Analysis: Key Changes Between House Bill H.5151 and Senate Bill S.3143
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This document updates the Fiscal Alliance Foundation's earlier analysis of House Bill H.5151[1] by examining the key changes introduced in the Senate bill (S.3143). While the Senate version retains the core centralized procurement and risk-shifting framework of the House bill, it introduces several notable adjustments. These include new compliance requirements, narrower cost-control measures, and targeted affordability provisions. The analysis below provides a section-by-section comparison of the most consequential changes.

1. Procurement Decisions Move Upstream (Plan-then-Procure Framework)

House Bill: Section 13 **Senate Bill:** New centralized procurement provisions in Chapter 25A

What Stayed the Same: The core two-step "plan-then-procure" structure is preserved. Department of Energy Resources (DOER) develops and publishes a Resource Solicitation Plan with the same targets (minimum 10 GW offshore wind + 10 GW solar by 2040). Department of Public Utilities (DPU) reviews and approves (or modifies/rejects) the plan within seven months. Once approved, DOER conducts competitive solicitations, selects bids, and negotiates long-term contracts (up to 30 years), subject to 90-day DPU review. Major decisions on scale, resource mix, and cost recovery remain locked in early through the statewide plan. Utilities continue to be excluded from active contracting and receive no remuneration.

What Changed in the Senate Version:

- Added extensive new bidder requirements, including detailed documentation on workforce development, economic development, diversity/equity/inclusion, apprenticeship program history, labor law compliance, safety violations, and a specific plan to deliver benefits to moderate- and low-income ratepayers. Proposals with firm commitments on these items receive preference.
- Created a new post-award price adjustment mechanism. After a bid is selected but before commercial operation, either DOER or the bidder may request upward or downward price adjustments for substantial and unforeseeable changes in law or costs beyond the party's reasonable control, subject to DPU approval and supported by the bidder's confidential bid file.
- Requires DOER to consult with DPU and the Attorney General before filing the Resource Solicitation Plan.

Public Participation in the Resource Solicitation Plan: As noted regarding Bill H.5151, the same concerns remain regarding public participation in the procurement planning process. While the bill

[1] Linowes, Lisa. Massachusetts Bill H.5151. Fiscal Alliance Foundation, March 5, 2026. https://assets.nationbuilder.com/fiscalalliancefoundation/pages/564/attachments/original/1776094454/Whitepaper_on_H5151_FINAL.pdf?1776094454

requires DOER to consult with the DPU and the Attorney General before filing the Resource Solicitation Plan, this consultation process does not provide for formal public participation, intervenor status, or adjudicatory proceedings. Major decisions on procurement scale, resource mix, and schedule are therefore largely established before the public has a meaningful opportunity to engage.

Implications: The core structural concern—front-loaded decisions that reduce later flexibility—remains intact and is now accompanied by new compliance burdens and a price adjustment process.

2. **Offshore Wind Pre-Development Risk Partially Shifted to Ratepayers**

House Bill: Sections 13 & 70 **Senate Bill:** New dedicated "Offshore Wind Pre-Development and Project Acceleration Program" in Chapter 25A

What Stayed the Same: The state can co-invest in early-stage soft costs (permitting, environmental/fisheries studies, pre-FEED engineering, interconnection planning, etc.). Repayment to the state occurs only if the project reaches commercial operation. There is no explicit statutory cap on total exposure and no clear recovery mechanism if a supported project fails.

What Changed in the Senate Version: The program is now established as its own explicit, standalone section and is more directly tied to the new centralized procurement framework.

Implications: Ratepayers remain the backstop for the riskiest phase of development. The core risk-shifting concern is retained in essentially the same form, though the policy is now more prominent and structured.

3. **APS Transitions to a Closed, Rising-Obligation Market**

House Bill: Section 9 **Senate Bill:** Section 27 (amends Section 11F½ of Chapter 25A)

What Stayed the Same: The program continues to close to new resources after a set date, while compliance obligations keep rising against a fixed pool of eligible projects. This structure maintains upward pressure on credit prices and shifts the program toward subsidizing existing facilities.

What Changed in the Senate Version: The closure is narrower than the House version. Only new biomass and new combined heat and power (CHP) projects are cut off after January 1, 2028. Other technologies (fuel cells, flywheels, efficient steam, and certain renewable thermal systems) remain eligible to qualify after that date. Some protections for low-income programs funded by Alternative Compliance Payments were adjusted.

Implications: The structural problem of a closed system with rising obligations remains intact, though the precise mechanics were narrowed. Because CHP has historically supplied the majority of Alternative Energy Certificates, the practical effect is still a meaningful slowdown in new supply growth after 2028.

4. **Mass Save Program Reforms**

The Senate version takes a markedly different approach to Mass Save than the House bill. While the House proposed a specific $1 billion mid-cycle reduction to the already-approved 2025–2027 plan—with explicit priority on cutting marketing, advertising, and administrative spending—the Senate bill drops that one-time cut entirely. Instead, it introduces a package of structural and governance reforms aimed at long-term cost control and accountability.

Key Changes in the Senate Bill:

- Removal of gas utilities from program administration: Gas distribution companies will no longer serve as Program Administrators. Administration will be consolidated, most likely under electric distribution companies or a centralized statewide structure. Gas utilities will continue to collect the efficiency surcharge from their ratepayers but will no longer design, deliver, or oversee programs.
- 5% cap on planning and administration spending: The bill caps spending on planning and administration at 5% of total program funds. This is narrower than the House approach; it does not automatically apply the same cap to marketing and advertising, which have historically been tracked as a separate budget category.
- Performance incentives made optional: Payments to utilities for meeting efficiency targets are no longer mandatory. The Department of Public Utilities (and the new oversight board) now has discretion over whether to include and award these incentives. This reduces the automatic financial upside utilities previously received for strong performance.
- New temporary oversight board: The bill creates a five-person Energy Efficiency Management Review and Financial Oversight board to conduct an independent review of program organization, finances, spending controls, contractor relationships, and customer access. The board must issue annual public reports with recommendations. It sunsets on December 31, 2030 and has no authority to set or approve budgets.
- Other structural requirements: Mid-term budget increases must be offset elsewhere in the plan. Cost-effectiveness testing continues to include the social value of greenhouse gas reductions. A minimum share of funds is directed to the low-income sector, and the program is directed to place greater emphasis on building decarbonization and electrification.

Implications: These changes represent a shift from the House's immediate, top-down budget reduction to a longer-term restructuring of how Mass Save is governed and delivered. Removing gas utilities from program administration is a significant structural change that concentrates operational control and raises questions about how gas-funded efficiency measures — particularly those supporting building decarbonization — will be prioritized going forward.

Making performance incentives optional, while leaving marketing and advertising spending uncapped, weakens one of the traditional financial drivers for aggressive customer outreach and high participation rates. The 5% cap on planning and administration will have limited immediate effect on the current plan but will constrain overhead costs in future three-year plans beginning in 2028. The temporary oversight board adds independent scrutiny and public reporting, but real budget authority remains with the Department of Public Utilities.

These reforms appear designed in part to reduce utility compensation and administrative involvement while allowing the state to claim it is addressing program costs. However, the larger cost drivers in the bill — centralized procurement commitments and renewable energy mandates — remain untouched. The practical impact on ratepayer costs will depend heavily on how the Department of Public Utilities and the new oversight board implement the reforms.

5. Expanded Oversight of Grid Investments (Non-Wires Alternatives)

House Bill: Section 38 **Senate Bill:** Primarily Sections 92B and 92D of Chapter 25, with related provisions

What Stayed the Same: Utilities must submit detailed, enumerated capital projects and rigorously evaluate non-wires alternatives (demand management, virtual power plants, distributed resources, etc.) before pursuing traditional infrastructure upgrades. Twice-yearly reporting on infrastructure deferral opportunities remains.

What Changed in the Senate Version: The requirements are strengthened and better integrated into a comprehensive distribution system planning framework, with greater emphasis on metrics, timelines, and cost minimization through non-wires solutions.

Implications: The core concern—expanded regulatory oversight that could introduce friction or delay upgrades—is retained and more aggressive.

6. Temporary Reduction in RPS Class I Requirements

The Senate bill introduces a provision not present in the House version: a temporary reduction in the annual RPS Class I increase from 3% to 1% for compliance years 2027 through 2029. This adjustment was included in the Cusack bill last year. The bill returns to higher annual increases after 2030.

According to Senate estimates, this change is expected to reduce ratepayer costs by roughly $213 million over those three years by lowering potential Alternative Compliance Payment exposure. Because meeting the original 3% annual increase had already become increasingly difficult, the practical effect on new renewable energy development during this period is likely to be limited.

7. **Broader Pattern: Imposition of Policy Mandates on Utilities**

A recurring feature of Massachusetts energy policy is the state's practice of requiring utilities to carry out major policy goals rather than funding and running those programs directly through the state budget. The Senate bill continues and extends this approach. Key elements include:

- Shift of financial and operational burden: Utilities are required to take on administrative work, arrange or provide upfront money, and manage risks, with the costs ultimately passed on to ratepayers through their electric and gas bills.
- Reduced transparency of costs: By running these costs through utility bills instead of the state budget, the true cost to the public is less visible.

Example — On-Bill Financing (Section 53)

One clear illustration of this approach is Section 53 of S.3143. This section requires electric utilities to create and run a voluntary on-bill financing program for customer projects such as rooftop solar and battery storage. Under this provision:

- Utilities must arrange or provide the upfront money for approved projects.
- Customers repay the cost over time as a line item on their regular electric bill.
- The repayment obligation stays with the property (the meter), not the individual customer.
- Although customers can choose whether or not to participate, utilities are required to offer and administer the program.
- Utilities can recover their costs, including the cost of capital and program administration, through distribution rates. This means customers who do not use the program can still end up helping pay for it.

The Senate estimates this program could generate $540 million in customer savings over 10 years. This is the Senate's own projection and assumes a certain level of customer participation and that monthly energy savings will offset the repayment charges for those who participate. Actual results will depend on how the program is implemented and how many customers choose to use it.

This model reflects a broader strategy of using utilities' balance sheets and billing systems to advance state policy goals while keeping the associated costs off the state's direct budget.

Example — Long-Term Bond Financing for Major Costs

Similar dynamics appear elsewhere in S.3143. The bill creates new authority allowing utilities to finance certain large costs — including grid modernization, storm recovery, and gas system transition — by issuing long-term bonds repaid through a dedicated charge on customer bills over many years.

The Senate estimates this could save ratepayers up to $7.1 billion over 10 years and presents it as one of the bill's major affordability measures. The savings would come from replacing the traditional mix of debt and equity financing with lower-cost, long-term bonds. While the bill does not legally require utilities to use this financing method, it creates strong political and regulatory pressure for them to do so. In practice, utilities are likely to use long-term bonds for these categories of spending, as resisting would put them at odds with the Senate and the DPU.

This approach reduces the near-term cost of major climate-related investments on customer bills, however, it also transfers significant long-term financial risk to ratepayers. The long-term bonds are repaid through a dedicated, non-bypassable charge on customer bills that is designed to remain in place for the full life of the bonds — typically 15 to 20 years or more. Once the bonds are issued, the state has limited ability to adjust or reduce the charge, even if future policy changes, slower electrification, or rising interest rates reduce the value of the underlying investments. In contrast, under traditional utility financing, the DPU retains ongoing authority to review costs in future rate cases. If the agency later determines that continued recovery of certain costs is no longer prudent, the utility's shareholders can be required to absorb some of the financial impact. This long-term bond structure removes much of that flexibility, locking ratepayers into repayment obligations with little ability to adjust course if circumstances change.

These examples illustrate a consistent pattern in the bill: the state directs utilities to carry out major policy priorities, requires them to absorb operational and financial responsibilities, and routes cost recovery through customer rates rather than through direct state appropriations.