Massachusetts Bill H.5151

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OVERVIEW

H.5151 (engrossed as amended February 26, 2026) advances a more centralized, state-directed framework for clean energy deployment and grid planning. While aimed at accelerating renewable development and promoted as addressing affordability, the bill front-loads major procurement commitments, shifts portions of early development risk toward ratepayers, and expands regulatory oversight in ways that could constrain flexibility and raise long-term costs.

The following five provisions represent the most consequential structural changes within H.5151 regarding ratepayer cost exposure, risk allocation, and regulatory oversight. [1]

Five Consequential Provisions and Associated Risks

1. Procurement Decisions Move Upstream (SECTION 13)

The bill moves major decisions regarding the scale and resource mix of energy projects to the beginning of the process through a "plan-then-procure" framework. By establishing 30-year contracts within a rigid statewide plan, the Commonwealth locks in procurement volumes and schedules before specific costs are fully known, which reduces the ability to adjust course if project costs rise or market conditions change.

[1] This document highlights provisions of H.5151 that appear most consequential for ratepayer cost exposure, risk allocation, and regulatory oversight. The bill contains numerous additional provisions addressing energy siting, permitting, and program administration that are not analyzed here because they do not, at this time, create identifiable ratepayer financial exposure.

2. Offshore Wind Pre-Development Risk Partially Shifted to Ratepayers (SECTIONS 13 & 70)

Early-stage "soft costs" for offshore wind—such as permitting, environmental studies, and engineering—are shifted from private developers to the Commonwealth. Repayment of these costs (estimated between $50 million and $300 million per GW) occurs only if a project reaches commercial operation. With no explicit cap on total exposure and no recovery mechanism for failed projects, ratepayers act as the primary insurer for the riskiest phase of development.

3. APS Transitions to a Closed, Rising Obligation Market (SECTION 9)

The Alternative Portfolio Standard (APS) will close to new qualifying resources after January 1, 2028, while the legal requirements for electricity suppliers to purchase credits continue to rise annually. This creates a closed system where a fixed supply of projects meets an increasing mandate, likely driving annual program costs from under 10 million to over 100 million as credit prices escalate.

4. Mass Save Imposes a Compressed $1 Billion Mid-Cycle Reduction (SECTION 69)

The bill mandates a $1 billion reduction in the current 2025–2027 Mass Save plan, specifically directing administrators to cut marketing and administrative spending first. However, because these "overhead" categories represent less than 10% of the budget and much of that is already contractually obligated, the full savings target will likely require significant adjustments to actual customer rebates and program eligibility.

5. Expanded Oversight of Grid Investments (SECTION 38)

Utilities must submit detailed, enumerated capital projects and rigorously evaluate non-wired alternatives—such as demand management, virtual power plants, and distributed resources—before pursuing traditional infrastructure upgrades. The provision also establishes twice-yearly reporting requirements focused on infrastructure deferral opportunities.

Overall Assessment

H.5151 advances the Commonwealth's statutory climate and clean-energy objectives through a more centralized approach to procurement, project financing, and grid investment decisions. The bill moves several key decisions away from market-driven processes and toward state-directed deployment targets. Provisions that front-load procurement commitments, shift portions of development risk to ratepayers, and expand regulatory oversight introduce structural challenges related to cost discipline, investment flexibility, and long-term ratepayer exposure.

I. Centralized Clean Energy Procurement (SECTION 13)

a. Overview

SECTION 13 centralizes large-scale clean energy procurement within state government and shortens approval times for long-term contracts. It places the state in control of key decisions affecting project risks and ratepayer costs. The bill establishes a two-step framework designed to support a 2040 target of approximately 10,000 MW each of offshore wind and solar.

b. Key Mechanism — The Plan-Then-Procure Framework

The provision creates a two-stage process:

Step 1: Resource Solicitation Plan

- DOER develops a master procurement plan
- DPU has a mandatory 7-month review window
- Approved plans trigger cost-recovery implementation

Step 2: Competitive Solicitation

- DOER conducts solicitations
- Contracts may run up to 30 years
- DPU has 90 days to approve or reject

Structural effect: The state, rather than utilities, becomes the primary market architect. The bill also broadens the definition of "energy services" to include transmission upgrades, so renewable-related grid costs could be part of the contracts. The provision does not alter existing transmission siting authority but may expand the types of transmission-related costs eligible for recovery from ratepayers through long-term contracts.

c. Policy Implications

SECTION 13 fundamentally changes how Massachusetts buys energy. Instead of vetting projects individually, the state locks in the "what, how much, and when" through a statewide plan before specific costs are known.

The plan must include minimum procurement targets of at least 10 GW of offshore wind and approximately 10 GW of solar by 2040, along with a schedule for future solicitations and a mechanism for recovering long-term contract costs from ratepayers.

Several structural features of the bill include:

Key decisions move earlier in the process. Major assumptions about procurement volumes, schedules, and cost recovery are embedded in the statewide plan before individual projects are proposed. Because contract review must be consistent with the approved plan, the opportunity to revisit underlying assumptions later may be limited.

Review timelines are compressed. The DPU must approve or reject the statewide plan within seven months, and once contracts are filed, the DPU has only 90 days to review them.

Utilities are removed as contracting intermediaries. Electric distribution companies will no longer receive remuneration for contract management, although essential functions such as contract execution, credit support, performance monitoring, and administration must still occur. In practice, this change reallocates rather than eliminates these costs.

Formal adjudicatory review is not guaranteed. Although DPU review is required for the plan and contracts, the bill does not explicitly require formal hearings under Chapter 30A, leaving uncertainty about the depth of economic scrutiny that may occur.

d. Bottom Line

SECTION 13 shifts key procurement decisions to the front end of the process, establishing the framework—including scale, schedule, and cost-recovery mechanisms—early on. This may accelerate project development but reduces flexibility to adjust if market conditions change or costs rise, potentially exposing ratepayers to higher long-term expenses. For ratepayers, the key risks include:

- **Upfront commitment risk:** Procurement volumes and timelines set before individual projects are fully evaluated.
- **Cost-shifting risk:** Removing utilities from contract administration does not eliminate the underlying management costs.
- **Process risk:** Important procurement decisions are made before full public and economic scrutiny takes place.

Ultimately, ratepayer outcomes will hinge on the Commonwealth's careful management of procurement scale, pacing, and contract oversight and how it balances the goal of accelerating clean energy deployment with long-term control.

II. Offshore Wind Pipeline Support (SECTIONS 13 & 70)

a. Overview

SECTION 13 adds Chapter 25A, Section 24 together with SECTION 70, to establish a coordinated framework intended to sustain Massachusetts' offshore wind development pipeline through the late 2020s and into 2040.

New Section 24 authorizes the Commonwealth to partner financially with offshore wind developers during early project development, while SECTION 70 links this support directly to the Commonwealth's long-term offshore wind procurement targets. The combined effect is to keep projects moving toward construction readiness even where significant development uncertainty remains.

b. Key Mechanism — State Co-Investment in Early Development

The bill creates a state-enabled mechanism targeting early-stage "soft costs" associated with offshore wind development. These costs include permitting, environmental studies, early-stage engineering and project design, and interconnection planning. Under this framework, the state finances a portion of these upfront development expenses, rather than requiring them to be borne entirely by project developers.

These expenditures typically represent 1–5 percent of total project cost. Assuming offshore wind capital costs of roughly $5,000–$6,000 per kW installed, early-stage development spending equates to about $50,000– $300,000 per MW, or roughly $50 million–$300 million per GW of installed capacity. Across a 10-GW development pipeline, this corresponds to roughly $0.5–$3.0 billion in early-stage project spending, depending on the level of state participation.

These costs occur before projects secure full financing and therefore carry the highest failure risk in the project lifecycle.

c. Policy Implications

The bill authorizes the Commonwealth to join in the highest-risk phase of offshore wind development, creating a potential cost pool that could reach hundreds of millions to several billion dollars across the planned pipeline. Without a cap or clear recovery if projects fail, public funds could be at risk before viability is clear.

Traditionally, developers and their investors bear pre-development risk by funding these soft-costs with no recovery guarantee if projects fail. This encourages careful evaluation.

SECTIONS 13 and 70 change this by allowing state support to lower developer risks early on. Repayment ties only to success, creating uneven risk: developers gain early-stage protection while ratepayers take losses on failures.

The absence of a statutory cap also means potential exposure may grow as the Commonwealth expands its offshore wind pipeline. If federal incentives, particularly the Clean Electricity Investment Tax Credit (§48E), decline or disappear, projects may face higher revenue requirements, increasing the likelihood that some projects struggle to secure financing or require higher long-term contract prices.

Once public funds have been committed, the Commonwealth may also face practical pressure to advance projects in order to avoid writing off prior investment, increasing the economic and political cost of project cancellation.

d. Bottom Line

SECTIONS 13 and 70 establish a state co-investment framework designed to keep offshore wind projects moving through development by shifting a portion of early-stage project risk to the Commonwealth and, ultimately, ratepayers.

If federal incentives weaken or project economics deteriorate, the Commonwealth may face a narrowing set of viable outcomes: either supported projects fail after public funds have been committed, or they proceed only at higher long-term contract prices borne by ratepayers.

As the offshore wind pipeline grows, this provision increases ratepayer risks due to delayed, reworked, or abandoned projects.

III. APS Program Changes (SECTION 9)

a. Overview

SECTION 9 closes the APS to new qualifying projects after January 1, 2028, while continuing to raise both the annual compliance requirement and the Alternative Compliance Payment (ACP). This alters the program's core function.

b. Key Mechanism

Beginning in 2028:

- No new projects will be allowed to qualify for APS.
- Existing qualified facilities will continue generating AECs.
- The APS compliance requirement will continue to increase each year.
- The ACP penalty ceiling will also continue to increase annually.

In practical terms, the program becomes a fixed-supply system with growing obligations, pushing credit process up.

c. Policy Implications

Historically, APS has had enough eligible supply to keep credit prices stable and overall program costs relatively modest — typically under $10 million per year.

Because the bill prevents new projects from entering APS after 2028, supply cannot expand to meet the rising requirement. As a result, annual program costs that have historically remained below $10 million per year could grow significantly, potentially exceeding $100 million annually over time, with those costs ultimately recovered from ratepayers.

d. Bottom Line

SECTION 9 transforms APS from a relatively low-cost program into a closed system where payment levels continue rising. As the annual requirement increases against a fixed group of eligible projects, ratepayer costs are expected to grow significantly and could increase by an order of magnitude over time.

IV. Mass Save Changes (SECTION 69)

a. Overview

SECTION 69 requires Mass Save Program Administrators to achieve $1 billion in near-term savings, with explicit direction to prioritize reductions in marketing, advertising, and administrative spending before making broader programmatic adjustments.

The mandate is imposed mid-cycle on the already approved 2025–2027 Mass Save plan, creating a compressed implementation timeline. Revised program plans must be filed with the DPU by July 1, 2026, with the DPU acting within 60 days.

b. Key Mechanism — $1 Billion Reduction Target

The provision establishes a top-down fiscal target intended to deliver near-term ratepayer relief. Program Administrators must first pursue savings in marketing, advertising, and administrative and planning costs. Only after those areas are addressed may broader program adjustments be considered.

Because the requirement is imposed mid-cycle, the revised savings plan must be developed and approved within a relatively short timeframe compared with the normal three-year planning process.

c. Policy Implications

Analysis released by the Fiscal Alliance Foundation found that Mass Save surcharges represent the single largest policy-driven component on Massachusetts electric bills, underscoring the program's scale and the importance of careful cost oversight.

However, the spending categories targeted for initial reductions represent only a small share of total program costs. In the DPU-approved revised 2025–2027 plan, combined program planning and administration, marketing, and advertising total approximately $441 million—about 9.8 percent of the $4.5 billion program budget. Participant incentives and rebates account for the dominant share of spending, totaling roughly $3 billion. Absent documented evidence of substantial inefficiencies, this structure suggests that reductions in these overhead categories alone are unlikely to achieve the full $1 billion statutory target.

Implementation is further complicated by the mid-cycle timing of the mandate. By the July 2026 filing deadline, the plan will be roughly 21 months into its three-year term, meaning many incentive commitments, contractor pipelines, and program agreements will already be underway.

As a result, achieving the required savings will likely require adjustments to core program elements— such as rebate levels, eligibility criteria, or program offerings.

d. Bottom Line

Mass Save represents a substantial policy-driven charge on Massachusetts electric bills and therefore represents the most significant area for reform if meaningful reductions in ratepayer costs are to be achieved However, SECTION 69 creates a structural challenge: it imposes a $1 billion reduction requirement late in the program cycle while directing attention to spending categories that represent less than 10 percent of total costs and are largely committed by mid-2026.

As a result, the full savings target is unlikely to be achieved through overhead reductions alone, increasing the likelihood that broader programmatic changes will be required.

While the provision signals legislative intent to address near-term ratepayer costs, its timing and scope limit effective implementation and introduce unintended effects on program delivery.

Given the forthcoming Inspector General review under SECTION 67, policymakers may wish to evaluate whether this approach represents the most effective path toward sustainable cost containment.

V. Enhanced Oversight of Grid Spending (SECTION 38)

a. Overview

SECTION 38 broadens state review of major electric distribution (and, where applicable, transmission) investments tied to electrification and grid-modernization policies. Although utilities will continue to own and operate the grid, the planning shifts to heavier regulatory checks.

b. Key Mechanism

SECTION 38 mandates utilities to submit “discrete, specific, enumerated” capital projects as part of their electric-sector modernization plans and to rigorously analyze lower-cost alternatives before proposing traditional grid upgrades. Utilities must also file twice-yearly reports identifying opportunities to reduce peak demand, pathways to enable third-party solutions, and potential infrastructure deferrals. Under this framework, utilities must demonstrate—using state-defined analytical methods—that traditional grid upgrades are necessary and that distributed alternatives have been fully evaluated.

c. Policy Implications

Massachusetts faces a period of rapid growth in grid investment as electrification, transportation electrification, and clean-energy integration increase demand for distribution infrastructure.

SECTION 38 reflects a legislative judgment that utilities should not independently determine the optimal mix of traditional infrastructure and distributed alternatives. Instead, the bill shifts greater emphasis toward state-directed planning processes.

The approach carries structural risks. Electric system planning is technically complex and must balance reliability, timing, and cost under conditions of substantial uncertainty about the pace, location, and characteristics of future electrification-driven load growth.

d. Bottom Line

SECTION 38 empowers regulators to oversee grid investments and prioritize preferred distributed alternatives.

Shifting to state-directed planning—premised on the view that utilities require close state supervision—could complicate needed expansions for electrification.

The impact hinges on execution. Applied too rigidly, it could delay critical upgrades, increase regulatory risk, and raise long-term costs for ratepayers.

Given the scale of the energy transition now underway, careful calibration by the DPU will be essential.

The Fiscal Alliance Foundation promotes individual liberty and greater fiscal responsibility and transparency in government for a better New England, through education and legal assistance.

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