GOBIERNO DE PUERTO RICO
JUNTA REGLAMENTADORA DE SERVICIO PÚBLICO
NEGOCIADO DE ENERGÍA DE PUERTO RICO

IN RE: BORRADOR DE ESTUDIO SOBRE MEDICIÓN NETA Y ENERGÍA DISTRIBUIDA	**CASO NÚM.:** NEPR-MI-2024-0006 **ASUNTO:** Publicación de Borrador de Estudio sobre Medición Neta y Energía Distribuida.

RESOLUCIÓN

El Artículo 4 de la Ley 114-2007[1] mandata al Negociado de Energía de la Junta Reglamentadora de Servicio Público de Puerto Rico ("Negociado de Energía") a realizar un estudio sobre medición neta y energía distribuida en el cual evaluará y considerará los costos y beneficios asociados a: (1) el programa de medición neta, (2) las tecnologías de generación distribuida, (3) la energía solar a menor escala, y (4) los sistemas de almacenamiento de energía. La Ley Núm. 10 aprobada el 10 de enero de 2024, enmendó los Arts. 4 y 9 de la Ley 114-2007.

Por otro lado, la Ley 57-2014[2] faculta al Negociado de Energía a realizar estudios e investigaciones periódicas sobre la generación, transmisión y distribución, utilización y consumo de energía, ya bien sea utilizando petróleo y/o sus derivados como combustible, gas natural, fuentes de energía renovable, conversión de desperdicios, así como cualquier otro mecanismo o tecnología que pueda ser utilizada como recurso energético, para determinar las necesidades energéticas de Puerto Rico durante cualquier período de tiempo.[3] A su vez, el Negociado de Energía tiene el poder de llevar a cabo las inspecciones, investigaciones y auditorías que estime necesarias para alcanzar los propósitos de la Ley 57-2014.[4]

Actuando dentro de los amplios poderes y deberes delegados, el Negociado de Energía publica el Borrador del Estudio sobre Medición Neta y Energía Distribuida y lo incluye como Anejo A de esta Resolución.

Publíquese.

Edison Avilés Deliz
Presidente

Ferdinand A. Ramos Soegaard
Comisionado Asociado

Sylvia B. Ugarte Araujo
Comisionada Asociada

Antonio Torres Miranda
Comisionado Asociado

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[1] *Ley del Programa de Medición Neta en la Autoridad de Energía Eléctrica*, según enmendada ("Ley 114-2007").

[2] *Ley de Transformación y ALIVIO Energético*, según enmendada ("Ley 57-2014").

[3] Art. 6.3(cc) de la Ley 57-2014.

[4] Art. 6.3(bb) de la Ley 57-2014.

NEGOCIADO DE ENERGÍA DE PUERTO RICO
NEPR
JUNTA REGLAMENTADORA DE SERVICIO PÚBLICO

CERTIFICACIÓN

Certifico que así lo acordó la mayoría de los miembros del Negociado de Energía de Puerto Rico el 14 de junio de 2024. La Comisionada Asociada Lillian Mateo no intervino. Certifico además que el 14 de junio de 2024 una copia de esta Resolución fue publicada en la página web del Negociado de Energía https://energia.pr.gov/; y he procedido con el archivo en autos de la Resolución emitida por el Negociado de Energía de Puerto Rico.

Para que así conste firmo la presente en San Juan, Puerto Rico, hoy, 14 de junio de 2024.

Sonia Seda Gaztambide
Secretaria

NEGOCIADO DE ENERGÍA DE PUERTO RICO
NEPR
JUNTA REGLAMENTADORA DE SERVICIO PÚBLICO

PUERTO RICO NET ENERGY METERING

JUNE 2024

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ACRONYMS AND ABBREVIATIONS

AC	Alternating current
APS	Arizona Public Service
BYOD	Bring your own device
CGS	Customer Grid-Supply
CGS+	Customer Grid-Supply Plus
CILTA	Contributions in lieu of taxes adjustment
ConEd	Consolidated Edison
CPP	Critical peak pricing
CPUC	California Public Utilities Commission
DC	Direct current
DEC	Duke Carolinas, LLC
DEP	Duke Energy Progress, LLC
DER	Distributed energy resources
DG	Distributed generation
FCA	Fuel charge adjustment
GW	Gigawatt
HB	House Bill
HECO	Hawaiian Electric
IOU	Investor-owned utilities
kW	Kilowatt
kWh	Kilowatt hour
MTC	Market transition credit
MW	Megawatt
MWh	Megawatt hour
NA	Not available/applicable
ND	Net difference
NEB	Net energy billing
NEM	Net Energy Metering
NMB	Net metering bridge
PA	Program Administrator
PCT	Participant Cost Test
PG&E	Pacific Gas and Electric Company
PPCA	Purchased power charge adjustment
PPOA	Power purchase and operations agreement
PREPA	Puerto Rico Electric Power Authority
PUC	Public utility commission
PV	Photovoltaics
RECs	Renewable Energy Credits
RIM	Ratepayer Impact Measure
RMI	Rocky Mountain Institute
RS	Retail Service
RSC	Rider Social Choice
RTP	Real-time pricing
SCE	Southern California Edison
SD	Standard deviation
SDG&E	San Diego Gas & Electric
SUBA-HH	Help to human subsidies
SUBA-NHH	Non-help to human subsidies
TOU	Time-of-use
TRC	Total Resource Cost
W	Watt

1 INTRODUCTION

Puerto Rico is transforming its electric system to meet the goal of 100% renewable energy as required by the *Puerto Rico Energy Public Policy Act* (“Act 17-2019”).[1] As of the end of 2023, there were over 750 MW of NEM capacity installed on 110,000 customer premises with an adoption rate in 2023 of over 3500 units a month.[2] The rate mechanism of net energy metering (NEM) has played a significant role in providing revenues that have enabled Puerto Rico to develop solar generation capability.

Adding renewable energy from solar and wind power projects to Puerto Rico’s generation fleet is an important contribution to decreasing its dependence on fossil fuels. Moreover, doing so mitigates the impact of climate change and can increase the resilience of Puerto Rico’s electric grid. In light of this, the *Public Policy on Energy Diversification by Means of Sustainable and Alternative Renewable Energy in Puerto Rico Act* (“Act 82-2010”) states, "The Government of Puerto Rico is compelled to create the necessary conditions in order for future generations to be able to progress and develop in a healthy environment, creating, in turn, the necessary tools to stabilize the price of energy and new economic development sources."[3] NEM enacted to promote adoption of PV and other renewable resources has been a vital tool in achieving those necessary conditions, and one that has been used by most states in some fashion.

The Energy Bureau of the Puerto Rico Public Service Regulatory Board ("Energy Bureau") is responsible for overseeing and ensuring the full execution and implementation of Act 17-2019, which amended is the *Puerto Rico Energy Transformation and RELIEF Act*, ("Act 57-2014”). In accordance with Act 57-2014, the Energy Bureau is responsible, among other duties, for establishing and implementing regulatory actions to guarantee the capacity, reliability, safety, and efficiency of the power system at reasonable electricity rates in Puerto Rico; the Energy Bureau also has the duty and responsibility to take all necessary regulatory actions to guarantee reasonable electric services rates.[4]

A fundamental principle of public utility regulation is the prudence standard. The prudence standard requires utilities to make reasoned decisions given the information that is known and knowable. Public utility commissions (PUCs) share this obligation as they fulfill their statutory responsibilities. What is important about this standard is that it requires the active pursuit and consideration of all relevant information that supports utility and regulatory decisions. Full information allows regulators and utilities to make reasoned decisions.

The legislature of Puerto Rico implicitly recognized the role of regulatory prudence when it passed The *Puerto Rico Net Metering Program Act* (as amended), and directed the Energy

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[1] The goals set by Act. 17-2019 are for Renewables to 40% by or before 2025; 60% by or before 2040; and 100% by or before 2050.

[2] Informe de Progreso de Interconexión de Sistemas de Generación Distribuida Trimestre octubre a diciembre 2023, LUMA (January 16 2024)

[3] *Public Policy on Energy Diversification by Means of Sustainable and Alternative Renewable Energy in Puerto Rico Act*, Act No. 82 of July 19, 2010. https://bvirtualogp.pr.gov/ogp/Bvirtual/leyesreferencia/PDF/2-ingles/0082-2010.pdf

[4] *Puerto Rico Energy Transformation and RELIEF Act*, Act No. 57 of May 27, 2014, as amended. https://bvirtualogp.pr.gov/ogp/Bvirtual/leyesreferencia/PDF/2-ingles/57-2014.pdf.

Bureau "to conduct a study, through an independent formal process and with participation of interested parties and the general public, to evaluate and consider the costs and benefits associated with: (1) the net metering program, (2) distributed generation technologies, 3) small scale solar energy projects, (4) energy storage systems."[5] At the time of its passage, the legislature understood that prudent regulation requires continual re-evaluation and adjustment of policies and practices based on research, experience, and directed and inquiry findings. A major challenge in fulfilling the requirements of the *Puerto Rico Net Metering Program Act* is acquiring sufficient information to perform the requisite cost/benefit cost analyses to compare and contract policy choices. While LUMA Energy ("LUMA") is working to develop many of the technical elements for such analyses, there is much to be done before a full impact characterization is possible.

Presumably because of the effectiveness of the current NEM program and the desire to maintain momentum in driving to 100% renewables, the legislature passed Act 10-2024 that postponed the study[6] until 2030 to continue the shift to renewables.[7] While it is clear that NEM has played a vital role in developing renewable capacity in Puerto Rico, one question remains: can other pricing and incentive mechanisms do better—especially as renewables provide an ever-increasing portion of the Puerto Rico supply mix?

The purpose of this report is to investigate and establish what is known and knowable about NEM to support prudent policy development by the Energy Bureau. To do this, this report provides context on NEM performance on four areas:

1. The structural and economic character and context of NEM
2. How and why NEM programs are evolving in various states around the country as experience is gained
3. Definition and evaluation of alternative mechanisms that can support Puerto Rico's goals for achieving renewable goals while supporting reliable, equitable, and efficient system operation
4. Information requirements for implementing and administering enhancements to, or adoption of, alternative to the current NEM system

The authors of this report recognize this draft is a necessary step in identifying mechanisms that will enhance Puerto Rico's renewable transition based on others' experience. The focus is on describing the *what* and *how* and—where possible—*why*. This is accomplished by comparing a number of NEM and successor programs across their features—describing their technical and financial characteristics so that similarities and differences are obvious and addressed. In

[5] *Puerto Rico Net Metering Program Act*, Act No. 114 of August 16, 2007, as amended. https://bvirtualogp.pr.gov/ogp/Bvirtual/leyesreferencia/PDF/2-ingles/114-2007.pdf

[6] *The act called for the study "to take into account the following factors: the costs of energy generation, the capacity value, the t*ransmission and distribution costs, system losses prevented, and environmental compliance costs avoided, among other factors deemed relevant and appropriate by the Bureau."

[7]

addition, three case studies were conducted to provide context as to why NEM was enacted, its performance, and why a successor service was adopted.

The authors understand that others may have different perspectives and understanding of the implications and that what we provide enables using the same factual basis. Given the richness of experience of the Puerto Rico solar community, we welcome feedback and discussion to improve the content of the report and correct any error that the report may contain.

We understand the importance of continuing the deployment of photovoltaics (PV) and storage currently supported by NEM. In the long run, we conclude that NEM—as currently formulated in Puerto Rico—may not be the best pricing mechanism to achieve Puerto Rico's goal of 100% renewable power supply, especially if rooftop solar and other behind-the-meter resources are to contribute substantially.

Many states that adopted NEM as a convenient method of pricing have now moved on to different approaches that more closely align the pricing mechanisms with value. As this report describes, as the penetration of NEM increases, so will the need to consider alternative pricing approaches along with technical provisions that govern when and how power is exported into the grid. We recommend that the Energy Bureau begin a public evaluation of alternatives to the current pricing system (based upon the questions articulated at the end of this report) in the interim, to maintain stability in the behind-the-meter solar market.

2 NET ENERGY METERING

2.1 HISTORY

NEM is a rate mechanism used to compensate retail electric customers for power that they produce with devices like PV on their premises. The simplicity of the NEM mechanism is that it relies upon existing rates to provide compensation for power generated. In effect, it is the equivalent of rolling the meter backwards, so that power produced by the device first fulfills the customers premises' energy needs and any production beyond the customer's real-time needs is exported to the grid for a bill credit. A feature of many NEM structures is that surplus power production in any billing period is carried forward to reduce the customer's bill in future periods. This feature effectively is the equivalent of using the grid as a storage device for customers with PV and other on-site generation. These features are especially attractive to residents that install small-scale (5–10 kW) on-site generation.

The first documented use of the NEM mechanism was in 1979 for a solar project powering a 286-unit federally subsidized, low-income housing complex in Massachusetts called Granite Place. The project architect Steve Strong recognized that the complex needed to maintain a power balance that required the ability to both import power when needed and export excess power to Boston Edison.[8] Strong understood the mechanics of the way meters work. The flow of power moved through an electro-mechanical meter that was able to measure power imported from the utility, and to run backwards to account for power that was exported to the utility.

Strong wired the project for the meter to run backwards when it produced more electricity than it needed and operate normally when the project was a net consumer. In doing so, he created the paradigm of net metering. Power produced by the on-site facility offset power that had been previous supplied from the grid for billing purposes; at the end of the billing period, the energy meter would register the net power, either imported or exported energy, which was then used for billing, hence, net metering (see Figure 1).

[8] However, the size of the solar installation was small relative to the complex's energy demand, making it unlikely that the system would actually produce excess electricity.

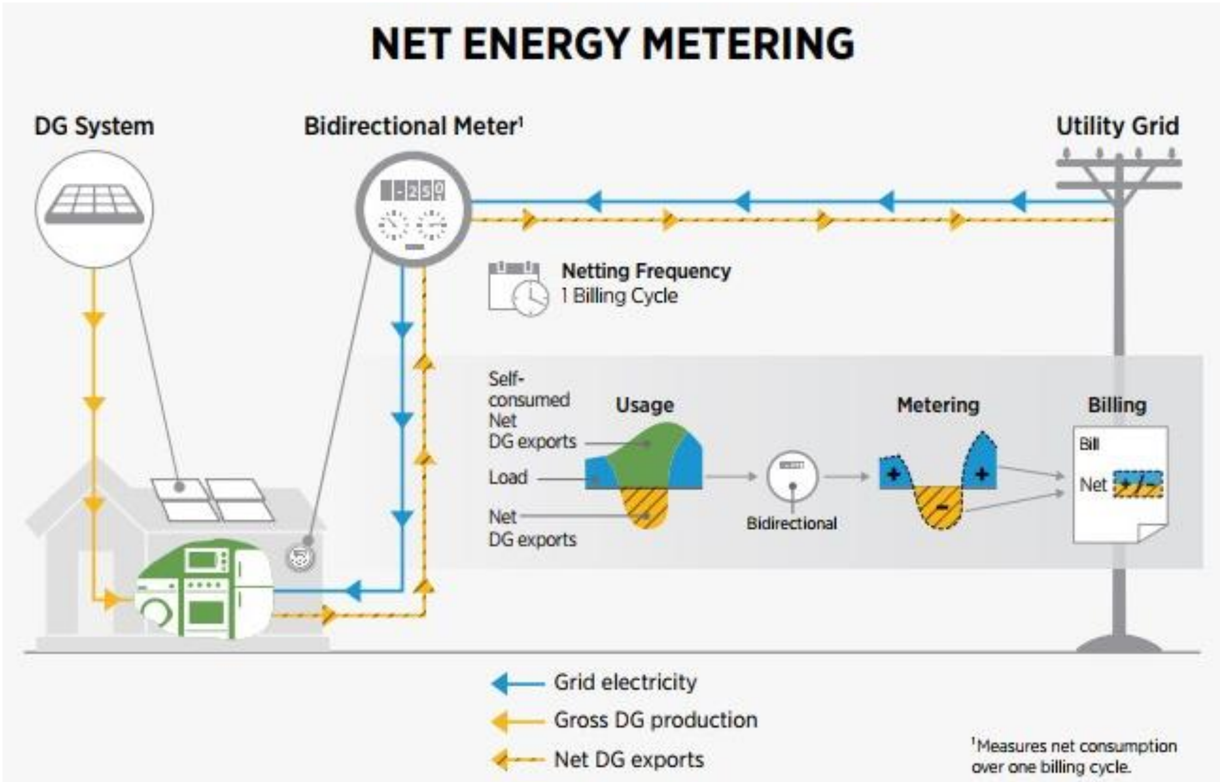


Figure 1. Net Energy Metering

Explaining the rationale of this approach, Strong commented, "It was intuitive, and it was almost just like, that's just the way it should be. We're producing electrons that are just as valuable as the ones delivered by the coal plant or the heavy residual fuel oil driven plant, and so it just made sense."[9] As Tom Stanton, Principal Researcher for Energy and Environment at the National Regulatory Research Institute, reported that "(i)nitially, NEM was largely understood to be…administratively simple…at a time when markets for solar PV and other DG [distributed generation] were uneconomic."[10] Therefore, NEM was established because it was convenient and practical—initially providing a mechanism to credit production against consumption and subsequently using any excess in any period to offset bills for consumption in future periods.

Granite Place developed an ad hoc approach, not supported by utility tariffs. Formalizing that approach and making it a rate option available to all customers required either regulatory actions implementing a pricing method by PUCs or state legislatures. The Idaho Public Utilities Commission issued an enabling order (Order No. 16025) for NEM in 1980, although the final tariffs implementing it were not approved until 1986. The Arizona Corporation Commission approved the first net metering tariffs for facilities below 100 kW in 1981. Minnesota became the first state to legislate NEM.[11] The legislative intent became the template of much that

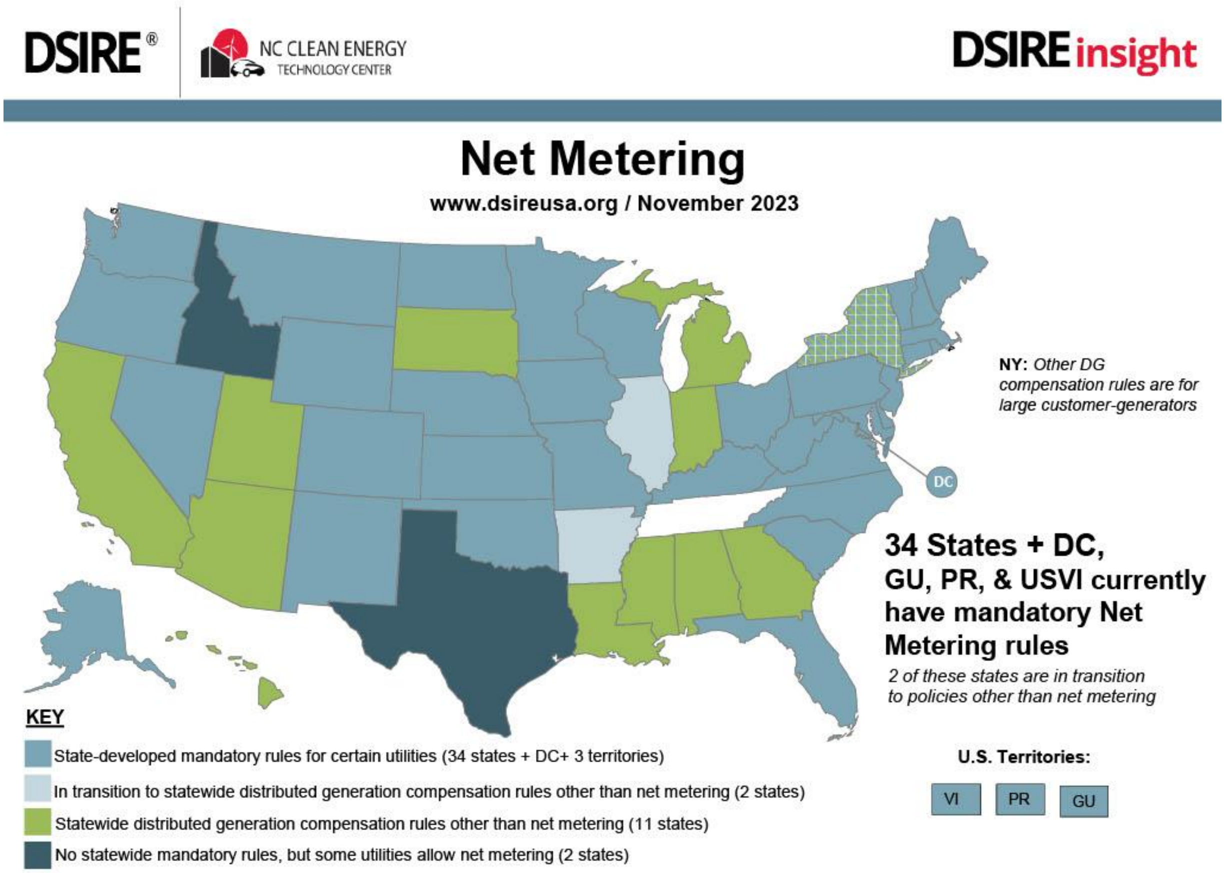
[9] Evans-Brown, S. "The Accidental History of Solar Energy," *Outside/In*, January 5, 2017. https://outsideinradio.org/shows/ep28

[10] Stanton, T., "Review of State Net Energy Metering and Successor Rate Designs," National Regulatory Research Institute Report 19-01, 2019. https://pubs.naruc.org/pub/A107102C-92E5-776D-4114-9148841DE66B

[11] Wan, Y., "Net Metering Programs," Topical Issues Brief, NREL/SP-460-21651, December 1996. https://www.nrel.gov/docs/legosti/old/21651.pdf

followed. It stated, "This section shall at all times be construed in accordance with its intent to give the maximum possible encouragement to cogeneration and small power production consistent with the protection of ratepayers and the public."[12]

Largely as the result of the *Energy Policy Act of 2005* requirement for states to investigate net metering, 43 states and the District of Columbia adopted a form of net metering.[13] As demonstrated by Figure 2, many states use NEM to encourage the adoption of solar power. Currently, a number of states are considering alternative forms of NEM, a subject explored later in this report.



Used with permission from N.C. Clean Energy Technology Center[13]

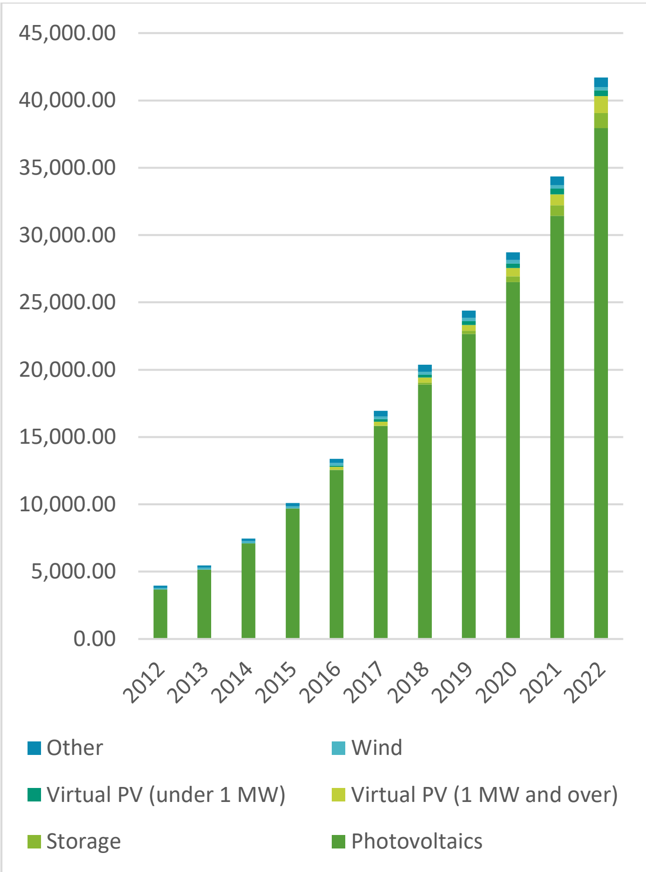
Figure 2. States with NEM

The implementation of net metering has not only contributed to the Minnesota legislature's objective of encouraging the installation of small power production but also spurred a solar revolution. As demonstrated by Figure 3 and Figure 4, it is now generally recognized that NEM has been successful in igniting the solar revolution, but there is now debate as to whether it has

[12] Minnesota Statutes 216B.164 COGENERATION AND SMALL POWER PRODUCTION Subd. 3a.Net metered facility.

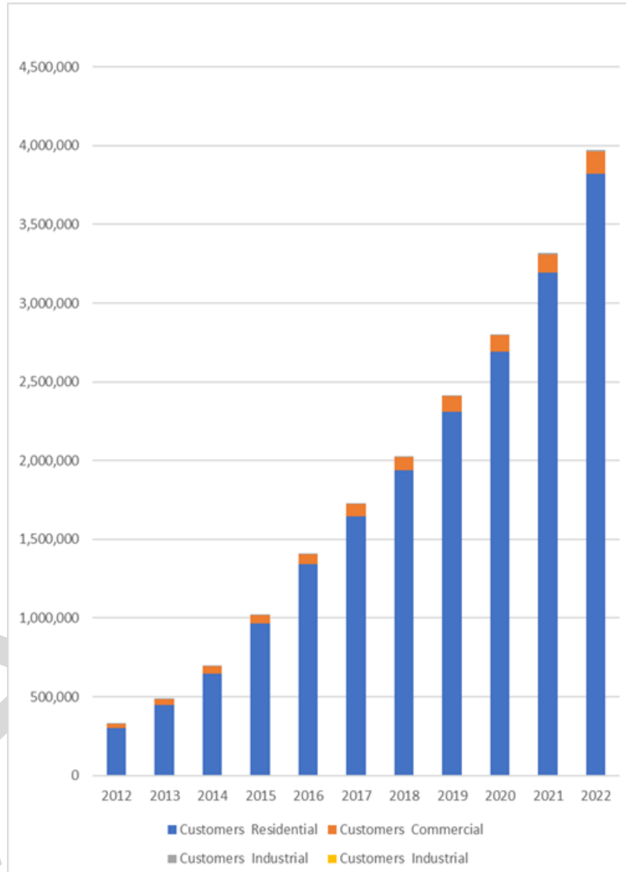
[13] N.C. Clean Energy Technology Center, "Database of State Incentives for Renewables & Efficiency (DSIRE®)," http://www.dsireusa.org/.

accomplished its primary objective of igniting the solar revolution, and it is time to refine pricing mechanisms for compensating on-site generation.



Note: graph developed using EIA data

Figure 3. U.S. NEM Capacity Addition by Type



Note: graph developed using EIA data

Figure 4. U.S. NEM Customer Participation

With the success of NEM, states are taking a closer look at the equity and efficiency of implications of NEM tariff design. The primary form of this debate is whether NEM is a subsidy, or a cost-shift, as discussed next. The purpose of this report is to provide an overview of NEM's success in Puerto Rico and nationwide, the implementation of alternatives to NEM, and issues that will affect the investigation of alternatives to NEM in Puerto Rico.

2.2 Regulatory Principles for Evaluating NEM and Its Alternatives

NEM was established as a rate mechanism because of its simplicity and convenience. The Solar Electric Power Association recognized that "(i)n many states, rising solar market penetration has triggered NEM policy and tariff reviews."[14] This raises the issue of what principles can guide that investigation.

The classic treatise relied on by public utility regulators that establishes principles of ratemaking is James Bonbright's *Principles of Public Utility Rates*.[15] The "Bonbright Principles" were developed in 1961—a very different time in the industry's history—when the industry was dominated by vertically integrated investor-owned utilities (IOUs) that were capturing economies of scale in generation, by building ever larger generating units. It was a time before energy efficiency or demand response was accepted as a legitimate alternative to building new power plants. Selling independent generation to utilities was an anomaly and not a standard business practice. The Bonbright Principles were also established before the technological revolution in renewables and storage, yet they still provide a starting point for the re-evaluation of NEM.

Bonbright's Principles have been relied on since 1961. Now, there is an effort to modernize them. The Edison Electric Institute distilled them into five core principles, as demonstrated in Figure 5. Analysts at the Rocky Mountain Institute (RMI) applied a "21st Century Interpretation" to the Bonbright Principles, also shown in Figure 5. The "RMI Principles" stress the importance of customer understanding but recognize that the structure of rates is not static, and that they may become "more sophisticated." The RMI Principles support the financial viability of the utility. The RMI Principles recognize the role of "dynamic and sophisticated price signals" in managing price volatility and high customer bills. The RMI Principles also recognize the importance of rate design reflecting an understanding of the physical impacts of DER. Finally, the RMI Principles recognize the importance of price signals in investment and optimizing economic efficiency.

The RMI Principles are predicated on the notion that ratemaking practices need to advance in order to accommodate and fully utilize the potential of distributed energy resources (DER). Economically efficient investment requires economically efficient operation. While the RMI Principles are concerned about the utility financial condition, they are silent on the financial viability of DER projects. It is important for projects that are being developed to support Puerto Rico's energy policies to also be financially viable. Further, while the RMI Principles refer to undue discrimination, it is prudent to expand the concerns for rate discrimination, to include equity issues.

[14] Solar Energy Power Association, "Ratemaking, Solar Value and Solar Net Energy Metering – A Primer," undated, pg. 2. https://www.energy.gov/sites/prod/files/2015/03/f20/sepa-nem-report-0713-print.pdf

[15] Bonbright, J., *Principles of Public Utility Rates*, Columbia University Press, 1961.

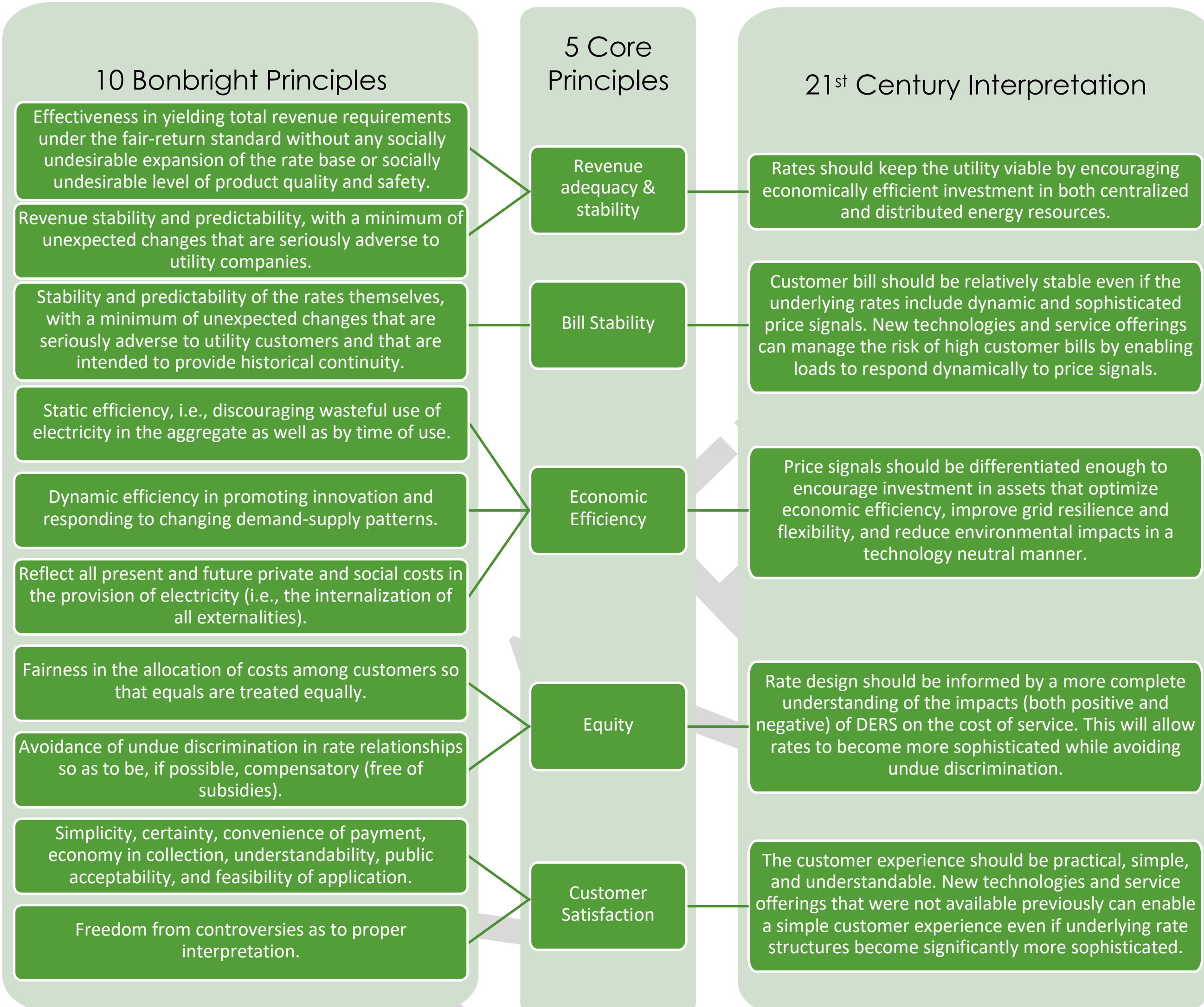


Figure 5. Bonbright Principles, Edison Electric Institute Core Principles,[16] and RMI's 21st Century Interpretation[17]

Given the evolution of the Bonbright Principles, it is possible to lay out some basic principles for evaluating NEM in Puerto Rico:

- Maximize the value of DER to Puerto Rico of resources being deployed
- Use DER as an asset to maintain bulk electric system and local distribution reliability
- Assure that the prices paid for power export are just and reasonable
- Meet equity goals

[16] Edison Electric Institute, "A Primer on Rate Design for Residential Distributed Generation," February 2006, pg. 6. https://www.naseo.org/Data/Sites/1/documents/2017-institute/2016-feb-naruc-primer-on-rate-design.pdf

[17] Glick, D. et al., "Rate Design of the Distribution Edge: Electricity Pricing for a Distributed Resource Future," RMI, September 2014. https://rmi.org/insight/rate-design-for-the-distributionedge-electricity-pricing-for-a-distributed-resource-future

- Assure adequate revenues to support DER development to meet renewable goals
- Provide customer protection

2.3 Implications of NEM

NEM has been successful at energizing customer-sided DER—in particular, solar PV in a number of jurisdictions. When NEM was utilized by only a small portion of a utility's customers, any adverse rate impacts or operational issues were negligible. The costs were socialized over sufficiently large enough of a base that recovery of the revenue shortfall required only a fractional change in the energy rate. The operational impacts of integrating a higher share of DG into the grid were once insignificant, but now have introduced new challenges for grid management and reliability. As NEM became a more widely available and used mechanism, its impacts have become more significant.

2.3.1 Rate Impacts

At the core of the economic inefficiency associated with the NEM pricing mechanism is its reliance on retail rates. Net metering employs the structure and rate levels ($/kWh) of retail rates to pay for net flows to the facility or household and to credit net flows from the facility. The costs underlying rates can be characterized as either fixed or variable costs. The fixed costs are primarily the capital costs of providing the utility infrastructure; variable costs cover the cost of producing and delivering electricity that varies with energy flows to customers. From the standpoint of economic efficiency, rates would optimally be designed so that the variable portion of the rate (typically referred to as the energy charge) reflects the marginal cost of supply. This is typically not the case with NEM rates because, according to Wolak, "the bulk of residential and small commercial distribution and transmission costs are recovered through relatively flat per kWh usage charges rather than per customer charges or coincident peak demand charges."[18] Borenstein states that as a consequence, "marginal retail rates well above marginal cost create a particularly potent incentive to install PV."[19]

As a result of this underlying rate design, there are two important rate issues associated with net metering for both consumers and utilities:

1. NEM results in an under collection of fixed costs resulting in a cost shift that increases costs for non-participating customers, and
2. NEM does not provide a price signal that supports efficient investment and operational decisions.

The recovery of fixed costs through energy charges creates the NEM equity issue. That is, NEM customers avoid paying some or all of the fixed cost incurred by their utility to provide them

[18] Wolak, F.A., "Efficient Pricing: The Key to Unlocking Radical Innovation in the Electricity Sector," Organisation for Economic Co-operation and Development, DAF/COMP/WP2(2017)4, June 2017

[19] Borenstein, S., "The private net benefits of residential solar pv: the role of electricity tariffs, tax incentives and rebates," *NBER Working Paper Series*, Working Paper 21342, 2015, pg. 8. http://www.nber.org/papers/w21342

service. This rate impact has been called a cost shift or a subsidy.[20] This report will use those two terms interchangeably.

The PV revolution in California that began in 2007[21] was fueled by three policies: 1) federal tax credits, 2) state subsidies, and 3) revenue streams for solar production provided by NEM. Because so much PV was installed on rooftops (currently almost 10%[22]), California presents an instructive example of a cost shift:

> The most indirect incentives for installing solar PV in California come from the residential rate structure and the way that residential PV is treated within that structure. IOUs in California—including PG&E [Pacific Gas and Electric Company]—collect virtually all residential customer revenue through increasing-block pricing, a volumetric charge that increases the marginal price per kWh as the household's total consumption increases within a billing period. These rates have little or no fixed monthly charge or other non-volumetric charge. As a result, high-usage electricity consumers face very high marginal prices, which increases the return to installing PV. Throughout the period studied here, the rate structures had 4 or 5 tiers with lowest-tier prices in the range of $0.12–0.15 and the highest-tier prices in the range of $0.28–0.48.[19]

It is important to understand why retail rates were as high as $0.48/kWh. These high rates were related, in large part, to cost recovery of excess power supply costs incurred by the state during the California Energy Crisis. During the energy crisis, the state's IOUs ceased to be credit-worthy buyers of power from the state's wholesale energy markets (the California Independent System Operator and California Power Exchange). The California Department of Water Resources was given the statutory authority to act on behalf of the state's IOUs to procure electric power and recover those costs; in 2002, the department issued $11.3 billion in bonds that were then recovered from the IOU's ratepayers over time.[23] Increased block rates were used for cost recovery from customers of the state's three IOUs: PG&E, Southern California Edison (SCE), and San Diego Gas & Electric (SDG&E). Therefore, it is not surprising early adopters of PV based upon NEM were "disproportionately wealthy."[19]

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[20] Within the lexicon of economics, there is a subtle difference between a cost shift and a subsidy. A cost shift occurs when revenues used to recover fixed costs are avoided by the NEM customer and reallocated to other (non-NEM) customers. A cross-subsidy exists when the incremental costs of serving a customer with solar is paying less than their incremental cost of service.

"The Faulhaber principle states that there are no cross-subsidies between customers if all customers are paying more than their incremental cost of service and less than their stand-alone cost of service." Technically, a cost shift can exist without a subsidy, because even with NEM, a customer may consume sufficient power that the rates that they pay cover their fully allocated fixed cost. In effect, studies that refer to the cost shift as a study implicitly assume that the existing rate design reflects fully allocated costs. As a consequence, this report uses the terms interchangeably. (Faulhaber, G., "Cross-Subsidization: Pricing in Public Enterprises," *American Economic Review*, 1975, 65(5), 966–977.)

[21] This is the year the California Solar Initiative went into effect.

[22] National Academies of Sciences, Engineering, and Medicine, *The role of net metering in the evolving electricity system*. Washington, DC: National Academies Press, 2023.

[23] Pacheco, J., Memo to Marybel Batjer, President California Public Utilities Commission, Subject: Rulemakings 19-07-017 and 15-01-012 - Defeasing the Power Supply Revenue Bonds and Initiation of the Wildfire Nonbypassable Charge," July 9, 2021, https://water.ca.gov/-/media/DWR-Website/Web-Pages/Programs/All-Programs/California-Energy-Resource-Scheduling/Files/Additional-Files/20200701-memo_CPUC_PowerBonds_Wildfire_NBC_Final-AccessChecked.pdf

To demonstrate the concept of a cost shift, two numbers are needed:

1. The market price of electricity and
2. The retail rate under which customers receive service.

For California, the rate of the highest pricing tier of $0.48/kWh is equal to $480/MWh. The average all-in price for electricity in the wholesale California market for 2004 was $53.46. Therefore, in this example, customers with on-site generation in the highest tier of pricing would receive a bill credit of $480/MWh while displacing power that costs $53.46 to buy from the system, resulting in a revenue shortfall of $426.54/MWh.[24] The cumulative shortfall would then be socialized among all customers, with non-NEM customers becoming responsible for the largest portion of that shortfall.[25] This is obviously an extreme example focused on the most expensive billing block, at a time when extraordinary costs were recovered in the variable portions of rates. At that time, equity concerns led to rates designed disproportionately to collect revenues related to resolving the California Energy Crisis from large more affluent customers; however, this rate design also created the greatest incentive to bypass consumption from the system by installing PV systems whose output was compensated though a NEM mechanism, thereby avoiding payments to amortize the cost of the California Energy Crisis..

PV installations grew rapidly in many areas, reaching almost 9% of residential customers in California by 2022.[22] This caused some to reconsider whether NEM was the best way to accommodate PV through utility services and is, in part, why some states moved from NEM to alternative forms of payment.

The concern over the pricing subsidies associated with NEM began to emerge with papers such as Alexander, Brown, and Faruqui's "Rethinking Rational for Net Metering: Quantifying Subsidy from Non-Solar to Solar Customers" in 2016.[26] That paper claimed that NEM is both unfair and regressive, i.e., having a larger impact on low-income customers—unfair because it results in a subsidy to PV (and other DER) installations because net injections to the grid are compensated at the retail rate but offset utility energy supply costs at a much lower rate as measured by wholesale supply cost. Using data from a California utility, the authors asserted that the subsidy (savings in fixed cost recovery) realized by the PV adopter was substantial, ranging from over $400/year to almost $1,800/year. While this has a minor effect on rates at very low PV adoption rates, it becomes a concern when penetration reaches 10%. The authors anticipating widescale adoption concluded that NEM is regressive because PV adoption requires a capital investment that is attractive to more wealthy homeowners because it takes several years to realize the full benefit. As a result, adoption rates are low among lower income customers, which results in them paying a disproportional share of the subsidy.

According to a National Academies of Sciences, Engineering, and Medicine report, "Low-income households, populations of color, and renters are more likely to face barriers to DG adoption

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[24] This is an extreme example with a customer with exceptionally high consumption that remains in the highest rate block, even after the impact of their on-site generation.

[25] Depending on the shortfall in revenues is reallocated, it is possible that some NEM customers will pay a portion of the shortfall. It is conceivable in the re-allocation process that they also receive higher NEM rates.

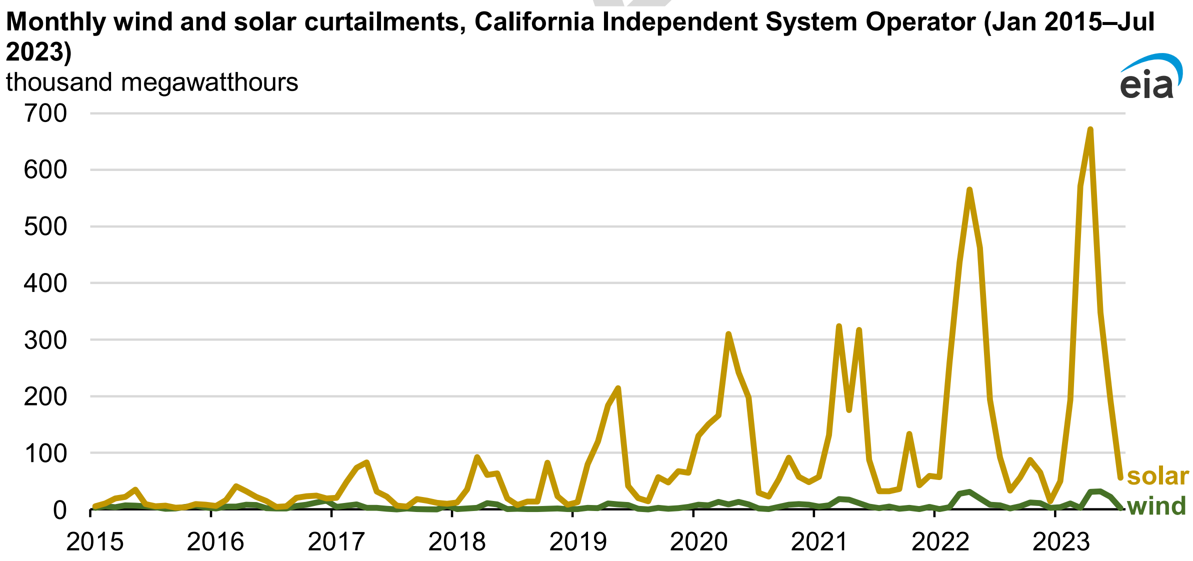
[26] Alexander, B., Brown, A., Faruqui, A. "Rethinking Rational for Net Metering: Quantifying Subsidy from Non-Solar to Solar Customers," *Public Utilities Fortnightly*, October 2016.

and therefore are more likely to be non-participants in net metering. As a result, economic transfers and any differential net metering benefits and costs between participating and non-participating customers have equity implications."[22]

The impact of rate structure on cost shifts will be discussed later in this report.

2.3.2 Inefficient Operation

A customer's net generation compensated through NEM processes is for all practical purposes "must-run" in the power system dispatch process. That means that no matter the cost of other generators on the system, the NEM customer will be able to inject their power into the grid. According to Joskow and Wolfram, "Almost all residential and small commercial consumers in the U.S. buy electricity on rate structures that do not vary with changes in overall supply and demand conditions, marginal costs, or wholesale market prices from either an ex-ante or real time perspective."[27] As a consequence, NEM customers do not receive price signals that maximize their value as a grid asset; therefore, inefficient (i.e., over) investment in residential PV is encouraged. A particularly extreme example occurs in California during periods of excess generation when the California Independent System Operator sells off system power for negative prices, i.e., paying to give it away. In 2022, California curtailed 2.4 million MWh of electricity, with 95% of excess attributed to solar power. This represents approximately 1% of the state's total annual power generation, or 5% of its solar energy production.[28] The pattern of increasing levels of curtailment is demonstrated in Figure 6.



Source: EIA[29]

[27] Joskow, P.L., Wolfram, C.D., "Dynamic Pricing of Electricity," *American Economic Review* 102, no. 3 (2012): 381–385. http://faculty.haas.berkeley.edu/wolfram/papers/AEA%20DYNAMIC%20PRICING.pdf

[28] Osaka, S., "Rooftop solar panels are flooding California's grid. That's a problem," *Washington Post*, April 22, 2024. https://www.washingtonpost.com/climate-environment/2024/04/22/california-solar-duck-curve-rooftop/

[29] EIA, "Solar and wind power curtailments are rising in California," October 30, 2023. https://www.eia.gov/todayinenergy/detail.php?id=60822

Figure 6. Substantial Solar Curtailments in California

Price is the most important mechanism for conveying information to customers and suppliers.[30] Customers use the prices reflected in their retail rates as a basis for consumption decisions and, ever more increasingly, to determine whether to invest in DER. Flat retail rates are not able to convey to NEM customers how their production will help operate a reliable electric system and what is the value of providing system support. This is particularly important as systems become increasingly distributed and reliant on renewable resources.

2.4 RETHINKING NEM – RATE STRUCTURES & RATE LEVELS

Efficiency and equity concerns about the must-run characteristics of power exported from the customer's premises and cross-subsidization of NEM customers have led to a focused conversation about alternatives to NEM. In viewing these alternatives, it is important to differentiate between rate structures and rate levels. Rate structure defines the overall rate mechanism, what is metered and charged (kWh, kW), whereas the rate level is the nominal value ($/kWh or $/kW) of the rate.

2.4.1 DER and Its Alternative

Three basic types of tariff structures are being employed to 1) compensate customers with PV or other on-site generation for the power that they produce and 2) charge them for the power that they consume (their structural relationships are shown in Table 1):

- **Net energy metering** compensates the customer for all power generated at the retail rate. When the customer is a net buyer of power from the utility in a billing period, the PV production is netted out and the customer pays the utility for the net consumption at the applicable retail rate. When the customer generates more than it consumes, the customer receives a bill credit for the power injected into the electric network priced at the retail rate. Other provisions such as minimum bills and rollover are discussed below.
- **Net energy billing** calculates net usage for billing (as NEM does) except. The difference in the two systems occurs when more energy is produced than grid energy consumed (i.e., the consumer is a net exporter). In that case, the bill credit is priced at a stipulated rate that is different than the tariff price level, price structure, or both. The NEM energy credit rate can be higher or lower than the tariff.[31]
- **Buy-all, sell-all** treats the consumption of power and production of power as two distinct transactions. The customer is deemed to purchase all power it uses for the facility from the utility at the applicable retail rate. All power that is produced by the customer's PV facility is assumed to be exported to the utility at an administratively determined rate. This requires separately metering the PV output.

[30] Hayek, F., "The Use of Knowledge in Society," *American Economic Review* 35, no. 4 (1945): 519–530.

[31] In the case of dynamic pricing during periods of scarcity, it is likely that the energy price used in NEB will be significantly higher than the tariff rate.

Both NEM and net energy billing (NEB) pay for power exports on a net basis, which means that DER production over a billing period is deemed to first service the facility electricity demand and surplus is exported. Hence, that energy reduces purchases by the customer from the grid (imports) and—under NEM—reduces the facility's bill at the same rate at which the facility is charged for input. NEB credits the bill for net imports at the stipulated import rate that is usually different, resulting in a different net billing outcome, depending on the carry-over provisions. With buy-all, sell-all billing, the grid purchases and injections of power are calculated separately to develop the final bill.

Table 1. Relationship Between DER Tariff Structures and Rates

	Rate Charged for Customer Consumption	Bill Credit for PV Power for Customer Consumption	Price of Export
NEM	Retail Rate	Retail Rate	Retail Rate
NEB	Retail Rate	Retail Rate	Administrative Rate
Buy-all, sell-all	Retail Rate	Retail Rate	Administrative Rate

2.4.2 The Use of Avoided Cost

2.4.2.1 Avoided costs defined

One way to develop a specific energy rate is through the use of avoided costs. The *Public Utilities Regulatory Policies Act of 1978* (PURPA) mandated that utilities purchase power from non-utility generators at avoided costs. Avoided costs were defined by PURPA as the cost that the utility would have incurred, but for the injection of energy from the non-utility generators. These rates were first used to compensate non-utility generators and then became a major element in the evaluation of energy efficiency programs.

The need to determine avoided costs led to a national debate over the value of electricity. Much of this debate focused on the long-standing principle that the value of electricity has two components: energy and capacity.[32] In effect, the capacity value measures the contribution of a generator to the reliability of the system. The question was how to measure those two components.

The energy component measures the value of electricity. In technical terms, this would be the shadow price of the reliability constraint used in economic dispatch. In the organized markets, it is the market price based on the bids and offers of generators in the market. The energy component can also be forecast using production cost models.

The capacity component for market sales and purchases was first developed by states in their development of avoided cost rates, using a variety of methods. One method, called the theory of the peaker, established the value of generator capacity based upon the cost of a peaker. A peaker was considered a measure of pure capacity because the only reason to build a peaker is

[32] The first academic treatise that made this point was Marcel P. Boiteux's "La tarification des demandes en pointe: Application de la théorie de la vente au coût marginal," 1949, *Revue générale de l'électricité*. For a fuller explanation of how generation capacity affects the value of electricity and markets see Carl Pechman's "Whither the FERC?: Overcoming the Existential Threat to Its Magic Pricing Formula through Prudent Regulation," National Regulatory Research Institute, January 2021. bit.ly/2XPGcnb.

for reliability. This is because peakers traditionally had the highest operating cost and lowest capital cost. As a consequence, building a peaker would not produce any energy savings (infra-marginal rents) as would be the case of building a base-load facility like a nuclear power plant.

As organized markets developed and independent system operators were formed, capacity markets were developed to capture the capacity value of generation (and increasingly demand response) to the electric system.

2.4.2.2 Implementation lessons for NEM from PURPA

California and New York both experienced unintended consequences in their implementation of PURPA. The core issue is that both states established PURPA regimes in which the price paid to non-utility generators did not vary with the supply of non-utility capacity and production. The experience demonstrated that if one technology (e.g., rooftop solar) were economical at a given price, then many projects would be economical and the growth in that technology would continue unfettered.

The experience of New York and California provides an important lesson in what happens when electric generation is mispriced. The states required their regulated electric utilities to purchase power without regard to how much power was needed, and at prices that were far above conventional supply. Once established, it took a regulatory fiat to reset price schedules—effectively ignoring the economic principle of supply and demand because when supply exceeded requirements (and expectation), prices did not change, and investment continued. California's qualifying facility acquisition process created a new "Gold Rush." By 1987, more than 15,000 MW of new capacity had signed contracts, with more than 3,000 MW coming online and operating.[33]

The effect of regulatory policies that ignored the interplay between supply and demand was to increase the financial commitment that utilities made on behalf of customers, while driving down the value of all generation. The impact of non-price-responsive avoided-cost methods was extreme for the Niagara Mohawk Power Company, an upstate New York utility. By 1993, Niagara Mohawk Power Company's non-utility generator purchase obligations were approximately 28 percent of its power supply, but 67 accounted for percent of costs.[34] The utility's anticipated installed capacity reserve margin grew to 40–50 percent by the late 1990s (as compared to the 18 percent requirement at the time). The company incurred substantial revenue shortfalls because rates did increase as fast as did the costs imposed by these contracts. (The utility restructured the contracts, with regulatory oversight, by paying independent power producers $3.6 billion in cash, 20.5 million shares of common stock, and the proceeds from the sale of an additional 22.4 million shares of stock to eliminate the unfunded obligation.[35])

[33] Ahern, W., "Implementing Avoided Cost Pricing for Alternative Electricity Generators in California," Mimeo, January 12, 1987.

[34] Securities and Exchange Commission, *Niagara Mohawk Securities and Exchange Commission 10-k for fiscal year ending December 31, 1993*, Washington, DC: Securities and Exchange Commission, 1993. http://www.getfilings.com/o0000071932-94-000038.html.

[35] "NiMo completes deal with independents," *Albany Business Review*, June 30, 1998. http://www.bizjournals.com/albany/stories/1998/06/29/daily6.html.

Lessons from PURPA implementation are important for the administration of NEM in the public interest. The short-term success in attracting investment in cogeneration in New York and California led to oversupply that increased costs to customers. Agile systems need to establish objectives (e.g., determine the optimal level of DER provided by NEM), track progress, and adapt. California, having experienced the role of resource acquisition based on fixed prices insensitive to supply, recognized that it had a looming problem, and set out to fix it. Prudent regulation requires forward-looking analysis of how circumstances might change and policies that will help guide the market to maximizing the welfare of Puerto Rico.

2.4.3 Some Nuances and Provisions

2.4.3.1 Rate Structure Affects the Level of Subsidy

Rate structure can have a significant impact on the level of subsidy. A recent study[36] looked at metered consumption and PV output for households in Austin, Texas, applying time-differentiate rates like time-of-use (TOU) and real-time pricing (RTP) (hourly prices) to render an annual bill for each customer that posted either a positive cost (usage exceeded PV output) or a bill credit (excess PV generation). For each household, the net difference (ND) over the year is calculated, where:

- ND = tariff revenue the tariff produces minus the cost to supply that usage less
- ND >0 results when the tariff collects more than the cost (a subsidizer)
- A negative ND value results when the tariff produces less revenue than the cost of supply

This allows comparing tariff structures separate from the choice of settlement, as net metered usage or separately metered and priced usage.

The authors found that TOU and RTP tariffs result in lower cross subsidies (ND) compared to a uniform price for billing by two orders of magnitude (from a mean subsidy of about $200/year under a uniform tariff to under $7/year for TOU and under $1 for RTP. The reason is that the energy rates more closely match actual energy supply costs and, as constructed for the study, the TOU and RTP tariff recover capacity costs separately from the kWh energy charge. Employing a buy-all, sell-all metering configuration resulted in reduced cross subsidies.

An additional analysis employed a demand charge. The analysis found little difference between employing net metering and net reconciliation in billing with separately metering the household and the PV and applying the tariff to each to produce the net difference. This result may not generally be the case because the NDs were calculated differently from unbundling an established tariff into it fixed and variable cost elements.[37]

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[36] Ansarin, M., Ghiassi-Farrokhfal, Y., Ketter, W., Collins, J., "Cross-subsidies among residential electricity prosumers from tariff design and metering infrastructure," *Energy Policy* 145 (2020).

[37] The study considered the household as a total supply obligation and although representative rate level was used revenues collected were made to equal incurred supply costs by applying an adjustment factor, so the negative NDs were offset by positive NDs.

The nominal magnitude of the mean cross subsidy is considerably lower than that reported for a California utility reflecting differences in the nominal level of utility rates but also hard to identify due to methodology differences.

NDs were calculated for individual households resulting in a wide distribution of outcomes in terms of the percentage of households that receive a subsidy, over 65% for a uniform rate dropping to under 50% for RTP and TOU; But as described above, the nominal level of the subside is substantially lower under time-differentiated rates. The study suggests the benefits of moving from a uniform to a time-differentiation rate for customers with PV are substantial, but the authors acknowledge the challenge in getting customers to accept dynamic pricing.

2.4.3.2 NEM Banking and Reconciliation

To accommodate the fact that DER output can vary so much month to month (or other billing periods), many NEM programs employ a provision of banking net injections. In a month with a negative energy reading (customer produces more than they consume), net exports are banked (by the utility acting as the bank) or carried forward, and the customer pays no energy costs for that billing cycle. A minimum bill and other charges may still apply so they may still have an amount due to the utility. When a customer consumes more than they produce, they are billed for the net consumption.

When customer generation exceeds their load, a deposit is made to the bank, providing a credit in that month that reduces the customers' bill. In the event that the credit is not fully used, and the bill is reduced to zero, any excess is banked for use in future months. The result is either that the bank is emptied, or a positive kWh bank balance remains and in the next month it can be used. Typically, there is an annual reconciliation that zeros out any unused forward balance. Note that if the applicable rate is based on TOU, then the banking is carried out on a value basis as opposed to a kWh basis.

2.4.3.3 NEB Banking and Reconciliation

NEB also uses a reconciliation process, but the rate applied to net exports is different from the retail rate used to calculate the customer's monthly energy charge when usage is greater than the DER output. Annual reconciliation of the bank balance simplifies this accounting, as does the use of a uniform ($/kWh) rate for both retail and exports, although the nominal level of the rates differ. But, with banking and end-of-year reconciliation, a customer who in some months has net grid export but overall was a net importer receives the full benefit of PV power produced at the tariff rate. If the customer is a net exporter, then the surplus is reconciled (credited) at the stipulated NEB export rate.

2.4.3.4 Buy-All, Sell-All Banking and Reconciliation

Buy-all, sell-all does not require reconciliation since it is self-correcting.

2.4.3.5 Rate Levels

There are a variety of different approaches that can be used for determining the energy rate used in NEM and NEB. Each of these approaches will result in different time patterns of rates and level of rates. These alternatives include the following:

- Multi-part tariffs have separate customer, demand, and energy charges. The use of multi-part tariffs shifts fixed cost recovery from the variable portion of the rate to a fixed charge. In a three-part tariff, the design of each of the components is cost based. This rate design, therefore, eliminates cost shift.
- Real-time prices are based on the market price of electricity. RTPs require a central dispatch system that can either determine the market price or provide the marginal cost of the last unit produced (which is equivalent to a competitive market price).
- Time-of-use rates differentiate the value of electricity, based upon the time that it is produced or consumed. TOU rates are based upon forecasts of market prices (value), for example, by using production cost models.

3 MATRIX OF U.S. NEM PROGRAMS

The details of NEM programs vary by state. Understanding these differences helps to frame the challenge that Puerto Rico faces in evaluating its NEM process. To present, examine, and compare the various NEM programs nationwide, a system of categories and classifications was developed to characterize program characteristics and values. These classifications facilitated the organization of complex and diverse NEM programs making them easier to understand and compare.

The comparison and assessment of NEM programs of different utilities in a variety of states (California's PG&E, New York's Consolidated Edison [ConEd], Hawaii's Hawaiian Electric [HECO], North Carolina's Duke Energy, Nevada's NV Energy, Minnesota's Minnesota Power, and Arizona's Arizona Public Service [APS]) focused on four primary areas that describe program features: 1) eligibility, 2) service structure, 3) pricing, and 4) administrative provisions.

Information from the review of each of these programs was organized into multiple matrices for visual side-by-side comparisons. The matrices list NEM programs horizontally, allowing for a comparison of similarities and differences across various categories and specific metrics. The categories of each matrix are described in Table 2.

Table 2. Categories and Features of Each Matrix

Eligibility	
Service Class	Identifies whether a customer is assigned to a new class or if they stay in the applicable tariff they otherwise would have been served on
Eligible DER Technology	Defines what DER is allowed (such as PV, wind, storage, or electric vehicle battery)
Contract Term	Details that subscribers are required to sign a contract with a term length, or guarantees service for a specified period
Service Structure	

Net Billing/Net Metering	Identifies either net metering, where energy producers are credited for the excess power they add to the grid, or net billing, where they are compensated at a different rate for the excess energy supplied
Energy Pricing Structure	Defines how energy (kWh) is used, metered, and billed according to rates: uniform, time-of-use, hours-used, or another structure
Peak Period (hours and seasons)	Refers to the specific times of day and seasons when electricity demand is highest, often resulting in higher energy prices due to increased consumption and strain on the power grid
Pricing	
Uniform or Block Energy Rate	Price based on either the uniform rate, where the cost per unit of energy remains constant, or the block energy rate, where the cost per unit varies depending on usage, with different rates for different tiers
Imports: Price for Peak Energy from the Grid	Price the customer pays for energy from the grid during peak hours
Exports: Price for Peak Energy to the Grid	Price the customer is compensated for energy supplied to the grid during peak hours
Imports: Price for Off-Peak Energy from the Grid	Price the customer pays for energy from the grid during off-peak hours
Exports: Price for Off-Peak Energy to the Grid	Price the customer is compensated for energy supplied to the grid during off-peak hours
Updates to Provisions	Addresses the frequency of rate changes within various NEM programs
Price for Demand	Identifies charges applied to the billing period metered maximum demand (coincident or non-coincident peak kW)
Administrative Provisions	
Carry Forward	Explains if surplus generation (kWh) in a billing period can be used in a subsequent month, months, or indefinitely. Also, notes whether surplus is compensated in forms or credit or a check
Special Charges	Identifies charges under the tariff applied that would not be under the otherwise-applicable tariff

3.1 Explanation of Matrix Categories

3.1.1 Eligibility

Eligibility is broken into several subcategories: Service Class and Eligibility, Eligible DER Technology, and Contract Term.

Service Class and Eligibility offers two possible outcomes: NEM customers belong to a distinct service class with different rates or structural provisions, or NEM customers remain in the general residential class with non-NEM customers. Those in a new NEM class have different rates compared to non-NEM customers, or some structural or administrative differences are applicable. The underlying cost of service studies and rate design differ for each of the separate classes. In either case, NEM or NEB can be employed.

Eligible DER Technology defines the types of DER permitted within the program. Typically, these are PV systems, wind turbines, energy storage systems, electric vehicle batteries, or other emerging technologies. Each NEM program has different rules and technologies allowed, with some programs having kW limits on certain technologies with a cap on the number of subscribers or a cap on the connected DER power output capability for each facility or in aggregate.

Lastly, Contract Term defines whether customers are under contract and, if so, for what duration. In most cases, a contract is required to interconnect the DER so that the terms and conditions are understood. While some programs lock in rates for a specific period, others follow a regular update schedule and some update periodically without a fixed contractual schedule. The contract defines how these provisions apply and for how long. Recently, when an established program substantially changed key provisions (e.g., rates that apply or switching from NEM to NEB), existing subscribers were grandfathered in under the initial terms for a defined period.

3.1.2 Service Structure

Service Structure is broken into the following subcategories: NEM or NEB, Energy Pricing Structure, and Peak Period.

The most fundamental category for assessing the service structure of programs designed to accommodate DER is the NEM or NEB subcategory. Since utilities may use the terms net metering and net billing in various ways, for the purpose herein the following definitions are used.

NEM credits a customer's bill for a billing period (usually monthly) for power injected into the grid when their solar panel (or other DER) output exceeds the energy (kWh) consumption of their property. This credit is given at the same rate ($/kWh) as the utility charges for supplying power to the property from the grid. Since these rates are equal, billing is simplified to only require a net meter reading of kWh for the billing period, hence, the name NEM. With standard meters capable of running backward when power is injected, billing becomes straightforward.

For example, consider this scenario:

Energy rate: $10/kWh

In the first 15 days of the month, the customer uses 2 kW/day with no PV production.

In the next 15 days, the customer uses 1 kW/day while the PV produces 2 kW/day.

At the end of the billing period, the meter reads 30 kWh used, which is what is billed.

Calculating the bill:

Total kWh used: 30 kWh

Energy cost: 30 kWh * $10/kWh = $9.00 (ignoring other charges)

Without PV output, the bill would have been $12.00.

In NEB, PV output and customer usage are metered separately because the rates for energy used and supplied differ. This means customers pay one rate for energy from the grid and receive a different rate for energy sent back to the grid. Typically, the rate for energy sent back is lower than what they pay for grid energy. The key aspect of NEB is the distinction between these two rates.

For example:

Charge: $0.20 for energy from the grid but pay only $0.10 for energy supplied to the grid.

Metered energy from the grid: 60 kWh at $0.20/kWh = $12.00

Metered PV output fed into the grid: 15 kWh at $0.10/kWh = $1.50 bill offset

Total bill: $10.50, which is $1.50 more than with NEM.

The difference in the total bill depends on the relative rates for buying and selling energy.

The NEM or NEB subcategory provides insight into the fundamental differences of the NEM programs evaluated.

A third category for financially accommodating DER is a buy-all, sell-all structure. A separate meter (from that which measures consumption) is attached to the DER and its output recorded and provide for billing. An energy bill is issued for the total amount of power supplied to the residence for all energy consumed and an energy credit applied for the power output of the DER. The bill is the net of the two but differs from NEM or NEB if the rates used or other billing provisions differ. (Note: buy-all, sell-all is not shown in the matric tables because none of the currently reviewed case studies used that method.[38])

The second subcategory in the tariff service (rate) structure is Energy Pricing Structure, which defines how utilities charge for metered energy services. They are employed to calculate payments for either energy imported to the grid and exported to the grid or both. The rate structures most often used are uniform, TOU, inclining block, and demand. NEM programs are complex and can also feature combinations of these different pricing structure categories.

A uniform rate is a pricing structure where customers are charged the same rate for each unit of electricity consumed regardless of the time of day or season. Unlike TOU rates, where prices fluctuate based on demand and time to reflect system conditions, a standard uniform rate maintains the same price throughout the day and year. This rate type is the most straightforward, making it easy for customers to understand and budget for their electricity expenses. Under a NEM structure it simplifies billing for service.

A TOU rate is a pricing structure that applies different energy consumption rates depending on the time of day or day of the week. Under TOU rates, utility companies typically divide the day into different periods, such as peak (high-demand) hours, and off-peak (low-demand) hours. Some TOUs add a third shoulder period. Customers are charged higher rates during peak hours when electricity demand is highest (and cost of supply highest) and lower rates during off-peak hours when demand is lower. The shoulder rate bridges reflect supply period transition costs, less than the peak but more than the off-peak. The TOU period can be applicable only on weekdays or every day of the week for some or all months and seasons; in the latter cases, the usage rate or the period definitions may differ.

An inclining block rate means the price of electricity increases as the amount of energy consumed by a customer increases, organized into pricing "blocks." This is the rate structure

[38] The final version of this report will include an additional case study from Austin, Texas, that uses the buy-all, sell-all method.

that underlies the California example of rate shift, earlier in this report. With inclining block rates, customers are charged at a lower baseline rate or initial block rate for electricity consumption up to a certain threshold, such as a specified number of kWh per billing period. For example, the first 200 kWh used in the billing period is charged $0.50/kWh. Once a customer's energy consumption passes this threshold, they enter a higher-priced block or tier, where the cost per kWh increases, say $10/kWh. Subsequent blocks may have even higher rates as energy consumption continues to rise. In a two-block rate all usage over a threshold, e.g., 200 kWh is charged at the higher rate. The number of blocks is a subject of the rate design process, sometimes employing three or more blocks. The purpose of an inclining block rate is two-fold, one to encourage energy conservation by discouraging excessive (higher block) electricity usage. It incentivizes customers to be mindful of their energy consumption habits as they approach higher tiers where electricity becomes more expensive. Another is that by disproportionately recovering fixed costs in the higher blocks, customers with exceptionally low electricity usage, which some contend are lower income customers, pay a lower average rate.

The demand rate is structurally different than energy charges because it charges for the energy used (flow of power to the facility) and separately for the stock of energy provided defined as the maximum level of demand (kW) recorded in the billing period. That maximum level of demand is what drives the decision to invest in more utility capital.

There are also special conditions, for example, a tiered percentage of a full rate structure. This is when a customer is compensated at a certain percentage of the retail rate for the energy they produce and sent back to the grid. This percentage depends on their tier. For example, the first 100 customers who become NEM customers might receive 90% of the retail rate, while the next 100 NEM customers fall into a different tier and receive 80%. In this scenario, customers who provide the same amount of electricity could receive significantly different compensation based on when they joined their program and their respective tier.

3.1.3 Pricing

The most complicated and detailed NEM category is pricing. This section provides prices in kWh for NEM customers in their respective NEM programs.

The first subcategory is Uniform or Block Energy Rate where corresponding prices for uniform rates or block rates are provided by NEM program. Not all NEM programs feature uniform or block rates; several states may have an "NA" for this category. Many programs offer customers the choice between uniform rates or TOU rates. In states with such options, uniform rate or block rate pricing information is included in this section, irrespective of whether all customers are enrolled in this rate.

The following categories pertain to TOU rates. As explained earlier, a TOU is a pricing method that applies to imports from or exports to the grid. For instance, in a state where a TOU structure is employed alongside net billing, which involves distinct rates for energy imported and exported to the grid, there are four distinct rates in play. To accommodate this scenario, the matrix allows for the following four subcategories: Imports: Price for Peak Energy from the Grid, Exports: Price for Peak Energy to the Grid, Imports: Price for Off-Peak Energy from the Grid, and Exports: Price for Off-Peak Energy to the Grid. It is important to note that not all NEM programs will provide answers for each of these categories. Some programs may only offer a uniform rate, resulting in NA for all TOU-related categories. Others may offer a TOU option but employ net metering, wherein the prices for imports from and exports to the grid are the same. By presenting these categories and filling in prices for various NEM programs, the matrix illustrates the complexities and commonalities of diverse pricing structures in a digestible and comparable format.

The next subcategory in the Pricing category is Updates to Provisions. This category addresses the frequency of rate changes within various NEM programs. Some programs offer locked-in rates, guaranteeing customers a set rate for a specific number of years. Others follow clear update schedules, while some undergo periodic updates. This category exhibits significant variability across programs and, therefore, has a diverse set of options.

The final subcategory in the Pricing category is Price for Demand. In the matrix, this category would display either a $/KW rate or NA if the NEM program does not implement a demand charge. A demand charge is a tariff mechanism based on the maximum measured demand during the billing period, quantified as a kW amount (e.g., 10 kW for a residence), and billed at the tariff demand rate ($/kW). While such charges are uncommon for residential customers (but typical for commercial and industrial clients), proposals are emerging to introduce demand charges to net metering (NM) tariffs. This adjustment aims to collect fixed charges as NEM usage declines. Conversely, if the tariff solely imposes charges based on $/kWh consumption, the $/kWh rate encompasses both fixed (independent of kWh usage volume) and variable costs (directly linked to kWh usage). In this scenario, solar-generated power not only offsets variable costs but also fixed costs, necessitating their recovery from other customers.

3.1.4 Administrative Provisions

The last of the four categories is Administrative Provisions, which describes NEM restrictions and rules not covered in the other sections. The two subcategories are Carry Forward and Special Charges.

Carry Forward involves crediting excess energy generated by a customer's renewable energy system to future billing periods. When a customer's renewable energy system produces more electricity than it consumes in a billing cycle, the surplus energy is typically sent back into the grid. There are various compensation options for this excess energy. Some companies offer direct compensation to customers (e.g., via checks), while many programs provide credits to customers. These credits can then be applied to reduce future electricity bills. However, the duration for which these credits can be carried forward varies across NEM programs. Some programs allow indefinite carryover of credits, while others settle them annually or zero them out after a specified period. The Carry Forward section outlines each program's specific rules and procedures regarding excess energy handling.

Special Charges encompass additional fees or charges specifically applied to NEM customers, distinct from the standard NEM rates listed in the pricing section. Unlike standard utility charges, special charges are unique to net metering customers. For instance, a grid access charge paid by all customers for grid access would not be classified as a special charge, as it applies universally, not solely to NEM customers. To qualify as a special charge, it must be specific to NEM customers and separate from the NEM electricity rate. The specifics of these special charges are listed for each NEM program, not all programs have them—in which case, there is an NA in this category.

3.2 COMPARISON OF CURRENT PROGRAM OFFERINGS

3.2.1 Current Eligibility

Among the seven states examined, two (California and Hawaii) introduced distinct Service Class identifiers specifically for NEM customers, while the other states retained NEM customers within their existing Service Class (see Table 3).

The NEM programs across various U.S. states exhibit both similarities and differences in the types of Eligible DER Technology they support. Common among many states is the inclusion of solar energy, with all seven states incorporating solar power in some form. However, the specifics vary: while California and Hawaii include both PV and storage, Arizona focuses solely on rooftop PV systems. New York and Hawaii stand out for their diversity, with New York allowing technologies like micro-hydroelectric, fuel cells, and micro combined heat and power, and Hawaii embracing hydroelectric, biomass, and hybrid systems. North Carolina and Hawaii also include biomass, but North Carolina's program is notably less specific, encompassing "wind-powered, biomass-fueled, and others." Wind energy is another common element, found in the programs of California, New York, Hawaii, and North Carolina. Nevada's program is distinct in its restriction to solar systems under 25 kW, highlighting a preference for small-scale solar installations. Overall, while solar energy is a universal component, the inclusion of diverse technologies like storage, biomass, and hydroelectric varies, reflecting each state's unique energy strategy and regulatory focus.

The NEM Contract Term across the seven states reveals a range of approaches to duration and rate stability for customers. Some states offer long-term certainty, such as New York and Nevada, both providing 20-year contracts, with Nevada guaranteeing a credit rate of 75–95% of the retail rate. North Carolina also offers a relatively long 15-year term for services if initiated before January 1, 2027. On the other hand, California has a two-tier approach, with a 9-year contract for interconnections made before 2027, transitioning to 2-year contracts, thereafter. Hawaii and Arizona offer mid-term stability with initial lock-in periods (7 years in Hawaii and 10 years in Arizona) followed by periodic updates (every 3 years for Hawaii and an unspecified update schedule for Arizona). Minnesota diverges by providing a continuous service model without specified term lengths, which means ongoing adjustments rather than fixed contract periods. These variations reflect different state strategies balancing long-term security for customers with the flexibility to adapt to changing market conditions and technological advancements.

Table 3. Current Eligibility

Matrix Category	PG&E	ConEd	HECO	Duke Energy	NV Energy	Minnesota Power	APS
Service Class (new or existing)	New	Existing	New (can opt out – see case study)	Existing	Existing	Existing	Existing
Eligible DER Technology	PV, PV with storage, wind	Solar, wind, micro-hydroelectric, fuel cells, micro combined heat and power	Solar, wind, hydroelectric, biomass, hybrid systems, storage	NMB: wind-powered, biomass-fueled, and others	Solar generated electricity less than 25 kW	Rooftop solar system	Solar (specifically PV)
Contract Term	9-year contract for interconnecting before 2027, 2-year contracts thereafter	20 years for NEM	Initial 7-year rate lock-in, once that is expired then updated every 3 years thereafter	15 years for service initiated prior to Jan 1, 2027	Guaranteed credit for their 75–95% compensation of the retail rate for 20 years	Continues service	10-year lock-in then update

3.2.2 Current Service Structure

Two states (New York and Minnesota) continue to employ traditional NEM, the remaining states have switched to NEB (see Table 4).

The Energy Pricing Structure across seven different states demonstrates a mix of approaches, reflecting varying priorities in rate design. California, Hawaii, and Arizona, all using the NEB structure that allows different rates for net usage and net grid imports utilize TOU rates for both imports and exports, encouraging customers to shift their energy usage to off-peak times.

The other states offering NEB use a uniform rate as the default. Nevada employs a uniform rate with an optional TOU rate and a tiered compensation structure for exports, ranging 75–95% of the retail rate, depending on the tier. North Carolina offers a uniform rate under a rider net metering bridge (NMB), with an option for TOU that includes critical peak pricing under a rider solar choice (RSC), which introduces higher rates during peak demand periods.

New York NEM offers a standard uniform rate but includes the option for TOU, providing flexibility for those who can benefit from adjusting usage under time-based pricing. Minnesota’s NEM by contrast, offer a uniform tariff rate. The diversity in pricing structures highlights the balance states strike between simplicity and incentivizing optimal energy usage patterns through TOU rates and varied compensation schemes.

Variations in Peak Period pricing schedules for net metering customers exhibit structural differences that reflect when electricity demand peaks. California, Hawaii, and Arizona (share a focus on evening peak periods, with slightly different times. California and Hawaii, for instance, designate peak periods as 4–9 pm and 5–9 pm, respectively, throughout the week. Arizona's peak period is shorter, 4–7 pm on weekdays.

In contrast, the New York has designated a much broader peak window of 8 am–midnight daily. North Carolina has a peaks hours weekday evenings, 6–9 pm. Nevada tailors peak times to its northern and southern areas, 3–9 pm and 6–9 pm, respectively, both limited to summer months and excluding holidays, unlike the others apply the peak year-round. Minnesota relies on a uniform rate for billing settlements.

Table 4. Current Service Structure

Matrix Category	PG&E	ConEd	HECO	Duke Energy	NV Energy	Minnesota Power	APS
NEM or NEB	NEB	NEM	NEB	NEB	NEB	NEM	NEB
Energy Pricing Structure (uniform or different for imports and exports)	Class-specific Import: TOU rate Export: hourly rate	Standard uniform rate with option for TOU for import and export	Import: TOU rate Export: hourly rate	Uniform rate (rider NMB) with option for TOU with critical peak pricing (RSC)	Uniform rate with option for TOU rate with Tier 1: 95%–Tier 4: 75% compensation for exports	Uniform rate	Standard TOU import and TOU export
Peak Period (hours and seasons)	4–9 pm (every day)	8 am–Midnight (every day)	5–9 pm (every day)	6–9 pm (Monday–Friday)	Summer Peak: June 1–Sept 30 All days excluding holidays: Northern Nevada: 3–9 pm Southern Nevada: 6–9 pm	None	4–7 pm (Monday–Friday)

3.2.3 Current Pricing

The two traditional NEM programs employ a uniform or block energy rate. Some states offer options alongside a TOU plan, whereas in Minnesota, the uniform rate is the only available pricing plan.

3.2.3.1 NEM Programs

The two traditional NEM programs apply the same rate to billing period net imports (from the grid as an energy billing charge) and to net exports (injections into the grid). New York uses a seasonal block rate system for residential customers that applies to NEM service. The cost per kWh varies by consumption levels and season. For example, from June to September, the peak season, the first 250 kWh are charged at $0.15112 and usage beyond this threshold is charged at $0.17373/kWh. The rest of the year a uniform (flat $/kWh) rate of $0.15112/kWh applies to all usage.

Nevada and Minnesota offer more straightforward pricing, for example with rates set at $0.12651 and $0.1220/kWh, respectively.

New York offers an optional summer-only TOU rate for NEM customers. The summer peak price is $0.3305/kWh and off-peak price is $0.1233/kWh for all other summer hours. The rest of the year the price at all hours is $0.15/kWh, a uniform rate.

3.2.3.2 NEB programs

Five of the states studied employ NEB, where different nominal usage ($/kWh) rates and, in some cases, different rate structures apply to net imports and exports (uniform, TOU, etc.).

Figure 7 shows the summer and winter peak prices for net imports and net exports. All have different prices for import and exports.[39] The largest nominal prices and differences are for the California and Hawaii tariffs included in this comparison by a factor of three or more. The AZ prices are nominally lower but also differ by a factor of three. The large difference is the distinguishing aspect to NEM compared to NEB adopted to better reflect the marginal value of imported power deemed as being less than the cost to provide service to residences, as discussed in the cases studies in the next section.

[39] NEB is defined in this study as a pricing structure where a different rate applies to imports and exports, and by that definition Minnesota is a NEB, but practically might be considered a NEM. But because there is a price difference, it might expand over time and alter the economics of PV ownership.

Figure 8 compares the price for off-peak imports and exports for different states. While the nominal level of the $/kWh prices are lower, they retain a large differential between the import and export price.

The California prices are distinguished by how they are set. The peak price applies to all usage during the peak period (4–9 pm year-round) but the off-peak price schedule is hourly—a different price is set for each hour. Prices are posted in advance and, hence, known to vary according to the period or seasons. The off-peak price depicted here is an average of off-peak prices. The reasoning and mechanics underlying this pricing structure are explained in the California case study in Section 4.1.

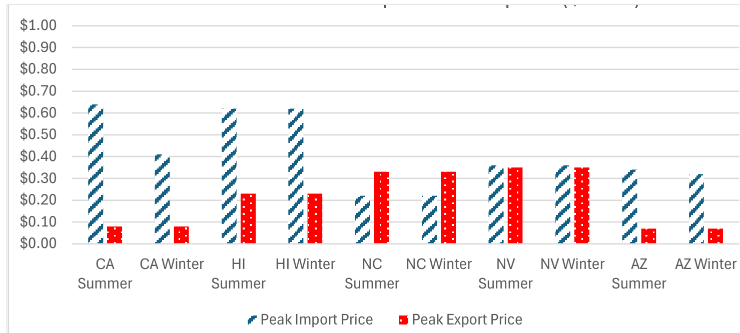


Figure 7. Peak Price for NEB Imports and Exports ($kWh)

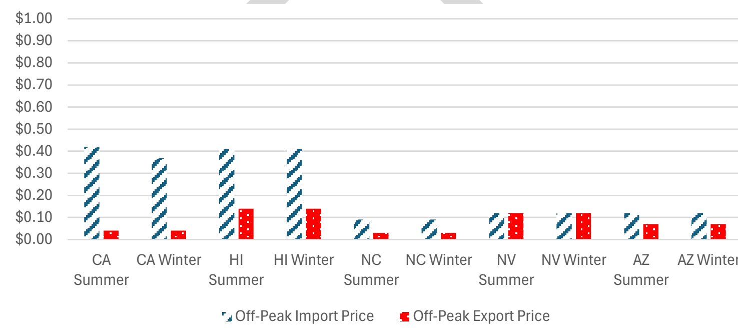


Figure 8. Off-Peak Price for NEB Imports and Exports ($kWh)

3.2.3.3 Other Settlement Provisions

The frequency at which NEM and NEB tariff provisions are updated varies across the seven states (see Table 5). California offers a relatively stable arrangement with a 9-year lock-in hourly rate for customers interconnecting up to 2027. After 2027, these rates will be updated every two years. In contrast, Nevada, Minnesota, and Arizona update their prices provisions yearly. In Arizona, this yearly update applies to new customers and those for which the 10-year locked-in rate has expired. Both New York and Hawaii have provisions to revise their rates every three years compared to the annual revisions in Nevada and Minnesota. North Carolina takes a different approach, with a specific revisit scheduled for 2027. The provision to adjust usage rates does not mean that they will be altered substantially or at all—just that they can be. What is locked in for subscribers is the rate structure as NEM or NEB but only as the provisions stipulate. A new structure could be enacted that applies to new subscribers going forward so the lock-in provide assurances to customers considering PV or other applicable on-site generation.

Only two of the seven states implement demand charges. In North Carolina, the demand charge is determined based on the applicable rate schedule. NEB customers elect an already available optional tariff that imposes demand charges. In Arizona, the TOU demand rate applies exclusively to on-peak hours, with rates set at $19.585/kW in the summer and $13.747/kW in the winter.

Table 5. Current Pricing

Matrix Category	PG&E	ConEd	HECO	Duke Energy	NV Energy	Minnesota Power	APS
Uniform or Block Energy Rate	NA	Block rate June–Sept: First 250 kWh $0.15112, over 250 kWh is $0.17373 Rest of the year: $0.15112/kWh	NA	$0.114311/kWh energy charge in addition to NMB customer and distribution energy charge $0.021482 kWh	Northern Nevada $0.12651/kWh	$0.1220/kWh	NA
Imports: Price for Peak Energy from the Grid	Summer: $0.64328/kWh Winter: $0.41177/kWh	June–Sept: $0.3305/kWh Rest of year: $0.1233/kWh	$0.620997/kWh (Hawaii Island)	Critical peak energy: $0.407415/kWh On-peak energy: $0.223842/kWh	Northern Nevada Summer on-peak: $0.36824/kWh	NA	Standard TOU, summer: $0.34396/kWh, winter: $0.32543/kWh TOU w/ demand, summer: $0.14227/kWh, winter: $0.09932/kWh
Exports: Price for Peak Energy to Grid	Hourly	All year: $0.0233/kWh	$0.231/kWh	$0.335/kWh for NMB and RSC	Northern Nevada Tier 1: $0.35638/kWh Tier 2: $0.33012/kWh Tier 3: $0.30386/kWh Tier 4: $0.28135/kWh	NA	$0.07619/kWh
Imports: Price for Off-Peak Energy Peak from the Grid	Summer: $0.42472/kWh Winter: $0.37582/kWh	All year: $0.0233 kWh	$0.413998/kWh	Off-peak energy: $0.097997/kWh Discount energy: $0.070848/kWh	$0.12651/kWh Northern Nevada example Energy sent back into the grid paid 75–95% of this standard rate depending on customer tier	NA	TOU, summer: $0.12345/kWh, winter: $0.12351/kWh Super off-peak, winter: $0.03495/kWh TOU w/ demand, summer: $0.05943/kWh, winter: $0.05938/kWh Super off-peak, winter: $0.03495/kWh

Matrix Category	PG&E	ConEd	HECO	Duke Energy	NV Energy	Minnesota Power	APS
Exports: Price for Off-Peak Energy to the Grid	Hourly, see case study	Same as from the grid for NEM See net billing rate in the details on the value of DER	$0.148/kWh (Hawaii Island, see case study for other islands)	$0.335/kWh net excess energy credit	Northern Nevada Tier 1, summer off-peak: $0.35638/kWh, all other winter hours: $0.07287/kWh Tier 2, summer off-peak: $0.06708/kWh, all other winter hours: $0.06750/kWh Tier 3, summer off-peak: $0.06174/kWh, all other winter hours: $0.05720/kWh Tier 4, summer off-peak: $0.05717/kWh, all other winter hours: $0.05753/kWh	NA	$0.07619/kWh
Updates to Provisions	Paid 9-year lock-in hourly rate applicable at time of interconnecting up to 2027; customers interconnecting after 2027 are paid scheduled rates updated every two years	Every three years	Every three years	To be revisited in 2027	Yearly	Yearly	Yearly. This only applies to new customers and customers ending their 10-year locked-in rate
Price for Demand	No demand charge	No demand charge	No demand charge	Demand charge is determined from the applicable schedule	No demand charge	No demand charge	TOU demand rate only: on-peak demand charge, summer: $19.585/kW, winter: $13.747/kW

3.2.4 Current Administrative Provisions

Carry Forward provisions allow customers greater access to the value of the power they produce by effectively using the grid to store excess production and use it during periods when load exceeds production. California and Hawaii use a monthly carryover system, resetting annually or at the end of contract terms so any year-end import balance is forfeited, New York and North Carolina reset balances periodically, either annually or on specific dates, which may reduce the benefit of power produced on-site (see Table 6). Nevada, in contrast, applies excess generation to future months without monetary compensation, while Minnesota stands out by compensating customers for surplus energy supplied to the grid through direct payments. Arizona offers a flexible model, allowing for either annual payouts or continued carryovers, catering to individual preferences. These differences reflect a nuanced balance between encouraging renewable energy production and addressing financial and grid management concerns across states.

Among the seven states analyzed, four do not impose Special Charges for NEM customers. Program-specific fee structures are assessed in New York, North Carolina, and Arizona. New York imposes a consumer benefit contribution, while North Carolina enforces a non-bypass charge of $0.29/kW plus an additional charge of $0.114311/kWh. In Arizona, customers face a grid access charge, with varying rates depending on their TOU classification. TOU customers incur a $0.29 non-bypassable charge per month per nameplate capacity (kW), and a grid access fee per month per nameplate capacity (kW) above 15 kW of $2.05.

Table 6. Current Administrative Provisions

Matrix Category	PG&E	ConEd	HECO	Duke Energy	NV Energy	Minnesota Power	APS
Carry Forward	Monthly carried over with final reconciliation at the end of the year	Credits carried over to the next monthly billing period until the end of the contract when the balance is forfeited	Monthly credit carried over with balance zeroed out at the end of the year	Credits carry over month to month but accrued credits will be reset to zero on May 31st each year—minimum charges apply	Credit from the previous month is given to any outstanding balance; if there is excess generation, more credit is given to be carried over to the next month but never paid out	If there is excess, the customer is paid for net energy supplied to the grid via check	Credits carried over monthly with option for end-of-year payout or carry over
Special Charges	None	Consumer benefit contribution	None	Non-bypassable charge per month per nameplate capacity (kW): $0.29 Grid access fee per month, per nameplate capacity (kW) above 15 kW: $2.05	none	None	Grid access charge for TOU: $0.242/kW-DC of installed generation TOU w/ demand: $0.215/kW

3.3 Key Changes in Program Offerings: Legacy NEM to Current NEB

3.3.1 Legacy Eligibility

Carolina, Nevada, and Arizona—reveal several patterns with respect to Service Class, Eligible DER Technology, and Contract Term (see Table 7). In terms of Service Class, California and Hawaii have introduced a new class for their current programs, distinguishing them from their legacy structures, while North Carolina, Nevada, and Arizona have retained their existing classes, with Arizona being an exception where the legacy class was newly created.

Regarding Eligible DER Technology, most states have maintained consistency between their legacy and current programs. California, Nevada, and Arizona have made no changes. However, North Carolina has slightly broadened its eligibility criteria in its current program.

Contract Term has generally shortened in the transition. California has shifted from a 20-year term under the legacy system to a more complex structure with shorter durations. Hawaii's current program offers an initial 7-year rate lock-in with periodic updates; thereafter, replacing the indefinite continuation of service in the legacy program. North Carolina's current program provides a 15-year term for services initiated before a specific date, in contrast to the minimum 1-year term under the legacy system. Nevada guarantees a reduced compensation rate for 20 years in the current program, while legacy customers remain on their pre-2016 pricing structure. Arizona's contract terms have been halved from 20 years in the legacy program to a 10-year lock-in for the current program. Overall, the trend shows a move toward more dynamic and potentially shorter contract durations, a maintenance of technology eligibility, and a varied approach to service class adjustments. (New York and Minnesota have made no changes to Eligibility, so they are not included in Table 7.)

Table 7. Legacy Eligibility with Current Eligibility for Comparison

Matrix Category	PG&E Current (NEM 3.0)	PG&E Legacy (NEM 2.0)	HECO Current (Smart DER)	HECO Legacy (NEM Program)	Duke Energy Current	Duke Energy Legacy	NV Energy Current	NV Energy Legacy	APS Current	APS Legacy
Service Class (new or existing)	New	Existing	New (can opt out – see case study)	Existing	Existing	Existing	Existing	Existing	Existing	New
Eligible DER Technology	PV, PV with storage, wind	PV, PV with storage, wind	Solar, wind, hydroelectric, biomass, hybrid systems, storage	Solar, wind, hydroelectric, biomass, hybrid systems, storage	NMB: wind-powered, biomass-fueled, and others	PV, wind-powered, micro-hydro or biomass-fueled generation	Solar-generated electricity less than 25 kW	Solar-generated electricity less than 25 kW	Solar (specifically PV)	Solar (specifically PV)
Contract Term	9-year contract for interconnecting before 2027, 2-year contracts thereafter	20 years contract term under applicable TOU rate	Initial 7-year rate lock-in, once that is expired then updated every 3 years thereafter	Continues service	15 years for service initiated prior to Jan 1, 2027	Minimum original term of one year	Guaranteed credit for their 75–95% compensation of the retail rate for 20 years	Customers who registered before 2016 stay on this pricing structure	10-year lock-in on the initial rate then rates are updated to reflect the current market	20-year lock-in, then the customer must transition to the new/current program

3.3.2 Legacy Service Structure

Comparing Energy Pricing Structure changes from legacy to current, California and Hawaii have shifted from uniform rates to using class-specific TOU rates for imports and hourly rates for exports (see Table 8). North Carolina and Nevada have introduced options for TOU rates, with Nevada incorporating tiered compensation for exports. Arizona maintains TOU rates for both imports and exports, but with standardized rates. (New York and Minnesota have made no changes to Service Structure, so they are not included in Table 8.)

Regarding Peak Period, new billing periods have been defined for all states except Arizona, which retains its 4–7 pm weekday peak. California, Hawaii, and North Carolina now have evening peak periods, with California at 4–9 pm daily, Hawaii at 5–9 pm daily, and North Carolina at 6–9 pm on weekdays. Nevada features seasonal peak periods, varying by region. The trend shows a move toward more time-sensitive pricing to better reflect usage patterns and incentivize efficient energy consumption and generation.

Table 8. Legacy Service Structure with Current Service Structure for Comparison

Matrix Category	PG&E Current (NEM 3.0)	PG&E Legacy (NEM 2.0)	HECO Current (Smart DER)	HECO Legacy (NEM Program)	Duke Energy Current	Duke Energy Legacy	NV Energy Current	NV Energy Legacy	APS Current	APS Legacy
NEM or NEB	NEB	NEM	NEB	NEM	NEB	NEM	NEB	NEM	NEB	NEB
Energy Pricing Structure (uniform or different for imports and exports)	Class-specific Import: TOU rate Export: hourly rate	Standard class TOU rate for imports and exports	Import: TOU rate Export: hourly rate	Inclining block rate	Uniform rate (rider NMB) with option for TOU with critical peak pricing (RSC)	Uniform rate	Uniform rate with option for TOU rate with Tier 1: 95%–Tier 4: 75% compensation for exports	Uniform rate	Standard TOU import and TOU export	Class-specific TOU or option for block rate for imports
Peak Period (hours and seasons)	4–9 pm (every day)	5–8 pm (Monday–Friday)	5–9 pm (every day)	NA	6–9pm (Monday–Friday)	None	Summer Peak: June 1–Sept 30 All days excluding holidays: Northern Nevada: 3–9 pm Southern Nevada: 6–9 pm	None	4–7 pm (Monday–Friday)	4–7 pm (Monday–Friday)

3.3.3 Legacy Pricing

Regarding, Uniform or Block Energy Rate, California and Arizona do not apply uniform pricing rates in either their legacy or current programs, maintaining a focus on TOU and other pricing mechanisms (see Table 9). Hawaii previously used an inclining block rate structure, with prices increasing at higher usage tiers, but has moved away from this under the current NEB. North Carolina has transitioned from 2009 energy rates to a specific current rate of $0.114311/kWh, plus additional customer and distribution energy charges. Nevada's current program features a uniform rate of $0.12651/kWh in Northern Nevada, up from $0.10603/kWh under the legacy program, reflecting a general increase in uniform rates. Overall, the shift from NEM to NEB results in the abandoning a uniform rate structure in favor of a time-differentiated structure, like TOU or even hourly rates, which allow better matching import and export prices to prevailing supply costs. (New York and Minnesota have made no changes to Pricing, so they are not included in Table 9.)

Examining TOU prices for imports during peak periods reveals that California, Hawaii, and Nevada have introduced higher rates in their current programs compared to legacy systems. North Carolina and Arizona have also adjusted their TOU rates, with Arizona maintaining a similar structure but increasing rates for both standard TOU and TOU with demand. For exports, California and Hawaii have moved from uniform or retail rates to more varied hourly or tiered pricing. North Carolina now offers specific export rates for net excess energy, while Nevada has implemented a tiered system based on customer classification. During off-peak periods, there are similar trends, current programs generally offer pricing structures to incentivize energy usage during off-peak times. The overall trend is toward more complicated and sophisticated and time-sensitive pricing mechanisms.

Table 9. Legacy Pricing with Current Pricing for Comparison

Matrix Category	PG&E Current (NEM 3.0)	PG&E Legacy (NEM 2.0)	HECO Current (Smart DER)	HECO Legacy (NEM Program)	Duke Energy Current	Duke Energy Legacy	NV Energy Current	NV Energy Legacy	APS Current	APS Legacy
Uniform or Block Energy Rate	NA	NA	NA	Block rate June–Sept: First 250 kWh $0.15112, over 250 kWh is $0.17373 Rest of the year: $0.15112/kWh	$0.114311/kWh energy charge in addition to NMB customer and distribution energy charge $0.021482 kWh	2009 energy charge	Northern Nevada $0.12651/kWh	$0.10603/ kWh	NA	Imports Summer First 400 kWh: $0.12384 Next 400 kWh: $0.17696 Next 2,200 kWh: $0.20716 Over 3,000 kWh: $0.22078 Winter All kWh: $0.12035
Imports: Price for Peak Energy from the Grid	Summer: $0.64328 /kWh Winter: $0.41177/ kWh	Summer: $0.59505 Winter: $0.50545	$0.620997/ kWh (Hawaii Island)	NA	Critical peak energy: $0.407415/kWh On-peak energy: $0.223842/kWh	NA	Northern Nevada Summer on-peak: $0.36824/kWh	NA	Standard TOU, summer: $0.34396/kWh, winter: $0.32543/kWh TOU w/ demand, summer: $0.14227/kWh, winter: $0.09932/kWh	Standard TOU, summer: $0.32334/kWh, winter: $0.26230/kWh TOU w/ demand, summer: $0.11609/kWh, winter: $0.07406/kWh
Exports: Price for Peak Energy to Grid	Hourly	Summer: $0.59505 Winter: $0.50545	$0.231/kWh	Energy credits—at full retail rate Need the values $/kWh	$0.335/kWh for NMB and RSC	NA	Northern Nevada Tier 1: $0.35638/kWh Tier 2: $0.33012/kWh Tier 3: $0.30386/kWh Tier 4: $0.28135/kWh	NA	$0.07619/kWh	$0.02895/kWh
Imports: Price for Off-Peak Energy Peak from the Grid	Summer: $0.42472/ kWh Winter: $0.37582/ kWh	Summer: $0.46009 Winter: $0.46684	$0.413998/ kWh	NA	Off-peak energy: $0.097997/kWh Discount energy: $0.070848/kWh	NA	$0.12651/kWh Northern Nevada example Energy sent back into the grid paid 75–95% of this standard rate depending on customer tier	NA	TOU, summer: $0.12345/kWh, winter: $0.12351/kWh Super off-peak, winter: $0.03495/kWh	Standard TOU, summer: $0.08054, winter: $0.07939 TOU w/ demand, summer: $0.05727/kWh, winter: $0.05297/kWh

Matrix Category	PG&E Current (NEM 3.0)	PG&E Legacy (NEM 2.0)	HECO Current (Smart DER)	HECO Legacy (NEM Program)	Duke Energy Current	Duke Energy Legacy	NV Energy Current	NV Energy Legacy	APS Current	APS Legacy
									TOU w/ demand, summer: $0.05943/kWh, winter: $0.05938/kWh Super off-peak, winter: $0.03495/kWh	
Exports: Price for Off-Peak Energy to the Grid	Hourly, see case study	Summer: $0.46009 Winter: $0.46684	$0.148/kWh (Hawaii Island, see case study for other islands)	Energy credits—at full retail rate	$0.335/kWh net excess energy credit	NA	Northern Nevada Tier 1, summer off-peak: $0.35638/kWh, all other winter hours: $0.07287/kWh Tier 2, summer off-peak: $0.06708/kWh, all other winter hours: $0.06750/kWh Tier 3, summer off-peak: $0.06174/kWh, all other winter hours: $0.05720/kWh Tier 4, summer off-peak: $0.05717/kWh, all other winter hours: $0.05753/kWh	NA	$0.07619/kWh	$0.02895/kWh

3.3.4 Legacy Administrative Provisions

The transition from net metering to net billing in several states has resulted in notable changes to the handling of excess energy carryover, i.e., Carry Forward (see Table 10). Both California and Hawaii have maintained their policies of carrying over excess energy monthly with final reconciliation at the end of the year. North Carolina has a similar policy of monthly carryover, but resets accrued credits to zero annually in May. Nevada continues to carry over monthly credits without final payouts, consistent with its legacy policy. Arizona offers a choice between end-of-year payout or carryover. (New York and Minnesota have made no changes to Administrative Provisions, so they are not included in Table 10.)

Regarding Special Charges, California and Hawaii have maintained their practice of not imposing additional fees in both legacy and current programs. North Carolina, however, has introduced non-bypassable charges for net billing customers, replacing the standby charges for larger systems in the legacy program. Arizona has added a grid access charge in the current program based on installed generation capacity, a change from no special charges in the legacy program. The pattern suggests a trend toward introducing specific charges for NEB, further differentiating import and export prices.

Table 10. Legacy Administrative Provisions with Current Administrative Provisions for Comparison

Matrix Category	PG&E Current (NEM 3.0)	PG&E Legacy (NEM 2.0)	HECO Current (Smart DER)	HECO Legacy (NEM Program)	Duke Energy Current	Duke Energy Legacy	NV Energy Current	NV Energy Legacy	APS Current	APS Legacy
Carry Forward	Monthly carried over with final reconciliation at the end of the year	Monthly carried over with final reconciliation at the end of the year	Monthly credit carried over with balance zeroed out at the end of the year	Monthly credit carried over with balance zeroed out at the end of the year	Credits carry over month to month but accrued credits will be reset to zero on May 31st each year—minimum charges apply	Credits carried over for a year and reset to zero on April 30th each year	Credit from the previous month is given to any outstanding balance; if there is excess generation, more credit is given to be carried over to the next month but never paid out	Credits carried over from month to month but non-transferable and non-payable at the end of a contract or if the customer moves addresses	Credits carried over monthly with option for end-of-year payout or carryover	Credits carried over from month to month with end of the year reconciliation
Special Charges	None	None	None	None	Non-bypassable charge per month per nameplate capacity (kW): $0.29 Grid access fee per month, per nameplate capacity (kW) above 15 kW: $2.05	Standby charge: $1.87/ kW/month for systems >100 kW. Excludes TOU demand rate customers with systems <60% planning capacity	none	None	Grid access charge for TOU: $0.242/kW-DC of installed generation TOU w/ demand: $0.215/kW	No

4 CASE STUDIES OF U.S. NEM POLICIES

To appreciate the nuances associated with the design of NEM and its successors, it is helpful to provide comparative studies between the states and perform deep dives with individual states. This section provides those deep dives for California, Hawaii, and North Carolina. Each has had unique experiences with NEM policy. California has been the leader in promoting solar through NEM (and internal subsidy programs). Hawaii, like Puerto Rico, is composed of islands, which have electrical limitations that frustrate application of NEM. North Carolina has undergone several iterations of NEM program adaptations.

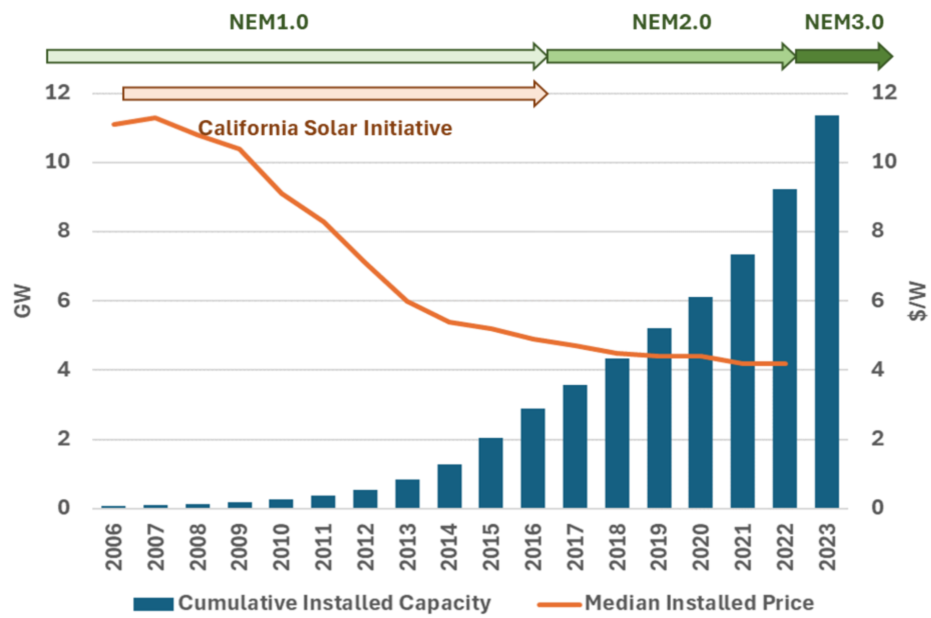
4.1 CALIFORNIA

4.1.1 Legislative Timeline

California's NEM policy significantly fostered the development of the solar PV market in California, making it the foremost state for solar energy across the country. As market fundamentals evolve, including the decline in installation costs and the increase in grid penetration, the NEM policy needs to adapt in response. Adjusting this policy is a complex process. During the rulemaking for the transition from NEM to NEB, the California Public Utilities Commission (CPUC) undertook these three important steps:

1. **Evaluating the existing NEM 2.0 program**
2. **Establishing guiding principles for NEM 3.0**
3. **Constructing the tariff design framework for NEM 3.0**

California has been the frontrunner in the development of the solar PV market in the U.S. The solar PV market in California experienced rapid growth starting in the early 2000s. This expansion is illustrated in Figure 9, which shows the cumulative installed capacity of residential solar PV systems. The market was in its nascency in 2006, with only 0.069 GW of installed capacity. By 2014, the cumulative installed capacity had surpassed 1 GW, marking a significant milestone in the state's solar journey. The growth trajectory continued, and by 2023, California's residential solar PV capacity exceeded 11 GW. Behind this rapid growth is the evolving policy landscape that supports the solar market. The policies have been changing alongside the market, adapting to new market fundamentals.



Note: Installed capacity data is from the California Distributed Generation Statistics,[40] while the cost data is from Lawrence Berkeley National Laboratory's Tracking the Sun Tool.[41]

Figure 9. Residential Solar PV Installation in California

4.1.1.1 NEM 1.0

Established by California Senate Bill 656,[42] NEM 1.0 marked the beginning of California's efforts to encourage renewable energy adoption through a supportive billing mechanism. This electricity tariff-based billing system was designed to stimulate private investment in renewable energy, foster in-state economic growth, diversify California's energy resource mix, and reduce utility interconnection and administrative costs. Under NEM 1.0, Section 2827 was added to the Public Utilities Code, mandating every electric utility in California to develop a standard contract or tariff enabling eligible customer-generators to receive financial credits on their electric bills for excess energy fed back into the grid. Customer-generators, who operated on-site electrical generating facilities to offset their own electrical requirements, received full retail rate bill credits for surplus power generated and supplied to the grid. These credits could be used to offset electricity bills monthly and could be carried over for up to one year, significantly incentivizing the adoption of solar PV systems.

In 2007, the California Solar Initiative was introduced as a landmark state-level incentive program to promote the adoption of solar PV systems across residential, commercial, and governmental sectors. Separate from the NEM policy, the California Solar Initiative provided substantial financial rebates to offset the high installation costs of solar systems, which were a significant barrier to market entry at the time. By offering these incentives, the California Solar

40 CPUC, *California Distributed Generation Statistics (DGStats)*, May 2024. https://www.californiadgstats.ca.gov/

41 Lawrence Berkeley National Laboratory, *Tracking the Sun Tool*, Energy Technologies Area, Berkeley Lab, 2024. https://emp.lbl.gov/tracking-sun-tool

42 Alquist, Stats. (1995), ch. 369. http://www.leginfo.ca.gov/pub/95-96/bill/sen/sb_0651-0700/sb_656_bill_950804_chaptered.html

Initiative played a crucial role in supporting the growth of California's solar market, encouraging early adopters, and driving down costs through increased demand and economies of scale. The program was instrumental in establishing California as a leader in solar energy, laying the groundwork for the state's renewable energy future.

4.1.1.2 NEM 2.0

The transition to NEM 2.0 began with California Assembly Bill 327,[43] which added Section 2827.1[44] to the Public Utilities Code, directing CPUC to create a new tariff that would ensure the sustainable growth of customer-sited renewable distributed generation, particularly for residential customers in disadvantaged communities. This bill also allowed projects greater than 1 MW that do not have significant impact on the distribution grid to be built to the size of the on-site load.

In 2016, CPUC approved Decision 16-01-044, officially adopting NEM 2.0. Under this new regime, customer-generators continued to receive full retail rate credit for energy exported to the grid within a 12-month billing cycle and compensation for net surplus energy. Additionally, NEM 2.0 introduced new charges to align the costs of NEM customers more closely with those of non-NEM customers. These included a one-time interconnection fee, monthly non-bypassable charges, and the requirement for NEM customers to use time-of-use rates. NEM 2.0 also set a review date for 2019 to evaluate the tariff's effectiveness and explore other compensation structures considering locational and time-differentiated values of customer-sited generation.

4.1.1.3 NEM 3.0

In 2022, CPUC reached the final decision for NEM 3.0, transitioning from NEM to NEB. This significant policy shift was the result of a detailed rulemaking process that included three critical steps: evaluating the existing NEM 2.0, establishing guiding principles for NEM 3.0, and constructing the tariff design framework for NEM 3.0. This section offers an in-depth review of each of these processes, examining how they informed policy making.

4.1.1.3.1 Evaluating the Existing NEM 2.0

In the process of formulating the NEM 3.0 policy, CPUC commissioned a "Lookback Study" to evaluate the impacts and cost-effectiveness of the existing NEM 2.0 program.[45] This study was integral in shaping the new rulemaking by providing detailed analyses through various cost-effectiveness tests. These tests, guided by CPUC's Standard Practice Manual (originally designed to evaluate demand-side management), assessed the program from multiple perspectives, including those of participants, utilities, and non-participants. The findings revealed critical insights into the economic and social implications of NEM 2.0, highlighting issues such as cost shifts, inequities, and the overall financial feasibility of the program. CPUC drew heavily on

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43 Perea, Stats. (2013), ch. 611. http://www.leginfo.ca.gov/pub/13-14/bill/asm/ab_0301-0350/ab_327_bill_20131007_chaptered.htm

44 California Public Utilities Code § 2827.1.

45 CPUC, "Net-Energy Metering 2.0 Lookback Study," January 21, 2021. https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/net-energy-metering-nem/nemrevisit/nem-2_lookback_study.pdf

these findings in developing the successor tariff that sought to address these concerns while balancing the overarching guiding principles to ensure fairness and sustainability across all customer groups.

The study performed four cost-effectiveness tests according to CPUC's Standard Practice Manual,[46] each focusing on a different perspective. The Participant Cost Test (PCT) measures the cost-effectiveness of the NEM program to participating customers. The benefits include bill savings, state rebates, and any tax refunds or credits, while the costs are the capital, financing, and other expenditures associated with installing the system under the program. The Total Resource Cost (TRC) test takes on the combined perspective of both customer and utility. The benefits include utility avoided costs and potential federal tax benefits, while the costs cover all expenditures associated with acquiring and installing the NEM system. The Ratepayer Impact Measure (RIM) test, also known as the Non-Participant Test, measures what happens to rates for all customers due to changes in utility revenues and operating costs caused by a program. Lastly, the Program Administrator (PA) test covers the PA's point of view. The benefits are the avoided costs, while the costs are the utility's costs to operate the NEM 2.0 program, including distribution upgrades and incremental billing costs.

Table 11 lists the summary of the results. A value greater than 1.0 indicates cost-effectiveness, with the benefits considered in a test outweighing the costs. These different tests show a consistent picture across the three utilities in California. The NEM program is favorable for participants (PCT) and program administrators (PA), while not meeting the threshold when both the participants' and the utility's perspectives are considered (TRC). Lastly, the RIM test suggests that while the bills for the participants decline, the rates increase for the non-participants.

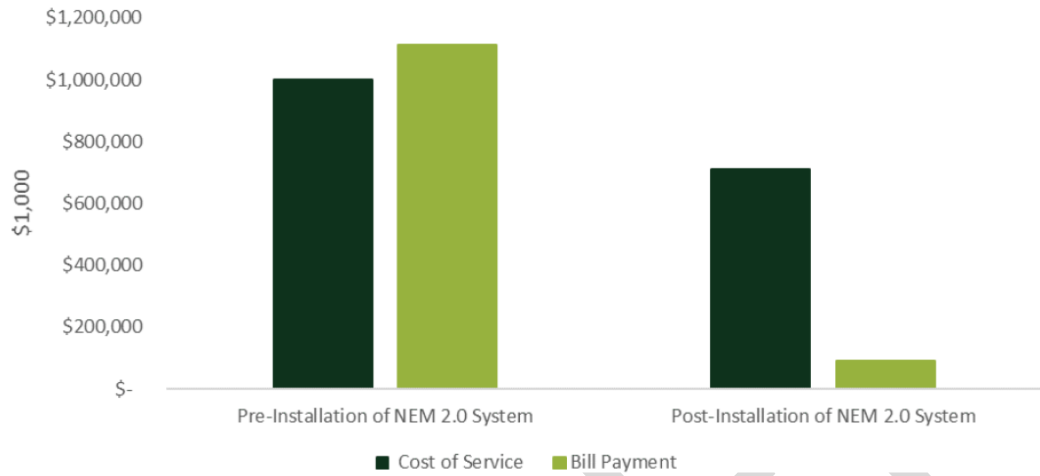
Table 11. Cost-Effectiveness Results by Electric Utility

Utility	Weighted Average Benefit-Cost Ratio			
	PCT	TRC	RIM	PA
PG&E	1.81	0.80	0.33	41.08
SCE	1.54	0.91	0.49	10.99
SDG&E	2.03	0.84	0.31	129.58
Total	1.77	0.84	0.37	22.98
Net Present Value Total Benefits (million $)	21,329	7,960	7,576	7,576
Net Present Value Total Costs (million $)	12,041	9,462	20,583	330

In addition to the cost-effectiveness tests, the study conducted a cost-of-service analysis, which compares an estimate of the utility cost of servicing a NEM customer for one year with an estimate of the customer's first year bills. While the cost-effectiveness tests cover the lifetime of the NEM systems, the cost-of-service analysis focuses solely on the first year. Figure 10 shows the aggregate results on cost of service for the utilities and bill payment for the residential customers. The pre-installation comparison reveals through counterfactual analysis that the solar adopters are those who tended to pay more than their cost of service in the absence of

[46] CPUC, "California Standard Practice Manual, Economic Analysis of Demand-Side Programs and Project," October 2001.

the NEM program. At the same time, the post-installation comparison demonstrates that the bill payment from the participants is smaller than the cost of service under the NEM program.



Used with permission from CPUC[45]

Figure 10. Residential Aggregate First Year Cost of Service and Bill Payment Pre- and Post-Installation Under NEM 2.0

CPUC noted in the NEM 3.0 rulemaking that the cost-effectiveness tests adhered to the definitions set by the Commission. Additionally, the avoided costs, which are crucial inputs to the analysis, were based on the official values approved on June 25, 2020, ensuring that the evaluation followed the established guidelines and utilized the most current data available.

CPUC drew three main conclusions[47] from the study and considered them as findings of fact in the rulemaking of NEM 3.0:

1. NEM 2.0 has negatively impacted non-participant ratepayers
2. NEM 2.0 is not cost-effective
3. NEM 2.0 disproportionately harms low-income customers not participating in the NEM tariff

The Lookback Study's results guided CPUC to address these issues by developing a successor tariff that aims to correct the cost shift, while balancing all eight guiding principles. Despite the positive TRC and PCT results for the commercial, agricultural, and industrial sectors, the CPUC emphasized the importance of the RIM test results to examine the disproportionate impacts on non-participants and ensure that benefits and costs are approximately equal for all customers.

4.1.1.3.2 Establishing Guiding Principles for NEM 3.0

Another critical step in the NEM 3.0 rulemaking process involved the development of a set of guiding principles. These principles aimed to support the creation of the successor tariff while addressing a broad spectrum of interests and concerns.[47] These included compliance with the statutory requirements of Public Utilities Code Section 2827.1: equity, consumer protection, fair

[47] D.21-02-007, Decision adopting guiding principles for the development of a successor to the current net energy metering tariff, CPUC. https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M366/K418/366418635.PDF

consideration of all technologies qualifying as renewable electrical generation facilities, alignment with the Commission's and California's energy policies, transparency, maximizing the value of customer-sited renewable generation, and ensuring competitive neutrality among load serving entities. On February 11, 2021, following initial scoping and the integration of feedback, the CPUC adopted eight Guiding Principles:

1. A successor to the net energy metering tariff should comply with the statutory requirements of Public Utilities Code Section 2827.1;
2. A successor to the net energy metering tariff should ensure equity among customers;
3. A successor to the net energy metering tariff should enhance consumer protection measures for customer-generators providing net energy metering services;
4. A successor to the net energy metering tariff should fairly consider all technologies that meet the definition of renewable electrical generation facility in Public Utilities Code Section 2827.1;
5. A successor to the net energy metering tariff should be coordinated with the Commission and California's energy policies, including, but not limited to, Senate Bill 100,[48] the Integrated Resource Planning process, Title 24 Building Energy Efficiency Standards, and California Executive Order B-55-18;
6. A successor to the net energy metering tariff should be transparent and understandable to all customers and should be uniform, to the extent possible, across all utilities;
7. A successor to the net energy metering tariff should maximize the value of customer-sited renewable generation to all customers and to the electrical system; and
8. A successor to the net energy metering tariff should consider competitive neutrality among load serving entities.[47]

These guiding principles were instrumental in shaping CPUC's policy formulation and in making specific determinations regarding the tariff. Below are examples of how these principles were applied:

Export Rate: The cornerstone of Guiding Principle No. 1 is ensuring that the costs associated with exports are roughly equivalent to the benefits those exports provide to all customers and the grid. This principle led CPUC to move away from retail export compensation rates based on retail import rates, in favor of rates derived from the Avoided Cost Calculator. This approach aligns the cost of distributed generation exports for utilities more closely with their value to the grid, thereby addressing the issue of cost shifts to non-participating customers in line with Guiding Principle No. 2, which emphasizes equity among customers.

TOU Rates: NEM 3.0 mandates that successor tariff customers adopt TOU rates, which significantly differ between peak and off-peak periods. This requirement is justified by Guiding Principle No. 7, which calls for maximizing the value of generation for all customers and the grid.

[48] De León, California Senate Bill 100, The 100 Percent Clean Energy Act of 2018, https://www.energy.ca.gov/sb100

TOU rates provide better price signals, encouraging customers to optimize their energy use, such as consuming electricity or charging storage batteries during lower-priced hours.

Support for Low-Income and Disadvantaged Communities: The emphasis on equity in Guiding Principle No. 2 was a driving force behind several policy designs targeting low-income and disadvantaged communities. As previously mentioned, the shift toward export rates based on avoided costs was partly justified by the need to address cost shifts to non-participants. Furthermore, CPUC recognized that equity also demands increased participation from low-income households. Therefore, in designing the export rate compensation, CPUC permitted three groups of households to qualify for an additional increase to the baseline rate, aiming for a payback period of nine years or less.[49] These groups include 1) residential households enrolled in the California Alternate Rates for Energy or Family Electric Rate Assistance programs, 2) resident-owners of single-family homes in disadvantaged communities, and 3) residential customers residing in California Indian Country.

4.1.1.3.3 Constructing the Tariff Design Framework for NEM 3.0

The conceptual framework for NEM 3.0, established by California Assembly Bill 327[43] in 2013, aims to balance two primary objectives: ensuring that the successor tariff aligns customer-sited renewable generation compensation more closely with the benefits it brings to the electric system and guaranteeing the sustainable growth of distributed renewable generation within the state. To transform this concept into a practical analytical framework for tariff design and to explore its implications, CPUC commissioned a study[50] at the onset of the rulemaking process. This study later became a foundational component of the process. The study's proposals served as the basis for tariff design discussions, and the analytical tools it introduced were adopted by stakeholders as a common framework to evaluate alternative proposals and comments.

The study's principal recommendation is for the successor tariff to shift from retail rate-based credits for energy fed back into the grid to export rates that reflect avoided costs and vary by time-of-day and season. This analysis identified the creation of a mandatory new successor rate for customers with on-site renewable generation as the framework's core element, aimed at enhancing the efficiency of behind-the-meter generation adoption and fostering more equitable outcomes than the existing NEM program. To achieve this, the study concluded that moving away from the traditional NEM compensation structure was necessary.

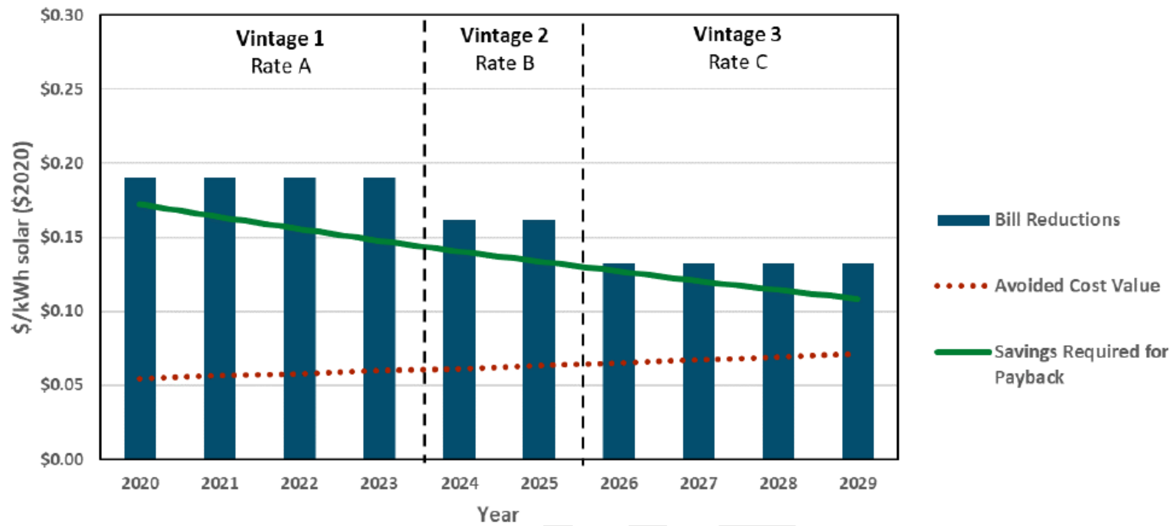
To facilitate sustained growth of distributed renewable generation amid significant changes to the compensation structure, the study proposed implementing a glide path.[50] This approach encompasses both a gradual rate reform and an external transitional support mechanism designed to ensure a reasonable payback period for customers investing in on-site renewable generation. Specifically, the study introduced the concept of a market transition credit (MTC), which would be fixed for a defined payback period for each NEM vintage, based on time, the number of subscribed customers, or the volume of customer-sited renewable generation

49 D.22-12-056, Decision Revising Net Energy Metering Tariff and Subtariffs, CPUC.

50 CPUC, "Alternative Ratemaking Mechanisms for Distributed Energy Resources in California: Successor Tariff Options Compliant with Assembly Bill 327," January 28, 2021.

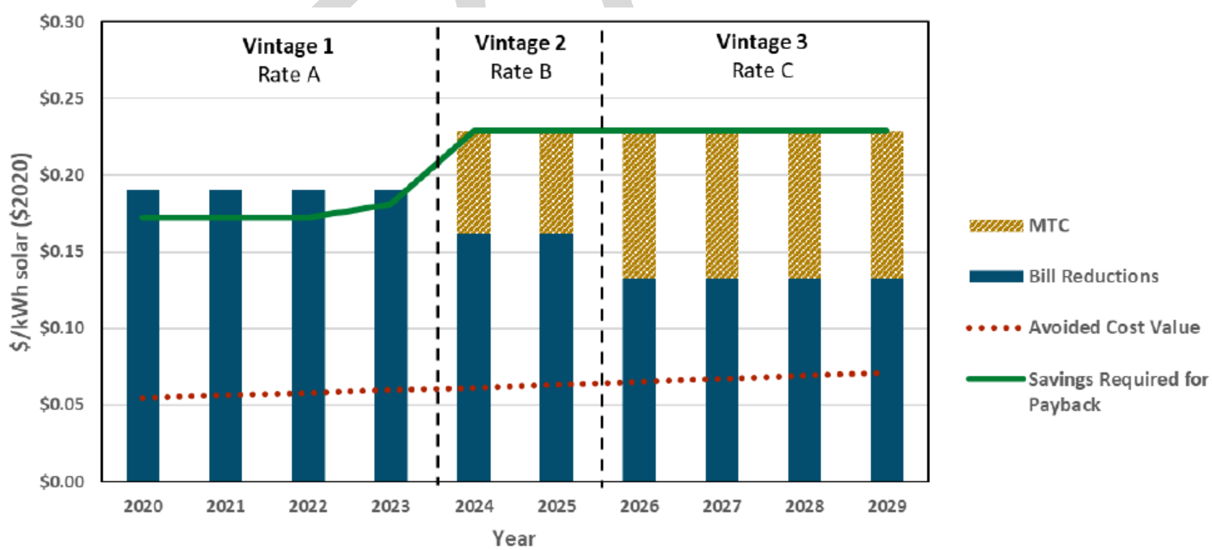
adoption. This mechanism aims to provide certainty for developers and enhance project financing by offering clarity on anticipated changes to rates and external credits.

The analytical framework devised by the study incorporated critical elements relevant to tariff design and, through scenario analysis, illustrated potential market evolution during the transition to the successor tariff. Figure 11 and Figure 12 exemplify the potential role of MTC under specific market conditions.



Used with permission from CPUC[50]

Figure 11. Bill Reductions and Market Transition Credit, Optimistic Scenario



Used with permission from CPUC[50]

Figure 12. Bill Reductions and Market Transition Credit, Flat Technology Cost Scenario

Figure 11 presents an "optimistic' scenario where technology costs continue to decrease significantly over time. These costs are depicted as savings required for payback (the green line), with the red line indicating the avoided cost—the benefit that exported electricity from distributed generation provides to the grid. The blue bars show bill reductions, representing the compensation received by customers. The difference between the benefit and the compensation represents the cost misalignment. As the rate regime evolves, this gap narrows for various customer cohorts. In this optimistic scenario, bill reductions consistently exceed technology costs, suggesting no need for additional credit to support market growth.

Conversely, Figure 12 illustrates a "conservative' scenario where technology costs rise in 2024 and then stabilize, creating a discrepancy between the savings needed for payback and the bill reductions (yellow bars). The size of these bars indicates the necessary value of the MTC to sustain a viable market, while their variation over time highlights the market's dynamic nature. This suggests that periodic reviews of underlying costs are essential to adjust external credits accordingly.

On January 28, 2021, CPUC integrated the study into the rulemaking process and subsequently organized a workshop with stakeholders to present its findings and facilitate a discussion. Ultimately, the study's primary proposals were incorporated as fundamental components of NEM 3.0. The concept of avoided cost was adopted as the basis for determining export rate compensation, and the MTC was established as an additional element to the base compensation throughout the glide path transition period (termed the ACC Plus Glide Path in NEM 3.0[49]).

4.2 HAWAII

Hawaii is actively pursuing the transition from dependence on fossil fuels to utilization of renewable energy sources. Hawaii's goal is to achieve 100% renewable energy generation by 2045. This milestone demonstrates Hawaii's dedication to a better relationship between its energy structure and usage, and its environment for its residents. Hawaii is driven more than most states to achieve these goals due to its specific geographic and economic circumstances as an island with limited natural resources and high energy costs due to a reliance on imported fossil fuels.

Hawaii's NEM programs have been pivotal in advancing the state's renewable energy objectives. This was achieved particularly with solar power making up 19% of the state's generation, the majority of which comes from these programs. As solar penetration increased, the need to modify the NEM mechanism became apparent to policy makers. This led Hawaii to transition to multiple new programs as time progressed to address any shortcomings.

- **The NEM programs evolved from simple net metering to advanced net billing models.**
- **Implementation of advanced inverters, battery storage, and smart meters in newer programs enhanced grid reliability and allowed for better energy management.**
- **Policy and rate designs have been and will be continuously be updated in order to support an energy market based heavily on renewables.**

NEM has been a crucial policy tool for moving toward Hawaii's target of 100% renewable energy. NEM was introduced as a mechanism to encourage the adoption of solar PV by residential and commercial customers.

This provides customers the incentive to install PV systems in order to offset their electricity bills with the energy they generate themselves and export surplus to the grid. NEM made solar power more accessible and affordable while advancing the state toward its renewable energy goals.

This section provides a case study on Hawaii's NEM programs for residential customers and how they have evolved from their origin to the present day (see Figure 13). This was done by focusing on the utility HECO and examining its NEM program structures, tariffs, and the transition from HECO's old programs to new ones.

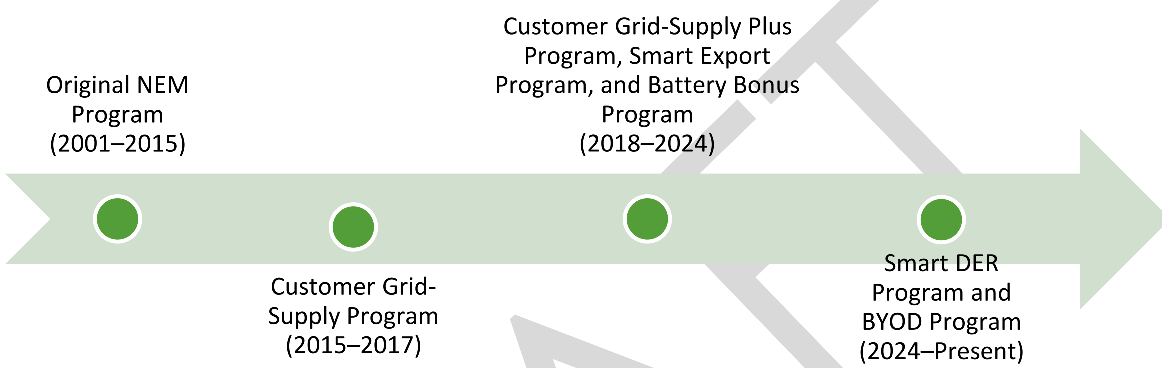


Figure 13. Timeline of Hawaiian Electric's Solar Program Open to New Customers

4.2.1 Introduction to the Original NEM Program (2001–2015)

Hawaii's NEM program began in 2001 and was available to customers and subscribers until 2015. Although the program closed in 2015 to new customers, those who entered the program earlier were grandfathered in to continue to participate under its original terms. The original NEM program was designed to support residential customers in acquiring technology for generating their own electricity from renewable sources and sending excess back to the grid. The renewable technologies allowed under this program were solar, wind, hydroelectric, biomass, hybrid systems, and storage, but in practice, the solar PV systems made up the bulk of the generation installed under this program. These renewable systems were limited to 100 kW of capacity.[51] In some specific situations, a customer could request a greater capacity system, but this was usually not the case for residential customers.

The legacy NEM program served customers under the same service class as non-NEM residential customers. Hence, the same rate structure and prices are applied. The system worked as follows: if a customer did not generate enough electricity to offset their usage in the billing period, they would import anything they needed from the utility (HECO) and pay for the electricity consumed at the standard residential retail rate. An example rate from the end of the legacy NEM program is listed in Table 12. If a customer generated more than they consumed,

[51] HECO, *Rule No. 18: Net Energy Metering*. 2001. https://www.hawaiianelectric.com/documents/billing_and_payment/rates/hawaii_electric_light_rules/18.pdf

they would receive energy credits for that excess production (import to the grid) at the same retail rate they would purchase energy from the grid with the caveat that credits were applied up to the point where the bill equaled the customer minimum charge. The minimum charge refers to the lowest electricity bill a net exporting NEM customer can receive, as there can be no negative or zero-cost bills. Any excess energy credits were carried over month to month to offset import costs in future months when the customer may not have generated enough to be a net exporter. This continues until the final reconciliation, where the remaining kWh credits will be offset by outstanding service charges at the end of the 12-month period.

Table 12. 2015 Standard Residential Import Rates/NEM Export Rates

Schedule 'R' Rate Charge Blocks	Base Rate [$/kWh]
First 350 kWh/Month	0.217096
Next 850 kWh/Month	0.228631
All Over 1200kWh/Month	0.247405

The original NEM program in Hawaii accelerated the state toward its renewable energy goals and can be seen in the growth of total solar energy consumed from 2001 to 2015 according to Energy Information Administration (EIA) data (see Table 13).[52]

Table 13. EIA Hawaii Solar Energy Consumption Data, 2001–2015

Year	2001	2005	2010	2015
Solar Energy Consumption (Billion Btu)	1236	1301	2278	8356

The financial incentives of energy credits at full retail rates given through the NEM program helped to contribute to a substantial increase in solar PV systems across the islands. However, questions were raised about whether the level of payments were necessary to achieve Hawaii's objectives. Payments for grid injections based on the retail tariff included both avoidable variable generation costs and also non-avoidable fixed cost recovery that results in a cost shift that is collected disproportionally from non-participating customers. The transformation to distributed renewable generation required investment to enable two-way flow from the renewable generation and to support the utility's ability to maintain grid stability with highly variable generation. These issues of fairness and equity caused the program design to be addressed.

4.2.2 Transition to the Customer Grid-Supply Program (2015–2017)

By 2015, the high penetration of solar led to concerns about the technical limitations of the grid as well as the increased financial burden being placed on non-NEM customers. Hawaii recognized the need to shift toward a more balanced and sustainable program to further develop distributed energy generation in Hawaii. The response was to create the Customer Grid-Supply (CGS) program, which was open to new customers from 2015 to 2017. When subscriptions for new customers to CGS closed in 2017, existing participants were grandfathered under the terms they subscribed under. A transition period will start on October 1, 2024, at

[52] EIA, *State Energy Data System (SEDS): 1960-2021 (complete): Hawaii*, 2023, https://www.eia.gov/state/seds/seds-data-complete.php?sid=HI#Production

which point, grandfathered customers will be required to transition to the successor Smart DER program 7 years after the day the customer initially signed legacy program contract.

The applicable renewable technologies and system capacity limits under CGS are the same as the original NEM program.[53] It serves customers under the same service class as non-NEM residential customers. However, CGS employs NEB to track energy generation and consumption to and from the grid to determine customer bills. Any electricity purchased from the grid would be at the normal non-NEM customer residential rate, while the rates for customer-exported electricity set by HECO are outlined in Table 14 and are specifically for CGS participants only. Although the rate structure now provides different export and import rates, CGS customers are identified as net importers or exporters in the same manner as the original NEM program. If a customer did not generate enough energy to cover its premises' usage, they would import the shortfall from the grid and pay for the electricity consumed at the retail rate. If a customer generated more than they consumed, they would receive energy credits for that excess production (import to the grid) at the rate in Table 14. They were applied up to where the bill equaled the customer minimum charge, as was previously the case. Any excess energy credits unused at the end of a billing period would be forfeited and could not be carried over in any way.

Table 14. CGS Program Export Rates

Island	Rate [$/kWh]
Oahu	0.1507
Hawaii Island	0.1514
Maui	0.1716
Molokai	0.2407
Lanai	0.2788

The CGS program helped to address some of the implementation issues associated with the original NEM program. Grid management challenges were mitigated by reducing the rate at which electricity was credited to CGS net export participants. This did not slow the rate of increased solar energy consumption and total output, as seen from the EIA data[52] in Table 15.

Table 15. EIA Hawaii Solar Energy Consumption Data, 2015–2017

Year	2015	2016	2017
Solar Energy Consumption (Billion Btu)	8356	9810	12573

The adjustment of export rates and implementation of a new billing mechanism was enacted to alleviate the fairness and equity issues associated with the original NEM. The lessening of financial incentives of solar adoption led to the slowing in the adoption of solar systems. The slower adoption of these systems indicated a need for further adjustment in policy to create a more effective NEM program and to continue supporting Hawaii's renewable energy goals.

[53] HECO, *Rule No. 23: Customer Grid Supply, 2015.* https://www.hawaiianelectric.com/documents/billing_and_payment/rates/hawaii_electric_light_rules/23.pdf

4.2.3 Transition to the Customer Grid-Supply Plus and Smart Export Program and the Addition of the Battery Bonus Program (2018–2024)

Hawaii's NEM policies implemented two new programs for customers, available beginning in 2018 through the end of March 2024: Customer Grid-Supply Plus (CGS+) and Smart Export. These programs were developed to address the limitations of the earlier programs, mainly looking to help solve grid reliability issues with the increased solar penetration to provide more flexibility in energy management. In addition, a partner program called Battery Bonus was introduced for any HECO customer on the islands of Oahu and Maui currently participating in any current or legacy NEM program. This was implemented to encourage the use of storage systems to stabilize grid demand, particularly during peak periods.

Both CGS+[54] and Smart Export[55] allow the same renewable technologies and system capacity limits as the previous programs. They also serve customers under the same service class as non-NEM residential customers and use NEB to charge for or credit energy generation and consumption from the grid, respectively, to render electric service bills. Like in the legacy program for solar adoption, a customer must pay the minimum charge for their bill, but excess credits for use on energy charges could still be carried over from month to month. The main change to excess credits in this program is the true-up process at the end of the 12-month period. A reconciliation process is performed at the end of the 12 months, which pays out via a check for any excess credits at the program's energy credit export rate. Another important change was that they required the use of advanced inverters on PV systems behind the meter. These inverters have capabilities that improve grid reliability through advanced voltage regulation, frequency support, reactive power control, and remote monitoring and control. Together, these factors help address issues associated with electric grid operation and high renewable penetration. There was also the addition of total connected solar capacity limits for both programs, the total MW each program could add by island (see Table 16).

Table 16. CGS+ and Smart Export Program Capacity Limits

CGS+		Smart Export	
Region	**Program Capacity**	**Region**	**Program Capacity**
Oahu	104.5 MW	**Oahu**	38.5 MW
Maui County	17 MW	**Maui County**	16.5 MW
Hawaii Island	22 MW	**Hawaii Island**	20 MW

The CGS+ program had many aspects similar to previous programs and Smart Export. However, CGS+ also had new and distinguishing features. The first was the reworking of the original CGS export rates from Table 14 to the new CGS+ export rates seen in Table 17. Like Smart Export, CGS+ requires customers to install a meter, either through the utility company or a third-party aggregator, that would allow the utility access to the smart meter. The smart meter allows the

[54] HECO, *Rule No. 24: Customer Grid Supply Plus*, 2024. https://www.hawaiianelectric.com/documents/billing_and_payment/rates/hawaii_electric_light_rules/24.pdf

[55] HECO, *Rule No. 25: Smart Export Program*, 2024. https://www.hawaiianelectric.com/documents/billing_and_payment/rates/hawaii_electric_light_rules/25.pdf

utility to remotely measure, monitor, evaluate, and verify technical compliance, solar device power output, and power quality, and control the facility's output as needed to optimize grid operation. This controllability requirement from HECO allows the utility to dispatch the power output on an ongoing basis or disconnect or curtail the customers' systems as a single group or block, but this control is limited to grid emergencies. All these features were implemented to address the ongoing challenge of maintaining a reliable grid to which substantial renewable technologies are interconnected.

Table 17. CGS+ Program Export Rates

Island	Rate [$/kWh]
Oahu	0.1008
Hawaii Island	0.1055
Maui	0.1217
Molokai	0.1677
Lanai	0.2080

While Smart Export was designed for systems with battery storage, it introduced significant new features, such as being the first NEM program in Hawaii with time-differentiated usage rates, as seen in Table 18. Notably, there were no credits given during daylight hours (9 am–4 pm). This program directly addressed the potential system operation associated with solar intermittency by offering no credit for exports during daylight hours. This was done to encourage any excess generation during those hours to be directed toward charging system batteries instead of injected into the grid. To complete this incentive, a battery adoption program was implemented.

Table 18. Smart Export Program Export Rates

Island	Rates [$/kWh]		
	12 am–9 am	9 am–4 pm	4 pm–12 am
Oahu	0.1497	No Credit	0.1497
Hawaii Island	0.1100	No Credit	0.1100
Maui	0.1441	No Credit	0.1441
Molokai	0.1664	No Credit	0.1664
Lanai	0.2079	No Credit	0.2079

In addition to CGS+ and Smart Export, the new Battery Bonus program began in 2018. As noted earlier, the program was only available in Oahu and Maui, with aggregate program capacity limits of 40 MW and 15 MW, respectively.[56] The driving force behind this program was to help address high demand during peak hours using this extra storage. Existing customers from any solar program, past or current, continued to receive the full benefits from their program. They were able to install a battery of any size and could add new solar panels as long as the total facility power production capacity was not more than double the size of the battery capacity. Battery Bonus customers would receive a one-time payment of $850/installed battery kW and $5/kW of capacity per month thereafter. In return, the customer would be required to enter

[56] HECO, "Battery Bonus," 2024. https://www.hawaiianelectric.com/documents/products_and_services/customer_renewable_programs/battery_bonus.pdf

into a 10-year contract and commit to export electricity from their battery for two consecutive hours every day during 6–8:30 pm. The electricity exported from the battery during this two-hour period is compensated at the same rate as the customer's current solar program's export rate. There were no penalties if the weather did not allow for complete battery charging. The 10-year contract can be terminated with a 60-day notice to HECO, with the customer required to repay a pro-rated portion of the incentive based on the number of years left in the contract.

CGS+ and Smart Export were enacted to contribute to the grid's stability in Hawaii through their controllability requirements and battery storage program design, respectively. The Battery Bonus program was also a major step in addressing the shortcomings of solar energy production during peak demands by using customer-side batteries to shift surplus behind-the-meter solar for use or export when it provides the greatest value to the system.

4.2.4 Transition to the Current Smart DER Program and Addition of the BYOD Program

The transition to the Smart Renewable Energy Export program, also known as the Smart DER program, began in April 2024. Smart DER's goals are to implement advanced metering infrastructure, advanced rate design TOU rates, and upgraded grid services. The provision applies to new solar grid connections and to facilities on legacy programs that have expired or the customer desires to switch. Accompanying this program is another battery-focused partner program called bring your own device (BYOD), which builds off the framework of the previous Battery Bonus program. In doing this, the plan is to create a more sustainable and efficient grid system that supports higher penetration of renewable energy and customer participation in NEM programs.

Many aspects of the Smart DER program remain the same as in the previous section, such as the allowed renewable technologies, the NEB structure, the minimum charge bill, and the excess credit payout. That said, many things have changed with this program. An important provision is that starting October 1, 2024, customers participating in CGS, CGS+, and Smart Export must transition to Smart DER 7 years after their initial contract date.[57] This is designed to provide for a gradual transition to technological and systems upgrades to achieve a modernized grid. The program also removed individual system capacity limits, which are now governed by Rule 14 Section H.[58] Another key implementation requirement is for advanced meters. These meters allow for two-way data sharing, which enables remote and detailed metering and communications of customers' electricity importing and exporting by HECO and enables the collection of more real-time data, increasing situational awareness. Every 15 minutes, energy use data is uploaded and can be viewed by the homeowner and utility, which can help understand energy usage better and lead to better energy management.

Another important factor in Smart DER is the service class under which program subscribers are served. Smart DER customers are to enroll in the Schedule ARD TOU R/Shift and Save TOU rates

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[57] HECO, *Rule No. 32: Smart Renewable Energy Program Export Rider*, 2024. https://www.hawaiianelectric.com/documents/billing_and_payment/rates/hawaii_electric_light_rules/32.pdf

[58] HECO, *Rule No. 14 Section H: Interconnection of Distributed Generating Facilities with the Company's Distribution*, 2024. https://www.hawaiianelectric.com/documents/billing_and_payment/rates/hawaii_electric_light_rules/14.pdf

(see Table 19) rather than the standard residential rate. Although Smart DER customers are encouraged to enroll in the Shift and Save rates, they can choose to opt out of those rates before commencing service in the program, but doing so slightly delays service initiation until July 1, 2024.

Table 19. Smart DER Program Import Rates (Schedule ARD TOU R/Shift and Save TOU Rates)

Island	Rates [$/kWh]		
	9 pm–9 am	9 am–5 pm	5 pm–9 am
Oahu	0.348430	0.174215	0.522645
Hawaii Island	0.413998	0.206999	0.620997
Maui	0.395618	0.197809	0.593427
Molokai	0.439466	0.219733	0.659199
Lanai	0.522160	0.261080	0.783240

Additionally, Smart DER improved and reworked the export rates from Smart Export. The export rates will be updated every three years but are locked in for the first seven years for first-time solar installation customers. Customers that transition to Smart DER from any existing NEM/solar programs will have their rates updated every three years. Examples of other export rate provisions are outlined in Figure 14. The current export rates are seen below in Table 20.

Smart Renewable Energy Export example situations

Year	1	2	3	4	5	6	7	8	9	10	11	12
1. New Customer	$0.30	$0.30	$0.30	$0.30	$0.30	$0.30	$0.30	$0.25	$0.25	$0.20	$0.20	$0.20
1a. Customer inherits lock in during year 5					$0.30	$0.30	$0.30	$0.25	$0.25	$0.20	$0.20	$0.20
1b. New Customer ending lock in after year 5	$0.30	$0.30	$0.30	$0.30	$0.30	$0.32	$0.25	$0.25	$0.25	$0.20	$0.20	$0.20
2. New Customer joining in year 5					$0.32	$0.32	$0.32	$0.32	$0.32	$0.32	$0.32	$0.20
3. Already participating customer	$0.30	$0.30	$0.30	$0.32	$0.32	$0.32	$0.25	$0.25	$0.25	$0.20	$0.20	$0.20
3a. Already participating customer (opting in)	$0.30	$0.30	$0.30	$0.32	$0.32	$0.32	$0.25	$0.25	$0.25	$0.20	$0.20	$0.20

Export rates shown in the above table are sample rates intended only to explain the 7 year lock in behavior.

Source: Hawaiian Electric

Figure 14. Smart DER Program Export Rate Example Situations

Table 20. Current Smart DER Program Export Rates

Island	Rates [$/kWh]		
	9 pm–9 am	9 am–5 pm	5 pm–9 am
Oahu	0.189	0.135	0.329
Hawaii Island	0.148	0.106	0.231
Maui	0.131	0.66	0.182
Molokai	0.174	0.179	0.272
Lanai	0.259	0.267	0.408

The BYOD program builds on the earlier Battery Bonus program to improve upon the same goals with altered provisions.[59] This is a 10-year program and has program capacity limits of 70 MW on Oahu, 17 MW on Hawaii Island, 17 MW on Maui, 1.45 MW on Lanai, and 1.45 MW on Molokai. A customer from any existing solar program can join it and still receive the full benefits from their current program. Although there is no battery capacity limit in previous solar programs, a customer can only add up to 1 kW of additional PV. BYOD customers receive incentives based on kW of battery capacity, similar to the Battery Bonus. New battery installations under Battery Bonus receive $100/kW upfront, and all customers, including those who are transitioning from Battery Bonus, receive $5/kW/month. The BYOD program plans to have three levels of participation. Currently, Level 2 (Utility Dispatch) and Level 3 (System Grid Service Program) are suspended and unavailable until further notice, leaving only Level 1 (Flexible User Dispatch) as an active option. BYOD Level 1 requires customers to commit two consecutive hours daily to export from their batteries. This follows the same exporting convention discussed in the previous section's Battery Bonus program. The BYOD program requires the customer to install advanced meters like those required in Smart DER. BYOD follows the same exporting rate design as the customer's underlying solar program. A new feature includes any excess credits gained from the BYOD program can be applied to a bill without limitation.[60] This means customers can create a credit balance in their account and choose to be paid out there or carry it over into the following months. The same contract termination rules from Battery Bonus apply to BYOD as well.

As Smart DER and BYOD are both in their initial stages, ongoing adjustments and improvements are necessary as the programs continue to roll out. This period will allow for performance data collection and feedback from participants to analyze, refine, and optimize the program's rate design, incentives, and overall structure.

[59] HECO, *Rule No. 33: Bring Your Own Device (BYOD)*, 2024. https://www.hawaiianelectric.com/documents/billing_and_payment/rates/hawaii_electric_light_rules/33.pdf.

[60] HECO, *Rule No. 32: Smart Renewable Energy Program Export Rider*, 2024. https://www.hawaiianelectric.com/documents/billing_and_payment/rates/hawaii_electric_light_rules/32.pdf.

4.3 NORTH CAROLINA

North Carolina is a state that has gone through substantial changes in their NEM rate. Because of the longevity of the program (established in 2000), the changes enacted in 2000–2023, and the new tariffs available (which includes a "bridge" or transitioning rate), North Carolina is a case study that is worth looking to in detail.

North Carolina currently has more than 350 MW of residential NEM PV capacity installed. Most of it was installed in 2015–2022, during a period in which credits were granted to residential customers under the NEM rider. By December 2021, North Carolina was the 17th state in terms of solar PV capacity—12 of the 16 states with higher total small-scaler solar capacity had already approved or initiated reforms to their NEM policies and tariffs. The Public Staff of the North Carolina Utilities Commission reviewed over 400 statements of position before approving the new NEM policy, which closed applications for new entrants under NEM and opened an NMB and RSC, both under a NEB scheme. Similar to other states in the country, the evaluation of NEM tariffs during 2021–2023 involved the following:

- **Requesting an embedded and marginal cost studies that evaluated the cost, benefits, and cross-subsidies associated with NEM.**
- **Defining which costs and benefits are included in these studies, and if any non-quantifiable benefit or cost is considered. Defining the criteria to evaluate the fairness or reasonableness of the proposed new NEM tariffs. For North Carolina, the Public Staff determined that 1) the embedded cost study best represents the overall retail rate and revenue situation of Duke, 2) reductions within 90–110% on an embedded cost basis are within an appropriate band of reasonableness, and 3) that the new proposed NEM tariffs achieve that goal.**
- **Easing the transition of legacy customers and facilitating the understanding of the new rate to all consumers. The Utilities Commission requested Duke Energy to establish an online calculator to explain the savings with the available rates.**

The NEM tariffs have been available for more than 20 years, although for the first 9 years, it was only available for customers under a TOU schedule. The NEM program has changed under North Carolina Utilities Commission orders published in 2005, 2006, 2009, and 2023, establishing three main periods that highlight not only the main attributes used to define a NEM program, but also how state-level policy and stakeholder involvement play into establishing these rules:

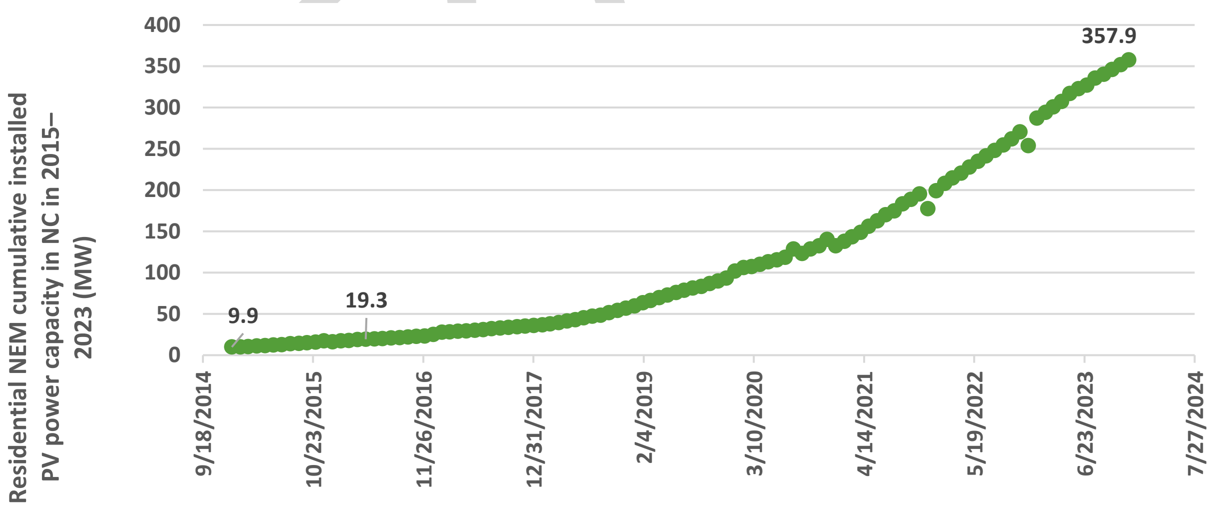
- *Early NEM period* (2000–2009, before the publication of 2009 NEM Order): During this period, NEM was available only to residential customers under a TOU schedule that substantially limited their participation and included other adjustments that showed lessons learned. Some of the lessons learned included the importance of adding and allowing customers to use batteries with solar PV (a prohibition was established in 2005 and removed in 2006) and allowing credits to be carried over for a full year instead of six months (the biannual reset was adjusted to annual reset of credits).

- *Regular NEM period* (2009 NEM order–June 30, 2023): This period was characterized by more traditional NEM rules, such as establishing a maximum capacity of the system equal to 20 kW or the maximum demand of the customer, netting exports with imports (not including a basic flat fee) and resetting credits (to zero) not used during the annual billing cycle.
- *New NEM period* (July 1, 2023–present): This period began with the end of the regular NEM rate and the establishment of an NMB and RSC, which ends the era of "credits," includes more details that can be hard to follow in detail, and provides a net billing scheme for valuing exports and imports at different rates. Existing customers were grandfathered into the new NMB.

The rest of this case study shows details on the NEM history in North Carolina and highlights details of the new rates—NMB and RSC—established July 1, 2023.

4.3.1 Timeline and History of NEM Programs

North Carolina has seen growth in the residential NEM PV installed capacity over the past 9 years, with a 35x increase since 2015 (see Figure 15). EIA estimates (form 861-M—preliminary data) that by December 2023 there were a total of 358 MW of installed net-metering capacity in the residential sector in North Carolina (or 45,827 installations), with 9 MW and 10.8 MW in the commercial and industrial sectors, respectively.



Note: Data was downloaded June 2024 from EIA's Electricity Data Browser—2023 data is preliminary.[61]

Figure 15. Residential NEM Cumulative Installed PV Power Capacity in North Carolina

[61] EIA, *Electricity Data Browser*, 2024. www.eia.gov/electricity/data/browser/#/topic/0?agg=2,1,0&fuel=0002&geo=g0000004&sec=g&linechart=~~~~~~&columnchart=ELEC.GEN.DPV-US-99.A&map=ELEC.GEN.DPV-US-99.A&freq=A&ctype=linechart&ltype=pin&rtype=s&maptype=0&rse=0&pin=

Beginning August 4, 2000, with the 2000 NEM order, the Commission first approved NEM rates in Docket No. E-100, Sub 83. This consisted of a pilot PV rider for a maximum of 25 customers per utility, each with a maximum capacity of 10 kW. The pilot riders provided residential and nonresidential participating customers owning small-scale PV facilities of 10 kW or less in capacity the opportunity to offset some or all of the electricity that would otherwise be supplied to them by the utility, and to receive a credit for any excess generation provided to the utility. Residential participants would not pay metering and stand-by charges.

in 2005, some changes were introduced via the 2005 NEM Order on October 20, 2005. The size was increased to 20 kW systems for residential systems, with energy storage technologies being explicitly prohibited. The participants had to be on a TOU schedule, and the credits were allowed to be carried month to month, and reset[62] twice a year, in the beginning of the summer and winter seasons. The NEM was a billing arrangement whereby the customer-generator is billed according to the difference over a billing period between the energy consumed and the energy generated by the renewable energy facility. Net metering allowed the customer to receive a billing credit for excess generation delivered to the utility grid. The compensation for excess energy credits was defined at rates commensurate with the TOU period (on-peak rates applied to on-peak excess energy).

The year after, on July 6, 2006, the 2006 NEM Order reduced the credit reset to once per year at the beginning of the summer billing period and lifted the prohibition toward batteries. The renewable energy credits (RECs) accrued by the excess energy were transferred to the utility.

> In the Commission's 2005 and 2006 NEM Orders, the Commission acknowledged that all parties conceded that NEM could result in potential subsidies for NEM customers but stated that other benefits had been proposed by supporters that could potentially offset such subsidies. To minimize those potential subsidies, the Commission established limits on NEM installations, required customers be on a TOU rate schedule, and granted RECs associated with excess energy at NEM installations to the utility.[63]

In 2007, the General Assembly enacted Senate Bill 3, which directed the Commission to "consider whether it is in public interest to adopt rules for electric public utilities for net metering of renewable energy facilities with a generation capacity of one MW or less."[63] In response, the Commission issued its order amending NEM on March 31, 2009 (2009 NEM Order), under which the NEM program could allow for customers under any residential rate schedule and not only TOU customers to participate. Those customers under TOU schedules could keep the RECs generated—instead of transferring them to the utility. Residential customers under regular non-TOU rates would still transfer the RECs generated to the utility.

[62] Credits reset refer to setting credits equal to zero. Thus, credits can be carried forward to the next month but expire on a date if not used. This implicitly incentivizes a maximum size of the PV system commensurate with the customer's annual energy needs, as a customer will avoid oversizing a system that will result in "overproduction" that is reset at the end of the year and, therefore, not billed.

[63] State of North Carolina Utilities Commission Raleigh, Docket No. E-100, Sub 180. 2022. https://starw1.ncuc.gov/NCUC/ViewFile.aspx?Id=e317a759-8dd6-4968-9acf-f709a96b5b08

The Commission commented on March 31, 2009,[64] on the importance of non-quantified benefits and the state policy favoring additional variable renewable energy.[64] The 2009 NEM Order established the rules that are in place for customers that are today called "legacy customers," specified in the rider NM (which is now closed for new customers on or after October 1, 2023). Under the rider NM, customers could net their energy charges portion (which, at today's energy charge rates, would be approximately $0.1143 cents/kWh). A basic flat fee could not be netted, meaning that those charges could not be displaced by credits from energy exports. In addition, accrued credits not used in a month were allowed to be carried forward[65] and were reset once per year at the beginning of the summer billing period (on May 31st) as established in the 2006 NEM Order.

In 2017 and 2021, two North Carolina House Bills were published, HB 589 in 2017 and HB 951 in 2021. In aggregate, these two HBs requested a state study of the costs and benefits of customer-site generation, requiring the Commission to "establish net metering rates under all tariff designs that ensures that the net metering retail customer pays its full fixed cost of service,"[66] and provided support for the development of renewable generation as a means of achieving carbon reduction goals.[67] In 2017, the legislature addressed cross-subsidization when it passed HB 589, stating "cross-subsidization should be avoided by holding harmless electric public utilities customers that do not participate in such arrangements."[68]

From 2021, Duke Energy Progress, LLC (DEP) and Duke Carolinas, LLC (DEC) fulfilled the requirements of conducting a rate case design study,[69] which included input from over 20 organizations that represented a broad range of interests. In November 2021, Duke filed an application for approval of NEM tariffs in compliance with HB 951. On January 2022, the commission established Docket No. E-100, Sub 180 and issued an order requesting comments and reply comments on the original application filed in Dockets Nos. E-7, Sub 1214; E-2, Sub 1219; and E-2, Sub 1076.

Duke proposed new NEM tariffs with innovative rate structures in compliance with HB 589 and HB 951 that work in conjunction with TOU and critical peak pricing (CPP). Some of the innovative components include netting over each TOU period and applying a net excess credit to net exports, as well as adding charges for bigger systems. The five innovative components of the proposed rates are described in more detailed below:

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64 State of North Carolina Utilities Commission Raleigh, Docket No. E-100, Sub 83. 2023. https://files.nc.gov/pubstaff/Order_Amending_Net_Metering_Policy_March_31_2009_Docket_No._E-100_Sub_83.pdf

65 If customer is in a TOU rate, the credits are applied first for usage within the same TOU period, then applying any remaining credits to lower TOU periods in descending order by price.

66 North Carolina House Bill 589 / SL 2017-192, Competitive Energy Solutions for NC, 2017. https://www.ncleg.gov/BillLookUp/2017/h589

67 North Carolina House Bill 951 / SL 2021-165, Energy Solutions for NC, 2021. https://www.ncleg.gov/BillLookUp/2021/H951

68 North Carolina House Bill 589 § 62-126, Article 6B, Distributed Resources Access Act, 2017. https://www.ncleg.gov/Sessions/2017/Bills/House/PDF/H589v6.pdf

69 Duke's rate design study was required by the Commission in Docket Nos. E-7, Sub 1214 and E-2, Sub 1219 (collectively, the Rate Case Dockets). The embedded cost analysis estimated a potential monthly subsidy in favor of each NEM customer of $25–30 for DEC and $35–40 for DEP. The marginal framework estimated a potential monthly subsidy in favor of each NEM customer of $30–35 for DEC and $58–63 for DEP.

1. A monthly minimum bill that applies only if the sum of specific charges[70] surpass a threshold, initially proposed to be $22 for DEC and $28 for DEP.
2. A monthly grid access fee that applies for solar PV capacities larger than 15 kW-DC, as large systems represent the greatest potential for under-recovery of fixed costs because those customer's billed kWh can be reduced substantially by the net metering arrangement.
3. Non-bypassable charges to recover costs related to demand-side management/energy efficiency programs, securitized storm costs, proposed to be $0.36/kW/month and $0.44/kW/month to DEC and DEP's customers, respectively.
4. Netting and exports: consumption and exports will be netted per TOU period with any net consumption billed to the customer at the rate in effect for that pricing period, and at the end of the month, NEM customers would be credited for any net monthly exports to the utility grid at an annualized rate for avoided energy costs as specified at the approved avoided cost rates. These are rates that DEC and DEP pays to utility-scale qualifying facilities under PURPA and are appropriate in the NEM context because the NEM customers deliver the same type of energy to the grid as the utility-scale facilities.
5. TOU-CPP Rates: net exports and consumption within pricing periods established by the TOU-CPP rate schedules, with any net excess energy exported to the grid from a customer-site facility credited to the customer each month at avoided cost rates. Under the proposed new tariffs, there would no longer be any reset of accrued and unused credits to zero at the beginning of the summer season each year.

On May 19, 2022, DEC and DEP filed a stipulation that presented a proposed bridge rate for NEM customers, which does not include a grid access fee or mandatory TOU rates, subject to participation caps. These are explained in detail in Table 21. The new tariffs, the bridge rate (NMB) and the new NEM rate (RSC) were approved effective July 1, 2023, for a period of four years from the effective rate. Six months prior to the expiration of these rates, DEC and DEP shall make a filing to continue the NEM tariffs with any modifications that are appropriate to address any further cross-subsidization issues discovered, to accommodate and recognize any new or additional benefits that have been validated by known and measurable data, to address the integration of storage with behind the meter generation, to otherwise comply with any statutory or regulatory changes that may occur.[63]

According to an *NC Newsline* article,[71] by March 2023, the NEM program had supported 43,000 households in North Carolina to install solar panels. Current customers under the legacy NM rider that dates back to 2009 can remain in this schedule until December 31, 2026, after which they will have to move to another rate.

[70] Charges include the basic customer charge and distribution costs and riders.

[71] Habash, Z. "Duke Energy's Wins at the State Utilities Commission Are Holding Back Necessary Climate Progress," *NC Newsline*, January 18, 2024. https://ncnewsline.com/2024/01/18/duke-energys-wins-at-the-state-utilities-commission-are-holding-back-necessary-climate-progress/.

4.3.2 New NEM Applicants

Today's new residential applicants have two options: apply to either the rider NMB or the RSC, or remain in their existing class. The main change between the legacy NEM rate and today's available rates (NMB and RSC) is that the schedule no longer considers energy credits, but instead the netting applies to the net energy delivered to the grid each billing period at a much lower rate than today's energy charge for the electricity consumed from the grid. In particular, under the NM legacy program, the net electricity delivered to the grid was valued at the energy charge (equal today to $0.1143/kWh) and, therefore, was carried forward if necessary. Under the NMB and RSC, the net electricity delivered is valued at a utility avoided cost as published by DEC and DEP.[72] The Commission website[73] called net excess energy credit equal to $0.335/kWh. Some other differences with the legacy NM rate include a new non-bypassable rate based on installed capacity, and the allowance of customers to retain RECs.

The main difference between the two new rates is that the NMB schedule doesn't require the residential customer to be in a TOU rate (although could be in TOU, in which case it almost acts as an RSC customer), whereas the RSC has this requirement. The new rates allow customers to remain in their existing class. The NMB rider will be closed on January 1, 2027, and every customer under that schedule will have to transfer to the RSC schedule. Applications under NMB will be granted on a "first-come first-served" basis, capped at specific annual maximum capacities, as shown in Table 21.

Table 21. Comparison of Two NEM Programs Available for New Applicants in North Carolina

Category	NMB	RSC
Open to new applicants	Now–December 31, 2026 Cannot be participating in North Carolina GreenPower Max. Capacity = min (20 kW-AC, max. monthly demand)	Now Customer has to be in TOU schedule (RSTC or RETC) Max. Capacity = min (20 kW-AC, max. monthly demand)
Capacity limits (AC)	2023: 1,250 kW 2024: 31,900 kW 2025: 35,100 kW 2026: 38,700 kW	No limits
Electricity supplied to the customer by DEC and DEP > electricity delivered to the grid by the customer during a period	Period = monthly billing period Customer is charged = energy charge ($0.1143/kWh) x net electricity supplied (kWh)	Period = TOU period For each TOU period: the Customer shall be billed for the net electricity supplied by the company, plus any other charges under the applicable rate schedule and riders

[72] G.S. § 62-156 requires the North Carolina Utilities Commission to biennially determine the rates to be paid by electric utilities for power purchases from small power producers according to certain standards prescribed therein. The approved avoided cost rates are also applied in fuel adjustment riders, Renewable Energy and Energy Efficiency Portfolio Standard riders, demand-side management and energy efficiency riders, Competitive Procurement of Renewable Energy riders, and the approved cost structure underlying the negotiated rates paid to larger qualifying facility generators who are not eligible for the standard tariff.

[73] Public Staff, "Avoided Costs Rates." North Carolina Utilities Commission, 2024. https://publicstaff.nc.gov/public-staff-divisions/economic-research-division/avoided-costs-rates.

Category	NMB	RSC
Electricity supplied to the customer by DEC and DEP < electricity delivered to the grid by the customer during a period	Period is a monthly billing period Customer is credited = net excess energy credit ($0.0335 cents/kWh) x net excess energy delivered to the grid (kWh)	Period is a TOU period For each TOU period: Customer is credited = net excess energy credit ($0.0335 cents/kWh) x net excess energy delivered to the grid (kWh)
If customer is in TOU schedule	Net electricity will be calculated for each TOU period. After offsetting usage in the same TOU period, any remaining excess energy will be applied to lower TOU periods in descending order by price. After net electricity has been calculated for all TOU periods, the customer shall be credited for any remaining net excess energy at the net excess energy credit	
If customer is in CPP schedule	Critical peak hours will be considered a separate TOU pricing period for the purpose of netting, such that electricity delivered to the grid by the customer during critical peak hours will be netted with electricity supplied by the company during critical peak hours.	
Other charges	Non-bypassable charge per month: $0.29/kW-AC Demand charge or other charges if applicable (see below in example "rider charge")	Non-bypassable charge per month: $0.29/kW-AC Grid access fee based on the customer's nameplate capacity in kW DC for solar generation or kW-AC for non-solar generation. The grid access fee will be $0 for customers with nameplate capacity at or below 15 kW, and $2.05/kW-AC/month above 15 kW.
Minimum bill	$22 specific to the portion of the customer's bill related to customer and distribution costs. The customer and distribution energy charges is applied to all energy per month, equal to $0.21482/kWh	$22 specific to the portion of the customer's bill related to customer and distribution costs. The customer and distribution energy charges is applied to on-peak, off-peak, and discount periods, ranging $0.144–0.483/kWh across periods and RSTC and RETC schedules Bill credits for net excess energy are not included in the calculation of the minimum bill charge. Bill credits will reduce a customer's total bill after the minimum bill charge has been applied
Billing meter	The billing meter will be a <u>single, bi-directional meter that records independently the net flow of electricity in each direction through the meter</u>, unless customer's overall electrical requirement merits a different meter. The customer grants the company the right to install, operate, and monitor special equipment to measure the customer's generating system output, or any part thereof, and to obtain any other data necessary to determine the operating characteristics and effects of the installation. All metering shall be at a location that is readily accessible by the company	
RECs	Any RECs associated with electricity delivered to the grid by the customer under this rider shall be retained by the customer	

Figure 16, Figure 17, and Table 22 provide a representative example of a residential customer located in DEC's service territory, which was estimated using DEC's solar estimator, for a customer with an average monthly consumption of 1,250 kWh. Although under both riders the customer will accrue savings, these are larger under the NMB than under the RSC schedule. This is likely to be at least partially due to the peak and off-peak schedule that do not coincide with the peak solar resource. Currently, the on-peak periods are either at 6–9 am (October–April) or 6–9 pm (May–September)—periods when the customer most likely will not be able to use their solar system to meet their own demand and will depend on the high grid rates to meet their energy needs. More research is required to determine the potential impact of switching on-peak rates to coincide with the solar resource.

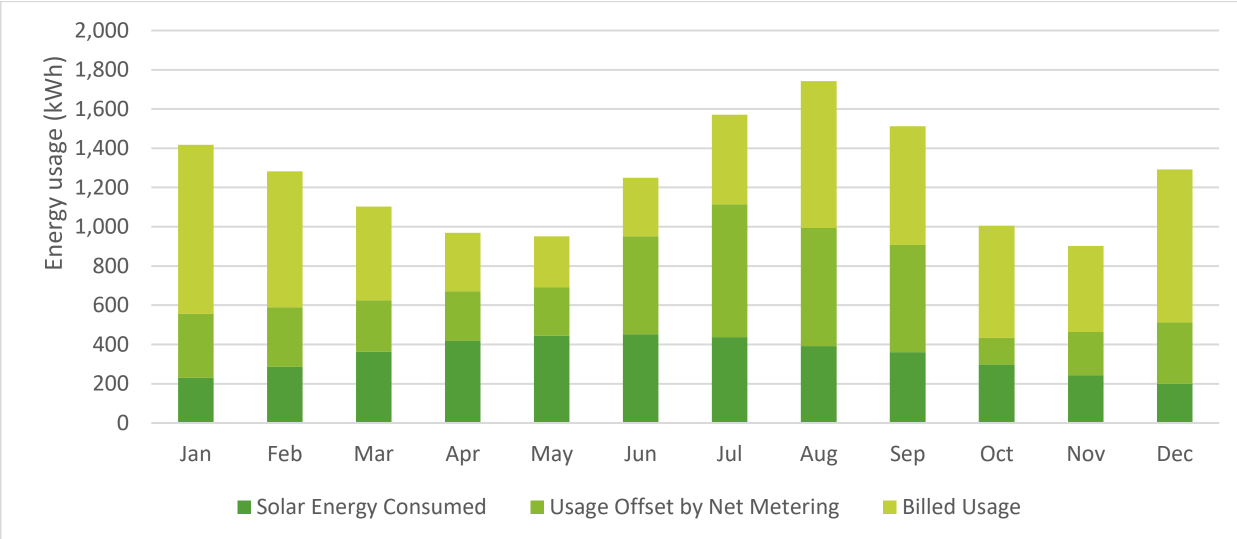
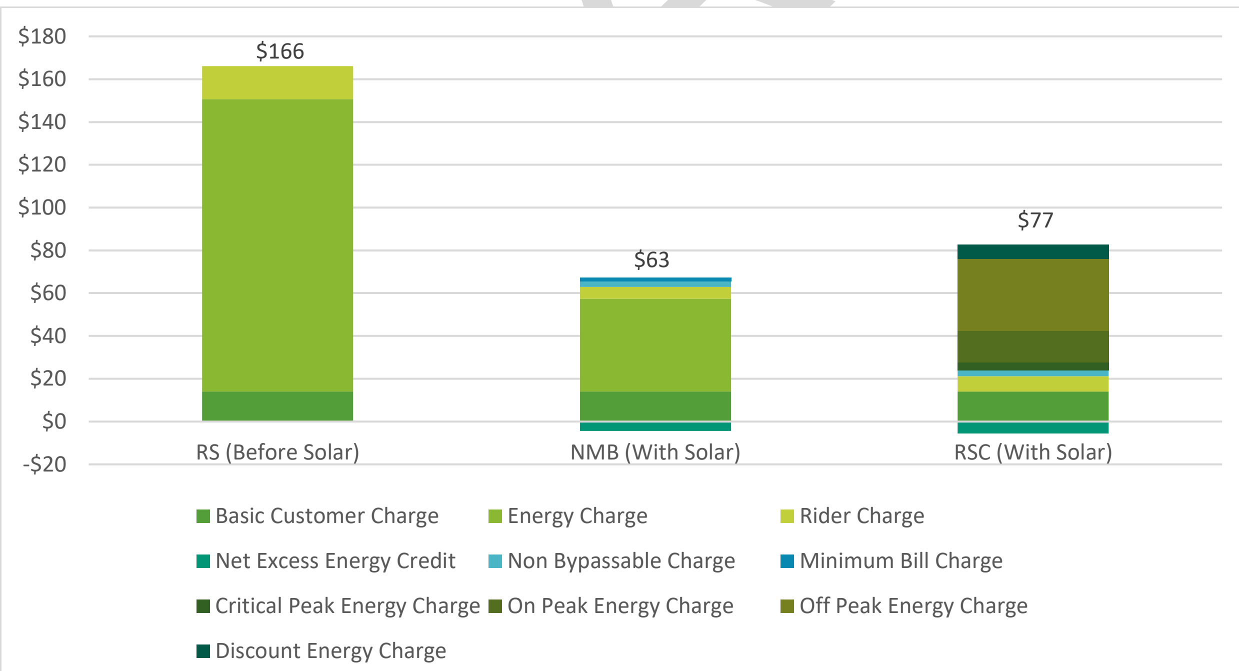


Figure 16. Example of Monthly Energy Usage for a Residential Home in DEC Territory, 8 kW-AC system



Note: See details in Table 22.

Figure 17. Example of Energy Bill for a Residential Home in DEC Territory, 8 kW-AC system, with a Monthly Energy Consumption of 1,250 kWh[74]

[74] Duke Energy, *Solar Bill Savings Estimator*, 2024. https://solar-estimator.duke-energy.app/estimate?jur=NC01&_gl=1%2Auain17%2A_ga%2ANzk3NzkyMDgyLjE3MDU5NDMyNDk.%2A_ga_HB58MJRNTY%

Table 22. Details of Example of Energy Bill for a Residential Home in DEC Territory, 8 kW-AC system, with a Monthly Energy Consumption of 1,250 kWh

Monthly Bill	RS (Before Solar)	NMB (8 kW-AC Solar PV System)	RSC (8 kW-AC Solar PV System)
Basic Customer Charge ($)	14	14	14
Energy Charge ($)	136.68	43.45	0
Critical Peak Energy Charge ($)			3.78
Peak Energy Charge ($)			14.81
Off-Peak Energy Charge ($)			33.7
Discount Energy Charge ($)			6.69
Rider Charge ($)	15.47	5.47	7.16
Net Excess Energy Credit ($)		-4.4	-5.59
Non-By-Passable Charge ($)		2.69	2.69
Minimum Bill Charge ($)		1.64	0
Total Bill ($)	**166**	**63**	**77**

5 Net Metering in Puerto Rico

5.1 Past and Present

5.1.1 Legislative Timeline

Net metering was first established in Puerto Rico in 2007 by the *Puerto Rico Net Metering Program Act*.[5] Installations of up to 25 kW and 1 MW were permitted for residential and commercial customers, respectively. The original text did not contain any expiration date for the policy. Since then, NEM, along with the power system itself, has seen a series of legislative updates. A bill in 2012 increased the limit on system size of up to 5 MW for commercial and industrial customers.[75] The *Puerto Rico Energy Transformation & RELIEF Act* of 2014 was aimed at increasing the efficiency and transparency of the electric system broadly. This legislation included provisions for improving the interconnection process by removing obstacles and expediting small generators.[4] In 2018, the sale and disposition of assets belonging to PREPA was authorized.[76] Most recently, in 2019, net metering was guaranteed for an additional 5 years (extended to 2024) and Puerto Rico's goal of achieving 100% renewables by 2050 was written into legislation. (Figure 18 provides an overview of legislative events related to net metering in Puerto Rico through 2019.) The rate was also expanded to include fuel charges incurred by PREPA.[77] On June 1, 2021, LUMA took over the operation and maintenance of Puerto Rico's

2AMTcxNTA5MDcxMi40LjEuMTcxNTA5MTYyOC4wLjAuMA..&_ga=2.134092295.807605785.1715090713-797792082.1705943249.

[75] S. B. 2472, No. 103-2012. 2012. https://bvirtualogp.pr.gov/ogp/Bvirtual/leyesreferencia/PDF/2-ingles/0103-2012.pdf.

[76] *Puerto Rico Electric Power System Transformation Act*, Act. No. 120 of June 21, 2018, as amended. https://bvirtualogp.pr.gov/ogp/Bvirtual/leyesreferencia/PDF/2-ingles/120-2018.pdf.

[77] *Puerto Rico Energy Public Policy Act*, Act. No. 17 of April 11, 2019. https://bvirtualogp.pr.gov/ogp/Bvirtual/leyesreferencia/PDF/2-ingles/17-2019.pdf

electric power transmission and distribution system from PREPA under a 15-year contract.[78] Despite the series of legislative updates, the technical and financial structure of NEM has not fundamentally changed since its inception. The payment structure for NEM customers has remained the same—they are paid for net injections at the rate they pay for net withdrawal.

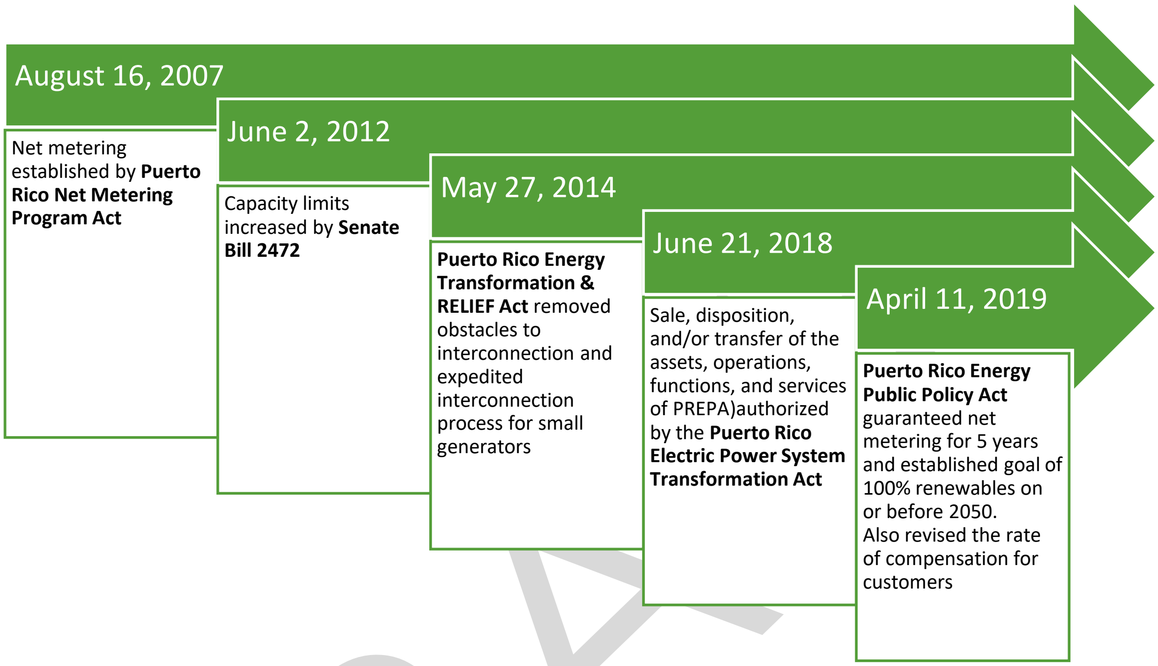


Figure 18. Overview of Legislative Events Related to NEM in Puerto Rico

5.1.2 Eligibility

There are no limits on which customers are eligible for NEM. Previous proposals have suggested some customers who already receive subsidies (e.g., low-income customers[79]) should not be eligible for NEM. These proposals were rejected by Puerto Rico Energy Commission and NEM remains open to all customers with renewable generation. [5,79] In addition to complying with various agency and environmental standards, the system must meet the following:

- System size <25 kW residential, <1 MW non-residential distribution interconnected, <5 MW non-residential transmission or sub-transmission interconnected
- Electrically connected behind the meter
- Installed by licensed engineer or expert electrician
- Be guaranteed for at least 5 years by the manufacturer
- Used primarily to offset customer's energy demand

[78] Galford, C., "LUMA Energy Takes over Operation of Puerto Rico's Electric Transmission, Distribution System," *Daily Energy Insider*, June 2, 2021, https://dailyenergyinsider.com/news/30526-luma-energy-takes-over-operation-of-puerto-ricos-electric-transmission-distribution-system/

[79] Commonwealth of Puerto Rico Puerto Rico Energy Commission, *In RE: Review of Rates of the Puerto Rico Electric Power Authority, Case No. Cepr-Ap-2015-0001 Subject: Submission of "Legal Issues"*, October 2017.

5.1.3 Current Rates

Utility customers in Puerto Rico pay a fixed monthly customer charge and a base electricity rate (both of which vary by customer class) in addition to several riders (which are the same for all customers and charged on an energy basis). General residential service is provided at \$0.04944/kWh for the first 425 kWh consumed and \$0.05564/kWh for additional consumption per month.[80] The rate charged to customers is the sum of that service rate plus each of the riders listed in Table 23. Each rider is designed to recover the cost of grid-operations expense. The general formula for calculating each is shown in Equation 1:

$$\frac{Cost\ Incurred\ + Previous\ Period\ Reconciliation}{Applicable\ Retail\ Sales}$$

Equation 1

The applicable retail sales for each are the net energy sales to all classes of customers (inflow - outflow).[80] In accordance with the 2017 Final Rate Order, the fuel charge adjustment (FCA), and purchased power charge adjustment (PPCA) factors are updated quarterly, while the help to human subsidies (SUBA-HH), non-help to human subsidies (SUBA-NHH), and contributions in lieu of taxes adjustment (CILTA) are updated annually.[79] In addition to volumetric energy charges, there is also a monthly customer charge. For residential customers, this is \$4/month.[81] The fixed charge generally recovers the cost of having a customer with net-zero energy consumption, including transmission and distribution, switchyard, substation, transmission transformers, protection breakers, sub-transmission network, transmission lines, distribution lines, vegetation management, service drops, meter maintenance, meter reading, billing, and customer service, etc.[79] While the base service rate is different for certain classes of residential customers, only the fixed block of the residential fixed rate for public housing is exempt from the riders below.[80] The other types of residential service include residential fixed rate for public housing, lifeline residential, and residential service for public housing projects. The monthly and base energy charges are highest for general residential service and lower for each of the other three kinds of service.[80]

[80] LUMA, *Current Rates for Electric Service in Puerto Rico Tariff*, 2024. https://lumapr.com/current-rates-for-electric-service-in-puerto-rico/?lang=en.

[81] Certain groups of residential customers pay a lower customer charge. Public housing residents can access a fixed rate, which is exempted from many of the charges listed in Table 23. For commercial and industrial customers, the fixed charge is much higher, ranging \$5–3,500/month depending on voltage and demand. Large industrial services (demand >12,000 kW) pay a monthly minimum of at least \$72,450.[80]

Table 23. Summary of Additional Customer Charges for Retail Electricity

Charge Name	For recovery of:	Average Rate (SD) [$/kWh]
FCA	Cost of fuel consumed by generating units on a quarterly basis	0.1183 (0.436)
PPCA	Cost of purchased sources of energy and capacity for the three forecasted months in the quarterly time period	0.374 (0.082)
SUBA-HH	Costs of subsidies providing help to humans: Credit for Consumption of Electrical Equipment Necessary to Preserve Life Residential Service for Public Housing Projects Rate Lifeline Residential Service Rate (Nutritional Assistance Program) Residential Fixed Rate for Public Housing under Ownership of the Public Housing Administration Residential Fuel Subsidy Public Lighting (Municipal) Puerto Rico Energy Bureau Assessment	0.122 (0.019)
SUBA-NHH	Costs of other subsidies: Analog Rate to the Residential to Churches and Social Welfare Organizations General Agricultural Service Credit for Incentives to the Tourism Sector (Hotel Discount) Residential Rate for Communal or Rural Aqueducts Credit to Small Merchants in Urban Centers (Downtown 10% Subsidy) Residential Rate to Common Areas of Residential Condominiums Act 73-2008 Industrial Tax Credit Irrigation District	0.009 (0.003)
CILTA	The total payment of contributions in lieu of taxes, which includes the qualifying municipalities consumption, excluding public lighting	0.060 (0.017)
Energy Efficiency	Expenses associated with the implementation and administration of energy efficiency programs	0.000 (0.000)

Note: Data is from LUMA;[80] Riders are variable depending on total demand and cost amount.

NEM customers in Puerto Rico are charged based on their net consumption and are compensated for excess generation at their otherwise applicable retail rate. In other words, exported energy is credited at the same rate at which the customer buys it.[5] The rate includes the additional charges listed in Table 23. In the original legislation, the compensation rate for NEM customers was set at the greater of $0.10 kWh and the price of electricity less the costs of fuel and energy.[5] Subsequent amendments revised the rate to be the “value of such energy according to the customer’s applicable rate.” [5,77] While the legislation calls for compensation based on the value of energy, non-energy components are included in the current compensation rates. For example, to the extent that customers produce power under NEM, the customer avoids contributing to the “cost of subsidies to help humans.” Thinking ahead, if the PREPA Plan of Adjustment Legacy Charge is collected through volumetric energy charges, should that cost recovery be avoided by customers receiving NEM?

In each billing period, either the net kWh for billing is positive (net import from the grid) or negative (net export). Customers are not compensated monthly for net exports. The excess is banked—applied as a credit to the following month's bill (reducing the net import). As a result, no negative electricity bills are issued except at the year-end reconciliation.

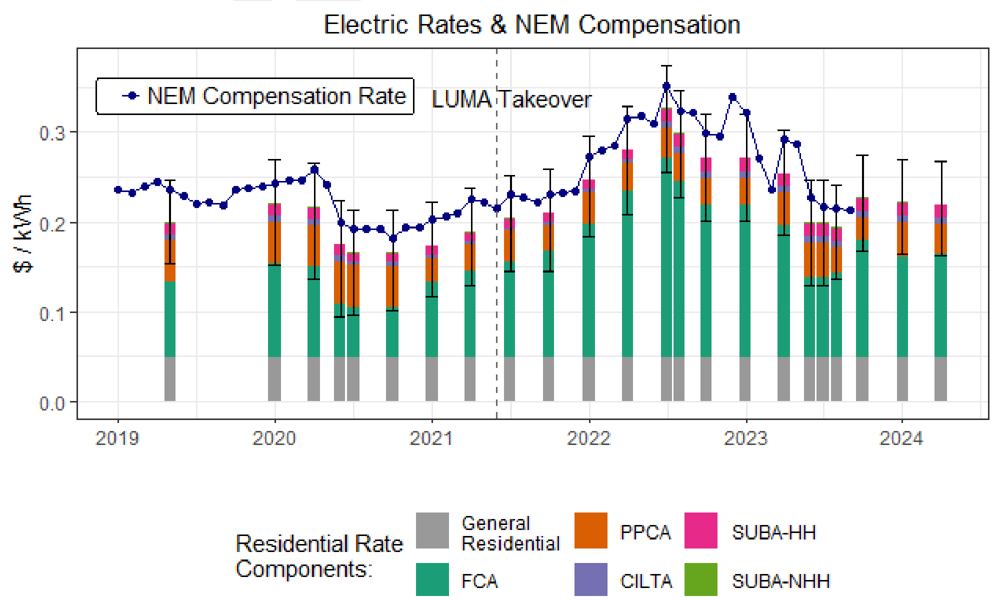
The rollover of credits bank is reconciled at the end of the fiscal year (June 30th). At that time, LUMA credits the customer's bill for 75% of the banked excess energy at a rate equal to the applicable rate less fuel and purchased power charges or $0.10/kWh—whichever is greater.[79] The remaining 25% of excess energy is distributed by PREPA as credits to the accounts of public schools.[79]

5.1.4 Charges

No additional charges are assessed on customers served under the NEM service. In fact, the original legislation from 2007 contains specific language to limit the ability of the electric system operator to increase charges in the future:

> The Electric Power Authority or the transmission and distribution network Contractor shall not impose any charge or modify the monthly electric power usage consumption rate of its net metering customers, or customers who interconnect any distributed generation system, without prior authorization from the Bureau as provided above. Likewise, the rate approved by the Bureau for net metering customers shall not be discriminatory or discourage entering into net metering agreements. No direct or indirect charge shall be imposed on the generation of renewable energy by prosumers.[5]

However, NEM customers are not exempt from the monthly minimum customer charge and they cannot have negative bills. The components of current NEM compensation and how they have changed are illustrated in Figure 19.



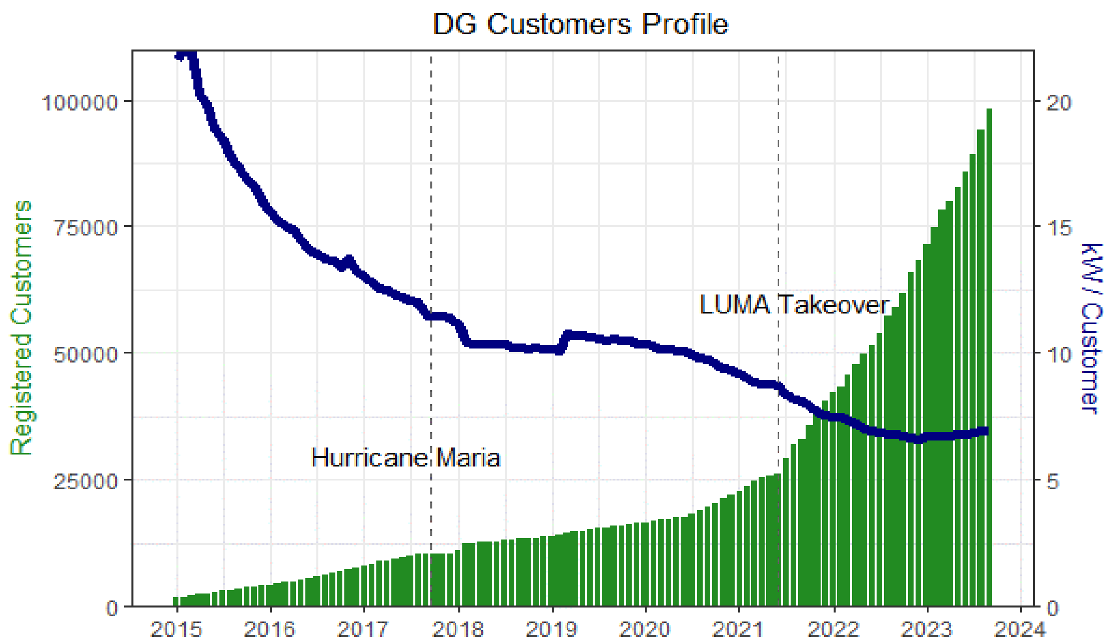
Note: Positive error bars capture customers with higher base monthly energy charges. Negative error bars show the rates of customers with a lower base monthly energy charge and those receiving a fuel oil subsidy.

Figure 19. General Residential *Electric Rates (Stacked Bars) and NEM Compensation Rates*

5.1.5 Adoption Overview

While the number of NEM customers grew steadily following hurricane Maria (2017), there has been substantial acceleration in the last several years (see Figure 20). Since LUMA took over grid operations in the summer of 2021, the number of distributed generation customers has more than tripled, passing 75,000 in 2023. Simultaneously, the average customer system size has decreased—reflecting an increase in smaller systems. The average system size appears to have settled around <7 kW as of the end of 2023 (see Figure 20).

Residential solar installations in Puerto Rico are either purchased directly by the property owner or financed through a power purchase and operations agreement (PPOA). The physical location of the system may be the same, but for PPOAs, a developer manages the upfront planning and costs of the system. In exchange, the homeowner pays the PPOA a fixed rate for electricity. Consistent with the increasing number of systems (see Figure 20), the energy exported to the grid from distributed PV has also been increasing (see Figure 21).



Note: Green bars represent the number of customers while the blue curve shows the average system size.

Figure 20. Puerto Rico Customer Adoption Characteristics

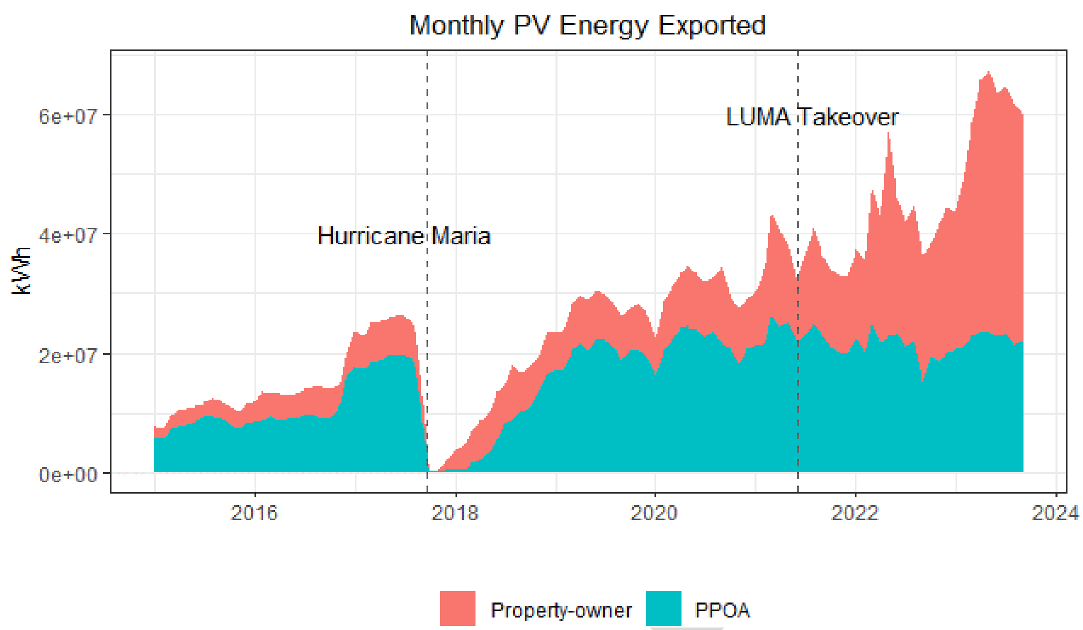


Figure 21. Energy Exported to the Puerto Rican Grid from Distributed PV Resources

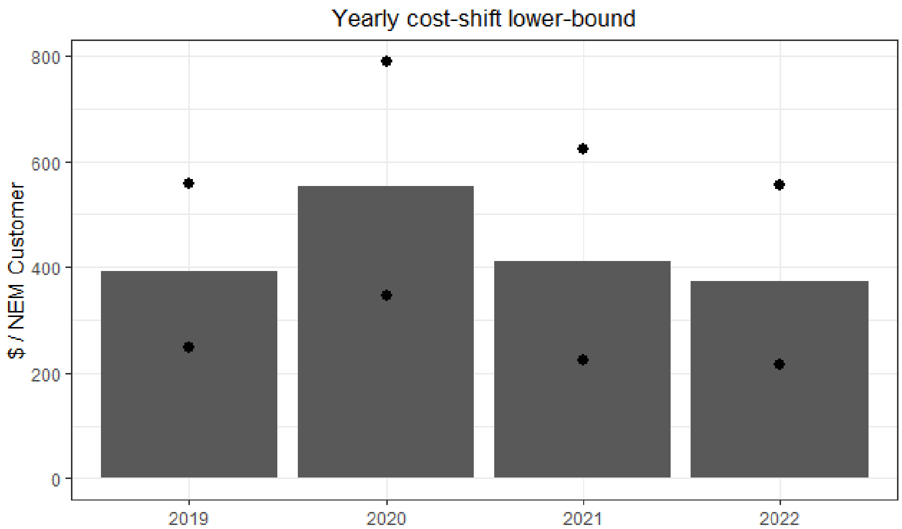
5.1.6 Cost Shift

The difference between the compensation paid to NEM customers and the customer's value of service to the grid results in a revenue shortfall to the grid operator. The shortfall is then collected largely (if not completely) from customers who do *not* participate in the NEM program, defined as a cost shift in Equation 2:

$$\text{Cost Shift} = \begin{pmatrix}\text{Retail}\\ \text{Rate}\end{pmatrix} - \begin{pmatrix}\text{Value of system energy savings}\\ \text{from customer generation}\end{pmatrix} \qquad \textbf{\textit{Equation 2}}$$

Each customer (NEM or not) consumes some amount of energy from the grid. This consumption is used as the basis for recovering various costs incurred by the utility (see Table 23). From the utility's perspective, a NEM customer only has net consumption. Assuming the gross consumption of NEM customers does not increase upon the installation of solar, their net consumption will be smaller than before adopting NEM. Since NEM customers are not compensated (in the same month) for exports exceeding their consumption, the decrease in net consumption is at least as large as their qualified exports to the grid. Thus, a lower bound for the cost shift per NEM customer can be calculated based on qualified exports, and the rates for riders, which are not avoidable.[80]

In the short-term, only the FCA decreases as the penetration of renewables increases and the grid operator needs to buy less fuel. The PPCA may also decrease over time as the operator needs to buy less energy, as a result of increasing NEM production and power from other contracts. However, the underlying cost of the remaining riders (see Table 23) does not decrease. As the applicable retail sales shrink, the cost paid by the remaining customers increases. A lower bound for the cost shift is estimated to be around $400/NEM customer/year (see Figure 22). This calculation calculation only includes the amount not recovered through rates, but leaves out the additional compensation paid to NEM customers at fiscal year end. From 2019 through 2022, the cumulative cost shift was $48,746,482. If NEM customers continue to sign-up at the rate seen since LUMA took control of operations, there should be ~285,000 registered customers by 2030. Given the average cost shift per NEM customer per year (see Figure 22), this would amount to an additional cumulative cost shift of $621,638,065[82] from 2023 through 2030.



Note: Bars represent customers on a general residential service rate. Points above and below each dot assume all consumers pay the maximum and minimum base rate, respectively.

Figure 22. Estimated Cost Shift Based on NEM-Qualified Net Exports and Riders That Are Unavoidable Energy Costs

5.2 Looking Ahead

LUMA has commenced the deployment of federally funded advanced metering infrastructure that will benefit all electricity customers,[83] and currently the Energy Bureau is considering LUMA's proposed requirements for IEEE Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces (IEEE STD 1547-2018)-compliant smart inverters to interconnect inverter-based resources to the distribution system.[84] An opportunity exists, through leveraging these technologies, to pay for discrete grid support services provided by DERs. Paying for discrete grid support services could better align the operational benefits derived by the integration of DER to the electric system. A compensation schedule for grid support services could enhance the compensation opportunities for those owning DER that pledge certain capabilities to the system operator. It is

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[82] This value was calculated based on the historical (2018-2023) dollars of cost shift per customer (estimated based on the methodology discussed above) and the projected number of future customers given adoption rates since June 2021. If we used the adjustment clause data from: Resolution and Order, *In re: Puerto Rico Electric Power Authority's Permanent Rate,* (NEPR-MI-2020-0001, issued on June 11, 2024) the estimate would decrease to $589,609,918. I the rate of adoption increase, the level of rate shift would also increase.

[83] Federal Emergency Management Agency, "FEMA Approved Project to Replace 1.5 Million PREPA Meters," December 10, 2023. https://www.fema.gov/press-release/20231211/fema-approved-project-replace-15-million-prepa-meters

[84] Puerto Rico Energy Bureau, *NEPR-MI-2019-0009, Interconnection Regulations*, 2016. https://energia.pr.gov/numero_orden/nepr-mi-2019-0009/

recommended that the Energy Bureau seeks to identify what DER grid services could qualify for compensation. Third-party DER grid-support, coordinated with the system operator, is the basis of integrated distribution planning and if adequately executed, can result in a more cost-effective solution when compared to other grid-support approaches that do not employ third-party facilities.

6 THE UNIQUENESS OF THE PUERTO RICO CHALLENGE

It is important to consider the case studies and findings of this report in context. Puerto Rico has a challenge in working to build a renewable future. DERs on customer premises are expected to be a significant part of that future, but how much, in what way, and at what price? The evidence is that the current program, if continued at its same pace through 2030, will result in non-NEM customers subsidizing NEM customers by over half a billion dollars. Importantly, NEM power is expensive—more so since the power is not dispatchable and is provided as must-take (the impact of which has not been evaluated in this report).

This report provides information on the evolution of NEM in other jurisdictions around the country. There are many valuable lessons, including the idea that NEM programs (e.g., in California) have failed basic benefit cost tests. But Puerto Rico is facing very different conditions than the mainland states. It is important to recognize some of the differences and similarities, which may limit and shape Puerto Rico's options.

6.1 HOW PUERTO IS DIFFERENT FROM THE MAINLAND

Puerto Rico is in a very different electric situation than the mainland states. Each of the states on the mainland are part of one of the three continental grid interconnections (see Figure 23). The geographic scope provides diversity in the renewable generation and has significant capacity and reserves that enable system support in the event that there is insufficient generation in one part of the interconnection. The interconnection also provides a state the opportunity to pay other states to take their excess solar generation when production exceeds demand. The inefficiencies associated with NEM in California have led them to adopt new pricing mechanisms that have reduced payment to NEM customers by moving to NEB. In fact, all of the states that have had substantial success in developing DER through NEM have largely moved to NEB.

Another important factor in comparing NEM in Puerto Rico with the mainland states is that, currently, Puerto Rico's electric rates are higher than any of those states. As a consequence, the rates based upon retail rates will be higher in Puerto Rico than those states.

The mainland states have better information on the regional value of electricity than Puerto Rico does. Many of the mainland states are part of organized markets that provide locational based marginal costs that provide detailed geographic specific information on the market price of electricity. In addition, the organized markets have different forms of capacity markets, which provide an estimate of the market value of electricity. In states where the utilities are not part of organized markets, those utilities operate sophisticated power dispatch centers that provide detailed pricing information. Under PREPA, the development of sophisticated dispatch lagged—a situation that LUMA is working to rectify.

An additional factor in comparison with the mainland is that consumption per capita is only one-fourth that of the average in the U.S. states. How that demand will grow over time will affect the benefits and costs of alternative mechanisms for pricing solar on customer premises.

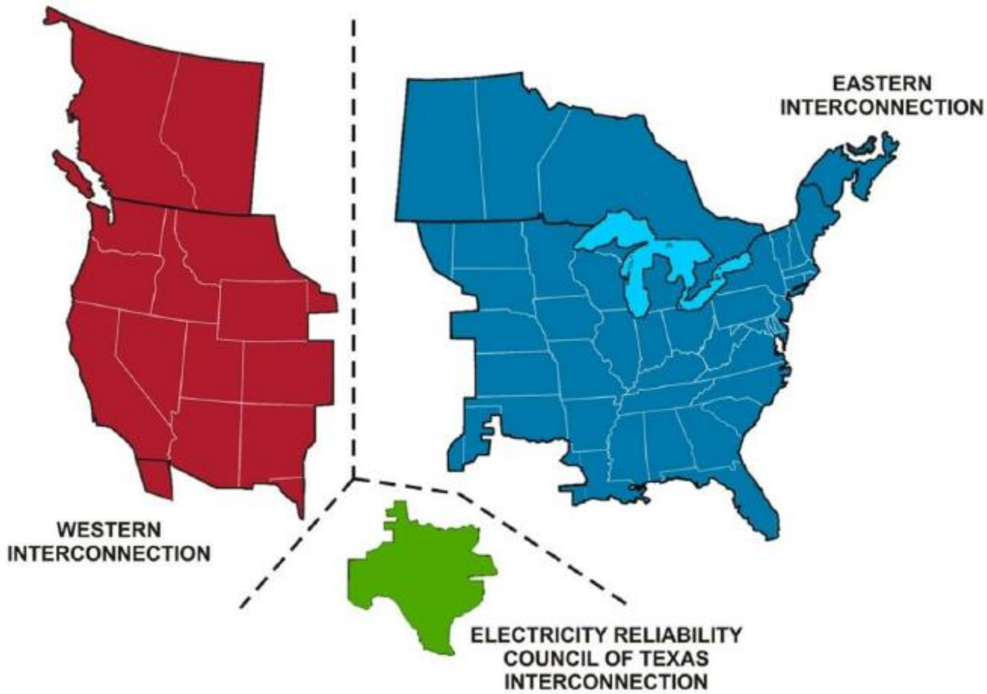

Figure 23. The three mainland U.S. interconnections

6.2 Puerto Rico and Hawaii Energy Comparison

Puerto Rico and Hawaii have many things in common regarding their energy systems. Most crucially, they are both islands with limited resources and lack of interconnection to other systems. This makes developing an energy strategy that maintains a stable grid, provides sufficient electricity, and makes containing costs more difficult than the mainland. Although these two islands face similar challenges, many things set them apart from each other.

Hawaii's current objective is to generate electricity from 100% renewable sources by 2045.[85] In 2023, the state generated 31% of its electricity from renewables, and of these, 19% was from solar power. Most of that 19% solar generation was from small-scale, customer-sited solar systems. While Hawaii is in the process of establishing a robust renewable energy system, it still relies on petroleum for about four-fifths of its total energy consumption. Hawaii has the highest average electricity prices (see Table 24), nearly triple that of the U.S. average.

85 EIA, *Hawaii State Energy Profile*, April 18, 2024. https://www.eia.gov/state/print.php?sid=HI

Puerto Rico has a policy of achieving 100% renewable sources by 2050.[86] Currently, the territory generates 94% of its electricity from fossil fuels. In 2022, petroleum-fired generation accounted for 63% of its electricity generation, the remaining 23% came from natural gas, 8% from coal, and 6% from renewables. The coal-fired generation is scheduled to be retired by 2028.

Puerto Rico has the highest average electricity price in the U.S., except for Hawaii (see Table 24).

Table 24. Hawaii, Puerto Rico, and U.S. Average Electricity Prices

Price Category [$/kWh]	Hawaii	Puerto Rico	U.S. Average
Residential	0.4393	0.2217	0.1610
Commercial	0.4082	0.2435	0.1281
Industrial	0.3634	0.2249	0.0781

Several federal programs are currently funding or will fund the deployment of mainly rooftop solar and energy storage throughout the island. It is expected that this deployment will significantly increase adoption of these facilities. To maximize benefit from these federally funded programs, it is necessary to evaluate how these facilities, e.g., distributed energy storage, can also support the grid as a whole. Consideration of how federally funded distributed energy storage could be employed by the system operator during periods of peak demand could result in increased system stability, thus, maximizing the operational benefit of the awarded federal funds. A program similar to the HECO's Battery Bonus could be designed to make this federally funded distributed energy storage available to the system operator during periods of peak demand to increase system stability. Determinations regarding if/how this peak-shaving service will be compensated—noting that these facilities are provided to the customer at no/reduced cost—will need to be made.

7 Questions to Facilitate Creating a Robust Regime for Compensating Solar Plus Storage

NEM is a pricing mechanism that has spurred the solar revolution. It was adopted because it was convenient. States that were early adopters of NEM have largely shifted to NEB. Puerto Rico has one electrical disadvantage over the 48 mainland states: it is not interconnected. So, like Hawaii, it must find innovative approaches to compensating DERs in a way that recognizes their operational value to the system. As described earlier, NEM does not do this. The question then, is what does a robust regime of compensating solar look like? Answering this, and its many sub-questions will help provide the Energy Bureau with the tools that it needs to develop pricing mechanisms that support the continued development of distributed solar and storage in an equitable and efficient manner.

What is the objective of NEM? NEM is only one mechanism that will be used to achieve Puerto Rico's energy future. This report has outlined what the authors believe are Puerto Rico's objectives—some may have been overstated, some understated. We look forward to a robust discussion of Puerto Rico's objectives.

[86] EIA, *Puerto Rico Territory Energy Profile*, February 15, 2024. https://www.eia.gov/state/print.php?sid=RQ

- Maximize the value to Puerto Rico of DER resources being deployed
- Use DER as an asset to maintain bulk electric system and local distribution reliability
- Assure that the prices paid for power exports are just and reasonable
- Meet equity goals
- Assure adequate revenues to support DER development to meet renewable goals
- Provide customer protection

7.1 System Planning & Operation

What are the technical capabilities of distributed solar and how can distributed solar and storage contribute to maintaining an electrically secure system? Technology has moved on since the early days of NEM in the late 1970s. Metering is now more sophisticated, enabling increased system control, and more detailed data for billing. The adoption of smart meters in Puerto Rico will increase the ability to adopt more sophisticated pricing mechanisms that support Puerto Rico's renewable energy goals.

How do current metering systems deployed in Puerto Rico affect the ability to implement different distributed solar pricing mechanisms?

What role should distributed solar play in supporting the island's transformation to an electric system that is 100% renewables? The National Renewable Energy Laboratory's "PR100 report" outlined three scenarios for DER solar deployment in Puerto Rico:

> Scenario 1. Economic adoption of DERs based on financial savings and the value of backup power to building owners, and prioritized for critical services like hospitals, fire stations, and grocery stores.
>
> Scenario 2. Equitable deployment of DERs expanded beyond Scenario 1 to include remote and very low-income households.
>
> Scenario 3. Maximum deployment of DERs on all suitable rooftops at a level that meets their critical loads.[87]

The above question needs to be addressed in the context of the other renewable resource options available to Puerto Rico. The PR100 report found that:

- Renewable energy potential assessed for Puerto Rico exceeds the current and projected total annual loads by more than tenfold through 2050.
- The technical potential of mature technologies—utility-scale PV, distributed PV, and land-based wind—is sufficient to achieve Puerto Rico's renewable energy goals.[87]

Are pricing mechanisms that provide access to control of batteries warranted and, if so, what are the benefits and costs of different options?

[87] National Renewable Energy Laboratory, "Puerto Rico Grid Resilience and Transitions to 100% Renewable Energy Study (PR100) Final Report," U.S. Department of Energy, March 2024. https://www.nrel.gov/docs/fy24osti/88384.pdf

7.2 COMMUNITY CONSIDERATIONS

Does community solar warrant a separate rate class, and if so, what pricing mechanisms are needed? The current NEM program focuses on individual customers. A large population is currently unable to access renewable energy, e.g., people residing in apartments, people living in dwellings with roofs that are structurally sound, and people in dwellings with electric wiring that may need updates to conform to code. Community solar can virtually supply these underserved customers. One way to do this is to establish a new rate class with rules on how to account for community facility injections and customer consumption. The advantages and disadvantages of establishing a new rate class need to be understood.

7.3 CUSTOMER IMPACTS

What information is needed about individual solar installations to understand equity? Currently, there is little information about the demographics of participants and their financial arrangements with providers. Demographic information of NEM customers would provide information about whether distributed solar is being developed equitably.

What is the nature of cost shift in Puerto Rico? How is it expected to grow?

What information is needed to provide customer protection? Solar is a unique investment for which most customers have no prior experience. As a consequence, there is an information asymmetry between the solar providers and the customer. The Energy Bureau has an interest in customer protection and it would be prudent regulation to know whether customers with purchase power agreements are being charged just and reasonable rates. For example, California collects extensive data on DG solar systems to support the administration and evaluation of the NEM program and inform future policymaking. The dataset includes system properties (e.g., size, tilt, location, pre-incentive cost), interconnection times (application received, completed, and approved dates), third-party ownership details (self-installed, power purchase agreement, lease, or pre-paid lease), and related equipment information (storage size, electric vehicle count). Additionally, system production data is collected for a subset of customers, enabling detailed analysis of program performance.

7.4 RATES

How will the implementation of NEM affect the cost recovery of PREPA's bankruptcy, in light of the United States Court of Appeals for the First Circuit Decision dated June 12, 2024?

What price is necessary to support investments in distributed solar plus storage? In economics, there is an axiom that more is preferred to less. But how much is enough to support the development of distributed solar plus storage? Should customers be paid for the full cost of the installation, or is there is a reliability value of having solar for which customers already have an incentive to pay? A starting point of this analysis is an understanding of the actual cost of providing solar plus storage in Puerto Rico.

How will NEM rates need to be modified to eliminate cost shift?

What are the important considerations for designing a transition plan for modifying the current NEM mechanisms, if it is modified?

What is the capacity value of distributed solar? Good electricity has two components: energy (flow) and capacity (stock). The capacity component plays a vital role in maintaining the reliability of the system. It does so by ensuring that adequate resources are available to serve expected demand, and it also does so to provide physical support to the operation of the system. The latter may be particularly important in the more electrically remote areas of Puerto Rico. Understanding this value provides the basis for developing an equitable and efficient pricing system for solar.

What are the current avoided costs of the Puerto Rico system? How are they calculated and how might they change in the future?

What changes are warranted with respect to retail rate design? Each of the states investigated in this report have long-standing regulatory relationships between the utility and state PUC. In this relationship, rates have been developed over time, based upon the regulatory requirements of the utility and cost-of-service studies. The cost-of-service studies that explicitly account for when and how NEM customers use and produce electricity will provide information on whether NEM customers are paying their cost of service, or whether and to what extent they are being subsidized by non-participating customers.

Which bill riders are appropriately included in NEM payments? What are equity considerations for doing so?

How would a compensation schedule for grid support services be designed and implemented?

8 CONCLUSION AND RECOMMENDATIONS

NEM has been successful at spurring a rooftop solar revolution. It was implemented because of its simplicity and convenience. As the penetration of customers compensated by NEM grows, so did concerns about whether it was an efficient and equitable pricing mechanisms. These concerns warrant the development of successor pricing mechanisms.

As with the states that were early adopters of NEM, Puerto Rico will find NEM unstainable in the long-run. New methods need to explored and adopted. An impediment to doing so, is PREPA's bankruptcy and the fact that prior to its bankruptcy it had not prepared basic analysis (e.g., cost of service study) that would provide the information necessary to support the full investigation and adoption of a distributed solar plus storage pricing mechanisms that would enhance the welfare of the people of Puerto Rico.

We recommend that the Energy Bureau commence regulatory processes that will provide the answers to questions raised in this report. Such a process should begin with a public vetting of this report. We believe that a collaborative approach to developing the information necessary to fully evaluate and implement alternatives to NEM is appropriate.