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 (created carbon of 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

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[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.

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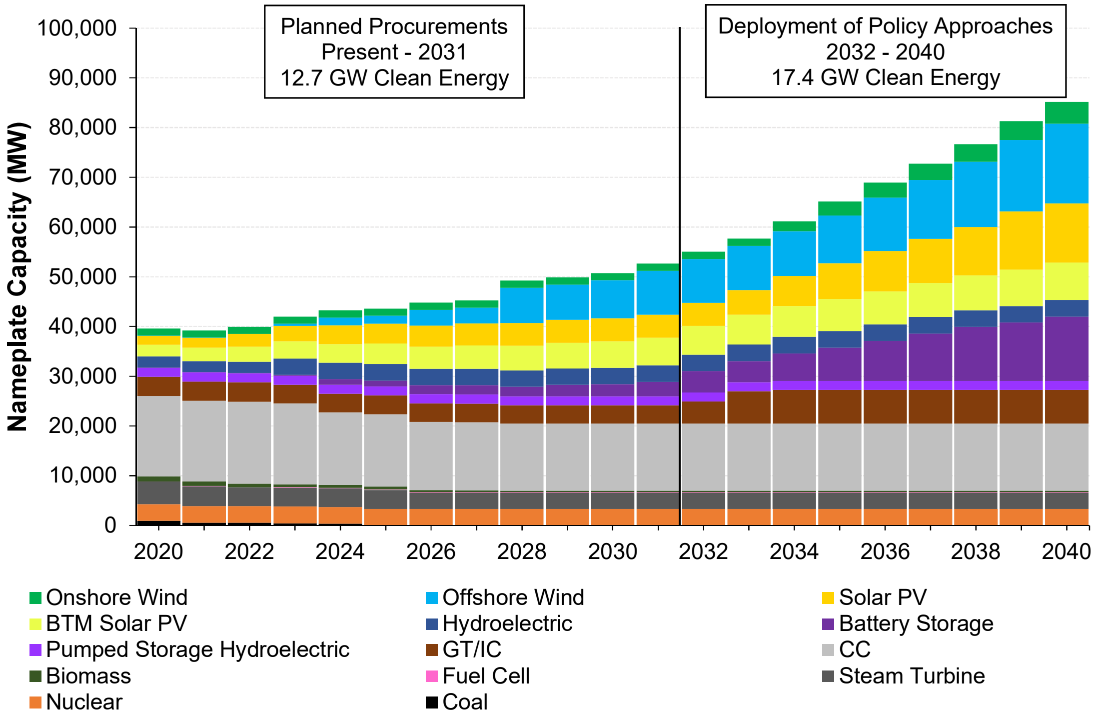
[10] Resources with higher PPA prices would be expected to submit *lower* (more negative) energy market offers. Thus, when there is overgeneration, the resources with lower PPA prices and higher, less negative, offers would be curtailed before resources with higher PPA prices and lower, more negative 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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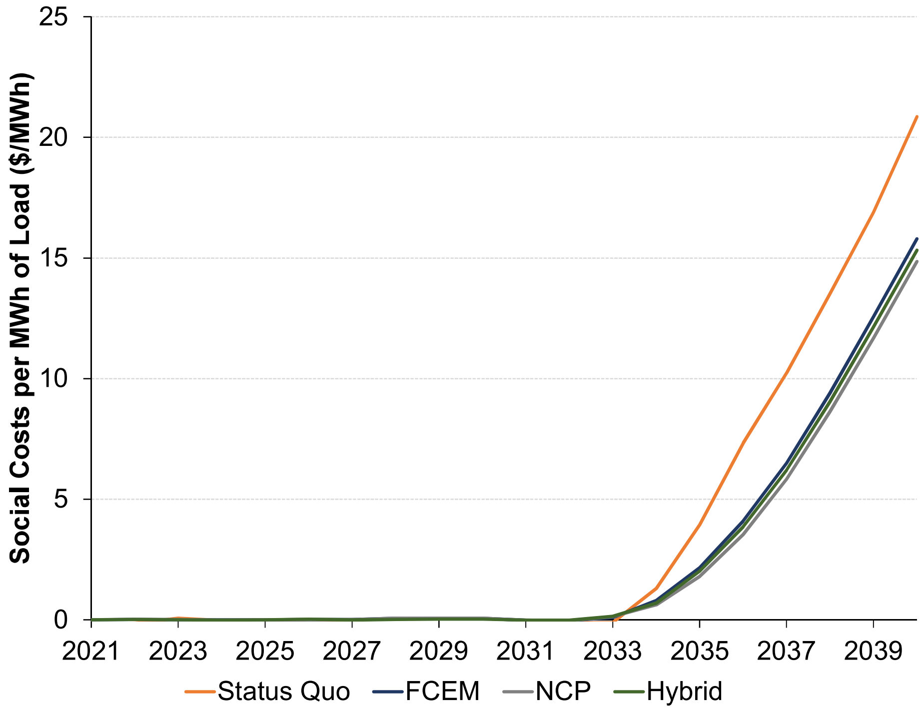
[12] Present value is calculated using a 5% real discount rate.

[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)

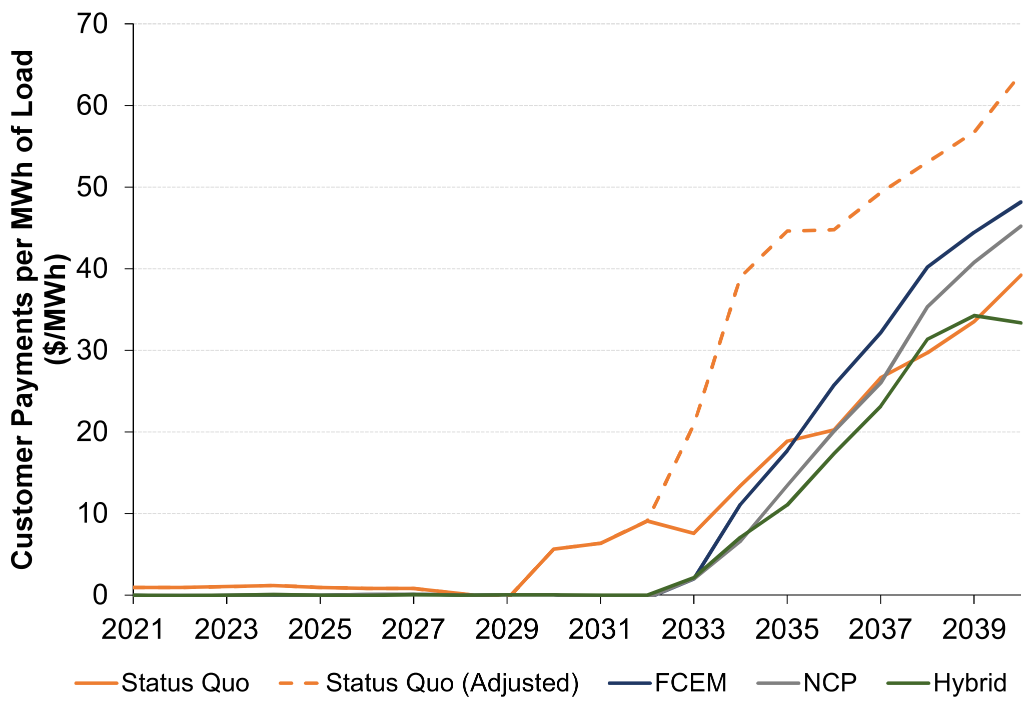
Total customer payments for wholesale energy include payments for energy, capacity and environmental attributes. Across the policy approaches in our study, the levels of payments in each category differ — thus, comparisons based on only one category may lead to incorrect conclusions about total costs. 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.

[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

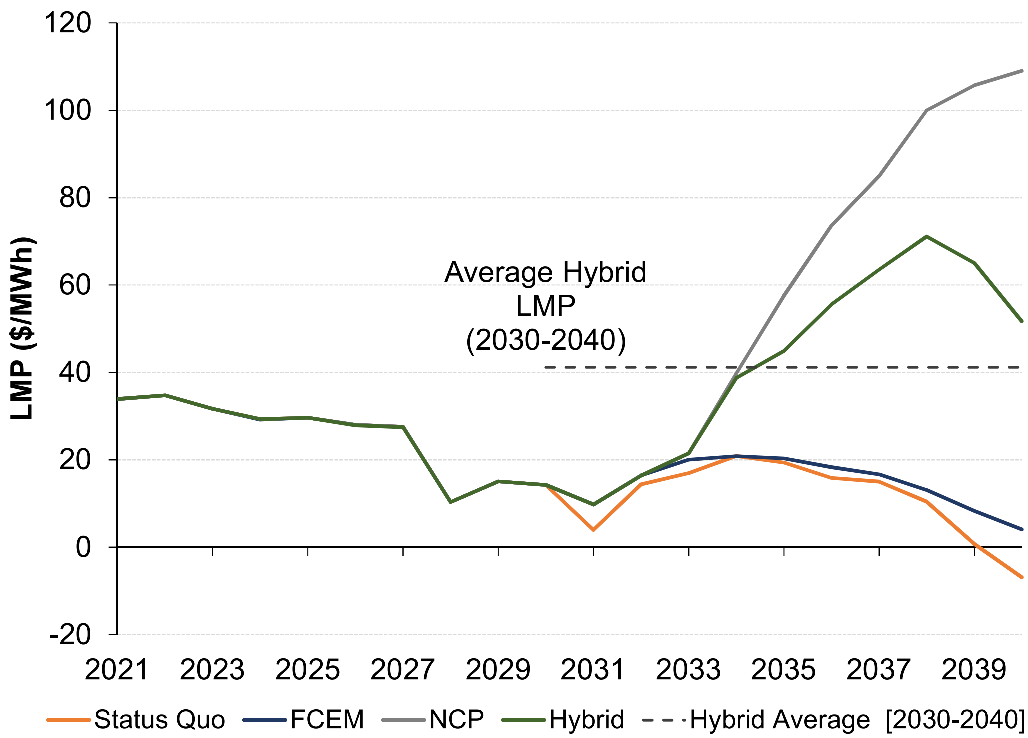
	Status Quo	Status Quo (Adjusted)	FCEM	Net Carbon Pricing	Hybrid Approach
Incremental Social Costs					
Central Case					
2021-2040 (PV)	6,027		4,296	3,935	4,119
2040	4,256		3,222	3,031	3,126
Scenarios					
2021-2040 (PV)	(4,125 - 9,249)		(3,148 - 5,798)	(2,922 - 5,613)	(3,026 - 5,888)
2040	(3,052 - 5,515)		(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.

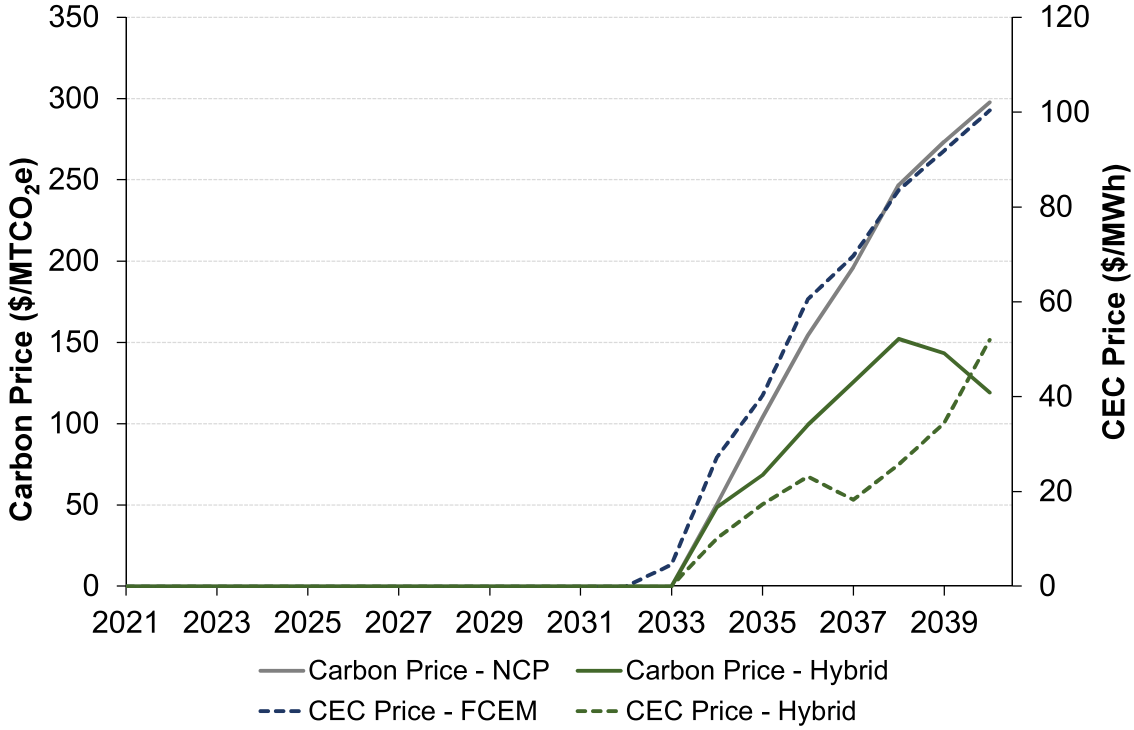
Across policy approaches, reliance on the wholesale energy market varies. In particular, the Status Quo procures an increasing quantity of energy over time through bilateral PPAs. Thus, the LMPs in **Figure ES-4** do not represent the price paid for energy through these PPAs, making the LMPs in this 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 ($2020/MTCO$_2$e and $2020/MWh)



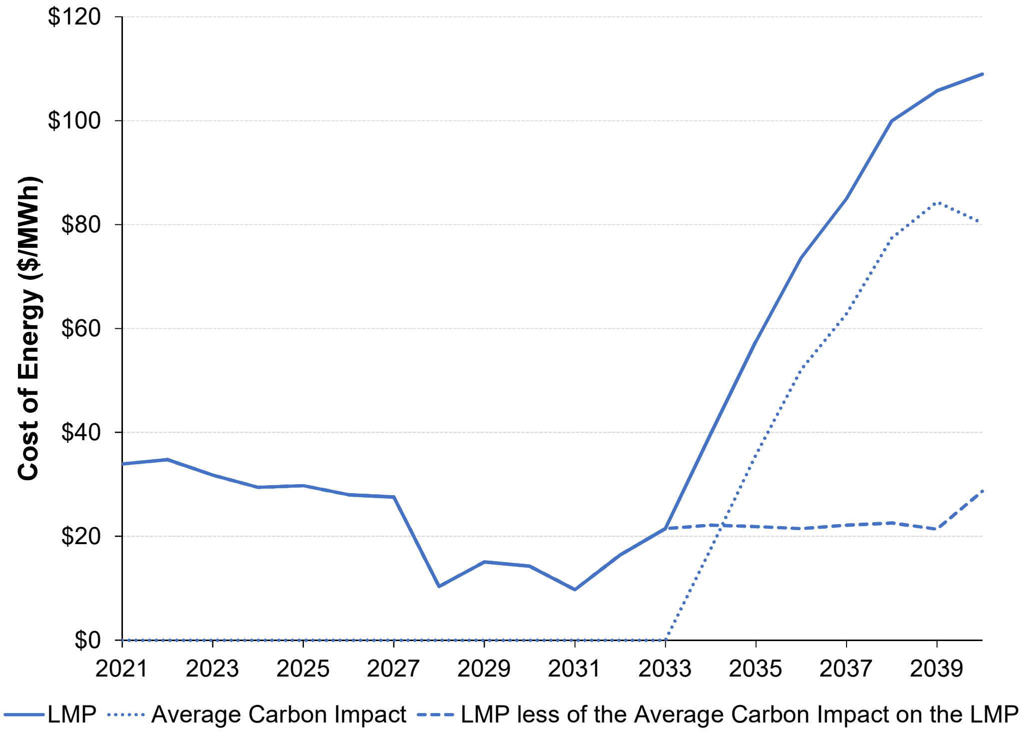
With CECs, the compensation for clean energy (and the payments by customers) is directly through the CEC price. However, with carbon pricing, there is no direct compensation for clean energy; rather, the "compensation" to clean energy (and lower emitting energy) is captured by the higher LMP, which reflects 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.