Understanding the Cost Shift Created by Net Energy Metering

SUBJECT LINE

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Executive Summary

Net energy metering (NEM) policy was introduced in the early 1980s in the U.S. to encourage the adoption of rooftop solar when the technology was expensive and adoption was minimal. Under first-generation net metering, customers who generate more electricity than they consume receive a credit at the full retail rate for the excess energy they export to the grid.[1] This arrangement has served its purpose as an effective mechanism to support solar technology and achieve sustainability goals. But solar costs have fallen and installations have grown, and the mechanism has created a growing cost shift from customers with solar to customers without solar.[2]

In the context of Colorado Springs Utilities (Springs Utilities), there are two main components to the cost shift. The first cost shift component primarily arises from a mismatch between the structure of Springs Utilities' costs and the structure of the company's rates. The majority of Springs Utilities' costs do not vary with energy consumption; they are driven by the infrastructure needed to meet peak demand and maintain the power grid. However, a significant share of those costs is recovered through per-kWh volumetric energy charges. When a solar customer reduces their net consumption through self-generation, they avoid paying the energy charge on those kilowatt-hours, including the fixed costs embedded in it. Those fixed costs do not disappear when the solar customer's net usage goes down; they are shifted to non-solar customers through higher rates. The second cost shift component arises because excess generation is credited at the full retail rate, which is higher than the utility's avoided cost; the resulting difference is effectively recovered from other customers.

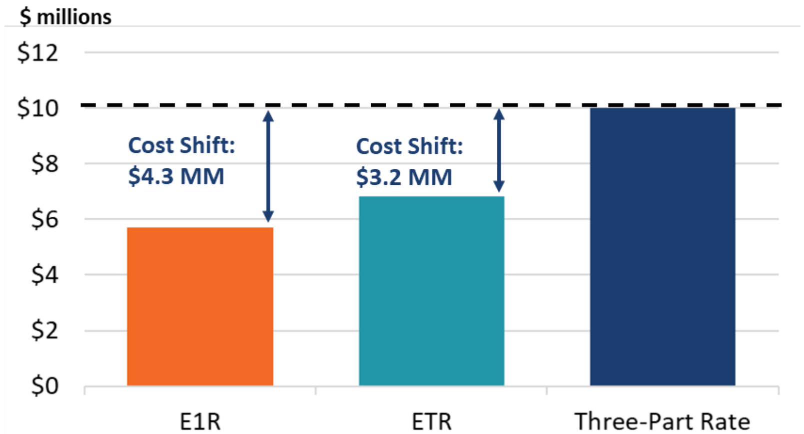
Using Springs Utilities' 2025 cost-of-service data, we constructed a "cost-reflective" rate, a rate that closely tracks how the costs are incurred, and compared the annual bills of residential NEM customers under the current rate and this cost-reflective rate. The total annual cost shift in 2025 is estimated at $4.3 million across Springs Utilities' approximately 11,000 NEM customers, or roughly $393 per solar customer per year (see Figure ES-1 below). On average, non-solar customers pay $21 per year more due to this cost shift, which will grow with each additional

1 First-generation net metering is also commonly referred to as traditional net metering or legacy net metering.

2 This cost shift is sometimes referred to as a "cross-subsidy" from customers without solar to customers with solar.

solar installation. As rates are set to increase by 6.5% and the number of NEM customers continues to increase in 2026, the cost shift to non-NEM customers would increase to $5 million in 2026.

FIGURE ES-1: REVENUE COLLECTED FROM 11,000 NEM CUSTOMERS UNDER E1R, ETR, AND THREE-PART RATE, AS OF 2025



Note: Total Annual Revenue for the NEM customer sample is calculated as the sum of annual bills of all residential NEM customers (8,422), using 2025 load and rate component data. Cost shift is calculated as: annual revenue collected under the three-part rate *minus* E1R or ETR annual revenue. The per-customer cost shift is then multiplied by the NEM population.

Transitioning NEM customers to the time-of-use ETR rate, the default rate for residential customers, will reduce some but not eliminate all of the cost shift, because the ETR rate is still largely energy-based while being time-based and lacks a demand charge to recover fixed infrastructure costs. It is important to note that the cost shift is not inherent to solar technology; it is a product of the prevailing NEM compensation mechanism and the current rate design, and it can be largely addressed through reforms that preserve the economic case for solar while ensuring all customers pay their fair share of utilizing the grid.

Utilities across the country have pursued three approaches to address this issue: i) revising export compensation to reflect actual grid value of rooftop solar; ii) restructuring rates to recover fixed costs through demand or fixed charges; or iii) pursuing both simultaneously. Each approach involves tradeoffs between implementation simplicity, customer impact, and effectiveness at eliminating the cost shift.

I. Introduction

Net energy metering (NEM) was introduced in the United States in the 1980s as an incentive mechanism to encourage the adoption of rooftop solar and other small-scale distributed generation.[3] The mechanism is straightforward: customers consume electricity generated from their installed rooftop solar systems and receive a credit on their bill at the full retail rate for any excess energy they export to the grid. Policymakers embraced this net metering mechanism as a way to promote solar energy at a time when the technology was expensive, adoption was minimal, and the cost of the credits was small enough to be absorbed by the broader customer base without meaningful impact.

More than 40 years later, the solar landscape has changed. Solar panel costs have fallen substantially over the past two decades. Installation volumes have grown exponentially, as have the credit amounts accruing to customers with solar. The NEM policy paired with the traditional residential electricity rate design that includes a flat energy charge has produced a growing gap between what solar customers pay for grid services and what those services cost, effectively creating a cost shift from solar customers to non-solar customers. There are two components to the cost shift:

1. **Cost shift from self-generation**: A typical residential volumetric retail rate recovers more than just energy costs. It also recovers costs for generation capacity, transmission, distribution poles and wires. When a customer uses their own solar generation on-site, they buy fewer kWh from the grid, but many of those grid costs do not fall proportionally just because the customer buys fewer kWh. Through self-generation, the customer avoids paying some grid-related costs embedded in the volumetric rate, even though they may still use and benefit from the grid. Since those costs still need to be recovered, they get collected from other customers.

2. **Cost shift from compensation for excess generation**: Under full retail net metering, each exported kWh is credited at the full retail rate. However, the value of that exported electricity to the utility is often closer to the avoided cost of energy, and sometimes avoided capacity or other system benefits, rather than the entire retail rate. As discussed above, the full volumetric retail rate typically includes energy, generation

[3] Colorado's first statewide net metering standards were adopted by the Colorado Public Utilities Commission (PUC) in 2005.

capacity, transmission and distribution costs. When the customer exports 1 kWh, the utility may avoid buying or producing 1 kWh of energy, but it generally does not avoid all the embedded grid costs. This implies that if the export credit exceeds the utility's avoided cost, the difference is effectively recovered from the rest of the customer base.

In this primer, we assess the level of cost shift from Colorado Springs Utilities (Springs Utilities) solar customers to non-solar customers under the current NEM compensation and the rate structure and how that level of cost shift may evolve as more customers install solar systems. We also highlight how select utilities across the country have addressed this issue through reforming their solar compensation framework and rate design for solar customers. Springs Utilities is working with its Board to develop an equitable approach for the community, and this document is intended to inform that process.

II. How Springs Utilities Establishes Electricity Rates

Before examining the mechanics of the cost shift, it is useful to review how Springs Utilities establishes electricity rates. Like all utilities across the US, Springs Utilities designs electricity rates to generate sufficient revenue to recover the total costs of providing service in a fair and efficient manner. In general, rates should reflect the cost of serving each customer or customer class, and they typically have three charges:

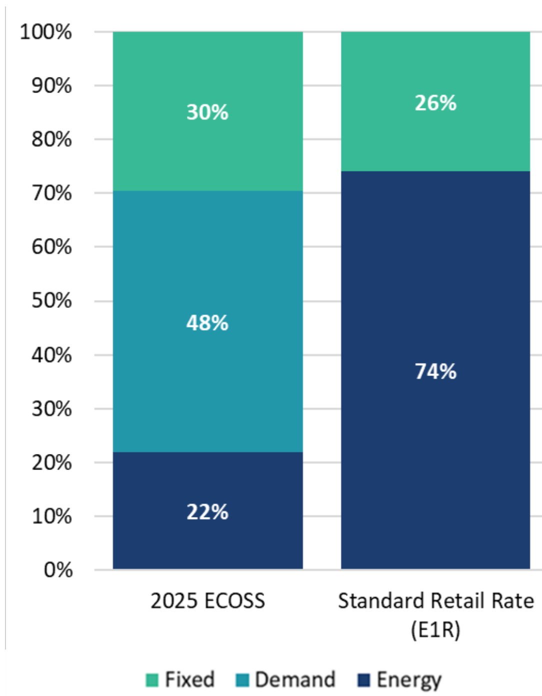
- A $/month **fixed charge** is used to recover costs that do not vary with how much energy customers use, such as billing system costs and customer service costs;
- A $/kWh **energy charge** is used to recover costs associated with producing or procuring electricity, primarily fuel and variable operating expenses. Energy-related costs represent about 22% of Springs Utilities' total costs (see Figure 1 below).
- A $/kW **demand charge** is used to recover costs to build and maintain the power plants and delivery network to serve peak electricity demand. Demand-related costs represent about 48% of Springs Utilities' total costs.[4]

Similar to many customers in the U.S., Springs Utilities residential customers are only assessed a fixed charge and an energy charge. In other words, the energy charge is used to recover both

[4] The demand charge is typically measured as the highest 15-minute average draw from the grid during a billing period, expressed in kilowatts (kW), and billed at a fixed rate per kW.

energy-related costs and demand-related costs. This recovery structure is a common and longstanding feature of retail rate design, driven in part by regulatory preferences for simplicity, and it works reasonably well when all customers consume roughly similar amounts of energy relative to their share of system costs. But NEM disrupts this alignment. Under the E1R rate, Springs Utilities recovers 74% of its costs through the energy charge. This means that for each kWh that a solar customer avoids buying through self generation, they avoid close to three quarters of the cost that Springs Utilities incurred to produce and deliver that kWh. In effect, the E1R rate structure allows solar customers to avoid paying a share of the costs they impose on the system, shifting those costs to non-solar customers as explained below.

FIGURE 1: SPRINGS UTILITIES COST STRUCTURE (LEFT) AND RATE STRUCTURE FOR AN AVERAGE SPRINGS UTILITIES RESIDENTIAL CUSTOMER UNDER E1R RATE SCHEDULE

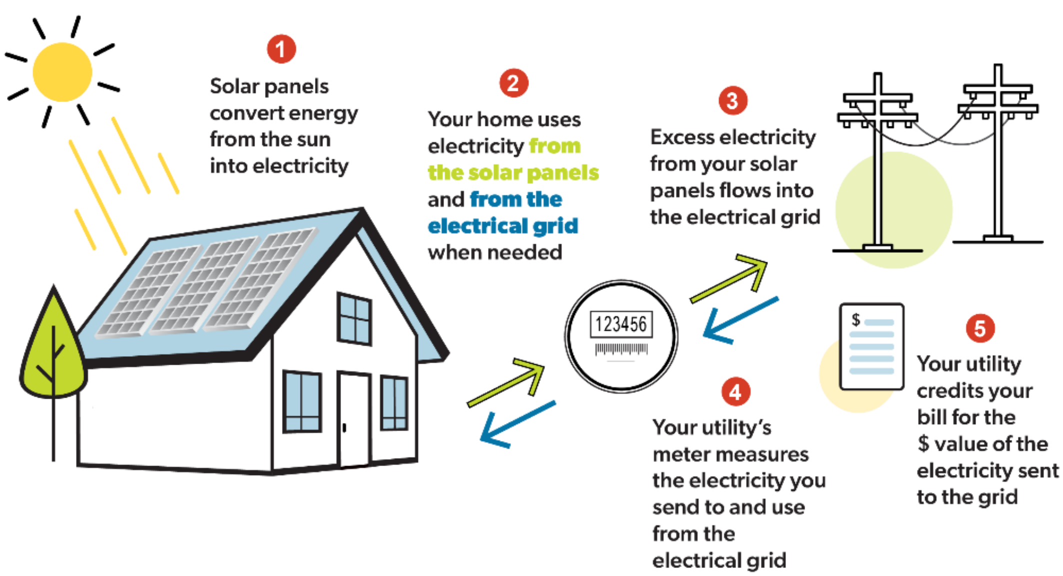


Note: ECOSS = Electricity Cost of Service Study

III. Net Energy Metering and the Issue of Cost-Shift

A customer with a rooftop solar system generates electricity during daylight hours. In some hours, the solar system produces more electricity than the household consumes, and the excess is sent back to the grid and consumed by neighboring homes and businesses. Under first-generation net energy metering, electricity delivered to the grid from the solar customer is compensated on a one-to-one basis for electricity that they purchase from the grid. At the end of the billing period, the customer pays only for their net consumption, or total consumption *minus* total self-generation, *regardless of when electricity was generated or purchased* (hence the term "net energy" metering). If the customer generates more than they consume in a given month, the excess credits typically roll forward to future months to offset customer's consumption in those months.

FIGURE 2: HOW NET METERING WORKS



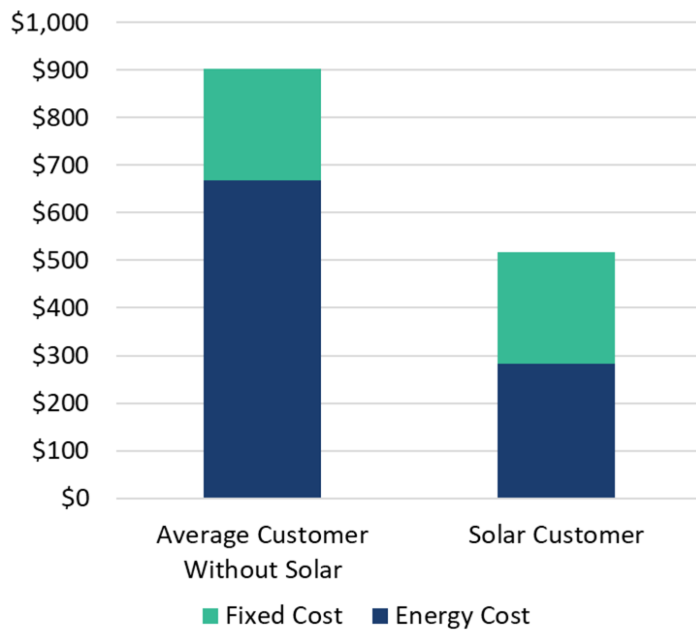
Source: https://www.oeb.ca/consumer-information-and-protection/net-metering

The first-generation NEM structure creates two distinct cost recovery issues for utilities like Springs Utilities. First, solar customers receive excessive compensation for exported energy. The full volumetric retail rate includes not only the costs of fuel, but also generation capacity, transmission network, distribution poles and wires. When a NEM customer exports a kWh, the value to the grid is primarily the avoided cost of generating that energy, about one-third of the volumetric retail rate. Crediting the export at the full volumetric retail rate overcompensates the solar customer for the other two thirds of the total costs of service—costs the utility never actually avoids.

Second, as explained above, because the majority of Springs Utilities' costs are actually fixed or demand-driven but are recovered on a per-kWh basis, any technology that reduces volumetric consumption creates a cost-recovery mismatch. When a solar customer reduces their net consumption through self-generation, they avoid paying the full volumetric energy charge on those kWh. In doing so, the solar customer also avoids paying their share of the fixed costs embedded in that charge. But those fixed costs do not simply disappear. The utility must still maintain the grid, still need to meet peak demand and provide service connections. The solar customer paying less for these fixed costs means that the balance has to be recovered from the remaining customers who do not have solar, in the form of higher rates. Effectively, the solar customer is cross-subsidized by customers without solar.

As seen in Figure 3 below, an average Springs Utilities solar customer pays about $400 less in annual electricity bills compared to an average customer without solar. This difference reflects in part the genuine energy cost savings that the solar customer creates through self-generation, but it also reflects the costs that are shifted to non-solar customers.

FIGURE 3: ANNUAL BILLS FOR AN AVERAGE CUSTOMER WITHOUT SOLAR AND AN AVERAGE CUSTOMER WITH SOLAR



Notes: Bill for average customer without solar is calculated using class-wide cost and usage data. Solar customer bill is calculated based on actual solar customer data.

The cross subsidy does not reflect any bad intent on the part of solar customers, who decided to install solar to lower their electricity bills, help achieve sustainability goals, or increase energy independence. Rather, the cross subsidy is a predictable consequence of recovering fixed costs through volumetric charges and then allowing some customers to reduce their volumetric consumption without a corresponding reduction in the costs they impose on the system.

It is important to acknowledge that from a power system perspective, rooftop solar does produce benefits beyond avoided energy, though those benefits do not amount to the full cost of providing service. Rooftop solar reduces emissions and can reduce losses in the delivery network if the generation is consumed locally. Under *some* circumstances, rooftop solar can also reduce the need for expensive generation assets to meet peak electricity demand. But even when accounting for these benefits, the value of rooftop solar does not add up to the total cost of serving those residential customers. In fact, these benefits can be more efficiently captured by utility-scale and community solar installations, which can be sited in optimal locations, oriented for maximum output, and paired with storage to shift generation to higher-value capacity hours. Rooftop solar, by contrast, is sited based on where people happen to live, oriented based on which way their roof faces, and generates most heavily during midday hours when total electricity demand and consequently the value of solar to the system are low.

Finally, the issue of cost shift is not inherent to solar technology itself; it is a product of how retail electricity rates are designed. If rates more accurately reflect the underlying cost structure—for example, where fixed costs are recovered through fixed and/or demand-based charges, and volumetric charges set closer to the actual marginal cost of energy—then a solar customer would reduce their bill in proportion to the costs they actually help the system avoid, and no cost shift would occur. A cost-reflective rate design also communicates to customers interested in adopting solar the real value of solar to their home and informs their adoption decision accordingly. Indeed, cost-reflective rate design is an important tool available for policymakers to address the cost shift issue, and it is the approach that many jurisdictions have adopted or are actively pursuing (see Section V below).

IV. Quantifying the Cost Shift for Springs Utilities

To quantify the cost shift, we compared what Springs Utilities' net-metered customers currently pay under the existing rate (E1R) to what they would pay under a cost-reflective rate designed to align charges with the costs each customer actually imposes on the system. The difference between these two amounts, aggregated across the full NEM customer population, represents the annual cost-shift from solar customers to non-solar customers.

The existing E1R rate recovers costs through two components:

- A flat $0.64/day access and facilities charge; and
- A $0.0876/kWh volumetric energy charge.

There is no demand charge. Because the energy charge carries the weight of recovering both energy-related and demand-related costs, a customer who reduces net consumption through solar self-generation avoids paying a significant share of the fixed infrastructure costs embedded in that charge.

We constructed a cost-reflective, three-part rate using data from Springs Utilities' 2025 cost-of-service study. The cost-reflective three-part rate has three components:

- A $0.73/day access and facilities charge to recover customer-related costs;[5]
- A $0.0259/kWh energy charge to recover only the energy-related costs that vary with consumption; and
- A $7.68/kW-month demand charge to recover the demand-related infrastructure costs based on each customer's peak draw from the grid between 5PM and 9PM, when demand for electricity is highest.

Under the three-part rate structure, a customer who installs solar reduces their energy charge, reflecting the system savings from reduced consumption, but continues to pay demand-related costs in proportion to the capacity they require from the grid during their peak usage periods.

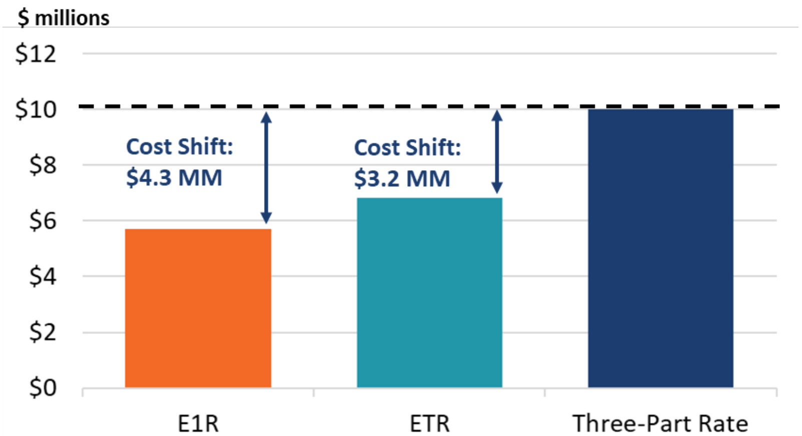
We applied these rates and calculated annual electricity bills for 8,422 residential NEM customers with complete usage records in 2025. The total cost shift in 2025 was $3.3 million, or about $393 per year per NEM customer. Applying this result to all 11,000 of Springs Utilities NEM customers, we estimated an annual cost shift of about $4.3 million (see Figure 4 below). On average, non-solar customers pay $21 more per year due to this cost shift. In 2026, rates are set to increase 6.5%, accordingly the cost shift to non-NEM customers would increase to $5 million.

As more customers install rooftop solar in the future, we expect the total cost shift amount to grow over time assuming the current NEM policy and the rate design persist. This is because each new net-metered customer shifts a similar increment of fixed costs onto the base of non-solar customers. Assuming the solar adoption rate continues to exceed the rate of overall customer growth, the cost shift can be expected to become more impactful to non-solar customers. Applying industry adoption trends, we estimate that the annual cost shift amount

[5] The cost-based access and facilities charge is higher than the E1R access and facilities charge, indicating a gap in fixed cost recovery under the existing rate. That gap is embedded in the E1R energy charge.

will grow to $8 million by 2030.[6, 7] Even if rooftop solar adoption rate were to slow by half, a $6.3 million cost shift would occur by 2030.[8]

FIGURE 4: REVENUE COLLECTED FROM 11,000 NEM CUSTOMERS UNDER E1R, ETR, AND THREE-PART RATE, AS OF 2025



Note: Total Annual Revenue for the NEM customer sample is calculated as the sum of annual bills of all residential NEM customers (8,422), using 2025 load and rate component data. Cost shift is calculated as: annual revenue collected under the three-part rate *minus* E1R or ETR annual revenue. The per-customer cost shift is then multiplied by the NEM population.

We also evaluated how the cost shift changes as Springs Utilities transitions residential customers to the time-of-use ETR rate as the default. The ETR rate introduces a higher $/kWh energy charge during system peak hours, sending a more accurate price signal about when electricity is most expensive to supply. In that respect, it is more cost-reflective than the E1R rate with a flat energy charge. But the ETR rate shares a fundamental limitation with E1R: it still recovers demand-related infrastructure costs through volumetric energy charges rather than through a demand charge. As a result, NEM customers can continue to avoid a significant portion of those fixed costs by reducing their metered consumption through solar self-generation. Under the ETR rate, we estimate the total annual cost shift across the 8,422 NEM customers to be $2.4 million—smaller than the $3.3 million under E1R, but still a substantial

6 Residential installed solar capacity is forecasted to increase at a 9% CAGR through 2030, according to SEIA's 2025 Solar Market Insight Report. Assuming average residential PV system sizes remain near recent observed levels, as observed in LBNL's October 2025 Update on Distributed Solar and Storage, residential solar customers are projected to increase at a 9% CAGR.

7 Assuming the rate structure does not change, and annual rate escalation of 6.5% in 2026 and 3% annually thereafter.

8 If adoption of solar grows at a faster rate than new residential customer growth, the subsidy would be magnified at a per non-solar customer level, as each customer switching to solar reduces the number of customers responsible for subsidizing the cost.

sum. For all 11,000 NEM customers, the annual cost shift is about $3.2 million (see Figure 4 above).

Finally, the distributional consequences of the cost shift warrant particular attention. In many parts of the country, customers who install rooftop solar tend to be homeowners with higher incomes. In contrast, customers who do not install solar tend to be renters, residents of multi-family buildings, or lower-income households. The cost therefore often shifts, in the aggregate, from more affluent customers to less affluent ones. In a period of broader affordability pressure on electricity bills, a regressive transfer that grows with each new solar installation is difficult to justify on equity grounds.

V. Approaches to NEM Policy Reform

Across the country, regulators and utilities have pursued efforts to reform NEM policy and address the extent of related cost shift. These efforts can be summarized into three categories.

The first approach is to change what and how NEM customers are paid for their exported energy. Rather than crediting exports at the full retail rate, a growing number of jurisdictions have moved to compensation levels that more closely reflect the value the exports provide to the grid. For example, Michigan replaced first-generation net metering with a framework built around an "inflow/outflow" billing mechanism. Customers are billed for electricity drawn from the grid (inflow) at the applicable retail rate, while exported generation (outflow) receives a credit based on the power supply component of the retail rate.[9] While this approach does not eliminate the cost shift resulting from customers' self-generation, it eliminates the cost shift due to excessive payments for exports.

A second approach focuses not on the export compensation policy itself but on the rate structure through which costs are recovered. If the underlying rate design more accurately assigns fixed infrastructure costs through demand charges or fixed charges rather than volumetric energy charges, the cost shift shrinks regardless of how exports are compensated. North Carolina pursued this approach, where rooftop solar customers are transitioned to rate structures that better reflect cost causation. Duke Energy's Residential Solar Choice (RSC) tariff requires solar customers to take service under a time-varying rate schedule. Under the RSC, imports and exports are netted within each time period, and any remaining excess generation is

9 Public Act 235 of 2023 significantly expanded the program by raising the cap for participation in the program to 10% of the utility's average in-state peak load and increasing eligible system size to 550 kW.

compensated at the utility's avoided cost rate, which is determined to be well below the retail rate.[10] While this approach reduces the cost shift resulting from customers' self-generation, it does not address the cost shift due to excessive payments for exports.

Some jurisdictions have pursued comprehensive reform, changing both the export compensation policy and the underlying rate design at the same time. This approach is more complex but produces the most complete alignment between what customers pay and what it costs to serve them. Arizona is a prominent example. In 2017, the state replaced net metering with a net billing structure for customers of the state's regulated utilities. Under Arizona's net billing program, exported energy is compensated at a rate derived from the utility's cost of procuring utility-scale solar resources rather than the full retail rate.[11] On the rate design side, APS requires all net billing customers to participate in one of the available time-varying rate plans. One of these plans includes a demand charge based on the customer's peak usage during on-peak hours, designed to ensure that solar customers who draw heavily from the grid during evening peaks contribute to the system costs of serving those peaks.[12]

The choice among these approaches involves real trade-offs. Each jurisdiction's approach reflects its own balance of consumer protection, the nature and extent of the cost shift issue, and specific regulatory and legislative requirements.

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[10] To soften the transition, the Commission approved a "Net Metering Bridge Rate" available to new solar customers through December 31, 2026. The Bridge Rate avoids mandatory TOU and critical peak pricing in the near term, but applies the same reduced export compensation and minimum bill provisions. Customers who enroll can remain on the Bridge Rate for up to 15 years from their interconnection date, after which they transition to the RSC structure. Legacy net metering customers—those who interconnected before October 2023—were grandfathered under prior rules for 10 years.

[11] The RCP has declined from $0.116/kWh in 2018 to approximately $0.076/kWh in 2023, representing roughly half the retail electricity rate. To provide a measure of stability, the ACC capped annual RCP reductions at 10% and allowed each customer to lock in their export rate for 10 years from the date of interconnection.

[12] Arizona also provided generous grandfathering for legacy solar customers: those who interconnected under the prior net metering rules retain their full-retail-rate compensation for 20 years from their date of interconnection.

VI. Conclusion

Net energy metering has been a successful policy story. It helped establish a rooftop solar market in the U.S. and in Colorado Springs at a time when the technology was expensive and unfamiliar, and it contributed to meaningful growth in distributed clean energy. That success, however, has created a new challenge: the compensation and rate design framework that made sense when solar adoption was small no longer produces fair outcomes for all Springs Utilities customers now that more than ten thousand customers participate in the NEM program.

Under the current rate structure, Springs Utilities' NEM customers pay approximately $5 million less per year than under the cost-reflective rate. That shortfall does not disappear; it is recovered from the remaining residential customers who do not have solar, adding an estimated $21 per year to each non-solar customer's bill. The amount is modest today, but it grows with every new solar installation. Under current trends, the annual cost shift is projected to reach $8 million by 2030.

The distributional pattern of this cost shift may compound the concern. In many communities, customers who adopt solar tend to be higher-income homeowners. Customers who bear the shifted costs tend to be renters, residents of multi-family buildings, and lower-income households—customers who are least positioned to install solar and least able to absorb higher bills. At a time when electricity affordability is already under pressure, a growing regressive transfer between customer groups is difficult to justify.

Importantly, the cost shift is not an inherent feature of solar energy. It is a product of a rate structure that recovers fixed infrastructure costs through volumetric energy charges, combined with a compensation policy that credits exports at the full retail rate. As jurisdictions across the country have demonstrated, cost-reflective rate design and updated export compensation can be introduced to address the cost shift created by the NEM policy while creating a more sustainable economic case for solar investments. These changes are not intended to discourage solar adoption. Rather, they aim to ensure that all customers who depend on the grid, including those with solar, contribute equitably to the costs of building and maintaining it.