Massachusetts Office of Energy Transformation: Financing the Transition Focus Area Work Group Progress Update

July 2025

Executive Summary

In July 2024, the Office of Energy Transformation (OET) established three Focus Area Work Groups (FAWGs), which develop recommendations and materials for consideration by the OET's multi-stakeholder Energy Transformation Advisory Board (ETAB or Advisory Board). One of the FAWGs is focused on establishing alternative mechanisms to finance the transition. The overarching goal of the Financing the Transition FAWG is to identify alternative mechanisms for financing electric distribution system infrastructure upgrades necessary to achieve Massachusetts' clean energy and climate mandates that reduce the cost of the energy transition for ratepayers and minimize bill impacts.

The Financing the Transition FAWG has met nine times since November 2024 with a range of stakeholder representatives from across sectors (e.g., labor, business, finance, environmental justice advocates, consumer advocates, utilities, technology providers, building owners, developers, and generators, among others). It is following a structured approach to decision-making, approved by the Advisory Board, involving three phases:

- Phase I — Assess Current Status and Needs
- Phase II — Identify and Assess Alternative Solutions
- Phase III — Conduct Implementation Evaluations and Make Recommendations

During Phase I, the FAWG identified a specific set of alternative financing and investment cost -recovery options — different from traditional utility ratemaking — to explore. These included:

- Capital Investment Projects
- Clean Energy Tariff
- Securitization
- Non-utility Distribution Entitlement Lease
- Public-Private Partnerships
- Environmental/ Energy Transition Bonds
- State Revolving Fund (SRF)
- Climate Superfund

During Phase II, the FAWG developed a comprehensive framework and approach for assessing the alternative financing approaches based on their financial impact, feasibility, governance issues, and other factors as compared to the current investment cost recovery approach. The FAWG is now engaging in a thorough assessment of each of the alternatives against the criteria. Phase III, involving a more detailed evaluation of the impacts of select alternative financing approaches on ratepayers and others and development of a package of recommended approaches for consideration by the Advisory Board.

Background

The Healey-Driscoll Administration established the nation's first Office of Energy Transformation (OET) in May 2024 with a mission to accelerate the energy transformation, with a focus on gas-to-electric transition, electric grid readiness, and an affordable and just transition for workers, businesses, and communities.

In July 2024, the administration announced the formation of the Energy Transformation Advisory Board (the ETAB or Advisory Board) to advise the OET. The Advisory Board includes a broad range of stakeholders, including labor, state and municipal officials, business, finance, environmental justice advocates, utilities, technology providers, building owners, consumer advocates, developers, and generators, among others. It provides an opportunity for the Administration to hear directly from the breadth of the energy ecosystem and impacted stakeholders from across the Commonwealth and creates a venue for them to work together to equitably and affordably advance the clean energy transition.

Also in July 2024, OET established three Focus Area Work Groups (FAWGs) designed to align OET's work with its mission and result in tangible, demonstrable, and transformative change. One of these FAWGs was tasked with establishing alternative mechanisms to finance the transition. This work group (referred to as the Financing the Transition or FTT FAWG) is responsible for identifying alternative mechanisms for financing electricity distribution system infrastructure upgrades necessary to achieve Massachusetts' clean energy and climate mandates that reduce the cost of the energy transition for ratepayers and minimize bill impacts.

While Advisory Board meetings and votes are public, the FAWGs meet under Chatham House Rules and are tasked with developing recommendations and materials within their specific focus area for the Advisory Board to consider as it develops its recommendations to OET. All information provided from the FAWGs to the Advisory Board is public.

Financing the Transition FAWG Mission and Approach

As noted above, the Advisory Board-approved mission and focus of the FTT FAWG is to identify alternative mechanisms for financing electricity distribution system infrastructure upgrades necessary to achieve the Commonwealth's clean energy and climate mandates and growing electric demand that minimize impacts on consumers' electricity bills, while providing an affordable, sustainable, and timely source of revenue to support investments.[1] The FAWG has met nine times since November 2024 with a range of stakeholder representatives from across the energy ecosystem (e.g., labor, business, finance, environmental justice advocates, utilities, consumer advocates, state and municipal officials, technology providers, building owners, developers, and generators, among others).

[1] In January 2025, the Advisory Board voted to provide the FTT FAWG the option to expand its scope to include alternative mechanisms for financing/funding other electric-sector activities and programs beyond distribution infrastructure investments, if the FAWG determines it would be productive and fill a current gap. Currently, the FAWG is still focusing its efforts on financing/funding distribution infrastructure investments.

FAWG members are subject matter experts and interested parties that have a level of decision-making authority within their organizations. Participation in the FAWG is open to all stakeholders, with membership shared with and affirmed by the Advisory Board. The FTT FAWG is supported by a team of professional facilitators from the Consensus Building Institute (CBI) and technical subject matter experts from Analysis Group.

The FTT FAWG, like each of the other FAWGs, is following a structured approach to decision-making, involving three phases:

- Phase I — Assess Current Status and Needs
- Phase II — Identify and Evaluate Alternative Solutions
- Phase III — Conduct Implementation Assessment and Make Recommendations

Progress to Date

The FTT FAWG has completed Phase I of its work on assessing current status and needs, designed (and received Advisory Board approval of) an approach to Phase II, and has begun to move ahead with this Phase II approach on identifying and assessing alternative options.

Phase I: Assessing Current Status and Needs

The FAWG began its work by ensuring all members had a basic understanding of key issues relevant to financing electricity distribution system upgrades. OET staff and technical subject matter experts shared background on Massachusetts' electric utilities and regulation of their prices and services, with a focus on issues like:

- How utility investment costs are recovered
- Who regulates what customers pay
- How utility base rates are built on the "Cost of Service"
- The different elements of customers' electric bills
- Financing costs for utility investments
- Background on Massachusetts Electric Distribution Companies' (EDCs') Electric Sector Modernization Plans (ESMPs) and their proposed distribution system investments

Overall, these background information sharing sessions emphasized the affordability challenges Massachusetts could face as the EDCs move forward with proposed electric distribution system investments to meet projected demand, including ESMP-related costs, and how these investments would impact customers' electricity bills under a status quo financing approach that utilizes traditional utility ratemaking. The sessions underscored a number of key points, including:

- Future distribution system investment costs are likely to rise faster than in the past due to increasing electric demand and evolving customer needs.
- Even with energy efficiency and flexible demand, which mitigate investment needs, it is likely that new, near-term investment to enhance the capabilities of the local electric grid will be required, at scale, to ready it to interconnect and operate with new distributed energy resources (DERs), handle electrification and economic growth, and be more resilient.

Potentially, the combination of these factors could result in an increase in customers' electricity costs in the near- and medium-term before they eventually level off. The goal of investigating and considering ways to innovate on financing and cost recovery for investment is to mitigate the magnitude and "lumpiness" of potential future rate impacts by, for example:

- de-risking investment
- smoothing rate adjustments
- assigning costs to beneficiaries in more direct and tailored ways
- avoiding investment costs/reducing rate base

Phase II: Identifying and Evaluating Alternative Solutions

After laying the substantive groundwork in Phase I, the FTT FAWG identified a set of alternative financing and investment-recovery options — different from traditional utility ratemaking — to explore in depth. These included, in no particular order:

- Capital Investment Projects (which currently exist and were used as a model/not assessed)
- Clean Energy Tariffs
- Securitization
- Non-Utility Distribution Entitlement Leases
- Public-Private Partnerships
- Environmental/Energy Transition Bonds
- State Revolving Fund (SRF)
- Climate Superfund

For each option, OET staff and subject matter experts from Analysis Group compiled and shared background on: 1) whether the approach has been used in Massachusetts or elsewhere for distribution (or other) investments; 2) investment and cost-recovery considerations; 3) governance considerations, such as who would need to approve the mechanism; and 4) other considerations, such as up front requirements, potential for pairing the approach with others or modifying it over time, and implications for utilities.

The FAWG may also consider the following additional financing and investment-recovery mechanisms, though these have not been fully detailed as of yet nor affirmed by all FAWG members as appropriate to explore at this time:

- Non-utility self-financing/ownership models (e.g., on-bill financing for customer-owned DERs)
- Carbon or greenhouse gas (GHG) fee to finance transition investments

The FAWG developed a comprehensive framework and approach for assessing alternative financing approaches. The assessment framework includes a total of 23 different criteria related to investment and cost recovery dollar benefits, implementation pathway challenges, and other intangibles. The FAWG developed a detailed description for each criterion and three-tier color coding scale (green vs. yellow vs. red) defining what constitutes positive vs. neutral vs. negative impacts within that criterion vis-a-vis ratepayers. An early version of this framework was approved by the Advisory Board in April 2025, and the complete up-to-date framework is available in the Appendix.

Currently, the FAWG is engaging in a thorough assessment of each of the alternatives using this framework. Analysis Group has developed and presented detailed “straw proposals” to the FAWG by running each alternative through the framework and explaining a basis for their color coding of each criterion. FAWG members will review and discuss these straw proposals and develop their own proposed assessments and explanations to be shared with the Advisory Board.

Upon completing this assessment process, the FAWG will move to Phase III of its work, focused on conducting an implementation evaluation and making recommendations. This final phase will involve a more detailed evaluation of the financial impacts of select alternative financing approaches and developing a package of recommendations for consideration by the Advisory Board.

Alternatives under consideration

This section provides background information on each of the alternative financing approaches the FAWG has reviewed in depth.

Capital Investment Projects (CIPs): ***Assigns costs. This mechanism currently exists and was used as an example and to serve as a comparison***. In 2021, the DPU established a provisional capital investment project (CIP) framework for planning and funding essential upgrades to the electric distribution system to enable DERs. Under this approach, utilities file CIP proposals with the DPU. Upon approval, all ratepayers fund the initial construction of shared infrastructure upgrades but are reimbursed over time from fees charged to future DER facilities that are able to interconnect due to these system upgrades. These CIPs must ensure that the cost to interconnect customers does not exceed $500/kW, that the utility will interconnect the new DER within the rate recovery period, and that construction can be completed within 4 years from the conclusion of the DPU’s adjudicatory process.

Clean Energy Tariffs: ***Expedites financing and assigns costs*.** This is not unlike a CIP but is initiated by a large load customer rather than the utility to support DERs. Large customers aiming to achieve specific energy goals on an expedited basis may seek to connect significant electric load to the grid and install low-carbon distributed energy resources such as renewables, storage, or microgrids that require system upgrades ahead of the schedule the utility has otherwise planned. Under a clean energy tariff, a large-load customer (or a cluster of customers) could approach the utility to identify specific system upgrades necessary to meet their needs and pay for the expedited upgrades to the distribution system to access those resources. The tariff would identify the types of projects and services that could be undertaken, along with schedules for planning and installation, and could be structured to include recovery of both the capital costs and ongoing delivery costs. If the benefits accrue to others in addition to the initiating large load customer, tariff costs would be allocated through the initiator and later beneficiaries. Under this approach, the utility still maintains ownership and operational control of the upgraded distribution system. The approach is not currently available in Massachusetts, though clean-energy tariffs are being explored elsewhere for customers interested in accessing advanced clean-energy generation technologies. Such a tariff could be developed and then reviewed and approved by the DPU and does not necessarily require enabling legislation.

Securitization: *Lowers borrowing costs, keeps costs out of rate base, and levelizes cost recovery*. The general intent of securitization, which can take many forms, is to lower the utility's borrowing costs (and hence ratepayer bills) and spread the costs over a longer period (i.e., levelizing cost recovery). Instead of large spikes, costs remain constant. This tool is not currently deployed in Massachusetts for distribution system upgrades, but it has been used in other contexts such as generation-related "regulatory assets" (such as unrecoverable market costs of power plants or contracts). It has also been used around the country for financing new equipment (such as pollution control equipment), storm related costs, and program costs (including resilience and energy efficiency). Authorizing legislation is required, after which the DPU would identify specific costs to be securitized and a special-purpose entity (either within or outside the utility structure) would be established to manage the transaction and its cost recovery. The relevant investments would be financed through special purpose bonds with repayment collected by the utility through a dedicated charge on customers' bills. The utility would continue to own and operate any assets, etc., under existing regulatory oversight and structures.

Non-Utility Distribution Entitlement Lease: *Provides external financing, keeps a portion of capital costs out of the rate base, and returns a portion of profits to ratepayers*. This alternative has not been used in Massachusetts and has not been implemented for distribution assets, though it has been used in California for transmission assets. Under this approach, a third party (e.g., a nonprofit organization) would enter into an agreement (a "distribution entitlement lease") with the utility to "lease" some of the utility's distribution assets. This can be thought of as akin to renting a lane on a highway. Rather than having the utility take on debt and/or issue equity to support all of its relevant distribution system investments, the third party leaseholder would pay for some portion of the investment costs in exchange for the right to recover these costs through DPU-authorized rates charged to customers (akin to drivers who use the highway lane paying a toll to the leaseholder). The leaseholder would then use a portion of the after-tax profits it receives from this cost recovery to provide, for example, bill credits or support other programs for customers of the utility. The approach would require legislative authorization and distribution entitlement leases would be subject to DPU approval. The entitlement lease holder could provide capital to the utility through a loan received from a commercial lender and recover its costs through a relatively smooth rate over a long-term period. The distribution rate for the lease entitlement would not be permitted to have a cost of capital that's higher than the utility's. The utility would continue to own and operate the equipment and distribution customers would see no difference in service or costs.

Public-Private Partnerships: *Lowers borrowing costs and keeps a portion of costs out of rate base.* Public-private partnerships can be constructed in a variety of ways. The general idea is that a public entity (which could be a municipality, public authority, or a state) takes on certain costs of distribution projects. As an example, to increase the resilience and reliability of the District of Columbia's (the District's) distribution system, the District's Transportation Department (DDOT) and the local utility entered into a public-private partnership (known as DC PLUG). The District provided financing through a low-cost public bond to be repaid via a charge on ratepayers' bills and DDOT took on the necessary road work for undergrounding distribution networks. Here in Massachusetts, such partnerships could advance general distribution capacity, build out portions of the grid to attract economic development, build energy storage, or build infrastructure for EV charging. The utility would continue to own and operate the distribution assets and system. Such public-private partnerships would require legislation and new action by the DPU.

Environmental/Energy Transition Bonds: *Lowers borrowing costs and keeps a portion of costs out of rate base.* Public entities, be that a municipality or state, could issue lower cost, special-purpose public bonds which in turn would provide lower cost capital to finance distribution investments carried out by the utility. Massachusetts uses state bonds to finance many infrastructure and other capital projects but has not yet funded utility distribution networks. If Massachusetts were to move forward with this approach, the bonds would be secured against a fee or payment on ratepayers' bills. The utility would retain ownership and operation of the distribution infrastructure. Such bonding capacity would likely have to be authorized through legislation in order for bond markets to provide appropriate capital to the issuing entity, and the DPU would need to take new action. While the bond would not affect the bonding cap of the utility, it might be included in the public entity's bond cap, depending on how it is viewed, and therefore pose an opportunity cost for financing of other public needs.

State-Revolving Loan Fund (SRF): *Lowers borrowing costs and keeps a portion of costs out of rate base.* Revolving loan funds have been used for many decades for water infrastructure. However, they have not been used for electricity infrastructure. Under this approach, the legislature could authorize and appropriate initial seed funding for a distribution system SRF (note: a state-administered fund could also be created that is seeded by third-party investors, compliance fees, etc.). A state entity would need to administer the fund, issuing low-cost loans to utilities who have identified high-priority projects that meet criteria typically set out by the legislature or the administering agency, with loan-repayment over time through customers' rates. Repayments of principal and interest back to the fund would in turn allow for the recycling of public funds to finance new projects and/or issue credits back to ratepayers. Risks to the public would likely be minimal and such SRFs would not be included in the state's bond cap. Legislation would be needed to initiate the SRF and establish associated governance parameters.

Climate Superfund: *Provides new sources of revenue, keeps a portion of costs out of rate base, and could require no "repayment" from ratepayers.* Superfund is a federal law that taxes certain companies, with the proceeds used to pay for the government's cleanup of toxic waste sites that do not have viable responsible parties to bear the cost. Two states, Vermont and New York, have enacted similar funds for climate infrastructure funding, with fees to be collected from companies that the law identifies as being responsible for GHG emissions during a historical period. These laws have not been implemented in full to date and have been subject to legal challenges. Creating such a climate superfund here in Massachusetts would require new legislation establishing who are the relevant responsible parties, the rate or fees to be paid, a fund to receive payments of fines, the uses of the funds (e.g., for electric distribution infrastructure projects meeting certain criteria, among other things), and an entity to administer the programs and/or project funding. Once established, the fund could provide any number of financing mechanisms to support electricity system infrastructure investments, including grants and loans. Since the funds or financing would be outside of utilities' rate base, this would lower the cost for ratepayers.

What's next

Currently, the FAWG is completing its Phase II assessment of each of its identified alternative financing approaches using its evaluation framework. It will share the outcomes of this assessment with the Advisory Board, and then move to its Phase III implementation evaluation and develop recommendations.

Appendix: **Financing the Transition Phase 2 Alternatives & Assessment Framework, April 2025**

FINANCING APPROACHES

Alternative Financing Approaches to Evaluate Using Assessment Framework (Approaches previously discussed)

Financing with lower-cost capital collected through rates/on a bill

1. Securitization
2. Environmental/Energy Transition Bonds

Providing funding through mechanisms outside of general utility ratepayer funding

3. Clean Energy Tariff
4. State Revolving Fund (SRF)
5. Climate Superfund

Hybrid/other

6. Non-Utility Distribution Entitlement Lease
7. Public-Private Partnerships (e.g. DC Plug)

Additional Ideas for Alternative Approaches (for Further Discussion by the FAWG Prior to Assessing)

Providing funding through mechanisms outside of general utility ratepayer funding

8. Non-utility self-financing/ownership models (e.g., on-bill financing for customer-owned DERs)

Hybrid/other

9. Carbon or GHG fee to finance transition investments

ASSESSMENT FRAMEWORK

Notes:

- For a given financing approach, it is only being compared to impacts that might occur under traditional regulation, and not with respect to whether one alternative financing approach is better than another alternative approach
- For each metric or variable of interest, where relevant, the color-coding of impacts is taken from the point of view of ratepayer impacts.
- The framework's metrics are not intended to characterize whether distribution investment projects have benefits or net benefits but rather focus on the relative impacts of alternative financing approaches for any projects that have been approved to go forward.

ISSUE			DATA / DESCRIPTION: Compared to traditional ratemaking, the extent to which the alternative financing approach...	COLOR CODING of impacts
Investment/ cost recovery (dollar benefits)	*Ratepayer impacts*	1. Reduces cost of capital	... can access lower capital costs (e.g., lower % cost of debt; lower % cost of shareholder equity; project $ cost) – relative to the utility's traditional capital cost (i.e., (a) % cost of debt; (b) allowed % return on equity times undepreciated investment in rate base); (c) approved capital structure for debt and equity).	• Green = lower cost to ratepayers • Yellow = no impact • Red = higher cost
		2. Develops new source of capital	...provides a new avenue through which investment in distribution infrastructure can be financed – above and beyond the local utility's access to their debt and equity capacity markets.	• Green = a new source of capital beyond the relevant utility's normal financing-acquisition channels is available through the alternative financing approach • Yellow = no impact • Red = the approach worsens the utility's reliance on traditional capital markets
		3. Levelizes cost recovery over time	...spreads recovery of project and financing costs evenly over time – relative to traditional asset depreciation (i.e., even over asset's useful life) and shareholder equity return (i.e., allowed % return on equity times undepreciated investment in rate base, which tends to have higher profits in early years of an asset's life).	• Green = lower near-term cost to ratepayers by flattening financing costs over time • Yellow = no impact • Red = N/A

Investment/ cost recovery (dollar benefits)	*Ratepayer impacts*	4. Mitigates rate base growth	...obtains project costs from a source other than the utility and therefore does not require the utility to (a) make the investment, (b) put the dollars into rate base, and (c) earn a return on the investment. [*This metric by itself does not itself indicate whether ratepayers otherwise pay more, or less, or the same, compared to traditional utility investment.]	• Green = avoids dollars going into the utility's rate base • Yellow = no impact • Red = N/A
		5. Total Net Present Value (NPV) impacts	... lowers overall costs from a present value point of view, taking into account the utility's discount rate and the timing and level of dollar flows over the life of the asset and its cost recovery.	• Green = lower overall cost to ratepayers • Yellow = no impact • Red = higher overall cost to ratepayers
		6. Near- vs. long-term rate (and/or bill) impacts/ Intertemporal equity of cost recovery	...reduces rate (or bill) impacts in the near term in exchange for increasing costs in the longer term over the life of the asset.	• Gradient of green (on the left) to red (on the right)

	7. Enables direct assignment of cost recovery from project beneficiaries	...limits cost recovery to those customers that directly benefit from a project (rather than more generalized cost recovery through an allocation to a larger customer class); other customers besides the direct beneficiaries do not pay for the investment.	• Green = direct beneficiaries pay for the portion of the investment that is proportional to the benefit they receive; other customers' rates are not affected (compared to a more traditional approach in which the entire customer class would have paid for some of the investment in their rates) • Yellow = direct beneficiaries pay for the investment, but it is not proportional to the benefit and may hinder adoption; other customers' rates are not affected • No impact
Investment/ cost recovery (dollar benefits)	8. Taxpayer impacts	...funds to pay for some or all of an investment and/or its financing costs are provided through the state's general fund rather than through utility rates, and assumes that the public funding either is incremental to other budget elements or takes funding away from other programs that would otherwise be supported in the general fund's budget [*This metric does not capture the costs avoided in utility ratepayers' bills]	• Green = N/A • Yellow = no impact on general fund • Red = taxpayers pay for some or all of the grid investment
	9. Low- and Moderate-Income (LMI) / Environmental Justice (EJ) impacts • E.g., public health, intergenerational EJ impacts	...provides particular benefits to LMI ratepayers or EJ communities (beyond lowering to ratepayers more generally)	• Green = provides particular benefits to LMI ratepayers • Yellow = no impact on LMI ratepayers
	10. Other investment / cost recovery impacts of note • E.g., impacts on balance of risk between ratepayers and shareholders, labor (job creation, wage levels), the incentives for non-wires alternatives or	[* Add any other notable investment or cost recovery impacts that are identified but not covered in the metrics above]	• Green = positive impact on the additional outcome metric • Yellow = N/A • Red = negative impact on the additional outcome metric

	the need for new distribution investment		
Implementation pathway (challenges)	11. Expected timeline (e.g., time to implementation)	...Able to be created/implemented in the same approximate timeframe as a new rate-case proceeding at the DPU (e.g., around 1 year); new programs or policies would likely have a multi-year timeline from deliberation, creation, and implementation.	• Green = expectation of a year of lead time to implement • Yellow = expectation of 2-3 years to implement • Red = expectation of 3+ years to implement
Implementation pathway (challenges)	12. Degree of barriers to implementation • E.g., DPU familiarity, legislative needs/risks, political support vs. opposition, legal risks, stakeholder buy-in	...requires considerable discussion before public decision-making body (e.g., legislature, DPU) to establish an understanding of the mechanics, intended outcomes, potential unintended consequences, and/or to build consensus and/or the record.	• Green = limited to no barriers to implementation • Yellow = more technically complicated, examples are available from elsewhere and will require engagement & socialization of approach • Red = complicated for any number of potential reasons (e.g., technical considerations, political differences, legal questions)
	13. Previous experience in implementing the approach	...approach has been used previously and is well understood/defined technically and in terms of legal and financing arrangements/provisions	• Green = has been used before in MA • Yellow = has been implemented in other states • Red = novel approach, not previously implemented
	14. Administrative and operational needs / costs	...approach does not require new institution/entity to administer the approach	• Green = no new agency or entity needed for implementation • Yellow = no new entity, but new program needed for implementation • Red = new agency/ entity needed for implementation

	15. Potential to scale	...suitable for large-scale investment projects (or large bundles of smaller individual projects) rather than smaller increments of financings and investments	• Green = approach is well-suited for large financings • Yellow = no impact • Red = approach is poorly suited for large financings
	16. Suitability for investments of different size(s)	...suitable for financing smaller increments of financings and investments	• Green = approach is suited to small financings as well as large ones • Yellow = no impact • Red = approach is poorly suited for small financings
Implementation pathway (challenges)	17. Replicability of the approach	...approach may be used repeatedly for new tranches of investments and financings	• Green = can be repeated once the framework is set up and operating • Yellow = mixed, may require upfront capital or action but is repeatable after (i.e., revolving loan fund) • Red = cannot easily be repeated (i.e., one time bond bill)
	18. Potential for impact by addition or withdrawal of federal program dollars	... approach is not likely to be directly affected by federal policy or federal dollars that may or may not be available	• Green = federal policy & dollars have little effect • Yellow = federal policies and dollars have some affect • Red = approach is not possible without federal policy and/or funding
Other intangibles	19. Adaptability of approach and type of investment • E.g. ability to match lifetime of underlying assets with cost-recovery period, and/or other factors	...approach may be tailored in its implementation so that it is well suited to different types of investments (e.g., bundles of assets with different useful lives)	• Green = the approach is highly adaptative to different investment types • Yellow = N/A • Red = the approach is limited to only certain types of investments

	20. Potential applicability to costs other than distribution investments E.g. transmission, generation, energy efficiency	...Massachusetts has the ability to take action to apply the approach to different parts of the electricity supply chain (e.g., transmission, central-station generation, behind-the-meter generation and storage, utility-scale generation and storage, energy efficiency and other DERs)	• Green = the action is technically suitable for other parts of the supply chain if MA has the jurisdiction to apply the approach to that/those parts beyond distribution • Yellow = N/A • Red = there are no other parts of the supply chain beyond distribution where MA could implement the approach
	21. Ability of repayment approach to be non-bypassable	...approach does not require a non-bypassable charge as the means to repay the investment	• Green = no non-bypassable charge is required • Yellow = requires a non-bypassable charge, but does not hinder implementation • Red = requires a non-bypassable charge (including an exit fee or fixed charge to recover costs from customers that exit or self-generated)
Other intangibles	22. Broader impact on utility • E.g., utility credit rating, cash flow, cost of capital, incentives for distribution system investments, potential for mitigating impacts, asset ownership/ operational responsibility, consideration for cumulative impact	...approach either does not disrupt the traditional utility business model which allows it to earn a return on investment in rate base or allows for alternative means to enable an investor-owned utility to attract capital and investor interest at relatively low cost	• Green = the utility has many opportunities to make significant investments (using traditional or non-traditional means), even if the approach is used for some share of total future investments • Yellow = the approach will erode the utility's ability to make investments and earn shareholder profits such that the utility may seek to restrict the application of the new approach • Red = utility opposes the approach due to concerns about erosion of core elements of the IOU's ability to be a profitable business capable of attracting capital at relatively low cost
	23. Other notable/unique elements • E.g., potential for attracting/utilizing outside funding, sustainability, interaction with other programs or financing tools/approaches, degree of/opportunity for transparency re: ratepayer/taxpayer	[* Add any implementation issues or outcomes that are identified but not covered in the metrics above]	• Green = positive impact on the additional issue or outcome metric • Yellow = N/A • Red = negative impact on the additional issue or outcome metric

	costs, degree of adaptability to changes in energy and/or transportation sectors, indirect economic benefits/costs, potential unintended consequences, additional impacts on pace of energy transition not already captured, etc.		

Additional notes on Phase 3

- Will include some discussion on prioritization/weighting of criteria, and consultation with the ETAB
- Alongside a determination of which alternatives to recommend on an individual basis, Phase 3 to include consideration of the overall package of recommendation. Factors to consider in deciding on and/or justifying the package could include:
    - Overall costs, savings, and sustainable budgeting
    - Carbon reduction benefits
    - Overall impact on state bond capacity limits and competing infrastructure needs
    - Impact on utilities' operational risk and capital structure.
    - Economic development and business impacts
    - How the package helps avoid socializing costs while privatizing profits