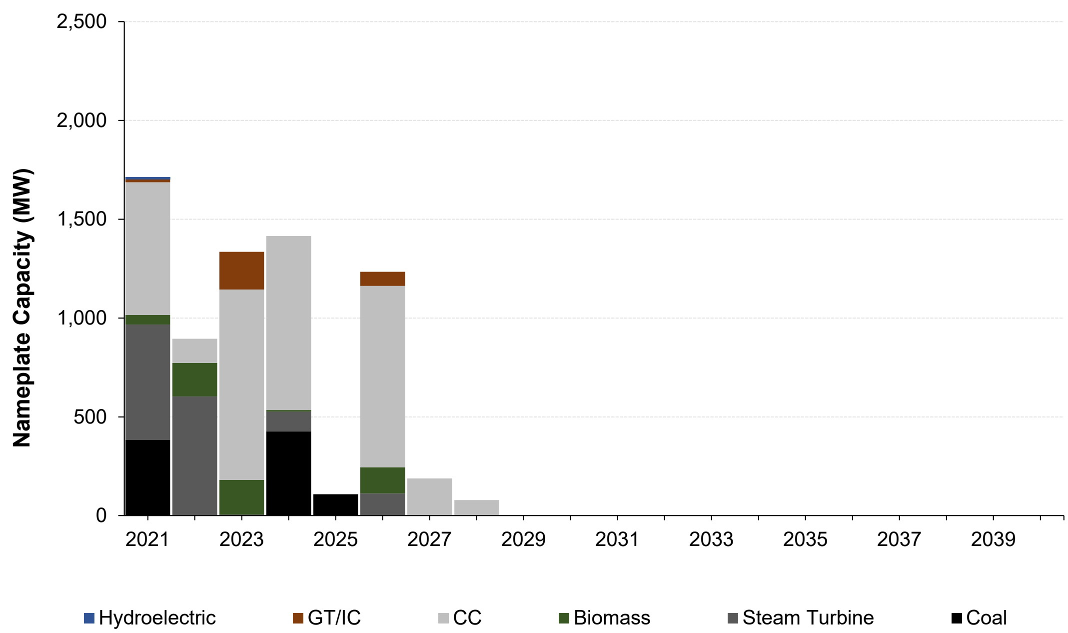


Figure B-20. Generation Mix, Hybrid Approach, 2021-2040 (MWh)

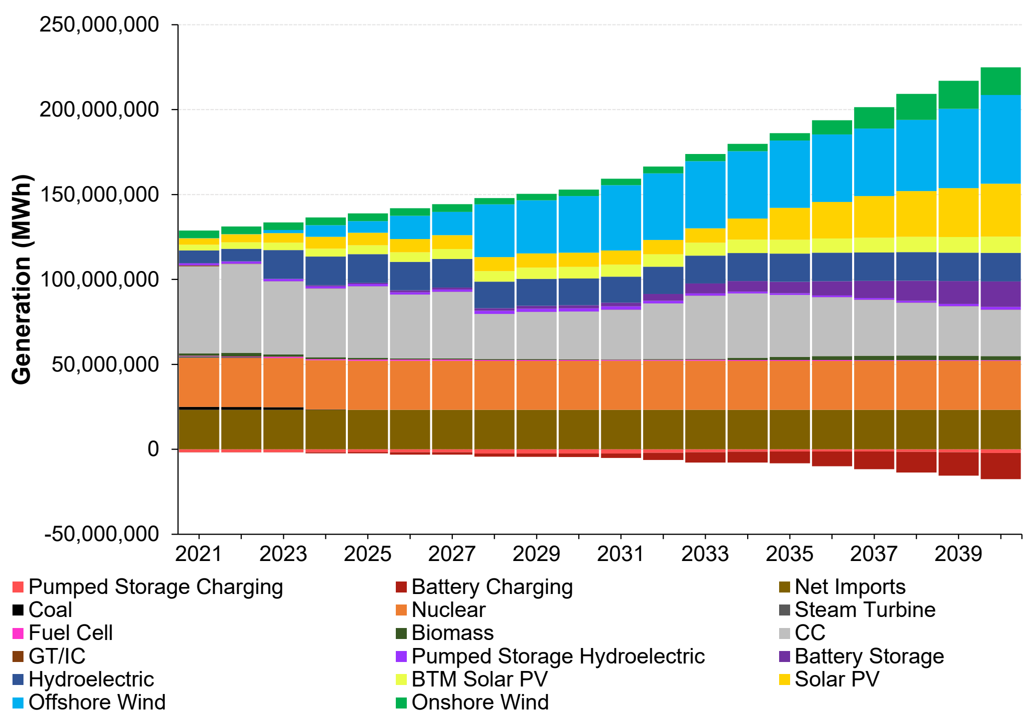


Figure B-21. Capacity Factors for Combined Cycle, Battery Storage, Offshore Wind, Onshore Wind, and Solar PV, Hybrid Approach, 2021-2040 (%)

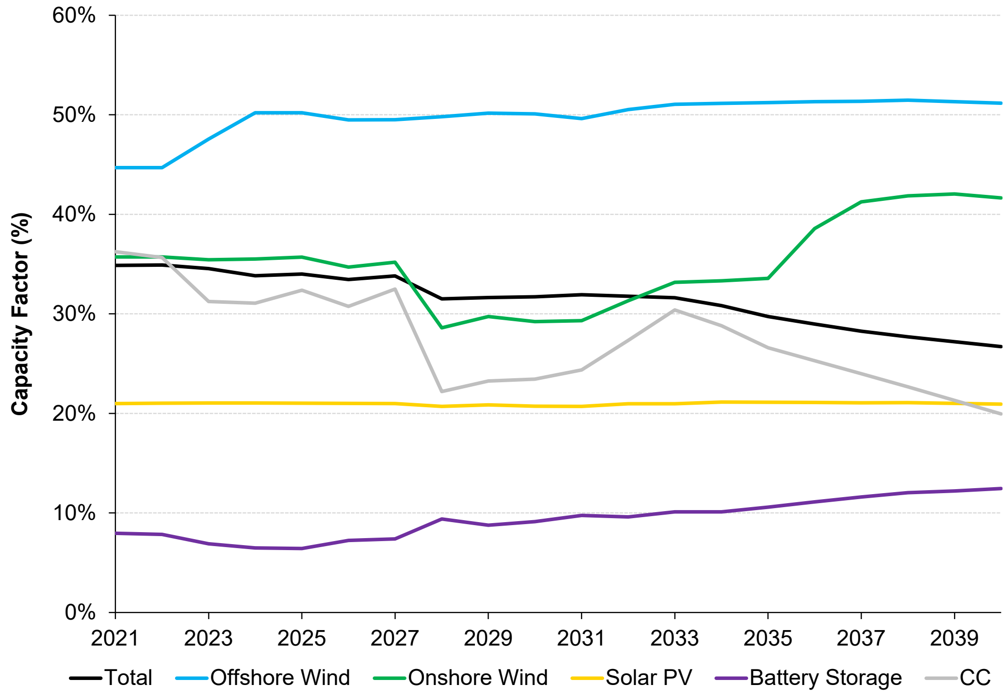
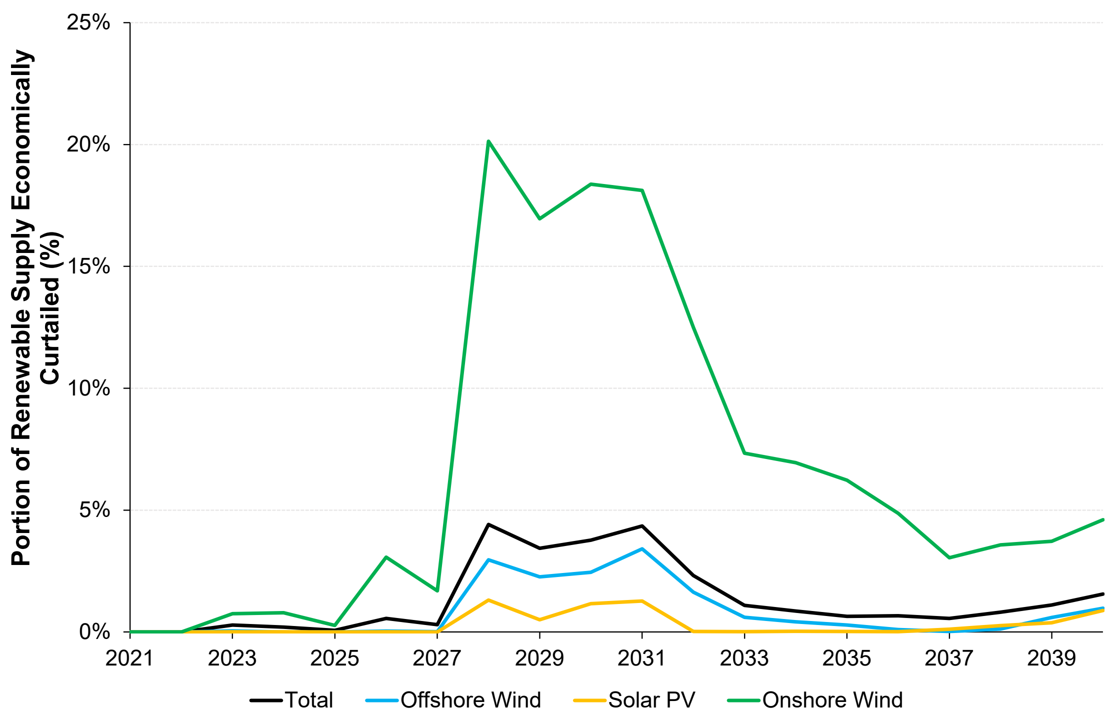


Figure B-22. Annual Curtailments by Technology Type, Variable Renewable Generation, Hybrid Approach, 2021-2040 (%)



B. Scenario Results

Figure B-23. Resource Mix Across Policy Approaches, Alternative Decarbonization Target Scenario, 2040 (MW)

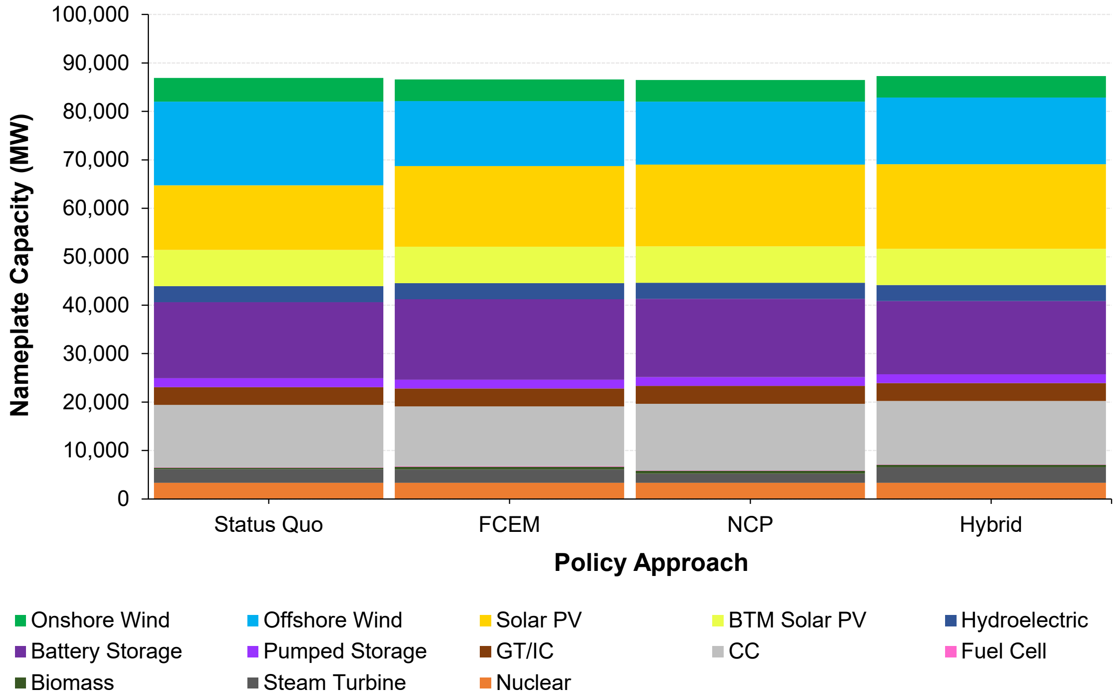


Figure B-24. Resource Mix Across Policy Approaches, Alternative Capital Costs Scenario, 2040 (MW)

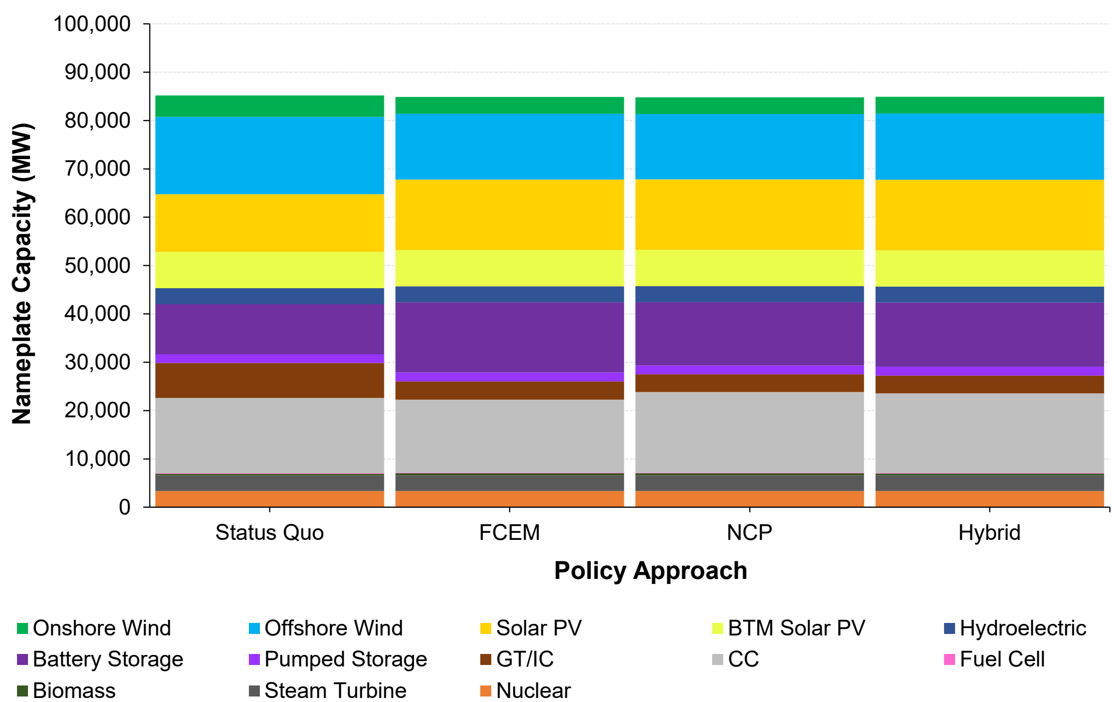


Figure B-25. Resource Mix Across Policy Approaches, Additional Retirements Scenario, 2040 (MW)

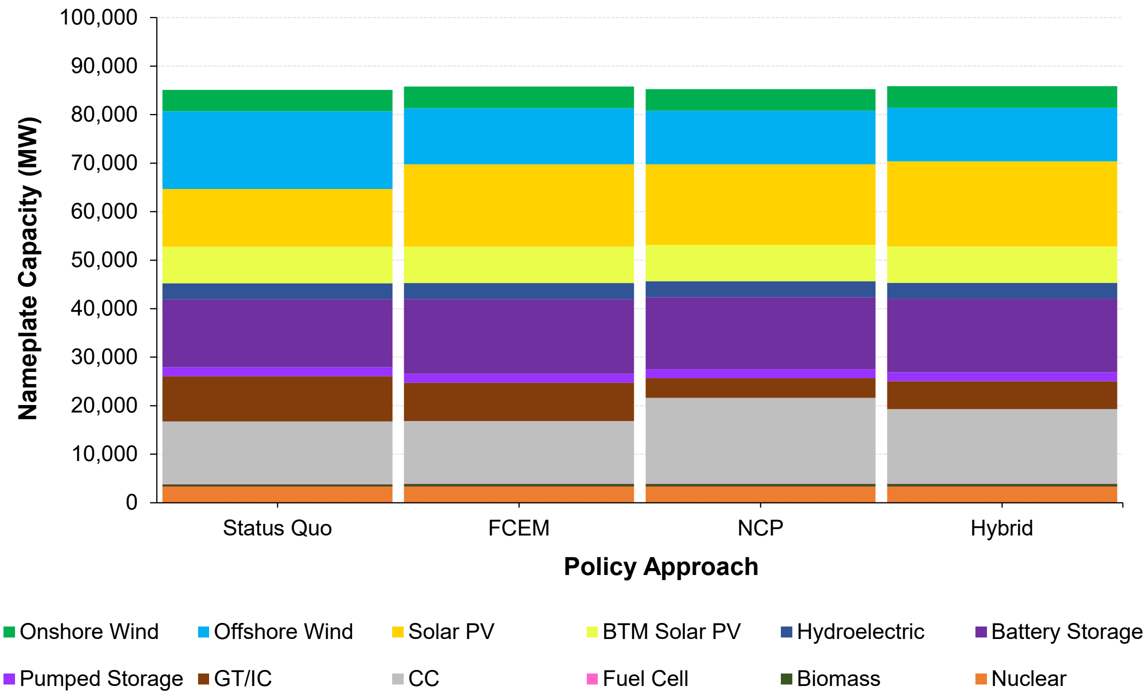


Figure B-26. Resource Mix Across Policy Approaches, Transmission Scenario, 2040 (MW)

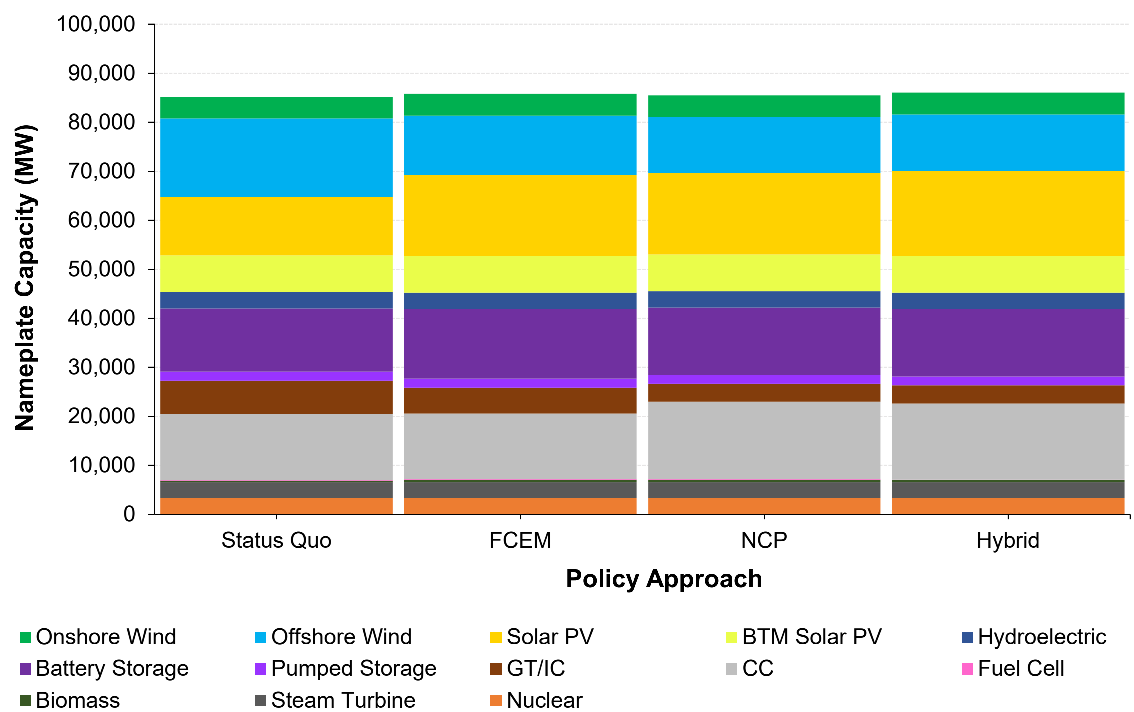


Figure B-27. Generation by Technology Type Across Policy Approaches, Alternative Decarbonization Target Scenario, 2040 (MWh)

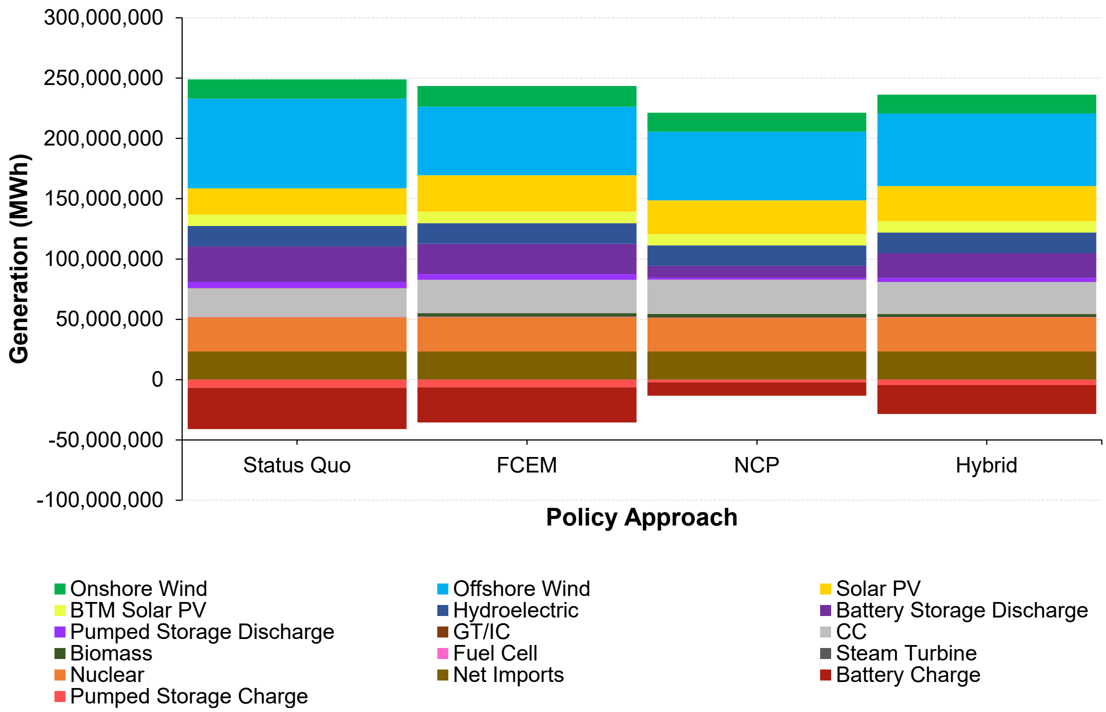


Figure B-28. Generation by Technology Type Across Policy Approaches, Alternative Capital Costs Scenario, 2040 (MWh)

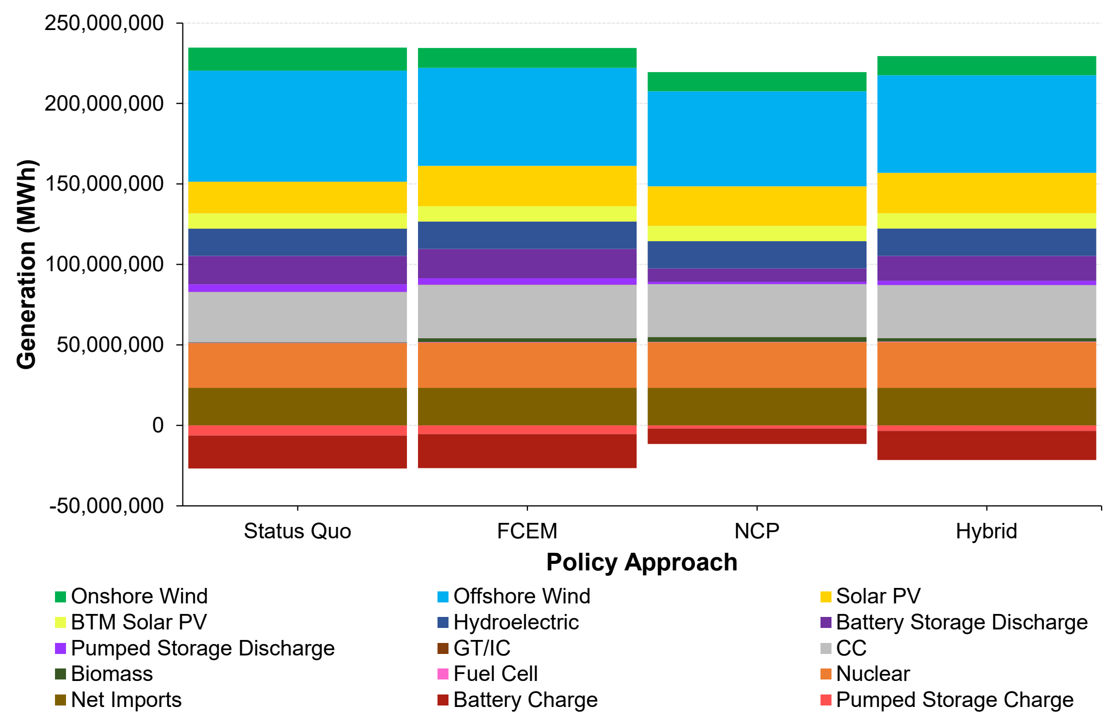


Figure B-29. Generation by Technology Type Across Policy Approaches, Additional Retirements Scenario, 2040 (MWh)

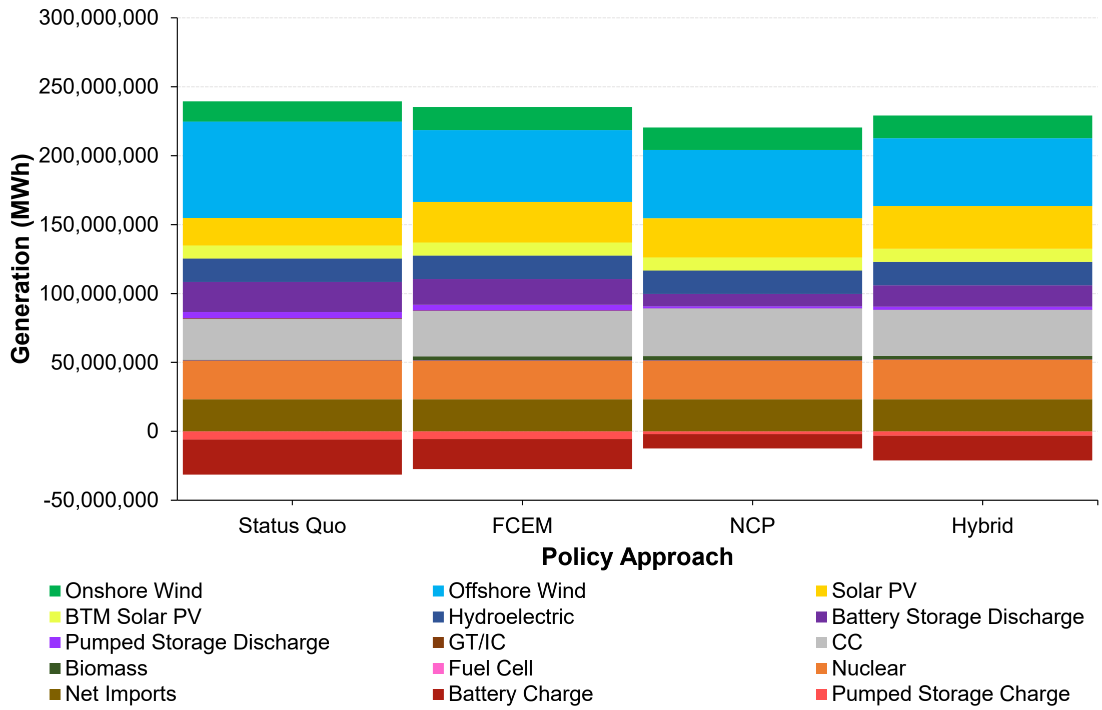


Figure B-30. Generation by Technology Type Across Policy Approaches, Transmission Scenario, 2040 (MWh)

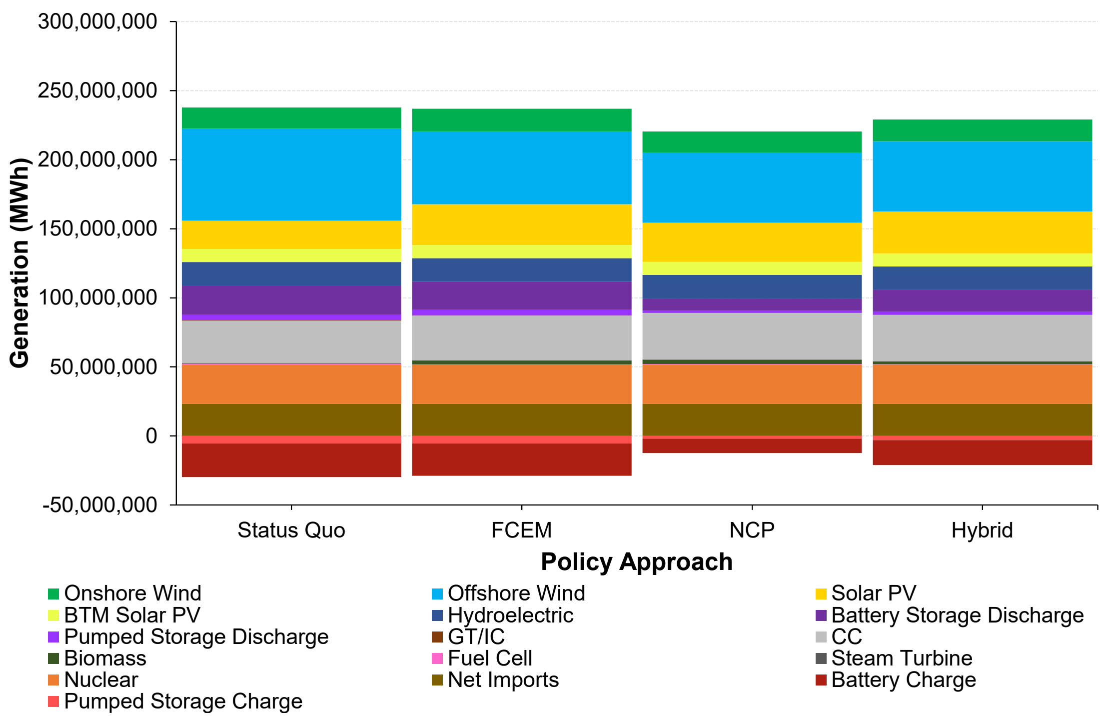
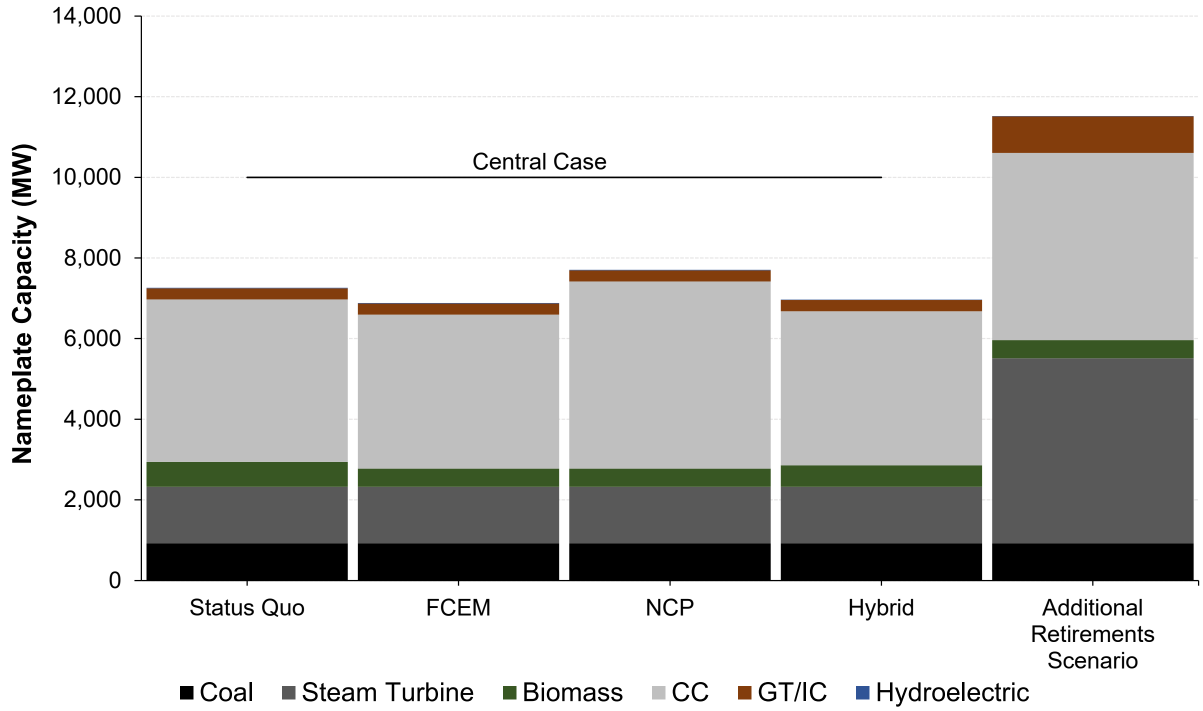


Figure B-31. Nameplate Capacity of Retirements, Central Case and Additional Retirements Scenario, 2040 (MW)



1. *Alternative LMP Hybrid Scenario*

Figure B-32. Carbon and CEC Prices, Hybrid Approach, for Central Case and Alternative LMP Scenario, 2021-2040 ($2020/MTCO$_2$e and $2020/MWh)

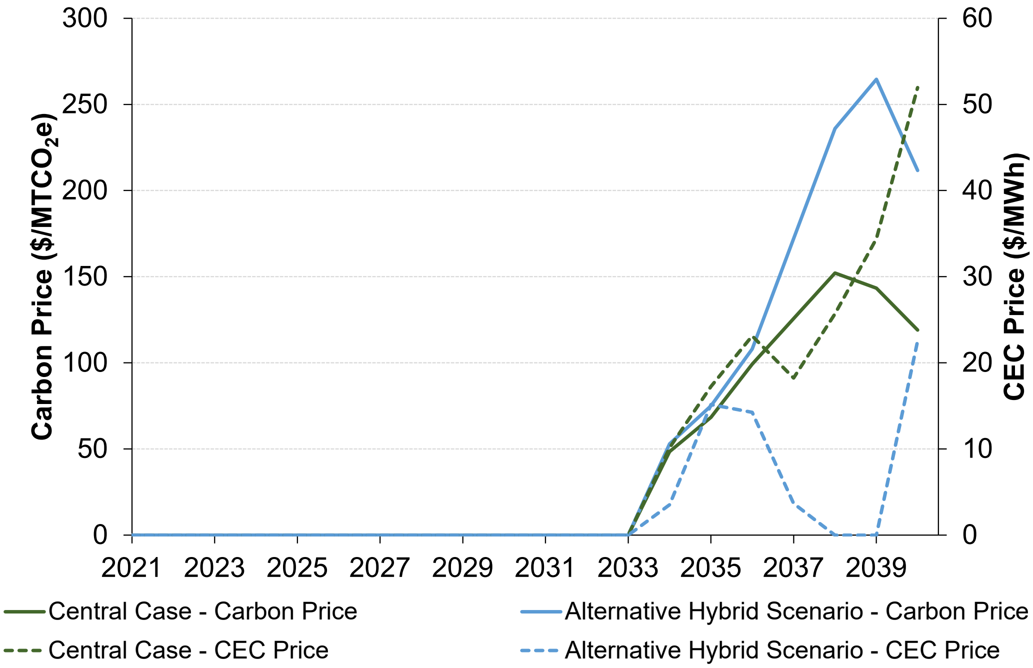
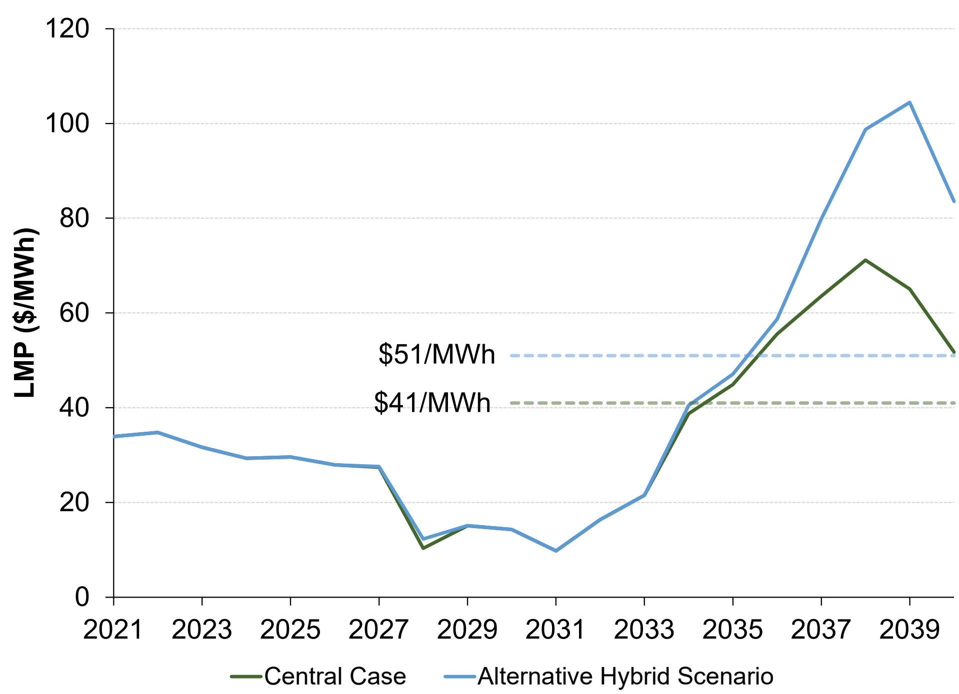


Figure B-33. Average Annual LMP, Hybrid Approach, for Central Case and Alternative LMP Scenario, 2021-2040 ($2020/MWh)



2. *Transmission Scenario Results*

Across policy approaches, the Maine-New Hampshire and SEMA/RI-NE interfaces experience the highest amounts of congestion. Under the decarbonization policy approaches, congestion on the Maine-New Hampshire line is the result of new onshore wind capacity brought online in Maine. Because the Reference scenario includes current state commitments for offshore wind, the SEMA/RI-NE interface experiences elevated levels of congestion under all approaches.

Figure B-34. Hours with Binding Transmission Constraints in 2040, by Policy Approach

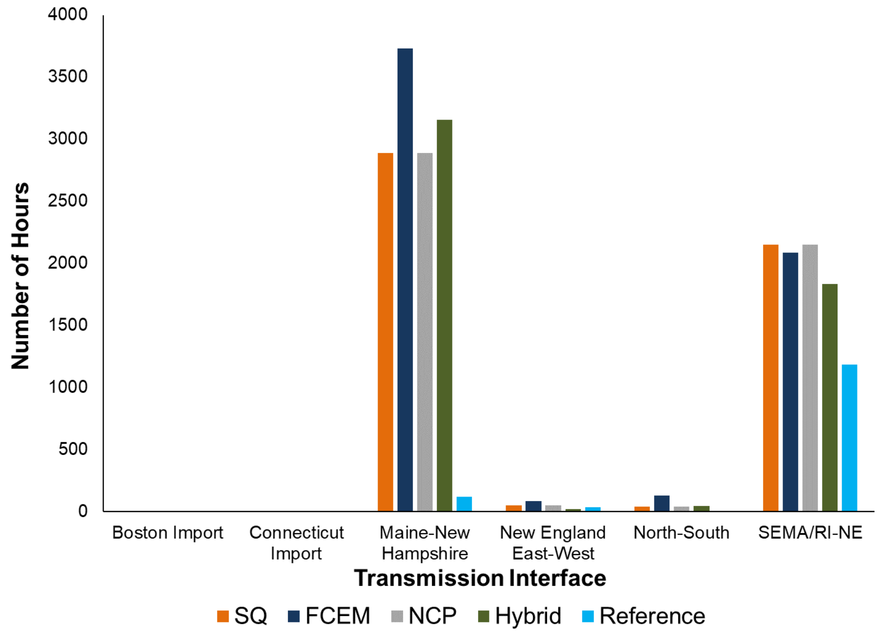


Figure B-35. Hourly Power Flows for Select Interfaces in 2040, by Policy Approach

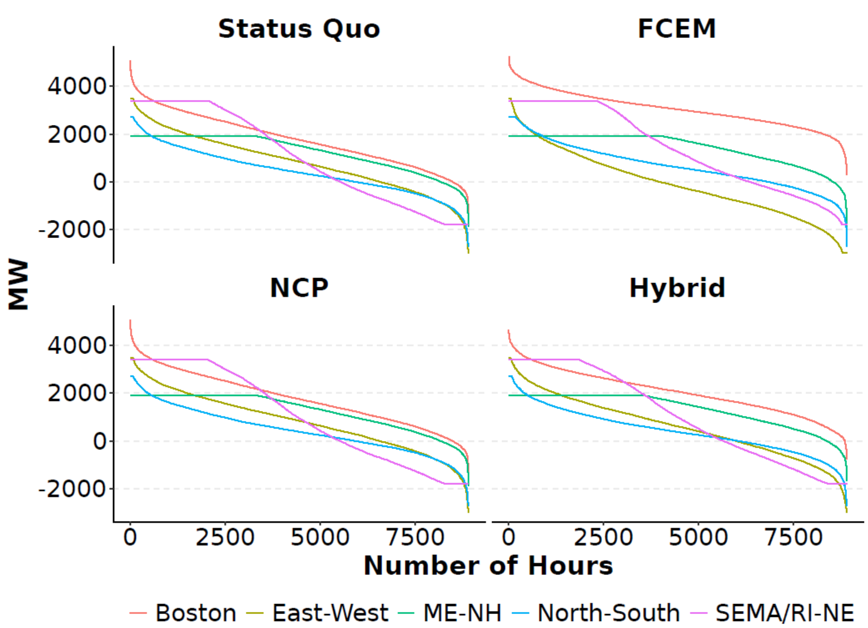


Figure B-36. Hourly Power Flows for SEMA/RI-NE, 2025, 2030, 2035, 2040

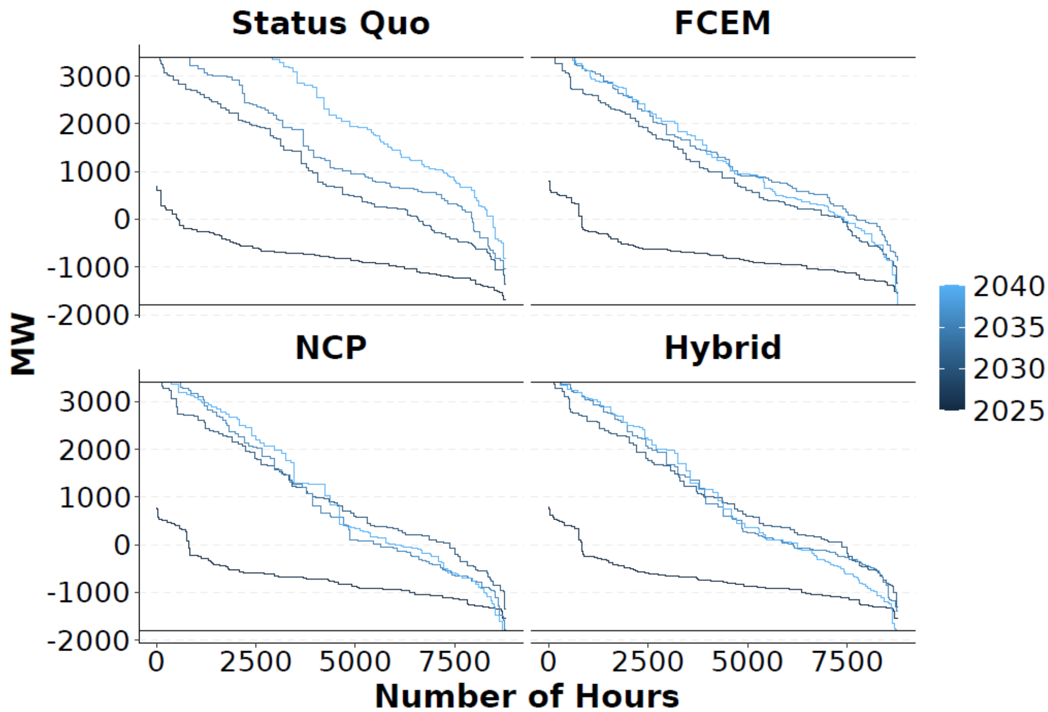


Figure B-37. Hourly Power Flows for Maine-New Hampshire, 2025, 2030, 2035, 2040

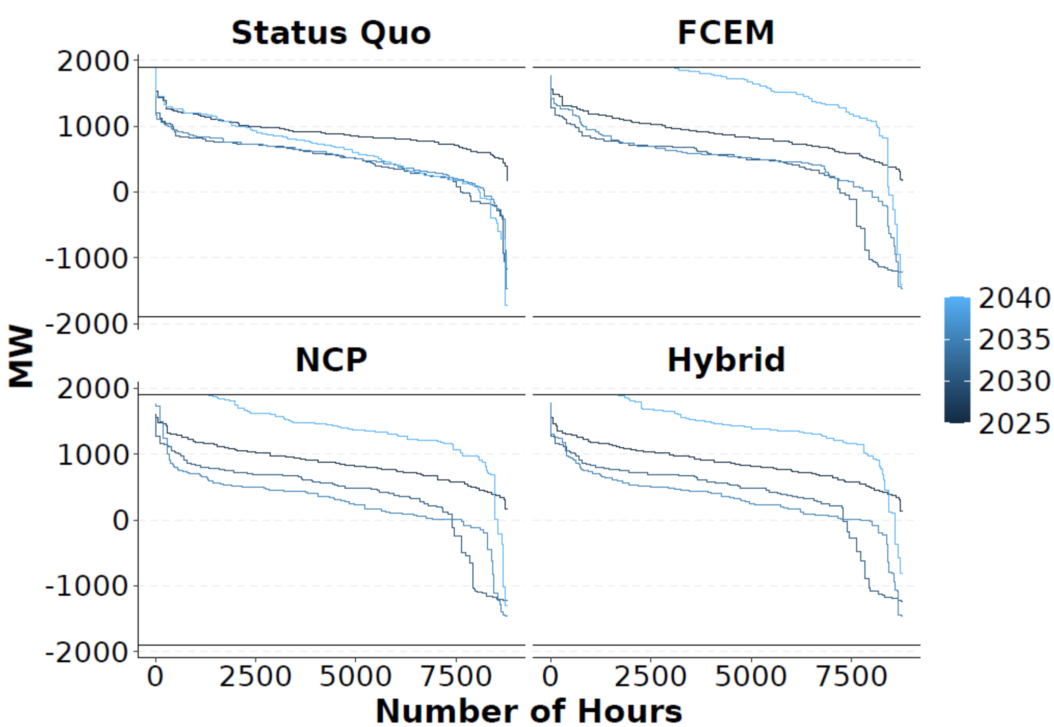
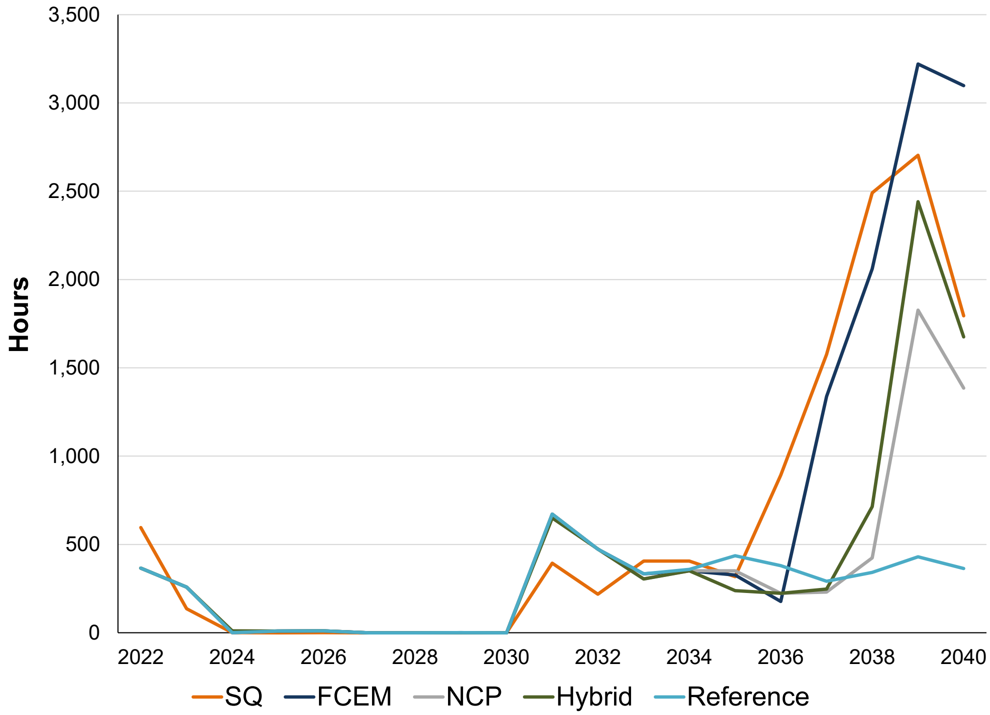


Figure B-38. Total Congestion by Policy Approach, 2022-2040



Appendix C Dynamic CEC

Our study evaluates a "uniform" FCEM that provides the same award for each unit of clean energy produced (*i.e.*, 1 CEC for every MWh of clean energy generated). Under a dynamic CEC approach, the quantity of CECs awarded is proportional to the emissions displaced by clean energy, which would depend on the marginal emission rate at the time of clean energy generation.[49] As our analysis shows, marginal emissions rates vary continuously hour-by-hour and potentially by large amounts, particularly with greater decarbonization. At present, in New England, marginal emissions generally reflect natural gas-fired resources, potentially varying from more-efficient combined cycle units to less efficient combustion turbines. However, when the energy market clears with a "clean" resource at the margin, the marginal emissions rate is zero, which will occur more frequently with greater deployment of variable renewable resources. Under the dynamic CEC approach, the quantity of CECs awarded would be 0 during hours when variable renewable resources are on the margin, as no emissions are displaced by new clean energy, and reflect gas-fired marginal emissions during periods when the market clears with gas-fired resources at the margin.

The idea behind the dynamic CEC approach is to increase the cost-effectiveness of carbon emissions abatement by making CEC awards proportional to the quantity of emissions abated. By making awards proportional to emission reductions, developers are incented to develop new clean energy resources that produce energy at times of the highest carbon emissions. With a uniform CEC, the FCEM provides the same incentive for clean energy generation except during periods with curtailments.[50] In contrast, just as a net carbon price will raise average LMPs during hours with the highest marginal emissions rate, the dynamic CECs will increase net revenues for clean generators able to operate during periods of higher marginal emissions.

While the idea behind dynamic CECs is appealing, several factors likely limit its promise compared to static CECs, raising questions about the merits of this approach. First, conceptually, the incentives from dynamic CECs certainly fall short of the incentives and associated benefits of Net Carbon Pricing. Moreover, our analysis indicates that the improvement in incentives from making CECs dynamic rather than static are quite limited. While dynamic CECs would diminish the incentive to offer negative prices, they would also compress the LMP spreads that support efficient operation of storage resources to reduce carbon emissions. Second, the potential of a dynamic CEC depends in large part on our ability to accurately forecast actual marginal emission rates avoided by clean resources. The difficulty in forecasting emissions avoided by clean resources raise a host of practical concerns that are either infeasible (or very costly) to fully resolve or could result in

[49] ISO-NE, "Pathways to the Future Grid: Evaluating clean energy and carbon pricing frameworks as alternative market designs to advance the region's clean energy transition," March 18, 2021, slide 13, available at https://nepool.com/wp-content/uploads/2021/03/NPC_FG_20210318_Supplemental-1.pdf.

[50] While uniform CECs reward the same quantity of clean energy produced regardless of when generation occurs, the clawback feature of prevailing PPA structures would tend to disincent production of clean energy during periods of curtailment and negative prices. That is, variable renewable energy supplying clean energy during periods of curtailment would be awarded CECs, the negative prices received for this energy (*i.e.*, that producers would pay) would erode the economic gain from the CEC, thus reducing the incentive supplied by CECs to produce energy during these periods.

potentially substantial uncertainty about CEC awards, with follow-on impacts for investments. The remainder of this section discuss these issues in turn.

A. Dynamic CECs do not create the same incentives as net carbon pricing, may not meaningfully improve on static CECs and may introduce new problems

In several respects, the dynamic CEC is unable to provide all of the same incentives for cost-effective emission reductions as Net Carbon Pricing. For example, as shown in the bottom row of **Table VI-1**, replicated below, the FCEM, using dynamic or static CECs, provides no incentive for increased generation from more efficient natural gas generators relative to less efficient natural gas units. Our quantitative analysis indicates that this difference can materially affect resource outcomes. As depicted in **Figure VI-1** and **Figure VI-2**, an important difference between Net Carbon Pricing and FCEM in our quantitative analysis is the amount of installed combined cycle versus combustion turbine capacity. Although combined cycle units are more costly to develop than combustion turbines (*i.e.*, have higher upfront capital costs), combined cycle units have significantly lower heat rates, resulting in lower unit fuel costs and a lower marginal emission rate. Net Carbon Pricing accounts for differences in carbon-intensity when balancing the tradeoffs between higher capital costs with lower operating costs, while the FCEM fails to do so. Introducing dynamic CECs does not change this outcome.

Table C-1. Cost-Effectiveness of Incentives for Emission Reductions Under Alternative Policy Approaches

Cost-Effectiveness of Key Resource Decisions	*Status Quo*	*FCEM*	*FCEM w/ Dynamic CECs*	*Net Carbon Pricing*	*Hybrid Approach*
Substitution of Clean for Fossil-Fuel Resources	*NA*	High	High	High	High
Choice Among Clean Energy Resources	*NA*	Low/Medium	Medium	High	Medium
Choice Among Fossil-Fuel Resources	Low	Low	Low	High	Medium

Thus, the scope for potential improvements in incentives from dynamic CECs is limited to the choice among clean energy resources with regard to when clean energy supplies are delivered so that they achieve the greatest emission reductions. To improve cost-effectiveness, dynamic CEC awards can account for two types of differences in (marginal) emissions rates. First is the difference in marginal emissions rates between two different fossil generation technologies, such as between a combined cycle and a combustion turbine unit. These differences may be modest in magnitude (as discussed in **Section VI.B.2.d**) and more difficult to predict reliably. Thus, while dynamic CECs could improve the price signals created by an FCEM to better incent supply of clean energy consistent with these differences in marginal emission rates, the potential gains in cost-effectiveness appear to be limited by the modest differences in marginal emission rates among fossil resources in New England, and the challenges to reliably forecasting intertemporal differences in marginal emission rates could make achieving any of these modest gains infeasible.

The second difference in marginal emission rates is between periods when fossil resources are on the margin (with marginal emissions reflecting these fossil resources) and periods when variable renewable resources are on the margin (with zero marginal emission rates). In this case, compared to static CECs, dynamic CECs would not be expected to provide greater incentives for variable renewable resources to supply during periods when fossil-fuel, rather than other clean energy, is on the margin. Static CECs create this incentive, without the need to add any dynamic component, because the margins earned by variable renewable resources during hours when these non-emitting resources are on the margin are eroded by the negative LMPs (set based on the negative priced offers from variable renewable resources that receive static CECs). However, dynamic CECs do not change this outcome. With dynamic CECs, during periods when variable renewable resources are on the margin, variable renewable resources earn no CECs and, thus, these resources make energy market offers at $0/MWh.[51] As a result, LMPs clear at offers of $0/MWh when variable renewable resources are on the margin. Thus, like outcomes with static CECs, resources under dynamic CECs earn little (or no) return when variable renewable resources are on the margin. Thus, static CECs and dynamic CECs have equivalent incentives with respect to avoiding production during periods of likely economic curtailments.

While dynamic CECs would not increase the incentive for developers to pursue projects that deliver energy during periods when variable renewable is on the margin, as described above, they would diminish the extent of negative LMPs. As discussed in the report, negative LMPs potentially have undesirable consequences for the energy market performance. However, eliminating negative LMPs has an adverse unintended consequence. Without negative LMPs, the spread in LMPs between periods when variable renewable resources are on the margin and periods when fossil resources are on the margin are substantially compressed. As discussed in **Section V.B.2**, widened LMP spreads are an important price signal for storage resources to incent storage of excess variable renewable supplies to be discharged in periods when they can displace emissions from fossil generation. Thus, the compression of LMP spreads from dynamic CECs would reduce the incentive for storage resources to cost-effectively displace carbon emissions and lead to inefficiently low incentives for storage resources (compared to those from Net Carbon Pricing), which would raise the cost of achieving emission targets.

Beyond these theoretical limitations of the dynamic CEC approach, there are practical issues to address with implementing a dynamic CEC. In principle, this dynamic value could reflect actual marginal emission rates or an estimate of marginal emission rates. We discuss each below.

[51] As explained earlier with respect to static CECs, a variable renewable resource will offer at a negative price in the energy market (reflecting the negative of the CEC price) given that the resource earns revenue at the CEC price for each clean MWh it produces. Under dynamic CECs, a variable renewable resource offsets no carbon emissions, earns no CECs, and thus earn no CEC revenue when variable renewable resources are on the margin. With no CEC revenue, producing energy during negative LMPs results in net losses. Accordingly, variable renewable resources will offer at $0/MWh in the energy market under a dynamic CEC approach.

B. Dynamic CEC values based on actual marginal emission rates

Dynamic CEC based on actual emission rates would award CECs based the outcomes of actual market clearing, contingent on the offers made by resources to deliver energy supply. In practice, however, dynamic CEC values based on the actual interval-by-interval marginal emission rates may be impractical and/or infeasible. The use of actual emission rates to determine dynamic CEC awards raises multiple complications including whether dynamic CEC values are calculated after the fact, during the settlement process, or during market-clearing, potentially affecting the resources that clear the market and resulting LMPs. However, both of these approaches likely create substantial issues that may not be surmountable.

If CEC awards were determined during settlement, after market clearing, then the information about the quantity of CECs market participants would earn would not be known to them before they submit their energy market offers to sell clean energy in the ISO-NE energy market. In this case, resources would submit energy market offers based on, at best, an estimate of the quantity of CECs generated if their offers clear the market. Because this estimate could be higher or lower than the actual quantity of CECs generated, clean energy resources would construct their offers with potentially substantial uncertainty about their SRMC. Such uncertainty could raise several issues. First, uncertainty in SRMC could introduce inefficiency into market clearing that could undermine the FCEM's ability to incent the most cost-effective emission reductions. For example, if resources with otherwise similar SRMCs offer energy at different prices due to different expectations of CEC awards, then higher cost resources may clear the market before lower cost resources. Because the scope of uncertainty regarding CEC awards could be large depending on whether variable renewable or gas-fired resources set the marginal emission rate, differences in expectations about CEC awards could lead to large differences in offers. In addition, market participants would bear the risk of uncertain CEC awards, thus adding uncertainty to the return earned from supplying. This uncertainty could cause resources to include risk premiums in their offers, which would raise LMPs.

Alternatively, the market could be designed such that market-clearing reflects both the known SRMC and the CEC price, such that market clearing would then select the most efficient set of resources to operate contingent on their SRMC and the total CEC value generated, which would be solved endogenously as a part of market clearing. However, it is unclear how such a market could be designed and whether such a design would be feasible.[52] Such an approach would add substantial computational complexity to the energy market's existing auction software. It is unclear whether such an auction would be computationally feasible and, at minimum, would likely substantially increase market clearing run-time and require substantial cost to develop new software.

C. Dynamic CEC values based on historical marginal emission rates

Dynamic CEC values can be set based on historical values of marginal emission rates. With historical marginal emission rates, market participants know the value of dynamic CECs when making energy market offers and, potentially, when making resource investments. Because historical marginal emission rates would be an

[52] For example, offers from clean energy resources could include an assumed CEC price along with other offer parameters (*i.e.*, energy prices for each block, start-up costs, minimum run times, etc.) with the market clearing algorithm minimizing costs contingent on the price and the quantity of CECs generated.

approximation of actual marginal emission rates, the benefit they provide in terms of aligning investment incentives with emission reductions depends on how accurately they reflect actual marginal emission rates in real time and how best to set dynamic CEC values given uncertainty in marginal emission rates (*e.g.*, reflecting the probability-weighted marginal emission rate).[53]

Thus, the extent to which a historical dynamic CEC provides a reasonable approximation depends on how the historical values are constructed and the extent to which the values are correlated with the actual values. This is largely an empirical issue dependent on many factors, including normal weather variation (from day-to-day and season-to-season) and the dependence of marginal emissions on system resources and loads (*i.e.*, will the pattern of marginal emissions evolve over time as New England transitions to a more decarbonized system such that the past patterns of marginal emission rates are not a good predictor of future marginal emission rates).

D. Assessment of tradeoffs between static and dynamic CECs

The decision to adopt dynamic CECs would need to reflect an assessment of the benefits and costs created by adding dynamic CECs to the FCEM. In terms of potential benefits, there are several considerations.

First, as we describe in Section VI.B and above, the benefits of dynamic CECs reflect only improved efficiency in the selection among clean energy resources with respect to differences in emissions when fossil resources are on the margin. As noted above, dynamic CECs would not change the incentives to avoid production in hours with economic curtailments, as static CECs already provide this incentive. And, the increased cost introduced by a dynamic CEC from reduced incentives for storage resources to cost-effectively reduce emissions could far outweigh any other gains. Thus, the scope of potential benefits is, at best, limited and potentially negative. Further understanding of the scope of these potential benefits would thus be important to understanding the potential gains from pursuing dynamic CECs.

Second, the benefit of the dynamic CEC approach would depend on reliably estimating actual marginal emission rates given daily and seasonal weather variations and changes in system resources. As noted above, this is largely an empirical issue, particularly to the extent that dynamic CECs should reflect a probability-weighted expected marginal emission rates. Importantly, assessment of the reliability of these forecasts would need to account for the administrative process by which dynamic CECs would be set, which would determine how frequently dynamic CECs would be updated, what data and methods would be used for such calculations, and the lag in time between historical information and periods when dynamic CECs would be in effect (and whether such differences meaningfully diminish accuracy). If policymakers consider pursuing a dynamic CEC

[53] Determining the optimal dynamic CEC value given uncertainty in marginal emission rates is potentially complex and requires further exploration. One issue is that dynamic CECs should account for uncertainty in marginal emission rates (under a range of potential market-clearing outcomes), such that the CEC incentives reflect the appropriate weighting of potential outcomes. This raises potential practical questions about how best to account for this uncertainty that would require further evaluation. A second issue is that the appropriate marginal emission rates should reflect the marginal emission rate when resource compensation reflects dynamic CECs, not based on uniform CECs or a market without any FCEM. To the extent that the supply of clean energy depends on CEC incentives, historical measurements of marginal emission rates made under a different system of incentives may differ from those under dynamic CECs.

(in spite of the conceptual limitations raised above), a first step should be further analysis of historical data to assess the likely uncertainty of any forecast of dynamic CECs.

Third, regardless of the approach used to determine dynamic CEC values, consideration should be given to how these dynamic values affect the uncertainty of the returns earned by developers of variable renewable resources. To the extent that dynamic CECs increase the uncertainty of these returns (as developers would need to consider not only uncertainty in future market conditions but how uncertain market conditions interact with dynamic CECs), particularly as the FCEM would require forward market-clearing three years in advance of the first year of delivery for new resources, this could increase price/quantity risk faced by developers, which could raise costs.

Fourth, with a dynamic CEC, offer prices for clean energy resources would be expected to vary with the quantity of CECs awarded. In particular, in hours when dynamic CECs are set to a low value (*i.e.*, when variable resources are likely to set market-clearing prices), market participants' incentive to offer energy at large, negative prices would be diminished because if they supply in those hours, they would earn few CECs. However, as discussed above, these changes to LMP offers would also compress LMP spreads, thus reducing incentives for battery storage and likely increasing aggregate system costs.