Draft Second Revised Long-Term Plan
Appendix C

Distributed Generation Solar and Community Solar Incentive Pricing Whitepaper

prepared for Illinois Power Agency

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Review of Distributed Generation Solar and Community Solar Incentive Pricing Programs in Other States

The review of the other state programs discussed here is focused on the structure, methodology and applicability of alternative approaches to determining pricing incentives to support the development of distributed generation (DG) solar and community solar (CS) projects. The goal is to provide information that could enhance value proposition of the IPA's Adjustable Block Program (ABP). The results of this review can provide a basis for discussions regarding the IPA's path forward to support the development of DG solar and CS projects.

Administrative Approach

The administrative approach to setting DG and CS incentives generally involves prices set by a state administrative or regulatory agency or a utility under the direction of a regulator. In some cases, the pricing incentives may be defined in the renewable energy enabling legislation. Typically, a modeling system such as the National Renewable Energy Laboratory (NREL) Cost of Renewable Energy Spreadsheet Tool (CREST) or System Advisor Model (SAM) is utilized to estimate the appropriate price to be paid for energy, capacity or RECs produced by DG or CS projects. These are cost-based cash flow modeling approaches that can determine the additional revenue required by a project in terms of higher electricity prices or higher REC prices that will enable the project to be economically viable. In this context, RECs provide the additional revenue stream needed to cover the difference between a project's revenues and tax incentives and the cost of building and operating the project. Based on the modeling inputs and assumptions, along with adjustments that usually reflect policy goals, the results can provide a range of pricing incentives that can be used by the solar program administrator to foster the development of DG solar or CS projects.

Setting incentive prices administratively, with or without a modeling framework, allows prices to be more closely aligned with public policy goals and generally provides project developers with a level of financial comfort since administratively set prices tend to be known over the contract period and developers consider projects with fixed price incentives to be easier to finance. Administratively set pricing incentives typically involve considerable input from stakeholders regarding the level of incentives as well as the inputs to modeling. Cost-based modeling provides a means to link program policy goals and the presumed cost of developing projects which should reflect on the economic viability of projects.

The IPA uses a modified version of the CREST model for establishing REC prices. For DG projects considered in the ABP, the Long-Term Renewable Resources Procurement Plan (LTRRPP) established sequential capacity blocks with declining REC prices for each successive block following Block 1. A base REC price was calculated for the 500 kW AC to 2,000 kW AC size category.[1] Subsequently, the prices for the other project capacity categories were set through adjustments that reflect the different economic and operating characteristics associated with projects of different sizes. The adjustments to the base REC price were calculated using the REC pricing model for DG with inputs for the system costs and operating characteristics for a typically sized project within each size category. CS REC prices were established using

[1] The ABP capacity size categories are: 10 kW or less; greater than 10 kW to 25 kW; greater than 25 kW to 100 kW; greater than 100 kW to 200 kW; greater than 200 kW to 500 kW; and greater than 500 kW to 2,000 kW.

the same REC pricing model but using different assumptions and inputs. These assumptions and inputs are focused on the different operating characteristics and economic issues that are associated with CS projects. A more detailed description of the ABP REC pricing model can be found in Appendix D of the Initial Plan.[2] The CREST model provides several advantages for deriving REC prices. These include: the model is publicly available without charge, it has been extensively reviewed by market participants and planning agencies, the model is fully transparent, and it was designed specifically to support cost-based development of incentives for renewable energy including DG solar and CS projects. The model can produce REC prices that are reasonably consistent with market conditions through a continuing process of updating assumptions and data inputs based on the latest information available on costs and market developments.

The key drawbacks to setting incentive prices administratively involve the tendency of administrative prices to become disconnected from market realities which can lead to less efficient and less cost-effective solar energy development. Cost-based modeling results are only as good as the assumptions and cost inputs applied to the model. The ability to structure the model inputs with the appropriate market-based information depends on the availability of data collected from stakeholders regarding the specifics of projects that have been initiated to date, from surveys of market participants regarding costs, equipment performance and market conditions, or through other publicly available data sources that have recently been updated. Stakeholder feedback, while valuable, can be dominated by project developers whose interests are in maximizing the value of project incentives which can lead to model inputs that are biased toward higher costs. The applicability and accuracy of market survey data can be difficult to determine while publicly available data tends to lag changes in market conditions by the time it is compiled and reported.

Setting pricing incentives administratively involves a process of trade-offs among fitting incentives to policy goals, encouraging project development and customer participation, and promoting efficiency and cost effectiveness to the maximum extent possible that is compatible with program policy goals. The administrative approach offers significant flexibility in addressing complications that can develop when specific program goals and performance requirements set by enabling legislation are not entirely compatible with market conditions or each other. Administratively set incentives for the development of DG and CS have been tried in other states with varying degrees of success. These programs continue to evolve as policy goals are modified and the states gain more experience with the development of DG and CS projects. An example of an evolving administrative approach is New Jersey's experience with the SREC Registration Program (SRP) and the subsequent Transition Incentive (TI) program.

New Jersey

The SRP, sometimes referred to as the legacy SREC program, set-up market-based incentives for PV solar facilities. The SREC program was established by the New Jersey Renewable Portfolio Standard rules which were implemented starting with the 2005 energy year (EY). PV systems of any size connected to the distribution system were eligible to participate in the program and receive SRECs. SREC prices were determined based on market trading in public exchanges and capped by the Solar Alternative Compliance Payment (SACP). The SREC legacy program resulted in 3,560 MW of installed solar capacity as of March

[2] https://www2.illinois.gov/sites/ipa/Pages/2018-Long-Term-Renewable-Appendix.aspx

31, 2021.[3] This installed capacity represented 2,815 MW of behind the meter installations, 736 MW of grid connected solar, and since 2019, 9 MW of CS installations.

This development success came at a significant price with traded SREC prices remaining above $200 throughout the SREC legacy program period. The following table shows the cumulative weighted average SREC prices and the SACPs for the EYs of 2016 through March of EY 2021.

Table 1: New Jersey SREC Prices

Energy Year[4]	**Wtd. Avg. SREC Price[5]**	**SACP[6] ($/MWh)**
EY 2021	215.50	248
EY 2020	211.50	258
EY 2019	207.80	268
EY 2018	212.70	308
EY 2017	226.81	315
EY 2016	229.90	323

The total cost to New Jersey ratepayers for SRECs from EY 2005 through EY 2017 amounted to more than $2.2 billion.[7] Throughout the later part of this period representatives of the New Jersey Division of Rate Counsel, which represents the state's ratepayers, raised concerns that the SREC program was not as efficient or cost-effective as it should be and that the program had become too expensive.

New Jersey's Clean Energy Act (CEA) of 2018 which expanded the state's clean energy goals and RPS targets also sought to address the high costs of the legacy SREC program. The CEA directed the New Jersey Board of Public Utilities (BPU or Board) to transition the solar market away from the legacy SREC program to a new approach to incentivizing solar development. The legacy SREC program was to be closed when the total amount of solar generation under the program reached 5.1% of the kWh sold in the state or by June 1, 2021, whichever occurred first. The modification to the RPS required that renewable resources should provide 35% of the electricity sold in the state by 2025 and 50% by 2030. The legislation set a net metering cap of 5.8% of electricity sales and set in motion decreases in the SACP from $300 to $268 in EY 2019 with the decline to continue through 2033 when the SACP will be $128. The CEA also set a cost cap for all Class I RECs (which included SRECs but not ORECs) at 9% of the total paid for electricity by all customers for EY 2019, EY 2020 and EY 2021, then the cap will be 7% for each year after EY 2021. The BPU was also directed to design and implement the Transition Incentive (TI) Program and the long-term Solar Successor Program.

The BPU established the TI Program in December 2019 to bridge the gap between the legacy SREC program and the Solar Successor Program. The legacy SREC program was closed on April 30, 2020, when the 5.1% limit was reached. Solar projects that submitted applications after October 29, 2018, which had not reached commercial operation by April 30, 2020, were shifted to the TI program. The base Transition REC (TREC) value was set by the BPU at $152/MWh based on extensive modeling of various scenarios

[3] NJBPU Clean Energy Program, https://njcleanenergy.com/renewable-energy/project-activity-reports
[4] The EY runs from June 1st through May 31st
[5] SREC prices as reported on the New Jersey Clean Energy Program website www.njcleanenergy.com.
[6] From SRECtrade website www.srectrade.com/markets/rps/srec/new_jersey
[7] Stefanie A. Brand, Director, New Jersey Division of Rate Counsel comments before the New Jersey Board of Public Utilities on New Jersey's Solar Market Transition, November 2, 2018.

using the SAM system.[8] The base TREC value is adjusted to provide differing incentives depending on the solar technology and size of the solar project. TREC Factors are designed to provide incentives based on the expected costs and revenues associated with different types of solar projects giving projects with the largest expected gap between project costs and revenues higher incentives. The goal of using these factors is to be sure that ratepayers are not providing anymore in the way of incentives than are necessary to encourage solar development. The following table shows the TREC prices, which are fixed over the 15-year qualifying life of a project, and the TREC factors used to determine the applicable TREC price.[9]

Table 2: New Jersey TREC Prices

Solar Project Type	TREC Factor	Effective TREC Price
Landfill, brownfield, areas of historic fill project location	1.0	$152
Grid supply: rooftop	1.0	$152
Net metered non-residential rooftop and carport	1.0	$152
Community solar	0.85	$129.20
Grid supply: ground mount	0.6	$91.20
Net metered residential ground mount	0.6	$91.20
Net metered residential roof top and carport	0.6	$91.20
Net metered non-residential ground mount	0.6	$91.20

The TI program will remain in effect for all projects that complete the program registration prior to August 27, 2021.The BPU Staff released a straw proposal for the Solar Successor Program on April 7, 2021, after significant discussions and input from stakeholders.[10] This proposal formed the basis for continuing discussions and provided recommendations to the Board for the design and implementation of the program that will determine solar incentives over the long-term to support the state's goal of 100% clean energy by 2050. The Board accepted essentially all of the Staff's recommendations for the structure of what is officially the Successor Solar Program. The program is a mix of administratively set incentives and incentives determined through competitive solicitations which are designed to continue to support the development of the solar industry in New Jersey while managing the costs to ratepayers. The incentives involve fixed payments for each MWh of solar electricity produced over an eligible project's 15-year qualification life. At the end of the project's qualification life, it will be eligible to receive Class I RECs.[11]

Incentives will be administratively determined for net metered residential projects (all types and all sizes), net metered non-residential projects of 5 MW or less, and all CS projects. The process for determining the values for these incentives will be based on the TI structure and provides the Board with the ability to adjust incentive values on a 3-year schedule to reflect evolving program and market conditions. Incentive values will be initially established using the SAM system to provide guidance for the Board. The Board will use forecasts of future costs to determine annual budget caps and MW targets, which will be subject to true-up at the end of each EY. Modeling to produce the incentive values will target the 50th percentile of

[8] New Jersey Solar Transition Pursuant to P.L. 2018, C.17 – TREC Base Compensation Schedule BPU Docket No. Q019010068, Order dated March 9, 2020.
[9] See: New Jersey Board of Public Utilities, In the Matter of a New Jersey Solar Transition Pursuant to P.L. 2018, C.17 – TREC Base Schedule Compensation, Docket No. Q019010068, Orders of March9, 2020 and December 6, 2019.
[10] See New Jersey Board of Public Utilities, Notice, Docket No. Q020020184, New Jersey 2019/2020 Solar Transition, Solar Successor Program: Staff Straw Proposal. May 5, 2021.
[11] New Jersey Class I RECs index price for the 2021 vintage as of April 30, 2021, was $9.76/MWh.

estimated project costs based on data from the legacy SREC program and the TI Program. The three-year incentive price reset will be based on updated modeling inputs that reflect policy changes, recent market conditions, and continuing stakeholder input. To address the issue of having a market segment fill up immediately upon opening, the proposed market segments will be opened in 3-month increments.

The following table shows the administratively set incentive values that were proposed by the BPU Staff for the initial 3-year period of the program.

Table 3: New Jersey Proposed Incentives

Market Segment	Proposed Incentive ($/MWh)
Net metered residential	85
Net metered non-residential 2 MW or less (rooftop, carport, canopy)	85
Net metered non-residential 2 MW or less (ground mount)	85
Community solar non-LMI	70
Community solar LMI[12]	90

Incentives for grid supply projects and net metered non-residential projects greater than 5 MW will be set through competitive solicitations. The Board will use a clearing price approach to set the incentives for these projects. Solicitations will be held annually starting in EY2022 to determine incentive prices for basic grid supply projects, grid supply built on desirable locations,[13] grid supply projects paired with storage, and net metered non-residential projects of greater than 5 MW. Separate solicitations will be held for each of the project type segments in which project developers or owners will bid an incentive price and MW capacity for their project. Bids will be ranked from lowest to highest then selected until the budget cap for that segment is reached. The Solicitation Manager and the BPU Staff will set a confidential not to exceed bid price for each solicitation. Accepted projects will need to demonstrate site control, have a completed system impact study or completed interconnection study, and post a $40/kW dc escrow. Selected projects would have a completion deadline of 24 months and would be eligible for one 12-month extension with the posting of an additional $40/kW dc escrow.

The BPU Staff's Straw Proposal recommendations for the Successor Solar Program's initial budget and capacity targets are shown in the following table.

Table 4:New Jersey Straw Proposal Capacity and Budgets

Project Type	Year 1 Capacity Target (MW)	Budget Cap
Residential Net Metered	150	$14,713,500
Commercial & Industrial Net Metered 2 MW or less (rooftop, carport, canopy)	110	$10,789,900
Commercial & Industrial Net Metered 2 MW or less (ground mount)	40	$3,923,600
Non-Residential Net Metered Greater than 2 MW	40	$3,923,600
Basic Grid Supply	130	$6,000,800
Grid Supply on Desired Locations	130	$12,001,600
Community Solar	150	$15,579,000
Total	750	$66,701,200

[12] CS projects that serve at least 51% low and moderate income (LMI) customers.

[13] Desirable locations include projects built on contaminated land (brownfield), landfills, rooftops, and in the built environment.

The actual capacity procured for the Solar Successor Program will be limited by the budgets that are governed by the cost cap established by the Clean Energy Act. The programs subject to the cost cap include legacy SRECs, TRECs, Successor Program incentives, and Class I RECs from other renewable technologies that are used to meet the RPS. The number of Class I RECs is scheduled to increase each year with the increasing requirements of the RPS. The last of the legacy SRECs, the highest cost incentives, are not scheduled to drop out of the cost cap calculations until the last 15-year contract expires in 2035. The estimated costs of the legacy SRECs and the annual increase in the Class I RECs taken together with the expected costs for TRECs and the Solar Successor Program incentives are likely to produce a budget squeeze in EY2026, EY2027 and EY2028. Since these are estimates and the annual budgets and cost caps are subject to true-ups each EY, the estimated deficits from the budget squeeze may not materialize. However, if the funding deficits remain after the true-up, the Board can reduce costs by carrying deficits over into later years, reducing the number of Class I RECs procured to meet the RPS targets, or reducing future Solar Successor Program incentives.

New Jersey's CS incentive program which was established in 2019 as the Community Solar Energy Pilot Plan. The Pilot Program is designed to provide the basis for a permanent CS program to be implemented in 2022. The CS incentives are currently included in the TI program capacity targets and will be incorporated as a part of the Solar Successor Program. The Pilot Program is scheduled to run for three program years (PY). PY1 received 252 applications representing 652 MW dc for a capacity target of 75 MW dc. The Board accepted the application from 45 projects with a total capacity amounting just under 78 MW dc.[14] In response to the high level of interest shown for PY1, the Board doubled the target capacity for PY2 to 150 MW dc of which at least 40% will be allocated to LMI projects. The Board is currently evaluating 410 applications for PY2. The Pilot Program allows participating utility customers to receive a credit on their electricity bills.

The Board uses a set of evaluation criteria to competitively score the applications submitted and provide a priority ranking for those projects to be selected. The evaluation criteria and scoring criteria were modified for PY2 applications and include the following:

[14] State of New Jersey Board of Public Utilities, Solar Successor Stakeholder Workshop #3: "Solar Equity and Inclusion; Community Solar," presentation April 28, 2021.

Table 5: New Jersey Community Solar Scoring

Evaluation Criteria	**Points Assigned**
Low and Moderate Income and Environmental Justice Attributes	25
Siting Preference (higher preference given for landfills, contaminated land (brownfields), rooftops, parking lots and other desirable locations)	20
Site Enhancement Bonus (landscaping and related improvements)	3
Location in Redevelopment or Economic Opportunity Zone Bonus	2
Community and Environmental Justice Engagement (preference for collaboration or partnership with municipalities, local community organizations or at affordable housing units)	15
Product Offering (scoring depends on guaranteed savings and flexibility of the program in meeting customers' needs)	15
Other Benefits (focused on jobs and job training)	10
Geographic Limit within the EDC Service Territory (preference given to projects with the shortest distance between the project and the subscribers based on whether the project is in the same municipality or an adjacent municipality to subscribers)	5
Project Maturity (higher scoring for projects with permits and a completed interconnection study)	5

The legacy SREC program was successful in encouraging solar development in New Jersey but using competitive exchanges to set prices subject to the SACP resulted in high costs to the ratepayer. The TI program relied on administratively set prices based on modeling for TRECs in an effort to combat the high costs of achieving the state's solar policy goals. The administratively set incentive pricing also allowed the Board to adjust the incentives to further specific policies for solar development. After considerable analysis and debate including substantial stakeholder input, the Solar Successor Program will rely on both administratively set incentives for DG projects with capacities of 5 MW or less and for CS projects, while the incentives for grid supply projects and projects with capacities of more than 5 MW will be determined through competitive solicitations subject to an administratively set price cap.

On July 28, 2021 the Board issued the Decision and Order to establish the Successor Solar Incentive Program.[15]

The incentive levels for the Administratively Determined Incentive component of the program will range from $70 to $120/SREC II as compared with the prior SREC value of $220. The Competitive Solar Incentive component is expected to hold the first competitive process by mid-2022.

Competitive Procurement

Competitive procurement of solar incentives, either SRECs or bundled electricity price contracts, generally involves a solicitation and auction for the product being sought with bids submitted during a specified submission period similar to the IPA's procurements conducted for wholesale electricity products or the competitive procurements for utility-scale RECs. Most competitive bidding programs are conducted by a third-party administrator and involve a not to exceed price cap or threshold above which bids are rejected as too expensive. In many instances the solar or renewable energy program enabling legislation will set overall limits on the total annual cost of the incentive program along with specific quantity goals or targets.

[15] New Jersey Board of Public Utilities, "NJBPU Approves 3,750 MW Successor Solar Incentive Program," July 28, 2021. https://www.nj.gov/bpu/newsroon/2021/approved20210728.html.

Bids are awarded based on the price bid, usually from lowest to highest, until the product acquisition quantity target is obtained or the cost cap is reached. Under a clearing price approach, all accepted bids are paid the clearing price which is the price of the last bid accepted while under a pay-as-bid approach each bidder is paid the price the bidder submitted. Most, although not all, competitive procurement programs focus on using competitive bidding to determine prices for larger projects. In many programs, incentives for smaller projects utilize a base price established through competitive bidding involving larger projects. Factors (multipliers) or adders are applied to the base price to compensate for the smaller projects' higher costs as well as to achieve policy goals which may include project locations to be encouraged, types of customers to be served, economic development goals, and other attributes the state's solar policies seek to encourage.

Competitive bidding processes to establish solar energy development incentives are generally regarded as being more transparent and better able to reflect market conditions than administratively set price incentives. Given that most solar programs involve cost caps, competitive bidding is better able to maximize the solar resource that can be developed within program cost limitations. Competitive procurements tend to involve more complexities ranging from establishing the appropriate cost cap or threshold benchmark, developing bidding rules, to minimizing the potential for bidder collusion and generally require more in the way of administrative infrastructure and costs. Delaware and Maine have utilized competitive procurements to establish pricing incentives for solar programs with varying degrees of success.

Delaware

Delaware determines SREC pricing through competitive bidding. The enabling legislation, which was signed into law in 2007 as the Renewable Energy Portfolio Standards Act (REPSA), requires the retail electricity providers in the state to buy electric energy from Eligible Energy Resources to a meet a specified percentage of annual retail load.[16] The original intent of the law was to have 25% of the retail load in the state supplied by Eligible Energy Resources with 3.5% to be supplied by solar sources. In 2021 the targets were increased to 40% and 10% respectively by 2035. Since 2012 regulated electric utilities in the state are responsible for procuring RECs and SRECs to meet these targets. REPSA established the Renewable Energy Task force to help define and implement the state's SREC procurement programs, to review the results of each procurement and to make recommendations regarding the structure of the programs.

Following an oversubscribed one-year Pilot Program for SREC Procurement in 2012, SREC Procurement Programs have been held from 2013 through 2019.[17] Each of these procurement programs involved competitive bidding for multiple project category and capacity tiers, with varying SREC targets and evolving SREC contract terms and bidding rules. The Sustainable Energy Utility (SEU) was set up as the central entity to manage the SREC Procurement Programs. The SEU administers all aspects of the bidding process, hires a third party to manage the SREC auctions (in 2019 and 2021 InClime is the third-party auction manager). Prices are determined through competitive bidding for each tier with an overall price

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[16] Eligible Energy Resources are defined by the law as resources that produce solar PV or solar thermal energy, wind energy, ocean energy, geothermal energy, energy produced from fuel cells powered by renewable fuels, biogas fuel sources, small-scale hydroelectric, biomass energy sources, and qualified landfill gas recovery sources.

[17] Delmarva Power initially filed an application for the 2020 SREC Procurement Program with the Delaware Public Service Commission in Docket No. 20-0106 but subsequently requested that the Commission indefinitely postpone the 2020 program.

cap set by the alternative compliance payment (ACP). Delmarva Power & Light (Delmarva Power) has the option to reject bids that are above a price threshold that it determines separately from the ACP. The winning bidders are awarded 20-year fixed price contracts with the price for the first 10 years of the contract being the bid price and the price for the second 10-years of the contract administratively set. For the 2021 SREC procurement contracts, the price for the second 10-years of the contract will be $20/SREC. The following table presents the weighted average SREC price for all tiers and the number of SRECs procured for the five years ending with the most recently held program in 2019.[18]

Table 6: Delaware SREC Prices

SREC Procurement Program	SRECs Procured	Weighted Average SREC Price ($/SREC)
2015	12,000	83.10
2016	11,446	66.56
2017	20,000	21.26
2018	18,236	28.75
2019	15,171	32.75

In February 2020 Delmarva Power submitted an application for the 2020 SREC procurement program to the Delaware Public Service Commission (DPSC) in Docket No. 20-0106. In April of 2020 Delmarva Power subsequently requested that the DPSC indefinitely postpone the 2020 program application citing changed circumstances driven mostly by the pandemic. The DPSC agreed to an indefinite postponement and deferred consideration of the SREC application until 2021.

A closer look at the 2019 SREC Procurement Program provides more details regarding the structure and operation of Delaware's SREC procurement programs. The minimum target for the procurement was 15,000 SRECs with a maximum of 20,000 SRECs. The 2019 program solicited SRECs for five solar project generation tiers which are defined based on project size, interconnection date, project ownership structure, and project location.[19] Winning bids received 20-year fixed price contracts with the first 10 years of the contract priced at the bid price and the last 10 years of the contract priced at $20/SREC. The ACP which set the ultimate cap for the bids received was $400/SREC. After being selected based on bid price, bidders were eligible to receive a 10% bonus to the price for using Delaware labor and a 10% bonus for using parts manufactured in Delaware. All projects were required to be operational within 12 months of the bid being accepted. The bidding window opened on June 20th and closed on July 3rd. The overall procurement quantity target of a minimum of 15,000 SRECs was met with the procurement of 15,171 SRECs. However, four of the five procurement tiers were undersubscribed while Tier 2, representing new solar systems of greater than 50 kW up to 500 kW, was oversubscribed. Tier 1 was also oversubscribed but after application of the Delmarva Power discretionary price threshold, the tier was undersubscribed.[20] It should be noted that while the ACP price cap was $400/SREC, Delmarva Power's discretionary price threshold was $50/SREC for this procurement program. New systems were defined as those systems that were interconnected on or after June 9, 2017. CS projects were required to bid into the tier appropriate to their systems size and other attributes.

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[18] Sustainable Electric Utility website, SREC Delaware Program, Yearly Solicitations, www.SRECDelaware.cim

[19] InClime presentation, 2019 Delaware SREC Procurement Program, https://wp-content/uploads/2019/07/2019-SREC-Delaware-Presentation-Clean.pdf.

[20] An SREC procurement tier can be undersubscribed either by not having attracted sufficient bids to meet the procurement target or by having bids rejected such that the target cannot be met.

The following tables provide an explanation of the five procurement tiers and show the SREC pricing results for the 2019 SREC program.

Table 7: Delaware SREC Procurement Targets

Tier	Tier Size and Attributes	SREC Procurement Target	SRECs Procured
1	New customer owned systems of 50 kW or less capacity	4,400	N/A
2	New systems greater than 50 kW up to 500 kW	2,300	N/A
3	New in-state systems greater than 500 kW up to 2 MW	3,300	N/A
4	New small leased systems of 50 kW or less and in-state systems greater than 2 MW	5,000	N/A
5	All existing in-state systems and qualified out-of-state systems	0 – 5,000[21]	N/A
Total		15,000 – 20,000	15,171

The high, low, and weighted average SREC prices for bids accepted in each tier in the 2019 procurement program are shown in the table below.

Table 8: Delaware 2019 Procurement Results

	Tier 1	Tier 2	Tier 3	Tier 4	Tier 5	Overall
High ($/SREC)	50.00	47.74	50.00	48.48	49.99	50.00
Low ($/SREC)	19.99	10.00	34.94	10.00	10.00	10.00
Weighted Average ($/SREC)	39.05	24.74	39.44	41.81	32.75	32.75

Delmarva Power submitted an application to the DPSC on May 5, 2021, for the 2021 SREC Procurement Program, the primary structure of which is based on the postponed 2020 program which was subsequently approved by the DPSC.[22] The 2021 solicitation will begin September 13, 2021 and will remain open through September 24, 2021. The primary changes proposed for the 2021 program relative to the 2019 program provide added flexibility in meeting individual tier and total program procurement targets, changing the definition of new project such that a new project is one that was interconnected after the date of the previous program procurement, and a reduction in the ACP to $150.[23] The total SREC procurement target of a minimum of 15,000 SRECs and a maximum of 20,000 SRECs remains the same. The targets for Tiers 1 to 4 were expanded to allow up to an additional 5,000 SRECs to be bid into each tier. Tiers 1 to 3 are given first priority in the solicitation for the first 10,000 SRECs, after 10,000 SRECs are procured from these tiers, SRECs can be procured from Tier 4 for a minimum of 5,000 SRECs up to a maximum of 10,000 SRECs. After the bids have been accepted in Tiers 1 through 4, Delmarva can procure up to 5,000 SRECs from Tier 5 to cover any remaining unsubscribed SREC targets. Also, after the winning bids in Tiers 1 to 5 have been selected, Delmarva Power at its discretion can purchase up to 5,000

[21] The amount of Tier 5 SRECs procured is based on whether Tiers 1 to 4 are filled and whether or not Delmarva Power & Light determines that SREC prices bid in this tier represent value for the ratepayer.

[22] Delaware Public Service Commission Docket 21-0337, https://depsc.delaware.gov/wp-content/uploads/sites/54/2021/05/item-10a-Docket-21-0337-Application-DPL-05-12-2021.pdf The DPSC approved Delmarva's 2021 SREC Solicitation filing in this Docket on July 29, 2021.

[23] The Renewable Energy Task Force reviews the results of each SREC procurement and takes into consideration stakeholder feedback before recommending modifications to the net procurement program. Delmarva Power & Light is represented on the Task Force.

additional SRECs from the lowest price losing bid in any tier not to exceed the total procurement maximum of 20,000 SRECs.

The Delaware SREC procurement process has been able to use a competitive bidding approach to keep SREC prices low in what is a relatively small market. No specific adders or base price factors are used other than to provide a winning bidder with a 10% bonus for using Delaware labor and a 10% bonus for using products manufactured in Delaware. With the 2021 program, new in-state customer-owned systems with third-party SREC ownership are given a priority with a higher price of up to 25% more than the lowest Tier 5 bid received. This program involves competitive bidding for all project types and sizes, however, there are not stringently defined policy goals for the development of community solar and participation by low and moderate income customers.

Maine

The Maine Legislature enacted the Act to Promote Solar Energy Projects and Distributed Generation Resources (the Maine Act)[24] in Maine during the 2019 legislative session.[25] This act created a competitive procurement program to obtain a total of 375 MW of distributed renewable generation in 5 procurement blocks representing two separate categories for projects of less than 5 MW of capacity. The price paid to selected bidders would be tied to the clearing price for the first block. The first category involved shared distributed generation (essentially CS) targeting 250 MW, which was open to all customer rate classes, and the second category for commercial and institutional customers targeting 125 MW, which was open to non-residential rate classes only). Each block was to procure 20% of the total procurement targets for each rate class. Subscribers to the shared projects and commercial and institutional customers participating in the program would receive credits on their electric bills equal to the contract rate times the share of the project generation or for the total output of the commercial and institutional project. The shared DG projects were required to have minimum subscriptions of 1 kW, 50% of subscribers to be 25 kW or less, and 10% of subscribers to be from low or moderate income households. The 50% for subscribers of 25 kW or less could be reduced to 20% if subscriptions from municipal governments were 30% or more of the total. The price for Block 1 would be determined by competitive bidding with price for blocks 2 through 5 to be 97% of the previous block's price.

The Maine Public Utilities Commission (MPUC) announced the Block 1 procurement on February 28, 2020, with the bid period for qualified bidders to open from July 1, 2020, through July 30, 2020. Enel X was engaged by the MPUC to administer the procurement. Qualified bidders were required to demonstrate:

- That they had a fully executed interconnection agreement,
- That all federal, state and local approvals and required permits had been obtained,
- That they had the financial capability to meet the financial assurance deposit at the time of executing a contract,
- That commercial and institutional projects had an agreement in which a commercial or institutional customer would receive the bill credits, and for shared projects show that the developer had experience meeting obligations to customers of similar type projects.

[24] Note the Maine Legislation refers to this act simply as "the Act." It is referred to as "the Maine Act" in this whitepaper to avoid any confusion with the Illinois Act.
[25] An Act to Promote Solar Energy Projects and Distributed Generation Resources in Maine (P.L.2019, Chapter 478)

Enel X received applications from 34 bidders for Block 1, 31 bidders were preliminarily qualified, and 14 bidders submitted applications to qualify 66 projects. Six bidders submitted bids for 18 shared DG projects and three bidders submitted bids for four commercial or institutional projects. The clearing price for the shared DG bids was $194.90/MWh and $192.00/MWh for commercial or institutional projects. These prices were to be fixed over the 20-year contract.[26]

After a review of the Block 1 procurement results, in an August 28, 2020 Order, the MPUC exercised its authority to reject bids received declaring that the clearing prices were too high and that following the review of bidding that the bidding process was not competitive. The MPUC subsequently issued a report on the Block 1 solicitation in November 2020.[27] The MPUC concluded that the high clearing prices and non-competitive bidding were due in part to the significant level of attrition in the number of bidders and projects that survived the qualification process and that the clearing prices did not reflect cost-based bids based on comparison with existing contracts for renewable resources reflected in the state's other renewable resource programs.

The MPUC issued the procurement announcement for the follow-up to the Block 1 procurement as is required by the Maine Act but indicated that since the legislature was considering major changes to the Maine Act or even its elimination, the MPUC will not establish a schedule or develop procurement parameters until the legislature determines the fate of the Act.[28] On July 1, 2021 the legislature amended the state law such that the Commission will not procure distributed generation resources through the competitive procurement process originally specified in the Maine Act.

The lessons that can be drawn from the Maine experience is that not all competitive bidding processes are successful in meeting state renewable energy procurement goals at reasonable prices. Contributing to the high clearing prices was the apparent lack of any price cap above which bids would be rejected.

Market-based pricing and index pricing

Market-based pricing is a method of incentive setting that is used to attempt to incorporate market signals in determining the pricing for solar incentives. Such an approach may begin with administratively determined prices or a competitive procurement, but then evolves to be responsive to changes in the market. Using index pricing typically ties the price of incentives to market indicators such as energy and capacity prices that are publicly available along with adders or multipliers (factors) that adjust the market price indicators to reflect compensation for the additional costs and benefits associated with DG or CS projects. Most programs adjust incentives upwards from initially established incentive prices to provide additional support for the higher capital and operating costs experienced by smaller DG and CS projects. Other adders, usually based on state policy goals, can provide additional compensation for environmental benefits such as the social cost of carbon emissions avoided as well as adders for building a project in preferred locations such as brownfield sites or to encourage the development of projects in low and moderate Income areas. While market index approaches start with direct ties to market conditions in terms of energy and capacity prices, the values of adders or multipliers can be difficult to quantify and are

[26] Maine Public Utilities Commission Competitive Procurement for the Output of Distributive Generation. Docket No 2020-00014, August 28, 2020.

[27] Maine Public Utilities Commission Report on Renewable Distributed Generation Solicitation, Presented to the Joint Standing Committee on Energy, Utilities and Technology, November 10, 2020.

[28] Maine Public Utilities Commission Procurement Announcement Distributed Generation Resources, Issued May 21, 2021.

commonly administratively developed and, in some instances, may not be supported by sufficient quantitative justification.

One goal of a market-based pricing mechanism is to phase-out incentives as the market becomes more robust and the need for incentives to make developing solar projects feasible decreases as the costs of solar generation decline over time. Depending on how market-based incentives are determined and implemented, these may lack transparency and introduce risks to customers. If the incentive is paid as an upfront, cash incentive, developers have a clear signal about how the incentive will reduce their costs. If the incentive is paid over time and subject to change over the life of a contract, developers will not know exactly what level of incentive payment to expect and bear that risk. However, it may incentivize customers to become early adopters of solar as they hope to capitalize on the higher prices earlier in the program.

Programs that use index pricing connect solar incentives to either current or previous actual energy, capacity, and/or REC prices that have been observed in the market. A benefit of using an index price is that prices track the current market prices and are inherently connected to real-world conditions as a result. Following real-world conditions can keep states from overfunding solar development. One of the main arguments against such an approach is that an index price can introduce a large degree of uncertainty for developers and customers as the incentives change based on changes in energy and capacity prices introducing volatility to the value of the incentives. This uncertainty with regard to the connection to current market prices is a risk that can result in increased financing costs.

New York

Unlike using administratively determined or competitive procurement approaches to provide incentives for residential and community solar, New York has implemented a market-based pricing rebate program in NY-SUN Incentive Program (NY-SUN). The New York State Energy Research and Development Authority (NYSERDA) began administering the NY-SUN in 2014 as part of PON2112. NY-SUN had an initial goal of 3,175 MW of installed capacity by 2023 with a budget of $763 million dollars. The NY-SUN program goal was increased in 2019 to 6,000 MW to be installed by 2025 with an accompanying budget increase of $573 million dollars.

The goal of the NY-SUN MW Block Program is to (i) provide certainty and transparency regarding incentive levels, (ii) account for regional market differences, (iii) provide a clear signal to industry that New York intends to ramp down and eliminate cash incentives in a reasonable timeframe, and (iv) allow for the elimination of those incentives sooner in regions where the market conditions can support it, based on market penetration, demand, and cost-effectiveness. A key objective of the program was for the ramp down to coincide with expected decreasing costs to install solar technologies over time and incent early adoption of solar in order to receive the higher prices.

NYSERDA established a declining block structure with associated budgets and MW targets for three regions throughout the state: Con Edison, PSEG Long Island, and the rest of state. The block incentive rates were set based on historical demand, market penetration, and installed cost per watt. The MW Block program is discretionary, with sizes and prices in each region and sector subject to change based on current market conditions. NY-SUN provides cash incentives for the following regions and sectors on a first-come, first-served basis as indicated with an “x” in Table 9.

Table 9: NY-SUN MW Block Program Incentives by Region/Sector[29]

Sector	ConEdison	PSEG Long Island	Upstate NY
Residential up to 25 kW	X	X	X
Nonresidential up to 750 kW		X	X
Nonresidential up to 7.5 MW	X		
Commercial/Industrial 750 kW to 7.5 MW			X

Given that the nature of the incentive payment through the NY-SUN initiative is a dollars per watt of installed capacity, it makes comparing this program to the ABP more complex and less direct than other states' programs that offer incentives based on energy or RECs produced as the ABP does. Incentives in the declining MW Block Program are awarded to applications based on the block in effect at the time of submission. Incentives step down to the next block when the current block has reached its MW target. Commercial and industrial projects receive 25% of the payments upfront with the remainder paid over a period of three years. Residential projects receive the full incentive upfront.[30] Customers who wish to participate in the program do not receive the incentive payments directly, but rather by working with Participating Contractors who are eligible to facilitate the incentive payment by submitting an application on the customer's behalf. The Participating Contractor facilitates the entire build process and is responsible for the quality of the PV system installed. The cash incentive payment is paid directly to the Participating Contractor and passed through in full to the customer in order to reduce out-of-pocket cost.[31,32]

As NY-SUN incentive payments reflect system size and are not performance-based, these values are presented based on system size and total payments to customers for a few system sizes. The three following tables provide an overview of the MW Block program prices, current status, and total capacity by region and sector.

Table 10: NY-SUN Residential System MW Block Program Details[33]

Region	Block 1 Price ($/W)	Current Block	Current Block Price ($/W)	Current Block Allocation (MW)	Current Block % Unfilled	Total Capacity All Blocks (MW)
Con Edison	$1.0	9	$0.20	120	60%	238
Long Island	$0.5	4	$0.2	77	0%	149
Upstate	$1.0	8	$0.35	152	18%	265

[29] All program capacity ratings are in Direct Current (DC).

[30] Residential system sizes are not to exceed 110% of the total kWh electric consumption for the previous 12 months, hence incentives for PV systems are capped at that level of consumption.

[31] https://portal.nyserda.ny.gov/servlet/servlet.FileDownload?file=00Pt000000MebsrEAB

[32] Incentives may be paid directly to the contractor and not passed through in full if payment assignment has been identified for nonresidential projects.

[33] Values were retrieved from NY-SUN dashboard on 5/31/2021. See for current values: https://www.nyserda.ny.gov/All-Programs/Programs/NY-Sun/Contractors/Dashboards-and-incentives/

Table 11: NY-SUN Commercial System MW Block Program Details

Region	Block 1 Price ($/W)	Current Block	Current Block Price ($/W)	Current Block Allocation (MW)	Current Block % Unfilled	Total Capacity All Blocks (MW)
Con Edison	$.63	3	$0.59	4.05	0%	39.05
Upstate	$.40	17	$0.11	615	0%	3,492

Table 12: NY-SUN Nonresidential System MW Block Program Details

Region	Block 1 Price ($/W)	Current Block	Current Block Price ($/W)	Current Block Allocation (MW)	Current Block % Unfilled	Total Capacity All Blocks (MW)
Con Edison	$1.0 to $0.60	9	$0.30	70	43%	262.5
Long Island	$0.50	6	$0.15	33	0%	84
Upstate	$1.0 to $0.60	10	$0.25	65	82%	228

For ABP program comparison purposes, the MW Block program upfront cash incentive can be translated into a dollars per MWh (REC equivalent) by making some assumptions about system size and production. NYISO reported an annual capacity factor for BTM solar of 12% for 2019, an increase from 11% in 2018.[34] Since these values show year-over-year production increases, it is reasonable to assume a similar trajectory of technological improvement exists - a 13% capacity factor in 2020. Using the current sector and region Block pricing from Table 10 through Table 12, an assumed capacity factor of 13%, assumed contract durations of 15 years for residential and 20 for commercial and nonresidential, and a discount rate of 6%, an illustrative REC price comparable to the ABP REC price can be derived. Illustrative, comparable values - using assumed system sizes in brackets - based on the assumptions listed above are presented in Table 13.

Table 13: NY-SUN Illustrative REC Prices ($/REC)[35]

Region	Residential (25 kW)	Commercial (500 kW)	Nonresidential (2000 kW)
ConEdison	$28	$83*	$42
Long Island	$28*	N/A	$21*
Upstate	$49	$15.50*	$35

The program includes additional incentives for low-to-moderate income households through “Affordable Solar” and “Multifamily Affordable Housing.” The Affordable Solar additional incentive has two provisions for low-to-moderate income households - one for onsite residential and one for community solar projects - and provides a standard incentive rate of $0.80 per watt in Upstate and Con Edison and $0.40 per watt on Long Island. The Multifamily Affordable Housing additional incentive provides payments to projects sited on regulated affordable housing. There are also additional incentives provided to projects located on brownfield or landfill sites or on parking solar canopies. For all additional incentives, “if MW Block funding is exhausted prior to additional incentives, the additional incentives will continue at the standard

[34] NY Renewables – Overview and YTD Operation. Cameron McPherson. March 20, 2020. https://www.nyiso.com/documents/20142/11452204/2019%20NYCA%20Renewables%20Presentation%20FINAL.pdf/051c94d2-026a-fbd6-b7ad-ee1a2dc8a3d7

[35] Note that prices indicated with an asterisk represent unrealistic prices as the MW Blocks are full.

incentive amount in place at time the MW block incentive was exhausted, until the funding for the additional incentive is exhausted as well."[36]

The "Community Adder" is an upfront cash incentive in addition to the standard region and sector incentive for community solar projects that is also paid on a per watt basis. The Community Adder replaced the legacy Market Transition Credit and Community Credit as those programs are fully allocated. This incentive is not available to customers of Con Edison or Long Island Power Authority or to residential solar projects.[37] Community Adders were assigned in Blocks to five utilities. All Blocks have been fully allocated in three service territories (National Grid, NYSEG, and Rochester Gas and Electric). 100 MW of capacity was allocated to Central Hudson, where 9 MW remain unfilled and will receive $0.30 per watt. 65 MW of capacity was allocated to Orange and Rockland, with approximately 4 MW of capacity remaining to receive $0.15 per watt.[38]

NYSERDA typically publishes quarterly reports to update on the progress of the MW Block program, though the most recent report as of May 2021 provides data as of Q1 2020. The report includes a high-level summary of uptake for the additional incentives and any news related to the MW Block program, such as the following information regarding market conditions leading to expanded Block capacity:

> *In response to market uptake and to provide certainty, 175 MW of additional capacity was added to the Upstate Commercial Block 14 in March 2020. The block maintains the current incentive level of $0.17/Watt.*[39]

This inclusion in the report shows the MW Block program's reactive nature to market signals. Additionally, the report provides data on the overall NY-SUN Program installed capacity, energy production, and program budget status. The data provided do not align directly with the regions and sectors in the MW Block program and are over a year out of date, therefore were omitted from this report.

In addition to the NY-SUN MW Block Program, New York offers additional incentives to solar installers. New York state has offered, since 1998, a Residential Solar Tax Credit for residential systems up to 25 kW. The credit is the lesser of 25% of qualified solar system expenditures or $5,000.[40]

A further program in New York that does not have a block structure but that decreases customer bills is the Value of Distributed Energy Resources (VDER). VDER was introduced in 2017 to address inequities in net metering, i.e. utilities charging non-solar customers more to make up for revenue lost on net metering.[41] In the VDER program, distributed solar system owners do not receive the full retail electric rate but instead a Value Stack Tariff rate, which is comprised of five components: energy value (LBMP), capacity value (ICAP), environmental value (E), demand reduction value (DRV), and locational system relief value (LSRV). The Value Stack Tariff rate will always be less than the retail rate of electricity. At this time, nonresidential solar customers must use VDER while residential customers can choose between VDER and net metering, although the NYPSC issued the Order Establishing Net Metering Successor Tariff on July 16,

[36] https://portal.nyserda.ny.gov/servlet/servlet.FileDownload?file=00Pt000000MebsrEAB
[37] https://www.nyserda.ny.gov/-/media/Files/Programs/NYSun/NY-Sun-Community-Adder-Fact-Sheet.pdf
[38] https://www.nyserda.ny.gov/All-Programs/Programs/NY-Sun/Contractors/Dashboards-and-incentives/Community-Adder
[39] NY-Sun Initiative Quarterly Performance Report to the Public Service Commission Quarter Ending March 31, 2020 Final Report. May 2020

[40] https://www.tax.ny.gov/pit/credits/solar_energy_system_equipment_credit.htm
[41] State of New York Public Service Commission, 3/9/2017, "Order On Net Energy Metering Transition, Phase One Of Value Of Distributed Energy Resources, And Related Matters" Cases 15-E-0751 and 15-E-0082.

2020 stating its intent to transition all customers to VDER.[42] Both the VDER and net metering programs are subject to a Customer Benefits Charge (CBC), which is applied on a dollars per watt of installed capacity and added to customer's monthly bills.[43,44] Because the Value Stack Tariff is highly tailored to project specifics (i.e. location, size, mount type, system degradation, etc.), it is not simple to produce a representative VDER value to use for comparison to the overall compensation provided under the ABP. Further, VDER represents an alternative to the net metering credit deducted from the CREST derived ABP REC price rather than something akin to a REC price.

Given the way the NY-SUN program is administered as a declining MW Block structure, it provides a high level of transparency to potential customers about what incentive they will receive for their system. As an upfront cash incentive payment, it lessens the initial burden on customers within a year of installing their system. Whereas ABP participants know what REC price they will receive over the life of their contracts, the payment for most of the blocks does not come as an upfront incentive, therefore lessening the cost over a long period of time rather than at the time of installation.

Combination approaches

Rather than just using competitive procurements or administratively determined prices to set incentive prices for small solar systems, some states have used a combination of the two approaches to set their incentive prices. Some states that started with either competitive procurements or administratively set prices have evolved into what are essentially combination approaches. There are two types of combination approaches: one that begins with a competitive procurement and uses the results to administratively determine prices, and one that begins with administratively determined prices - typically determined using a model such as CREST or SAM – and bidders submit REC price bids between $0/REC and the upper bound of the administratively set price.

Combination approaches that begin with a competitive procurement have the advantage that pricing is based on bids made by developers of solar projects and therefore may more accurately reflect their costs than modeled prices. One issue with using competitive procurements is that unless procurements are held regularly, the prices resulting from the procurement can become stale. Another issue is that using competitive procurements adds costs associated with conducting annual procurements to implement the program.

Under combination approaches that begin with administratively set prices, the administrative price represents the highest possible price, a price ceiling, a developer can receive for the RECs produced. The ceiling price is typically determined by using a model, which reflects specific input parameters related to solar costs, or through the legislation, which is usually written in order to achieve policy goals. As a method that uses either specific goals or cost parameters, this approach offers flexibility to be tailored to best reflect the goals of the solar incentive program. An issue with using a price ceiling, that is publicly reported, rather than just setting an administratively determined price as in the ABP is that developers may likely bid close to the ceiling price, therefore diminishing the value in introducing flexibility in the REC price.

Although the programs are implemented differently, both Massachusetts and Rhode Island have selected combination approaches to incentivize solar development in their respective states. The Solar

[42] Net metering programs were extended until 2022 for residential customers.
[43] https://www.solarreviews.com/blog/new-york-changes-net-metering-vder
[44] CBCs for the net metering successor program have not yet been finalized.

Massachusetts Renewable Target Program (SMART) in Massachusetts and the Renewable Energy Growth Program (REG) in Rhode Island are both performance-based incentive (PBI) programs. SMART began with a competitive procurement leading to administratively determined prices, while the REG program uses the NREL CREST model to determine program year ceiling prices for various project sizes under which developers must bid to be accepted. The maximum project size funded through each of these programs is 5 MW. Both programs offer some prioritization to projects sized 25 kW and lower.

Massachusetts

Prior to the SMART program being implemented in 2018, solar projects in Massachusetts were eligible for pricing incentives through the Solar Renewable Energy Certificates (SREC) program. One SREC is equal to one megawatt hour (MWh) of generation by a solar facility for the first ten years the system is in operation. Participants in the program sell their SRECs to the utilities through the state's SREC market, with utilities purchasing SRECS in order to comply with the state RPS goals.[45]

The SREC program was successful; the program launched in 2010 with a capacity of 400 MW that was filled by 2013, which led to the distinction between the pre-2014 SREC I and post-2014 SREC II programs. The SREC-II program was launched in 2014 with a capacity goal of 1,600 MW, which was met in 2017. The SREC program did not offer fixed pricing per REC over the contract term, instead the SREC pricing was based on market supply and demand, with an annual Solar Alternative Compliance Payment (SACP) that utilities are required to pay should they not meet the company's solar goals mandated by the state. The SACP serves as a functional price cap on SREC prices. The SACPs for 2019 were $404 per REC for SREC-Is and $333 per REC for SREC-IIs. SRECTrade recorded prices between November 2019 and November 2020 of $270-$290 per REC for SREC-IIs and $349-$360 per REC for SREC-Is, which fall well below the SACP price caps.[46] Projects are not eligible for both SRECs and the SMART solar pricing incentives; however, projects that qualified for SRECs will be paid for the full 10 years of eligibility (i.e. the program will continue paying projects for SRECs through 2027).

In 2018, the SMART program was adopted to replace the SREC program.[47] The SMART program capacity was initially capped at 1,600 MW ac, where the allocation of the 1,600 MW was set equal to the distribution company's 2016 load share and applied consistently across 8 Capacity Blocks.[48] Each block has a set-aside to be filled with no less than 20% and up to 35% of projects sized <=25 kW ac.

[45] https://news.energysage.com/srecs-in-massachusetts-prices-and-program-status/
[46] https://www.srectrade.com/markets/rps/srec/massachusetts
[47] https://www.mass.gov/doc/225-cmr-2000-smart-clean/download
[48] https://clearesult5.sharepoint.com/sites/MassSMARTSolar/Shared%20Documents/Forms/AllItems.aspx?id=%2Fsites%2FMassSMARTSolar%2FShared%20Documents%2Fmasmartsolar%20documents%2FProgram%20Information%2FSMART%2DProgram%2DOverview%2Epdf&parent=%2Fsites%2FMassSMARTSolar%2FShared%20Documents%2Fmasmartsolar%20documents%2FProgram%20Information&p=true&originalPath=aHR0cHM6Ly9jbGVhcmVzdWx0NS5zaGFyZXBvaW50LmNvbS86Yjovcy9NYXNzU01BUlRTb2xhci9FVmxlWGswVDFNTk5uM005eUE1V3l6WUJoQWhUZHJUTDVvU0Q3V3N0NThRWHZ3P3J0aW1lPWNzNGZyZHdlMlVn

Table 10:MASS SMART Program Total Capacity Available per Capacity Block (MW ac)[49]

Distribution Company	Block 1	Block 2	Block 3	Block 4	Block 5	Block 6	Block 7	Block 8	Total
Fitchburg Gas & Electric d/b/a Until	4	4	4	4	N/A	N/A	N/A	N/A	16
Massachusetts Electric d/b/a National Grid	90	90	90	90	90	90	90	90	720
Nantucket Electric d/b/a National Grid	3	3	N/A	N/A	N/A	N/A	N/A	N/A	6
NSTAR d/b/a Eversource Energy	92	92	92	92	92	92	92	92	732
WMECO d/b/a Eversource Energy	16	16	16	16	16	16	16	16	126
Total Capacity	204	204	201	201	197	197	197	197	1,600

Block 1 Base Compensation Rates were established in January 2018 using the results of a single competitive procurement for projects between 1 and 5 MW. The approximately 100 MW of capacity per distribution company selected in the procurement was deducted from the Block 1 total available capacity. Base Compensation Rates for projects sized smaller than 1 to 5 MW were established using the predetermined multipliers (factors) shown in Table 11 below.

Table 11: MASS SMART Program Base Compensation Rate Factors & Contract Length

Generation Unit Capacity	Base Compensation Rate Factor	Term Length
Low income <=25 kW AC	230%	10-year
<= 25 kW AC	200%	10-year
> 25 kW AC - 250 kW AC	150%	20-year
> 250 kW AC - 500 kW AC	125%	20-year
> 500 kW AC - 1,000 kW AC	110%	20-year
> 1,000 kW AC - 5,000 kW AC	100%	20-year

Base Compensation Rates by distribution company for Block 1 are shown in Table 12. For each successive Capacity Block, Base Compensation Rates decline by 4%.

Table 12: MASS SMART Program Block 1 Base Compensation Rates ($/MWh)[50]

Distribution Company	Low income <=25 kW AC	<= 25 kW AC	> 25 kW AC - 250 kW AC	> 250 kW AC - 500 kW AC	> 500 kW AC - 1,000 kW AC	> 1,000 kW AC - 5,000 kW AC
Fitchburg Gas & Electric & Massachusetts Electric	$357.95	$311.26	$233.45	$194.54	$171.19	$155.63
Nantucket Electric & NSTAR Electric	$391.00	$340.00	$255.00	$212.50	$187.00	$170.00
WMECO	$328.62	$285.76	$214.32	$178.60	$157.17	$142.88

[49] Note the numbers in these tables have been rounded.

[50] Base Compensation Rates for Fitchburg Gas & Electric decline by 8.8% over four Capacity Blocks. Base Compensation Rates for Nantucket Electric decline by 16% over two Capacity Blocks.

In the SMART program, there are four Compensation Rate Adder categories: Location Based Adders, Off-taker Adders, Energy Storage Adders, and Solar Tracking Adders. Location Based and Off-taker adders both have several subcategories. Projects larger than 25 kW ac can qualify for one adder from each of the four Compensation Rate Adder Categories. Systems 25 kW and smaller may only qualify for the Energy Storage adder unless the subscribers are considered Low Income, then the project may qualify for one of the two Low Income Off-taker adders. Compensation Rate Adders shown in Table 13: represent the adder value for the first 80 MW tranche, whereby the value of the adder for each tranche decreases by 4% from the previous tranche. The Department of Energy Resources (DOER) has the authority to make changes to those tranches subsequent to the initial 80 MW tranche; DOER has reduced the subsequent tranche size to 60 MW for the Community Shared Solar adder. Information has not been provided on how the adder values were calculated or determined.

Table 13: MASS SMART Program Tranche 1 Compensation Rate Adders ($/MWh)

Adder Category	Adder Type	Adder Value
Location Based	Building Mounted	$20
	Floating Solar	$30
	Brownfield	$30
	Eligible Landfill	$40
	Canopy Solar	$60
	Agricultural	$60
Off-taker Based	Low Income Property Owner	$30
	Low Income Community Shared Solar	$60
	Public Entity	$20
	Community Shared Solar	$50
Energy Storage	Energy Storage + PV	Variable
Solar Tracking	Solar Tracking	$10

Incentive payments under the SMART program are calculated differently for standalone facilities than fpr behind-the-meter (BTM) facilities. For standalone facilities, the incentive payments will always equal the total compensation rate (i.e. the sum of the Base Compensation Rate plus all adders and minus any subtractors) for which a system initially qualifies under SMART. The incentive payment a customer will receive each billing period is calculated as follows:

Standalone Solar Incentive Payment = (Base Compensation Rate + Compensation Rate Adders – Greenfield Subtractor[51]) * total kWh generated – value of energy generated

Since customers may receive a net metering credit or an alternative on-bill credit or neither credit, customers with net metered generation units or alternative on-bill generation units will receive bill

[51] There are four Land Use categories that warrant a Greenfield Subtractor. These range from $0.50/MWh to $2.50/MWh per acre of land the facility occupies.

credits, while non-net metered customers will receive direct compensation subject to the qualifying facility tariff. The value of energy generated will be calculated in one of the three following ways:

Net Metered Generation Unit Energy Value = total kWh generated * net metering credit rate[52]

Alternative On-Bill Credit Generation Unit[53] Energy Value = total kWh generated * energy compensation rate

Non-Net Metered Generation Unit Energy Value = total kWh generated * distribution company's Qualified Facility Value

For BTM facilities, the incentive payments are calculated in a way that approximates the avoided cost of electricity for each kWh of on-site generation. The value of energy rate for BTM facilities is determined at the time of contracting and does not vary over the contract term.[54]

BTM Net-Metered Generation Unit value of energy = volumetric distribution rate + volumetric transmission rate + volumetric transition rate + 3-year average basic service kWh charge

Alterative On-Bill & Non-Net Metered Generation Unit value of energy = [0.65*(3-year average basic service kWh + volumetric distribution rate + volumetric transmission rate + volumetric transition rate charge) + 0.35*(3-year average basic service kWh charge)]

As an example, the highest and lowest value of energy rates for different customer classes from the published 2021 BTM solar generation units by distribution company are shown in Table 14 below. These values also serve as a proxy for the net metering credit customers would receive, though the net metering credit would be based on just the current year basic service charge.

Table 14: MASS SMART Program Lowest & Highest Value of Energy for 2021 ($/MWh)

Distribution Company	**Lowest 2021 VOE**	**Highest 2021 VOE**
Fitchburg Gas & Electric	$125.00	$241.90
Massachusetts Electric	$135.11	$223.00
Nantucket Electric	$143.39	$233.00
NSTAR Electric	$114.37	$216.71
WMECO	$195.26	$108.98

[52] Net metering credit rate is the sum of the distribution company's basic service charge, distribution charge, transmission charge, and transition charge.

[53] Alternative On-Bill Credit is the value of the net excess electricity generated by a facility and fed back to the utility on a monthly basis.

[54] Per DOER *Solar Massachusetts Renewable Target (SMART) Program Summary* April 26, 2018 presentation: Because of this structure, Behind-the-Meter facilities will not necessarily always receive the total compensation rate for which a system is qualified under SMART, but may receive more or less depending on 1) the future retail price of electricity, and 2) the amount of electricity exported by the facility to the grid (i.e. facilities that export more electricity may receive less total compensation because their avoided electricity costs will be lower than if the electricity was consumed behind-the-meter)

The SMART program has been successful in terms of approved projects and the interest from potential subscribers to the program. As of April 15, 2021, 470 MW ac of projects have been approved with another 745 MW ac qualified, which means a project has received a preliminary statement of qualification and has a reservation in a capacity block.[55] All distribution companies except for NSTAR have opened all of their Capacity Blocks and have little capacity that has not been approved or at least qualified. Table 15shows the total capacity approved, qualified, and remaining for each distribution company.

Table 15: MASS SMART Program Capacity Approved, Qualified, and Remaining for initial 8 Capacity Blocks (MW ac)

Distribution Company	Approved	Qualified	Remaining Capacity
Fitchburg Gas & Electric	9	7	0
Massachusetts Electric	277	399	44
Nantucket Electric	2	0	4
NSTAR Electric	100	302	330
WMECO	83	36	7
Total	**470**	**744**	**386**

Based on data updated daily as of end of May 2021, only the CS and energy storage adders have been allocated capacity in tranches beyond the first two 60 MW tranches, with CS project applications being assigned to tranche 13 out of 16.[56]

In April 2020, the MA DOER issued emergency regulations under the SMART program. These regulations expanded the program capacity by 1,600 MW, which led to the opening of an additional 8 Capacity Blocks each for NSTAR and WMECO (now combined into one distribution company “Eversource Energy”) and Massachusetts Electric.[57] The regulations also drew on lessons learned from the rollout of the program to date with changes including: increasing the Greenfield Subtractor by 250%, new land use restrictions, expanded eligibility and creation of a set-aside for low-income projects, creation of a set-aside for midsize projects between 25 kW and 500 kW, a requirement for inclusion of energy storage for projects over 500 kW, and an increase to the public entity project adder.[58] These changes do not apply to projects awarded contracts prior to the updated regulations going into effect.

A February 2020 article in Utility Dive highlighted a key issue with the SMART program rollout related to project interconnection.[59] National Grid conducted a cluster study to determine how projects over 1 MW

[55] Program data available for download here: https://www.mass.gov/info-details/solar-massachusetts-renewable-target-smart-program#program-data-

[56] https://masmartsolareversource.powerclerk.com/MvcAccount/Login

[57] https://clearesult5.sharepoint.com/:x:/s/MassSMARTSolar/ERxwXZde-5pJvMdKuOULQzkBtWXbog290Gn17p7dM6ia8w?e=c17ydi

[58] https://www.pierceatwood.com/alerts/massachusetts-issues-emergency-rules-governing-solar-projects-under-smart-program

[59] https://www.utilitydive.com/news/as-massachusetts-solar-installs-plummet-stalled-interconnections-land-use/572925/

may impact the transmission grid, which stalled several solar projects that were already under construction.

The state's net metering cap is close to being filled, which also creates uncertainty for developers about the all-in compensation price for future projects. Becky Gallagher of Sunpower was quoted in the article citing the unknown value, cash flow, and revenue stream for new projects as a disruption to development.

The total compensation paid to SMART facilities is meant to account for the energy generated and all other incentives provided, as the ABP does. The declining block structured program is the most similar to the ABP program's structure. Although the ABP and SMART have both used a 4% decrease in administratively set pricing between Capacity Blocks, the SMART program started with a single competitive procurement in 2018 to determine the initial Base Compensation Rates for the first Block, whereas prices for the first ABP block were modeled using NREL's CREST model. While the SMART program has filled 12 out of 16 60 MW tranches for which the compensation adder allocated to CS has declined with each tranche, projects in the low-income CS category are still receiving the first tranche adder.

A key difference between the ABP and SMART programs is the use of subtractors and strict land use requirements under the SMART program. Massachusetts is smaller and more land-constrained than Illinois, which could explain the need for stricter land-use rules and the use of subtractors for developing on desirable land.

Rhode Island

The Rhode Island REG program represents another PBI for both small-scale solar projects (i.e. under 25 kW DC nameplate capacity) and solar, wind, hydro, and anaerobic digester projects up to 5 MW DC nameplate capacity.[60] While the REG program provides incentives for four technologies, this discussion will focus only on the distributed solar category. An important item to note when comparing the REG program to others presented in this memo is that it uses DC rather than AC for its program capacity targets. Unlike under the ABP program in Illinois, participants in the REG program are not eligible for net metering because REG program systems are considered front-of-the-meter and enter the grid immediately rather than being used to serve local load first.

As part of the REG Program, all selected projects are subject to quality and quantity assurance reviews by the Rhode Island Office of Energy Resources (OER) through its selected consultant. Cadmus group worked on the annual Quality Assurance reports for 2017, 2018, and 2019. In the 2019 REG program year, Cadmus completed 90 inspections of small-scale projects, 8 medium-scale projects, and 4 large-scale projects using its PV Quality Evaluation and Scoring Tool (PVQUEST) that identifies the most common PV installation deficiencies. Compared to its study of systems in 2018, Cadmus found only 31 percent of small-scale projects exhibited major deficiencies, down from 47 percent in 2018. They also found that the average quality scores for projects in 2019 were 0.70 points higher than scores in the 2018 study. Cadmus worked with OER to publish a Minimum Technical Guidance document and developed a web-based training for the REG Program to help guide applicants on best installation practices.[61] The goal of this

[60] The maximum size for hydropower projects is 1 MW.
[61] http://www.energy.ri.gov/documents/renewable/RI-REG-Minimum-Tech-Guidance_2019.pdf

effort that OER and Cadmus have worked on is to increase the likelihood that projects in the REG program are successful.

The REG program started in 2015 with a target of 160 MW to be filled within five years, where the annual target was 25 MW for 2015, 40 MW for 2016 through 2019, and the remaining unfilled capacity for 2020.[62] In 2017, the program was extended by S.B. 112A through 2029 with an annual capacity target of 40 MW and a cumulative total of 400 MW. The cumulative target in the REG program allows for some flexibility in the annual target in the event that some years see more or less enrollment in the program compared to others. Although the distribution of an annual enrollment target to different Renewable Energy Classes is subject to change, the distribution across classes for 2020 is shown in Table 16. For small-scale solar projects, the program accepts applications on a rolling basis for the full year until the enrollment target is fulfilled. For projects larger than 25 kW, applications are accepted during three two-weeklong open enrollment periods throughout the year.

Table 16. 2021 REG Program Targets and Ceiling Prices

Renewable Energy Class (Nameplate kW DC)	Annual Enrollment Target (Nameplate MW DC)	Ceiling price (including ITC/PTC & Bonus Depreciation) ($/MWh)	Term of Service (years)
Small-Scale Solar (1-10 kW)	6.95	$296.50	15
Small-Scale Solar (11-25 kW)		$234.50	20
Medium-Scale Solar (26-250 kW)	3	$211.50	20
Commercial-Scale Solar (251-999 kW)	8.244	$182.50	20
Large-Scale Solar (1,000-5,000 kW)	18.294	$136.50	20
Community Remote DG Commercial Solar (251-999 kW)	3	$209.90	20
Community Remote DG Large Solar (1,000-5,000 kW)	3	$157.00	20

Unlike many of the other state-run DG incentive programs, the REG program is administered by the state's only utility, National Grid. The Public Utilities Commission (PUC) approves the solar incentive ceiling prices for each Renewable Energy Class annually; the ceiling prices represent the highest possible incentive price an applicant could receive, though the actual incentive rate a program participant receives is as bid and may be lower than the ceiling price. Ceiling prices are derived using the NREL CREST model, which the consultant for the REG program updates annually. During the open enrollment period, applicants submit bids that must be lower than the administratively determined ceiling price and for the entire output of the project. National Grid selects projects based on lowest proposed prices and soonest commercial operation date until the enrollment target for the Renewable Energy Class is met. Unfulfilled capacity in a given Renewable Energy Class is rolled over to the next year. Results from each open enrollment period

[62] While the 160 MW was allocated across the four technologies, only 5 MW out of the 40 MW annually was allocated to wind, anaerobic digesters, and hydro.

are posted on the National Grid program website.[63] By way of example, Table 17 below provides a summary of projects selected in the 2020 third open enrollment period. Aside from a few medium-scale solar bids, most of the accepted bids were within a few dollars per MWh of the class ceiling price. Adders are allowed under the REG program for projects that are built on less desirable land, however as of 2020 the only adder that a participant can receive is $5 per REC for development on carports under the Solar Carport Incentive set-aside.

Table 17. REG Program 2020 Third Open Enrollment Results[64]

Renewable Energy Class	Number of Projects Selected	Project Size Range (Nameplate kW)	Total Capacity Selected (Nameplate kW)	Accepted Price Range ($/MWh)	Class Ceiling Price ($/MWh)
Small-Scale Solar (1-25 kW)[65]	N/A	N/A	690	N/A	
Medium-Scale Solar (26-250 kW)	17	43 - 250	2,667	$190.50 - $211.50	$211.50
Commercial-Scale Solar (251-999 kW)	4	392 - 998	3,046	$180.00 - $181.40	$182.50
Large-Scale Solar (1,000-5,000 kW)	1	2,766	2,766	$136.40	$136.50
Community Remote DG Commercial Solar (251-999 kW)	0	N/A	N/A	N/A	$209.90
Community Remote DG Large Solar (1,000-5,000 kW)	1	2,995	2,995	$156.00	$157.00

Applicants that have a bid accepted must submit a Performance Guarantee Deposit within five days of being accepted. The REG program tariff specifies that the amount of the Deposit will be calculated as $15 per REC for Small DG projects and $25 per REC for large DG projects multiplied by the estimated RECs to be generated during the project's first full year in service. This deposit is refunded to applicants in quarterly payments during the first year, where projects that do not reach completion forfeit the deposit paid.[66] Throughout the term of the contract, 15 or 20 years, National Grid owns the rights to RECs, energy, and capacity, if the company chooses to participate in the Forward Capacity Market (FCM). Therefore, the participant does not receive any payments for these three products, instead only receiving the PBI as bid under the ceiling price.

Participants choose whether they would like to receive their PBI as a direct payment or a combination of direct payment and bill credits, where community solar participants must select the combination

[63] https://ngus.force.com/s/article/Rhode-Island-Renewable-Energy-Growth-Program

[64] http://www.ripuc.ri.gov/eventsactions/docket/4983-NGrid-REG2020-ThirdEnrollment%20(12-22-20).pdf

[65] For small-scale solar projects selected, the only information provided is total program capacity available as of 5/24/2021: https://ngus.force.com/s/article/Residential-Renewable-Energy-Growth-program-available-cap

[66] https://ngus.force.com/servlet/servlet.FileDownload?file=0150W00000ETZqA

approach. If the direct payment approach is selected, the participant receives the price they offered into the program at the time of selection multiplied by the amount of energy produced. For participants that select the combination approach, the Bill Credit is calculated as follows and then subtracted from the PBI:

*Bill Credit = Credit for Allocated Generated Energy **

(Distribution Charge + Transmission Charge + Transition Charge + Last Resort Service Charge)

If the PBI is greater than the bill credits, the participant receives a direct payment in the form of a check. If the PBI is less than the bill credits, the participant receives the full amount of the bill credit, not to exceed the sum of delivery charges and the last resort service charge.

One of the main merits of the combination approach used in the Rhode Island REG program is that it allows for a high level of transparency in the process for setting prices and information provided on selected projects. A key difference in the administration of the REG program as compared to the ABP is that the REG program compensation is done on bill credits. While CREST is used to determine incentive prices as under the ABP, REG program users bid for the all-in modeled incentive and any credits for net-metering and energy value are deducted from the customer's bill at the utility level.

Analysis of Small Subscriber Adder

Definition and Objectives

In general, CS projects face additional costs and feature reduced eligibility for direct energy-related revenues as compared with DG systems. For example, in Illinois, on the revenue side, subscribers to CS projects are only eligible for energy-only net metering, while on the cost side, there is the cost of acquiring, maintaining, and managing subscribers. In Minnesota, participation by residential customers in CS gardens is hampered by higher customer acquisition and management costs.[67] Comments submitted by stakeholders, in response to the Minnesota Public Utilities Commission's (MN PUC) request for comments on whether any adder should be applied to the value of solar rate (VOS)[68] for residential and low-income residential subscribers to CS gardens[69], included the following: (i) an adder should be applied to cover the additional recruitment and administrative costs associated with residential subscriptions, and (ii) an adder should be applied to cover higher customer acquisition costs, and higher outreach and marketing costs.[70] The higher customer acquisition and administrative costs create a hurdle for the participation of small subscribers, which is typically addressed by the small subscriber adder.

[67] See Minnesota Solar Energy Industries Comments on extending the Residential Adder at: https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={E0AADD75-0000-C43C-BDCD-E299E808EF40}&documentTitle=202011-168426-02

[68] The value of solar rate is intended to reflect the value society places on the addition of solar to the power grid and to capture the costs avoided by solar generation in comparison to generation from a natural gas combustion turbine.

[69] A community solar garden is a facility that generates electricity by means of a ground-mounted or roof-mounted solar photovoltaic device whereby subscribers receive a bill credit for the electricity generated in proportion to the size of their subscription.

[70] See summary of stakeholder comments at: https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={4C1BDCDD-FAA4-400A-9CD8-30EC1898873E}&documentTitle=20173-129559-01

Additional costs may be incurred by developers of CS projects with residential and small commercial subscribers. The costs can be divided into Year 1 and Year 2-Project Life costs.[71] Year 1 costs, that cover subscriber acquisition and management, include the upfront administration costs which cover marketing and communications, customer acquisition set-up, outreach set-up, administration set-up, and Year 1 subscriber management costs. The Year 2-Project Life costs cover lifetime subscriber management costs and include costs for outreach, sales, sign-up transactions, customer service, and billing administration.

The objective of the small subscriber adder is to provide a level playing field for small subscribers to account for these additional costs. The adder incentivizes the development of projects with small subscribers. Legislation in states that have implemented CS have language to incentivize such development. In Minnesota, the authorizing statute for CS requires that programs approved by the MN PUC must "reasonably allow for the creation, financing, and accessibility of community solar gardens".[72] In Illinois, the Act requires that the Illinois Power Agency propose terms and conditions that "ensure robust participation opportunities for residential and small commercial customers and those who cannot install renewable energy on their own properties."[73]

In Massachusetts and Illinois, the small subscriber adder is applied to projects with sizes 25 kW or less and covers residential and small commercial customers. In Minnesota, the adder applies to all residential customers which are split into two groups: <250 kW and ≥250 kW.

Experience in other states

Small subscriber adders or the equivalent are currently being implemented in Massachusetts and Minnesota. In Massachusetts the adder is referred to as the Low-Income Community Shared Solar Adder. In Minnesota it is referred to as the Residential Adder.

Minnesota

The Minnesota the Residential Adder only applies to Residential Subscribers. The original values of the adder were proposed by the Minnesota Department of Commerce in response to the MN PUC's request for comments on whether any adder should be applied to the VOS. The Department of Commerce proposed an adder that was stepped down over a 3-year period, decreasing by 1¢/kWh ($10/REC) each year, as shown below:[74]

- 2.5 ¢/kWh ($25/REC) - 2018
- 1.5 ¢/kWh ($15/REC) - 2019
- 0.5 ¢/kWh ($5/REC) - 2020

[71] See Elevate Energy comments on Draft LTRRPP at: https://www2.illinois.gov/sites/ipa/Documents/2018ProcurementPlan/2018-LTRenewable-Elevate-Energy-Comments.pdf

[72] See https://www.revisor.mn.gov/statutes/cite/216B.1641/pdf , page 1, (e)(1)

[73] 20 ILCS 3855/1-75(c)(1)(N).

[74] The report by the Minnesota Department of Commerce can be found at:

https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={4C1BDCDD-FAA4-400A-9CD8-30EC1898873E}&documentTitle=20173-129559-01

The MN PUC sought additional stakeholder input prior to making a decision on whether or not to implement a VOS small subscriber adder. The commission also asked Xcel Energy, the responsible utility, to conduct an analysis of the incremental cost of implementing the adder. In their analysis Xcel Energy concluded that they did not believe the incremental costs justified the implementation of an adder and therefore opposed the adder.[75]

In their Order the MN PUC noted:

> "In considering whether to adopt an adder, the Commission is mindful of the importance of the Legislature's policy goal to enable the creation, financing, and accessibility of solar gardens. Doing so requires consideration of how to establish incentives while minimizing corresponding program costs. Balancing these interests facilitates successful outcomes and furthers the public interest."[76] (Underlining added for emphasis)

The MN PUC further noted:

> "The record in this case demonstrates that the costs of obtaining and serving residential subscribers are higher than other subscribers. The record also demonstrates that an adder is reasonably likely to both incentivize continued development of gardens that include residential subscribers and prevent an abrupt halt to such subscriptions. The Commission also concurs, however, with the Department's initial recommendation to place a time-limit on the adder as a way to limit program costs and to allow for timely analysis of the adder's effectiveness, along with consideration of any further changes." (Underlining added for emphasis)

The MN PUC adopted a Residential Adder as follows:

- 1.5 ¢/kWh ($15/REC) for a 2-year term, as a pilot.
- The adder would apply to any project application with a VOS vintage year of 2019 or 2020.
- Once the adder was attached to a garden application, it would apply to all residential subscriptions in that garden over the 25-year life of the garden, commencing at the date of operation.

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[75] See Excel Energy analysis at:
https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={C046C461-0000-CD1F-A2DB-333E2F0A0192}&documentTitle=20182-140436-01

[76] See MN PUC Order at:
https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={B0DE1D67-0000-C217-96A6-3A771CB0C0B1}&documentTitle=201811-147853-01

The pilot program for the Residential Adder expired at the end of 2020. Stakeholders have petitioned the MN PUC to extend the current Residential Adder for another two years.[77] The MN PUC is considering the request.

Massachusetts

In Massachusetts the Low-Income Community Shared Solar Adder was adopted as part of the SMART program.

A Community Shared Solar Tariff Generation Unit is defined as "A Solar Tariff Generation Unit that provides electricity or bill credits to three or more Customers of Record. No more than two participants may receive bill credits in excess of those produced annually by 25 kW of nameplate AC capacity, and the combined share of said participants' capacity shall not exceed 50% of the total capacity of the Generation Unit, except in the case of Generation Units smaller than 100 kW AC."[78] A Low Income Community Shared Solar Tariff Generation Unit is defined as "A Community Shared Solar Tariff Generation Unit with at least 50% of its energy output allocated to Low Income Customers in the form of electricity or bill credits."[79] For a Community Shared Solar Tariff Generation Unit to qualify as a Low-Income Community Shared Solar Tariff Generation Unit, "No more than two participants may receive bill credits in excess of those produced annually by 25 kW of nameplate capacity, and the combined share of said participants' capacity shall not exceed 50% of the total capacity of the Generation Unit."[80]

The Community Shared Solar Adder, which is reserved for Low-Income Community Shared Solar Tariff Generation Units, applies to projects with at least 50% of their capacity allocated to subscriptions of 25 kW or less. The value of the adder, which is included in the legislation is $0.06/kWh or $60/REC.[81] Compensation is for a period of 10 years.[82]

Massachusetts did not share any information on how the value of the Low-Income Community Shared Solar adder, other adders for the SMART program, or the multipliers for the Base Compensation Rate were developed.

[77] See comments by Cooperative Energy Futures, Minnesota Solar Energy Industries Association, and US Solar Corporation, and at: https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={E05BDD75-0000-C01A-BBE6-022EC0984D76}&documentTitle=202011-168424-01; https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={E0AADD75-0000-C43C-BDCD-E299E808EF40}&documentTitle=202011-168426-02; https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={10BE4976-0000-C017-8A7B-6D398682EF0A}&documentTitle=202012-168906-01

[78] 225 CMR 20.00 at https://www.mass.gov/doc/225-cmr-2000-final-071020-clean/download at page 2.

[79] Id. at page 4.

[80] Id. at page 17, (f)1.

[81] Id. at pages 24-25, (b).

[82] Id. at page 21, 20.07 (1).

Methodological Approaches

The table below shows a comparison of the small subscriber adders in Illinois, Massachusetts, and Minnesota for 50% residential participation. Minnesota does not base its adder on the level of participation but just applies it to all residential customers.

Table 18: Comparison of Small Subscriber Adders

State	Name of Adder	Value of Adder ($/REC)
Illinois	Small Subscriber Adder	$22.34 – Group A $21.77 – Group B
Massachusetts	Low-Income Community Shared Solar Adder	$60
Minnesota	Residential Adder	$15

Minnesota

In Minnesota the initial value of the Residential Adder was an approximation of the difference between the applicable retail rate (ARR) for residential customers subscribing to a garden with a capacity of more than 250 kW and the VOS rate, as shown in Table 1 of the report by the Minnesota Department of Commerce.[83] As explained in the report, under the initial CS garden program rules, subscribers to a CS garden received a credit on their bills based on the ARR. The MN PUC later issued an Order approving a VOS rate for the CS garden program.

The methodology for the VOS rate takes into account avoided costs for fuel, operation and maintenance (fixed and variable), generation capacity, reserve capacity, transmission capacity, distribution capacity, and environmental. The ARR is calculated using total retail revenues including the energy charge, demand charge, and customer charge, divided by total retail sales to the specific class. Under the ARR methodology rates vary by customer class. The VOS on the other hand results in a single VOS rate for all customers. The difference between the ARR residential customers with a capacity of more than 250 kW and the VOS rate is approximately 2.5c/kWh ($25/REC), which is the base rate that the Minnesota Department of Commerce recommended to the MN PUC. The PUC adopted a lower rate of 1.5c/kWh ($15/REC).

Massachusetts

Massachusetts does not provide any information on how the Low-Income Community Shared Solar adder is calculated. The adder is, however, included in the legislation which means changes to the value of the adder would require changes to the legislation. While it is not clear why Massachusetts decided not to disclose the calculations for the adder it could be that an actual analysis was not performed, and the adder was based on either stakeholder preferences or what the SMART program considers a reasonable value, while taking into account budget and other considerations. Furthermore, this adder is not directly comparable as it is reserved for low-income subscribers, not residential subscribers more generally.

[83] The report by the Minnesota Department of Commerce can be found at: https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={4C1BDCDD-FAA4-400A-9CD8-30EC1898873E}&documentTitle=20173-129559-01

Illinois

The ABP value for the small subscriber adder was based on an analysis of the expected costs for subscriber acquisition and management which took into account stakeholder comments.

In the Draft Plan for Comments that was issued on September 29, 2017, the adder, which was then called the Residential Participation Adder, was based on modelling data provided by Elevate Energy in their response to the IPA's June 6, 2017 request for comments.[84] Elevate Energy modelled a 1,000 kW system and determined the system's 25-year administration and customer acquisition costs for 100% commercial participation (i.e., 0% residential participation), and 100% residential participation.

Comments on the Residential Participation Adder were received from Elevate Energy,[85] Joint Solar Parties ("JSP")[86], and Coalition for Community Solar Access ("CCSA").[87] In these comments stakeholders were generally advocating for higher values of the adder. Elevate Energy noted that the Elevate Business Case Tool, data from which the IPA had relied on in setting the Draft Plan adders, had a formulaic error which did not accurately account for all the outreach costs --- it did not calculate the total new subscribers correctly and subsequently reduced overall costs. Elevate indicated that they had corrected this error. Elevate also noted that their models for subscriber management costs were based on hypothetical scenarios and the values they presented were not intended to determine REC prices specifically but to show the relative value of potential prices based on certain inputs. Elevate Energy further noted that only the solar industry has actual data that measures the performance of projects in relation to subscriber management costs, and that unless the industry begins to publish this data, there would be no way for their model to reflect the actual performance costs.

JSP commented that the proposed $7.89/REC adder for 50% Residential Participation may be too low for management of this customer group. In their comments on the Residential Adder, CCSA noted that the proposed adder underestimated actual costs, and recommended using the results of the analysis by the Rhode Island Office of Energy Resources (RIOER) on cost assumptions for community solar.[88] RIOER conducted an industry survey on community solar administrative costs related to projects that allocate at least 50% of their capacity to subscription sizes of 25 kW or less. The RIOER survey results indicated that the upfront (one time) subscriber acquisition costs associated with these projects are $0.25/Watt, and

[84] See https://www.illinois.gov/sites/ipa/Documents/Elevate-Energy-L-RRPP-Request-Comments-20170714-Updated.pdf (Page 14).

[85] https://www2.illinois.gov/sites/ipa/Documents/2018ProcurementPlan/2018-LTRenewable-Elevate-Energy-Comments.pdf

[86] https://www2.illinois.gov/sites/ipa/Documents/2018ProcurementPlan/2018-LTRenewable-Joint-Solar-Parties-Comments.pdf

[87] https://www2.illinois.gov/sites/ipa/Documents/2018ProcurementPlan/2018-LTRenewable-Coalition-for-Community-Solar-Access-Comments.pdf

[88] https://www.illinois.gov/sites/ipa/Documents/2018ProcurementPlan/2018-LTRenewable-Coalition-for-Community-Solar-Access-Comments.pdf.

that the ongoing (annual) costs associated with subscriber replacement is \$0.02/Watt/year, and the ongoing (annual) cost of subscriber management and billing is about \$0.01/Watt/year.[89]

For the Initial Plan, issued on August 6, 2018, the IPA implemented the recommendation by CCSA to use the RIOER cost assumptions in developing the adder, which was reconstituted as the small subscriber adder, to accommodate small commercial customers as well.

The review of the implementation of the small subscriber adders in Minnesota and Massachusetts, show a clear need for such an adder to provide a level playing field for small subscribers to account for the additional costs that are related to small subscribers. As the record in the Minnesota docket showed, and as confirmed by the MN PUC Order, the costs of obtaining and serving residential subscribers are higher than for other subscribers. Stakeholders in the Illinois docket also noted that an adder is needed in order to account for the additional costs related to small subscribers, related to acquiring, maintaining, and managing the small subscribers.

The review of the methodological approaches for the small subscriber adders in Minnesota, Massachusetts, and Illinois, shows that there does not appear to be a uniform approach for calculating the adders. Minnesota used a simple approximation of the difference between the ARR and VOS. Massachusetts did not provide an analysis but recommended a value which was included in the legislation. Illinois, after stakeholder input performed an analysis of the expected costs for subscriber acquisition and management. However, as noted by Elevate Energy, only the solar industry has actual data for subscriber management costs, and unless the solar industry begins to publish this data, there would be no way to reflect the actual performance costs in any calculation of the small subscriber adder. As shown in the calculations of the small subscriber adder in Illinois, different cost assumptions will produce different values for the adder, and it is difficult to satisfy every stakeholder. There was no consensus in Minnesota among stakeholders regarding the value of the adder and the MN PUC decided to split the difference by adopting \$15/REC as opposed to the originally proposed \$25/REC on the high end and \$5/REC on the low end.

In Illinois, the Act requires that the Illinois Power Agency propose terms and conditions that "ensure robust participation opportunities for residential and small commercial customers and those who cannot install renewable energy on their own properties." The legislative requirement, as well as the record which shows that there are additional costs related to small subscribers, means that to ensure that the benefits of solar energy are widely shared by Illinois residents, the ABP should offer the small subscriber adder for CS projects. The question is what the value of that adder should be, and for what level(s) of subscription. The Initial Plan included 25%, 50%, and 75% participation levels. The First Revised Plan removed the 75% participation level. The reasoning behind the elimination was to recognize that the desire to achieve at least 25% small subscriber participation in CS. This level of participation had been more than met by the CS projects accepted then and there was concern that the adders may be over-incentivizing small subscriber participation to the detriment of participation by larger subscribers while creating outsized impacts on available funding. The issue of available funding is key, and while the idea of having the small subscriber adder has merit, the available funding will determine how successful the incentive program will be.

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[89] SEA. (2016) Rhode Island Renewable Energy Growth Program: 2017 2nd Draft Ceiling Price Recommendations. Available at: http://sos.ri.gov/documents/publicinfo/omdocs/minutes/6154/2016/49211.pdf.

Recommendations

The programs reviewed here offer some insights for the IPA regarding the approaches available to update the ABP REC pricing approach. New Jersey's solar DG and CS program evolved from the use of exchange trading to set SREC prices to a transition period in which cost-based modeling provides the guidance for administratively setting SREC prices. Legacy SREC prices for EY 2021 average $215.50/SREC while the base price for the Transition program was set at $152/SREC. Under the Successor Solar Program, prices for DG projects smaller than 2 MW and all CS projects will be set administratively and prices for projects greater than 2 MW will be determined through competitive procurements. The proposed administratively set SREC values for the first three years of the program for CS projects and DG solar projects less than 2 MW range from $70/SREC to $90/SREC. The SREC prices for the competitively based Delaware procurement for EY 2019, the last year for which procurements were held, ranged from $10.00 to $50.00 with a weighted average across project classifications of $32.50/SREC. The values of SRECs show a range of values due to the different specific project requirements, budgetary considerations, and policy goals for each state's program.

Another consideration to draw on for the ABP from other states' program implementation is the extent to which net metering is accounted for in the incentive prices offered. Participation in some programs such as the NY-SUN program will preclude customers from receiving net metering going forward, with the aim of the upfront solar incentive to replace the net metering program. Other programs such as REG in Rhode Island provide on-bill credits that reflect actual facility generation and net metering revenue. To the extent that the IPA can make changes to the way the ABP and net metering interface, it may be worth considering how other incentives interact with net metering.

Going forward, there are three incentive pricing approaches available to the IPA for improving the REC pricing approach used for the ABP.

1. Update and tighten the inputs and assumptions to the cost-based CREST model to reflect changes in market conditions, tax incentives, and the regulatory environment that have occurred since the REC pricing model was first used in 2017. A focus of the updates would be to incorporate into the model project cost and operating information that can be obtained from a review of the costs and operating characteristics of the projects that have been built under the ABP to date. Information regarding the use of modeling systems and the development of adders in other state programs, especially with regard to how these administratively set incentives incorporate market data, would be reviewed for any inputs that could be used for ABP CREST modeling. A program of administratively set REC prices could be continued by the adoption of a new cost-based modeling system such as NREL's System Advisor Model (SAM). However, while SAM has additional capabilities relative to CREST such as some Monte Carlo based simulation options, these additional capabilities would not add significant value to the modeling approach for the IPA's purposes. SAM still suffers from the drawbacks that affect all cost-based modeling in that the cost inputs are developed based on available cost and operating information and the results are not directly tied to market conditions. Substituting SAM for the CREST model would also involve substantial additional costs to bring that model to the point of being ready for use for the ABP.
2. An alternative to cost-based modeling would be to develop a formulaic approach to establishing REC prices similar to the methodology used for determining ZEC prices. In general terms, this

approach could start with publicly available estimates of the cost of generation from various sized CS and DG solar generation projects[90] and technologies. Subsequently, the energy and capacity revenues these projects could earn based on current market prices, any net metering credits, and applicable tax incentives would be subtracted from the costs of generation. The resulting potential shortfall in revenues that would make CS and DG projects viable would be addressed through adders or factors such as the social cost of carbon and incentives to meet policy goals involving project location and customer make-up.

3. A competitive procurement for the largest ABP project size class to establish the baseline price for the rest of the ABP Competitive procurements. Adders and/or factors would be used to modify the baseline price to reflect the higher costs of the other size classifications and to reflect program policy goals. However, while competitive procurements have been utilized successfully to a varying extent in several states, competitive bidding may not be applicable to the ABP.

[90] Lazard annually publishes estimates for the levelized cost of electricity from various generation technologies including roof-top residential solar PV, solar PV for commercial and institutional DG applications, and community solar PV.