Reimagining the Renewable Portfolio Standard

Integrating Electricity Prices into a Value-Based RPS

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ACKNOWLEDGMENTS

This work was supported by Yale Center for Business and the Environment.

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The research for this report was conducted in Kenneth Gillingham's course Energy Economics and Policy Analysis.

The report was edited by Chris Lewis, news editor at Yale Center for Business and the Environment. The graphic design was created by Henk van Assen, Senior Critic at Yale University School of Art, together with Meghan Lynch and Izzy Natale, designers at HvADESIGN.

March 2020

Executive Summary

Renewable Portfolio Standards (RPSs), using Renewable Energy Credits (RECs) to track and commoditize renewable energy generation, have made significant contributions to renewable energy deployment. A truly clean electricity grid, however, will need to rely on zero-carbon energy throughout the day and year, and everywhere electricity is used. RPSs have been unable to achieve these goals due to inherent limitations of a market for RECs.

In states with the most aggressive clean energy policies, the shortcomings of RPSs are becoming more acute. In areas of high solar penetration, for example, solar power generates electricity during the day, but fails to provide energy during the evening hours when demand peaks. The resulting overproduction and waste of renewable energy — and related symptoms of poor renewable energy integration — call for a dramatic change to clean energy policy development.

Our research team proposes a new policy framework called the value-based renewable portfolio standard, or VRPS. The currency of a VRPS is the value of renewable energy credit, or VREC, which integrates the time- and location-dependent value of electricity into clean energy subsidies. Overall, we found that a VRPS will:

- **Incentivize renewable energy** where and when it is most valuable.
- **Increase profitability of storage investments** by valuing the time-dependent characteristics of electricity.
- **Encourage renewable energy siting near high-priced markets**.
- **Support a robust, transparent inter-state market** while preserving climate change mitigation benefits.

Policymakers have recognized the challenges posed by mismatched load and renewable energy generation resulting from the REC-based RPS approach. In response, they have proposed modifications to RPS markets, such as geographic limitations and time-of-use multipliers, to deliver meaningful environmental outcomes. These proposals tend to fragment markets, resulting in poor economic efficiency. Meanwhile, proposals to make renewable energy subsidy markets more robust result in REC markets that overlook critical characteristics of electricity markets which do not deliver desired climate change mitigation. The VRPS bridges the gap between market function and environmental outcomes through transparent time- and location-dependent valuation of renewable energy.

Introduction

Twenty-nine states and Washington, D.C. have a renewable portfolio standard (RPS) to mandate renewable energy deployment and an accompanying renewable energy credit (REC) compliance market to track the ownership of renewable attributes for RPS compliance.[1] RPSs, however, incentivize an overall quantity of renewable energy without regard to where or when this electricity is generated, making it a blunt tool for integrating renewable energy into the grid, leading to such issues like the "Duck Curve" first observed in California.

The Duck Curve, a result of high penetration of solar photovoltaics, is characterized by renewable energy overproduction, zero or negative energy prices, and wasteful renewable energy curtailment during the day; and a sharp increase in fossil fuel generation after the sun sets. In this paper, we propose an entirely new subsidy market structure to account for, credit and incentivize renewable energy and its environmental attributes. We call this next-generation policy tool a value-based renewable portfolio standard, or VRPS. A VRPS requires a proportion of the grid's total dollar value of electricity be met with renewable energy, as opposed to the total energy, measured in a unit like megawatt-hours (MWh). We propose the VRPS as a policy tool to address the limitations to simply increasing renewable penetration, particularly solar, to date. This paper evaluates which policy — the VRPS or the RPS — better incentivizes technologies that improve renewable energy integration onto the grid. To do so, we modeled solar photovoltaic generation with lithium-ion battery storage ("solar+storage") investments in California as a case study. We selected California because of its ambitious renewable energy goals and observable Duck Curve, though we believe a VRPS policy could be applicable to other markets as solar penetration increases.

Markets with high solar penetration, such as California, have seen significant amounts of midday overgeneration and curtailment, yet have been unable to meet peak loads with renewable generation. Shifting renewable energy generation to peak periods produces real climate change benefits; peaking natural gas power plants, including those in California, are much less efficient than the combined-cycle natural gas power plants used to meet baseload power.[2] A VRPS provides incentives to invest in storage in parallel with renewable energy, and to use this storage to deliver clean energy during periods of peak demand.

Policymakers have recognized the challenges surrounding mismatched load and renewable energy generation resulting from the current RPS approach. In response, they have proposed a number of policies including seasonally adjusted REC multipliers, carbon offset adjustments to RECs, and clean

1 Galen Barbose, "U.S. Renewables Portfolio Standards 2017 Annual Status Report," Lawrence Berkeley National Lab, 2017, emp.lbl.gov/sites/default/files/2017-annual-rps-summary-report.pdf; Edward Holt et al., "The Role of Renewable Energy Certificates in Developing New Renewable Energy Projects," National Renewable Energy Laboratory, 2011, www.nrel.gov/docs/fy11osti/51904.pdf.

2 "Renewables Portfolio Standard," California Energy Commission (CEC), accessed October 11, 2019, www.energy.ca.gov/portfolio/.

peak standards to account for the temporally varying aspects of electricity generation. For example, a 2016 report to Arizona's Residential Utility Consumer Office advocated for a clean peak standard (CPS), calling it a "RPS 2.0," and argued that a new approach beyond the traditional quantity-based RPS is needed to ensure that as states achieve higher levels of renewable energy penetration, these resources continue to contribute value to the grid.[3]

Economists, however, have noted that state-by-state RPS policies have already resulted in thin, fragmented markets with large disparities in REC prices, a symptom of economic inefficiency.[4] While policies like the CPS proposed above highlight the fundamental issue with using a REC-based RPS for renewable energy promotion, it would further fragment a market in need of integration. Electricity markets are fundamentally geographically and temporally dependent, but RECs — the "renewable attributes" of electricity — do not take these characteristics into account. This challenge will only increase in magnitude as more intermittent renewables come online.

In response to the shortcomings of REC-based RPS model outlined above, we propose the VRPS as an entirely new subsidy market structure to account for, credit and incentivize renewable energy and its environmental attributes — an "RPS 3.0" that will better match today's renewable energy goals and challenges.

To account for value under a VRPS, we propose a replacement for the REC: the value of renewable energy credit, or VREC. As its name suggests, the VREC is derived from the total value of renewable energy generation, rather than the total quantity. For the purpose of this paper, value is defined as the product of the quantity of electricity generated (MWh) over a given hour on a given market node and its locational marginal price (LMP, $ per MWh) on the hourly, day-ahead wholesale market. A single VREC is defined as the renewable attributes of $100 of this electricity value. The following equation shows the total quantity of VRECs produced by a renewable energy resource in a given hour:

$$\text{VRECs} = \frac{\text{Electricity (MWh)} * \text{LMP (\$/MWh)}}{\$100}$$

To illustrate, Figure 1 shows the per-MWh revenue received from renewable energy from electricity sales and subsidy payments under traditional RPS and VRPS policies under three hypothetical prices: $80, $40, and $0 per MWh. These prices represent peak, off-peak, and renewable over-generation scenarios. The hypothetical VREC and REC prices are $100 and $40, respectively. The per-MWh market price is shown

3 Lon Huber, "Evolving the RPS: A Clean Peak Standard for a Smarter Renewable Future," Strategen Consulting for Arizona's Residential Utility Consumer Office, 1 Dec. 2016, www.strategen.com/reports-1/2017/9/19/evolving-the-rps-a-clean-peak-standard-for-a-smarter-renewable-future.

4 David Berry, "The Market for Tradable Renewable Energy Credits," Ecological Economics 42 (May 2002): 369–79, www.sciencedirect.com/science/article/pii/S0921800902001283; Richard Schmalensee, "Evaluating Policies to Increase Electricity Generation from Renewable Energy," *Review of Environmental Economics & Policy 6*, no. 1 (Winter 2012): 45–64, https://doi.org/10.1093/reep/rer020; Lisa Koperski, "Why the Renewable Energy Credit Market Needs Standardization," 13 Wash. J. L. Tech. & Arts 69 13 no. 1 (2017): 70–108, digital.law.washington.edu/dspace-law/handle/1773.1/1746.

in blue, which is the same in both panels, and the subsidy amount is shown in green. Note that because VRECs are awarded per dollar of value, the subsidy amount *per unit of energy* increases proportionately with price.

FIGURE 1. Example wholesale market prices and corresponding subsidy amounts ($100/VREC; $40/REC).

Under an RPS, RECs provide a consistent additional $40 per MWh. In contrast, because the VREC revenue changes with wholesale market price, the per-MWh subsidy is equivalent when the wholesale price is $40, but greater when the wholesale price is higher. The difference between RECs and VRECs is particularly extreme when the wholesale price reaches zero. Under an RPS system, the generator can collect the REC payment even though there is no demand for the energy, and therefore little, if any, net reduction in carbon emissions. In contrast, at zero price, no VRECs are generated, so generators receive no subsidy. Relative to an RPS, a VRPS incentivizes shifting generation from low-value to high-value times.

In practice, VRECs could be defined by other price metrics, such as the real-time spot price. However, we propose using the day-ahead hourly price because it would allow renewable energy and storage providers to plan charging and discharging cycles on a timescale complementary to the daily cycles of renewable generation. Furthermore, in U.S. independent system operator (ISO) areas such as the California ISO, the vast majority of electricity is sold in the day-ahead market.[5]

5 Herman K. Trabish, "How Electricity Gets Bought and Sold in California," Greentech Media, March 29, 2012, www.greentechmedia.com/articles/read/how-electricity-gets-bought-and-sold-in-california.

Policymakers could use a number of other metrics to appropriately account for the temporal and spatial variation in carbon and other pollutant emissions in clean energy subsidies. For example, WattTime, a nonprofit that promotes clean energy, proposes the concept of *emissionality*, a metric reflecting "the fossil-fueled emissions that are displaced by new renewable energy" generation (Bronski and Richardson 2018).[6] As a climate change mitigation policy, an RPS based on emissionality might be superior to wholesale price in directly targeting carbon emissions reductions. However, emissionality is a proprietary metric; carbon emissions are not measured or collected in all markets and can be complicated to calculate across time and geography. In contrast, the day-ahead hourly wholesale price reflects marginal efficiency and emissions trends broadly, but is also a transparent, fundamental metric in functioning competitive wholesale markets, making it easy to implement across multiple markets.

In this report, we analyze solar+storage as a case study of a technology that would benefit under a VRPS. VRECs, however, are intended to be a technology-agnostic, market-based policy. Solar+storage is currently a relatively expensive technology, and it is possible that less expensive technologies would also compete. Solar PV developers might site solar in areas with high electricity prices, or they might build transmission to reach high-priced load centers. Instead of adding batteries, they may install tracking solar PV to produce more energy during the morning and evening peaks. Or perhaps developers will shift away from PV and balance their portfolios with technologies that generate electricity at times of peak demand, such as offshore wind turbines. Most likely, the result will be a mix of these strategies. The strength of a VRPS and VRECs is that policymakers do not need to know which of these solutions will be most successful; rather, they can rely on a well-designed market to deliver the desired policy goals.

Research Objectives and Methodology

This study assessed the viability of the VREC and VRPS market first by developing a profit-maximizing solar+storage charge and discharge model for a range of facilities — with varying levels of PV power, battery power, and battery storage capacities — across a series of market pricing nodes. Then, we assessed the relative profitability of these facilities, as measured by the unlevered internal rate of return (IRR), under RPS and VRPS policies.

Solar+Storage Optimization Model

We estimated possible revenue increases generated from storing electricity generated by solar PV in lithium-ion batteries, then selling that electricity during peak hours in the California wholesale energy market. We used California ISO price data and California solar PV production data combined with a range of modeled battery configurations across market nodes with varying electricity prices.

6 Peter Bronski and Henry Richardson, "Corporations can generate one-third more impact with their renewables investment. Here's how.," Smart Energy Decisions, July 13, 2018, www.smartenergydecisions.com/columns/2018/07/13/corporations-can-generate-one-third-more-impact-with-their-renewables-investment-heres-how.

The solar+storage model relies on data from two sources: hourly day-ahead LMP data from the California ISO and electricity generation data for solar projects that received subsidies from the California Solar Initiative (CSI).

The LMP data include hourly day-ahead LMPs for three aggregate pricing nodes in California for 2017.[7] Aggregate pricing nodes are groups of connected nodes that contain less price variability than individual nodes. While VRECs should be calculated at the level at which LMPs are set, for the purposes of this analysis, aggregate pricing nodes (hereafter, "nodes") sufficiently represented the spatial and temporal variability in electricity prices and greatly reduced data processing loads. We calculated the average price for each node over the course of the year and randomly selected a node within $0.10 of the median, 10th and 90th percentile prices to represent the range of prices across the ISO territory. The low-, medium-, and high-priced nodes had average hourly prices of $31.42/MWh, $33.84/MWh, and $35.64/MWh, respectively.

The solar data include generation from solar PV projects in the Pacific Gas & Electric service territory with complete 2016 generation at 15-minute intervals, which included three projects.[8] While more recent solar generation data would have been preferable, 2016 data was the most recent available at the time of this analysis.[9] Although wholesale electricity prices change from year to year, the hourly solar production pattern is independent of price. Any hour missing from the CSI data was assumed to have no generation and was imputed with a zero. We aggregated solar production data to the hour and joined price data from each of the three nodes. While the CSI data did not include maximum or "nameplate" capacity (in kilowatts or kW), capacity for each was roughly inferred by the maximum electricity generated by each facility in a single hour: 23 kW, 47 kW, and 141 kW, respectively. Figure 2 summarizes the average hourly PV generation and node price for the three PV facilities and three nodes analyzed.

7 Two days of node price data were missing (March 12 and September 22), so the price data include only 363 days.
8 "Raw Interval Dataset (.zip)," California Distributed Generation Statistics (CDGS), 2017, www.californiadgstats.ca.gov/downloads/. The projects from CDGS are application IDs A-1611, A-1619, and A-1637.
9 February 29, 2016 was removed from the CSI data because there were only 28 days in February of 2017.

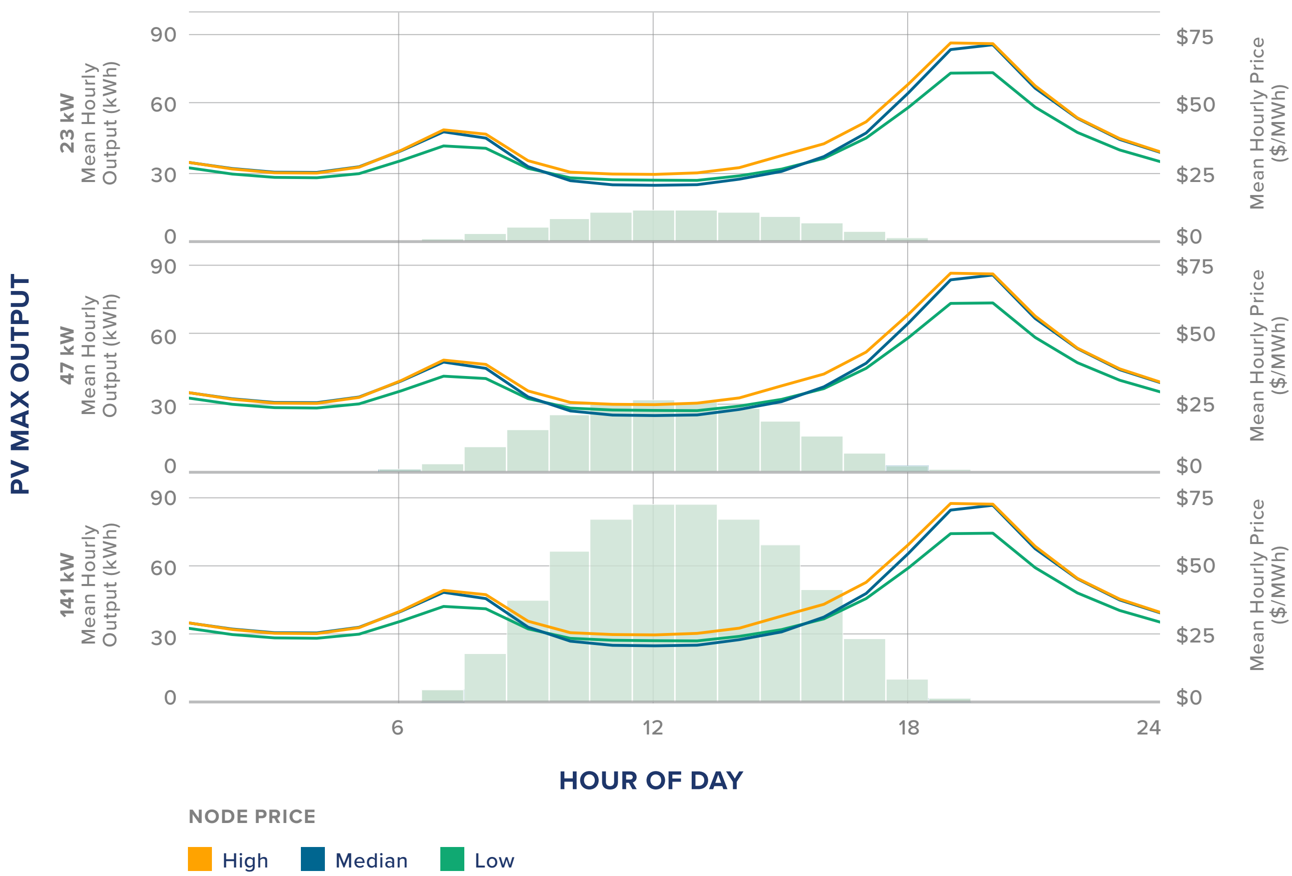

FIGURE 2. Generation profile of three California solar facilities (left axis, orange bars) with price profile of three California ISO nodes (right axis, colored lines).

We modeled each solar facility with all possible combinations of 25 kW, 50 kW, 100 kW, 150 kW, and 300 kW batteries with 1 hour, 2 hour, and 4 hour storage capacities. For each solar facility, node and battery size, we created an algorithm for the facility to maximize revenue from electricity sales. In the model, the solar+storage facility has access to the hourly wholesale prices for the current hour and following day (that is, the following 24-hour period) during each hour. The logic of selling electricity directly to the grid, charging, and discharging is determined by the wholesale electricity price in the current hour, prices over the following day, battery power (in kW) for charging and discharging, total energy storage capacity of the battery (in kWh), and battery round-trip efficiency (RTE). The assumed RTE is 80%, consistent with other studies on the topic.[10]

10 Nicole Miller, "Simulating Financial Returns of Arbitrage Opportunities Using Lithium-Ion Battery Storage Paired with Photovoltaic Systems in 3 U.S. Wholesale Electricity Markets," Duke University, May 2018, dukespace.lib.duke.edu/dspace/bitstream/handle/10161/16539/Miller_MP_Final.pdf.

The following describes the charge and discharge behavior of the modeled solar+storage facilities:

1. Starting with the first day, the battery will plan to charge during the hour with the lowest price if the price in the later hour times the battery's RTE is greater than the current price so that selling the power at the later hour will increase revenue.
2. If the PV generation during that hour exceeds the battery's power capacity or available storage capacity, it will sell the remainder directly to the grid.
3. The battery will schedule that energy to be stored until the highest price hour in the forthcoming 24 hours, and discharge in that hour, reducing available storage capacity.
4. The process will repeat for the hour with the next-lowest price, and discharge during the hour(s) with highest price(s), subject to the battery's remaining power and energy capacity.
5. When there is no revenue-increasing discharge hours or battery storage capacity remaining, any additional generation will be sold directly to the grid.

Financial Model

We developed a financial model to evaluate each of the three solar facilities with and without storage under RPS and VRPS policies on the low-, median-, and high-priced nodes from the optimization model. All projects were assumed to have a 20-year life, based on National Renewable Energy Laboratory (NREL) end-of-life estimates for solar modules.[11] Total capital cost was assumed to be $1.03 per watt based on NREL's 2017 solar PV system cost benchmark analysis.[12] The financial model used the average market price for each facility configuration from the optimization model. Market prices were randomly varied up or down by up to 5% each year to mimic fluctuations in the market. We used NREL's 2018 baseline estimates for operations and maintenance costs and assumed that they decline at an annual 1% rate.[13] To account for inflation over the lifetime of the project, nominal operations and maintenance costs are increased by 2% annually. We derived battery cost estimates per unit energy storage ($ per kWh) from NREL.[14]

Given uncertainty in the expected market-determined VREC price, we modeled each solar facility and battery configuration under three VREC prices. To determine a VREC price comparable to recent California REC prices, we calculated the ratio of California's actual solar expenditures for RPS compliance to solar PV's market price equivalent from our data. The market price equivalent is the average wholesale node price weighted by hourly solar electric production from the CSI data. In California, most electricity is "bundled" with RECs through power purchase agreements (PPAs), so these individual

11 Dirk Jordan and Sarah Kurtz, "Photovoltaic Degradation Rates — An Analytical Review," National Renewable Energy Lab, 2012, www.nrel.gov/docs/fy12osti/51664.pdf.
12 Ran Fu et al., "U.S. Solar Photovoltaic System Cost Benchmark: Q1 2017," National Renewable Energy Laboratory, 2017, www.nrel.gov/docs/fy17osti/68925.pdf.
13 "2018 Utility-Scale PV Operations and Maintenance (O&M) Costs," National Renewable Energy Laboratory, 2018, https://atb.nrel.gov/electricity/2018/index.html?t=su&s=om.
14 Ran Fu et al, "2018 U.S. Utility-Scale Photovoltaics-Plus-Energy Storage System Costs Benchmark," National Renewable Energy Laboratory, Nov. 2018, www.nrel.gov/docs/fy19osti/71714.pdf.

revenue streams are not directly observable. The market price equivalent represents the average price solar would have received if it participated in the competitive day-ahead wholesale market. The assumed total bundled price is the statewide average total solar photovoltaic RPS procurement expenditure of $0.12/kWh.[15]

To develop VREC price scenarios, we compared the RPS expenditures to the value currently delivered by solar. The wholesale electric price currently received by solar facilities is estimated from the CSI data without storage, which ranged from $0.024–0.028 per kWh. That is, under the RPS, the $0.12 California currently pays is up to five times the wholesale value of the solar generation in subsidies, implying a 400% subsidy per unit of value. By definition, the comparable VREC price would be $400: a $400 subsidy per $100 of wholesale electricity value. A VRPS, however, is expected to lower subsidy costs per unit value. To evaluate a range of potential VREC prices, we analyzed solar+storage financial performance under a VREC price of $400, along with two lower values in $75 increments: $325 and $250.

For the RPS model, we applied the average 2017 PPA and REC prices from the California Public Utilities Commission and prices were kept consistent throughout all scenarios.[16] The REC model is nearly identical to the VREC model, but applies a REC price of $75 per MWh, which is representative of revenue generated from RECs in California.[17]

To see if these projects would be profitable pre-tax, the study compares all scenarios by their unlevered pre-tax IRR to avoid factoring in the effects of post-tax subsidies like the Investment Tax Credit. This approach isolates the effects of the RPS and VRPS policies compared here, but results in conservative estimates in IRR given that project profitability would likely improve as other financial incentives are added.

Results

Solar+Storage Optimization

In our model, the battery storage optimization algorithm shifted electricity delivered to the grid from the lowest-priced hours to the highest-priced period across all combinations of nodes, PV facilities and battery sizes. Solar+storage behavior was extremely consistent across nodes.

15 “2018 Padilla Report,” California Public Utilities Commission, May 2018, www.cpuc.ca.gov/uploadedFiles/CPUCWebsite/Content/About_Us/Organization/Divisions/Office_of_Governmental_Affairs/Legislation/2018/MASTER%202018%20PADILLA%20REPORT_FINAL.pdf.

16 “2018 Padilla Report—Costs and Cost Savings for the RPS Program,” California Public Utilities Commission, 2018, www.cpuc.ca.gov/uploadedFiles/CPUCWebsite/Content/About_Us/Organization/Divisions/Office_of_Governmental_Affairs/Legislation/2018/MASTER%202018%20PADILLA%20REPORT_FINAL.pdf.

17 Ibid.

Figure 3 shows the average hourly output of the medium (43 kW) PV facility paired with nine different battery configurations at the median-priced nodes' average hourly prices. As battery power (rows) and storage capacity (columns) increase, the facility shifts more of its production from low-priced hours when electricity is produced (blue) to high-priced hours when electricity is discharged from the battery (green).

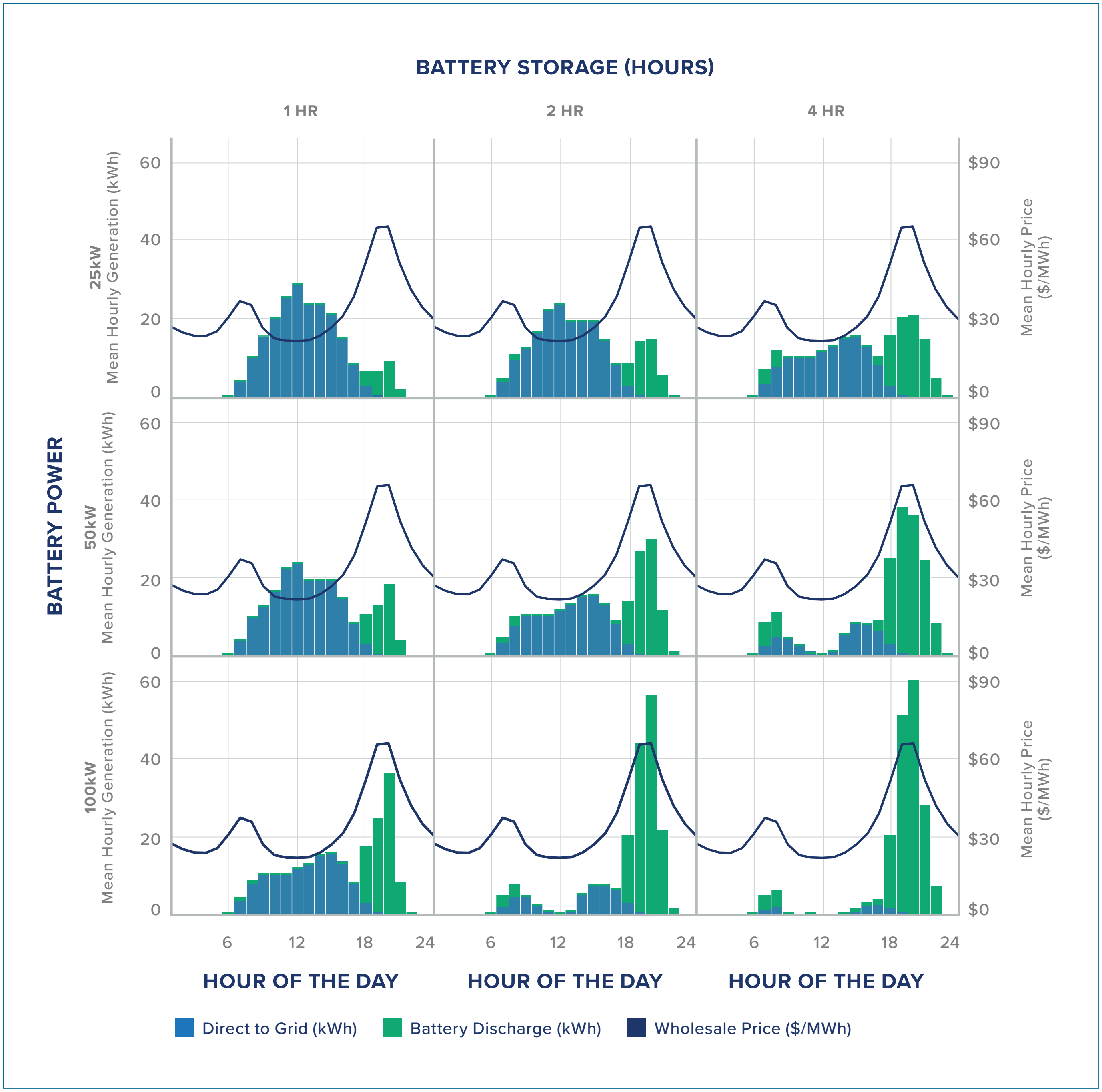

FIGURE 3. Average optimized hourly production profiles of 43 kW solar+storage facility on median node across battery sizes.

Due to this shift in generation, the model found that solar facilities increased their wholesale market revenue by between 7% (for the largest solar facility with the smallest battery modeled) and 159% (for the smallest solar facility with the largest battery). The profitability of these battery configurations, however, also depends on the additional costs of storage, not simply the additional benefits. The financial model presented in the following section accounts for these lifetime costs and benefits from storage additions.

POLICY TYPE	SUBSIDY PRICE	PROJECT SIZE	NODE PRICE	STORAGE SCENARIOS	STORAGE UNLEVERED IRR	NO STORAGE UNLEVERED IRR
RPS	$75/REC	23 kW	High	25 kW (1 hr.)	7%	**15%**
		47 kW	High	25 kW (1 hr.)	12%	**17%**
		141 kW	High	25 kW (1 hr.)	13%	**15%**
VRPS	$250/VREC	23 kW	High	25 kW (2 hr.)	**10%**	9%
		47 kW	High	25 kW (1 hr.)	**15%**	10%
		141 kW	High	25 kW (2 hr.)	**12%**	9%
	$325/VREC	23 kW	High	25 kW (2 hr.)	**13%**	12%
		47 kW	High	25 kW (1 hr.)	**19%**	14%
		141 kW	High	25 kW (2 hr.)	**15%**	12%
	$400/VREC	23 kW	High	25 kW (2 hr.)	**16%**	15%
		47 kW	High	25 kW (1 hr.)	**23%**	17%
		141 kW	High	25 kW (1 hr.)	**18%**	15%

TABLE 1. Highest IRR node price and solar+storage scenarios by policy type and subsidy price.

Financial Model

Together, the REC and VREC model shows that, all else equal, a VRPS policy would shift incentives to make solar+storage more profitable than solar alone. Table 1 shows the financial results under both RPS and VRPS policies, including the node and battery configuration with the highest IRR compared with the no-storage IRR for each scenario modeled. In all RPS policy scenarios, the profit maximizing strategy (bolded) is to not install storage. In contrast, the model found that the profit-maximizing strategy under a VRPS policy always included storage.

NODE PRICE	STORAGE SCENARIO	STORAGE UNLEVERED IRR
Low	25 kW (2 hr.)	13%
Median	25 kW (2 hr.)	14%
High	25 kW (1 hr.)	**19%**

TABLE 2. Unlevered IRR for highest-IRR solar+storage battery configuration, for 47 kW solar facility by node price ($325/VREC scenario).

Additionally, the VREC model revealed a preference for the highest-priced node in all scenarios, whereas the REC model showed no geographic differences. To illustrate, Table 2 shows the financial results for the 47 kW facility across all three nodes under the VRPS policy. The IRR is highest for the high-price node. Because VRECs incorporate the spatial differences in electricity price, solar deployment in a VREC setting is more sensitive to geographic price variability, which is dampened under an RPS.

Notably, not only is the highest-IRR scenario on the highest-priced node, it also includes a smaller battery (a one-hour battery) than the profit-maximizing configurations on the other nodes. This outcome suggests that appropriate siting may also reduce the total amount of storage needed to provide a given level of electricity value.

Overall, the financial model shows that the VREC both incentivizes storage that would have been uneconomical in a traditional RPS and incentivizes renewable energy production where electricity is most expensive and therefore most in demand. These findings clearly illustrate the policy's positive impact on a project finance level.

Discussion and Conclusions

As states continue to implement more aggressive clean energy policies, integrating renewable resources onto the grid will become increasingly important. In particular, solar PV provides diminishing added benefits as penetration increases and can even strain the grid through misalignment between generation and demand. The Duck Curve is most defined in California but is emerging in other jurisdictions such as New England and the Mid-Atlantic. A VRPS policy, with the VREC as its currency, has the potential to meet these changing needs.

A VRPS has two major benefits over a traditional RPS: policy cost and environmental outcomes. A VRPS subsidizes renewable energy in proportion to the value it provides to the electric grid, increasing the economic efficiency relative to an RPS by reducing subsidy costs for energy that provides relatively little marginal value. Second, the VRPS incentivizes renewable energy both when and where it has the highest potential to offset inefficient, costly and polluting legacy generation. Our model indicates both that a VRPS incentivizes storage, a key technology for meeting peak demand with renewable energy, and renewable deployment on higher-priced nodes, showing a spatial preference for deploying renewable energy where it is most expensive. That is, a VRPS incentivizes renewable energy both when and where electricity is needed most.

For the purposes of this paper, we have framed VRECs in terms of renewable energy, but have not attempted to define in detail which resources qualify. The VREC concept, however, could be easily extended to clean and zero-carbon energy sources that are not typically considered renewable, such as nuclear, carbon capture and storage, and large hydropower. While we do not take a strong position on these details, we encourage policymakers to consider the ultimate goals of reducing greenhouse gas emissions and other pollutants when structuring incentive programs for clean energy.

The potential for VRECs is possibly highest in the context of national policy. Economists have long argued that the current paradigm of state-by-state RPS policies have resulted in fragmented, thin and inefficient markets.[18] The standard proposed solution for this suite of problems is a national RPS policy without the myriad locally determined restrictions, multipliers and other policy details.

In the United States, a market that can help understand how a national RPS would function already exists: the voluntary REC market, in which private parties can claim the renewable attributes of electricity generation by purchasing RECs. Suppliers of voluntary RECs tend to be far away from load centers and their REC-buying customers: the states with the highest generation of RECs are in the middle of the country, but the buyers are concentrated on the populated coasts.[19] A nationwide RPS and REC market, therefore, would not only fail to account for the temporal variations in renewable energy benefits, but exacerbate the failure to account for locational variations and the geographical distribution of greenhouse gas emissions. The VRPS is an ideal instrument for a national policy because it accounts for the variable locational value of electricity, incentivizing generators to site facilities near and build transmission to load centers.

Other policy proposals to address the shortcomings of RECs tend to lead to increased market fragmentation. A clean peak standard, for example, would create a sub-market during pre-determined hours of the year, further limiting market robustness. These two proposed solutions — a national RPS and a local clean peak standard — illustrate the tension between the desire for a competitive, liquid market and meaningful contribution to reducing the grid's pollution and energy inputs. The VRPS bridges the gap between market function and environmental outcomes through transparent time- and location-dependent valuation of renewable energy.

18 Berry, "Tradable Renewable Energy Credits"; Schmalensee, "Evaluating Policies"; Koperski, "Renewable Energy Credit Market."

19 Todd Jones, "Two Markets, Overlapping Goals: Exploring the Intersection of RPS and Voluntary Markets for Renewable Energy in the U.S.," Center for Resource Solutions, 2017, www.resource-solutions.org/wp-content/uploads/2017/08/RPS-and-Voluntary-Markets.pdf.

Though a VRPS implemented in a single state would not address the issues of larger scale geographic differences and market fragmentation, inefficiency and illiquidity, it would still be preferable to an RPS. Furthermore, it easily could — and should — be designed to develop into a single, more efficient and more liquid market by explicitly allowing trading between states with compatible programs, regardless of the distance between states.

This report illustrates the projected outcomes of a VRPS in California using solar+storage investment as a proof of concept. However, the market-based design of a VRPS is a key strength of the policy, and solar+storage is likely not the only technology that will compete favorably under VRECs. The strength of a VRPS and VRECs is that policymakers do not need to know which solutions will be most successful; rather, they can rely on a well-designed market to deliver the desired policy goals.