

Cost Allocation - The Standard Offer Block component of the straw proposal provides an increasing volume of clean energy that reduces Standard Offer supply obligations or can be incorporated directly into Standard Offer supply volumes. This approach could collect revenue from Standard Offer customers to pay FTM DER projects in the program, while price effects from the new projects would also be experienced by Standard Offer customers. Is this approach to cost allocation and provision of program benefits feasible within available Maine ratemaking structures?

Feasibility depends heavily on which specific cost recovery method is chosen, because that choice determines whether Standard Offer customers alone bear both the costs and the benefits of the program, or whether the exposure is spread more broadly. Maine has a competitive supply market, and Standard Offer customers can and do migrate to competitive suppliers. This migration will likely increase due to the newly passed Community Choice Aggregation law, LD 2112, which allows municipalities to enroll their residents and small businesses with a competitive supplier on an opt out basis. If Part 1 costs are recovered only from Standard Offer customers, the recovery base will likely shrink over the life of a 20-year contract even as compensation obligations to DER projects remain fixed. Over time, this dynamic could itself become a driver of migration: as the recovery base narrows, per-customer costs would rise for those remaining on Standard Offer, creating an added incentive for both individual customers and municipalities to move to competitive or CCA supply, further shrinking the base and compounding the problem.

Capacity – How should capacity be treated and valued in the program? Should capacity be included in the Standard Offer Block and conveyed to the Block at ISO-NE Forward Capacity Market settlement price? Or available to be retained and monetized by projects? Are there other approaches to procuring and valuing capacity that DOER should consider?

We recommend capacity be retained and monetized by projects, rather than conveyed to the Standard Offer Block at ISO-NE Forward Capacity Market (FCM) settlement price. Doing this is consistent with the value stacking principals laid out in the straw proposal.

Cost Recovery - this straw proposal considers whether to recover Part 1. Standard Offer Block costs from either Standard Offer customers or all Maine ratepayers. Which recovery option should be chosen and why? Is there an alternative recovery option that is not reflected here that should be considered? What is the alternative and why?

We recommend recovery from all Maine ratepayers, rather than Standard Offer customers alone. The straw proposal's stated goals of affordable energy costs, reliable and resilient grid, community benefits, are framed at the level of Maine ratepayers generally, not Standard Offer customers specifically. The price-stability and long-term supply-hedge value the Block provides likely has spillover effects on overall market prices that benefit all customers, including those with competitive suppliers.

Additionally, limiting recovery to Standard Offer customers creates exposure to a shrinking recovery base as customers migrate to competitive supply either independently or via community choice aggregation, particularly over a 20-year contract horizon. All-ratepayer recovery avoids this risk and provides more durable cost recovery for utilities and more predictable revenue certainty for project financing.

The straw proposal already proposes recovering DSS costs from all ratepayers in the applicable utility territory, on the reasoning that distribution services are comparable to conventional delivery-charge costs.

Based on the straw proposal, what additional cost allocation options or considerations should be accounted for? If participating DER projects should bear a portion of program costs, such as through an export charge on energy or capacity, how should those charges be set?

If DOER adopts an export charge on top of compensation that is already set based on the net value DERs provide, this risks double-charging developers for the same distribution value the DSS component is designed to credit them for.

After reading the straw proposal, what are the primary requirements for implementation? For example, what technical or administrative dependencies do you identify, which should be addressed to make the straw proposal feasible?

A clear, standardized data-sharing pipeline that allows DER owners to operate assets with real-time telemetry, not batch or delayed reporting. Real-time settlement infrastructure and software should be built out now, even if initial DSS settlement remains monthly, so the system doesn't need to be rebuilt when the program moves to sub-monthly or sub-daily settlement in later phases.

Beyond data infrastructure, we'd highlight:

- Common technical standards: Flexible interconnection and future ADMS/DERMS integration standards should be consistent across both utilities so program evolution doesn't stall due to inconsistent utility technology roadmaps.
- MPUC capacity: Agency staffing and resources to review tariffs, long-term agreements, and conduct ongoing oversight are critical for implementation and should be planned for now.

- A defined rulemaking timeline: MPUC should commit to a clear schedule for finalizing Part 1 and Part 2 tariffs, so the program isn't delayed by procedural uncertainty.

1. What additional aspects of a FTM DER program should be considered?

The program should be designed in a way that could expand to cover BTM resources in the future, even if FTM is the initial focus. Coordination with Efficiency Maine Trust will be essential so FTM dispatch signals don't conflict with BTM demand-response signals, ideally through a shared data platform or a joint dispatch protocol established before either program scales significantly.

We'd also suggest a built-in program review. Given the straw proposal is explicitly designed to evolve as utility planning and technical capabilities mature, DOER should consider a mandatory comprehensive review every three to five years, to revisit price-setting methodology, technology assumptions, and cost allocation, rather than leaving evolution open-ended.