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ASSESSMENT FRAMEWORK – CLEAN ENERGY (DISTRIBUTION) TARIFF Utilities create targeted surcharges for customers requesting upgrades, while maintaining equipment ownership and operation.

ISSUE		DATA / DESCRIPTION (ANALYSIS GROUP)	FINAL COLOR CODING	COLOR CODING DEFINITION
Investment/ cost recovery (dollar benefits)	Ratepayer impacts	1. Reduces cost of capital		Green = lower cost to ratepayers Yellow = no impact Red = higher cost
		2. Develops new source of capital		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		Green = lower near-term cost to ratepayers by flattening financing costs over time Yellow = no impact Red = N/A
		4. Mitigates rate base growth		Green = avoids dollars going into the utility's rate base Yellow = no impact Red = N/A
		5. Total Net Present Value (NPV) impacts		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		Gradient of green (on the left) to red (on the right)
		7. Enables direct assignment of cost recovery from project beneficiaries		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 Red = No impact
	8. Taxpayer impacts	The clean energy distribution tariff does not include taxpayer-funded investment.		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 <i>E.g., public health, intergenerational EJ impacts</i>	The clean energy distribution tariff is not designed to provide particular benefits to LMI customers (except by relieving them of paying for the cost of investments that provides direct benefits to other customers).		Green = provides particular benefits to LMI ratepayers Yellow = no impact on LMI ratepayers
	10. Other investment / cost recovery impacts of note			

	<i>E.g., impacts on balance of risk between ratepayers and shareholders, labor (job creation, wage levels), the incentives for non-wires alternatives or the need for new distribution investment</i>	N/A		Green = positive impact on the additional outcome metric Yellow = N/A Red = negative impact on the additional outcome metric
Implementation pathway (challenges)	11. Expected timeline (e.g., time to implementation)	A clean energy distribution tariff could be introduced and approved as part of a utility rate case, likely without the need for new authorizing legislation.		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
	12. Degree of barriers to implementation <i>E.g., DPU familiarity, legislative needs/risks, political support vs. opposition, legal risks, stakeholder buy-in</i>	The DPU would need to approve the new clean energy distribution tariff after determining (likely in a rate case) that its assignment of costs and eligibility requirements are just and reasonable. The novelty of the rate design might add complications to DPU's review of it in the context of a rate case.		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	A clean energy tariff has been under consideration in other states as a way to enable customers in states without customer choice to have the option to purchase generation service with certain attributes (e.g., advanced generation technology with above-market costs). This type of special-purpose tariff has not been used as contemplated in Massachusetts (or elsewhere) for distribution-related investment. It would be novel to determine the price and other terms and conditions of service (e.g., eligibility or requirements for who must or may take service under the clean distribution tariff). (NOTE: It is akin to the Capital Investment Project (CIP) plans, so there is some precedent/understanding of some elements of this approach.)		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	No new institution or agency would be needed for implementing such a new tariff.		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	In theory, the clean energy distribution tariff could be used for investments of different sizes and scales, although it is logical that for larger distribution system investments affecting large groups of customers, there could be less need for a special tariff to directly assign costs to specific customers.		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)	In theory, the clean energy distribution tariff could be used for investments of different sizes and scales, although it is logical that for larger distribution system investments affecting large groups of customers, there could be less need for a special tariff to directly assign costs to specific customers.		Green = approach is suited to small financings as well as large ones Yellow = no impact Red = approach is poorly suited for small financings
	17. Replicability of the approach	In theory, the approach could be used repeatedly for new tranches of investments and financings for particular groups of customers, unless (for example) the DPU found that the creation of multiple separate tariffs was burdensome administratively.		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	Clean energy distribution tariffs do not appear to be directly affected by federal program budgets.		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
	19. Adaptability of approach and type of investment	In theory, implementation of this approach could be		Green = the approach is highly adaptable to different investment types Yellow = N/A Red =

Other intangibles	<i>E.g. ability to match lifetime of underlying assets with cost-recovery period, and/or other factors</i>	tailored to different types of investments (e.g., bundles of assets with different useful lives).		Green = the approach is highly adaptive 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 <i>E.g. transmission, generation, energy efficiency</i>	This approach seems potentially applicable to distributed energy resources, as long as the utility investment (and ownership) is consistent with Massachusetts law. It is unlikely to be applicable to central-station generation.		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	To the extent that the utility is making a distribution investment on behalf of a particular group of benefiting customers who will be paying for the investment over time, this approach might require some sort of back-stop repayment mechanism (e.g., exit fee; backstop cost recovery plan) if those customers leave the system.		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)
	22. Broader impact on utility <i>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</i>	This may create opportunities for tailored distribution system investment aligned with the distribution utility's business model.		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 <i>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 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.</i>	This approach may create opportunities for tailored distribution system investment that can meet some customers' needs.		Green = positive impact on the additional issue or outcome metric Yellow = N/A Red = negative impact on the additional issue or outcome metric

ASSESSMENT FRAMEWORK - SECURITIZATION Spreads costs over time through lower-cost capital (e.g., low-cost debt financing, as opposed to combined debt/equity financing). A utility usually issues a bond—often backed by state government—for the amount needed to cover the expenditure.

ISSUE		DATA / DESCRIPTION (ANALYSIS GROUP)	UPDATED / CONFIRMED COLOR CODING	COLOR CODING DEFINITION
Investment/ cost recovery (dollar benefits)	Ratepayer impacts	1. Reduces cost of capital Securitization allows access to lower cost by: (a) replacing the utility's cost of equity (i.e., allowed shareholder return on equity) with lower-cost debt; (b) accessing lower cost debt by reducing regulatory risk associated with utility's normal cost of corporate debt; and (c) having a capital structure of 100% debt rather than some combination of the regulator's preferred capital structure (e.g., 50% debt/50% equity) in the capital costs allowed in rates.		Green = lower cost to ratepayers Yellow = no impact Red = higher cost
		2. Develops new source of capital Securitization can open up the opportunity for the utility to access a new source of capital outside of the utility's conventional debt and equity capital markets with positive impacts on the utility's financial balance sheet (compared to issuing new securities for equity or taking on more debt). S&P Global Ratings (a major credit rating agency) reports that it "will often deconsolidate (i.e., remove) securitization debt from the utility's balance sheet. Accordingly, this improves a utility's financial measures and credit quality.... Absent securitization, a utility would typically recover the associated expenses over a longer timeframe, leveraging the utility's balance sheet and weakening its financial performance and credit quality. K. Ryan and G. Grosberg, "The Rationale Behind U.S. Utility Securitization And Reasons For Recent Growth," S&P Global RatingsDirect, May 2, 2024, https://csgwest.org/wp-content/uploads/2024/08/RatingsDirect_CreditFAQTheRationaleBehindUSUtilitySecuritizationAndReasonsForRecentGrowth_57532202_Jun-05-2024_PDF.pdf .		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 Securitization typically spreads recovery of project and financing costs evenly over the time during which costs are recovered.		Green = lower near-term cost to ratepayers by flattening financing costs over time Yellow = no impact Red = N/A
		4. Mitigates rate base growth A securitization of assets (including regulatory assets or bundles of expenditures) avoids inclusion of the associated dollars into the utility's rate base.		Green = avoids dollars going into the utility's rate base Yellow = no impact Red = N/A
		5. Total Net Present Value (NPV) impacts Even though a securitization lowers near-term charges for a particular asset's cost recovery (due to levelization of cost recovery, compared to ratebasing the asset), it can increase charges in later years relative to a ratebasing method. Thus one needs to know the cost-recovery period for the securitized asset (compared to ratebase treatment) and the impact of the lower financing costs (i.e., difference between the utility weighted average cost of capital (WACC) and the securitized cost of debt) to know whether a particular securitization action increases or decreases the NPV of the investment.	It depends	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 Relative to ratebase financing, securitization typically lowers near-term rate impacts (e.g., the first 10 years of a 30-year cost-recovery period) but can result in rates higher than they would have been in the longer term (e.g., the end years of that cost-recovery period), although these considerations depend upon the length of the securitization bond and the difference between the utility WACC and the securitized cost of debt. For an asset with a long useful life, this will tend to improve intertemporal equity.		Gradient of green (on the left) to red (on the right)
		7. Enables direct assignment of cost recovery from project beneficiaries Securitization costs are typically recovered from a broad group of ratepayers, rather than directly assigned to particular sets of customers, but nothing inherent to securitization requires this to be the case.		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 Red = No impact
	8. Taxpayer impacts Securitization-related costs are typically recovered through utility rates, rather than from the state's budget/taxpayers.		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 Securitization-related costs are typically recovered from affected customer classes and without rate-design discounts or other		Green = provides particular benefits to LMI ratepayers Yellow = no impact on LMI	

	<ul style="list-style-type: none"> E.g., public health, intergenerational EJ impacts 	adjustments for LMI customers.		ratepayers
	10. Other investment / cost recovery impacts of note <ul style="list-style-type: none"> E.g., impacts on balance of risk between ratepayers and shareholders, labor (job creation, wage levels), the incentives for non-wires alternatives or the need for new distribution investment 	Separate from the question of whether securitizations lower cost, they tend to shift risk from utility shareholders (under traditional ratemaking) to utility ratepayers because under traditional ratemaking, rates are set such that they provide the utility with the opportunity to earn the profit level (i.e., return on equity) allowed by regulators without guaranteeing that the allowed return is achieved, and because the allowed profit level may change over time subject to regulators' decisions in later rate cases. Under securitization, the utility accesses relatively low-cost debt because the authorizing legislation and regulators' financing orders mean that recovery of all securitized costs is certain and regulators are not allowed to change the terms and conditions of cost recovery over time. On the other hand, neither the utility nor its shareholders receive direct financial benefit from securitization and, in some cases, may be forgoing profits/returns they could otherwise earn.		Green = positive impact on the additional outcome metric Yellow = N/A Red = negative impact on the additional outcome metric
Implementation pathway (challenges)	11. Expected timeline (e.g., time to implementation)	Securitizations of new sets of dollars (e.g., grid investments, non-wires alternatives to utility investment) will require Massachusetts to enact new legislation and the DPU to approve specific securitization financing proposals. The first new securitizations would likely require 2-3 years to go into effect, as a result of the time for DPU review (although enactment of legislation could set a particular time limit – e.g., 6 months). After legislation is enacted, subsequent securitization proposals could take less than 1 year.		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
	12. Degree of barriers to implementation <ul style="list-style-type: none"> E.g., DPU familiarity, legislative needs/risks, political support vs. opposition, legal risks, stakeholder buy-in 	Implementation of securitization for new grid-related costs will likely require new legislation authorizing the utility's use of this financing approach and directing the terms and conditions of the DPU's approval of any proposed securitizations by Massachusetts utilities.		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	Although securitizations have been used in Massachusetts (e.g., approved and implemented in the 1999-early 2000s period for the above-market stranded costs associated with certain power plants at the time the state's electric industry was restructured), it has been several years since any new securitizations have occurred here. Since then, dozens of other states have approved and utilized billions in securitizations for other stranded costs, wildfire costs, storm costs, pollution-control equipment, resilience investments.		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	No new administrative agency is needed for implementation of securitizations, although the utility issuing the securitization will need to establish a special-purpose-entity vehicle to wall-off the recovery of costs and the related revenue streams, relative to the utility's other costs and revenues.		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	Experience shows that utility securitizations in the U.S. have allowed for recovery of costs in the range of ~\$50 million into the billions per securitization. (Example: The securitizations of stranded costs in Massachusetts several decades ago were for amounts between ~\$150 million and ~\$725 million.)		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)	Experience shows that utility securitizations in the U.S. have allowed for recovery of costs ranging from ~\$50 to several billion dollars per securitization. The securitizations of stranded costs in Massachusetts several decades ago were for amounts between ~\$150 million and \$725 million.		Green = approach is suited to small financings as well as large ones Yellow = no impact Red = approach is poorly suited for small financings
	17. Replicability of the approach	There are no obvious a priori barriers to having a utility do more than one securitization, except for ensuring that each receives regulatory approvals with review of cumulative impacts (including analyses of sequential securitizations compared to traditional investment recovery), and acceptance by the bond markets/rating agencies. (For example, PG&E and LPA have both conducted multiple securitizations over a short period.)		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	Securitizations do not appear to be directly affected by federal program budgets.		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
	19. Adaptability of approach and type of investment <ul style="list-style-type: none"> E.g. ability to match lifetime of underlying assets with cost-recovery period, and/or other factors 	The length of securitization cost-recovery periods can be adapted to investments of different types and asset lives.		Green = the approach is highly adaptive to different investment types Yellow = N/A Red = the approach is limited to only certain types of investments

Other intangibles	<p>20. Potential applicability to costs other than distribution investments</p> <p><i>E.g. transmission, generation, energy efficiency</i></p>	<p>Securitization of utility investment in non-wires alternatives to local grid investments and energy efficiency would be novel, but nothing prevents legislation from allowing such use for utility-funded programs or investments.</p> <p>Given the structure of the electric industry in Massachusetts (where utility-owned high-voltage transmission is federally regulated and where generation facilities operate in competitive markets), it is not obvious how securitizations of such assets could occur.</p>		<p>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</p>
	<p>21. Ability of repayment approach to be non-bypassable</p>	<p>Typically, securitizations require imposition of a non-bypassable charge on utility customers' bills. To address situations at the time of electric industry restructuring where a customer could disconnect from the grid and self-generate and thus avoid a non-bypassable charge, Massachusetts adopted requirements for exit fees for customers over a certain size that fully disconnected from the grid.</p>		<p>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)</p>
	<p>22. Broader impact on utility</p> <p><i>· 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</i></p>	<p>According to S&P Global Ratings (a major credit-rating agency), "securitization often results in improved credit measures for the utility. Because securitization bonds are typically recovered through a dedicated source of revenue--in the form of an irrevocable, non-bypassable charge on the customer's bill with full recovery mandated by statute--S&P Global Ratings will often deconsolidate (i.e., remove) securitization debt from the utility's balance sheet. Accordingly, this improves a utility's financial measures and credit quality...Absent securitization, a utility would typically recover the associated expenses over a longer timeframe, leveraging the utility's balance sheet and weakening its financial performance and credit quality. Furthermore, S&P Global Ratings typically makes an analytical adjustment to the financial statements of the sponsoring utility that effectively removes utility-related securitization bonds from its balance sheet, thereby improving the utility's credit metrics. In addition, since a utility's risk of default is usually higher than the risk of recovering costs through a non-bypassable charge on the customer's bill, the interest rate for securitization is usually lower than a utility independently financing these costs. As such, the impact to the customer bill is less, modestly reducing regulatory risk for the utility." Depends on scale of deployment.</p> <p>K. Ryan and G. Grosberg, "The Rationale Behind U.S. Utility Securitization And Reasons For Recent Growth," S&P Global RatingsDirect, May 2, 2024 (hereafter "S&P Global RatingsDirect, May 2, 2024"), https://csgwest.org/wp-content/uploads/2024/08/RatingsDirect_CreditFAQTheRationaleBehindUSUtilitySecuritizationAndReasonsForRecentGrowth_57532202_Jun-05-2024.PDF.pdf.</p>		<p>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</p>
	<p>23. Other notable/unique elements</p> <p><i>· 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 costs, degree of adaptability to changes in energy and/or transportation sectors, indirect economic benefits/costs, potential unintended consequences, impacts on pace of energy transition not already captured, etc.</i></p>	<p>Securitizations typically require that there be a transparent charge on customers' bills; depending upon the set of costs that are securitized and recovered through such separate charges, the need for some other separate line-item changes on customers' bills may go away.</p>		<p>Green = positive impact on the additional issue or outcome metric Yellow = N/A Red = negative impact on the additional issue or outcome metric</p>

ASSESSMENT FRAMEWORK – DISTRIBUTION ENTITLEMENT LEASE A model where third parties (typically nonprofits) lease a portion of utility project costs/capacity, providing upfront funding through bonds.

ISSUE		DATA / DESCRIPTION (ANALYSIS GROUP)	UPDATED / CONFIRMED COLOR CODING	COLOR CODING DEFINITION
Investment/ cost recovery (dollar benefits)	Ratepayer impacts	1. Reduces cost of capital		Green = lower cost to ratepayers Yellow = no impact Red = higher cost
		2. Develops new source of capital		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		Green = lower near-term cost to ratepayers by flattening financing costs over time Yellow = no impact Red = N/A
		4. Mitigates rate base growth		Green = avoids dollars going into the utility's rate base Yellow = no impact Red = N/A
		5. Total Net Present Value (NPV) impacts	It depends	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		Gradient of green (on the left) to red (on the right)
		7. Enables direct assignment of cost recovery from project beneficiaries		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 Red = No impact
	8. Taxpayer impacts	Lease-entitlement costs are typically recovered through utility rates, rather than the state's budget.		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	A lessee could commit to share profits through a specific mechanism such as providing assistance to LMI ratepayers and/or disadvantaged communities; if so, this would provide specific positive benefits to such ratepayers/communities. Assistance commitments could come in the form of bill-paying assistance, energy efficiency measures or other beneficial programs.		Green = provides particular benefits to LMI ratepayers Yellow = no impact on LMI ratepayers

	<p>10. Other investment / cost recovery impacts of note</p> <p><i>· E.g., impacts on balance of risk between ratepayers and shareholders, labor (job creation, wage levels), the incentives for non-wires alternatives or the need for new distribution investment</i></p>	<p>The construction, ownership and operations of the assets will be under the control of the utility and oversight of the DPU, so there should be no additional risk borne by ratepayers as compared to current regulation/recovery mechanisms. The amount of "profit" earned by the utility on the asset would be reduced commensurate with the percentage of the lease position taken.</p>		<p>Green = positive impact on the additional outcome metric Yellow = N/A Red = negative impact on the additional outcome metric</p>
Implementation pathway (challenges)	<p>11. Expected timeline (e.g., time to implementation)</p>	<p>Authority for utilities to enter into lease-entitlement agreements would likely require Massachusetts to enact new legislation and the DPU to approve specific lease-entitlement agreement proposals. The first new entitlement lease would likely require 2-3 years to go into effect, as a result of those steps (although enactment of legislation could set a particular time limit – e.g., 6 months – for the DPU's review and approval of proposed financing proposals). After legislation is enacted, subsequent lease-entitlement proposals could take less than 1 year.</p>		<p>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</p>
	<p>12. Degree of barriers to implementation</p> <p><i>· E.g., DPU familiarity, legislative needs/risks, political support vs. opposition, legal risks, stakeholder buy-in</i></p>	<p>Implementation of lease-entitlement agreements would likely require new legislation authorizing the utility's use of this financing approach and directing the terms and conditions of the DPU's approval of any proposed agreements by Massachusetts utilities.</p>		<p>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)</p>
	<p>13. Previous experience in implementing the approach</p>	<p>Massachusetts has not previously implemented lease-entitlement agreements, but they have been relied upon in California for transmission asset investments.</p>		<p>Green = has been used before in MA Yellow = has been implemented in other states Red = novel approach, not previously implemented</p>
	<p>14. Administrative and operational needs / costs</p>	<p>Although no new program or entity is anticipated, there are potential administrative complexities/needed expertise. Unlike with transmission entitlement leases, there is no engineering/market tool for allocating revenue, so this would need to be accomplished through very clear contracting and after-the-fact calculation.</p>		<p>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</p>
	<p>15. Potential to scale</p>	<p>Experience in California indicates that there is the potential to scale the size of investments subject to lease-entitlement agreements (and financings).</p> <p>In addition to potential impacts on utilities' legal and operational risk, scalability will depend on how much capital/capacity there is out there for this model.</p>		<p>Green = approach is well-suited for large financings Yellow = no impact Red = approach is poorly suited for large financings</p>
	<p>16. Suitability for investments of different size(s)</p>	<p>Experience in California indicates that there is the potential to scale the size of investments subject to lease-entitlement agreements (and financings).</p>		<p>Green = approach is suited to small financings as well as large ones Yellow = no impact Red = approach is poorly suited for small financings</p>
	<p>17. Replicability of the approach</p>	<p>Experience in California indicates that there is the potential to replicate this financing approach.</p> <p>Once you develop a model and have a standardized structure, terms, etc., additional uses of it could become lower maintenance.</p>		<p>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)</p>
	<p>18. Potential for impact by addition or withdrawal of federal program dollars</p>	<p>Distribution entitlement leases do not appear to be directly affected by federal program budgets.</p>		<p>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</p>
	<p>19. Adaptability of approach and type of investment</p> <p><i>· E.g. ability to match lifetime of underlying assets with cost-recovery period.</i></p>	<p>The length of lease-entitlement agreements can be adapted to investments of different types and asset lives.</p>		<p>Green = the approach is highly adaptative to different investment types Yellow = N/A Red = the approach is limited to only certain types of investments</p>
	<p>20. Potential applicability to costs other than distribution investments</p> <p><i>E.g. transmission, generation, energy efficiency</i></p>	<p>It is not obvious how this approach could be applied to generation-related assets, or behind-the-meter/non-wires alternatives. In California, the approach has already been used for transmission entitlement leases.</p>		<p>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</p>

Other intangibles	21. Ability of repayment approach to be non-bypassable	The approach has been used without a non-bypassable charge in place in the California transmission lease-entitlement examples.		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)
	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	There does not appear to be evidence that this approach has had negative impacts on participating utilities in California. However, utility operational and legal risk grows along with the overall scale of the use of this and other alternative financing tools. If the utility is leasing the asset, who is responsible if something goes wrong? There was a question as to whether this may even make this red. Similarly, if this becomes a debt equivalent on the utility's balance sheet, then at scale that could be problematic.		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 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.	In California where this approach has been used for transmission entitlement agreements, there have been positive impacts in low-income communities where the lessee's charitable contributions have funded programs to lower bills and provide access to energy efficiency and solar projects.		Green = positive impact on the additional issue or outcome metric Yellow = N/A Red = negative impact on the additional issue or outcome metric

ASSESSMENT FRAMEWORK – CLIMATE SUPERFUND

Recently adopted in Vermont and New York (2024), this approach collects fees from entities responsible for historical GHG emissions to fund climate infrastructure. New York's law imposes retroactive fees on companies for GHG emissions during 2000-2018. Responsible parties collectively pay into a fund for climate adaptation projects. This approach could be used to fund grid modernization.

ISSUE		DATA / DESCRIPTION (ANALYSIS GROUP)	UPDATED / CONFIRMED COLOR CODING	COLOR CODING DEFINITION
Investment/ cost recovery (dollar benefits)	Ratepayer impacts	1. Reduces cost of capital		Green = lower cost to ratepayers Yellow = no impact Red = higher cost
		2. Develops new source of capital		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		Green = lower near-term cost to ratepayers by flattening financing costs over time Yellow = no impact Red = N/A
		4. Mitigates rate base growth		Green = avoids dollars going into the utility's rate base Yellow = no impact Red = N/A
		5. Total Net Present Value (NPV) impacts		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		Gradient of green (on the left) to red (on the right)
		7. Enables direct assignment of cost recovery from project beneficiaries		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 Red = No impact
	8. Taxpayer impacts		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 <i>E.g., public health, intergenerational EJ impacts</i>		Green = provides particular benefits to LMI ratepayers Yellow = no impact on LMI ratepayers	
	10. Other investment / cost recovery impacts of note		Green = positive impact on the additional outcome metric Yellow = N/A Red = negative impact on the additional outcome metric	

	<i>E.g., impacts on balance or risk between ratepayers and shareholders, labor (job creation, wage levels), the incentives for non-wires alternatives or the need for new distribution investment</i>			
Implementation pathway (challenges)	11. Expected timeline (e.g., time to implementation)	Presumably, this approach would involve the time it would take to enact legislation, develop implementing rules for issues not defined fully in the statute, begin implementation and enforcement, begin penalty collection, and undergo possible court reviews. This would likely take longer than 3 years.		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
	12. Degree of barriers to implementation <i>E.g., DPU familiarity, legislative needs/risks, political support vs. opposition, legal risks, stakeholder buy-in</i>	This approach has been adopted statutorily in two states (New York and Vermont), but not yet implemented, and these statutes have now been contested in the courts. This legal uncertainty adds a potential layer of complexity.		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	This is a novel approach for climate from an implementation point of view, but similar to existing superfund programs/assessments. Given lack of actual implementation of this approach elsewhere, it remains somewhat novel (though that could change with VT and/or NY moving forward).		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	Although no new agency would appear to be needed to administer such an approach, no Massachusetts agency (or agency in any other state) has experience in designing regulations to implement the program for climate (e.g., identifying the data on which emissions shares are calculated, allocation methodologies for assigning responsibility for historical emissions, designing enforcement mechanisms, the programs and purposes that could be funded out of the climate superfund proceeds).		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	Given the challenges that will likely accompany such a climate superfund program, the political/administrative/legal/technical transaction costs may be high, so the program might be best suited for raising large amounts of money. That said, it is possible that the higher the amount of money to be raised through this mechanism generally, the more likely the opposition to its enactment. It is unknown how much competition there would be for the use of the funds raised through this approach (e.g., should it be used to reduce taxes, for investment in the grid, or for some other purpose(s), such as helping individual customers pay to decarbonize homes and buildings).	It depends	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)	If the program were enacted and funds raised (including for the purpose of funding grid investments), then presumably it could be used for investments of different sizes.		Green = approach is suited to small financings as well as large ones Yellow = no impact Red = approach is poorly suited for small financings
	17. Replicability of the approach	If the climate superfund is designed to identify emitters with responsibility for past GHG emissions during a particular time period (and not for emissions tied to ongoing sales), then the program would generate some fixed quantity of funding (i.e., revenues raised from the emitters). The logic of the program would not seem to provide for repeated actions against emitters, so presumably the pot of funding would be fixed. Depending upon the rules and decision-making governing uses of the funds in the climate superfund pot, there could be multiple tranches of investment funded.		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	This approach does not appear to be directly affected by federal policy or federal dollars that may or may not be available in the future, although federal litigation to stop the state from implementing this approach might occur at least in the near future.		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 <i>E.g. ability to match lifetime of underlying assets with cost recovery period, and/or other factors</i>	Depending upon the policies adopted for eligible activities that could be funded from the climate superfund, this approach could be adaptive to different types of distribution-system investments (e.g., projects with assets of different useful lives).		Green = the approach is highly adaptive 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 <i>E.g. transmission, generation, energy efficiency</i>	Depending upon the policies adopted for eligible activities that could be funded from the climate superfund, this approach could be adaptive to different types of non distribution-system investments (e.g., transmission, generation).		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	This approach would not involve cost recovery from electricity ratepayers and would not require a non-bypassable charge.		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)
	22. Broader impact on utility	Even though this approach would mean that the utility would forego the opportunity to earn a profit on investment, it would not appear to disrupt the traditional utility business model because it would provide capital without direct cost to customers. Depending on the structure of this approach and the response of fossil fuel companies, the result could be higher gas or oil prices for utilities, affecting both utilities and ratepayers.		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

	<p>23. Other notable/unique elements</p> <p><i>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 costs, degree of adaptability to changes in energy and/or transportation sectors, indirect economic benefits/costs, potential unintended consequences).</i></p>	<p>Question about whether there could be incentives to sell assets subject to the penalty in order to escape liability, leading to churn in the market. This would depend on the structure of the approach and should be looked into.</p>		<p>Green = positive impact on the additional issue or outcome metric Yellow = N/A Red = negative impact on the additional issue or outcome metric</p>
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ASSESSMENT FRAMEWORK – ENERGY/ENVIRONMENTAL TRANSITION BONDS

These bonds, issued by public authorities, provide low-cost financing of infrastructure projects that may otherwise be owned and funded by private entities. The bonds are repaid by users of the projects. Examples include the DC Water agency Green Infrastructure performance bonds and Private Activity bonds (tax-exempt and issued by local governments).

ISSUE		DATA / DESCRIPTION (ANALYSIS GROUP)	UPDATED / CONFIRMED COLOR CODING	COLOR CODING DEFINITION
Investment/ cost recovery (dollar benefits)	Ratepayer impacts	1. Reduces cost of capital		Green = lower cost to ratepayers Yellow = no impact Red = higher cost
		2. Develops new source of capital		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		Green = lower near-term cost to ratepayers by flattening financing costs over time Yellow = no impact Red = N/A
		4. Mitigates rate base growth		Green = avoids dollars going into the utility's rate base Yellow = no impact Red = N/A
	5. Total Net Present Value (NPV) impacts	Even though the bond would lower near-term charges for a particular asset's cost recovery (due to levelization of the bond repayment schedule), it could increase charges in later years relative to a ratebasing method. Thus in order to know whether the NPV is higher versus lower compared to traditional ratebase treatment, one needs to know the cost-recovery period for the debt repayment (compared to ratebase treatment) and the difference in the interest payments for the bond compared to the utility's total debt and equity financing costs.	It depends.	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	This approach could reduce rate (or bill) impacts in the near term in exchange for increasing costs in the longer term over the life of the asset. For an asset with a long useful life, this will tend to improve intertemporal equity.		Gradient of green (on the left) to red (on the right)
	7. Enables direct assignment of cost recovery from project beneficiaries	The current assessment is coded as a state-issued bond. It could become green if structured to be assigned to an individual EDC's customer base, but would need to be structured as a revenue-backed bond. Under this scenario, the state would go to market on behalf of the utility. Recommendation that this become a gradient instead of red. Requires further review.		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 Red = No impact
	8. Taxpayer impacts	This approach could affect the ability of the governmental bond issuer to issue other bonds if this issuance causes the government to hit its maximum bonding capability (e.g., limits). That said, taxpayers of that public partner would not be affected because the utility's ratepayers (rather than taxpayers) will pick up the bond-repayment requirements. If taxpayer does pay, then this would be red.		Green = N/A Yellow = no impact on general fund Red = taxpayers pay for some or all of the grid investment

	<p>9. Low- and Moderate-Income (LMI) / Environmental Justice (EJ) impacts</p> <ul style="list-style-type: none"> · E.g., public health, intergenerational EJ impacts 	<p>There do not appear to be impacts that particularly benefit or harm LMI households or EJ communities, but depends on whether taxpayer or ratepayer pays.</p>	<p>It depends</p>	<p>Green = provides particular benefits to LMI ratepayers Yellow = no impact on LMI ratepayers</p>
	<p>10. Other investment / cost recovery impacts of note</p> <ul style="list-style-type: none"> · E.g., impacts on balance of risk between ratepayers and shareholders, labor (job creation, wage levels), the incentives for non-wires alternatives or the need for new distribution investment 	<p>N/A</p>		<p>Green = positive impact on the additional outcome metric Yellow = N/A Red = negative impact on the additional outcome metric</p>
Implementation pathway (challenges)	<p>11. Expected timeline (e.g., time to implementation)</p>	<p>The principal factor affecting the timing of this approach is the time it would take to generate interest by the prospective governmental bond issuer (e.g., several years to socialize the idea and gain sufficient support for the bond issuance).</p> <p>Could be longer than 3 years depending on who pays.</p>		<p>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</p>
	<p>12. Degree of barriers to implementation</p> <ul style="list-style-type: none"> · E.g., DPU familiarity, legislative needs/risks, political support vs. opposition, legal risks, stakeholder buy-in 	<p>This novel approach might require consensus-building efforts to generate proposals for the bond issuance and related cost-recovery ideas, and for consideration by the affected partners and the regulators whose approvals would be required for recovering the costs through utility rates.</p>		<p>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)</p>
	<p>13. Previous experience in implementing the approach</p>	<p>Public utilities have long utilized the tool to finance distribution system upgrades, so there is ample precedent. The question is whether TE bonds could be issued by a suitable issuer—the Commonwealth or an issuing state agency—to finance IOU distribution system upgrades. Public private partnerships such as DC Plug may also provide a relevant model.</p>		<p>Green = has been used before in MA Yellow = has been implemented in other states Red = novel approach, not previously implemented</p>
	<p>14. Administrative and operational needs / costs</p>	<p>It is not likely that a new agency would be required to implement this action, although new implementing mechanisms would be needed (e.g., getting the prospective governmental bond issuer to be willing to issue bonds; negotiating agreements between the utility and the bond issuer with respect to affected projects to be co-funded/financed; designing the rationale for and tariff element to recover costs of the bond issuer's debt from utility ratepayers; gaining DPU approval of such project plans, cost recovery, tariff changes).</p>		<p>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</p>
	<p>15. Potential to scale</p>	<p>Depends on if this is a revenue-backed bond and market response. Once established, if well-received, can be scaled.</p>	<p>It depends</p>	<p>Green = approach is well-suited for large financings Yellow = no impact Red = approach is poorly suited for large financings</p>

	16. Suitability for investments of different size(s)	Although there might be transaction costs (e.g., associated with developing, considering, designing, getting approvals for, and implementing the ideas) for the bond issuance that make it more suitable for larger (rather than smaller) investment sizes, in theory the approach could be suitable for financings of various sizes.		Green = approach is suited to small financings as well as large ones Yellow = no impact Red = approach is poorly suited for small financings
	17. Replicability of the approach	There does not appear to be a limit on the replicability of this approach once the framework is set up, approved and implemented.		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	The prospects for energy/environmental transition bonds do not appear 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	This approach might be used for financing investments in assets with varying useful lives.		Green = the approach is highly adaptive 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	This approach might be used for distributed energy resource investments (e.g., energy efficiency, microgrids in a particular locality).		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	Cost recovery would not likely require a non-bypassable charge, but it depends.		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)
	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	This approach would not likely disrupt traditional utility business model considerations.		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 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.	Could provide options to create the means to finance shorter-term transactions/investments and refinance with longer-term financing (e.g. CIP model)		Green = positive impact on the additional issue or outcome metric Yellow = N/A Red = negative impact on the additional issue or outcome metric

ASSESSMENT FRAMEWORK – PUBLIC-PRIVATE PARTNERSHIP

This approach involves collaboration between public entities and utilities to fund infrastructure projects. The DC Power Line Undergrounding (DC PLUG) initiative (\$500 million) serves as a prime example, combining: a) ratepayer-funded utility investments with below-average returns, b) low-cost public bonds repaid through customer fees, and c) DC transportation department contributions. This model could support distribution-system expansion, targeted grid development for economic growth, or EV charging infrastructure.

ISSUE		DATA / DESCRIPTION (ANALYSIS GROUP)	UPDATED / CONFIRMED COLOR CODING	COLOR CODING DEFINITION
Investment/ cost recovery (dollar benefits)	Ratepayer impacts	1. Reduces cost of capital Assuming that the public-private partnership involves a combination of investment provided by the utility (i.e., the private partner) and by a public-sector partner (e.g., local government, state government), the public partner's contribution will likely be provided by debt financing alone while the private partner's investment will be provided through a combination of debt and equity financing. The utility's ratepayers pay rates that recover the combined costs of the two partners, with lower capital costs for the portion of the investment contributed by the public partner.		Green = lower cost to ratepayers Yellow = no impact Red = higher cost
		2. Develops new source of capital A public-private partnership enables the utility to access a new source of capital (e.g., from the public partner) for the portion of the total investment cost that is financed through the public partner's debt financing. That public partner goes to the capital market to borrow a lump sum amount of funds, which it will pay back from the stream of revenues it receives over time from the utility's customers.		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 It is possible (if not likely) that the repayment of the public partner's debt (and the associated cost recovery through the utility customers' rates) involves a levelized repayment schedule. If that were the case, then the combined cost recovery (i.e., of the public partner's debt repayment plus the utility's traditional cost recovery of the investment as well as the debt and equity financing) would be more levelized compared to having the financing taking place entirely through the utility's traditional cost recovery approach.		Green = lower near-term cost to ratepayers by flattening financing costs over time Yellow = no impact Red = N/A
		4. Mitigates rate base growth Because some portion of the capital investment would be financed through the public partner's debt, those dollars would not go into the utility's rate base.		Green = avoids dollars going into the utility's rate base Yellow = no impact Red = N/A
		5. Total Net Present Value (NPV) impacts Even though a public/private partnership would lower near-term charges for a particular asset's cost recovery (due to levelization of the public partner's cost recovery), it could increase charges in later years relative to a ratebasing method. Thus one needs to know the cost-recovery period for the debt repayment (compared to ratebase treatment) and the difference in the cost of debt to know whether this method increases or decreases the NPV of the investment.	It depends	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 This approach could reduce rate (or bill) impacts in the near term but possibly result in higher costs in later years over the life of the asset, relative to a traditional ratebasing method. For an asset with a long useful life, this will tend to improve intertemporal equity.		Gradient of green (on the left) to red (on the right)
		7. Enables direct assignment of cost recovery from project beneficiaries Depending upon the geographic profile of the public partner (e.g., the Commonwealth of Massachusetts versus one or more local governments in the service territory of a particular utility), the costs could be broadly or more narrowly assigned to the utility's ratepayers.		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 Red = No impact

	<p>8. Taxpayer impacts</p>	<p>Assuming that the public partner (e.g., a government) will issue bonds to finance its share of the investment (with repayment by the utility's ratepayers), this approach could affect use of that partner's bonding capability (e.g., limits) and might mean that the public partner might need to forego use of its bonding capacity for other purposes. That said, taxpayers of that public partner would not be affected because the utility's ratepayers will pick up the bond-repayment requirements.</p>		<p>Green = N/A Yellow = no impact on general fund Red = taxpayers pay for some or all of the grid investment</p>
	<p>9. Low- and Moderate-Income (LMI) / Environmental Justice (EJ) impacts</p> <p>· E.g., public health, intergenerational EJ impacts</p>	<p>There do not appear to be impacts that particularly benefit or harm LMI households or EJ communities.</p>		<p>Green = provides particular benefits to LMI ratepayers Yellow = no impact on LMI ratepayers</p>
	<p>10. Other investment / cost recovery impacts of note</p> <p>· E.g., impacts on balance of risk between ratepayers and shareholders, labor (job creation, wage levels), the incentives for non-wires alternatives or the need for new distribution investment</p>	<p>N/A</p>		<p>Green = positive impact on the additional outcome metric Yellow = N/A Red = negative impact on the additional outcome metric</p>
<p>Implementation pathway (challenges)</p>	<p>11. Expected timeline (e.g., time to implementation)</p>	<p>The principal factor affecting the timing of such a public/private partnership is the time it would take to generate interest by one or more public-sector partners. Based on the experience of the D.C. Plug public/private initiative in Washington, D.C., a series of intense storms that blacked out several areas of the District led to the appointment of a Power Line Undergrounding Task Force (in 2012), which developed ideas that eventually culminated in proposals by the utility and the DC government to work together to address the grid resilience issues through project plans and innovative financing arrangements, with a series of plans ultimately approved by D.C. utility regulators (2017-2021).</p> <p>In theory, there could be a shorter timeline if local governments in a utility's service territory were persuaded of the advantages of issuing bonds to support local grid investments in conjunction with discussions/plans by the local utility to upgrade infrastructure in that town with a utility rate-rider charged to customers in that locality (with approval by the DPU).</p>		<p>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</p>
	<p>12. Degree of barriers to implementation</p> <p>· E.g., DPU familiarity, legislative needs/risks, political support vs. opposition, legal risks, stakeholder buy-in</p>	<p>This novel approach might require consensus-building efforts to generate proposals for public/private partnership funding and cost-recovery ideas, and for consideration by the affected partners and the regulators whose approvals would be required for recovering the costs through utility rates.</p>		<p>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)</p>

	13. Previous experience in implementing the approach	There is experience with such an approach elsewhere.		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	It is not likely that a new agency would be required to implement this action, although new implementing mechanisms would be necessary (e.g., getting the public partner to be willing to issue bonds; negotiating agreements between the utility and the public partner with respect to affected projects to be co-funded/financed; designing the rationale for and tariff element to recover costs of the public-partner's debt from utility ratepayers; gaining DPU approval of such project plans, cost recovery, tariff changes).		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	It is unclear whether there are practical size limitations (e.g., running into bonding-capacity ceilings of the public partner).	It depends	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)	Although there might be transaction costs (e.g., associated with developing, considering, designing, getting approvals for, and implementing the ideas) for public/private partnerships that make it more suitable for larger (rather than smaller) investment sizes, in theory the approach could be suitable for financings of various sizes.		Green = approach is suited to small financings as well as large ones Yellow = no impact Red = approach is poorly suited for small financings
	17. Replicability of the approach	Experience in the D.C. Plug Initiative suggests that this approach can be repeated once the framework is set up and operating.		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	The prospects for a public/private partnership do not appear 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	A public/private partnership might be used for a bundle of assets with different lives.		Green = the approach is highly adaptive 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	A public/private partnership might be used for distributed energy resource investments (e.g. microgrids in a particular locality).		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	Cost recovery would not likely require a non-bypassable charge.		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)
	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	Evaluation would be on a case-by-case basis to determine if the capital structure would impact the utility, for example if the utility doesn't have enough investment in the project (equity) to reasonably own/operate it (by making enough of a return to make the investment).		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 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.

The availability of this mechanism might provide localities with different investment options based on their willingness to pay (e.g., for innovative investments, for enhanced resilience) although it might need to be accompanied by intentional efforts to ensure that all communities have baseline services supported by all utility ratepayers.

Green = positive impact on the additional issue or outcome metric Yellow = N/A Red = negative impact on the additional issue or outcome metric

ASSESSMENT FRAMEWORK – STATE REVOLVING FUND

This approach provides low-cost loans for infrastructure projects, with repayment recycled to fund additional projects. For example, Massachusetts participates in a water project SRF through the Department of Environmental Protection, with initial seed funding provided by federal capitalization grants (through EPA). Community water agencies borrow from the SRF for drinking water projects and repay the loans through water user fees. Repaid funds are used for subsequent loans from the SRF. In theory, a comparable program could be created for a Distribution-System SRF.

ISSUE		DATA / DESCRIPTION (ANALYSIS GROUP)	UPDATED / CONFIRMED COLOR CODING	COLOR CODING DEFINITION
Investment/ cost recovery (dollar benefits)	Ratepayer impacts	1. Reduces cost of capital This approach would begin with an initial seed-funding of dollars into a state revolving fund to support investments in the distribution grid (e.g., the source of the original dollars could be public funds raised through the issuance of bonds). These funds would then be managed and invested, with loans to utilities to make the investment. The financing costs for the utility investment would likely involve lower cost capital than the debt and equity the utility would use to finance investment through its access to traditional capital markets. Costs to ratepayers to repay these loans to the SRF would reduce the overall cost of capital charged in rates to customers.		Green = lower cost to ratepayers Yellow = no impact Red = higher cost
		2. Develops new source of capital This would involve a new source of debt capital for the investments in the grid.		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 Presumably, the repayment of any loans the utility obtains from the revolving fund would have a level repayment schedule (although it could vary depending upon the terms of the repayment of principal and interest). If the debt raised from the revolving fund displaced shareholder investment, then repayment would lead to lower near-term costs to ratepayers compared to traditional ratebase treatment of the investment and its financing.		Green = lower near-term cost to ratepayers by flattening financing costs over time Yellow = no impact Red = N/A
		4. Mitigates rate base growth The dollars the utility receives from the revolving fund would not go into rate base.		Green = avoids dollars going into the utility's rate base Yellow = no impact Red = N/A
		5. Total Net Present Value (NPV) impacts Without knowing the length of the repayment period and the repayment schedule compared to ratebase treatment, and differences between the cost of debt and utility weighted average cost of capital (WACC), it is uncertain whether this approach would lower or raise the NPV of any particular investment.	It depends.	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 If the repayment schedule were longer than the cost recovery period for an asset under traditional ratemaking and if the repayment schedule involved levelized cost recovery, then this could mean lower near-term rate impacts but potentially higher longer-term rate impacts relative to ratebase treatment (e.g., depending upon length of repayment, cost of debt, etc.).		Gradient of green (on the left) to red (on the right)
		7. Enables direct assignment of cost recovery from project beneficiaries This approach is not designed to allocate costs to specific set of beneficiaries; the approach focuses only on lowering the overall cost of financing 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 Red = No impact

	8. Taxpayer impacts	This approach would likely require an initial appropriation of public funds to provide initial monies into the revolving fund. This approach could affect the ability of the state (as the bond issuer) to issue other bonds if this issuance causes the government to hit its maximum bonding capability (e.g., limits). After the initial seed-funding of the revolving fund from the government's budget, the use of the money in the revolving fund (for loans to utilities) and the repayment of loans issued by the revolving fund (paid for by utility ratepayers) would not affect taxpayer-funded government budgets. At the end of the life of the revolving funds, money in the fund could go back to the original source (e.g., the government's general fund).		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 <i>· E.g., public health, intergenerational EJ impacts</i>	There do not appear to be impacts that particularly benefit or harm LMI households or EJ communities.		Green = provides particular benefits to LMI ratepayers Yellow = no impact on LMI ratepayers
	10. Other investment / cost recovery impacts of note <i>· E.g., impacts on balance of risk between ratepayers and shareholders, labor (job creation, wage levels), the incentives for non-wires alternatives or the need for new distribution investment</i>	N/A		Green = positive impact on the additional outcome metric Yellow = N/A Red = negative impact on the additional outcome metric
Implementation pathway (challenges)	11. Expected timeline (e.g., time to implementation)	The principal factor affecting the timing of this approach is the time it would take (e.g., several years to socialize the idea and gain sufficient support for the bond issuance) to generate interest by the state legislature (i.e., to authorize and appropriate the funding).		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
	12. Degree of barriers to implementation <i>· E.g., DPU familiarity, legislative needs/risks, political support vs. opposition, legal risks, stakeholder buy-in</i>	This novel approach might require consensus-building efforts to generate proposals for the bond issuance and related cost-recovery ideas, and for consideration by the state legislature and the regulators whose approvals would be required for recovering the costs through utility rates.		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	This approach has not previously been used for electric-sector investment.		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	This approach could be administered by an existing state agency (e.g., Massachusetts Clean Energy Center, Dept of Energy Resources) but would likely require new regulations and/or program rules for the administration of the revolving fund.		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	In theory, the approach could be used for large financings; the fact that it would require initial seed funding from the state government (and fit within the state's bonding limits) to provide opportunities for various utility investments might suggest that the approach is limited in scale and/or poorly suited for very-large financings.		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)	In theory, the approach could be used for financing investments of various sizes.		Green = approach is suited to small financings as well as large ones Yellow = no impact Red = approach is poorly suited for small financings
	17. Replicability of the approach	This approach is designed to provide a mechanism for multiple rounds of funding, as monies are replenished in the fund as recipients repay the loan issued by the revolving fund.		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	The availability of federal dollars to support seed-funding of the revolving fund (in addition to state funding) could increase its size and potential impact.		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	The approach could support 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	In theory (and limited principally by the amount of dollars available in the fund), this approach could be used to support investment in assets in 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	This approach does not require a non-bypassable charge on electricity bills 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)
	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	Given the likely practical limits on the size of investments that can be funded through this approach, it is not likely to disrupt the traditional utility business model and 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 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.	N/A		Green = positive impact on the additional issue or outcome metric Yellow = N/A Red = negative impact on the additional issue or outcome metric

Key Assumptions for Alternative Financing Approaches

Assumptions	Traditional	Securitization	Public-Private Partnership (Taxpayer)		Public-Private Partnership (Debt)		Clean Energy Tariff		State Revolving Fund
			Private Partner	Public Partner (Taxpayer Funded)	Private Partner	Public Partner (Debt Financed)	Traditional	Tariff for Large Load Customer(s)	
Capital Investment	\$1,000,000,000	\$1,000,000,000	\$500,000,000	\$500,000,000	\$500,000,000	\$500,000,000	\$900,000,000	\$100,000,000	\$1,000,000,000
Time Period	40	40	40	40	40	40	40	40	40
Financing Assumptions									
Debt Share	50.00%	100.00%	50.00%		50.00%	100.00%	50.00%	50.00%	100.00%
Equity Share	50.00%		50.00%		50.00%		50.00%	50.00%	
Cost of Debt	4.60%	4.00%	4.60%		4.60%	3.50%	4.60%	4.60%	3.50%
Cost of Equity	9.60%		9.60%		9.60%		9.60%	9.60%	
WACC / Discount Rate	7.10%	7.10%	7.10%	7.10%	7.10%	7.10%	7.10%	7.10%	7.10%

Notes:

[1] An illustrative weighted-average cost of capital (WACC) was calculated based on MA investor owned utility rate filings. Nominal costs are discounted using the WACC for all approaches.

[2] Securitization cost of debt was estimated based on a review of AAA corporate bond yields over the past 10 years.

[3] Both public-private partnership options assume an equal investment split between the private partner and the public partner. In the taxpayer funded option, the public share of the revenue requirement is assumed to be collected from taxpayers and spread evenly over the cost recovery time period. In the debt-financed option, the public share of the revenue requirement is assumed to be funded by a state agency through a debt obligation and recovered from ratepayers.

[4] State agency financed cost of debt for both the public-private partnership option and the state revolving seed fund is estimated based on a review of treasury notes and MA General Obligation bond yields over the past 10 years.

[5] For the Clean Energy Tariff option, \$900 million of the \$1 billion initial investment is assumed to be added to the general rate base and recovered under the traditional approach. The remaining amount is assumed to be funded by the initiating customer(s) through a special tariff.

Sources:

[A] MA DPU 23-150; 22-22; 18-150; 15-155.

[B] "Moody's Seasoned Aaa Corporate Bond Yield", FRED, available at <https://fred.stlouisfed.org/series/DAAA>.

[C] "Moody's Seasoned Baa Corporate Bond Yield", FRED, available at <https://fred.stlouisfed.org/series/DBAA>.

[D] "Market Yield on U.S. Treasury Securities at 30-Year Constant Maturity, Quoted on an Investment Basis", FRED, available at <https://fred.stlouisfed.org/series/DGS30>.

[E] "Official Statements", Massachusetts Investor Program, available at <https://www.massbondholder.com/financial-documents/official-statements>.

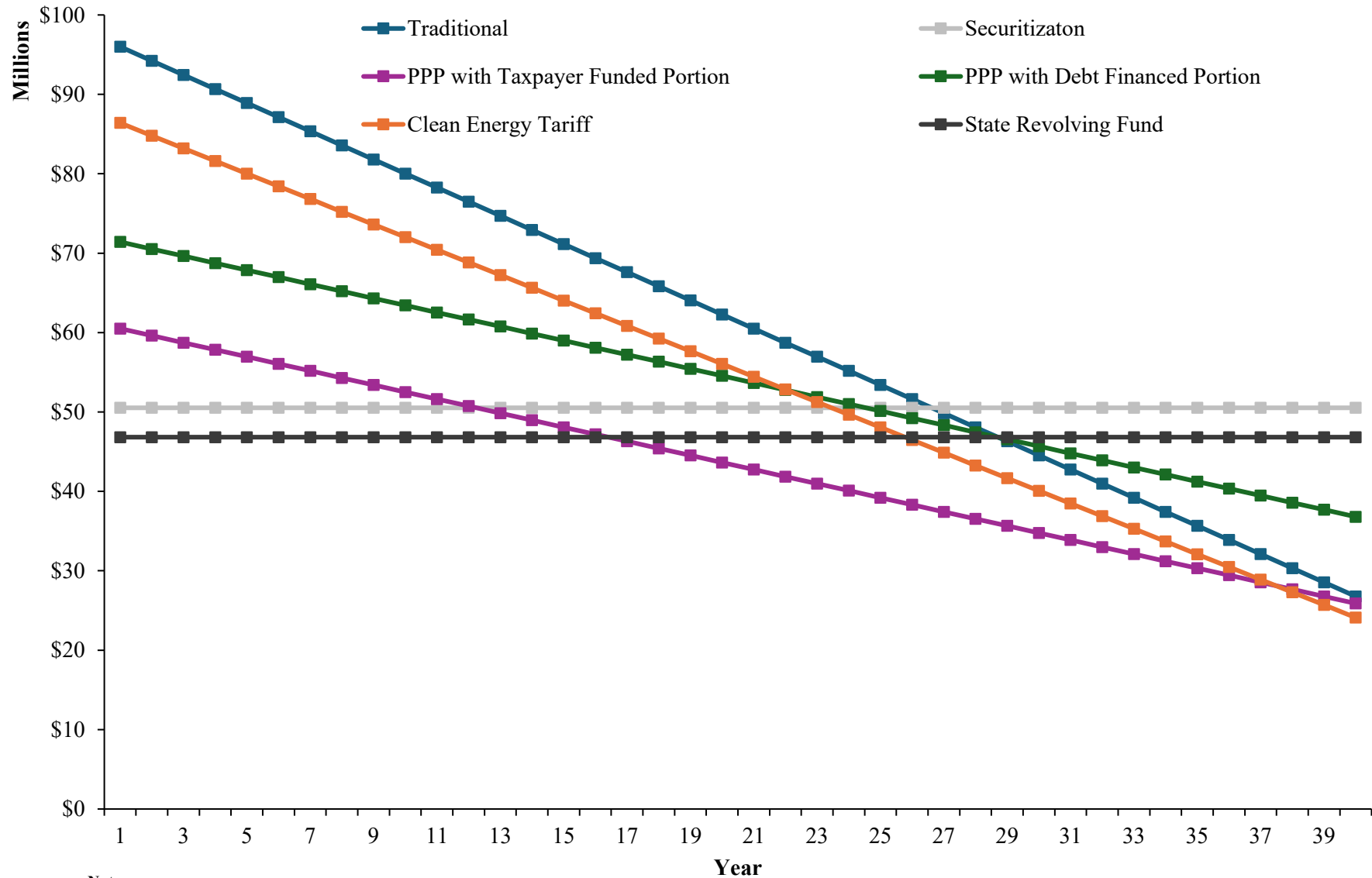
Revenue Requirement (Nominal \$)

Year	Traditional	Securitization	PPP with Taxpayer Funded Portion	PPP with Debt Financed Portion	Clean Energy Tariff	State Revolving Fund
1	96,000,000	50,523,489	60,500,000	71,413,641	86,400,000	46,827,282
2	94,225,000	50,523,489	59,612,500	70,526,141	84,802,500	46,827,282
3	92,450,000	50,523,489	58,725,000	69,638,641	83,205,000	46,827,282
4	90,675,000	50,523,489	57,837,500	68,751,141	81,607,500	46,827,282
5	88,900,000	50,523,489	56,950,000	67,863,641	80,010,000	46,827,282
6	87,125,000	50,523,489	56,062,500	66,976,141	78,412,500	46,827,282
7	85,350,000	50,523,489	55,175,000	66,088,641	76,815,000	46,827,282
8	83,575,000	50,523,489	54,287,500	65,201,141	75,217,500	46,827,282
9	81,800,000	50,523,489	53,400,000	64,313,641	73,620,000	46,827,282
10	80,025,000	50,523,489	52,512,500	63,426,141	72,022,500	46,827,282
11	78,250,000	50,523,489	51,625,000	62,538,641	70,425,000	46,827,282
12	76,475,000	50,523,489	50,737,500	61,651,141	68,827,500	46,827,282
13	74,700,000	50,523,489	49,850,000	60,763,641	67,230,000	46,827,282
14	72,925,000	50,523,489	48,962,500	59,876,141	65,632,500	46,827,282
15	71,150,000	50,523,489	48,075,000	58,988,641	64,035,000	46,827,282
16	69,375,000	50,523,489	47,187,500	58,101,141	62,437,500	46,827,282
17	67,600,000	50,523,489	46,300,000	57,213,641	60,840,000	46,827,282
18	65,825,000	50,523,489	45,412,500	56,326,141	59,242,500	46,827,282
19	64,050,000	50,523,489	44,525,000	55,438,641	57,645,000	46,827,282
20	62,275,000	50,523,489	43,637,500	54,551,141	56,047,500	46,827,282
21	60,500,000	50,523,489	42,750,000	53,663,641	54,450,000	46,827,282
22	58,725,000	50,523,489	41,862,500	52,776,141	52,852,500	46,827,282
23	56,950,000	50,523,489	40,975,000	51,888,641	51,255,000	46,827,282
24	55,175,000	50,523,489	40,087,500	51,001,141	49,657,500	46,827,282
25	53,400,000	50,523,489	39,200,000	50,113,641	48,060,000	46,827,282
26	51,625,000	50,523,489	38,312,500	49,226,141	46,462,500	46,827,282
27	49,850,000	50,523,489	37,425,000	48,338,641	44,865,000	46,827,282
28	48,075,000	50,523,489	36,537,500	47,451,141	43,267,500	46,827,282
29	46,300,000	50,523,489	35,650,000	46,563,641	41,670,000	46,827,282
30	44,525,000	50,523,489	34,762,500	45,676,141	40,072,500	46,827,282
31	42,750,000	50,523,489	33,875,000	44,788,641	38,475,000	46,827,282
32	40,975,000	50,523,489	32,987,500	43,901,141	36,877,500	46,827,282
33	39,200,000	50,523,489	32,100,000	43,013,641	35,280,000	46,827,282
34	37,425,000	50,523,489	31,212,500	42,126,141	33,682,500	46,827,282
35	35,650,000	50,523,489	30,325,000	41,238,641	32,085,000	46,827,282
36	33,875,000	50,523,489	29,437,500	40,351,141	30,487,500	46,827,282
37	32,100,000	50,523,489	28,550,000	39,463,641	28,890,000	46,827,282
38	30,325,000	50,523,489	27,662,500	38,576,141	27,292,500	46,827,282
39	28,550,000	50,523,489	26,775,000	37,688,641	25,695,000	46,827,282
40	26,775,000	50,523,489	25,887,500	36,801,141	24,097,500	46,827,282
Total	2,455,500,000	2,020,939,573	1,727,750,000	2,164,295,645	2,209,950,000	1,873,091,290

Note:

[1] This analysis assumes a \$1 billion investment in distribution-system assets using *illustrative* financing assumptions for Massachusetts' investor-owned utilities, for commercial debt markets, and for contributions from parties (e.g., general fund; specific large electric-using customers) other than core electric ratepayers. The analysis focuses on comparing financing approaches using common assumptions. The analysis does not account for actual conditions that might exist with any actual finding, or for indirect or second-order impacts of certain financing alternatives.

Annual Revenue Requirement to Recover \$1B Capital Requirement (Nominal \$)



Note:

[1] This analysis assumes a \$1 billion investment in distribution-system assets using *illustrative* financing assumptions for Massachusetts’ investor-owned utilities, for commercial debt markets, and for contributions from parties (e.g., general fund; specific large electric-using customers) other than core electric ratepayers. The analysis focuses on comparing financing approaches using common assumptions. The analysis does not account for actual conditions that might exist with any actual finding, or for indirect or second-order impacts of certain financing alternatives.

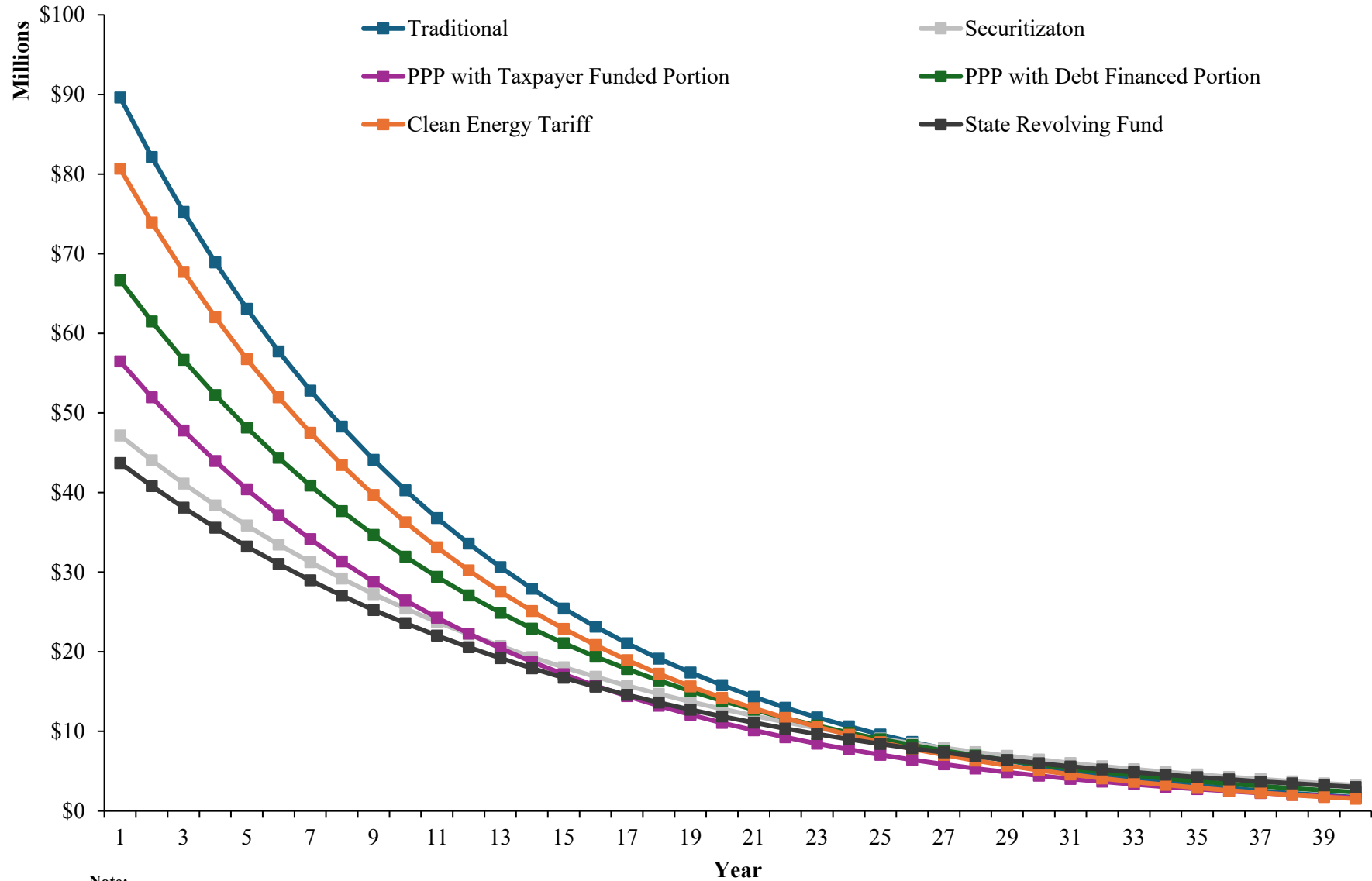
Revenue Requirement (Discounted \$)

Year	Traditional	Securitization	PPP with Taxpayer Funded Portion	PPP with Debt Financed Portion	Clean Energy Tariff	State Revolving Fund
1	89,635,854	47,174,126	56,489,262	66,679,403	80,672,269	43,722,953
2	82,146,148	44,046,803	51,970,679	61,485,284	73,931,533	40,824,419
3	75,255,545	41,126,800	47,802,941	56,686,791	67,729,990	38,118,038
4	68,917,526	38,400,374	43,959,387	52,254,299	62,025,774	35,591,072
5	63,089,111	35,854,691	40,415,353	48,160,369	56,780,200	33,231,627
6	57,730,586	33,477,769	37,148,017	44,379,591	51,957,527	31,028,596
7	52,805,265	31,258,421	34,136,269	40,888,439	47,524,739	28,971,612
8	48,279,262	29,186,201	31,360,579	37,665,126	43,451,335	27,050,991
9	44,121,276	27,251,355	28,802,887	34,689,486	39,709,149	25,257,695
10	40,302,406	25,444,776	26,446,487	31,942,844	36,272,165	23,583,282
11	36,795,962	23,757,961	24,275,931	29,407,917	33,116,366	22,019,871
12	33,577,305	22,182,970	22,276,934	27,068,704	30,219,575	20,560,104
13	30,623,687	20,712,390	20,436,289	24,910,398	27,561,319	19,197,109
14	27,914,114	19,339,300	18,741,787	22,919,293	25,122,703	17,924,472
15	25,429,208	18,057,236	17,182,139	21,082,705	22,886,288	16,736,201
16	23,151,091	16,860,164	15,746,913	19,388,898	20,835,982	15,626,705
17	21,063,265	15,742,450	14,426,467	17,827,013	18,956,939	14,590,761
18	19,150,512	14,698,833	13,211,890	16,387,003	17,235,461	13,623,493
19	17,398,796	13,724,401	12,094,947	15,059,572	15,658,916	12,720,348
20	15,795,171	12,814,567	11,068,033	13,836,123	14,215,653	11,877,076
21	14,327,700	11,965,048	10,124,119	12,708,704	12,894,930	11,089,707
22	12,985,380	11,171,847	9,256,713	11,669,957	11,686,842	10,354,535
23	11,758,066	10,431,230	8,459,820	10,713,083	10,582,260	9,668,100
24	10,636,409	9,739,710	7,727,903	9,831,790	9,572,768	9,027,171
25	9,611,795	9,094,034	7,055,849	9,020,263	8,650,615	8,428,731
26	8,676,285	8,491,161	6,438,938	8,273,124	7,808,657	7,869,963
27	7,822,570	7,928,255	5,872,812	7,585,404	7,040,313	7,348,238
28	7,043,915	7,402,666	5,353,449	6,952,508	6,339,524	6,861,100
29	6,334,121	6,911,920	4,877,136	6,370,188	5,700,709	6,406,256
30	5,687,479	6,453,707	4,440,449	5,834,522	5,118,731	5,981,565
31	5,098,736	6,025,870	4,040,226	5,341,882	4,588,862	5,585,028
32	4,563,057	5,626,396	3,673,553	4,888,918	4,106,751	5,214,779
33	4,075,994	5,253,404	3,337,740	4,472,534	3,668,395	4,869,074
34	3,633,455	4,905,139	3,030,306	4,089,872	3,270,110	4,546,288
35	3,231,678	4,579,962	2,748,966	3,738,289	2,908,510	4,244,900
36	2,867,202	4,276,342	2,491,609	3,415,347	2,580,482	3,963,492
37	2,536,849	3,992,849	2,256,294	3,118,794	2,283,164	3,700,740
38	2,237,695	3,728,151	2,041,228	2,846,550	2,013,926	3,455,406
39	1,967,056	3,481,000	1,844,761	2,596,696	1,770,351	3,226,336
40	1,722,466	3,250,233	1,665,372	2,367,459	1,550,219	3,012,452
Total	1,000,000,000	665,820,511	664,730,435	808,555,143	900,000,000	617,110,287

Note:

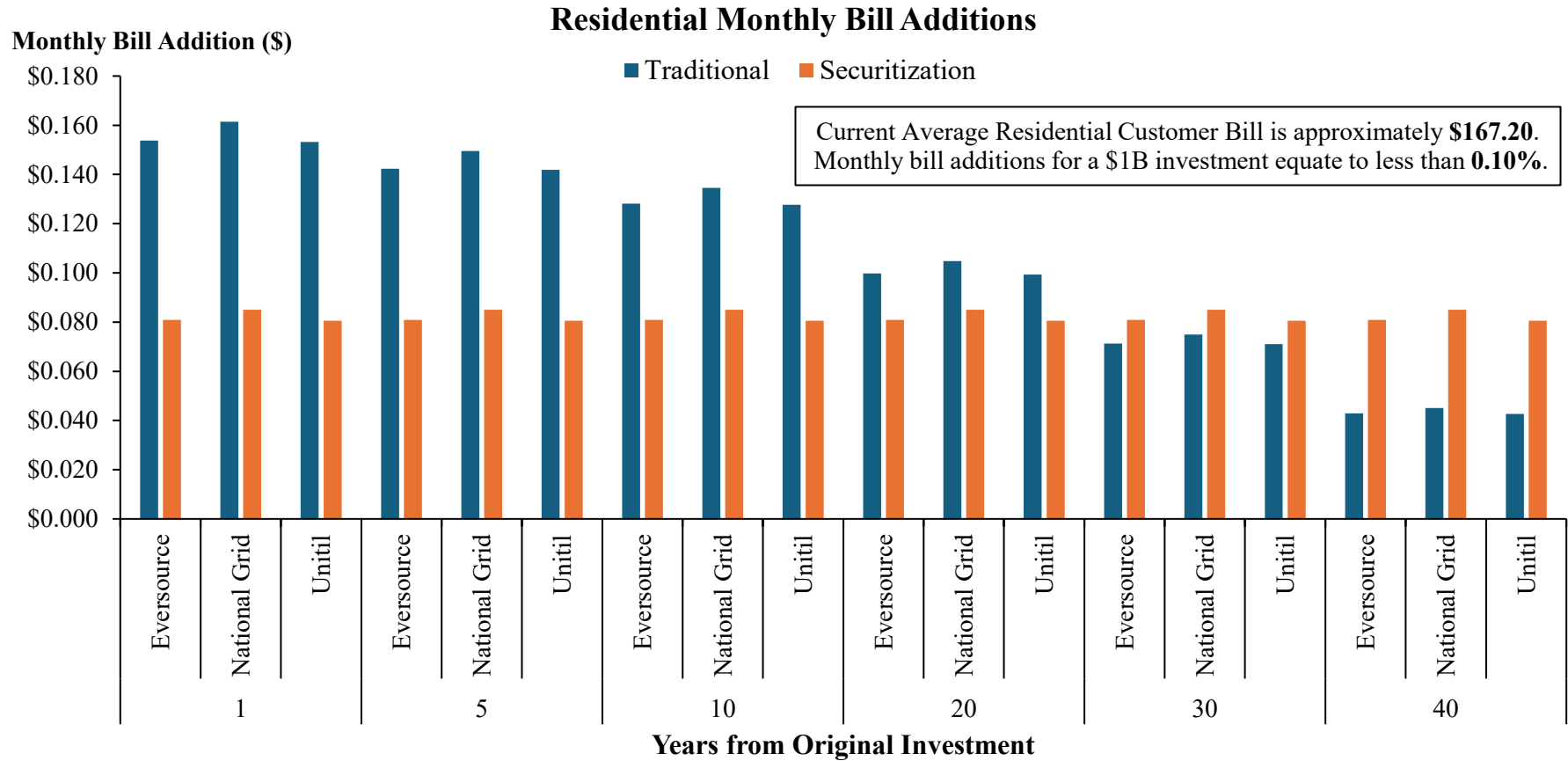
[1] This analysis assumes a \$1 billion investment in distribution-system assets using *illustrative* financing assumptions for Massachusetts' investor-owned utilities, for commercial debt markets, and for contributions from parties (e.g., general fund; specific large electric-using customers) other than core electric ratepayers. The analysis focuses on comparing financing approaches using common assumptions. The analysis does not account for actual conditions that might exist with any actual finding, or for indirect or second-order impacts of certain financing alternatives.

Annual Revenue Requirement to Recover \$1B Capital Requirement (Discounted \$)



Note:

[1] This analysis assumes a \$1 billion investment in distribution-system assets using *illustrative* financing assumptions for Massachusetts’ investor-owned utilities, for commercial debt markets, and for contributions from parties (e.g., general fund; specific large electric-using customers) other than core electric ratepayers. The analysis focuses on comparing financing approaches using common assumptions. The analysis does not account for actual conditions that might exist with any actual finding, or for indirect or second-order impacts of certain financing alternatives.



Notes:

- [1] This analysis assumes a \$1 billion investment in distribution-system assets using *illustrative* financing assumptions for Massachusetts’ investor-owned utilities, for commercial debt markets, and for contributions from parties (e.g., general fund; specific large electric-using customers) other than core electric ratepayers. The analysis focuses on comparing financing approaches using common assumptions. The analysis does not account for actual conditions that might exist with any actual finding, or for indirect or second-order impacts of certain financing alternatives.
- [2] The initial \$1B investment is converted into annual revenue requirements under both the traditional and securitization approaches and allocated across utilities based on their share of total electric load and within utilities by rate class revenue allocation percentages.
- [3] For each utility, the rate class revenue allocation percentage, total test-year kWh, and total number of bills are derived from recent rate cases.
- [4] The average kWh per bill is calculated for each utility as total test-year kWh divided by the total number of bills.
- [5] The monthly bill addition is calculated by allocating the revenue requirement by share of electric load and rate class revenue allocation percentage, converting the result to a per-kWh amount using total test-year kWh, converting to a monthly value, and multiplying by the average kWh per bill.

Sources:

- [A] U.S. Energy Information Administration (EIA), *Electric Sales, Revenue, and Average Price: Residential Average Monthly Bill by Census Division and State (Table 5.a)*, data for 2024.
- [B] Massachusetts Electric Company Nantucket Electric Company d/b/a National Grid, 2025 Performance-Based Ratemaking (PBR) Filing, Book 1 of 2, D.P.U. 25-73, filed June 13, 2025.
- [C] NSTAR Electric Company d/b/a Eversource Energy, Proposed Distribution Rates and Bill Impacts, Exhibit ES-RDC-1, D.P.U. 25-136.
- [D] Fitchburg Gas and Electric Light Company d/b/a Unital, Electric Division Rate Design and Revenue Allocation, Exhibit Unital-ECRP-14, D.P.U. 25-xxx.

Proposal for a Carbon Fee and State Revolving Fund

Introduction

Outlined below is a proposal for a Carbon Fee where the revenues in part would be used to establish a State Revolving Fund (SRF). This proposal is presented to the Office of Energy Transformation's (OET) Financing the Transition (FTT) Focus Area Working Group (FAWG).

This summary addresses carbon pricing generally and an assessment of Massachusetts emissions and policy priorities. From this, a proposed design consistent with the state's emissions profile and policy priorities is presented for discussion.

Carbon Pricing

Carbon pricing is a charge, in \$/Metric Ton (MT), paid by businesses, utilities and other entities that combust CO₂, reflecting in part the environmental damages resulting from these emissions. Ideally, it is applied economy-wide, including fossil generation, natural gas and fuel oil delivered to homes and businesses, transportation of goods and people using gasoline and diesel, and fuel burned for industrial uses.

Carbon pricing is considered market based. Businesses can avoid or reduce charges in their operations (e.g., by purchasing electric trucks for operations) or in their product line (e.g., by offering heat pumps instead of delivering fuel oil), or they can continue to emit and pay for their emissions. Retail customers may see a portion of the charge as compliance costs flow through the supply chain. They also have a choice – to adopt energy efficiency measures, buy an EV or plug-in hybrid vehicle, etc. – or pay the costs for carbon embedded in these products. These decisions in aggregate help to find lower cost ways of reducing emissions.

Carbon pricing can be seen as a complement to other emissions reducing measures such as renewables purchase mandates or incentives to install heat pumps which together seek to achieve a given emissions reduction target. In this policy context, which is the case in Massachusetts (MA), adding carbon pricing at a modest level to the mix will capture some emissions reductions not captured by mandates and incentives. These additional low-cost reductions will help the state meet its emissions reduction goals at lower overall cost.

Carbon pricing is not new; it has been long and widely deployed around the globe. At last count, the World Bank identified 73 national and 75 subnational jurisdictions which employ some form of carbon pricing.¹

Massachusetts Carbon Emissions and Policy Priorities

Massachusetts recorded carbon emissions in 2021 were 54.6 million MT². For this purpose, fossil generation was removed because this sector is already covered by the Regional Greenhouse Gas Initiative and an estimate of aviation emissions were removed because this

¹ World Bank Group, State and Trends of Carbon Pricing, 2025.

² Summary of Massachusetts GHG Emissions, Sector Sublimits tab, year 2021.

largely represents interstate travel and therefore may not be subject to MA jurisdiction, resulting in a 2021 covered value of 45.7 million MT.³

Observations regarding policy priorities were gathered from FAWG discussions and other sources. Many policy priorities were identified, and they included affordability (particularly with respect to residential electric bills), low- and moderate-income customers' energy burden, and the critical role electrification will play in meeting the state's emissions reduction goal. In addition, a stable source of lower cost funding for electric distribution investment and similar investment was also seen as desirable.

Proposed Carbon Fee/State Revolving Fund (SRF) Design for MA

A modest fee of \$15/MT is proposed starting in 2028 and increasing at approximately 3.3%/year.⁴ This moderate value represents a complementary role carbon pricing could play in MA. From the resulting revenues, estimated a slightly above \$500mm/year, a \$10/month credit is applied to all Electric Distribution Company (EDC) customer bills, and an additional \$10/month credit is applied to low-income customer EDC bills. These credits are intended to help with affordability and with low-income energy burden. In addition, these credits can help reduce the cost of electricity, making it slightly less expensive to switch from higher emitting fossil fuels to electricity⁵ ⁶ – a critical success factor in helping MA achieve its emissions reduction goals.

After these credits there are additional revenues available to establish an SRF. In the context of the FTT FAWG, these are low-cost loans that can be made available to EDCs for grid enhancement projects, establishing a sustainable revenue source separate from electric customers or taxpayers. A portion of these funds could also be made available as low-cost loans for Distributed Energy Resources projects or other purposes. Over time, and including repaid loans, the working SRF balance may grow to approximately \$1B.

³ It is likely that further minor adjustments will be made.

⁴ A cap-and-trade program was considered, but MA by itself is not a large enough emissions market so a Carbon Fee is proposed here.

⁵ A clean energy transition generally and carbon pricing and electrification in particular raises the issue of a related transition for the existing workforce ties to fossil businesses. Proposed here is a one-time \$50M placeholder to address this transition.

⁶ A related issue is leakage – that is the need to maintain competitive of fossil-based companies in MA with similarly situated companies outside of MA competing in the same markets. A careful program design and funds should also be made available for this purpose.

Carbon Fee Revenue and Uses Projections

Policy Variables		
Variable	Value	Description
First Year Carbon Fee (\$/MT)	15.00	Fee applied to all emitters above a certain size for fossil fuel consumed in MA
Res Electric LDC Customer Bill Credit (\$/month)	10.00	Monthly Bill Credit, First Use of Revenues
Low Income Additional Res Electric LDC Customer Bill Credit (\$/month)	10.00	Monthly Bill Credit, Second Use of Revenues (1)
Electric LDC Customer Bill Credit Annual Escalation (%)	2.32%	CPI-W, Rate applied to Res and Low Income Electric LDC Customers, Speculative (2)
Carbon Fee Annual Escalation (%)	3.32%	CPI-W+1%, Rate applied to Carbon Fee, Speculative
Annual Energy-Related GHG Emissions Rate of Reduction (%)	-3.13%	Estimated Annual Rate of Reduction Needed to Achieve an 85% Reduction in Energy-Related GHG Emissions by 2050 (3)
Low Income Res Electric Customers as a % of Total Res Elec LDC Customers (%)	15%	Percentage of Customers Eligible for Low Income Electric LDC Customer Bill Credit
1st Year Seed Funding (\$mm)	50	Seed Funding in First Year of Program Operation
Proportion of Seed Funding Applied to Grants (%)	75%	To Be Made Available for Workforce Retraining and Other Climate Related Purposes
Funds Not Immediately Subject to Revolving Fund Repayment (%)	10%	Toggle to Account for Potential Grants instead of Loans, or Non or Late Performance of Loans
Average Loan Repayment Duration (Years)	15	Based loosely on the average small solar PV installation loan duration
Exogenous Variables		
Variable	Value	Description
MA Carbon Emissions in 2021 (MMT CO2)	56	EIA Table CO2.t1 for 2021, last year available. Derived from 2021 MA GHG Emissions Inventory, last year available.
First Year Statewide Carbon Emissions (MMT CO2)	45	Assume 2028 is 1st Year of Program. Apply Estimated Emissions Rate of Reduction from 2021 to 2028.
Portion of Energy-Related Emissions Subject to Carbon Fee	90%	Assume Emissions From Sources Below Designated Compliance Threshold Are 10%
Number of MA Residential Electric LDC Customers (mm)	2.8	Estimate of Number of Households in MA (2020-2024) from US Census Data. Proxy for number of MA res electric LDC customer accounts.
Annual Growth Rate in Number of Households in MA (%)	0.4%	Official Projections for MA Developed by MAPC and others. Speculative.
Annual Growth Rate in Number of Low Income Households (%)	0.4%	Assumed to be the Same as the Estimated Growth Rate in Number of Households
Intermediate Calculations		
Year	Carbon Fee (\$/MT)	Statewide Emissions Subject to Carbon Fee (MMT)
2028	15.00	40.3
2029	15.50	39.1
2030	16.01	37.9
2031	16.54	36.7

2032	17.09	35.5
2033	17.66	34.4
2034	18.25	33.3
2035	18.85	32.3
2036	19.48	31.3
2037	20.13	30.3
2038	20.79	29.3
2039	21.48	28.4
2040	22.20	27.5

Carbon Fee Revenues, Uses, and Fund Balances - Results for 2028 - 2040

Carbon Fee Revenues	<i>Electric LDC Cust Bill Credit (\$MM)</i>	<i>Electric LDC Low Income Additional Cust Bill Credit (\$MM)</i>	Carbon Fee Funding for SRF (\$MM) (4)	Loan Repayment Funding for SRF (\$MM) (5)	Funds Balance, Including Outstanding Loans (\$MM) (6)
605	336	50	231	0	231
606	345	52	209	14	454
606	355	53	198	26	678
607	364	55	188	38	904
607	374	56	177	50	1,131
608	384	58	166	60	1,357
608	395	59	154	70	1,581
609	406	61	142	79	1,802
609	417	63	130	88	2,020
610	428	64	117	96	2,233
610	440	66	104	103	2,440
611	452	68	91	109	2,641
611	464	70	78	114	2,833

(1) Additional Bill Credit for Qualifying Customers.

(2) Cleveland Fed long-term projection of CPI, based on a Statista projection through 2029. Admittedly speculative. Value should be updated each year, perhaps tied to Social Security annual updates, so use CPI-W.

(3) MA Energy-Related Carbon 1990 Emissions from the 1990 Massachusetts GHG Inventory (94.4 MMT CO2e) and MA Energy-Related 2050 Target (14.0 MMT CO2e).

(4) First Year Value Includes Portion of Seed Funding for State Revolving Fund. Remainder (i.e.; 75%) could be Used for Fossil Worker Retraining or other Grants, etc. Alternatively, 100% could be used outside of SRF.

(5) Assumes Levelized Payments. Loan Repayment Funding Will Continue After 2040.

(6) Balance Approximates the Sum of That Year's Contribution and the Amount Brought Forward from the Previous Year. Some or All of the Previous Years' Funds May Have Been Loaned Out.

Customer-Owned Peak Power & Emissions Reduction (COPPER) Program



Executive Summary

1. Create \$500 MM revolving loan fund for customer-owned solar + storage installations; seed funds provided by ratepayers or taxpayers (see Slide 9).
2. Loans will be offered to customers located on circuits slated for peak capacity upgrades under ESMPs; 0% interest loans available to eligible low-income customers; no liens on borrowers' properties.
3. Aggregated solar + storage systems on these circuits will defer or avoid utility-owned peak capacity upgrades.
4. Proceeds from loan repayments will be rolled back into this program for additional installations, or could be reimbursed to the rate-base.



Targeting Solar + Storage Incentives to Reduce Ratepayers Costs

- Current Massachusetts policy provides for the installation of hundreds of MW of distributed solar PV and energy storage systems per year (e.g., 900 MW of solar specified for 2025 in SMART 3 program)
- COPPER Program uses concessionary debt to incentivize aggregated installations of solar + storage systems on circuits where they will defer or avoid peak capacity upgrades (e.g., 65 MW capacity + 2 hours of storage).
- The same 65 MW of solar + storage capacity would be installed elsewhere across the Commonwealth as a base case, so this proposal would not increase the incremental cost of the SMART program, net metering, etc. **The proposed low-cost, long-term debt fund functions to *target* rapid solar + storage deployment to distribution grid nodes where the aggregation will reduce costs to the rate-base by deferring or avoiding onerous grid upgrades.**

Customer-Owned Alternative to Utility Investment

The delivery component of electricity bills (which funds grid upgrades) is a primary driver of recent electricity bill increases.



For example, Eversource's Electric Sector Modernization Plan (ESMP) from 2024 calls for ~\$200 MM per year in peak load & capacity upgrades, >\$1 B over 5 years.

Customer-Owned Alternative to Utility Investment

- The Customer-Owned Peak Power & Emissions Reduction (COPPER) Program creates a \$500 MM debt fund within MassSave to finance aggregations of solar + storage systems that defer or avoid planned utility peak capacity investments.
- As a conservative estimate, a fund of this size would be sufficient to build ~65 MWac of solar capacity paired with two hours of energy storage (~130 MWh)



Defer or Avoid Distribution Grid Upgrades

Solar + storage systems reduce peak demand at the circuit-level. By keeping peak demand below a critical threshold, aggregations defer or avoid substation upgrades.

Table 1. Chelsea/East Boston/Lynn (C-EB-L) peak load comparing Eversource 2017 assumptions to adjustments using ISO New England's CELT 2019 (MW)

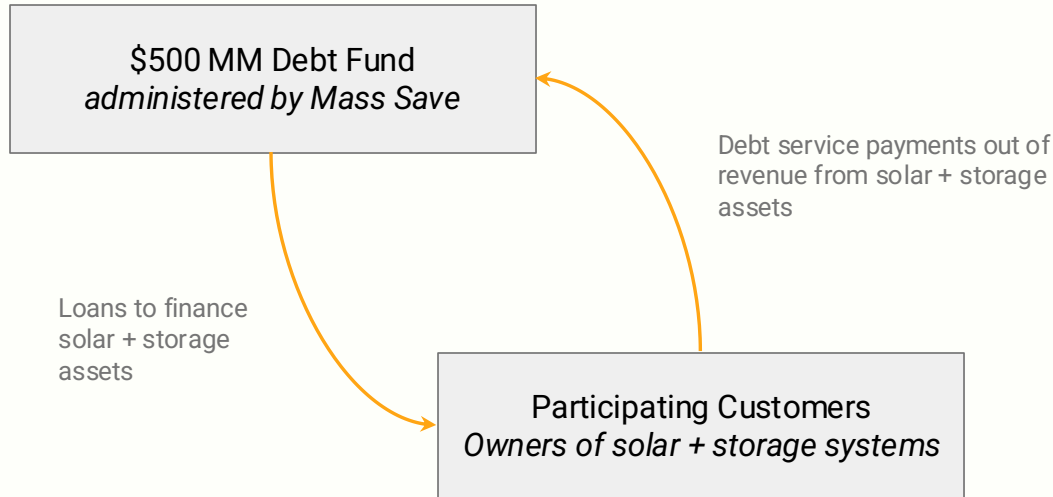
	2018	2019	2020	2021	2022	2023	Annual % Change
Eversource 2017 Discovery Response	303.4	306.6	309.8	313.0	316.3	323.0	1.0%

For example, 23 MW of peak capacity reduction by 2023 ($\frac{1}{3}$ of 65 MW program) would have been sufficient to meet projected load growth and avoid East Eagle Substation upgrade ([\\$103 MM](#)), which was triggered at 300 MW ([source](#)).



Revolving Fund Limits Delivery Cost Escalation

Unlike conventional utility asset financing, which increases ratepayer costs with each incremental investment, COPPER uses a one-time seed investment to create a revolving fund with the potential to support 100 MW+ of peak demand reduction over time. **The capital investment is repaid only by participating customers, which avoids future charges to ratepayers.**



Loan Fund Structure

- 20 year loan at up to 6% interest.
 - Lower interest rates available for LMI customers, e.g., 3% for 80% - 100% AMI, 0% for <80% AMI.
 - Target weighted average interest rate across program to be high enough to support direct program administrative costs.
- Solar + storage assets installed by pre-approved vendors and owned by host customers.
- Participating customers' annual revenue from solar + storage assets (electricity value, SMART incentives, ConnectedSolutions) is greater than the cost of debt service; avg. participant saves ~\$1k on electricity bills per year.
- Debt service payments replenish the loan fund over time to support future installations.
- Loans are collateralized with solar + storage assets only (no property liens); defaults reduce loan fund principle and are not sent to collections.



Potential Sources of Debt

If the COPPER Program is not capitalized in full upfront and/or hosted within MassSave, these sources of debt may be suitable alternatives and/or supplements:

- Electric rate reduction bonds (RRBs)
 - Most applicable if hosted within MassSave
 - 20 year, ~4% RRB could be matched with 20 year ~5% COPPER loans to minimize or avoid incremental charge to ratepayers
- MassDevelopment bonds, which may be tax-exempt
- Renewable Energy Trust Fund
- Massachusetts Community Climate Bank
- Nonprofit program-related investments (PRIs)



Discussion

- Overall impressions / questions?
- What place does this program have in our portfolio of recommendations?
 - Reducing CAPEX vs. reducing cost of capital
- Key questions that can be addressed by Analysis Group quantitative analysis?
- Adequate incentives and protections for LMI customers?

