Maine Distributed Generation Successor Program Study

Distributed Generation Stakeholder Group

Workshop #2: Inputs for the Maine BCA Test & Intro to Successor Programs

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Today's Agenda

1. Introduction (5 mins)
2. The Maine Test (45 mins)
   a) Finish discussion of impacts to include in the Maine Test
   b) Discuss methods for developing inputs to the benefit-cost analysis and the rate impact analysis
3. Successor program designs (60 mins)
   a) Goals of discussion
   b) Maine policy context
   c) DG program design elements
   d) Value enhancing strategies
   e) Potential successor program design options
4. Next DG Stakeholder meeting (10 mins)
   a) Next DG stakeholder meeting on October 7
   b) Homework assignment for the next meeting

The Maine Test

Maine Test: Results from homework assignment

Type of Impact	Impact	# Yes Votes	Stakeholders in Favor	# No Votes	Stakeholders Opposed
Utility System	All	all	NSPM	0	
Participant	Participant impacts	5	UMaine, BCC/CEI, CMP, NLE, CLF	0	
Other fuels	Other fuels	*Not relevant for the technologies in this study*			
Low-income	Low-income	6	UMaine, BCC/CEI, CMP, MMA, NLE, CLF	0	
Societal	GHG emissions	5	UMaine, BCC/CEI, CMP, NLE, CLF	0	
	Other environmental	5	UMaine, BCC/CEI, CMP, NLE, CLF	0	
	Macroeconomic	4	UMaine, BCC/CEI, NLE, CLF	0	
	Energy security	5	UMaine, BCC/CEI, CMP, NLE, CLF	0	
	Energy equity	5	UMaine, BCC/CEI, CMP, NLE, CLF	0	
	Resilience	5	UMaine, BCC/CEI, CMP, NLE, CLF	0	

Total parties responding to date: 6

Maine Test: Additional Stakeholder Input

- Verbal comments from parties who did not provide a response to the homework assignment.
- Additional comments from those who did.
- Remaining items to discuss?

Methods: utility system impacts

Type of Impact	Impact	Method
Generation	Energy	AESC 2021
	Capacity	AESC 2021
	Environmental Compliance	AESC 2021
	RPS Compliance Costs	AESC 2021
	Market Price Effects	AESC 2021
Transmission	Transmission	AESC add-on analysis for Maine
Distribution	Distribution	AESC add-on analysis for Maine
General	Renewable Energy Credit Prices	Sustainable Energy Advantage (SEA)
	Utility Portion of DG Costs	Based on program design and total cost from SEA
	Utility Portion of Storage Costs	Based on program design and total cost from SEA
	Program Administration	With input from Maine utilities
	Utility Performance Incentives	There are no performance incentives for DG
	Credit and Collection	This impact is too small to quantify for this purpose.
	Risk, Reliability, Resilience	Address qualitatively

Methods: non-utility system impacts

Type of Impact	Impact	Method
Participant	Participant Share of DG Cost	Based on program design and total cost of DG from SEA
	Participant Benefits	Address qualitatively
Other fuels	Other fuels	Not relevant for the DG technologies assumed in this study
Low-income	Low-income	Address qualitatively & address in program design
Societal	GHG emissions	AESC & Efficiency Maine assumptions
	Other environmental	SO2 & NOx from AESC 2021, other impacts addressed qualitatively
	Macroeconomic	IMPLAN analysis. Results presented in job-years.
	Energy security	Address qualitatively
	Energy equity	Address qualitatively
	Resilience	Address qualitatively

Avoided Energy Supply Components in New England (AESC)

Study of avoided costs in New England

- Prepared roughly every three years since 2003. Latest was in 2021.
- Overseen and vetted by a Study Group of 30 members.
  - 12 New England energy efficiency program administrators, including Efficiency Maine.
  - 18 additional members, including commissions, energy offices, and consumer advocates, including the Maine PUC.
- Prepared by team of independent contractors.
  - Synapse and SEA have prepared many of them, including the 2021 version.

Outputs

- Contains cost streams of marginal energy costs that can be avoided in future years due to reductions in the use of electricity, natural gas, and other fuels.
- Energy and capacity market price forecasts for specific to ISO-NE zones.
- Values for some societal impacts, such as greenhouse gases.
- Can be used for program-based energy efficiency or other demand-side resources across all six New England states.

AESC 2021 – Sensitivity for a DG Study

The primary scenarios assume historical levels of climate policies

- Several additional sensitivities were run to reflect different policies

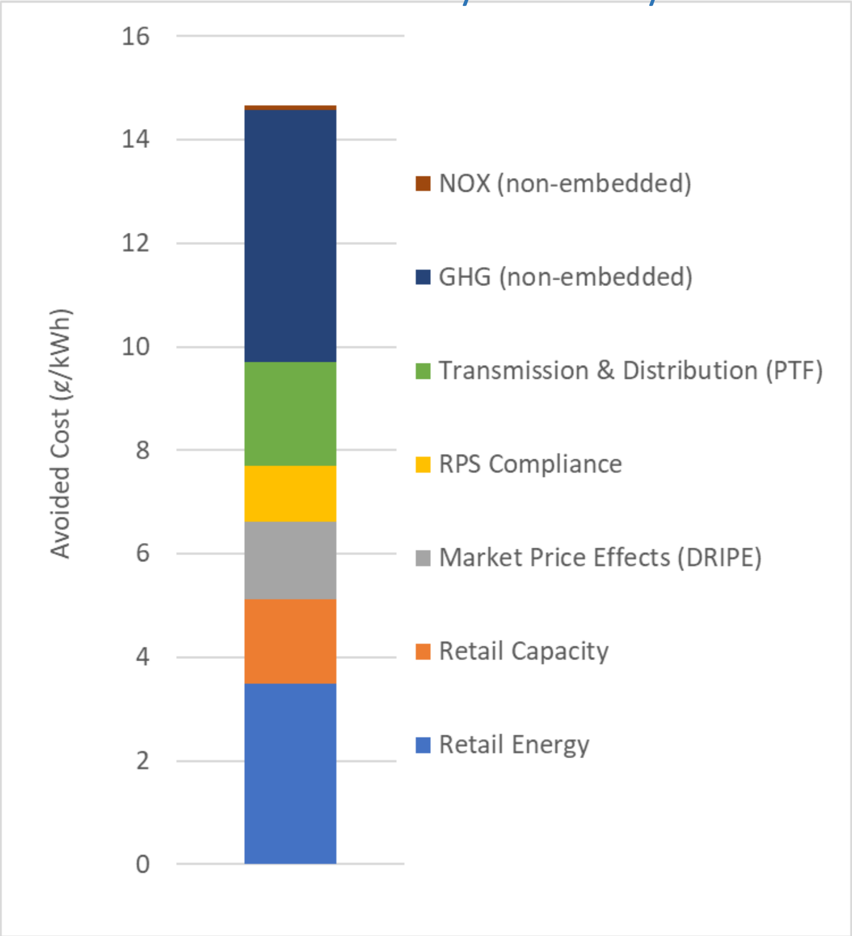
All-In Climate Policy Sensitivity

- Projection of a future with ambitious climate policies throughout New England
- Assumes energy efficiency plus increased levels of electrification & clean energy
- Appropriate for modeling clean energy programs

Notes to chart:

- Non-embedded refers to the environmental impacts that are not included in costs or rates.
- PTF = Pool Transmission Facilities.
- RPS = Renewable Portfolio Standard.
- DRIPE = demand reduction induced price effects.
- Retail capacity = retail price of ISO-NE capacity market.
- Retail energy = retail price of ISO-NE energy market.

Summary of Avoided Costs from All-In Climate Policy Sensitivity.



Actual impacts for DG in Maine will vary from these due to operating hours and location.

BCA Modeling Assumptions

Utilities

- We will model CMP & Versant together, to provide average results
- Results will be generally applicable to each utility

Study period

- DG to be installed during 2024-2028
- Study period to include 25 years (DG operating life) after 2028

Discount rate

- Use the same rate as Efficiency Maine: 2.8%
- The current yield of 10-year U.S. Treasury securities, plus two hundred basis points, adjusted for inflation. (Code of Maine Rules 95-648)

Avoided costs for DG operation

- Use hourly avoided costs from AESC 2021, grouped into logical periods:
- Winter, summer; on-peak and off-peak for each

AESC 2021 Case

- All-In Climate Policy Sensitivity
- Assumes energy efficiency plus increased levels of electrification & clean energy

Rate impact modeling assumptions

Utilities

- We will model CMP & Versant together, to provide average results
- Results will be generally applicable to each utility

Customer types

- We will model all customer types combined, to provide average results
- Results will provide sufficient information on direction and magnitude

Load forecast

- ISO-NE CELT Report?
- Synapse load forecast for Maine Climate Council?

Electricity rate forecasts

- Start with current rates
- Generation rates increase commensurate with AESC market price forecasts
- Transmission, distribution, riders, etc., increase at 1% real each year

Successor Program Design Options

Goal of Discussion

- Provide common understanding of policy options, enabling DGSG members to provide feedback on Successor Program design
  - Understand what mainly does (and does not) drive program cost (and/or affect cost effectiveness)
  - Define context → how does the Successor Program fit into the larger renewable energy policy context?
  - Define and describe primary policy options → what primary design options are available? What specific design elements may be varied? How do these options impact modeling?
  - Describe and define value-enhancing strategies
  - Provide an example of a continuum of options for successor design (ranging from most to least costly)
- Introduce homework assignment – soliciting input on Successor Program Design

The Big Picture:
What Really Drives Cost and Value?

How We Recommend Modeling/Designing DG/DER Program Options

- We (at SEA) have done this quite a few times (including but certainly not limited to):
  - Support to MA DOER directly leading to **MA SREC II and MA SMART** development
  - Support to NJ BPU directly leading to NJ Transition Incentive
  - Support to NYSERDA that led to policy process for developing **NY-Sun**
  - Support to the CT Green Bank in developing the Solar Home Renewable Energy Credit (SHREC) program;
  - And more (including Rhode Island)
- And what we've learned is this:
  - Very few program design elements are inherently determinative of the cost of a program to ratepayers
  - Other than these choices, **there is no single "best" or most effective design element for limiting costs to ratepayers/producing a cost-effective program overall** – e.g., you can just as easily end up with a too-rich competitive procurement just as much as you can have a too-skinny "standard offer"
  - Keeping an open mind can allow stakeholders to "focus on interests, not positions", which can open up avenues to real and lasting consensus

What Elements Are Most Determinative of DG/DER Program Cost?

- The core drivers of DG/DER program cost to ratepayers in organized, restructured markets are:
  - The "attributes" (energy, capacity, RECs and other wholesale market products) conveyed by the DG/DER project owner to the electric distribution company (EDC); and
  - The amount received by the project owner from the EDC in consideration for said attributes (and particularly if that amount is intended to pay **no more than project capital/operating costs plus a market-based return to investors**)
- All factors equal, programs in which fewer attributes are exchanged tend to result in higher costs to ratepayers
  - Fewer attributes exchanged = less certain revenue for project owners, resulting in higher revenue risk (and higher costs of debt and equity) for eligible projects (and fewer opportunities for EDCs to monetize said attributes to the benefit of ratepayers through their sale)
- Conversely, and all factors equal, programs in which more attributes exchanged tend to result in lower costs to ratepayers
  - More attributes exchanged = more certain revenue, resulting in lower revenue risk (and lower costs of debt and equity) and more opportunities for EDCs to monetize attributes to the benefit of ratepayers through their sale

Other than That...

- Other design elements can be designed, limited, expanded, mitigated to achieve overall program goals;
- It is possible to adopt an array of value-enhancing strategies that can either offset intentional choices to increase program costs, or otherwise expand the scale and applicability of program benefits

Program Design Elements

Goals/Design Criteria for Successor Program

Goal	Source	Implication for Successor Design
Optimizes net benefits and ratepayer cost-effectiveness	Interim Report	Successor program should consider and incorporate explicit design elements enhancing ratepayer and societal benefits
Accounts for barriers faced by low-and moderate-income, fixed income and historically marginalized communities	Interim Report	Tangible, direct benefits to said communities should be baked into successor program design (not just indirect "ratepayer savings"/"lower costs")
Achieves program objectives at the lowest cost to ratepayers possible	Interim Report	Successor program should incorporate, where possible, the benefits of competition and competitive pricing, while also ensuring development of viable projects
Targets locations with highest value to grid, informed by information from a more holistic grid planning approach	Interim Report, LD 936	Successor program should rely on value-enhancing approaches that send clear price or non-price signals to disincentivize siting in areas that suboptimize the transmission and distribution systems
Considers all types of DG, including those paired with storage, and maximizes the value of storage deployments	Interim Report, LD 936	Successor design should explicitly account for revenue requirements and optimal deployment of energy storage projects across multiple proven use cases
Supports development of DG by "small companies" based in Maine	LD 936	Successor should provide stable and predictable program that supports entrepreneurial development
Determining appropriate duration for long-term contracts	LD 936	Successor program should convey value in such a way that minimizes cost, but also provides clear incentives to operate beyond contract/tariff term and until end of the project's useful life
Prioritizes siting on previously impacted land, in areas to directly serve customer load and in areas to serve load within LMI communities, or to optimize grid performance or serve a non-wires alternative function	LD 936	Successor program should, through design, account for key public policy goals listed here, and provide direct benefits that are calculated to achieve said public policy goals

Note on Following Slides

- List of design elements, options, modeling implications, etc. are not exhaustive; focus on most critical policy decisions, and those decisions with meaningful implications for modeling
- Many design elements are interrelated – selecting one option (e.g. compensation mechanism = net energy billing) may have implications for other options (e.g., counterparty is not electric distribution company) - interrelatedness critical when designing overall policy, but complexity not addressed in slides below
- Listed options may have additional considerations (e.g., a net energy billing program must have rules on how credits may or may not be carried forward) that are not addressed below

Primary Design Elements and Options

Compensation mechanism:	• Net metering/billing • Buy all, sell all
Attribute offtaker	• EDC • Public entity
Purchased attributes	• Energy • Capacity • RECs
Credit offtaker enrollment	• Project owner • EDC • Opt-out enrollment
Price-setting mechanism	• Tied to retail rates • Administratively-set • Competitive
Fixed/variable	• Fixed incentive rate • Variable incentive rate
Project diversity dimensions	• Technology, project size • Siting & interconnection • Customer/credit offtaker type
Project diversity mechanism	• Carve-out • Differentiated incentive level
Storage incentive type	• Up-front • Performance-based • RE production incentive adder
Storage dispatch strategy	• Defined periods • Event-based • EDC control
Contract/tariff term	• 10 years • 15 years • 20 years
Other elements	• Incentive access requirements • Project size • Treatment of credits

Design Element: Compensation Mechanism (1)

- Description: mechanism used to incent DG development
- Primary options:
  - **Net energy metering/volumetric** – owner can self-consume; excess production credited as *kWh* for use in future periods or allocated to other bills
  - **Net energy billing/monetary** (distinct from name of current program) – owner can self-consume; excess production credited as *$* for use in future periods or allocated to other bills
  - **Buy all, sell all** – all output sold to offtaker; does not necessarily interact with customer bill (e.g. Rhode Island REG program)
  - **Combination –** owner receives and may distribute certain bill credits tied to retail rates (in exchange for a fee), PLUS additional incentive (either fixed or floating to achieve target total incentive rate) for purchase of RECs (e.g., MA SMART)
- Important to note:
  - While NEB is a <u>variant</u> of the first two options, both concepts could be applied differently as well
  - Therefore, including them as design options =/= continuing the current NEB programs

Design Element: Compensation Mechanism (2)

- Primary Modeling Implications:
  - Bill credits (including "net credits" from adopting consolidated billing) are a clear, established and relatively simple means of ease of conveying value to participating customers (including low income customers)
  - On one hand, net energy billing and net energy metering unequivocally result in net lost EDC revenue, which can lead to the shifting of certain costs if left unmitigated
    - **Note:** net lost revenue is not equivalent to pass-through of added resource cost. Functionally, even if a program resulted in no net lost revenue, purchasing DG/DER resources can (and often does) result in higher costs passed on overall (which has implications for benefit-cost analysis)
  - On the other hand, such cost shifts and net lost revenue can be mitigated to a point of indifference by:
    - Providing significant benefits to low-income customers
    - Utilizing monetary rather than volumetric credits
    - Limiting the sizing of projects or shares of projects to customer load, and/or
    - Designing or implementing alternative bill credits

- Useful references:
  - https://www.nrel.gov/state-local-tribal/blog/posts/back-to-basics-unraveling-how-distributed-generation-is-compensated-and-why-its-important.html

Design Element: Attribute Offtaker

- Description: entity purchasing project attributes (types of potential attributes described on next slide)
- Primary options:
  - Electric distribution company (EDC) (tariff or contract)
  - State of Maine
  - Other third-party offtaker
- Primary modeling implication:
  - Offtaker creditworthiness affects project cost of capital
- Alignment with established priorities:
  - More creditworthy offtakers lower risk to project owners (and their investors), thereby lowering project revenue requirements
- Useful references:
  - https://www.nrel.gov/docs/fy20osti/76881.pdf

Design Element: Purchased Attributes (1)

- Description: incentive program must define which attributes associated with project production are purchased by the offtaker, and which are retained by project owner

- Primary attributes:
  - **Energy** – value of energy, and right to sell into wholesale markets
  - **Capacity –** value of capacity, and right to sell into wholesale markets
  - **RECs –** environmental attributes – right to sell to other entities, or to retain to claim use of "green" electricity

- Modeling implications for program designs with <u>limited</u> attribute transfer to EDCs
  - Though project owners would be able to privately monetize the gains from the sale of attributes, project owners also bear the risk of monetizing these attributes
  - Though EDCs would be able to avoid the financial risks (and administrative costs) associated with monetizing as many attributes, EDCs would also be unable to utilize the gains from the sale of attributes to offset the cost of the program to their ratepayers (particularly during periods in which rates are high)

Design Element: Purchased Attributes (2)

- Modeling implications for program designs with broad attribute transfer to EDCs
  - Though project owners would lose the ability to privately monetize the gains from the sale of attributes, project owners would also incur fewer risks associated with that monetization by selling their attributes to the EDCs (resulting in lower financing costs for eligible resources)
  - Though ratepayers would instead indirectly bear more financial risks (and EDC administrative costs) associated with monetizing the gains from attribute sales on behalf of their ratepayers, the EDCs would gain an enhanced ability to offset the cost of a DG/DER program to their ratepayers (particularly during a period in which rate is high)

- Additional considerations:
  - Requires consideration of whether offtaker monetizes conveyed attributes; e.g., does offtaker (e.g., EDC) sell capacity to offset incentive payment costs?
  - For BTM systems, considerable discussion/debate on whether bidding capacity into forward capacity market or retaining capacity rights as a load reducer produces greater net benefits (studied in design of CT Energy Storage Solutions BTM program). See, for example, pp. 41-42 of PURA Order June 30, 2021 in Docket 20-07-01: https://www.dpuc.state.ct.us/dockcurr.nsf/8e6fc37a54110e3e852576190052b64d/7709a7321f6b16a785258704006181a6?OpenDocument

Design Element: Credit Offtaker Enrollment (1)

- Description: customer purchasing credits produced by project (if applicable – not applicable for buy all, sell all designs)

- Primary options:
  - Customers recruited and enrolled by project owner
  - Customers enrolled by EDC – see, for example, Connecticut SCEF program or NY Solar for All: https://www.nyserda.ny.gov/solar-for-all
  - Customers enrolled on an opt-out basis - see, for example, New York opt-out Community Distributed Generation proposal: https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7bE47A5326-9969-4E1F-9914-CB5666B53AFA%7d

- Primary modeling implication:
  - Recruiting offtakers, managing billing processes, etc. represent significant administrative costs

Design Element: Credit Offtaker Enrollment (2)

- Alignment with established priorities:
  - When project owners are required to recruit credit offtakers, they may include credit score requirements to minimize defaults, which can result in less access for lower income customers
- Additional considerations:
  - An additional important consideration is how project owners are paid for credits by credit offtakers; possibility for EDC to offer consolidated billing, reducing administrative burden
  - EDC enrollment could be on an opt-in or opt-out basis
- Useful references:
  - https://www.nrel.gov/docs/fy20osti/76881.pdf

Design Element: Price-Setting Mechanism (1)

- Description: mechanism used to establish initial incentive rate or price cap

- Primary options:
  - **Competitive solicitation –** program administrator holds solicitation to establish clearing price. May be based on clearing price (all resources paid the same, based on marginal bid) or bid price (each winning resource is paid the price it bid).
    - Examples: CT NRES, RI Renewable Energy Growth >25 kW projects
  - **Hybrid of Competitive Solicitation/Administratively-Set Price –** price initially set through competitive solicitation; prices adjusted subsequently at pre-determined rate (e.g. declining/adjustable block incentive).
    - Example: MA SMART

Design Element: Price-Setting Mechanism (2)

- Additional considerations:
  - For administratively-set incentives, how will pricing for future rounds/tranches be established? Defined trajectory? Updates based on updated revenue requirement estimates?
- Primary modeling implication:
  - In theory, competitive and administratively-set approaches should result in comparable payment rate, so they will not be distinct in our modeling
  - If future pricing is pegged to initial price (e.g., set reductions from initial price based on achieving MW deployment levels), it may result in more predictable program cost, **but may also yield payments that are higher than necessary or too low to stimulate development if there are large changes to underlying revenue requirements (e.g., change to investment tax credit or increases in capital cost observed since start of COVID-19 pandemic)**

Declining Block Incentive Example: MA SMART

- Defined MW blocks, by EDC, by project size
- Initial incentive levels based on competitive solicitation, scaled for different project size classes
- Prices decline according to defined trajectory as MW thresholds (blocks) are reached

Summary of Behind-the-Meter Base Compensation Rates by Service Territory, Generation Unit Capacity, and Capacity Block[9]

Electric Distribution Company	Generation Unit Capacity	Base Compensation Rate Factor	erm Lengt	Block 1	Block 2	Block 3	Block 4	Block 5	Block 6	Block 7	Block 8	Block 9	Block 10	Block 11	Block 12	Block 13	Block 14	Block 15	Block 16
Massachusetts Electric d/b/a National Grid[3]	Low income less than or equal to 25 kW AC	230%	10-year	$0.35795	$0.34363	$0.32989	$0.31669	$0.30402	$0.29186	$0.28019	$0.26898	$0.26360	$0.25833	$0.25316	$0.24810	$0.24314	$0.23827	$0.23351	$0.22884
	Less than or equal to 25 kW AC	200%	10-year	$0.31126	$0.29881	$0.28686	$0.27538	$0.26437	$0.25379	$0.24364	$0.23390	$0.22922	$0.22463	$0.22014	$0.21574	$0.21142	$0.20719	$0.20305	$0.19899
	Greater than 25 kW AC to 250 kW AC	150%	20-year	$0.23345	$0.22411	$0.21514	$0.20654	$0.19828	$0.19034	$0.18273	$0.17542	$0.17191	$0.16847	$0.16511	$0.16180	$0.15857	$0.15540	$0.15229	$0.14924
	Greater than 250 kW AC to 500 kW AC	125%	20-year	$0.19454	$0.18676	$0.17929	$0.17211	$0.16523	$0.15862	$0.15228	$0.14618	$0.14326	$0.14040	$0.13759	$0.13484	$0.13214	$0.12950	$0.12691	$0.12437
	Greater than 500 kW AC to 1,000 kW AC	110%	20-year	$0.17119	$0.16435	$0.15777	$0.15146	$0.14540	$0.13959	$0.13400	$0.12864	$0.12607	$0.12355	$0.12108	$0.11866	$0.11628	$0.11396	$0.11168	$0.10944
	Greater than 1,000 kW AC to 5,000 kW AC	100%	20-year	$0.15563	$0.14940	$0.14343	$0.13769	$0.13218	$0.12690	$0.12182	$0.11695	$0.11461	$0.11232	$0.11007	$0.10787	$0.10571	$0.10360	$0.10153	$0.09949
Eversource East d/b/a Eversource Energy[6,8]	Low income less than or equal to 25 kW AC	230%	10-year	$0.39100	$0.37536	$0.36035	$0.34593	$0.33209	$0.31881	$0.30606	$0.29382	$0.28794	$0.28218	$0.27654	$0.27101	$0.26559	$0.26027	$0.25507	$0.24997
	Less than or equal to 25 kW AC	200%	10-year	$0.34000	$0.32640	$0.31334	$0.30081	$0.28878	$0.27723	$0.26614	$0.25549	$0.25038	$0.24537	$0.24047	$0.23566	$0.23094	$0.22633	$0.22180	$0.21736
	Greater than 25 kW AC to 250 kW AC	150%	20-year	$0.25500	$0.24480	$0.23501	$0.22561	$0.21658	$0.20792	$0.19960	$0.19162	$0.18779	$0.18403	$0.18035	$0.17674	$0.17321	$0.16974	$0.16635	$0.16302
	Greater than 250 kW AC to 500 kW AC	125%	20-year	$0.21250	$0.20400	$0.19584	$0.18801	$0.18049	$0.17327	$0.16634	$0.15968	$0.15649	$0.15336	$0.15029	$0.14729	$0.14434	$0.14145	$0.13862	$0.13585
	Greater than 500 kW AC to 1,000 kW AC	110%	20-year	$0.18700	$0.17952	$0.17234	$0.16545	$0.15883	$0.15247	$0.14638	$0.14052	$0.13771	$0.13496	$0.13226	$0.12961	$0.12702	$0.12448	$0.12199	$0.11955
	Greater than 1,000 kW AC to 5,000 kW AC	100%	20-year	$0.17000	$0.16320	$0.15667	$0.15041	$0.14439	$0.13861	$0.13307	$0.12775	$0.12519	$0.12269	$0.12023	$0.11783	$0.11547	$0.11316	$0.11090	$0.10868
Eversource West d/b/a Eversource Energy[7,8]	Low income less than or equal to 25 kW AC	230%	10-year	$0.32862	$0.31548	$0.30286	$0.29075	$0.27912	$0.26795	$0.25723	$0.24694	$0.24200	$0.23716	$0.23242	$0.22777	$0.22322	$0.21875	$0.21438	$0.21009
	Less than or equal to 25 kW AC	200%	10-year	$0.28576	$0.27433	$0.26336	$0.25282	$0.24271	$0.23300	$0.22368	$0.21473	$0.21044	$0.20623	$0.20211	$0.19806	$0.19410	$0.19022	$0.18642	$0.18269
	Greater than 25 kW AC to 250 kW AC	150%	20-year	$0.21432	$0.20575	$0.19752	$0.18962	$0.18203	$0.17475	$0.16776	$0.16105	$0.15783	$0.15467	$0.15158	$0.14855	$0.14558	$0.14267	$0.13981	$0.13702
	Greater than 250 kW AC to 500 kW AC	125%	20-year	$0.17860	$0.17146	$0.16460	$0.15801	$0.15169	$0.14563	$0.13980	$0.13421	$0.13152	$0.12889	$0.12632	$0.12379	$0.12131	$0.11889	$0.11651	$0.11418
	Greater than 500 kW AC to 1,000 kW AC	110%	20-year	$0.15717	$0.15088	$0.14485	$0.13905	$0.13349	$0.12815	$0.12302	$0.11810	$0.11574	$0.11343	$0.11116	$0.10893	$0.10676	$0.10462	$0.10253	$0.10048
	Greater than 1,000 kW AC to 5,000 kW AC	100%	20-year	$0.14288	$0.13716	$0.13168	$0.12641	$0.12135	$0.11650	$0.11184	$0.10737	$0.10522	$0.10312	$0.10105	$0.09903	$0.09705	$0.09511	$0.09321	$0.09134

Design Element: Fixed/Variable Payments

- Description: incentive rate remains fixed at initial level or varies over time
- Primary options:
  - **Fixed rate –** rate is fixed over the incentive term
  - **Variable rate –** rate varies over the incentive term; often, this is because incentive is based on retail rates or another relevant index
- Primary modeling implications:
  - Fixed rates will generally reduce project risk, lowering cost of capital
  - Fixed (or otherwise known and fully predictable) rates provide a hedge – if energy prices increase, ratepayers benefit; if they decrease, negative impact on ratepayers/rates
- Alignment with established priorities:
  - Overall, fixed rates reduce cost to ratepayers (relative to continuation of NEB business as usual) though they transfer some risks (i.e., risk of increased costs from energy price reductions) to ratepayers

Design Element: Capacity Allocation to Eligible Projects (1)

- Description: approach to establishing available MW and, if applicable, changes when MW thresholds are reached (tranches)

- Primary options:
  - **Time-based**– defined MW available per year or per solicitation (e.g., CT NRES)
  - **MW tranches –** available MW organized into tranches with adjustments to price as MW thresholds are achieved (a declining block incentive or DBI)
  - **No defined limit** – no specific MW limit defined, or defined for program as a whole, regardless of time

Design Element: Capacity Allocation to Eligible Projects (2)

- Primary modeling implications:
  - Outcomes highly dependent upon future market development
  - While modeling can be conducted to demonstrate potential differences, hard to anticipate future developments that would drive differences
  - Example: future with higher than anticipated capital cost reductions would lead to faster deployment using MW tranches
- Alignment with established priorities:
  - Time-based approach, with incentive setting mechanism that is tied to contemporaneous revenue requirements, allows for greater control of pace of deployment
  - Tranche-based approach provides for greater flexibility, allowing resources to be deployed more quickly in response to conditions favorable to resource deployment

Design Element: Project Diversity Mechanisms (1)

- Description: mechanisms for promoting the inclusion of multiple project types. Project characteristics that may be incentivized could include:
  - Technology
  - Project size
  - Siting characteristics
  - Interconnection characteristics
  - BTM vs. IFOM
  - Customer/offtaker type (e.g., LMI, public entity, environmental justice community)
- Primary options:
  - **Carve-outs –** setting aside portion of MW goal to specific technologies
  - **Differentiated incentive levels –** providing higher incentive levels to project types that are more expensive or provide greater benefits (examples include adders (e.g., MA SMART) or bid preferences (e.g., CT NRES/SCEF))
  - **Combination of the above**

Design Element: Project Diversity Mechanisms (2)

- Primary modeling implications:
  - All factors equal, project diversity mechanisms will increase program incentive costs
  - However, **with passage of the Inflation Reduction Act (IRA), project owners can benefit from certain bonus credits** (e.g. for low income/disadvantaged communities and projects on brownfields/in energy communities that are i**n excess of their incremental project costs** relative to greenfield ground-mounted projects
  - Without project diversity mechanisms (particularly without at least a carve-out), **there is a strong possibility our modeling will produce a more homogeneous set of projects (e.g., largest eligible solar developed on cleared land)** that do not necessarily meet public policy objectives.
  - Such an outcome may be lowest cost, **but selected projects can and will get harder to develop and reach commercial operation, given greater siting scrutiny and grid saturation**

- Alignment with established priorities:
  - **Certain project types may provide incremental public policy value** (e.g., increased resilience from renewables co-located with load or protection of open spaces from siting renewables on disturbed plots)

Design Element: Storage Dispatch/Revenue (1)

- Description: incentives for pairing storage with DG may be designed numerous ways; design of incentive generally tied to obligations with regard to storage dispatch
- Primary options:
  - **Incentive design (may be combined):**
    - Up front incentive (may be tied to dispatch requirements). Example: CT ESS program
    - Performance-based incentive – payment based on discharging during specified periods. Example: ConnectedSolutions
    - RE incentive adder – incentive tied to production from paired RE system (may be tied to dispatch requirements). Example: MA SMART ESS adder
  - **Storage dispatch strategy (may be combined):**
    - Defined periods – regular discharge required or incentivized during defined periods. Example: MA Clean Peak Standard
    - Event-based dispatch – discharge required or incentivized in response to events called by program administrator, often with notification the night before. Example: ConnectedSolutions.
    - EDC control – EDC retains full control of battery (owner may use during outages). Sometimes called tolling agreement. Some similarities to NWA. Example: Green Mountain Power BYOD storage program

Design Element: Storage Dispatch/Revenue (2)

- Primary modeling implications:
  - **Benefits of performance-based incentive easier to model**, as incentive only paid for specified battery dispatch behavior, while **other approaches will likely include some degree of noncompliance** for which resources **may or may not receive compensation**
  - Challenging to quantify benefits of storage to distribution system – l**argely depends on project location and utility treatment of storage in distribution modeling**.
  - Depending on EDCs ability to dispatch storage effectively, **granting EDCs control of storage assets may increase realized distribution benefits, but value would be dependent on specifics of design**

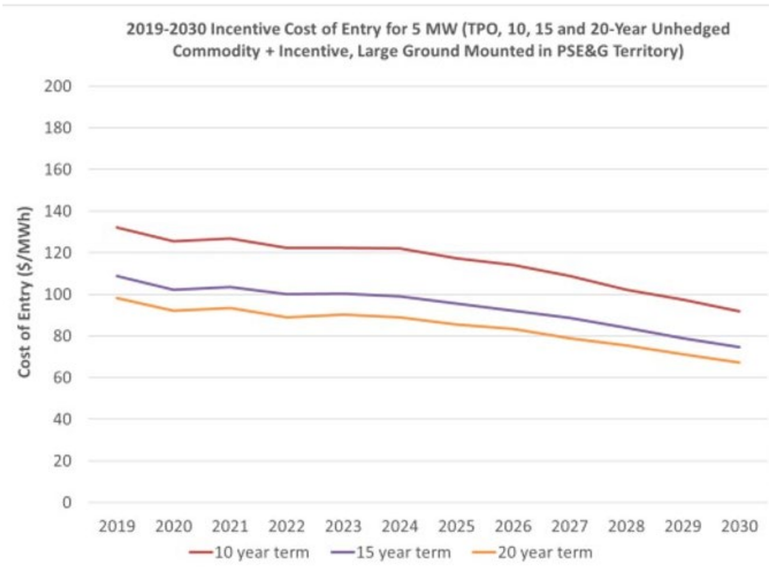
Design Element: Contract/Tariff Term

- Description: term over which incentive is available to project

- Primary options:
  - Depending on technology, project useful life may be 10-25 or more years
  - Incentive terms of 10-20 years most common

- Primary modeling implications:
  - Longer incentive term reduces required incentive rate
  - On the other hand, it increases the period over which incentive must be paid out; lower payments spread over a longer period of time generally tend to yield higher net present value
  - Modeling must consider potential revenues after incentive term

- Alignment with established priorities:
  - Longer terms likely to reduce near-term ratepayer impacts



Source: June 14, 2019 SEA, Cadmus presentation to NJ Solar Transition Stakeholder Group https://njcleanenergy.com/files/file/JuneSolarTransitionSlides.pdf

Other Design Elements

- *Incentive access requirements, queueing*: what development milestones are required for a project to bid on a solicitation or secure incentive eligibility
- *Treatment of credits*: if applicable, ability to roll forward or cash out credits; *note – this is an important input for modeling*
- *Eligible project size range*

Value Enhancing Strategies

Value-Enhancing Strategies

- Value-enhancing are distinct from design elements listed above in that they may impact successor program, but they can be implemented independently (and may have implications for other policies)
- Note that following strategies drawn primarily from LD 936

Value-Enhancing Strategy: TOU Rates

- Time-of-use (TOU or sometimes time-varying rates – TVR) encourage energy usage during periods of lower demand
- Customer TOU rates have been a recent and ongoing subject of regulatory proceedings
- TOU rates can be applied to DER programs as well, incentivizing resources that produce energy during more valuable periods, and encouraging dispatchable resources to be dispatched during valuable periods
- Considerations:
  - For future programs – is compensation based on TOU rates?
  - Is the design of TOU rates intended for load, appropriate for compensation for DG?

Value-Enhancing Strategy: Finance Policies

Selected finance enabling policies included in Maine Distributed Solar Valuation Study

Policy/Program	Description	Relevant to NEB Successor?
Loan program	Many different models (subsidized, un-subsidized, different capital sources, etc.), but intent is to lower cost of capital	Possible, although capital market for 2-5 MW projects well established; no (or fewer) equity concerns relative to residential market
PACE financing	Financing secured by lien on property, allowing debt to remain with property	Unlikely; more applicable to BTM applications
On-bill financing	Repayment of loan through utility bills	Unlikely; more applicable to residential/small business
Green banks	Public or quasi-public institutions offering a variety of programs and financing to benefit clean energy	Possible; depends on specific program adopted. Green Bank programs can adapt to market needs. Could provide project financing, programs to support new businesses supporting supply chain, etc.
Third-party ownership	Ownership of resource by entity that may not be the host or recipient of credits	Yes, to the extent that the policy would place limitations on ownership structure/options

Value-Enhancing Strategy: Interconnection Cost Allocation

- As is true throughout the region, interconnection cost and timeline have become critical project barriers in Maine
- Traditional approach allocates 100% of upgrade costs to cost causer (resource triggering the need); group studies generally result in some level of sharing
- Some jurisdictions (MA – 20-75, NY – 20-E-0543) have adopted approaches that allocate costs on a pro-rata basis, including, in some instances, socializing upgrade costs across customer base, with interconnecting DG projects paying their pro-rata share of enabled DG as they interconnect
- MA also proposed having distribution customers pay for some portion of upgrade costs (without a plan to be reimbursed by interconnecting DG), using a rationale that upgrades may benefit load as well as DG
- These approaches may help:
  - Produce a more equitable outcome for interconnecting DG
  - Manage interconnection costs
  - Provide more predictable/transparent interconnection costs
- All of the above could be considered in the context of aligning DG deployment with other policy objectives

Other value enhancing strategies

- Alternative interconnection limit approaches
  - Dynamic/flexible interconnection limits – resources can be curtailed in real time based on system conditions: https://www.nrel.gov/docs/fy19osti/72102.pdf
  - Operating envelope agreements – establish a schedule laying out export limits at different times: https://eta-publications.lbl.gov/sites/default/files/81960.pdf
- Treatment of resources as load reducers or generation
  - As discussed in Case 2021-00128, treatment of tariff rate NEB facilities as either load reducers or generation may yield different impacts on other customers within the given EDC territory

Putting It All Together:

Example Successor Programs For Evaluation/Modeling

Example NEB Successor Program Designs For Evaluation/Modeling Purposes (1)

Policy Option	Option 1	Option 2	Option 3	Option 4
Project Size Range	1-5 MW	1-5 MW	1-5 MW	1-5 MW
Attribute Offtaker	EDC	EDC	EDC	EDC
Attributes Monetized on Behalf of Ratepayers	Energy	Energy + RECs	Energy + Capacity + RECs + all other market products	Energy + Capacity + RECs + all other market products
Cost/Risk to Ratepayers	Higher cost and risk (fewer attributes monetized on ratepayers' behalf)	Moderate cost/risk (add'l value from REC resales offsets program cost, esp. if prices rise)	Lower cost/risk (add'l value from REC resales offsets program cost, esp. if prices rise)	Same as Option 3
Cost/Risk to Project Owners	Higher cost and risk (fewer certain revenue streams & higher financing costs)	Moderate cost and risk (add'l certain REC revenue = reduced financing costs)	Moderate cost and risk (Certain revenue for all attributes = lowest relative financing costs)	Same as Option 3
Fixed/Variable Payment to Project Owners	Could be fixed or variable, but note that fixed values reduce risk/enhance financeability under any of the above options			
Customer/Credit Offtaker(s) and Enrollment	EDC customers	EDC customers	EDC customers (with some or all customers enrolled by EDC)	None (EDC is sole offtaker)
Capacity Allocation for Eligible Projects	No defined limit (functionally, project capacity is first come, first served)	Possible to utilize annual capacity allocations, potentially with prices determined annually or set by clearing/as-bid price, or to use capacity tranches that adjust downwards (or upwards, if need be to respond to market conditions) with successive blocks.		More likely than not to be a competitive procurement, but could also be administratively-set
Compensation Mechanism	Mix of volumetric (residential accounts) and monetary (C&I accounts) crediting	Monetary crediting or volumetric crediting (in general, cost to ratepayers tends to be most sensitive to cash-out and carry-forward terms)		Payment made directly to project owner; no bill credits

DISCLAIMER: It is unclear at this time if Option #4 is compliant with LD 936's requirement for the DGSG's evaluation of different program types that any eligible "distributed generation project" have "identified residential, commercial and institutional customers"

Example NEB Successor Program Designs For Evaluation/Modeling Purposes (2)

Policy Type	*#1: Shared Financial Interest – Highest Cost/ Highest Project Owner & Ratepayer Risk*	*#2: Shared Financial Interest – Moderate Cost/Moderate Project Owner & Ratepayer Risk*	*#3: Shared Financial Interest – Lowest Cost/Lowest Developer/Ratepayer Risk*	*#4: Qualifying Facility – Lowest Cost/ Lowest Developer/ Ratepayer Risk*
Program Price-Setting Mechanism	None (price and escalation rate set by policy, prices for attributes set in open markets for said attributes)	Administratively-set price (or competitive procurement) for RECs	Administratively-set price (or competitive procurement) for RECs, Capacity and other market products	Administratively-set price (or competitive procurement) for RECs, Capacity (via FCM) and other market products
Project Diversity Approach	None (no specific carve-outs or differentiated incentive levels)	Carve-outs, adders or bid preferences for (e.g.): • On-site/BTM projects • Projects on carports/disturbed parcels of land • Projects claiming bonus ITC and CEIC values under Inflation Reduction Act (including "energy communities", serving/sited in low income/disadvantaged communities, etc.)		Single, undifferentiated procurement or standard offer class (no carve-outs, adders or bid preferences)
Tariff/Contract Term	20 years (BAU)	10, 15 or 20 years (shorter durations tend to have lower cost NPVs, but can raise complex questions around post-tariff revenue or continued project operation)		
Storage Dispatch/ Revenue	Defined period for dispatch (or event-based), choice is contingent on technical design	• *Dispatch:* Defined period for dispatch, event-based or EDC controlled, choice is contingent on technical design (in other words, "it depends") • *Revenue:* Also contingent on design		

DISCLAIMER: It is unclear at this time if Option #4 is compliant with LD 936's requirement for the DGSG's evaluation of different program types that any eligible "distributed generation project" have "identified residential, commercial and institutional customers"

Next Steps

Next DG Stakeholder Meeting

Target date

- October 7

Agenda for next meeting

- Finish successor program designs
- TBD

Homework assignment:

- Respond to prompt related to program design preferences – consultant team will distribute. For each design element described (or those you wish to weigh in on), please select which option you prefer, and provide a brief explanation why

Acronyms

Avoided Energy Supply Cost (AESC)

Benefit-cost analysis (BCA)

Bright Community Capital (BCC)

Central Maine Power (CMP)

Distributed energy resources (DERs)

Distributed generation (DG)

Maine Municipal Association (MMA)

National Standard Practice Manual (NSPM)

Non-energy impacts (NEIs)

Non-wires alternative (NWA)

Sustainable Energy Advantage (SEA)

University of Maine (UMaine)