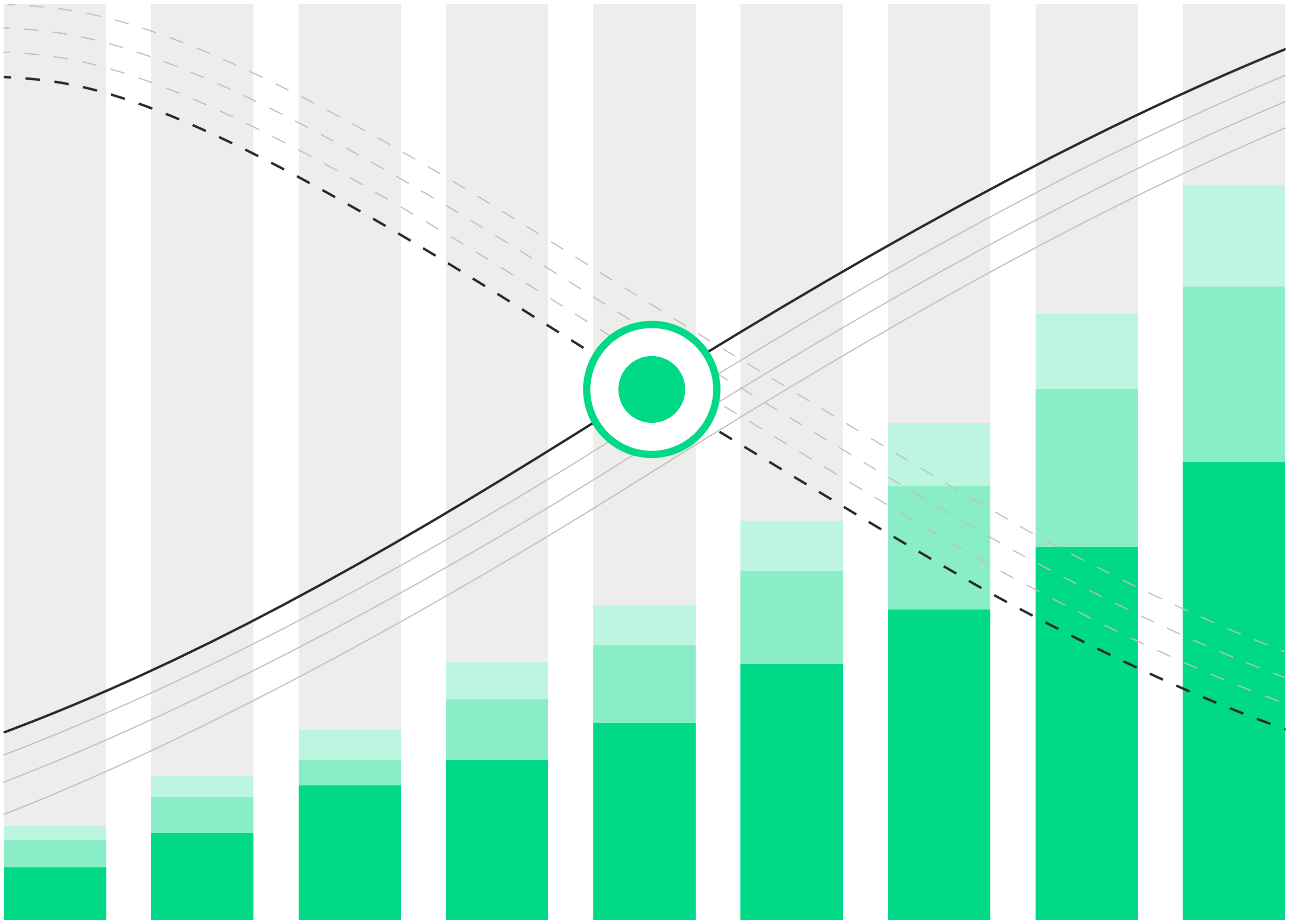

A WHITE PAPER
IN DEFENSE OF RPS

A Future for Renewable Portfolio Standards in the United States

prepared by

RECMINT

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Contents

Executive Summary

The United States is at a pivotal point in the politics of the 21st century energy transition. The resonance of political themes such as "affordability"— and in particular the themes of affordability of electric and gas utility costs—are colliding with the physical limitations of the nation's grid infrastructure. Rapidly accelerating load growth stemming from data centers and AI development, in addition to broader electrification and higher rates of electric vehicle (EV) adoption, are pushing up electricity prices due to massive new investments in grid infrastructure to meet demand. At the same time, the relative flexibility of distributed energy resources (DERs)—smaller projects sited at the distribution system level that do not require significant ratepayer investments in transmission infrastructure—have proven themselves to be one of the most efficient ways to add electrons to the grid in the face of growing demand. This is in large part due to the dramatically reduced timelines these projects require in order to interconnect to the grid.

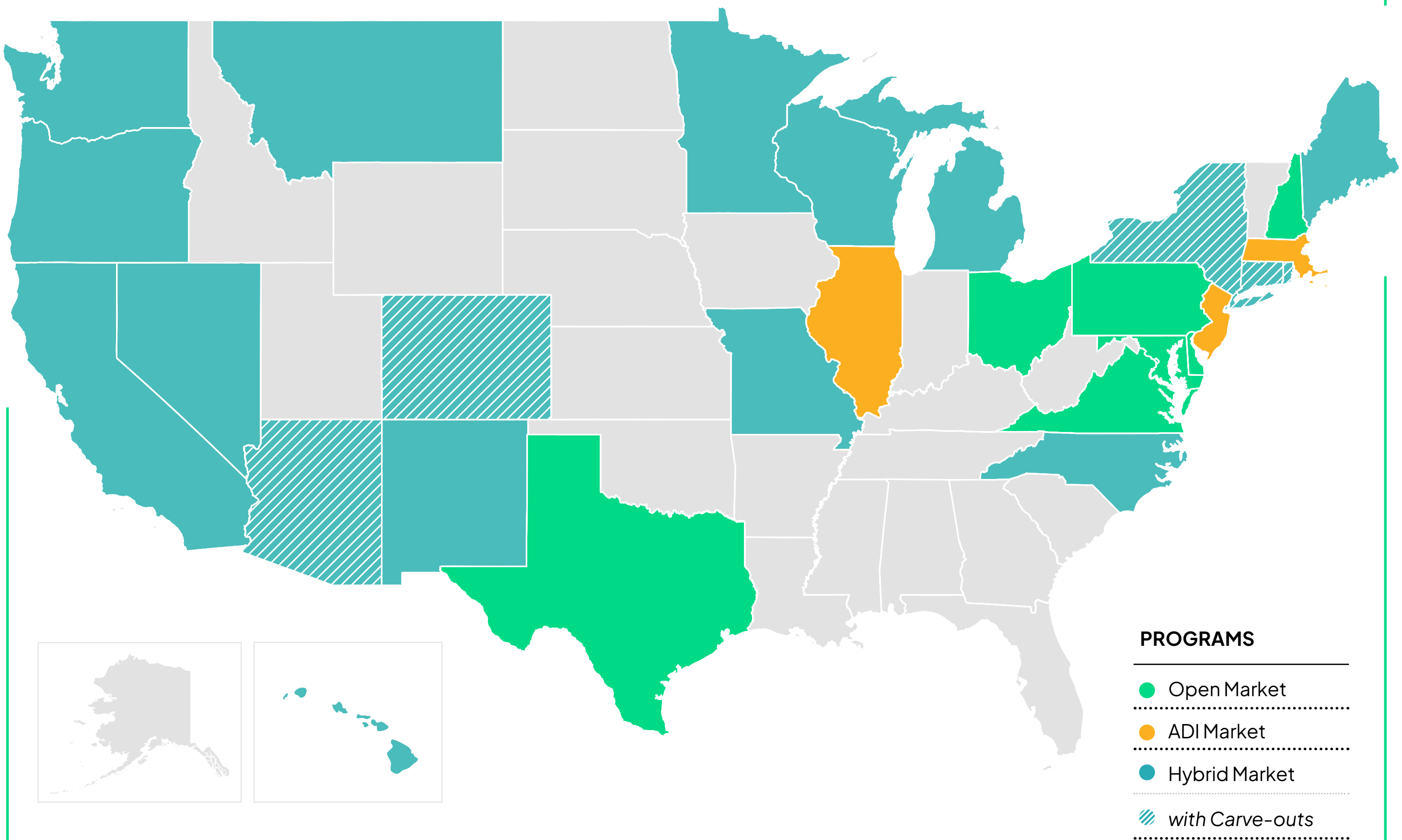
Coinciding with this historic moment is the rollback of federal policy support for renewable energy. While the repeal of federal incentives as a result of the One Big Beautiful Bill Act represents a net negative with respect to achieving clean energy goals, it has had the unexpected side effect of uniquely positioning states to chart their own future when it comes to incentivizing clean energy development in order to meet this growing demand. The collision of these factors have created a prime opportunity in 2026 to bolster state-level programs to shift toward designs that achieve the shared aims of affordability, flexibility, and administrative efficiency.

THE GOAL IS ABUNDANTLY CLEAR:

We need flexible, distributed, clean energy resources to be deployed as quickly as possible, while ensuring that this path can help put downward pressure on customer rates.

The states are the primary actors responsible for the implementation of one of the oldest and most effective renewable energy policies in our country—the Renewable Portfolio Standard (RPS). The market design of the RPS programs has taken three broad forms: (1) an open market where supply and demand determines the pricing for renewable energy certificates (RECs), (2) an administratively determined rate (ADR) market where the state regulator establishes REC prices based on market information, and (3) a hybrid market where the state or the utility procures RECs through a centralized procurement process. **Figure 1** provides a breakdown of market structure for each of the 29 states with RPS programs.

FIGURE 1: **THREE FORMS OF RPS PROGRAMS**



The current political moment necessitates a review of current RPS designs to ensure that states have the appropriate incentive mechanisms that are responsive to the market's needs and can meet the moment at hand. In an open market design, RECs are traded as a commodity where supply and demand determine pricing for the REC. The open market RPS model operates as a regulated commodity market with a price ceiling in the ACP, eligibility constraints, and flexibility mechanisms such as banking provisions and vintage rules. The regulator sets the obligation, defines the guardrails, and enforces compliance. But market participants ultimately determine REC pricing through entirely decentralized transactions. The model's strengths lie in price discovery, liquidity, and least-cost compliance across broad resource pools. Key states with an open market design are Virginia and Maryland, each of which is discussed in more detail in this report.

In an ADR market, a state regulator or entity establishes the price for RECs rather than a floating market-based price. In ADR markets, REC procurement is often centralized or partially centralized through a state entity (for example, a power authority or utility commission). That entity conducts competitive solicitations for renewable energy or REC contracts, frequently offering long-term agreements that establish fixed or indexed REC compensation levels. Key states with an ADR market design are Illinois and New Jersey, which are also discussed in more detail in this report. Figure 2 below provides a comparison of the open market and ADR market design structures.

FIGURE 2: **OPEN MARKET VS. ADR**

Two ways to price a Renewable Energy Certificate (REC)

	OPEN MARKET REC	ADMINISTERED / UTILITY
Does it reveal the real market price?	REC prices are discovered through actual transactions, giving regulators and market participants a live signal of supply, demand, and compliance costs.	Prices are set administratively, typically on a yearly or multi-year cadence, which can create a timing delay actual market conditions and project costs.
Does it support affordability?	The price changes in real-time based on supply and demand, so buyers can seek the lowest-cost eligible RECs supporting least-cost compliance.	Administratively set prices are locked in at a fixed level for a fixed timeframe, creating the risk of overpayment if they are set above what the market would otherwise clear.
Does it adapt when conditions change?	Prices can adjust as costs, supply, demand, tariffs, and project economics shift.	Price changes depend on formal approval cycles that typically occur yearly or on a multi-year cadence rather than in real-time.
Does it limit administrative burden?	Regulators set the rules for participation in the market and monitor compliance, but there is little administrative burden on market pricing.	Regulators establish REC pricing, requiring significant docket engagement plus oversight of contract terms and procurement structures.
Does it have any downsides?	If there is oversupply of RECs or weak RPS targets, this can depress REC prices and not serve as a driver of greater renewable development.	These markets can lead to over-subscription, waitlists, lotteries, and ratepayer overpayment as part of the program structure.

While there are benefits of each market design, an open market creates the greatest opportunity for flexibility while balancing the shared goal of affordability. The states with open market designs are able to respond to real-time market conditions while not overinflating REC pricing that can exacerbate affordability concerns. This paper highlights model open market design goals that can produce a successful RPS market over time.

BEST PRACTICES OF RPS PROGRAMS

	Best Practice	Key Principles
1	**Set ambitious, yet realistic RPS goals**	Set targets high enough to balance REC supply and demand and avoid persistent undersupply or oversupply. Adjust goals as market conditions change.
2	**Increase RPS requirements consistently**	Ratchet REC demand upward predictably to keep pace with supply, support price stability, and signal continued investment in renewable generation.
3	**Set an appropriate, flexible ACP**	Set the ACP above expected REC market prices so compliance favors renewable investment over paying the penalty. Allow periodic adjustments as market conditions change.
4	**Use flexible, time-limited banking rules**	Allow surplus RECs to be banked to reduce year-to-year price volatility, but limit their life—typically 2–5 years—to avoid oversupply and support new development..
5	**Favor new capacity over existing capacity**	Prioritize newer RECs and limit older vintages to ensure RPS compliance drives development of new renewable generation rather than relying on legacy projects.

Review of RPS Development and Solar Deployment

Ambitious RPS goals at the state-level have been a major driver of solar development for at least two decades. As a policy design, the RPS emerged in the late 1990s[1] as a mechanism to internalize the public benefits of renewable electricity and expand generation from wind, solar, biomass, geothermal, and other eligible renewable resources. State RPS policies are widely credited with spurring roughly half of all U.S. renewable generation growth over the past two decades, particularly wind and solar capacity additions.[2] These policies created demand for RECs from utility compliance requirements, while also providing supplemental revenue streams to renewable energy projects and lowering the overall financing risk for these projects.

While efforts at the national level to implement a federal RPS have never materialized, states have been at the forefront of policy implementation and have independently adopted mandatory standards that require electricity suppliers to procure a specified percentage (or amount) of renewable energy or associated credits (RECs). The basic mechanics of the RPS are that these renewable energy requirements ratchet up as time goes on. In the early days, these goals only envisioned a small share of the state's energy supply be met with renewable energy. As the climate crisis has evolved and deepened in severity, and as federal policy commitment dampened in response to the first Trump administration's withdrawal from climate commitments, we saw 16 states adopt enhanced RPS requirements focused on achieving 100% renewable energy by 2040 to 2050.[3]

By 2023, 29 states plus the District of Columbia have active RPS programs, with a growing number of states expanding to Clean Electricity Standards (CES) that include additional zero-carbon resources such as nuclear energy.[4] RPS designs vary widely, though the foundation is the use of the REC to measure compliance: each megawatt-hour (MWh) of qualifying renewable generation creates a tradable REC that can be purchased by the load-serving entity to demonstrate compliance.

There are three overarching compliance strategies:

1. **Open market** where supply and demand determines the pricing for RECs,
2. **Administratively determined rate (ADR) market** where the state regulator establishes REC prices based on market information, and
3. **Hybrid market** where the state or the utility procures RECs through a centralized procurement process.

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1 Will add citation.
2 Will add citation.
3 100% RPS goals in combination with Clean Energy Standard (CES) goals that tend to be inclusive of electric sector emissions standards. CES' also tends to be inclusive of nuclear energy and fossil generation with carbon capture and sequestration.
4 Ibid.

In an open market design, RECs are traded as a commodity where supply and demand determine pricing for the REC.[5] Market-based REC prices broadly include state RPS targets, alternative compliance payment (ACP) levels, and inter-state credit eligibility.[6] Early early markets, particularly in the PJM region, also included a carve out for small-scale solar projects, often called an Solar REC (SREC). Prices in these SREC markets were initially high as supply lagged demand, but they have fallen over time as more small-scale solar projects were built and generated SRECs.[7]

The other REC market structure is the ADR structure. In these markets, a state regulator establishes the price for RECs rather than a market-based price. Illinois is an example of a state that shifted from an open market toward administrative procurement and structured pricing via the Illinois Power Agency (IPA) and its Long-Term Procurement Plan under the Clean Energy Jobs Act (CEJA). The IPA conducts competitive procurements for RECs from utility-scale and distributed renewable resources, and more recently has undertaken administrative REC pricing models to set price levels that support investment thresholds for developers. New Jersey has also shifted from its open market SREC design to an ADR model, citing similar reasons for the shift.

While advocates of the ADR have praised the approach noting that it creates predictable price signals for project financing, it also has introduced an additional layer of regulatory and administrative bureaucracy that has not translated to a healthy REC market and pronounced project buildout. For instance, the shift to an administratively determined REC price in Illinois has resulted in more limited project buildout, as project developers and critics have noted that the underlying incentive is too low to sufficiently support project economics.

This critique speaks to an underlying reality of renewable energy project development, which is that while project costs generally have a downward trajectory, these dynamics change year-over-year and are anything but static. Inflationary pressures, supply-chain and labor dynamics, land use, zoning, interconnection challenges, and federal policy dynamics all have dramatic impacts on overall project economics, which an administratively-determined REC is simply not able to reflect in an effective and timely manner.

Moreover, at a time when affordability is paramount, lawmakers and stakeholders would do well to examine the benefits of the administratively-determined design relative to the open market-oriented approach based on the benefits of flexibility, reduced administrative burden, and customer affordability. This paper will provide a closer examination of the benefits of the open market design as it relates to these key goals.

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5 EPA Clean Energy-Environment Technical Forum, Renewable Energy Certificates: Background & Resources
6 Resource Solutions, *Overview of Renewable Portfolio Standard Design Options* (2017), available at https://resource-solutions.org/wp-content/uploads/2018/01/CREEI-RPS-Design-Report-English.pdf
7 Lawrence Berkeley National Laboratory, *U.S. State Renewables Portfolio Standards: 2024 Status Update* (2024), available at https://emp.lbl.gov/publications/us-state-renewables-portfolio-clean-0

Open Market RPS Model Overview: Core Characteristics and Market Mechanics

An open market RPS model is best understood as a regulated compliance market layered on top of competitive wholesale electricity markets. After the state has successfully passed legislation establishing or expanding a RPS, a regulating agency (typically the state Public Utility Commission) confirms how much renewable energy must be procured and then establishes the compliance architecture. Beyond those guardrails, price formation and procurement are largely left to market actors. RECs function as the core compliance currency, and their value is determined through bilateral transactions, brokered markets, and forward contracting via third-parties.

At its foundation, the open market model separates the environmental attribute of renewable generation from the underlying electricity. One REC represents one megawatt-hour of eligible renewable production, and these certificates can be traded independently of energy. This unbundling is central to liquidity: it allows load-serving entities (LSEs) to procure renewable compliance without necessarily changing their physical energy procurement arrangements. In most RPS states, RECs are tracked through regional electronic registries that verify generation, prevent double counting, and record transfers and retirements of RECs (e.g. PJM-GATS, NYGATS, NE-GIS).

The most consequential design levers of an open market are the alternative compliance payment (ACP), geographic eligibility rules, carve-out breadth, banking provisions, and target escalation schedules. These parameters collectively determine whether the market operates in persistent surplus, periodic scarcity, or structural equilibrium. The design is vital to ensure that price signals are strong and stable enough to support sustained renewable deployment. As demonstrated throughout this report, the intentional design of these elements in an open market construct is essential to creating a well-functioning RPS market that results in robust renewable project development.

OPEN MARKET CHARACTERISTICS

Does it reveal the real market price?	REC prices are discovered through actual transactions, giving regulators and market participants a live signal of supply, demand, and compliance costs.
Does it support affordability?	The price changes in real-time based on supply and demand, so buyers can seek the lowest-cost eligible RECs supporting least-cost compliance.
Does it adapt when conditions change?	Prices can adjust as costs, supply, demand, tariffs, and project economics shift.
Does it limit administrative burden?	Regulators set the rules for participation in the market and monitor compliance, but there is little administrative burden on market pricing.
Does it have any downsides?	If there is oversupply of RECs or weak RPS targets, this can depress REC prices and not serve as a driver of greater renewable development.

Alternative Compliance Payment

The most important regulatory instrument in this framework is the Alternative Compliance Payment (ACP). The ACP functions as a statutory penalty for failing to procure sufficient RECs and, in practice, establishes a price ceiling. If REC prices approach the ACP, LSEs are indifferent between purchasing RECs and paying the penalty. As a result, REC prices functionally do not exceed the ACP. If a state has a technology-specific carve-outs, which typically focus on solar, the program may establish a higher, separate ACP reflecting the higher cost profile of distributed or emerging technologies.

As a general rule, in tight, undersupplied markets, REC prices gravitate toward the ACP; in over-supplied markets, they collapse toward marginal cost. The ACP therefore anchors both price expectations and project financing assumptions and is one of central features of the well-functioning REC market. Over time, many states schedule the ACP to decline, signaling an expectation that technology costs will fall and tightening long-run price ceilings.
It should be noted that while the cost trajectory for renewable energy technologies (particularly wind and solar) have a long-term downward trend over the past few decades, project costs can still vary dramatically due to several factors outside of developer control. These include inflationary pressures, supply-chain constraints, labor conditions, siting, zoning, and interconnection.

While these are all discrete issues that have their own set of individualized policy solutions, there is no single policy solution. This means that the evolving market conditions favor dynamic price responsiveness to ensure sustained project buildout.

Compliance Schedules and Banking Provisions

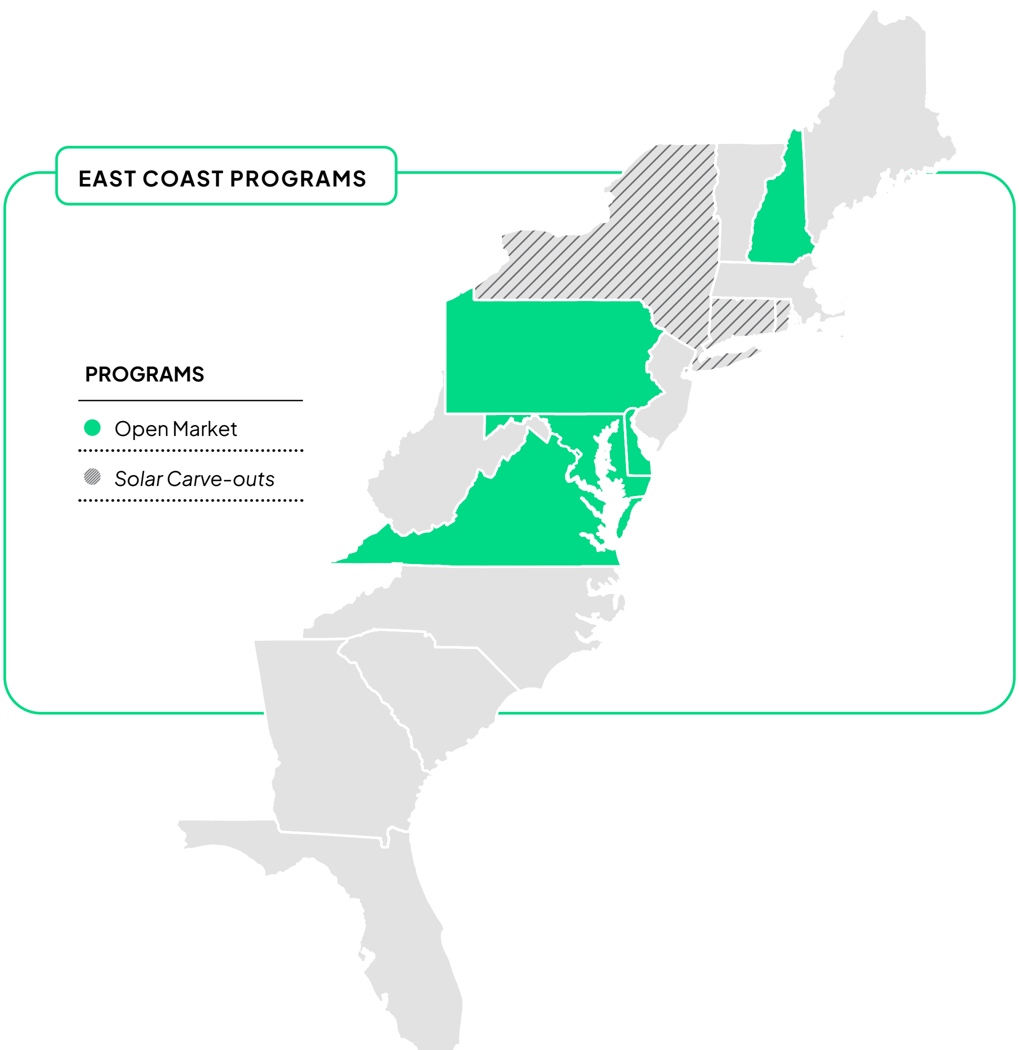
Compliance schedules further shape price behavior. Most RPS programs operate on annual compliance cycles with a subsequent true-up period, during which LSEs reconcile their REC obligations. Banking provisions typically allow excess RECs to be carried forward for a defined number of years. Banking smooths short-term volatility but can also amplify cyclical dynamics. In periods of rapid buildout, excess supply accumulates in banked inventories. When obligations rise more slowly than supply, prices can deteriorate sharply as the market recognizes a structural surplus.

Conversely, when obligations accelerate or supply growth stalls, banked inventories cushion price spikes. Borrowing from future compliance years, where permitted, can further soften near-term price stress. These mechanisms of banking, borrowing, and true-up timing are critical to understanding forward curves and spot price movements in open REC markets. Moreover, designing these mechanisms in concert with other market mechanics is vital to developing a robust market design. Put simply, these mechanics, when well-designed, serve the function of limiting price volatility as it gives utilities a certain level of flexibility in when to exercise the REC attribute to meet their compliance obligation.

Technology-specific Carve-outs

Open market RPS programs are often described as neutral toward all renewable technologies. At the same time, many of these designs are structured through tiered obligations and carve-outs that create multiple sub-markets. A common framework distinguishes between Tier I (new renewable resources) and Tier II (existing or legacy resources). Many states layer additional tiers or carve-outs for specific technologies (i.e, solar or offshore wind) or for specific project scales (i.e., distributed/small projects or utility-scale projects).

Each carve-out effectively creates a distinct compliance pool or sub-market with its own discrete supply-demand balance and pricing dynamics. Distributed solar carve-outs are a specific tool used in many open markets to incentivize greater development of rooftop and smaller scale solar projects. These carve-outs need to be carefully calibrated so that REC supply can keep up with the statutory targets and prices are balanced.



Geographic Eligibility

Geographic eligibility rules are equally consequential to RPS market designs. Some states permit broad regional eligibility, allowing RECs from any generator within a multi-state ISO or RTO footprint to qualify for compliance. This broader eligibility expands supply and deepens liquidity, but it can also depress REC prices.

An alternative approach is to restrict eligibility to in-state or adjacent-state resources, sometimes layering delivery requirements or multipliers for local generation. Tighter geographic constraints support in-state economic development objectives and enhance local price support but at the cost of reduced market depth and potentially higher compliance expenditures. The breadth of eligibility often determines whether an RPS functions as a regional commodity market (as is the case of the broad and multi-state PJM region) or a relatively insulated state-level market where out-of-state development has limited impact on state REC pricing (such as New York).

Vintage Rules

Vintage and commercial operation date requirements also influence supply elasticity. Most programs restrict eligibility to facilities that commence operation after a specified date, preserving the incremental build signal and preventing older RPS-eligible projects from flooding the market with low-cost RECs. Vintage rules determine how long a REC remains eligible for compliance. Combined with banking provisions, vintage rules define effective REC supply over time by decoupling REC compliance from the temporal constraints of generation timing. These structural parameters shape how quickly supply can respond to price signals and how persistent price movements become.

Non-RPS Design Elements

Finally, it should that there are several aspects of RPS design that must be considered outside of pure REC market functionality and internal REC design mechanics that are imperative for a state to achieve successful renewable energy deployment. This is because REC design is largely a question of ensuring the project is financially viable. While it is vital for states to create a market construct that ensures financially bankable projects, there are several factors outside of the RPS design that must be considered to ensure that physical aspects of solar project development are successful. Those factors include:

- Project siting
- Local permitting
- Utility Interconnection
- Project compensation (Net Energy Metering vs. Value of Solar/Value of DERs vs. wholesale pricing)
- Customer billing and crediting.

All of these factors have immense implications for both project costs and deliverability. Put plainly, even the best designed RPS is likely to be unsuccessful if exogenous factors informing physical project development are not addressed. As discussed in further detail below, while many of the model open market states profiled herein have well-functioning REC market mechanics, they also face issues unrelated to REC functionality. It is therefore vital to remember that even the best-intentioned fixes to RPS design cannot address structural issues with the market if these issues around project siting, permitting, and interconnection inhibit projects from physically being developed.

Advantages of an Open Market REC Model

There are three central advantages of an open market model. These include real time price discovery, affordability, and low administrative burden.

Real time price discovery: Open REC markets enable continuous price discovery by allowing supply and demand to interact dynamically, rather than relying on periodic administrative updates. As project costs, technology efficiencies, trade dynamics, and market participation evolve, REC prices adjust in real time to reflect those changes, ensuring that incentives remain aligned with actual market conditions. This flexibility allows developers to make investment decisions based on current economics rather than outdated assumptions, which under an ADR style structure, can take several years to incorporate into program design. In turn, it reduces the risk of prolonged mispricing and enables the most responsive and efficient buildout of renewable generation.

Greater Affordability: Because open markets continuously equilibrate supply and demand, they naturally drive prices toward the minimum level required to support project development. When supply is abundant, prices fall, preventing overcompensation; when supply is constrained, prices rise just enough to incentivize new project entry. This dynamic ensures that ratepayers are not locked into above-market pricing and that subsidies remain right-sized over time. By contrast to administratively set prices that can lag behind cost declines, open markets consistently identify the least-cost pathway to meeting renewable energy targets. In the age of the affordability-driven political environment, all state policy-makers should be evaluating ways in which they could source least-cost policy pathways.

Low Administrative Burden: Additionally, open market frameworks shift the responsibility for coordination and price formation from regulators to market participants, significantly reducing the need for ongoing administrative intervention. Once program rules and compliance structures are established, regulators primarily oversee verification and enforcement rather than actively managing procurement or pricing. This “set it and forget it” approach minimizes the need for complex modeling, frequent rulemakings, and iterative approval processes. The result is a more streamlined system with lower overhead costs, fewer procedural delays, and reduced administrative expenses which are very real soft costs that add up to being material costs for projects—and ultimately borne by ratepayers.

Model Open Markets:
Real World Examples from Maryland and Virginia

The benefit of states leading the charge on energy policy design is that each of these markets operate as policy laboratories where RPS design has been refined over years of lessons learned. Over the past two decades, several markets have been incrementally addressing the aforementioned issues on an incremental basis by gradually improving design features. This section provides an overview of the Maryland and Virginia markets, which have had successful REC markets for different reasons. Each state includes both beneficial designs as well as opportunities for additional policy reform to improve market dynamics.

Maryland

Maryland is one of the oldest examples of an RPS with an open and competitive market design. Maryland established its RPS in 2004, which initially required electricity providers to procure 7.5% of retail electricity from renewable energy sources. Electricity suppliers could meet this requirement by obtaining Tier 1 (solar, wind, qualifying biomass, etc.) and Tier 2 (large hydroelectric power) RECs. Maryland was also a first adopter of creating a solar carve-out, which created a distinct solar-specific sub-market for REC trading and compliance.

In Maryland, where LSEs fail to meet the RPS requirement, they must make an Alternative Compliance Payment (ACP). Historically, Maryland has met less than 1% of compliance from the RPS through ACP, which indicates that the market for Tier 1 and Tier 2 RECs was reasonably well-functioning.

However, this dynamic has shifted in recent years toward an over-reliance on the ACP instead of compliance via REC procurement. This distinction matters and illustrates a vital point about market design: while there are ways to build flexibility into RPS design and particularly the ACP value, REC markets like Maryland that are also subject to underlying structural market features, such as siting, interconnection, and permitting that can limit the overall availability of projects and therefore REC supply.

What works well? The Maryland Solar Carve-out

The Maryland market is based upon the principle of price flexibility, which allows market participants to adjust to changes in supply and demand in real time without having to wait for reconsideration that would be required out of an ADR model. Maryland's open market model further benefits from having the nation's highest solar-specific carve-out. This has dramatically incentivized solar project development in the state, and distributed solar project development in particular.

From 2016-2018, an overabundance of SRECs in Maryland caused the SREC price to decrease from $120 to $5. To address this, the legislature passed the Clean Energy Jobs Act in 2019 which raised the solar carve-out from 2.5% to 6% for 2020 with a long-term increase to 14.5%, which spurred demand. Once the oversupply of SRECs were retired, the price rose and reached the ACP in 2022. The solar carve-out has been a success in terms of driving higher levels of distributed solar deployment. At the same time, siting and permitting constraints at the local level have limited the availability of larger scale solar projects, which is hampering the state's ability to reach the higher solar carveout goals.

What works well? Preferential Siting Multipliers

Legislation can help to address undersupply scenarios, such as those that exist in Maryland due to the local permitting and siting challenges. In 2024, when build rates were lower than expected, the legislature passed the Brighter Tomorrow Act to increase development. This lawcreated a 1.5x price multiplier for systems that meet certification requirements, while still allowing supply and demand to set the base price. These preferential siting multipliers drive solar deployment away from greenfield development and toward preferred siting areas, such as brownfields and rooftops, which meets an important policy goal for Maryland.

As solar deployment increases, project siting will become increasingly important. Policymakers will need to balance the priorities of land conservation and renewable energy development. Mechanisms such as the preferential siting multiplier allow flexibility in design for policymakers to achieve additional social, equity, and environmental goals.

Room for Improvement:
Maryland has experienced an increasing reliance on ACP as a compliance pathway

Over the last few years, Maryland has faced an undesirable policy outcome: dramatically high reliance on LSEs meeting their compliance obligations by paying the ACP rather than purchasing RECs. This is partially due to the structure of the ACP itself and partly informed by other exogenous factors such as project siting, interconnection, and land-use constraints. The result is a system in which the ACP—intended as a backstop—has become an increasingly routine compliance pathway, signaling that the marginal unit of compliance is no longer met through market-based procurement of RECs.

First, there are ways to address the ACP itself via recalibration of the payment level, structure, and function within the compliance framework. For instance, increasing the ACP would re-establish it as a binding ceiling and reinforce REC procurement as the economically rational compliance pathway, particularly in tight market conditions.

Alternatively, policymakers could introduce a dynamic or indexed ACP that adjusts in response to observed market prices or supply conditions, thereby preventing prolonged periods where the ACP is cheaper than procuring RECs. More structural reforms could include limiting the proportion of compliance that can be met through ACP payments or redirecting ACP revenues more explicitly toward near-term REC supply creation, thereby tightening the linkage between compliance payments and actual renewable deployment. It should be noted that Maryland is a unique example of a state where funds collected through the ACP go directly to the Strategic Energy Investment Fund (SEIF), which supports clean energy programs, but could more explicitly fund renewable project development. Each of these approaches seeks to restore the ACP's original role as a penalty mechanism rather than a parallel compliance pathway.

Room for Improvement: **Addressing External Factors**

There are several additional exogenous factors impacting the underlying undersupply of RECs. Maryland's increasingly ambitious RPS targets—particularly for Tier 1 and solar—have outpaced the availability of REC-generating projects. These projects remain constrained by siting limitations, interconnection bottlenecks, and broader land-use challenges. In addition, participation in a regional REC market means that Maryland must compete with neighboring states for available supply, particularly where those states offer more favorable economics or fewer development constraints.

A telling example of this scenario is playing out among Maryland policymakers who are debating a transition away from the existing open market REC design and toward an ADR-style program. Advocates of the bill claim that the provisions to transition to an ADR-style incentive program will enhance the program. However, those opposed to the bill have noted that simply shifting to an ADR-style procurement process and capacity block program is not a salve. Indeed, doing so could slow development if more is not done to address the state's underlying structural issues such as permitting and interconnection that are inhibiting projects from actually being able to build.[8,9,10]

These external dynamics collectively suppress the availability of eligible RECs and shift the supply curve inward, making ACP compliance more attractive or, in some cases, unavoidable. Addressing these constraints through permitting reform, interconnection improvements, and targeted in-state development incentives will be critical to restoring balance between REC supply and compliance demand to reduce reliance on ACP payments. Vitally, simply changing the structure of the incentive program alone will do nothing to improve development prospects if siting, permitting, and interconnection challenges are not addressed.

8 https://www.bakerdonelson.com/maryland-lawmakers-weigh-sweeping-solar-expansion-with-the-affordable-solar-act
9 https://permitpower.org/wp-content/uploads/sites/35/2026/01/Unleashing-Marylands-Residential-Solar-Market-1.pdf
10 https://marylandmatters.org/2023/05/27/sluggish-pace-of-interconnection-might-jeopardize-states-renewable-goals-report-says/

Virginia

In 2020, the Virginia legislature passed the Virginia Clean Economy Act creating Virginia's first mandatory RPS. This law replaced the state's previous voluntary renewable portfolio program, which had not produced a robust renewable market. Under the new law, between 2021-2024, eligible renewable energy generation resources for compliance with the Virginia RPS were required to be located either in Virginia or anywhere in the PJM region. However, beginning in 2025, the statute created more stringent implementation requirements, including tightening the categories of RPS eligible sources and requiring projects to be located in Virginia.

What works well? **Distributed Generation Carve-outs Incentivize Sub-Sectors**

Like Maryland, Virginia has various carve-outs built into their RPS design in order to incentivize development of specific sub-sectors. Virginia also has a distributed generation (DG) carveout, whereby the utilities must procure a share of RECs from in-state solar resources that are smaller than 1 MW in size. The legislature expanded this carveout from 1% currently to 4.5% between 2026-2030 and 5% between 2031-2045. This expansion was intended to rebalance the carve-out which experienced oversupply.

An additional feature of Virginia's DG carve-out is a requirement to first purchase DG RECs from qualifying low-and-moderate income (LMI) customer projects, up to a maximum of 25% of the carveout. If there are not enough qualifying LMI project RECs, then the utility must purchase up to 25% of the carveout from public school projects. These additional carve-outs were developed to achieve important public policy goals - in the event of a REC oversupply, LMI and public school projects will be given priority in terms of purchase.

What works well? **Differentiated ACP values between utility-scale and DG**

Like every RPS market, Virginia has an ACP that is administratively set. That said, unlike other states, Virginia differentiates between utility-scale solar and DG solar with respect to the ACP. This is a marked difference between a state like Maryland, which has just one ACP value across all renewable technologies regardless of size. This design distinction allows the state to better target and incentivize DG solar relative to utility-scale projects, which implicitly recognizes the substantial difference in project economics between the two project types.

Furthermore, Virginia allows for an incremental 1% increase in the ACP value annually. This means that the value is not stagnant but accounts for inflation, which builds flexibility into the program design.

Room for improvement: **Utility-ownership of assets creates liquidity challenges**

Another defining feature of Virginia's REC market is the dominant role of vertically integrated utilities. Under the Virginia Clean Economy Act (VCEA), these utilities are required to meet clean energy targets and are explicitly authorized—and in many cases expected—to do so through utility-owned or utility-contracted generation as opposed to owned or operated by third-party project developers.

This has an important effect. RECs are often "self-supplied" (i.e., generated and retired internally), which means there is less liquidity in the market given that fewer RECs circulate in secondary markets. As a result, Virginia lacks the liquid REC trading environment seen in PJM states like Pennsylvania.

Room for Improvement: **Addressing External Factors**

As is the case in Maryland, there are factors outside of the consideration of pure RPS design that dramatically impact project deployments in Virginia. While interconnection challenges abound in both Maryland and Virginia, the issues themselves are informed by different realities—namely the nature of a deregulated vs. regulated energy market. Maryland is a deregulated energy market where utilities are not permitted to own generation. In contrast, Virginia is a regulated market of Virginia where the investor-owned utilities are vertically integrated and can own generation. However, third-party owned projects do exist in Virginia and have historically faced lengthy interconnection queues and other interconnection challenges that impair project economics.

Additionally, siting is a significant constraint, as Virginia has faced increasing local opposition to utility-scale solar projects. This has resulted in fewer projects reaching development milestones and the potential that Virginia may not reach its VCEA targets. Policymakers have worked over the last few legislative sessions to include new requirements on localities to perform a more thorough review of solar projects and to no longer establish an automatic ban on the development of these resources.

ADR Model Overview: Structure, Compliance Mechanics, and Market Implications

In contrast to the open market model, the ADR model represents a vastly different market design and structure. While ADR markets preserve the core compliance obligation of an RPS market, the ADR design modifies how compliance is determined. Rather than relying primarily on floating market REC prices determined through decentralized trading, the ADR model is an administratively structured payment framework that replaces spot market price discovery.

The ADR functions as a compliance payment that utilities or suppliers must remit if they do not procure sufficient qualifying renewable resources. In contrast to the traditional ACP, which functions as a ceiling where REC prices can fall anywhere below the ceiling, in an ADR market, a central authority sets the cost of compliance (i.e. the REC price).

REC procurement is often centralized in ADR markets through a state entity (for example, a power authority or utility commission). That entity may conduct competitive solicitations for renewable energy or REC contracts, frequently offering long-term agreements that establish fixed or indexed REC compensation levels. If the LSEs fails to meet compliance through contracted resources, they remit ADR payments at a defined price.

In an open market model, REC prices float continuously based on supply and demand, with the ACP providing a ceiling. In an ADR model, compensation levels are often determined through structured procurement processes or administratively defined schedules, which themselves are informed by assessing underlying project costs.

Compliance schedules under ADR designs typically remain annual, but the path to compliance is more structured. Long-term contracts awarded through centralized solicitations reduce any sense of merchant exposure and dampen short-term volatility. Banking provisions may still exist, but their importance diminishes relative to open market systems because most supply is pre-contracted and obligations are aligned with procurement planning cycles.

One aspect of ADR frameworks is that geographic eligibility rules tend to be even more restrictive. Because procurement is planned around state policy objectives and determined by a state-level agency, eligibility often prioritizes in-state resources. Unlike open markets that may permit REC purchases throughout a broader region to minimize compliance cost, ADR programs are frequently designed to internalize local economic multipliers. In general, this tighter geographic control further distances ADR markets from commodity-style trading environments.

Risk allocation under ADR models is also distinct. In open markets, developers often bear merchant REC price risk unless long-term bilateral contracts are secured. In ADR markets, long-term state-backed contracts transfer much of that risk to ratepayers or regulated entities, as those contracts are designed to ensure economic attractiveness and project buildout without the visibility of least-cost, most efficient price discovery. The tradeoff in these markets is reduced volatility and financing uncertainty but without dynamic price discovery and without lower program cost.

In contrast to open market RPS design—where price volatility, liquidity, and third-party merchant risk define the ecosystem—the ADR approach prioritizes stability and policy-directed deployment with an assumption that the framework will result in predictable buildout. While ADR models can limit some level of price volatility, the gains in reducing short-term price swings are offset by ratepayers often bearing the burden of higher costs given that longer-term ADR contracts are backed by regulated entities. ADR markets are designed to avoid REC price volatility. While there is good reason to oppose significant price volatility, ADR markets ultimately sacrifice on price efficiency and cost savings.

ADR Markets in Practice: Case Study of New Jersey and Illinois

Most RPS programs were initially designed with the least-cost approach in mind and deployed an open REC market design. It was only after years of price volatility that some states began to shift to the ADR model as a way to limit price volatility and the resulting impacts on project deployment. This section unpacks the example of two states—New Jersey and Illinois—that were initially open market models and transitioned to ADR designs for similar reasons. Both markets have important policy designs and market drawbacks.

New Jersey

New Jersey maintains one of the oldest and most structurally complex RPS programs in the United States. Established in the early 2000s, the program has evolved from a relatively straightforward open market REC model akin to fellow PJM states like Virginia or Maryland into a hybrid compliance framework that blends commodity-style trading with administratively managed procurement, particularly for the solar and offshore wind segments.

The New Jersey RPS requires electricity suppliers to procure a defined percentage of retail sales from qualifying renewable resources. The obligation is tiered. “Class I” resources include solar, wind, geothermal, biomass, and certain hydro; “Class II” resources cover legacy hydro and waste-to-energy. Within Class I, New Jersey historically implemented a distinct solar carve-out, which created one of the most active SREC markets in the country. The RPS percentage requirements have ratcheted upward over time, with the state targeting 50 percent renewable energy by 2030, alongside specific carve-outs for distributed solar and offshore wind.

The Open Market Foundations

The New Jersey market operates within PJM, and RECs are tracked and retired through the PJM Generation Attribute Tracking System (PJM-GATS). In its original structure, the program functioned as a relatively pure open market REC system. LSEs were responsible for procuring sufficient RECs annually, and they could acquire RECs via bilateral contracts or secondary spot markets.

Geographic eligibility rules historically allowed certain out-of-state Class I RECs to qualify, though solar eligibility has been more tightly restricted to in-state generation. This distinction proved consequential: broader Class I eligibility deepened liquidity and moderated prices, while the solar carve-out that is limited largely to in-state distributed generation produced tighter supply-demand balances and sharper price cycles.

The Solar Market Transition: From SRECs to Administratively Structured Incentives
New Jersey's original SREC market exemplified both the strengths and weaknesses of open market carve-outs. High SREC prices in early years stimulated rapid distributed solar deployment. However, because supply growth outpaced statutory demand ramps, the market experienced repeated oversupply cycles. The legislature responded with periodic RPS accelerations and adjustments to stabilize the market.

In response to this volatility the state ultimately transitioned away from fully floating SREC pricing. The legacy SREC program was closed, and new projects were moved into successor incentive programs featuring administratively determined or structured compensation mechanisms. Under the Successor Solar Incentive (SuSI) framework, compensation shifted toward fixed incentive values established through competitive solicitations (in the case of the utility-scale CSI) or predetermined schedules (in the case of distributed solar). This marked a structural pivot toward ADR-style administration, and one of the first in the nation to take this approach.

Room for Improvement: Cost of compliance

One of the most common critiques of the SuSI structure is that it suppresses price discovery and misaligns incentives over time. Under the legacy SREC market, prices adjusted dynamically to reflect supply-demand conditions, with the ACP acting as a ceiling. In the SuSI framework, however, compensation is fixed through Administratively Determined Incentives (ADI) with values set by the Board of Public Utilities in advance for long durations (often 15 years). Since these incentive levels are now administratively determined, it creates a risk that incentive levels may either overshoot or undershoot actual market conditions which results in ratepayers bearing a higher cost for renewables procurement under an ADR system.

In fact, New Jersey's ratepayer advocate—an independent agency laser-focused on ensuring affordability of rates for all customers, but particularly low and moderate-income customers—has openly criticized the " relatively efficient" system of ADR relative to other market-based policy frameworks.[11] Unlike open markets, there is no continuous mechanism for prices to recalibrate, meaning mispricing of incentives can persist until the next program adjustment. For the sake of this conversation, "mispricing" means that ratepayers are overpaying for RECs. Under SREC markets, prices were at least partially disciplined by supply/demand. Under ADI, the state is essentially "guessing" incentive levels.

While the ADI model increases revenue certainty for developers, it also means the solar REC market is no longer a true tradable commodity market, limiting transparency and reducing the role of competitive market forces in determining value. In effect, New Jersey has traded the volatility and cyclicality of the SREC market for a more stable but less flexible and more administratively dependent system.

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11 *In the Matter of the Three-Year Review of the Administratively Determined Incentive Program BPU Docket No. QO20020184*, State of New Jersey Division of Rate Counsel, pg 3.

Room for Improvement: Administrative complexity

An additional concern is that the New Jersey ADI program introduces administrative rigidity and slower responsiveness to market conditions. Because incentive levels, eligibility rules, and procurement volumes are set through regulatory processes, adjustments require formal proceedings, stakeholder input, and Board approval. This can create lag relative to real-world changes in project costs, interconnection timelines, or supply chain dynamics.

Illinois

Illinois' RPS has undergone one of the most significant structural evolutions among U.S. states. While originally conceived as an open market system, the program now operates through a highly centralized, administratively managed procurement framework. The transformation, which culminated in the Clean Energy Jobs Act (CEJA) of 2021, shifted Illinois away from merchant, an open market RPS design and toward a system in which the state, through the Illinois Power Agency (IPA), effectively sets and administers renewable attribute compensation.

The Solar Market Transition: From SRECs to Administratively Structured Incentives

Illinois first enacted its RPS in 2007 as part of broader energy legislation. The original design required investor-owned utilities and alternative retail electric suppliers (or ARES) to procure RECs as a compliance instrument, and the program was nominally structured as an open market framework. However, a major disruption occurred in 2011 when legislative changes decoupled alternative retail suppliers from RPS compliance obligations, shifting the bulk of compliance responsibility to default utility supply. As customers shifted away from default supply and to ARES, the funding pool for supporting REC procurement effectively dried up, creating structural funding constraints and sharply reducing REC demand. For several years, the RPS was widely regarded as dysfunctional as renewable development stalled due to little financial incentive to build projects.

The 2016 Future Energy Jobs Act (FEJA) sought to address this, and other issues, by fundamentally restructuring the RPS. It established long-term renewable procurement planning through multi-year Long-Term Renewable Resources Procurement Plans administered by the IPA and approved by the Illinois Commerce Commission (ICC). The state adopted a target of 25 percent renewable energy by 2025 and created defined procurement categories for utility-scale wind, utility-scale solar, distributed generation (DG), and community solar.

Under FEJA, REC compensation was determined through competitive procurements conducted by the IPA rather than through continuous secondary market trading. Winning projects received long-term REC contracts, typically 15–20 years in duration. The program completely replaced floating REC markets with scheduled and centrally administered procurement rounds, creating more predictable revenue streams and significantly reducing merchant exposure.

The 2021 Clean Energy Jobs Act (CEJA) further expanded and formalized Illinois' administrative approach. CEJA accelerated renewable targets toward 40 percent by 2030 and 50 percent by 2040, while substantially increasing funding allocations for renewable procurement. The IPA's authority was expanded to conduct ongoing competitive procurements across multiple categories. CEJA also introduced administratively determined REC pricing for certain distributed generation and community solar categories. This mechanism is, for all intents and purposes, an ADR construct.

Room for Improvement: **Regulatory lag**

In Illinois, the Illinois Power Authority (IPA) fixes REC rates through its Long-Term Renewable Resources Procurement Plans. This LTRRP must be updated every two years and then approved by the Illinois Corporation Commission. Historically, this is a long and administratively complex process. For example, in the last iteration of this plan development, the IPA made two sets of requests for stakeholder feedback for its 2024 Plan, due in June 2023. The IPA then filed its draft plan on August 15, 2023 with comments due by the end of September 2023. The final 2024 Plan, filed on October 20, 2023, was approved on February 20, 2024 and published on April 19, 2024. However, a petition to re-open was filed in August 2025 before being resolved and approved on October 16, 2025. Just four days later, on October 20, the IPA filed their 2026 Plan for approval of additional REC price changes.

Furthermore, during a Program Year, the only way that the IPA can change a block price without ICC review is if the change does not deviate more than 10% from the ICC-approved value, a provision which has never been used. Meanwhile, contracts under the ABP also generally last for about 15 or 20 years, locking generators into fixed prices for the duration of the contract and restricting the ability for participants to respond in real time to market changes. So while fixed prices can protect participants from market volatility, it can also lock in higher or lower than market rates for long periods of time.

Room for Improvement: **Oversubscription and project waitlists**

Another disadvantage of the ADR process in Illinois is that it does not optimize for market participation, due to the simple fact that market participants have varying cost profiles across the project development landscape. A benefit is that Illinois has created a system where REC prices are often known, stable, and, critically, attractive relative to project costs. At the same time, the state has imposed finite annual procurement budgets and capacity targets which has resulted in a structural imbalance. Developer demand to participate in the program consistently exceeds the volume of capacity the state is willing (or able) to procure in a given cycle.

When applications exceed available capacity within a block, which is a common occurrence, the IPA cannot simply allow all projects to proceed, because doing so would exceed statutory budget constraints. Unlike an open market, where price would fall until supply matches demand, the ADR model does not permit price to adjust downward in real time to reflect real market conditions (in this case, an oversupply of the market e.g. that the price is too high relative to supply and real developer costs). The implication here of course is that ratepayers are overpaying for these projects relative to their actual costs.

The result of the ADR model in Illinois is that it has created a functional lottery system for projects that sit on a waitlist and effectively replaces price competition with queue competition, which also comes at a cost on the project development side. Developers are incentivized to invest in early stage project origination, interconnection and permitting without any certainty of securing a REC contract, while also flooding the interconnection with a higher share of speculative or marginal projects in order to increase chances of project selection. This may sound marginal on the surface, but these development activities can and significantly increase the overall cost of projects, further bidding up the REC price requirement.

From the lottery system to the waitlist, a recognized feature of the system is project overcompensation at the expense of REC price volatility. As we will discuss in more detail below, there are many ways to address the issue of REC volatility under an open market construct via design features without requiring a transition to an ADR structure.

Room for Improvement: **Program affordability**

Illinois has market indicators such as persistent oversubscription, reliance on modeled rather than observed cost data, stakeholder criticism of pricing methodology, and lagged adjustments to declining technology costs that collectively suggest REC compensation levels have exceeded the minimum required to support project development. This outcome is consistent with the underlying ADR-style design, which prioritizes investment certainty and deployment over continuous price discovery. At a historical peak in the 2022 solicitation, the Illinois Shines program was nearly 4 times oversubscribed on Day 1.[12] The program is clearly deeply attractive to project developers, suggesting that projects are well compensated relative to other markets.

The lag between cost declines and REC pricing adjustments is the primary culprit driving the disparity. In Illinois, even IPA documentation has noted 2-8% year-over-year solar cost declines in its pricing model updates. The block pricing in the Illinois program is only assessed every two years and locks in values until capacity fills. This means that during periods of rapid cost decline, REC values can temporarily exceed actual cost requirements of projects resulting in project overcompensation. Compare this to open market designs where supply-demand factors are constantly in equilibrium and set the most efficient price of compliance.

12 https://ipa.illinois.gov/content/dam/soi/en/web/ipa/documents/22-0231-ipa-verified-petition-for-reopening-2-dec-2022.pdf pg 6

Design Principles for the Model Open Market RPS Design

As described previously, there are several real world examples of states that have implemented an open market design. The implementation of best practice design does not occur all at once: while many states have implemented elements of a model open market design, no one state has enacted all of these policy goals simultaneously. For example, some open market models require recalibration of the RPS targets or the ACP (price ceiling) where liquidity or financial payment becomes an issue. This section highlights the primary drivers of a successful open market design, borrowing from the Maryland and Virginia examples and highlighting additional areas for improvement.

Importantly, policymakers should be intentional about designing open market rules and mechanics in a way that reaches several goals: limiting price volatility to a level that appropriately balances project development and affordability, while providing market flexibility to make changes where necessary.

In most instances, there is typically an acceptable band of REC pricing required by project developers to economically develop and build a solar project in a particular market but that is not set so high as to create a windfall. This is a state-specific examination. In order to establish a well-supported upper limit to that band, an ACP must be thoughtfully considered based on market dynamics. The price floor is functionally informed by an RPS target that increases over time, which creates the momentum for the market to invest in greater quantities of renewable projects.. Policymakers should be aware that this target REC price range implicitly exists in every state market, and intentional policy design can support the creation of the range.

A pertinent and recent example of policymakers intentionally correcting this dynamic is Virginia where Governor Spanberger signed HB 628 into law in April 2026. As mentioned previously, the law increases the distributed solar carve-out from 1% to 4.5% from 2026 to 2030 and to 5% between 2031 and 2045. This will increase the demand for RECs from smaller solar projects, which leveled off in the prior two-year period due to oversupply. Reducing the oversupply will ultimately rebalance the market and the price of these RECs will reflect that rebalancing.[13]

Establishing the right RPS targets and calibrating the ACP accordingly are two foundational elements of a functioning open market. There are several additional key aspects of a model open market RPS design for consideration. These include establishing the appropriate guardrails for RECs that may be used for compliance. Appropriate banking rules can ensure that RECs can be used over a multi-year period, smoothing year-over-year compliance. Vintage rules can ensure that RPS compliance transitions from a greater reliance on older systems toward future reliance on new projects, in order to incentivize further project development in the market. In sum, the RPS does not operate in a vacuum and even the best designed RPS policy requires some degree of flexibility. The figure below provides additional information on these best practices.

13 https://www.flettexchange.com/blog/post/virginias-rps-laws-just-changed-market-report-va-srecs

BEST PRACTICES FOR RPS DESIGN

1 RPS goals (% of retail sales, supply, etc.) need to be ambitious, yet realistic.

It is vital for a well-functioning REC market to achieve supply-demand equilibrium that is consistently maintained. An over or under supply of RECs will result in substantial price volatility. Creating significant enough demand for REC generation so the state does not experience undersupply and ACP payments is an essential initial first step to RPS formation. If oversupply begins to emerge, a recalibration to increase RPS goals is then necessary.

2 RPS increases must ratchet up consistently.

In addition to setting ambitious RPS goals at the outset, establishing consistent increases in the demand for RECs is also essential to maintain price stability. This tool ensures that demand is keeping pace with REC supply over the length of the program, and it sends a signal to the market to invest in renewable generation in the market.

3 ACP must be set appropriately and should allow for flexibility.

Incentivizing the appropriate supply of RECs is a delicate balance. In open markets, compliance is deeply informed by the ACP, which acts as a functional price ceiling. In a high-functioning REC market, the ACP must be set above the expected market price of RECs to drive investment in new renewable energy projects. If set too low, obligated entities will simply pay the fee instead of building or buying clean energy, rendering the entire RPS policy ineffective. Moreover, it's essential that state authorities are given the flexibility to adjust the ACP periodically to reflect market conditions.

4 Banking rules should allow surplus RECs to smooth year-over-year compliance.

To prevent oversupply and maintain the value of new RECs, banked RECs should have an expiration date such as limiting the bankable life to 2-5 years after the year of generation. Creating flexibility within banking rules is also imperative to act as a counterbalance against dramatic price volatility. For instance, in times of shortage or undersupply, allowing utilities to bank previous vintage RECs for future compliance years can mitigate high REC prices in instances of REC oversupply. However, this must be designed with flexibility in mind, as too much banking could stifle new development.

5 Market design should favor new capacity over existing capacity.

RPS rules should favor newly generated RECs over vintage RECs in order to encourage new capacity. This may also be reflected in banking rules (limiting the number of years a REC may be banked and carried forward) or in vintage rules. Vintage rules distinguish between the year of generation to prevent RECs from decades-old projects from being used to meet current standards.

Conclusion

The United States finds itself at an inflection point for renewable energy policy. As federal support for clean energy has receded and affordability has become the dominant lens for energy policy, states are left to determine how best to maintain robust renewable development. The RPS remains one of the most durable and effective tools available to states for driving renewable deployment, but its success is not automatic. It depends heavily on the underlying market design chosen to implement it.

As this paper has demonstrated, the open market REC model and the ADR model are two specific examples of state policy choices. The open market model allows supply and demand to determine REC pricing in real time, which means they can consistently identify the least-cost path to compliance. This helps avoid the structural overpayment risks inherent to ADR markets and requires far less ongoing regulatory intervention than ADR frameworks. Maryland and Virginia illustrate that open markets can be tailored with targeted design features such as solar carve-outs, preferential siting multipliers, and differentiated ACP values to advance specific policy priorities without sacrificing the core efficiency benefits of market-based price discovery.

By contrast, an ADR market provides long-term stability for renewable developers. It comes with a tradeoff, as the experiences of New Jersey and Illinois show that these policy designs can lead to regulatory lag, oversubscription, and potentially higher costs ultimately borne by ratepayers. Policymakers should carefully consider these tradeoffs in assessing how best to update RPS market design. One option for policymakers is to strengthen their RPS programs is to recalibrate ACP levels, adjust carve-outs, and fine-tune banking and vintage rules, rather than abandoning market-based price discovery altogether.