

2025 Review of New Hampshire's Renewable Portfolio Standard

Prepared for:
the New Hampshire Department of Energy



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Acronyms

ACP	Alternative Compliance Payment
CES	Clean Energy Standard
CES-E	Clean Energy Standard - Existing
COD	Commercial operation date
DEEP	Connecticut Department of Energy & Environment Protection
GHG	Greenhouse Gas
GW / GWh	Gigawatt / Gigawatt-hour
ISO-NE	Independent System Operator New England
LFG	Landfill Gas
LSE	Load-serving entity
MW / MWh	Megawatt / Megawatt-hour
NEPOOL GIS	New England Power Pool Generation Information System
NE-REMO	New England Renewable Energy Market Outlook (Service by SEA)
NH DOE	New Hampshire Department of Energy
PUC	Public Utilities Commission
REC	Renewable energy certificate
RES	Renewable Energy Standard
RFP	Request for proposals
RGGI	Regional Greenhouse Gas Initiative
RPS	Renewable portfolio standard
SEA	Sustainable Energy Advantage, LLC

Executive Summary

The New Hampshire Department of Energy (NH DOE) selected Sustainable Energy Advantage, LLC (SEA), through a competitive process, to conduct the state’s 2025 Renewable Portfolio Standard (RPS) review. The RPS review, required under RSA 362-F, is intended to assess the adequacy of RPS-eligible supply to meet future compliance needs, evaluate the design and impact of potential adjustments to RPS classes, and examine complementary policy mechanisms, including multi-year energy and Renewable Energy Certificate (REC) contracting, to ensure the program continues to meet its objectives as cost effectively as possible. This year’s RPS review¹ also considers the potential development of a Clean Energy Standard (CES), which could – if adopted – expand the state’s use of hydroelectric and nuclear generation. Finally, NH DOE also asked SEA to “provide an analysis and identify a method(s) for setting the New Hampshire RPS Class III obligation on a prospective basis.” As a result, this review includes an analysis of NH Class III in the context of the regional RPS marketplace.

Context and Market Developments

Each New England state has an RPS.² The resources used for, and associated cost of, RPS compliance in New Hampshire is impacted by myriad interactions across this regional marketplace. Since the last RPS review in 2018, changes in both regional policies and underlying market fundamentals have impacted the RPS compliance dynamics in New Hampshire.

Notably, Connecticut’s Public Act 25-173 (enacted 2025) removed nearly all biomass and landfill gas resources from CT Class I eligibility effective October 1, 2025. This eliminates a major competing source of demand for generation that is also qualified for New Hampshire Class III. With those certificates no longer eligible for CT Class I, New Hampshire Class III is now the only premium market outlet for approximately 110 MW of biomass capacity – almost all of which is in New Hampshire. This new dynamic elevates the importance of how, when, and at what percentage the NH Class II target is set – and whether that determination is binding.

Historically, NH law has allowed Class III targets to be adjusted after the end of the production and compliance year (but before the end of the REC trading year) based on observed market conditions and supply availability. While intended to offer the flexibility to react to market realities, the timing created significant uncertainty for both buyers and sellers, and the implementation requirements (i.e., reducing demand to between 85% and 95% of available supply) converted a would-be shortage to a guaranteed surplus. Collectively, this encouraged RPS-obligated entities to delay REC purchases until the final NH-III target was known and discouraged the owners of existing NH-III certified assets from both investing in and maximizing production at existing assets. Looking ahead, establishing a binding Class III target that provides clear, predictable market signals could better support continued operation of existing biomass facilities while minimizing reliance on ACPs and maintaining cost-effective RPS compliance.

For other classes, REC prices have fluctuated in response to changing supply-demand balances amid evolving market conditions. These changes are explained and reflected throughout this report.

¹ Prior reviews were conducted in 2011 and 2018.

² Rhode Island and Vermont use the term Renewable Energy Standard (RES).

Analytical Approach and Scenarios

SEA applied its New England Renewable Energy Market Outlook (NE-REMO) modeling suite to evaluate supply, demand, and cost outcomes for New Hampshire's RPS through 2040 under multiple policy scenarios. The **Reference Case** reflected current statutory requirements, while three alternatives explored potential adjustments:

- **Reference + Adjusted Class III:** Establishing a fixed 5 percent Class III obligation beginning in 2025.
- **Consolidate I + II / III (Adjusted) + IV:** Merging "new" and "existing" classes to simplify compliance.
- **Consolidate All:** Combining all classes into a single statewide requirement.

Key Findings

Modeling results indicate that setting the Class III obligation at 5 percent (for 2025 and beyond) would achieve high utilization of available biomass and landfill-gas generation, sustain local economic benefits, and reduce Alternative Compliance Payments. This scenario produced the largest ratepayer benefit, with a 16-year present-value savings of \$21.5 million (in 2025 dollars) relative to the Reference Case. The Consolidate I + II / III + IV scenario yielded \$5.1 million in savings, while the Consolidate All case was effectively at parity with the Reference Case. The reason the Consolidate All Case did not produce meaningful savings is that it is assumed to consolidate all current targets – including 8% for Class III. These findings demonstrate that adjustments to RPS class design and target structure can affect compliance outcomes and ratepayer costs. NH DOE may wish to evaluate these options for alignment with broader policy objectives.

Complementary Policy Considerations

The report also evaluates additional policy tools that could expand New Hampshire's renewable and non-emitting portfolio. If implemented with clear eligibility criteria and moderate initial targets, a Clean Energy Standard (CES) could both hedge energy costs and reduce attributable emissions by recognizing non-emitting resources such as large hydro and nuclear.

Separately, experience across the Northeast shows that multi-year contracting for bundled energy and RECs, implemented through the distribution utilities in coordination with state regulators, can lower financing costs, reduce ratepayer exposure to price uncertainty, enhance long-term market predictability, and result in a lower cost of energy for New Hampshire consumers. Integrating such mechanisms into New Hampshire's RPS compliance strategy could advance renewable energy goals while supporting cost-effectiveness objectives.

Conclusion

As New Hampshire considers the evolution of its RPS and related policies, it is important to clearly articulate what the policies are trying to accomplish. Adjustments to class-specific eligibility, targets, and other terms are best proposed after the desired outcomes are clearly stated. The analysis and observations presented in this report are intended to support informed decision-making at the Department and the General Court for the benefit of New Hampshire ratepayers.

1 Background

New Hampshire's 2007 Renewable Portfolio Standard (RPS) statute³ requires the New Hampshire Department of Energy (NH DOE) to review the RPS program and report its findings to the General Court by November 1, 2025. Accordingly, the NH DOE conducted a stakeholder process, which included public meetings during April, May, and June 2025 and offered a written comment period through September 1, 2025.

In parallel, the NH DOE selected Sustainable Energy Advantage, LLC (SEA), through an RFP process, to conduct this report and underlying analysis. Since 1998, SEA has specialized in analysis at the intersection of renewable energy policy design and quantitative market modeling. SEA has been conducting detailed quantitative analyses of the New England RPS landscape on a continuous basis since 2005, including as the consultant selected to conduct New Hampshire's 2018 RPS review.

The purpose of this review and report is to support informed decision-making related to the potential evolution of New Hampshire's RPS and procurement policies. This report addresses the topics identified in the 2007 RPS statute, including (listed verbatim):

- The adequacy or potential adequacy of sources to meet the class requirements of RSA 362-F:3;⁴
- The class requirements of all sources in light of existing and expected market conditions;
- The potential for addition of a thermal energy component to the electric renewable portfolio standard;
- Increasing the class requirements relative to classes I and II beyond 2025;
- The possible introduction of any new classes such as an energy efficiency class or the consolidation of existing ones;
- The timeframe and manner in which new renewable class I and II sources might transition to and be treated as existing renewable sources and if appropriate, how corresponding portfolio standards of new and existing sources might be adjusted;
- The experience with and an evaluation of the benefits and risks of using multi-year purchase agreements for certificates, along with purchased power, relative to meeting the purposes and goals of this chapter at the least cost to consumers and in consideration of the restructuring policy principles of RSA 374-F:3;⁵
- Alternative methods for renewable portfolio standard compliance, such as competitive procurement through a centralized entity on behalf of all consumers in all areas of the state; and
- The distribution of the renewable energy fund established in RSA 362-F:10.⁶

Additionally, at the NH DOE's direction, this report considers the current and expected future production of NH Class III supply and its increased availability for RPS compliance in NH given changes to CT Class I eligibility criteria enacted and effective in 2025. Based on these changes, this report assesses outcomes and implications of setting the NH Class III target on a prospective basis for calendar year 2025 and beyond.

³ See [RSA Section 362-F:5](#).

⁴ See [RSA Section 362-F:3](#).

⁵ See [RSA Section 374-F:3](#).

⁶ See [RSA Section 362-F:10](#).

This report is organized as follows:

- **Section 1** introduces the analysis and outlines the purpose, statutory basis, and scope of the review.
- **Section 2** defines the RPS policy and provides national and regional context.
- **Section 3** summarizes New Hampshire’s RPS and describes key market evolutions.
- **Section 4** describes SEA’s analytical approach and methodology.
- **Section 5** defines the scenarios analyzed, establishing the baseline and alternative pathways evaluated.
- **Section 6** summarizes core assumptions, including key demand and supply inputs, applied in SEA’s modeling.
- **Section 7** presents the modeling results, observations, and implications for all four scenarios.
- **Section 8** examines the potential for New Hampshire’s consideration of a Clean Energy Standard.
- **Section 9** considers the question of “transitioning Class I & II from ‘New’ to ‘Existing’”.
- **Section 10** explores the potential role of multi-year energy & certificate contracts in RPS compliance.

2 Introduction to Renewable Portfolio Standards

2.1 Definition, Objectives, and National Context

An RPS, also known as a Renewable Energy Standard (RES), is a policy intended to increase the use of renewable energy sources for electricity generation. RPS policies, and increasingly, Clean Energy Standards (CES), also establish mandates and parameters for the continued use of existing renewable energy and/or non-emitting generators to meet retail energy needs. These policies require RPS-obligated load-serving entities (LSEs) to serve their retail customers with a stated minimum percentage of electricity from eligible renewable, clean, non-emitting, or low-impact resources each year. It is common for RPS policies to include multiple requirements, differentiating the obligation by resource type, vintage (i.e., commercial operation date), size (in kW or MW), emissions criteria, and/or other characteristics. RPS policies vary by state in structure, resource eligibility, flexibility mechanisms, and enforcement procedures.

Twenty-nine states and the District of Columbia have RPS policies.⁷ An additional seven states have renewable portfolio goals, which are intended to influence purchasing choices but are not mandatory. The variations in RPS policy design reflect the range of states’ policy objectives, which may include but are not limited to:

- Spurring the development, financing, and construction of *new* renewable energy resources,
- Maintaining the *existing* fleet of renewable energy resources,
- *Diversifying* the state (and regional) fuel mix,
- Driving *local job creation* and *local economic development* benefits,
- Maintaining the *economic benefits of existing facilities*,
- Increasing *energy independence*, and
- Achieving other *environmental and climate objectives*.

⁷ Galen L Barbose, “U.S. State Renewables Portfolio & Clean Electricity Standards: 2024 Status Update,” Lawrence Berkeley National Laboratory, August 2024, <https://emp.lbl.gov/publications/us-state-renewables-portfolio-clean-0>

2.2 Summary of Key Features in New England RPS Markets

Each of the six New England states has an RPS, and each is unique in ways that reflect local industries and economies, and their impact on policy objectives. The result is a complex web of overlapping, but not standardized, markets. The practical implication is that some resources are eligible to support RPS compliance across multiple markets while others are eligible in only one. The market value of Renewable Energy Certificates (RECs) – and the ultimate cost of RPS compliance – is determined by the confluence of these eligibility dynamics, available supply, and state-by-state RPS targets. SEA has been modeling these dynamics since 2005 and has deployed its market models and knowledge in the development of this report.

New England states began adopting RPS programs in the early 2000s to meet a combination of policy goals, including resource diversification, environmental objectives, and local economic development. Connecticut, Massachusetts, and Maine were among the first states to enact RPS legislation in 1997 and 1998, followed by Rhode Island in 2004. New Hampshire established its program in 2007, and Maine converted its earlier, more flexible requirement focused on existing resources into a modern RPS emphasizing new renewable generation that same year. Vermont initially pursued a voluntary renewable goal before adopting a formal RPS in 2015. Over time, these programs have undergone revisions, reflecting evolving policy priorities and market conditions. For example, recent (2025) amendments to Connecticut’s RPS (i.e., the discontinuance of biomass and landfill gas eligibility) will have a direct impact on NH’s Class III market. These dynamics and impacts are discussed later in this report.

2.2.1 Regional RPS Classes and Targets

RPS policies commonly separate resource mandates by “class” (or “tier”). The objective is generally to separate the treatment of ‘new’ and ‘existing’ resources. Eligible “placed in service” dates (also referred to as vintage dates) are specified by legislation or regulation. Classes and eligibility criteria are also used to focus on specific characteristics (e.g., technology, size, fuel type) and incentivize development (if ‘new’) or continued operation (if ‘existing’) of certain groups of facilities – especially those of economic significance to the applicable state (e.g., fuel cells in CT, paper mills in ME, and biomass in NH).

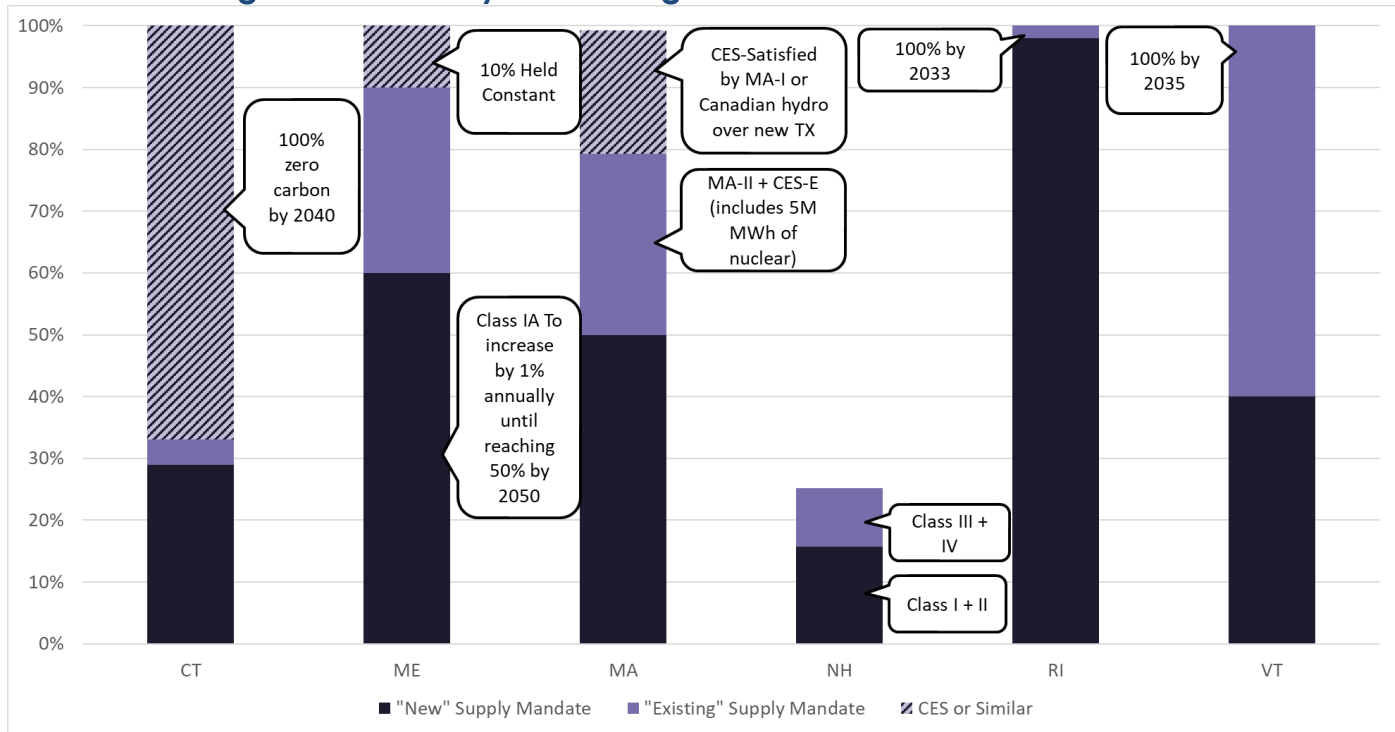
Figure 1 lists the current classes in each New England state’s RPS and summarizes the resource type to which is applies.

Figure 1: Summary of New England RPS Classes by State

Connecticut	Class I.....	New Renewables
	Class II.....	Existing Renewables
	Class III.....	Conservation and Load Management
Maine	Class I.....	New Renewables
	Class IA.....	New Renewables, No Refurbishments
	Class I Thermal.....	Converts Heating from Fossil to Renewable
	Class II.....	Existing Renewables
Massachusetts	Class I.....	New Renewables
	SREC I/II.....	Solar Obligation Carveouts
	Class II.....	Existing Renewables
	Class II Waste-to-Energy...	Existing Municipal Solid Waste
New Hampshire	Class I.....	New Renewables
	Class I Thermal.....	Converts Heating from Fossil to Renewable
	Class II.....	Solar Only
	Class III.....	Pre-2006 Biomass & Landfill Gas ≤ 25 MW
	Class IV.....	Pre-2006 Hydro ≤ 5 MW
Rhode Island	New.....	New Renewables
	New or Existing.....	Existing Renewables (New also eligible)
Vermont	Tier I.....	Existing Renewables
	Tier II.....	In-State Distributed Generation < 5 MW
	Tier III.....	Energy Transformation Projects

Where “class” denotes eligibility criteria, “target” denotes volume and plays a critical role in understanding how each state’s policy objectives are divided between ‘new’ and ‘existing’ resources. Here too, it is important to consider local industry and economic (e.g., job) benefits. States hosting few renewable energy facilities (at the time original RPS legislation is passed) are likely to focus on ‘new’ classes. States with many existing renewable energy generators (typically hydroelectric and biomass) are likely to incorporate more focus on preventing attrition of its existing fleet. In recent years, MA and ME have created ‘Clean Energy Standards’ (or similar policies) – and CT enacted a ‘zero carbon by 2040’ law – in recognition of the need to expand the discussion of climate and emissions policies to include nuclear and/or large hydroelectric generators.⁸ These new policies are discussed in Section 8. Ultimately, state classes and targets should align with policy objectives – which should be clearly stated in writing and reviewed periodically. This report provides an opportunity to review NH’s RPS in the context of regional RPS programs and current market dynamics. Figure 2 summarizes the New England states’ RPS mandates in 2040 by segmenting each state’s classes into three categories: ‘new,’ ‘existing,’ and ‘CES or similar.’

⁸ This is a general characterization meant only to signal a market trend. All state and class-specific eligibility, targets, and other details are parsed accurately and included in SEA’s analysis. For example, MA has both a CES and CES-E and each is specific about the vintage dates of both generation and, when applicable, associated transmission. The MA CES-E allows up to 2.5M certificates annually from each of Millstone and Seabrook. ME has created a Class III that includes both nuclear and large hydro.

Figure 2: Summary of New England RPS & CES Mandates in 2040

2.2.2 Regional RPS Vintage Requirements & Eligibilities

Commercial Operation Date (COD) also plays an important role in RPS eligibility. New Hampshire Class I and comparable RPS classes targeting 'new' facilities have vintage requirements setting a date after which a facility must have begun operating to qualify as 'new.' These dates vary widely based mostly on the date the original RPS legislation was passed. Facilities with CODs earlier than these vintage requirements generally fall into 'existing' classes, with exceptions for refurbished facilities or incremental capacity. Table 1 summarizes vintage requirements across New England's RPS markets.

Table 1: Summary of Vintage Requirements by Class

State	ME	CT	MA	NH	RI	VT
Class I ('New')⁹	Post-8/31/04	None, except for hydro (Post-7/1/03) and nuclear (post-10/1/23)	Post-12/31/97	Post-12/31/05	Post-12/31/97	Post-6/30/15
Class II ('Existing')	Pre-9/1/05	None	Pre-1/1/98	Pre-1/1/06	Pre-1/1/98	Pre-7/1/15

⁹ And Vermont Tier II (which, despite the numbering convention, is for new resources)

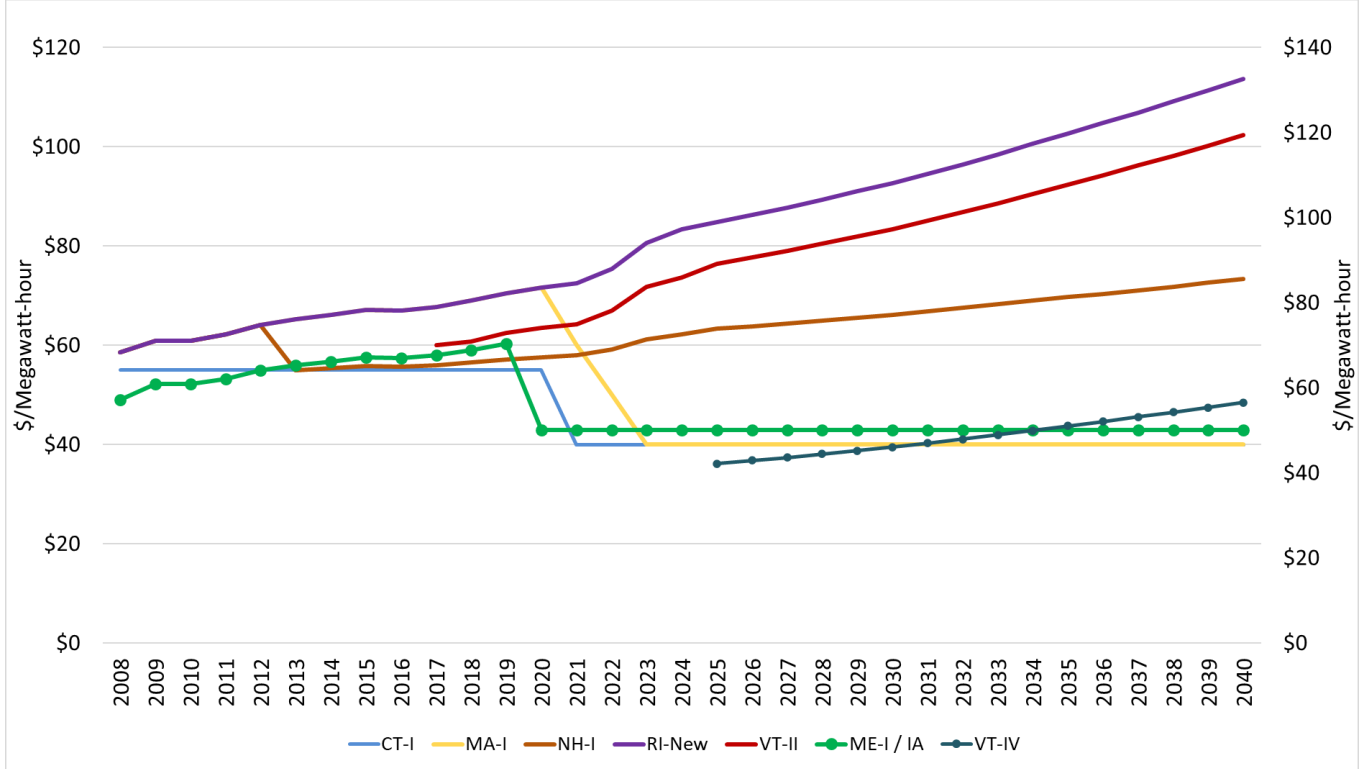
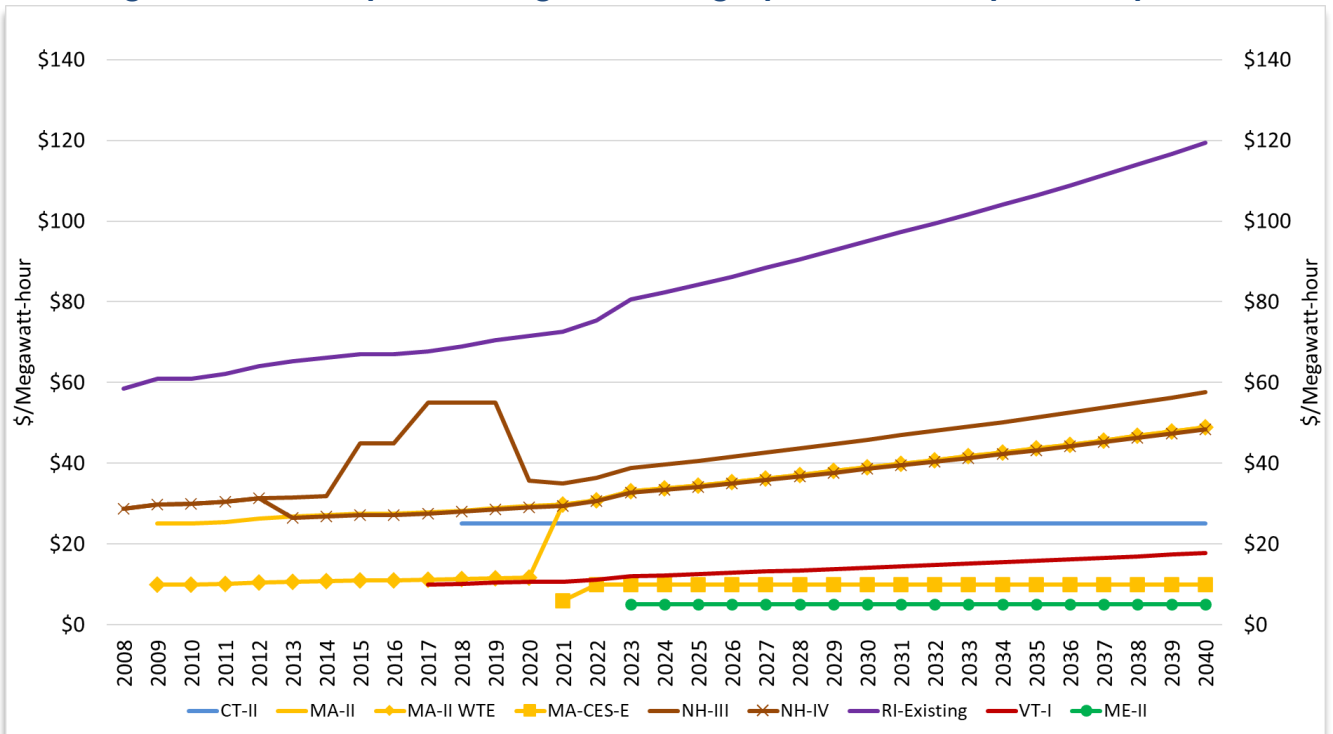
2.2.3 Role of Adjacent Control Areas

The New England Power Pool has physical ties to three adjacent control areas: New York, Quebec, and New Brunswick. Whereas the NEPOOL GIS automatically creates certificates for each MWh of production from facilities located within ISO-NE, unit-specific certificates representing production originating from adjacent control areas are only created when both the energy and attributes are imported into ISO-NE and settled with a specific counterparty.¹⁰ This mechanism allows renewable energy imports to contribute to New England states' RPS compliance and ensures that the attributes are not counted towards any policies or claims in the jurisdiction of origin. Through these rules, wind, hydroelectric, biomass, landfill gas, and other generators in neighboring jurisdictions have been participating in New England RPS markets for over 20 years. These same rules allow New England generators to export energy and RECs to neighboring control areas. As a practical matter, however, this has only been economically attractive in limited circumstances. Nonetheless, as renewable energy policies and targets evolve in New York and Canada, it is possible that the frequency and quantity of renewable energy imports from these regions will evolve with them.

2.2.4 Alternative Compliance Payments

The Alternative Compliance Payment (ACP) is an important flexibility and ratepayer protection measure. If an RPS-obligated entity does not purchase the requisite number of class-specific certificates – owing either to availability or business decisions – then it must make up the difference through ACPs. If the ACP rate is less than the premium for new market entry, then the ACP effectively serves as a price cap. ACP rates differ by state, by class, and sometimes by year. Figure 3 and Figure 4 summarize actual ACP rates from 2008 through 2025 (to provide context) and expected ACP rates from 2026 through 2040. Some ACP rates are fixed, while others are adjusted annually by inflation or a fraction of inflation (typically CPI). As a result, available eligible REC supply will (barring contractual commitments to the contrary) go to the highest-valued market (with the highest ACP rate) first. In a supply shortage, this may leave markets with lower ACP rates short and mean that the obligated entities need to use the alternative compliance mechanism to fulfill their RPS obligations. Regional ACP rates are set either by legislation or by regulation (with legislative guidance). Periodic revisions occur, with the process and results varying by state. All states except Connecticut initially established ACP rates that escalated with CPI (or a fraction thereof). The figures below show that Maine and Massachusetts have since transitioned to fixed ACP rates for Class I, Connecticut reduced its fixed ACP rate, and that the fixed versus escalating dynamic will cause regional ACP rates to diverge over time. Given the evolution of market conditions and the interdependencies of RPS markets, the region would benefit from policymaker coordination on this topic.

¹⁰ Rule 2.7, "New England Power Pool (NEPOOL) Generation Information System (GIS) Operating Rules" (NEPOOL, 2024), <https://nepoolgis.com/wp-content/uploads/sites/3/2020/07/GIS-Operating-Rules-Effective-7-1-21.doc>

Figure 3: Summary of 'New' RPS Category ACP Rates, by State, by Year**Figure 4: Summary of 'Existing' RPS Category ACP Rates, by State, by Year**

3 New Hampshire RPS & Regional Market Evolutions

3.1 New Hampshire RPS Definitions, Targets, and Demand

New Hampshire's RPS is comprised of four (4) classes, plus a carve-out for thermal resources that is a subcomponent of Class I. Investor-owned utilities, cooperatives, and competitive load-serving entities are all obligated under NH's RPS law. Municipal utilities are exempt. Obligated entities demonstrate compliance on a calendar year basis, either through the purchase of RECs or by making Alternative Compliance Payments (ACPs). The key characteristics of each class are summarized below:

The **Class I** RPS obligation is intended to spur the development and operation of new renewable energy facilities. Eligible technologies include wind energy; hydrogen derived from biomass fuels, water, or methane gas; eligible biomass; methane gas; ocean energy; solar energy not used to satisfy Class II (see below); and incremental new production of electricity in any year from an eligible biomass, methane or hydroelectric generating facility above its historical baseline. To qualify, a facility must have a commercial operation date (COD) on or after January 1, 2006, and meet specified emissions limits. Beginning in 2014, a portion of the Class I obligation was dedicated to a **Thermal Carve-out**. Eligible resources include biomass, geothermal, solar thermal, methane gas, combined heat and power (CHP), and "Useful Thermal Energy" all qualify as thermal fuel sources, with biomass thermal required to meet emissions limitations.

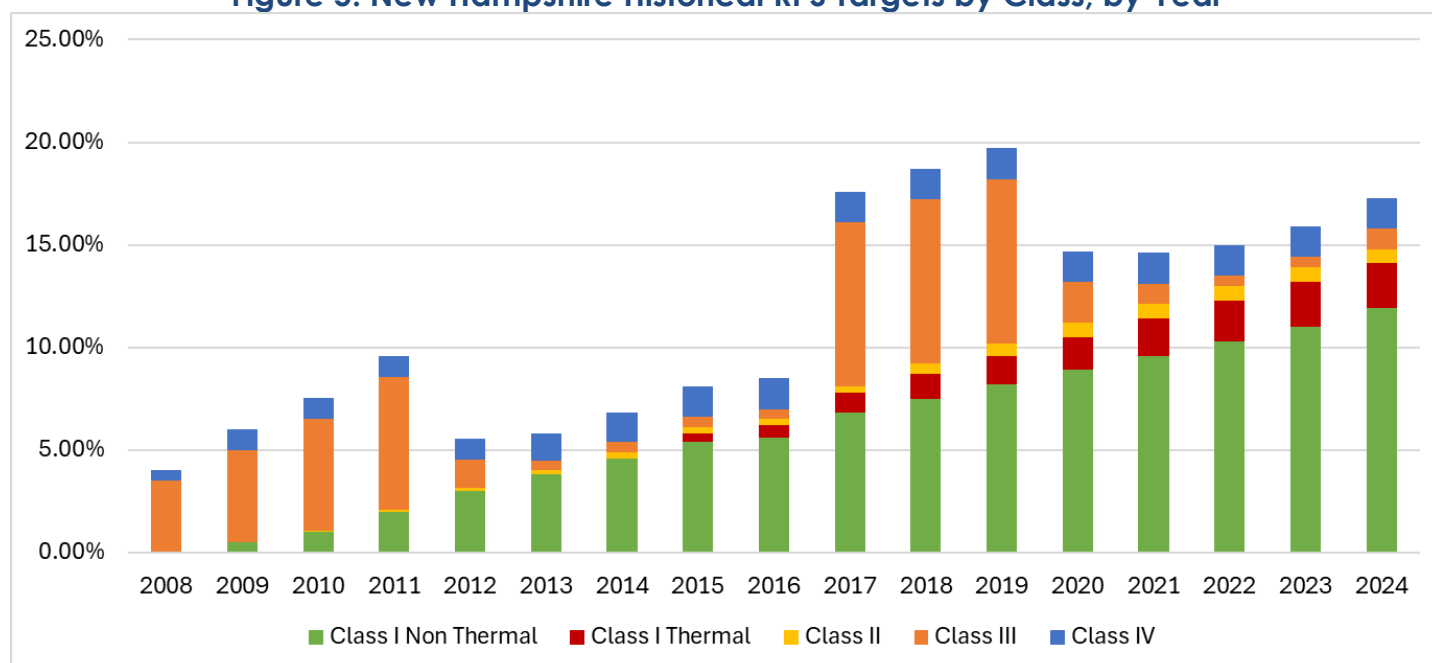
Class II became effective in 2010 and is dedicated to solar facilities. As with Class I, eligible resources must have entered commercial operation on or after January 1, 2006. The Class II target (fixed at 0.7% per year) is adjusted downward by the volume of customer-sited solar production that has not sought REC certification for any alternate RPS market. In this case, the RECs associated with these NH customer-sited facilities are assumed serve NH RPS-obligated load. This adjustment resulted in a Class II obligation of 0% for 2023 and 2024. Based on ISO-NE's 2025 BTM PV Energy Forecast for NH (which was developed with input from New Hampshire utilities and policymakers through the Distributed Generation Forecast Working Group), it is reasonable to assume that NH Class II will continue to be adjusted to zero. As a result, options for eliminating Class II or consolidating Class I and Class II are explored in the scenario analysis section of this report. In the meantime, RECs from Class II resources, to the extent not used to satisfy a Class II obligation, may be certified and sold to meet Class I obligations in NH, ME, MA, and CT. The RI RES does not accept RECs from BTM facilities in other states. NH-II RECs are also eligible for VT Tier IV.

The **Class III** and **Class IV** compliance obligations commenced in 2008. Both classes are intended to support the continued operation of existing facilities, those with COD no later than December 31, 2005. **Class III**-eligible facilities include biomass and landfill gas facilities with a gross nameplate capacity less than or equal to 25 MW and must meet the same emissions limits as Class I. Pursuant to changes implemented during 2017, Class III landfill gas facilities may not locate more than 10 MW on a single landfill site. **Class IV**-eligible facilities include hydroelectric less than or equal to 5 MW that have installed both upstream and downstream diadromous fish passages and have been approved by FERC. Hydroelectric facilities less than or equal to 1 MW must comply with FERC fish passage restoration requirements and be interconnected to New Hampshire's electric distribution system.

Eligible facilities may be located in ISO-NE, or in an adjacent control area (except Class I Thermal) if the energy is delivered to New England and settled in the market settlement system. New Hampshire does not certify facilities interconnected behind the retail meter in other states.

Figure 5 illustrates actual, historical RPS targets by class between 2008 and 2024. Classes I, I-Thermal, II, and IV have been implemented without adjustment. Class III has been implemented with adjustments that are guided by legislation and affected by both available supply and the state's understanding of the potential impact of other markets. It is important to note that **regional RPS laws and dynamics have changed in 2025, so it is no longer appropriate to consider past adjustments when setting forward-looking targets and policies.**

Figure 5: New Hampshire Historical RPS Targets by Class, by Year



3.2 Regional Market Evolution: Biomass and landfill gas no longer eligible for CT Class I

Connecticut's Public Act 25-173 (SB 4),¹¹ passed in June 2025 and signed on July 1, 2025, includes significant reforms to the Connecticut RPS. For the purpose of this report, the most impactful change is the removal of nearly all biomass and landfill gas as CT Class I eligible resources beginning October 1, 2025.

Since its inception in 2008, NH Class III has competed with CT Class I for eligible biomass and landfill gas (LFG) supply. From 2008 through 2016, CT-I was a more financially compelling market than NH-III because (i) the ACP rate was higher in CT-I than NH-III (allowing the *potential* for higher REC prices), and (ii) the CT-I market traded higher REC volumes with greater liquidity than NH-III. During this period, it was often easier to sell into CT-I than NH-III. As a result, compliance

¹¹ [Public Act 25-173: An Act Concerning Energy Affordability, Access and Accountability](#)

reporting substantiated the sale of NH-III eligible biomass and LFG to CT-I rather than NH-III and NH policymakers reduced NH-III targets from 8% to 1.4% in 2012 (this was done by legislation) and 0.5% in 2013 through 2016 (this was done through the PUC¹² under legislative authority). For 2017 through 2019, the legislature increased the NH-III ACP rate to \$55 – making it the same as the CT-I ACP rate and triggering a more equal distribution of biomass and LFG supply between CT-I and NH-III. As a result, NH-III targets remained at 8% for 2017 – 2019. Beginning in 2020, the NH-III ACP rate was reduced to \$35.61. Supply once again favored the CT-I market, even after the CT-I ACP rate was reduced from \$55 to \$40 beginning in 2021. Once again, increased competition from the CT-I market triggered NH-III regulatory reviews and subsequent target reductions for 2020 through 2024. Annual targets for all classes were summarized in Figure 5 above. These reviews generally concluded during the first quarter of the calendar year following the subject compliance year. This allowed policymakers to evaluate actual production for the applicable compliance year. Because the NEPOOL GIS quarterly certificate transfer periods begin on a 4.5-month lag from the end of the production quarter, NH-III obligated entities (i.e., buyers) and NH-III certified facilities (i.e., sellers) were able to complete certificate transactions after the NH-III target adjustments and before the applicable year’s compliance filing was due. While the market fundamentals (ACP rate, supply availability) aligned with NH-III target reductions in 2020 and 2021, those dynamics started to shift between 2022 and 2024. Beginning January 1, 2022, CT implemented its biomass and landfill gas “phasedown,” which limited certain facilities (subject to specific COD, CT certification, and contracting criteria) to selling no more than 50% of their REC production for CT-I compliance. Then, for compliance year 2024, the NH-III ACP rate (\$40.23) eclipsed the 2024 CT-I ACP rate (\$40). In a market driven purely by rational economics, a higher ACP rate in NH-III (compared to CT-I) would have caused all NH-III eligible production (not already contracted to CT) to sell into the NH-III market. For example, if the 2024 ACP rate differential between NH-III and CT-I translated to a \$0.25 higher REC price in NH-III, that would mean approximately \$25,000 more in 2024 revenue to a 15 MW biomass facility. Under today’s market conditions, the 2025 REC price differential between NH-III and CT-I has the potential to be approximately \$1.50 (higher in NH-III), which would mean approximately \$150,000 of additional 2025 revenue to a 15 MW biomass facility. Of course, both examples assume a world in which both policymakers and market participants treated the 8% NH-III target as binding. In practice, however, a review was conducted, and the NH-III target was reduced from 8% to 1% (i.e., the target was not binding).

3.3 Consideration of *Prospective Target-Setting* for NH Class III

Looking ahead, the market dynamics for NH-III in 2025 and beyond are different, and **the past should not be used to guide the future**. The gap between the NH-III ACP rate (which increases with CPI) and the CT-I ACP rate (which is fixed at \$40) will continue to widen (e.g., \$41.59 v. \$40 in 2025). More impactfully, neither biomass nor landfill gas is eligible for CT-I beginning October 1, 2025. The former means that all NH-III/CT-I supply should be able to earn higher REC prices in NH-III than CT-I; the latter means that the CT-I market is completely foreclosed¹³ to biomass and landfill gas for 2026 and beyond. Some NH-III certified biomass and landfill gas are eligible for other “premium” RPS markets (e.g., RI-New, Maine Class I or IA, or even MA-I for certain LFG projects) but **there is approximately 110 MW of biomass capacity that is not certified for any other “premium” market**. If the NH-III target is not set – at a minimum – to absorb the expected production from these facilities, the marginal RECs not sold into NH-III are likely to receive REC prices <\$5/MWh (rather than a NH-III price of ~\$40/MWh). These facts should be considered when setting NH-III targets for 2025 and beyond. The takeaway from current market rules and conditions is that if New Hampshire’s policy objectives include supporting the

¹² Which is now the Department of Energy (DOE)

¹³ One biomass facility (Plainfield Renewable Energy) remains eligible for CT-I, but this facility is not eligible for NH-III. It is possible that additional exceptions will arise, but none of the candidates is also NH-III eligible and therefore does not impact this analysis.

continued operation of NH-III certified biomass facilities, then forward looking NH-III targets should be set at a level that requires consistent staffing, fuel sourcing, and operation at these facilities and is binding – that is, no longer subject to review and adjustment during or after the calendar year¹⁴ ends.

New Hampshire’s RSA¹⁵ Chapter 362 Section F authorizes NH DOE “after notice and hearing” to modify the Class III target. This by itself is not uncommon; statutes in other New England states also grant the applicable regulatory entity the authority to adjust RPS targets from time to time. What is unique about New Hampshire’s current legislative authority is that once the decision to adjust the target is made, the applicable legislation specifies the revised target be “equal to an amount between 85 percent and 95 percent of the reasonably expected potential annual output of available eligible sources after taking into account demand from similar programs in other states.” To over-simplify, this has been interpreted and implemented to date as (1) determine annual output (for the applicable year) of NH-III certified supply, (2) remove the output assumed to be sold to “similar programs in other states”, and then (3) calculate a revised target that is between 85% and 95% of the remaining output. Therefore, **the current law and implementation identify a potential shortage and convert it into a guaranteed surplus.** This outcome not only reduces the quantity of NH-III certified supply required to serve New Hampshire ratepayers but also ensures that a portion (specifically 5% to 15%) of the NH-III certificates not sold to other markets also cannot be sold into NH-III. Now that NH-III targets have been adjusted ten times¹⁶ using this methodology, RPS-obligated entities have increasingly refrained from making NH-III REC purchases throughout the year on the assumption that DOE will reduce the requirement after the calendar year ends. This uncertainty may have also contributed to biomass operating, staffing, fuel purchasing, maintenance, and repair decisions throughout the year, as the NH-III obligation was not binding and would not be known until after facility operators had made all production-related decisions for the calendar year.

SEA’s objective is to support an informed dialogue on this topic. If the outcome described above does not align with New Hampshire’s current policy objectives, then alternate approaches could be considered. As previously explained, the dynamics between NH-III and “similar programs in other states” have changed dramatically. Historical results are not an indicator of future outcomes. A considerable amount of supply (approximately 110 MW) has no financially viable alternative to NH-III.

Any state is most likely to achieve its objectives by promoting stable markets through clear price and volume signals. This provides visibility and increases market participation. When policy adjustments are considered, the process should include stakeholder feedback and any conclusion resulting in policy changes should be reached – and announced publicly – at least six months before the changes take effect. This maximizes the possibility of a smooth transition to the new policy element(s).

If New Hampshire’s objective is to support the continued operation of the existing Class III biomass fleet, then it would be reasonable to consider resetting the NH-III target to a level that maximizes both production and economic benefits from existing NH-III facilities while minimizing NH-III compliance via ACPs. The ‘Reference + Adjusted Class III’ scenario explores the potential impact of setting NH-III at 5% for 2025 - 2040. Additional details associated with that scenario are described in Section 7.2.

¹⁴ “Calendar year” (as opposed to NEPOOL GIS certificate trading periods) is referenced here because it denotes the period during which operating decisions affecting production can be made.

¹⁵ Revised Statutes Annotated

¹⁶ 2012 - 2016 and 2020 - 2024, inclusive.

4 Analytical Approach & Methodology

4.1 Analysis and Models

In this analysis, SEA evaluates the impacts of three alternative scenarios using models developed for SEA's New England REMO (NE-REMO). NE-REMO is a suite of MS Excel-based models developed by SEA that forecast scenario-specific renewable energy supply, demand, and REC price trajectories for New England. The NE-REMO models are designed to project Class I market supply, demand, and price throughout the region. NE-REMO also forecasts the NH-III marketplace, which has historically been tied to the Class I market through eligibility overlap with CT-I (see Changes to CT RPS above). The assumptions and methods deployed herein are consistent with SEA's NE-REMO analysis and are not intended to reflect the DOE's view on expected outcomes.

Due to the timelines implicit in the development process, near-term renewable energy supply is defined by existing facilities, plus projects under development that are in the advanced stages of permitting and have either identified long-term power purchasers (either through competitive solicitation or bilateral negotiation) or an alternative path to securing financing. Alternative paths include policies providing revenue through tariffs, net metering, or standard offers. These projects are subject to customized, probabilistic adjustments regarding deployment timing and likelihood of achieving commercial operation. Near-term REC prices are forecast as a function of existing, RPS-certified renewable energy supplies, near-term renewable additions, regional RPS demand, ACP levels in each market, and other dynamic factors including banking, imports, and the deployment of discretionary supply including merchant biomass plants and imports from other markets outside of New England.

The long-term REC price forecast —where new market entry is required to fulfill demand —is based on a supply curve analysis that considers developable technical potential, resource cost, and the commodity market value of production over the study period. These factors are used to identify the marginal, REC price-setting resource for each year in which new renewable energy additions are required to satisfy RPS demand. For this analysis, the REC price forecast starts in the year 2025 and runs through 2040.

The alternative scenarios being analyzed take effect starting in 2025 for the "Reference Case" and "Reference + Adjusted Class III," and in 2027 for the "Consolidate I+II, Consolidate III (adjusted) + IV" and "Consolidate All" cases. No exemptions are offered to otherwise obligated entities.

The NE-REMO models are proprietary to SEA and are business sensitive. Case-specific results are summarized and explained herein. The underlying MS Excel models cannot be made available without irreparable harm to SEA and will not be distributed. The approach, methodology, and outputs of the NE-REMO models have, however, been stress tested through major, region-wide, multi-stakeholder processes including multiple rounds of the Avoided Energy Supply Cost (AESC) Study, as well as RPS reviews and adjacent policy analyses — most recently in Massachusetts, Maine, and Vermont.

4.2 Assumptions

Assumptions regarding regional renewable portfolio standards, and related or supporting policies, are based on current statutes and policies in place across the six New England states. Forward-looking statutes (for example, when state entities have renewable procurement authority that has not yet been exercised) have been interpreted by SEA and are held constant across all scenarios. With respect to renewable energy supply currently serving New Hampshire under long-term contracts, SEA has estimated the existing commitments of obligated entities. These contractual obligations are modeled in aggregate, and the resulting quantities are treated as a hedge of the RPS supply obligation in all scenarios. Key assumptions are summarized in both the body and appendices.

4.3 Results and Evaluation Metrics

The results of this preliminary analysis focus on direct ratepayer impact (the changes in RPS compliance costs which are passed on to New Hampshire ratepayers). Direct ratepayer impact is a function of REC price and unhedged RPS obligation (which itself is a function of load, RPS targets, and existing contractual commitments). The unhedged cost of RPS compliance is the product of scenario-specific spot REC prices and unhedged RPS demand for each RPS Class and will be used as a proxy for assessing the relative ratepayer impact across all modeled scenarios. While the proposed changes have the potential to impact wholesale energy and capacity market prices, this potential interaction is not addressed in this analysis. Ratepayer impact will be measured by average (unhedged) REC price and the present value of the cost differential between the Reference Case and each modeled alternative.

4.4 Regional Market

New England RPS markets must never be evaluated in isolation. Through the NE-REMO models, this analysis considers the applicable markets both individually and together. Overlapping eligibility creates opportunities for supply migration. At the same time, however, small differences in eligibility and contracting policies may cause state REC prices to either converge or diverge with changes in supply and demand conditions. This analysis fully accounts for NH's interaction with a regional renewables market that is complex, involving overlapping eligibility of many state RPS tiers throughout the region.

5 Scenario Analysis: Definitions

Reference Case Scenario Definition: The Reference Case provides a baseline for evaluating the incremental impact of each alternative scenario. The Reference Case assumes legislation and regulation currently in effect in each state. Neither the Reference Case nor alternative scenario cases endeavor to interpret the potential future legislative or regulatory actions in New Hampshire or other states. The reference case was developed in September 2025 under SEA's NE-REMO service.

RPS Alternative Scenario Definitions: This analysis includes three (3) alternative RPS scenarios. Each is summarized below. **Please note that the thermal carve-out is assumed to be retained (unchanged) in each case.**

1) Reference + Adjusted Class III

- a. Assesses the impact of a NH-III target revision from 8% to 5%, for 2025 through 2040.

- b. No changes to NH-III ACP rate.

2) The “Consolidate I+II, Consolidate III (adjusted) + IV” Case

- a. Combines Classes I & II (“New”) and Classes III & IV (“Existing”).
- b. Uses current, individual targets for all Classes through 2026.
- c. Combines NH-I and NH-II targets beginning 2027, **AND**
 - i. Increase target by 0.5% per year until it reaches 20% in 2040; target remains constant thereafter.
- d. Combines NH-III and NH-IV targets beginning 2027.
 - i. NH-III uses adjusted target of 5% whereas NH-IV utilizes current targets.
- e. No changes to NH-I and NH-II ACP rates.
- f. Assumes the combined NH-III and NH-IV Class is subject to the NH-III ACP.

3) The “Consolidate All” Case

- a. Uses current, individual targets for all Classes through 2026
- b. Combines NH-I, NH-II, NH-III, and NH-IV targets beginning 2027.
- c. Assumes the new, combined Class is subject to the NH-I ACP.

Additional Analysis and Observations

This report also considers two additional potential adjustments to the NH RPS – (1) the addition of a new class similar to a ‘Clean Energy Standard’ and (2) transitioning the treatment of Class I and Class II resources from ‘New’ to ‘Existing’. These topics are discussed in Section 8 and Section 9, respectively. Finally, this report includes a discussion of the potential tradeoffs of adopting a long-term contracting program as a co-policy to support RPS policy objectives at the least cost to NH ratepayers. Long-term energy and certificate contracts are discussed in Section 10.

6 Summary of Assumptions

This section summarizes key demand and supply assumptions utilized in SEA’s quantitative modeling. These assumptions are held constant across all scenarios. Additional details are provided in the appendix.

Table 2: Major Demand Assumptions

Key Demand Inputs	Description of Assumption
Load Forecast	ISO-NE 2025 CELT, adjusted for SEA forecast of behind the meter (BTM) generators; Includes SEA Base Case assumption of beneficial electrification.
Load Exemptions	Municipal and Cooperative Utilities (Muni only in NH)
RPS Targets (other than NH)	Per current statute. All states, all classes.
MA MLP GGES Target	0% now, 50% in 2030, 75% in 2040, 100% in 2050
Tax Credit Impact	Status Quo (OBBBA, with Treasury guidance on eligibility)
Tariff Impact	Current tariffs assumed to moderate beginning in 2029
Treatment of BTM Resources (CT, RI, MA, ME, VT)	Offset production added to load beginning 2035
Treatment of BTM Resources: NH	No change. BTM consumption continues to reduce RPS-obligated load

Table 3: Major Supply Assumptions

Key Supply Inputs	Description of Assumption
MA/CT/RI 2023/24 & 2025/26 OSW RFPs	MA: 1200 MW CT: 0 RI: 0
MA OSW Procurement (Post-83C)	2,800 MW
OSW Supply Attrition	
For COP Secured	0%
For COP in Progress (advanced)	5%
For COP in progress (less advanced)	20%
Gulf of ME leases, before 2028 RFP	40%
Gulf of ME leases, after 2028 RFP	20%
CT Zero Carbon RFP: MW; Timing	29 MW solar by 7/1/2028
CT Expedited Zero Carbon RFP	300 MW solar by 1/1/2030
MW; Timing	
N. ME Gen + Tx: MW; Timing; CF over line	1,200 MW, Avg. COD 7/1/2033, 41.37%
Vineyard Wind (804.5 MW)	Full production by 4/1/2026
Revolution Wind 1 (704 MW)	Full production by 1/1/2027
ME OSW Procurements ¹	2,500 MW
VT OSW Procurement ¹	200 MW
CT OSW Procurement (Post-2026)	None
RI OSW Procurements (Post-2026)	None
NH OSW Procurement	None
ME Chap. 321 Procurement Round 2	300 MW solar equivalent; Avg. COD 1/2030
ME Chap. 321 Procurement Round 3	Remainder of volume not awarded in Rd. 2; Avg. COD 7/2031
NH SB 54 Class I Procurement	None
NECEC Tx Line (Sec. 83D Procurement)	Moves forward without additional extension: 1/1/2026

6.1 Other Assumptions

Market analysis suggests that **approximately 85% of total NH-III-eligible supply has become certified**. Most of the uncertified 15% are landfill gas facilities located in New York. With LFG no longer eligible for CT-I, it is possible that this supply will seek NH-III certification – although important to acknowledge that the requirement to import both energy and RECs from New York to New England creates an ongoing administrative cost and burden that may deter participation in NH-III. For this reason, additional NH-III supply has not been included in this analysis.

RPS Compliance Banking: This analysis uses historical banking data (through 2023). Beginning in 2027, bank balances are consolidated in line with scenario definitions. New Hampshire allows banking in all classes for 2 years. The amount of banked compliance deployed each year cannot exceed 30% of current year's obligation.

The **discount rate** for present value analysis in this report is 9.9%, which is intended to represent the utilities' pre-tax weighted average cost of capital. The same value was used in the 2018 RPS Review.

7 Modeling Results, Observations, and Implications

How the models work: Estimating total compliance cost through near- and long-term REC price forecasting.

As described in the Approach and Methodology section, this analysis leverages SEA's NE-REMO, a suite of models that forecast renewable energy buildouts and REC prices under varying supply and demand scenarios, including alternative RPS target trajectories.

Near-term REC prices are driven by existing RPS-qualified supply, advanced-stage renewable projects with defined financing paths, and regional RPS demand. Forecasts account for project-specific probabilities of commercial operation and incorporate market mechanisms such as banking, borrowing, imports, and discretionary curtailment, as well as applicable alternative compliance payment (ACP) rate levels.

Long-term REC price forecasts are derived from a supply-curve framework that evaluates the technical potential, cost, and market value of renewable resources. The model identifies the marginal resource needed to meet RPS demand in each forecast year, with REC prices corresponding to the marginal cost of entry, the premium required for the highest-cost resource needed to achieve compliance.

Using this framework, compliance cost is estimated for each class in each scenario, for the years 2025 through 2040, inclusive. We then calculate a levelized annual cost and present value that to 2025 dollars. Finally, we take the difference between each custom scenario and the Reference Case to show the expected annual cost or savings of each scenario to NH ratepayers.

7.1 Reference Case

The purpose of the Reference Case is to set a baseline – to create a point of comparison for the three alternative scenarios. The Reference Case is derived from SEA's NE-REMO analysis conducted in September 2025. This report provides a differential analysis in which the results of each scenario measure and summarize the degree of change from the Reference Case.

The Reference Case results depict regional Class I markets in approximate equilibrium for the next several years – in part due to Connecticut's 2025 action to reduce its Class I RPS targets. Supply is expected to lag demand in the late 2020s and early 2030s as the market waits for procured supply to come to fruition, while Class I targets continue to increase. Recent land-based renewable procurements have resulted in few selections or materialized developments. Meanwhile, projects eligible to respond to next rounds of solicitations – both ongoing and planned near-term rounds – continue to face permitting delays, interconnection bottlenecks, and supply chain constraints. Similarly, offshore wind faces substantial development headwinds, including federal permitting pauses and supply chain disruptions, which are pushing the bulk of offshore wind deployment into the mid-2030s. Despite CT-I no longer being an eligible market outlet for biomass and LFG beginning October 1, 2025, NH-III (modeled at 8% in the Reference Case) remains short throughout the analysis period (although significantly less short than SEA's other NE-REMO model runs before CT's eligibility change). The reason for the shortage is that some NH-III supply is eligible for ME-I/IA and RI-New where higher ACP rates allow for higher REC prices and these facilities are assumed to make revenue-maximizing decisions. The NH-IV Reference Case reflects a modest

shortage, with REC prices near the ACP. This is largely the result of overlapping eligibility with MA-II, with certified supply insufficient to fulfill both markets.

7.2 Reference + Adjusted Class III

In the Reference + Adjusted Class III scenario, NH-III targets are set to 5% for 2025 – 2040 and all other classes remain unchanged. NH-III at 5% is a test case intended to set NH-III demand to approximate the expected production (based on market and facility-specific conditions, not theoretical maximums) from NH-III certified facilities that are not eligible to certify for any other premium RPS markets, and therefore have no alternative RPS market outlets other than to sell all certificates into the NH-III market. The 5% target is presumed to be affirmed prior to the start of the compliance year and is assumed to be binding (i.e., not subject to review or adjustment during or after the compliance year). These conditions are necessary to support rational decisions by both (i) biomass facility owners operating facilities and producing electricity and RECs and (ii) entities purchasing RECs for RPS compliance, as well as to support a liquid market. Under the modeled conditions, the 5% target would facilitate biomass production and the associated economic benefits, while minimizing RPS-obligated entities' use of the ACP to meet compliance. If this pathway is pursued, SEA recommends a Class III target review in early 2030 to assess expected NH load for 2031 – 2040 and its potential impact on the reasonableness of maintaining a 5% Class III obligation. This scenario would require two changes to the applicable enabling legislation – one to set the NH-III target at 5% (for 2025 through 2040), and another to remove the Class III modification provision and replace it with RPS reviews in 2030, 2035, and 2040.

- **Ratepayer Impact:** The 'Reference + Adjusted Class III' case produces a levelized annual ratepayer *benefit* estimated at \$21.49 million per year, in 2025 dollars. A comparison of case-specific levelized REC prices is provided in Table 4.

7.3 Consolidate I+II and increase, Consolidate III (Adjusted)+IV

In the Consolidate I+II, Consolidate III (Adjusted)+IV scenario, Class I is combined with Class II, and Class III is combined with Class IV. The Class I target (net of the Thermal carve-out, which remains unchanged) of 12.8% is combined with the Class II target of 0.7% for an aggregated target of 13.5% in both 2025 and 2026. Beginning in 2027, the combined target increases at 0.5% per year, reaching 20% in 2040. The Class III target is adjusted to 5% and held constant and the Class IV target is held constant at the current level of 1.5%, resulting in a combined target of 6.5% for 2025 – 2040. The combined Class I+II uses the current Class I ACP rate schedule. The combined III+IV uses the current Class III ACP rate schedule.

- **Ratepayer Impact:** The 'Consolidate I+II and increase, Consolidate III (Adjusted)+IV' case produces a levelized annual ratepayer *benefit* estimated at approximately \$5.15 million per year, in 2025 dollars. This represents the net impact of a slight increase in cost to comply with a higher (and modestly increasing) Class I+II target and a decrease in cost to comply with a combined 6.5% Class III+IV target – due to reduction in NH-III targets – where biomass, landfill gas, and hydro (which must meet the Class IV criteria) are all permitted to meet the standard. A comparison of case-specific levelized REC prices is provided in Table 4.

7.4 Consolidate All

In the Consolidate All alternative scenario, the current targets for NH Class I, II, III, and IV are combined into a single class. Only the Thermal carve-out remains as separate. The combined Class is assumed to adopt the current NH Class I ACP rate.

- **Ratepayer Impact:** The ‘Consolidate All’ case produces a levelized annual ratepayer *benefit* estimated at approximately \$0.31 million per year, in 2025 dollars. The reason the Consolidate All Case did not produce meaningful savings is that it is assumed to consolidate all current targets – including 8% for Class III.

The aggregation of all NH Classes creates a more complex dynamic than the other cases. After accounting for supply that are only eligible in NH Classes I and III with no alternative market outlets and available NH Classes II and IV supply, the remaining demand for the ‘Combined All’ Class in any given year is expected to be fulfilled by supply that is eligible in multiple RPS Class I markets in the region (i.e., regional Class I supply). The REC prices for the ‘Combined All’ Class therefore converges with regional Class I REC prices once the consolidation takes place. When substantial volumes of offshore wind (are assumed to) come on-line in the mid-to-late 2030s, regional Class I REC prices soften significantly. This dynamic results in modest reduction in ratepayer cost compared to the Reference Case, which required the use of ACPs – which has a higher rate than the modeled Class I REC price for this ‘Consolidate All’ case - to fulfill NH-III RPS compliance. In this scenario, regional Class I resources, which has a lower price, may substitute some NH Class III and Class IV biomass and hydro resources for NH RPS compliance. At that point, it is possible that the legacy supply formerly protected by Class III and Class IV may find the economics of continued operation difficult to justify.

Table 4: Summary of Modeling Results

	Reference Case	Reference + Adjusted Class III	Consolidate I+II and increase, Consolidate III (adjusted)+IV	Consolidate All
REC Prices (‘25-‘40, levelized)	Class I: \$38.01 Class II: \$29.77 Class III: \$45.61 Class IV: \$28.33	Class I: \$38.01 Class II: \$29.77 Class III: \$37.54 Class IV: \$28.33	Class I+II: \$39.51 Class III+IV: \$40.82	Class I+II+III+IV: \$40.10
Ratepayer Cost*	\$106.86M (n/a)	\$85.37M (-20.11%)	\$101.71M (-4.82%)	\$106.55M (-0.29%)
Ratepayer Impact* (Relative to the Reference Case)	(n/a)	Net Savings of \$21.49M	Net Savings of \$5.15M	Net Savings of \$0.31M
* Expressed as a 16-year net present value (NPV), in 2025 dollars, using 9.90% discount rate				

8 Consideration of a Clean Energy Standard

The energy policy landscape is constantly evolving. The late 1990s and early 2000s brought electric sector restructuring and the advent of RPS mandates. When the RPS alone proved insufficient to support new project financing at the scale required meet the sum of regional targets, state-sponsored long-term contracting co-policies were developed in the 2010s -- and expanded in the early 2020s – to provide the creditworthy revenue certainty required to spur financing at competitive rates and deliver the benefits of long-term, fixed price contracts from new renewable energy facilities to the region’s ratepayers (the issues, options, and implications of long-term contracting policies are discussed in Section 10).

In parallel, some states also adopted greenhouse gas goals including through, but not limited to, the Regional Greenhouse Gas Initiative (RGGI). Over time, the pursuit of RPS targets and GHG goals led to an evolution in the narrative related to the role of non-emitting resources, including facilities built well before RPS mandates existed. Broadly speaking, as new resources became more difficult to site, permit, finance, and contract, the economics and greenhouse gas benefits of investing in the continued operation of existing facilities became more attractive. Today, with heightened focus on affordability, policymakers are actively discussing and adopting policies that engage all available clean energy resources. The resulting policy vehicles are generally referred to as Clean Energy Standards (CES).

Like RPS, CES policies are not homogeneous, but they generally focus on non-emitting resources and include major roles for both nuclear (existing and new) and large-scale hydroelectric generation (both domestic and from eastern Canada).

The **Massachusetts CES** was the region's first; its initial compliance year was 2018. MA CES-eligible supply is narrowly defined as hydropower from facilities larger than 30 MW that were built after 1/1/2011 and whose energy is delivered to ISO-NE over a transmission line built after 2016. The policy was purpose built to provide a mandate that aligned with the state's purchase of over 9 TWh of energy and certificates over the New England Clean Energy Connect transmission line – which is expected to be energized in late 2025 or early 2026. The CES target (which is 30% in 2025 and increases to 80% by 2050) “wraps around” the MA Class I target (27% in 2025), meaning that the MA CES creates an incremental 3% clean energy demand in 2025 (and an incremental 20% by 2050). MA Class I supply is also eligible to fulfill the CES and has, in fact, been the only supply available to do so between 2018 and 2026. The MA CES has an ACP rate of \$35. With MA Class I REC prices currently trading just below \$40, 2025 CES compliance will come at least partially from ACPs. That is expected to change in 2026 once hydro supply deliveries over NECEC begin.

The first compliance year for the **Massachusetts Clean Energy Standard– Existing (MA CES-E)** mandate was 2021. Designed as a bookend to the MA CES, the MA CES-E is for hydropower from facilities larger than 30 MW that were built *before* 1/1/2011 and, for facilities not located within ISO-NE, whose energy is delivered over transmission line built *before* 2017. For reasons related to historical contracting and greenhouse gas accounting, supply from Massachusetts, Connecticut, New Hampshire, and eastern Canada are eligible. The MA CES-E also makes eligible up to 2.5 million certificates from each of the Millstone and Seabrook nuclear power stations. The CES-E target was originally set at 20% in 2021. In recognition of the fact that “existing” supply is finite, MA DOER established a formula to adjust the target each year based on changes in load. The target was 20% in 2022, 26% in 2023, 27% in 2024, and 26% in 2025. The MA CES-E has an ACP rate of \$10. MA CES-E certificates are currently trading just below the ACP rate.

During its 2025 legislative session, **Maine established a Class III target that is comparable to a CES**. The target begins at 1% in 2031 and increases to 10% for 2040+. Nuclear and hydropower (that can physically be delivered to the ISO-NE control area or to the Maritimes control area) are eligible. Class I or IA RECs can also be used to fulfill the requirement. The legislature set the maximum Class III ACP rate at \$50. The actual rate will depend on PUC rulemaking.

In 2022, **Connecticut codified a target of ‘zero-carbon electricity supply by 2040’** through [Public Act 22-5](#). Specific classes, eligibility and intermediary targets have not been established either by subsequent law or regulation. In fact, the legislature *reduced* CT Class I RPS targets from 40% in 2030+ to 29% in 2030+ (intermediary targets were reduced as well).

Rhode Island does not currently have a CES but does have the flexibility to enter long-term contracts for large hydroelectric supply that would effectively replace a portion of the RPS mandate. This authority does not currently extend to nuclear supply.

Vermont does not have a CES either, and none of its four tiers allows nuclear supply. Vermont Tier I has liberal eligibility, however, which allows compliance with large hydro – including hydro from Canada that is imported as part of the system mix purchases.

Observations and Implications: Over the last several years, regional policymakers have made adjustments to prioritize existing supply, including both large hydro and nuclear. As NH policymakers seek to balance supply diversity, local, economic benefits, and affordability, it is reasonable to investigate the potential merits and roles of supplementing NH's RPS with an additional class like MA's CES-E or Maine's Class III. One of the key considerations is NH's interest in contracting for both energy and certificates from one or both of Seabrook and/or Millstone. If there is interest, timing may be important. Between an existing contract with Connecticut and entitlements of regional MLPs, approximately 85% of Millstone certificates are tied up through 2029. If you assume 2.5M certificates will be sold into the MA CES-E market, then the portion of certificates sold through 2029 increases to ~99%. Seabrook offers more near-term opportunities. Existing (publicly available) contracts and entitlements represent about 30% of Seabrook's annual certificate production. If you assume 2.5M certificates will be sold into the MA CES-E market, the number increases to ~55%. So, from the nuclear perspective, supply is expected to be available for contracting from Seabrook in the near-term, and a much larger amount of supply – from either Seabrook or Millstone – is expected to be available beginning in 2030.

The future availability of regional (including Canadian) hydro is harder to forecast. MA has contracted for 9.45 TWh of new supply from eastern Canada, the MA CES-E has created demand for ~14 TWh (9 TWh if you assume full use of nuclear eligibility) of existing hydro supply, and existing New England (and Canadian) hydro is a key contributor to Maine's Class II, Vermont's Tier I, and (at much smaller volumes) MA Class II, CT Class I, and Rhode Island's "Existing" class. The Canadian landscape has also changed. Quebec has a long history of exporting (hydro) supply to New England. But both Canadian load and clean energy mandates have increased recently, creating greater demand for hydro (and other clean or renewable resources) in Canada. As a result, Canadian policymakers and utility company leads are now more cautious about exporting large volumes of supply to New England. For these reasons, if New Hampshire was to establish a new class (for nuclear and large hydro) like Maine's Class III, it may be prudent to scale percentage target increases to the nuclear supply expected to be available before and after 2030.

The MA CES-E market provides a reasonable proxy for potential compliance cost outcomes in a market where both nuclear and large hydro are eligible. As previously stated, the MA CES-E limits Seabrook and Millstone participation to 2.5M certificates each. This likely means that large hydro is the marginal – and therefore price-setting – compliance resource. MA CES-E certificates are currently trading at approximately \$9.50 (just below the \$10 ACP rate). For illustration, if New Hampshire were to establish a CES of 1% in 2030, increasing to 10% for 2039+, without a limit on nuclear participation and with an ACP rate of \$10, the expected NPV cost would fall within the range of \$16 to \$25 million in 2025 dollars (assuming REC prices ranging from \$6.00 to \$9.50).

9 Consideration of Transitioning Class I & II from ‘New’ to ‘Existing’

Earlier sections of this report emphasize the complexity and interconnectedness of regional RPS markets. The ability of certain supply (particularly any wind or solar built since 2006) to participate in any of the regional Class I RPS markets means that **New Hampshire cannot effectively implement a policy by itself that establishes a “timeframe and manner in which Class I & II might be treated as ‘existing’.”** Unless all six New England states make a coordinated change in Class I RPS eligibility, treating NH Class I and/or NH Class II supply as ‘existing’ after a specified number of years will simply result in the associated RECs being sold into other markets.

For this topic, it is appropriate to step back and discuss the policy objective. What would New Hampshire be trying to accomplish with this change? What is the outcome that New Hampshire policymakers are trying to produce? Once the objectives are identified and agreed, policy options and implications can be discussed. While considering this question, it is important to remember that eligibility and ACP rate will be the key considerations driving market behavior and outcomes. Rational economics dictate that supply will seek its highest value market. If NH creates another ‘existing’ class for “early year” Class I and II supply or consolidates existing classes (including “early year” Class I and II supply), participation will depend on the availability and market value of alternative markets. As discussed in Section 3.2, as of October 1, 2025, certain biomass projects have no “premium market” alternatives to NH Class III. Therefore, one can reasonably count on their participation in the NH Class III market. The same cannot be said of NH Class I and II supply, which are actively traded throughout New England Class I markets. Therefore, there is no option for New Hampshire to create a policy, in isolation, that effectively migrates supply from a ‘new’ to ‘existing’ class.

10 Consideration of Multi-Year Energy & Certificate Contracts in the Context of Cost-Effective Energy Policymaking

RPS policies have proven effective in sending price signals to facilitate market participation and providing revenue to support the development, investment, and continued operation of eligible resources. Nevertheless, particularly in New England, they alone have not proven sufficient to drive investment in capital-intensive new generation or to ensure the continued operation and maintenance in existing renewable resources.

Developers and generators face significant revenue and price uncertainty under RPS-based markets, where short-term REC prices can vary widely with fluctuating supply-demand balances from changing market conditions and policy adjustments. As observed in a recent report¹⁷ issued by the Connecticut Department of Energy & Environment Protection (DEEP), “price volatility in the REC market means the RPS does not provide the revenue certainty needed for new renewable energy projects to obtain financing and come online.” This volatility and uncertainty increase financing costs and risk premiums for new projects, challenging the ability to deploy sufficient renewable energy projects to meet RPS goals, while raising the overall cost of doing so. At the same time, existing generation projects are exposed to fluctuating market conditions that challenge continued operation and maintenance.

To achieve energy policy objectives cost effectively, legislators and policymakers in competitive market states have turned to complementing RPS policies with procurement co-policies to secure multi-year energy and certificate contracts, accomplishing what RPS alone cannot. These policies aim to:

¹⁷ Connecticut Department of Energy & Environment Protection, Draft Report on Select Connecticut Energy Supply Issues (Feb. 20, 2024), <https://acrobat.adobe.com/id/urn:aaid:sc:VA6C2:c9f1d5ea-77a8-4f4d-b378-13105078a886>

- Create revenue certainty and attract investment in renewable energy generation projects that might not otherwise come to fruition under RPS alone;
- Reducing ratepayer costs by lowering financing costs, securing production below forecasted cost of marginal alternative resources, or enabling economies of scale;
- Hedge against future volatility in generation service wholesale energy costs and RPS compliance costs to reduce retail electricity rate volatility;
- Secure the right to claim renewable energy by securing generation attributes, typically represented by purchase of RECs among other generation products; and
- Encourage developers to locate projects, select specific technologies, or incorporate features that provide sought-after benefits to the soliciting state's ratepayers or broader economy.

To date, multiple states in the region and across the U.S. have developed extensive experience with renewable energy multi-year contract procurements. In addition, many states with vertically integrated monopoly structures have extensive experience with renewable energy solicitations through integrated resource planning or other regulatory procurement processes, and countries around the globe have accumulated an extensive body of experience with renewable energy contract procurement through solicitations, tenders, or auctions. As New Hampshire evaluates its approach to meeting RPS compliance – balancing ratepayer costs with broader state policy objectives – it is reasonable to consider the role multi-year contracting could play, as well as the state's potential role in designing and administering such procurements. Although there are multiple approaches to pursuing multi-year contracts, the following discussion focuses on state-administered central competitive procurement, the predominant model used by states in the Northeast.

10.1 Benefits of Multi-Year Contract Procurements

Multi-year contract procurement plays a critical and necessary role in complementing RPS policies to advance renewable energy development. By providing a predictable revenue stream over a defined period, multi-year contracts create the revenue certainty developers need to secure lower-cost financing, directly lowering levelized cost of energy (LCOE) for new renewable generation to serve RPS compliance.

Multi-year contracts also enhance market efficiency and competition. Predictable and transparent procurement processes send clear signals to developers, encouraging robust participation and fostering competition that can help drive down prices over successive solicitations. A predictable contracting framework and schedule reduce “boom-bust” cycles driven by short-term market dynamics, allowing for a steadier buildout of renewable capacity and better alignment of supply with policy targets. The resulting market confidence not only reduces costs but also supports a more diverse and resilient renewable energy portfolio.

From a policy perspective, multi-year contract procurement policies offer a mechanism for aligning renewable energy development with broader state objectives. Procurement and contract design can be tailored to advance specific project attributes, such as encouraging development in preferred locations, supporting emerging technologies, or promoting economic development and job creation. Policymakers may be able to leverage renewable energy investments to achieve multiple policy objectives, including grid reliability, regional equity, and local economic benefits, while still emphasizing cost efficiency and competitive outcomes.

From a ratepayer perspective, multi-year contracts contribute to price stability. In markets characterized by short-term price fluctuations, both in wholesale energy and REC markets, multi-year contracts act as a hedge, locking in energy and certificate prices and insulating ratepayers from future volatility. By securing predictable, competitively determined contract prices, states can smooth retail electricity rate impacts and provide greater cost certainty for utilities and regulators. Minimizing ratepayer exposure to price uncertainty and volatility over time is a core principle of least-cost procurement policy design.

Taken together, these benefits demonstrate that incorporating multi-year contracting into New Hampshire's RPS framework can improve its cost-effectiveness, predictability, and overall policy alignment.

10.2 Issues, Options, and Implications

As New Hampshire evaluates its path toward meeting RPS compliance in a way that balances ratepayer costs and broader policy objectives, experiences from peer states highlight both the opportunities and potential tradeoffs of multi-year contracting as a tool. Multi-year contracts can facilitate renewable energy investment at lower cost, but effective implementation of multi-year contract procurements requires thoughtful designs and administration that balance risk, cost, and policy outcomes.

Contract Length: Contract length directly affects project economics and ratepayer exposure. Historically, 10- to 20-year contracts are common in New England and adjacent states, providing the revenue certainty required to enable financing. Several states (e.g. Connecticut, Rhode Island, and New York), as well as utility and voluntary buyers, now have authority to offer 25 to 30-year contracts, particularly for offshore wind. The longer contract lengths align with expectations for longer economic lives for renewable energy sources and are expected to further reduce financing risk and the associated cost of capital. The greater revenue certainty results in lower per-unit costs.¹⁸

Contract Product: The products covered under a multi-year contract—energy, capacity, RECs, or bundled combinations thereof—determine how risk and value are allocated among developers, offtake entities, and ultimately ratepayers. Purchasing a specific product provides a hedge for that component, reducing revenue volatility but not necessarily total cost. Energy-only or REC-only contracts often provide insufficient revenue certainty to secure low-cost financing, resulting in higher financing costs and, consequently, higher bid prices. Contracts that exclude RECs allow those certificates to be sold elsewhere, potentially crediting renewable generation to another state and undermining New Hampshire's RPS compliance.

By contrast, bundled energy-and-REC contracts provide stronger hedging for developers and greater compliance certainty for states. The vast majority of contracting across New England, except in Maine, has relied on bundled power purchase agreements for precisely these reasons. However, for purchasing RECs via multi-year fixed-price contracts, there is some

¹⁸ It is possible, however, that longer contract terms may create ratepayer exposure to above-market prices if market or technology costs decline. To mitigate this risk, it is possible to retain the 20-year contract option with a right of first refusal on an extension at a predetermined price.

possibility that the REC transaction could someday be above the spot market in New England.¹⁹ Any capacity component included in a contract carries significant uncertainty due to ongoing reforms to capacity accreditation and market design.

Project Viability and Delivery Risk: Awarded projects failing to reach commercial operation increase costs, delay compliance, and undermine confidence in procurement programs. Awarded projects may fail to reach commercial operation due to permitting, interconnection, supply chain challenges, or other macroeconomic conditions. States have mitigated these risks through minimum thresholds, clear contractual milestones, and financial security requirements. All recent state policy-backed solicitations have minimum bid eligibility thresholds tied to project maturity. Recent rounds of New York Tier 1 land-based large-scale renewable solicitations have raised the barrier to bid with the intent to capture projects with greater regulatory and cost certainty.²⁰ Massachusetts, New York, and Connecticut all require development and performance security that is refundable only upon achieving commercial operation, discouraging speculative bidding. With the transition to a cluster study interconnection process pursuant to FERC Order 2023, aligning solicitation schedules with ISO-NE cluster studies – an approach adopted by New York for their 2025 RFP for Tier 1 large-scale renewables – may also improve cost accuracy and reduce attrition risk.

In light of recent macroeconomic disruptions impacting the renewable energy sector (supply chain, inflation, interest rate increases due largely to COVID-19 and the Ukraine war), recent offshore wind procurements (e.g., Massachusetts Section 83C Round IV, New York ORECRFPs) and some land-based renewable procurements (e.g., New York Tier 1 RESRFPs) have adopted inflation and interest-rate indexing between bid submission and financial close, protecting developers from exogenous cost shocks – but shifting some risk previously borne exclusively by bidders to ratepayers.

Investment Signals and Market Competition: Limited participation in solicitations could reduce competition and raise bid prices beyond those of a competitive market. Predictable and transparent procurement schedule with clear volumetric targets could help build a robust development pipeline that is prepared to respond to upcoming solicitations. Greater competitive pressure and greater readiness may translate to lower bid prices. In addition, greater visibility and certainty enable developers to plan their project pipelines and development activities (e.g., interconnection, permitting, and financing) more effectively and to target participation in solicitations for which their projects have sufficient maturity. This reduces bid risk to developers and contingency costs, as well as minimizes the likelihood of the state awarding immature or speculative projects that may not reach commercial operation. New York’s annual Tier 1 solicitations have provided developers with clear visibility into timing and volumes, which have in turn supported a more robust and competitive market. In contrast, several New England states have faced challenges providing similar long-term procurement visibility due to limited statutory authority, though new legislations in Maine (e.g., [P.L. 2025, Chapter 392](#) and the associated [Contaminated Land RFP](#)) and Massachusetts (e.g., [Chapter 179 of the Acts of 2022](#) and the associated [Section 83C RFPs](#) for offshore wind generation) have established clearer procurement targets and timelines. In addition, Connecticut,

¹⁹ Note that the practice of procuring RECs and thereby enabling projects to get financed and built will reduce spot market prices relative to what they would have been. In this context, the appropriate benchmark for whether a past REC purchase is over market is what REC prices would have been absent the purchase (and others like it), not the current spot REC price. However, the former can only be estimated by modeling, while the latter is calculable. It is for this reason that retrospective analysis of overmarket costs of contracting RECs may have an inherent bias towards overstating the costs.

²⁰ For example, in its [RESRFP25-1](#), New York established minimum threshold requirements for interconnection (for those in the ongoing NYISO cluster study, evidence the developer has notified NYISO of intent to progress to Phase 2), permitting (“awareness” of permitting requirements and a timeline for obtaining permits), and development experience (previous experience developing a renewable generation facility of similar scale to commercial operation). New York [characterized](#) the solicitation as advancing “shovel-ready renewable energy projects, with a focus on qualifying projects that seek to access existing federal tax credits that will expire.”

Maine, Massachusetts, and Rhode Island are all in various stages of multi-year procurement planning processes that are expected to provide clearer signals of long-term procurement needs.

Grid Integration and Locational Efficiency: The siting of renewable energy projects has important implications for system reliability and cost. Projects located in areas of persistent congestion or frequent negative pricing events can exacerbate curtailment and reduce system efficiency. To mitigate these outcomes, many recent large-scale renewables procurements in New England have included contract provisions that limit compensation during periods of negative locational marginal prices for some (e.g., X number of hours annually) or all times during which energy prices are negative. These measures provide market-based incentives for developers to locate projects where their output aligns with system needs. However, such provisions may increase bid prices, particularly if the risk is unbounded, as developers would face basis risk and price suppression risk due to subsequent project development.

Retaining legacy supply: While discussions of multi-year contracting often focus on facilitating new renewable deployment, supporting the continued operation of legacy (i.e., pre-restructuring) renewable generation can also make sense from both land-use and economic perspectives, particularly when the all-in cost per MWh of new generation exceeds the cost of maintaining production from existing facilities (adjusted for differences in value due to production profile or location).

Owners of operating facilities facing equipment failures or performance degradation beyond their useful lives must justify investments in maintenance, overhauls, replacements, refurbishments, or repowering. The less costly of these actions may be supportable under expected market revenues from the wholesale electricity market and spot REC market. However, larger investments with multi-year payback periods may be difficult to justify without sufficient revenue stability or regulatory certainty.

These observations suggest that New Hampshire's legislators, policymakers, and regulators could consider creating procurement or contracting opportunities for legacy renewable generation as a way to "level the playing field," retaining cost-effective existing supply at costs below those of replacement with new generation. Because the per-unit scale of investment for extending the life, or reusing the site, of legacy facilities is generally smaller than that for new projects, such support may not require the same contract duration or scope of hedging typically needed to attract investment in new renewable development. Ensuring that cost-effective existing facilities remain operational can be an important component of a least-cost strategy, complementing new investment by preserving affordable renewable generation already online.

A Appendix A: Supporting Assumptions

A.1 Current NH Renewable Portfolio Standard (RPS) Targets

Table 5: Summary of New Hampshire RPS Compliance Obligation Targets, by Class

	Class I, Non-Thermal	Class I, Thermal	Class I, TOTAL	Class II	Class III	Class IV
2025	12.8%	2.2%	15.0%	0.7%	8.0%	1.5%
2026	12.8%	2.2%	15.0%	0.7%	8.0%	1.5%
2027	12.8%	2.2%	15.0%	0.7%	8.0%	1.5%
2028	12.8%	2.2%	15.0%	0.7%	8.0%	1.5%
2029	12.8%	2.2%	15.0%	0.7%	8.0%	1.5%
2030	12.8%	2.2%	15.0%	0.7%	8.0%	1.5%
2031	12.8%	2.2%	15.0%	0.7%	8.0%	1.5%
2032	12.8%	2.2%	15.0%	0.7%	8.0%	1.5%
2033	12.8%	2.2%	15.0%	0.7%	8.0%	1.5%
2034	12.8%	2.2%	15.0%	0.7%	8.0%	1.5%
2035	12.8%	2.2%	15.0%	0.7%	8.0%	1.5%
2036	12.8%	2.2%	15.0%	0.7%	8.0%	1.5%
2037	12.8%	2.2%	15.0%	0.7%	8.0%	1.5%
2038	12.8%	2.2%	15.0%	0.7%	8.0%	1.5%
2039	12.8%	2.2%	15.0%	0.7%	8.0%	1.5%
2040	12.8%	2.2%	15.0%	0.7%	8.0%	1.5%

A.2 Load Forecast & Reference Case Compliance Obligations

Table 6: Load Forecast & Reference Case Compliance Obligations (GWh)

	RPS- Obligated NH Load Forecast	NH-I Obligation	NH-II Obligation	NH-III Obligation	NH-IV Obligation
2025	11,135	1,425	78	891	167
2026	11,184	1,432	78	895	168
2027	11,243	1,439	79	899	169
2028	11,324	1,450	79	906	170
2029	11,429	1,463	80	914	171
2030	11,559	1,480	81	925	173
2031	11,718	1,500	82	937	176
2032	11,901	1,523	83	952	179
2033	12,106	1,550	85	968	182
2034	12,338	1,579	86	987	185
2035	12,640	1,618	88	1,011	190
2036	12,943	1,657	91	1,035	194
2037	13,247	1,696	93	1,060	199
2038	13,548	1,734	95	1,084	203
2039	13,846	1,772	97	1,108	208
2040	14,140	1,810	99	1,131	212