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Distributional Effects of Net Metering Policies and Residential Solar Plus Behind-the-meter Storage Adoption

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Abstract

Net metering schemes (NEM), typically implemented to incentivize investment on distributed energy resources (DER), could be regressive, given that DER adopters in the U.S. are wealthier on average than non-adopters and due to the possibility that DER owners shift certain costs onto passive customers. By using a dataset containing close to 100,000 customers' half-hourly load data and income quintiles from Chicago, IL, we simulate the operation of residential solar and behind-the-meter battery systems under 20%, 45% and 70% adoption levels and calculate both resulting bills for every client in the dataset, as well as cost shifts arising from the combination of NEM and the allocation of network and policy costs (i.e., residual costs) through volumetric charges (i.e., in $/kWh). Additionally, we consider different tariff designs. Results show that the combination of NEM schemes and recovery of residual costs through volumetric charges may cause important cost shifting effects from DER adopters onto non-adopters, rising equity and fairness concerns. Firstly, under NEM schemes, we calculate that adopter customers may, on average, obtain bill reductions of 71% when installing solar or solar plus storage, whereas non-adopters can see their bills increased 18% in high DER penetration scenarios (i.e., 45% penetration). Moreover, under the same NEM schemes, 45% adoption and considering solar plus storage adoption alone, we calculate that customers from the two lowest income quintiles may suffer bill increases in the 16-19% range on average, while removing NEM schemes reduces these increases to the 11-12% range.

Keywords: Net Metering; Distributed Energy Resources; Energy Policy; Tariff Design; Residual Cost Recovery.

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1 Introduction

Given that electricity markets may involve a mix of regulated and competitive activities, prices (or tariffs) paid by end-consumers can be composed by the combination of regulated and unregulated charges.[1][2] In general, procedures used in jurisdictions to set regulated tariffs[3] that will then be passed on to consumers follow roughly the following steps:

Firstly, the total amount of revenues that companies are allowed to collect from customers in a certain period is determined[4], given their (approved) costs and a regulated rate-of-return. This process varies widely across jurisdictions, and many approaches have been proposed in order to provide efficiency incentives to companies while maintaining a reasonable regulatory cost (Pérez-Arriaga, 2013).

Secondly, the structure of the tariff is set. This entails, for instance, deciding whether tariffs would vary across time or point of connection; if tariffs would change across customer classes; if they would involve a fixed charge, a volumetric charge –in \$/kWh- and/or a capacity charge –in \$/kW-, etc.

Finally, the third step consists in deciding which types of the company's costs will be allocated to each element of the designed structure (Pérez-Arriaga, 2013).

In the face of a widespread penetration of distributed energy resources (DER) in electric grids, such as residential solar PV, batteries, electric heat pumps, etc., an inadequate tariff design (second and third steps) may have uneven consequences across different socioeconomic groups. In the U.S., owners of residential solar systems are wealthier than non-owners, given that more than 80% of solar owners belong to the top 3 income quintiles (Barbose et al., 2018). If, for instance, an important portion of utilities costs are collected through the volumetric charge of tariffs, solar adopters, whose electricity consumption from the grid is lower, would contribute less to paying for the electric infrastructure (e.g., networks), and thus, uncollected revenues would have to be obtained from other customer groups (S. Burger et al., 2019).

Moreover, other types of DERs, such as behind-the-meter (BTM) batteries, could provide an even greater opportunity to reduce electricity bills paid by adopter clients (Hledik & Greenstein, 2016). These resources allow the consumer to manage the amounts of electricity they consume from the system flexibly and could be used to further optimize their consumption. For instance, battery adopters might be able to increase their consumption in low rate hours and decrease it during times in which tariffs are higher. In addition, battery adopters might be able to reduce overall peak demand, which in some cases is subject to additional charges. In any case, batteries grant consumers greater flexibility to respond to price signals, which makes tariff design even more important in these cases.

[1] E.g., Texas, Massachusetts, Australia, the U.K. and others (M. J. Morey and L. D. Kirsch, 2016).

[2] In other cases e.g., Chile, most of California and others., even when some activities have been deregulated (e.g., generation), the tariff that end-consumers pay is completely determined or approved by the regulator.

[3] Either those that remunerate only regulated activities or those that will remunerate the complete electricity value chain.

[4] E.g., in the case of distribution companies a period of 4-8 years is common, which is called "price control".

Adding further complexity to the context, net metering (NEM) schemes are widely adopted in the U.S. and around the world in order to incentivize investment on residential solar PV systems and more recently, on behind-the-meter storage (California Public Utilities Commission, 2019; The Commonwealth of Massachusetts Department of Public Utilities, 2019). Under the most simple definition, these schemes consist on valuing net imports (i.e., consumption) and net exports of power from customers premises to the grid[5] at the full retail tariff.

In many jurisdictions in the U.S. and other countries, an important fraction of network costs are recovered through volumetric charges (Brown & Faruqui, 2014). Hence, given that NEM policies help DER adopters avoiding some of these costs, we argue that these policies may increase undesireable distributional impacts of DER adoption[6], under some tariff designs.

In this context, the present work aims at answering the following research questions:

1. How do different tariff designs combined with NEM schemes interact with different levels of solar PV and BTM storage adoption, in terms of the economic impact on adopters and non-adopters of DER?
2. How would the benefits and costs of solar and storage adoption be distributed across different income quintiles?
3. How do different tariff designs combined with NEM schemes and solar plus storage adoption interact with other aspects relevant to policy making, such as the economic value that adopters draw from the adoption of BTM storage and potential costs/benefits due to increased/decreased needs regarding network assets?

To answer these questions we structure the present document as follows:

- The following sub-sections in the present Section summarize the theoretical background on tariff design and current open questions in the literature regarding equity and fairness concerns in the subject.
- Section 2 details methods used in this work: data; assumptions; and mathematical formulation of models used.
- Section 3 summarizes results and provides the corresponding analysis.
- Section 4 provides the concluding remarks and implications of our work.

1.1 The challenge of designing electricity tariffs

As explained above, designing electricity tariffs entails deciding the format or structure as well as the cost streams allocated to each type of charge in the tariff, for each consumer. This is in essence, a complex[7] problem, since there are several, and sometimes competing objectives that a

[5] I.e., when generation exceeds consumption.

[6] I.e., benefiting high-income consumers which are normally the ones that adopt DER, allowing them to reduce their bills while increasing electricity costs for non-adopters.

[7] Or "wicked", as defined by (Rittel & Webber, 1973).

tariff design must comply with in order to be reasonably adequate for implementation and gain social acceptance.

Bonbright, 1962 is often cited as the seminal work in which the objectives or principles of tariff design were established. Later on, (Pérez-Arriaga, 2013) and others (e.g., (Rábago & Valova, 2018)) have continued to clarify and re-interpret these principles and adapt them to contemporary contexts. In any case, there are three primarily relevant principles that are common to these works: (1) revenue sufficiency (i.e., the ability of the tariff design to collect the revenues required or approved for the utility and remunerate the activity adequately); (2) equitable and fair allocation of costs across customer classes; and (3) economic efficiency (i.e., provide incentives so products are consumed by whoever benefits most from them). Other principles established by previously mentioned works are transparency, simplicity, stability, among others. In the present work, we concentrate on the first three.

Although not necessarily an easy task, there are several comprehensive works that provide guidance on how to achieve economically efficient (and revenue-sufficient) tariffs for the electricity service[8]. However, achieving a fair and/or equitable allocation of costs seems to be an open problem both in the academic and policy-making arenas (S. P. Burger et al., 2020). The following sections of this work aim at summarizing state-of-the-art recommendations for achieving economically efficient and revenue-sufficient electricity tariffs and present the main challenges that arise when dealing with equity and fairness issues.

1.1.1 Achieving economically efficient and revenue-sufficient electricity tariffs

In this work we assume that tariffs should recover the costs that remunerate the whole electricity value chain. In this context, a revenue-sufficient electricity tariff should collect from end-consumers the whole range of cost streams that stem from the electricity service: those related to electricity generation (i.e., energy, capacity and ancillary services), network investments and operation (i.e., transmission and distribution grids), electricity losses in all previous processes and any other costs that are assigned to the electricity service.[9]

In terms of economic efficiency, the guiding principle is to charge consumers as close as possible to the short-term marginal cost of their consumption (Borenstein, 2016b; Pérez-Arriaga, 2013). As we will see ahead in this Section, there are several reasons why tariffs solely based on short-run marginal costs will not be sufficient to pay for the complete supply chain of the electric service. In these cases, tariffs should be complemented by other charges that can, in theory, minimize deadweight loss of departing from marginal cost pricing (Borenstein, 2016b).

In the case of the generation segment, there are three main cost streams that should be allocated onto the final consumer: the marginal cost of generated energy[10], capacity costs and ancillary

[8] E.g., see (Borenstein, 2016b; S. Burger et al., 2019; Hogan, 2013; MIT Energy Initiative, 2016; Rivier & Pérez-arriaga, 1993).

[9] For instance, in many jurisdictions, costs of several policies related or unrelated to the electricity service are incorporated in end-consumer tariffs (MIT Energy Initiative, 2016).

[10] Captured by the wholesale price of energy in deregulated markets.

services.

The marginal cost of energy, varies over time[11] and throughout the different nodes in the system due to losses and network congestion. Ideally, this cost should be included in tariffs through a volumetric charge (in $/kWh) that mimics as close as possible the short-run marginal cost of producing and delivering electric energy to the consumer at all times and throughout all nodes in the system (S. Burger et al., 2019; MIT Energy Initiative, 2016). In reality, the latter can be difficult due to implementation costs[12] or fairness considerations.[13][14]

Capacity costs arise in certain markets as a consequence of capping the maximum value that the short-run marginal cost of energy can take, among other practical reasons (Joskow, 2008). This is a common practice among regulators and it is done in jurisdictions such as California, the Pennsylvania, Jersey, Maryland Power Pool (PJM), Chile, U.K., and others. Given this price cap, sales of energy in the wholesale market are insufficient to remunerate investment and operating costs of a sufficiently reliable electricity service (Joskow, 2008). Consequently, these markets need some form of capacity payment or capacity market to make the market whole.

These capacity costs are driven mainly by the aggregated impact of customers consumption decisions on future investments on generation capacity and thus, an economically efficient charge should take the form of a peak-coincident demand charge (S. Burger et al., 2019). This type of charges can be included in final tariffs through a $/kW term and should capture the extent to which each consumers' load contributes to the overall demand peak that may trigger the need for generation investments.

Operating reserves and other ancillary services[15] tend to represent a small fraction of generation costs (1-2%) according to some authors (MIT Energy Initiative, 2016), however, they can still provide an attractive business opportunity for distributed energy resources. Costs that stem from these services are varied and, given their relative low value, they tend to be averaged and added as an uplift to volumetric charges in end-user tariffs. Recommendations in the literature suggest that at least, these costs should be conveyed with higher time and spatial granularity (MIT Energy Initiative, 2016), in order to capture more accurately the value/costs that DER and consumers' actions may add to the system in terms of requirements for ancillary services.

In the case of network costs (transmission and distribution investment and operation), it is a widely accepted fact that it is impossible to recover them resorting solely on pricing on the basis of marginal costs. Although there are several reasons for this, the primary causes of this effect are a combination of the discrete character of investments in network assets and the presence of steep economies of scale (Pérez-Arriaga, 2013). The lumpiness in network investments triggers a

[11] Due to demand levels, available generation, network constraints and losses stemming from power flows through the grid.

[12] Given that highly granular price signals need advanced IT infrastructure to be deployed, both to deliver the signal to the end-consumer and to allow them to react to these prices.

[13] E.g., poor consumers living in rural areas with high losses may be subject to very high marginal costs of energy.

[14] In practice, policy-makers can resort to approximations to these ideal time and spatially-granular energy prices, such as time-of-use tariffs and zonal locational marginal prices (LMP) and gradually move forward with the implementation of more efficient price signals (see (MIT Energy Initiative, 2016) for further detail).

[15] E.g., black-start capability, reactive power supply, etc.

sustained difference between the optimally adapted network[16] and the real one, given that network assets will tend to go through an over-investment cycle earlier on their lifetime, depressing marginal cost-based price signals. Moreover, the presence of economies of scale makes it more efficient to perform larger investments at once, rather than building smaller and more incremental network assets on a more gradual basis. The latter increases the tendency to have an over-dimensioned grid, which in turn reduces marginal cost prices even more.

Given the latter, ideally, network costs can still be allocated using a combination of marginal cost-based prices and other measures that can reduce the economically inefficient effects of non-marginal pricing.

Figure 1 shows recommendations by (S. Burger et al., 2019; MIT Energy Initiative, 2016). As shown in the Figure, if nodal locational marginal prices are available[17], network energy losses and congestions may trigger differences on these LMP measured at the different sides of a transmission line or a distribution feeder. Consequently, differences of power injections and withdrawals in the line, valued at LMP, can be high enough to pay for energy losses and part of investment and operation costs of the asset.

Nodal LMP (either at the transmission or distribution levels) can, in theory, capture well the marginal effects of consumption and generation decisions on the short-term operation of the power system (Hogan, 2013). However, due to the causes explained earlier[18] these signals fail to capture the long-term marginal effects of these decisions[19]. Some authors argue that the latter can be captured by peak-coincident demand charges (S. Burger et al., 2019; MIT Energy Initiative, 2016). As in the case of capacity costs, these charges can be added to the final tariff in \$/kW, however in this case, ideally, the magnitude of the charge should convey the contribution of consumption/generation peaks to the need for future network investments.

As shown in Figure 1, after collecting revenues stemming from nodal LMP and forward-looking demand charges, there may be costs yet to be recovered to make investors whole. These costs are typically labelled as residual and it is very difficult to devise a way of allocating them, given that they are not "caused" by any identifiable action of any agent in the system. Other costs typically allocated onto the electricity bill, such as the cost of environmental policies or other public policies face the same issues (MIT Energy Initiative, 2016).

If only economic efficiency is the concern, then the literature suggests that a criterion based on Ramsey pricing could be used.[20] This entails assigning residual costs as fixed charges (\$/consumer) inversely to wealth demand elasticity[21] of consumers. This way, consumers that value electricity higher will pay more and deadweight loss, in theory, would be minimized (Borenstein, 2016b; S. Burger et al., 2019; MIT Energy Initiative, 2016). In practice, the strict application of the principle

[16] I.e., the one that under ideal conditions would make marginal price signals high enough to pay for all network costs.

[17] I.e., prices that convey the marginal cost of energy at the different nodes of a network.

[18] E.g., economies of scale, lumpiness of network investments and others.

[19] I.e., the potential need -or deferral of the need- for investment in network assets.

[20] See (Ramsey, 1927) for the original application of Ramsey pricing in the context of taxation.

[21] I.e., the change on electricity demand due to a change in wealth.

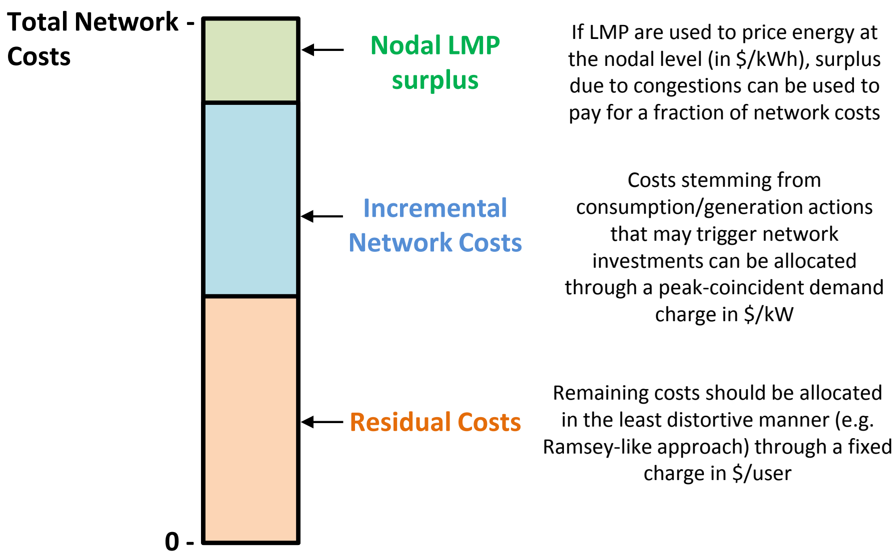


Figure 1: Economically efficient and revenue-sufficient charges for allocating network costs (MIT Energy Initiative, 2016).

can be unfeasible both due to fairness concerns and the difficulty of estimating consumer demand elasticity. Still, this criterion has been applied to some extent when utilities provide discount rates to commercial and industrial customers who can move their operations to alternative jurisdictions (Borenstein, 2016b). Consequently (and ignoring fairness concerns for now), some form of proxy for demand elasticity could be used in practice to set rates using the Ramsey rationale.

1.1.2 Achieving equitable and/or fair electricity tariffs

The concepts of equity and fairness are yet to be definitely defined in the energy economics and policy arena. However, in order to maintain a clear division across both concepts and their underlying importance in tariff design, we will use definitions provided by (S. Burger et al., 2019).

Equity is understood in this work as allocative equity as defined by (S. Burger et al., 2019). Authors of this work define allocative equity as:

"*(...) we define an allocatively equitable tariff as a tariff that treats identical customers equally (...). In practice, this has two key implications:*

1. *Marginal consumption or production decisions are charged or paid according to the marginal costs or values they create.*
2. *Residual costs are allocated according to customer characteristics that are not impacted by their short term electricity consumption or production decisions. In other words, one customer's behavior cannot cause another customer to pay more or less residual costs.*"

Firstly, note that (S. Burger et al., 2019) consider identical consumers to be the ones that make identical power consumption/generation decisions[22], which entails as a corollary, that demand elasticity could play a role in the definition of identical customers. As a consequence, a Ramsey criterion to allocate residual costs can be considered equitable under this definition.

Secondly, we underscore that an important consequence of this definition of equity, is that an equitable tariff would minimize residual costs shifts between customers.

Consequently, under this definition of equity, we can safely assume that more economically efficient tariffs will also be more equitable. As demonstrated by (S. Burger et al., 2019) using flat volumetric tariffs as a base case, more economically efficient tariffs would always reduce cross subsidies of marginal costs and cost shifts of residual costs between customers, improving equity as understood here.

Following (S. Burger et al., 2019) definition for a fair (or distributionally equitable) tariff, we understand the concept as "*(...) a tariff structure (...) (that) meets locally defined standards of social justice with respect to the distribution of goods between vulnerable and non-vulnerable customers*".

Under this definition of fairness, it is impossible to state that economically efficient tariffs would also maximize fairness, given that fairness as defined here obeys to locally defined standards of social justice which are inherently subjective. For instance, under the strict application of Ramsey criterion for the allocation of residual costs (which is both economically efficient and equitable), low-income customers that use electricity only for basic needs would pay proportionally more than wealthier customers using electricity for leisure activities, effect that could clearly be deemed to be unfair by some.

Although several customer characteristics may be used to define social justice standards and vulnerability, in this document we concentrate on income and how different tariff designs affect low-income customers (i.e., vulnerable).

1.2 Net metering schemes: definitions, objectives and controversies

Net metering is a broad term when considering the specifics of each application[23], however, in general it refers to a scheme where customers that have installed generation assets (in most cases PV systems) are billed on the basis of the net energy they consume by the end of the billing period.[24] The underlying mechanics of the strict application of this definition, imply that injections of power to the grid are valued at exactly the same price as power consumption. In contrast, other schemes such as net billing[25], consist on valuing net injections of power at a reduced monetary value compared to the full retail tariff, under the assumption that injections of power should not avoid certain costs, such as residual network or policy costs.

Probably due to its simplicity, net metering is widely used in the U.S. and many other countries as a way to incentivize investments in residential solar and, more recently, on BTM storage. In

[22] I.e., regarding time, magnitude and location.

[23] See for instance, (Hughes & Bell, 2006).

[24] That is, all energy used at their premises, minus energy generated by their generation assets.

[25] See (Zinaman et al., 2017) for an overview of different metering and billing arrangements.

effect, Figure 2 shows the adoption of NEM schemes across the different states in the U.S., where almost 80% of states have implemented mandatory NEM schemes for certain utilities.

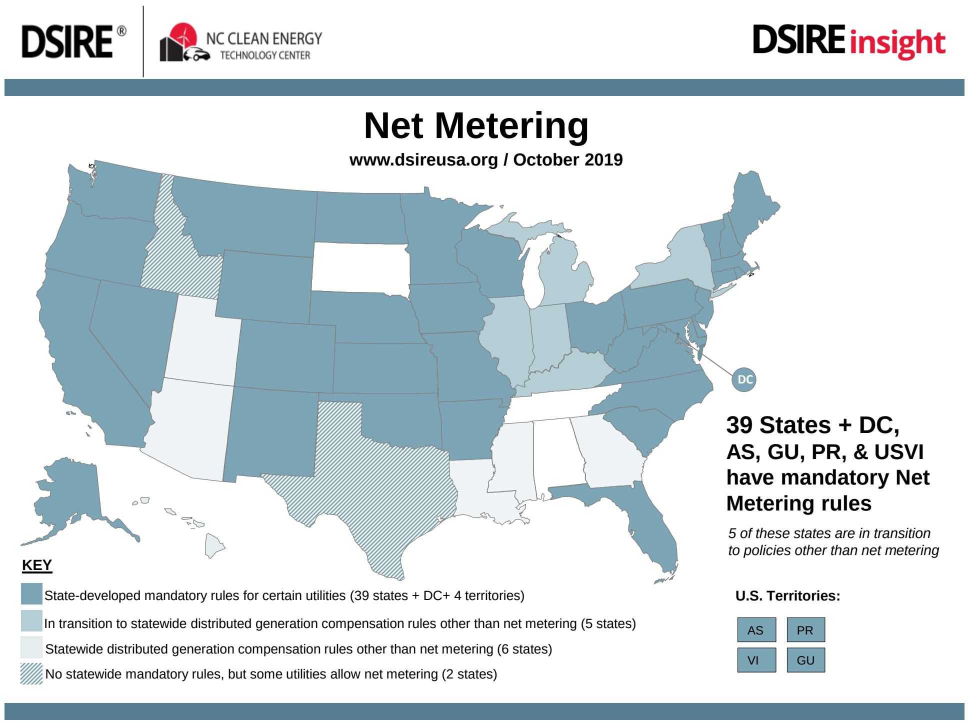


Figure 2: Net metering schemes in the U.S. (NC Clean Energy Technology Center, 2019).

Moreover, NEM schemes that have historically been applied mostly to incentivize investment in solar PV in the U.S. have been more recently extended to BTM storage. In January 2019 California issued a decision to extend net metering to solar plus storage facilities, as long as energy generated by storage assets is provided by the solar system (and not from the grid) (California Public Utilities Commission, 2019). A month afterwards, Massachusetts issued a similar decision, where it allowed BTM storage owners to be included in the state's NEM scheme, as long as the power generated by the assets is charged by a net metering facility (e.g., solar system) or charged from the grid but the storage system is unable to export to the grid (The Commonwealth of Massachusetts Department of Public Utilities, 2019).

It is important to note that under a net metering scheme and flat two-part tariffs, where charges are divided between a flat volumetric charge and fixed charges, a BTM storage system has no economic value. This is so since losses in the charging-discharging cycle would make it uneconomical to charge and discharge the asset (even in combination with a solar system). However, utilities in California and Massachusetts also offer their customers time-of-use (ToU) tariffs[26], which, in combination with BTM storage and net metering allow the solar owner to shift excess solar generation to high-price hours[27], thus increasing the value of storage in contrast to the flat tariff

[26] I.e., tariffs with volumetric charges that differ depending on the time of the day.
[27] E.g., peak hours in the ToU tariff.

case.

At the policy level, net metering is a controversial issue. Advocates of these schemes argue that distributed solar generation provides more benefits than costs and that paying the full retail tariff for solar generation approximates better (in contrast to valuing solar generation at a lower price, e.g., at the wholesale price of energy) to the overall value that the technology delivers. Among benefits cited are the creation of green jobs, reduced network needs[28], reduced environmental footprint of the energy supply (carbon emissions and local pollutants), among others (Muro & Saha, 2016; Roberts, 2016; Solar Energy Industries Association, 2020).

However, detractors typically highlight the potential risks for revenue collection on part of utilities and cross-subsidies that may arise with the policy. In effect, simplistic tariff designs[29] combined with NEM may reduce revenue collection from DER adopters, potentially requiring utilities to collect these costs from non-adopters (Tanton, 2018). Moreover, adopters have been shown to be wealthier on average (Barbose et al., 2018), which makes NEM policies regressive according to some authors (S. P. Burger, 2019). Also, this potential re-allocation of costs onto non-adopters may increase incentives to install DER and consequently increase revenue collection problems.[30]

Finally, others authors have argued that distorting economic signals may not be a serious issue when DER adoption is low. However, negative effects will increase in magnitude once DER penetration reaches more important levels, urging policy-makers to look for alternatives to NEM (Borenstein, 2016a). Adding to the latter, even advocates of NEM acknowledge that higher penetrations of DER would require a reconsideration of NEM schemes and tariff designs, given that the marginal value of DER decreases with an increasing penetration level and that costs imposed to the grid may escalate (Bull, 2015; Muro & Saha, 2016).

1.3 State-of-the-art and contributions of this work

Recently, distributional effects, cross-subsidies or cost-shifting effects of high DER penetration facing different tariff designs and billing arrangements have received relatively increased attention on part of researchers, probably given the increase of DER penetration in markets globally. However, the literature seems to be mostly focused on solar PV, with scarce insights on BTM storage. The present work aims to filling this gap.

As stated above, several authors have studied distributional effects of rooftop solar under different price designs and billing arrangements. For instance, (Simshauser, 2016) studies net load patterns of solar adopters in Queensland, Australia and concludes that these customers' load exhibit very similar peak load values in comparison to non-solar adopters, and thus, they are being subsidized by non-adopters. The author proposes considering demand charges, in addition to volumetric and fixed charges, as a way to reduce wealth transfers between adopters and non-adopters.

[28] Based on the notion that energy is being generated at the same location of consumption.
[29] E.g., recovering residual costs through volumetric tariffs.
[30] This effect has been denominated "death spiral" (MIT Energy Initiative, 2016).

Using a similar empirical model, (Strielkowski et al., 2017) concludes that in the U.K., rooftop solar penetration has led to bill increases for non-adopters. Furthermore, (Johnson et al., 2017) studies how high penetrations of rooftop solar may shift the allocation of network costs across different customer classes in the presence of net metering schemes. Based on data from New Jersey, U.S., the authors show that C&I customers, whose peak demand occurs with higher correlation to solar availability, see their bills reduced, while systemic peak shifting to the afternoon increases costs allocated onto residential consumers.

Some authors have explored the role of fixed charges as means to avoid distributional effects of solar adoption and revenue-sufficiency issues on part of utilities. For instance, (Clastres et al., 2019) forecasts that until 2021, residential solar adoption in France will cause some cost shifting onto non-adopters but concludes that the effect will not be of considerable magnitude for consumers. However, authors calculate that impacts on revenue-collection on part of utilities could be relevant and study how fixed charges can provide a solution to this issue. (Feger et al., 2017) also investigates the role of fixed charges in this setting. Using a large sample of data stemming from 135,000 customers in Bern, Switzerland, authors determine optimal tariffs that would trigger the adoption of solar PV up to certain targets and preserve equity regarding economic impacts on adopters and non-adopters. One of the principal conclusions of the study is that increased reliance on fixed charges is necessary to equalize effects among different customer groups. More recently, (S. P. Burger, 2019) studies distributional impacts of solar PV adoption in Chicago, IL, based on a large dataset of customers (close to 100,000) and suggests that progressive fixed charges could be used to reduce cost shifting effects of rooftop solar adoption.

Although there has been greater focus on solar PV, some authors have studied BTM storage in this context. For instance, based on an illustrative case study of one customer in Madrid, Spain, (Eid et al., 2014) studies revenue collection and cost shifting issues stemming from solar PV adoption, including BTM storage in the analysis. In particular, authors conclude that adding a demand charge to the tariff applied to customers may incentivize investment in storage without necessarily contributing to cross-subsidies across customers. Authors seem to assume that these demand charges allocate utilities costs that can be saved by greater self-generation of customers during these peak hours. In terms of our work, for the authors, these charges seem to allocate marginal costs onto consumers and not residual costs. We argue that it is residual cost allocation which may cause cost-shifting across customers and thus, the study fails to address the fundamental issue underlying cost shifting among adopters and non-adopters. On a similar vein, using load and income data from 1,000 customers in Vermont, U.S., (Hledik & Greenstein, 2016) studies distributional impacts of demand charges and how these charges may incentivize investment on BTM storage. The study however, does not address distributional impacts of BTM storage adoption, since it focuses mainly on revenue opportunities for storage systems depending on customers load profile and the application of demand charges. Finally, (Schittekatte et al., 2018) addresses residual cost allocation through demand charges and studies if they contribute to solving equity issues underlying the application of volumetric charges and net metering, when facing DER adoption.

Authors directly address the issue of cost shifting when consumers are able to invest in solar and BTM storage and conclude that demand charges could further equity concerns, given that they incentivize investment in BTM storage to avoid demand charges and shift sunk (i.e., residual) costs from storage adopters onto non-adopters.

The present work makes novel contributions to the literature in several dimensions. Firstly, to our knowledge, this is the first analysis to weigh distributional concerns of NEM schemes currently being applied for energy storage in jurisdictions such as California and Massachusetts. Secondly, the study involves data from nearly 100,000 customers in Chicago, IL (as in the case of (S. P. Burger, 2019)), being the first BTM storage study concerning distributional effects with such a large data set regarding income and half-hourly load profiles. Finally, to our knowledge, our study is the first to consider the interplay between time-varying energy charges, net metering (and absence of net metering) policies and solar plus storage adoption on cross subsidies among adopters and non-adopters of different socioeconomic backgrounds.

2 Methodology

The methodology used in this work is, in many ways, based on (S. P. Burger, 2019) and (S. P. Burger et al., 2020), which aimed at studying the distributional effects of solar adoption and the application of different tariff designs on customers located in Chicago, Illinois and served by Commonwealth Edison (ComEd). On our part, we depart from the latter and include storage in the analysis.

Given our desire to provide insights that are easily comparable to the seminal work of (S. P. Burger, 2019) and (S. P. Burger et al., 2020), we have used the same dataset and maintained methodological steps developed by the authors as much as possible. However, we have built upon these methods and developed some innovations to include as accurately as possible the modeling of storage operation and relevant aspects of tariff designs previously not studied in detail (i.e., net metering or absence of net metering schemes).

2.1 General description of the methodology

Our calculations involve the following five steps:

1. **DER adoption scenario, tariff design and net metering regime selection**: A fundamental purpose of this work is to calculate electricity bills that customers pertaining to each income quintile would pay, under several scenarios of solar PV and storage adoption. Consequently, the first parameters we choose for calculations are the overall adoption levels of residential solar PV systems among customers. Additionally, we assume throughout the whole study that only solar adopters install batteries and thus, the second parameter we choose for calculations is whether solar adopters have installed batteries or not[31].

[31]Our model allows the consideration of partial adoption levels of batteries among solar owners, however, to

At this stage it is also important to choose which tariff design we wish to study, which is key in customers' DER operation and bill calculations. As we will detail in Section 2.4, we used real data from ComEd 2016 tariffs to compute several tariffs designs and thus, study the different incentives and socioeconomic effects these designs produce, in combination with different NEM policies and solar plus storage adoption levels. Types of tariffs used in the present study are flat volumetric tariffs, time-of-use (ToU) tariffs and real-time pricing (RTP) tariffs, each with different cost streams recovered through volumetric and fixed charges.

Finally, at this stage we also choose which net metering scheme would operate. In this work we have defined three different schemes: NEM "On"; NEM "On-California", which mimics current NEM regime in force in California and Massachusetts; and NEM "Off". These schemes will be described in further detail in Section 2.4.

2. **Random assignment of DER ownership according to historical adoption and application DER sizing criteria**: Once we have chosen the overall adoption levels of solar and storage adoption, we proceed to randomly assign these assets across customers within different income groups. Solar adoption probabilities across different income quintiles are based on historical data provided by (Barbose et al., 2018) and scaled according to the overall adoption level chosen. Furthermore, it is not only relevant if households adopt solar or solar plus storage systems, but also, what are the technical parameters of these assets[32]. As will be detailed ahead, we assume a solar installed capacity high enough to provide for 90% of the adopter customer's yearly load.[33] For storage on the other hand, we use parameters from (Lazard, 2019) and assume that batteries installed capacity (i.e., kW) will be 60% of solar maximum power; a storage capacity equivalent to 4 hours at nominal output; and 90% round trip efficiency.

3. **Estimate power consumption and injections for all clients**: Having assigned which clients adopt/do not adopt either solar or solar plus storage systems, the next step entails calculating how much power each customer would consume/inject to the grid, when facing the chosen tariff design and NEM scheme. In the case of non-adopters, this calculation is straightforward, and we assume that their power consumption is equal to the half-hourly load data from 2016. Solar adopters on the other hand, will generate their own energy according to their installed capacity and solar resource available (i.e., solar radiation). We use solar availability data for Chicago, which has been estimated by (S. P. Burger, 2019) using the procedure roughly described in Section 2.5.

   Finally, for each solar plus storage adopter, we assume that the battery is operated so as to minimize the customer bill at the end of the year. For this purpose we assume that the customers possess perfect information regarding electricity charges throughout the whole year

maintain the analysis as simple as possible, we chose to consider storage adoption as binary (either full adoption or no adoption).

[32] I.e., nominal power output and nominal charging power, storage capacity and round-trip efficiency for storage systems.

[33] This is based on current trends in Illinois, where solar installations offset, on average 90% of customers' load (Davidson & Margolis, 2015).

and that they are able to respond to these charges by adapting the operation of their battery. Under this assumption, we use a linear optimization model (see Section 2.6), in order to calculate the minimum cost (or maximum profit) operation of the DER portfolio of each client. Given the large number of customers, we have parallelized these calculations and used a server cluster[34] to obtain results in reasonable times.

4. **Calculate preliminary yearly bills**: After obtaining the amount of energy consumed/injected by each customer at each time period, we proceed to calculate the yearly bills according to the chosen tariff design and net metering scheme.
5. **Residual costs recovery check**: As described in Section 1.1, electricity costs can be classified in two types: marginal and residual. As explained earlier, residual costs are the ones that will not vary with respect to customers behavior and thus, cannot be efficiently recovered through marginal cost-based prices[35]. These costs are usually recovered through flat volumetric charges[36] and thus, solar adoption helps customers reduce their contribution to residual cost recovery. Moreover, we assume in our calculations that all residual costs must be recovered and thus, after calculating preliminary tariffs, we need to quantify the amount of residual costs that are yet to be recovered and re-assign these costs among customers somehow.

   For the latter, we assume that all network costs in tariffs (distribution and transmission), as well as all policy costs are residual.

   Then, after calculating DER operation for all customers and computing the amount of residual costs that have failed to be recovered through bills, we assign the remainder of costs to customers through a flat volumetric charge (equal to each customer).
6. **Calculate final yearly bills**: Finally, we proceed to calculate the final bill for all customers, using the additional flat volumetric charge that would recover the remaining residual costs. One important assumption in this step, is that customers do not change their consumption/injection patterns according to this additional residual cost charge.

2.2 Customer data description

We base calculations on anonymous data from 100,170 customers served by ComEd in Chicago, Illinois, which was cleaned and provided by authors of (S. P. Burger et al., 2020).

The data include customers' load for 2016 on a half-hourly basis, each client's Delivery Service Class[37] and their 9-digit ZIP code. Delivery Service Classes are relevant in this context, since they determine certain components of each client's electricity bill, as we will detail ahead, and because in the U.S., 99% of residential solar systems have been installed by Single Family Homes (Barbose et al., 2018).

[34] MIT Engaging cluster.

[35] E.g., differences in locational marginal prices throughout the distribution network or forward-looking demand charges (MIT Energy Initiative, 2016).

[36] As it is done currently in the case of ComEd flat default tariff.

[37] I.e., Single Family Homes, Multi Family Homes, and if they own Electric Space Heating or not.

As explained by (S. P. Burger et al., 2020), ComEd applied a "15/15-rule" to the data in order to avoid any the identification of individual clients. This means that any ZIP code that contained fewer than 15 customers per Customer Service Class was removed, as well as customers that represent more than 15% of the total consumption in their Customer Service Class.

Customer income quintile data were taken from the American Community Survey (ACS) (U.S. Census Bureau, 2018), which provides data for Census Block Groups across the U.S. Authors in (S. P. Burger et al., 2020) then use a commercial dataset provided by Melissa Data (Melissa Data, 2020) in order to match each 9-digit ZIP code to the corresponding Census Block Group. After this process, 1,975 customers were discarded due to the lack of necessary data.

Table 1 shows the number of customers by income quintile and Delivery Service Class.

Income Quintile	**Income Range**	**Multi Family**	**Multi Family (ESH)**	**Single Family**	**Single Family (ESH)**	**Total**
I	\$9,250 - \$34,911	10785	736	8136	0	19657
II	\$34,912 - \$46,875	4764	555	14342	3	19664
III	\$46,876 - \$59,355	5315	1168	13130	9	19622
IV	\$59,356 - \$80,083	5743	1105	12789	15	19652
V	\$80,084 - \$234,063	7410	423	11698	69	19600
Total	-	34017	3987	60095	96	98195

Table 1: Number of customers by income quintile and Delivery Service Class in the dataset used for calculations.

2.3 DER adoption probability

In this work, DER adoption is assumed to be exogenous. In order to assign the character of adopter or non-adopter to customers pertaining to different income quintiles, we use results provided by (Barbose et al., 2018). The study investigates income trends of residential solar PV adopters in the U.S. and provides distribution of adopters by income quintile for individual states and the country in aggregate. For this study, we use country-wide values for the year 2016, which are shown in Table 2.

Income Quintile	**I**	**II**	**III**	**IV**	**V**
Fraction of Adopters	7.9%	13.1%	25.1%	28.9%	25.0%

Table 2: Distribution of solar PV adopters in the U.S. by quintile in 2016 (Barbose et al., 2018).

Fractions of adopters are used as probabilities of adoption for each quintile. Hence, for each penetration scenario, total solar PV adopters will be distributed to each quintile bin according to these values.

Regarding storage, to our knowledge, there is no study such as the latter. Hence, in our calculations we assume that either all or no solar PV adopters install BTM storage, and then compare results when needed. This simple approach will help us to show trends and fundamental issues without increasing unnecessarily the amount of scenarios reported. However, our models can be easily adapted to consider probabilities for the adoption of BTM storage, as in the case of solar PV.

Finally, we focus the analysis on solar-coupled storage and thus leave out of the study the consideration of stand-alone storage.

2.4 Tariff designs and NEM regimes

Table 3 summarizes each tariff design and the format used to recover each cost stream of electricity production and delivery and Table 4 summarizes each charge values range.

Cost stream	**Energy (generation)**	**Distribution network**	**Distribution fixed (metering and customer charges)**	**Transmission network**	**Policy**
Tariff name			**Tariff format**		
Flat	Volumetric (flat)	Volumetric (flat)	Fixed	Volumetric (flat)	Volumetric (flat)
ToU	Volumetric (3-part)	Volumetric (flat)	Fixed	Volumetric (flat)	Volumetric (flat)
RTP	Volumetric (hourly variation)	Volumetric (flat)	Fixed	Volumetric (flat)	Volumetric (flat)
RTP-Efficient	Volumetric (hourly variation)	Fixed	Fixed	Fixed	Fixed

Table 3: Tariff designs and cost allocations considered in the present study.

In order to compute each tariff, we used real tariffs charged by ComEd to customers in the year 2016.[38] In particular, our flat tariff was the default tariff for residential customers in ComEd that year, which included volumetric charges (in \$/kWh) to recover generation costs; distribution and transmission network costs; and policy costs. Also, the tariff considered a fixed charge (on a \$/client-month basis) to recover metering and other customer-specific costs.

To calculate illustrative examples of more time-granular tariffs, we also take 2016 locational

[38]See appendix C for the complete tariff dataset.

Cost stream	Energy (generation)	Distribution network	Distribution fixed (metering and customer charges)	Transmission network	Policy
Tariff name	**Charges values**				
Flat	0.046-0.055 \$/kWh (2)	0.019-0.032 \$/kWh (1) (2)	11.41-15.82 \$-mth (1) (2)	0.011-0.013 \$/kWh (2)	~0.005 \$/kWh (2)
ToU	See Figure 4	0.019-0.032 \$/kWh (1) (2)	11.41-15.82 \$-mth (1) (2)	0.011-0.013 \$/kWh (2)	~0.005 \$/kWh (2)
RTP	See Figure 5	0.019-0.032 \$/kWh (1) (2)	11.41-15.82 \$-mth (1) (2)	0.011-0.013 \$/kWh (2)	~0.005 \$/kWh (2)
RTP-Efficient	See Figure 5	16.261 \$-mth	11.41-15.82 \$-mth (1) (2)	6.37 \$-mth	2.46 \$-mth

(1): Changes with Delivery Service Class.
(2): Changes with month.

Table 4: Tariff designs and cost allocations considered in the present study.

marginal prices (LMP) at ComEd's load zone[39] and calculate time-of-use and real time pricing tariffs, which, as depicted in Tables 3 and 4, are arranged as a combination of time-varying volumetric charges to recover generation costs and both flat volumetric and fixed charges to recover the rest of cost streams.

For time-of-use tariffs, we use ComEd's current definition of Off Peak, Peak and Super Peak periods (ComEd, 2020) which are shown in Figure 3.[40] Based on these periods, we calculate the minimum square error solution that would approximate our real-time LMP data best, by allowing that the values of charges in each period varies by month. Figure 4 shows the resulting charges.

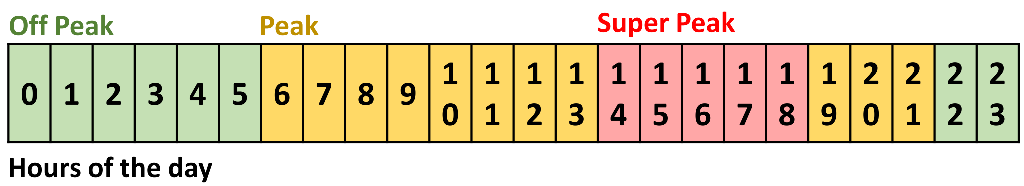


Figure 3: Time-of-use charges periods as defined by ComEd in its RTOUPP tariff.

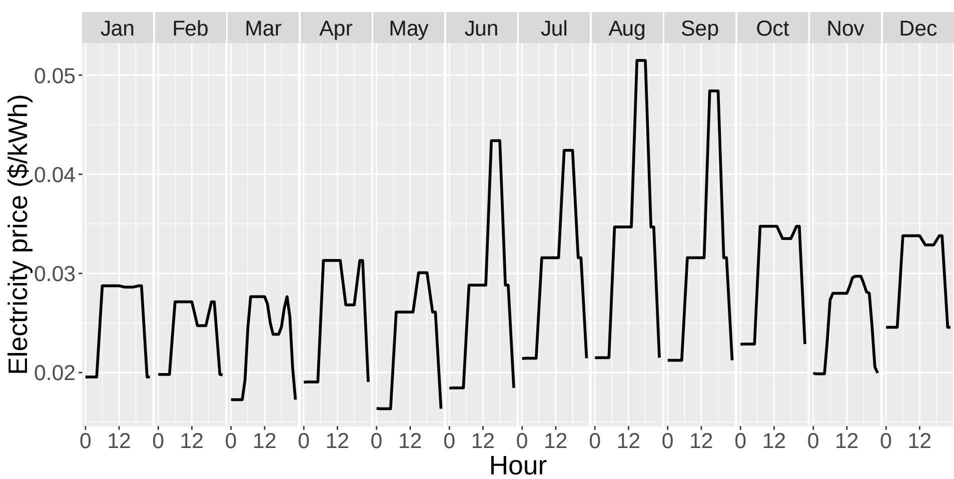


Figure 4: Time-of-use charges that include energy and capacity costs.

In the case of RTP tariffs (RTP and RTP-Efficient), we calculate energy charges by replacing the flat tariff's flat volumetric charge with our LMP prices from the PJM market in the U.S. Figure 5 shows the hourly average value for these charges.

As shown in Table 4, time-of-use and RTP tariffs also consider the flat volumetric charges to recover network and policy costs, as well as a fixed charge that recovers customer-specific cost streams. On the other hand, our RTP-Efficient tariff recovers all costs that are not associated to electricity generation, through fixed charges, equal for all customers.

[39] Same prices as used by (S. P. Burger et al., 2020).

[40] Note that despite having used these definitions for the ToU periods, we left the actual charge values to follow our LMP data via a minimum squared error approximation. Consequently, hours labelled as Super Peak, for instance, are not necessarily always the ones with highest charges (e.g., see month of January in Figure 4).

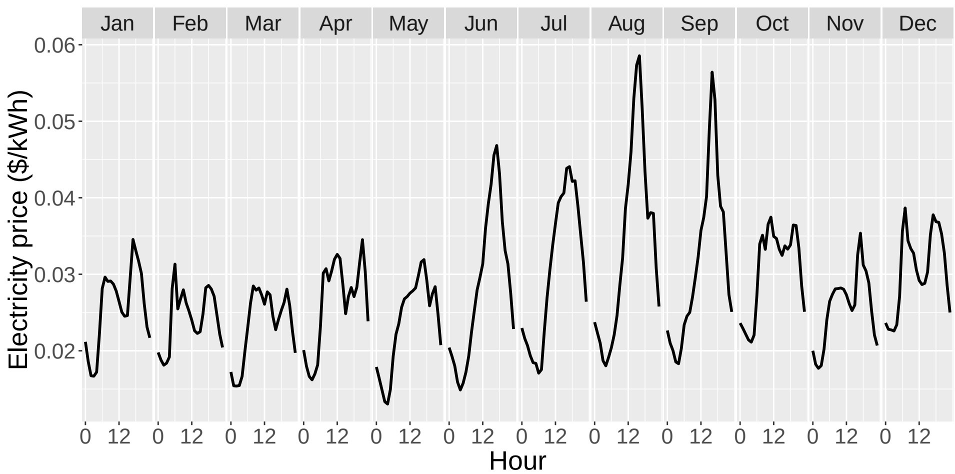


Figure 5: Real time pricing charges that include energy and capacity costs (hourly average).

In addition to several tariff designs, we consider three options for NEM schemes[41]:

- **NEM "On"**: The first option, which we call NEM "On", consists on the strict application of NEM; consumers are charged/paid the full volumetric retail tariff for consumption/exports of power to the grid.
- **NEM "On-California"**: The second scenario mimics NEM schemes currently in force in California and Massachusetts in the U.S., where consumers are paid the full volumetric retail tariff, applicable to each time of the day, for grid exports that stem directly from solar generation or BTM storage that has been exclusively charged from solar panels (and not from the grid). Otherwise, their exports are valued at a lower rate, which in this work we assume to be equal to the energy charge of the tariff.
- **NEM "Off"**: The third and last NEM regime considered is the NEM "Off" regime, where power consumption is priced at the full volumetric tariff but power exports are priced according to energy charges alone.

2.5 Solar generation modeling

In order to obtain a normalized solar generation profile applicable to the relevant jurisdiction, we use the same methods and data as (S. P. Burger, 2019).

In general terms, the model used to generate the profile is pvlib python, a Python-based tool developed by Sandia National Laboratories.[42]

The model uses solar irradiation and weather data, as well as PV system parameters such as efficiency, sizing of inverter, azimuth and other parameters. In this case, we use default parameters for a residential installation with 180° azimuth.[43] [44]

[41]See Section 2.6 for the mathematical implementation of these schemes.
[42]For a complete description of the model see (F. Holmgren et al., 2018).
[43]180° azimuth is the most common configuration among U.S. residential solar systems (Barbose & Naïm, 2019).
[44]Parameters are the same as used in (S. P. Burger, 2019), i.e., System Type: Fixed Tilt; Tilt: 41.9; DC-AC

2.6 Storage operation modeling

In order to estimate how batteries would operate under the different tariff designs and NEM regimes, we develop a linear optimization model that is run for every customer that has been assigned a battery in our calculations.

Table 5 shows the nomenclature used in the mathematical formulation of the model.

Symbol	Description	Units
Sets		
T	Set of time periods in the simulated year	
U	Set of customers	
Parameters		
η^c	Charging efficiency of the battery	p.u.
η^g	Discharging efficiency of the battery	p.u.
σ_t	Unitary solar generation profile	p.u.
$\mathrm{C}_u^{\mathrm{b}}$	Battery installed capacity for customer u	kW
$\mathrm{C}_u^{\mathrm{s}}$	Solar installed capacity for customer u	kW
D	Battery storage duration	Hours
$\mathrm{L}_{u,t}$	Customer u's household electricity load at time period t	kWh
$\mathrm{P}_{u,t}^{NEM-On}$	Two-way or NEM electricity charges	\$/kWh
$\mathrm{P}_{u,t}^{NEM-Off}$	Consumption-only or No NEM electricity charges	\$/kWh
Decision Variables		
$c_{u,t}$	Power consumption for charging the battery at time t	kWh
$g_{u,t}$	Power generated when discharging the battery at time t	kWh
$l_{u,t}$	Net load for customer u at time t	kWh
$l_{u,t}^{+}$	Auxiliary variable that represents power consumed from the grid by customer u	kWh
$soc_{u,t}$	State-of-charge (i.e., stored energy) of the battery	kWh

Table 5: Optimization model nomenclature.

2.6.1 Mathematical formulation for NEM "On" and NEM "Off" regimes

The model minimizes the total bill paid by the customer, considering all volumetric charges under perfect foresight.[45] Equation (1) is the objective function of the model (see Table 5 for detailed nomenclature). It is important to clarify here that the term $l_{u,t}$ represents the customer u's net load, and is calculated by summing up the customer's electricity consumption ($\mathrm{L}_{u,t}$) (e.g., household appliances), plus power consumed to charge the battery ($c_{u,t}$), minus the power output from the battery ($g_{u,t}$) and power output from installed solar PV panels ($s_{u,t}$) (see equation (2) for

Derating: 1.3; Losses: 14% (system) and 4% (inverter); Temperature coefficient: -0.004; and Albedo: 0.2.

[45] Since we do not consider demand charges and fixed charges do not influence the operation of customer's DER portfolio.

the mathematical formulation). The model is run separately and independently for each customer $u \in U$.

$$\min_{g_{u,t},c_{u,t}} \sum_{t \in T} (\mathrm{P}^{NEM-On}_{u,t} \cdot l_{u,t} + \mathrm{P}^{NEM-Off}_{u,t} \cdot \max(0, l_{u,t})) \tag{1}$$

s.t.:

$$l_{u,t} = \mathrm{L}_{u,t} - g_{u,t} + c_{u,t} - s_{u,t} \qquad \forall t \in T, \tag{2}$$

The left-hand side of the objective function represents the minimization of the customer's bill under the NEM "On" regime. That is to say, at any point in time t, both injections of power to the grid and consumption of power from the grid[46], are both valued at the same rate. Hence, when we run the model under a tariff design considering the NEM "On" case, all volumetric charges will be allocated in the $\mathrm{P}^{NEM-On}_{u,t}$ term of the equation and the $\mathrm{P}^{NEM-Off}_{u,t}$ term will be equal to 0 for all t.

In the case where there is no NEM scheme in force, we differentiate between two-way (or NEM-On) charges and consumption only (or NEM-Off) charges. Hence, when we run the model under a tariff that does not include a NEM scheme, we will allocate charges that remunerate electricity generation (i.e., generated energy costs) in the $\mathrm{P}^{NEM-On}_{u,t}$ term and all other volumetric charges[47] in the $\mathrm{P}^{NEM-Off}_{u,t}$ term. Consequently, injections of power to the grid on part of the consumer (negative values of $l_{u,t}$), will be valued at $\mathrm{P}^{NEM-On}_{u,t}$, whereas consumption of power from the grid (positive values of $l_{u,t}$), will be valued at $\mathrm{P}^{NEM-On}_{u,t} + \mathrm{P}^{NEM-Off}_{u,t}$.

In all NEM scenarios, the models work under the assumption that the operator of the battery is able to foresee all electricity charges with complete certainty throughout the simulated year (i.e., perfect foresight of charges). This constitutes an idealization of the real problem, where charges may change throughout the year (e.g., under real-time pricing). Since more realistic considerations would constrain the ability of the battery to optimize the customer's consumption, what we estimate here is a lower bound of the bill that the storage owner would pay, if he/she could not foresee electricity charges with complete certainty.

Note that the optimization problem composed by equation (1), (2) and the subsequent constraints can be easily transformed to an equivalent linear optimization model by defining the auxiliary variable $l^+_{u,t}$; replacing the term $\max(0, l_{u,t})$ with $l^+_{u,t}$; and adding the following constraints:

$$l^+_{u,t} \geq l_{u,t} \qquad \forall t \in T, \tag{3}$$

$$l^+_{u,t} \geq 0 \qquad \forall t \in T, \tag{4}$$

[46] I.e., both negative and positive values of $l_{u,t}$, respectively.

[47] I.e., distribution network, transmission network and policy costs.

The model also includes constraints that allow us to simulate in a simple way, the physical operation of batteries. For instance, equation (5) links the state of charge ($soc_{u,t}$) of the battery in each time period with electricity generation and charging decisions. On the other hand, (6) sets the storage capacity limit for the battery equal to the maximum power output times the duration (i.e., the maximum amount of time that the battery can generate electricity at nominal output if fully charged), while (7) and (8) set upper bounds of power output and input according to the assumed limits of the battery.

$$soc_{u,t} = soc_{u,t-1} - \frac{g_{u,t}}{\eta^g} + c_{u,t} \cdot \eta^c \qquad \forall t \in T, \tag{5}$$

$$0 \leq soc_{u,t} \leq \mathrm{C}^{\mathrm{b}}_u \cdot \mathrm{D} \qquad \forall t \in T, \tag{6}$$

$$0 \leq g_{u,t} \leq \mathrm{C}^{\mathrm{b}}_u \qquad \forall t \in T, \tag{7}$$

$$0 \leq c_{u,t} \leq \mathrm{C}^{\mathrm{b}}_u \qquad \forall t \in T, \tag{8}$$

Additionally, solar generation for customer u at time t, is given by the solar profile, which in our case is common for all users:

$$s_{u,t} \leq \sigma_t \cdot \mathrm{C}^{\mathrm{s}}_u \qquad \forall t \in T, \tag{9}$$

2.6.2 Mathematical formulation for the NEM "On-California" regime

We also model an additional NEM regime, which aims at modeling NEM schemes in force in California and Massachusetts, where storage can gain NEM credits only if the system is charged with power generated in consumer's premises (exclusively solar in the case of California).

In order to model this NEM regime, we modify our model in order to allow for the storage system to charge exclusively from the solar generated power and not using power consumed from the grid.

Firstly, we remove the term $c_{u,t}$ from equation (2), in order to avoid the model to consider an explicit monetary cost when charging the battery. Consequently, we replace equation (2) by (10):

$$l_{u,t} = \mathrm{L}_{u,t} - g_{u,t} - s_{u,t} \qquad \forall t \in T, \tag{10}$$

Secondly, we replace equation (9) with the following:

$$s_{u,t} + c_{u,t} \leq \sigma_t \cdot \mathrm{C}^{\mathrm{s}}_u \qquad \forall t \in T. \tag{11}$$

Consequently, solar available power (right hand side of constraint (11)) should be distributed among solar generation and storage charging power. This way we ensure that the battery charges only when there is solar power available and that total charging power is limited by total solar availability.

The rest of the set-up in this case is identical to the NEM "On" case described above.

2.6.3 Assumptions

Regarding batteries technical parameters, we base our assumptions in the most recent Lazard report (Lazard, 2019). Hence, we assume a 90% round-trip efficiency, with equal charging and discharging efficiencies. Moreover, we assume a 4-hour storage duration and an installed capacity equal to 60% that of the customer's solar installed capacity.

Solar installed capacity is calculated for each customer separately, on the basis that the solar energy generated would offset 90% of the customer's yearly load.[48]

The rest of parameters have been calculated as described in Section 2.4 for electricity charges and Section 2.5 for the solar generation profile.

3 Results and Discussion

3.1 DER adoption by quintile and illustrative operation results

Figures 6 and 7 show results regarding sizing of solar and storage systems across the different income quintiles in the sample of customers. Data for the graphs were generated by assuming a 70% adoption of solar and storage, but the distribution is the same for different adoption levels.

We see in these figures that as income increases, the size of both solar and storage systems also rises in the mean. This occurs because we have assumed that each customer sizes its solar system in order to offset a certain fixed fraction of its yearly consumption before the adoption. The latter trend arises given that as income quintile increases, customers consume more energy on a yearly basis, on average. Storage install capacity is set as a fraction of the solar system's installed capacity, so sizes of storage systems follow the same trend in this case.

Furthermore, in order to illustrate how DER operation changes according to each tariff design and NEM regime, Figure 8 shows the average operation of solar and storage systems for one particular customer, over the course of the simulated year.[49] In addition, Figure 9 shows the hourly average original load (i.e., prior to DER adoption) and net load (i.e., considering DER operation) for the same customer.

In Figure 8, we see that under a flat tariff[50] and NEM schemes, storage does not operate. For the NEM "On" case, this makes sense because any time the storage system would charge, it would consume energy from the grid at the same price that it would obtain when selling that energy back to the grid, at any time. Given that the charging and discharging process involves 10% of energy

[48] Which is the mean energy offset for solar owners in Illinois (Davidson & Margolis, 2015).

[49] Note that generation is plotted as negative values and charging or consumption as positive values.

[50] First column of Figure 8.

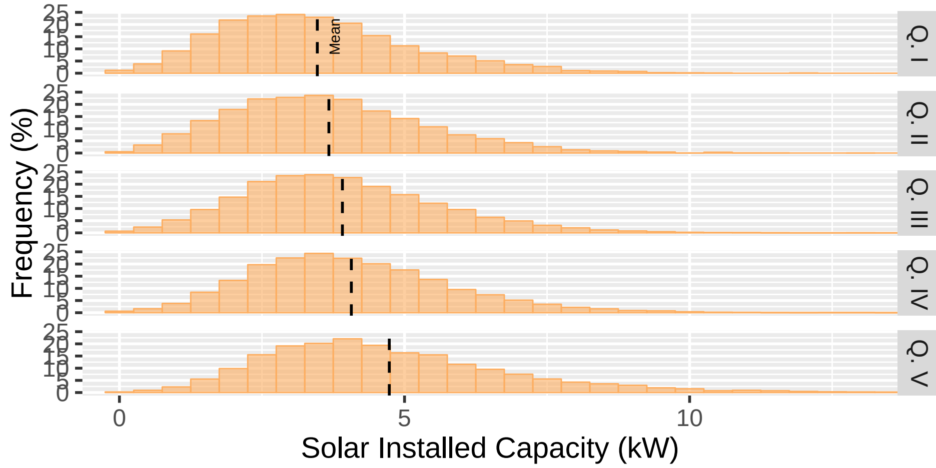


Figure 6: Solar installed capacity for each adopter customer in the 70% DER adoption scenario.

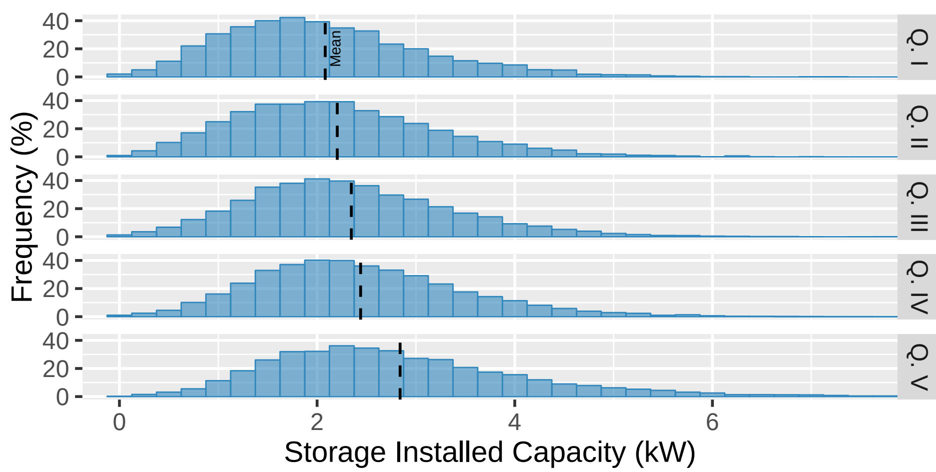


Figure 7: Storage installed capacity for each adopter customer in the 70% DER adoption scenario.

losses, the latter is not economical. On the other hand, under the NEM "California" regime, the result is reasonable since there is no need to shift solar generation from low price to high price hours. In this case, solar earns the full retail tariff at all times.

On the other hand, when NEM schemes are removed, it becomes economical to operate the storage system, and thus, customers obtain a reduction on their bills because of this. This is so since without NEM policies, excess solar power[51] is sold back to the grid at a price lower[52] than the full retail tariff. With storage, customers have the ability to avoid selling this excess power and shift it to reduce their consumption in hours where solar generation is lower (e.g., at night). This way, under a flat tariff and no NEM regime, customers always consume energy but flatten out this consumption, spreading solar power usage throughout solar and non-solar hours.[53]

Under ToU and RTP tariffs operation regimes are similar. Under the NEM "On" regime, storage operation is influenced only by low and high price periods stemming from time-varying energy charges. Note that in both these cases, all customers will follow the same set of prices, which may trigger operating problems in the grid to which customers are connected. Although we have not modeled operation of the grid, we explore these potential problems further in Section 3.5. In the NEM "On-California" case, we see that storage charging is constrained to solar hours and thus, storage operation is more limited than in the previous case.

With ToU and RTP tariffs, combined with the NEM "Off" regime, operation of the storage asset is guided by low/high prices due to time varying charges and the need to avoid net exports of power to avoid losing value for the generated energy. In this case, storage is incentivized to charge during solar hours and help avoid solar exports to the grid. The battery then uses its stored energy to reduce net consumption during high prices and thus, avoid costly power consumption. The latter explains why in this scenario, we see considerable amount of charging during solar hours in contrast to the NEM "On" case.

The RTP-Efficient case is different, given that in both NEM "On" and NEM "Off" cases, the storage system responds only to time varying energy charges[54] and thus, operation in both cases is determined by arbitrage between high and low price hours that stem from energy charges alone. In the NEM "On-California" case, the battery operates under the same rationale but in a more constrained manner, charging during solar hours alone.

Interestingly, Figure 9 helps understand how the different tariff designs and NEM regimes change customers interactions with the distribution grid. We see for instance, that in all cases where the battery is not incentivized to interact with solar to avoid power exports[55], net consumption exhibits important load peaks, which could signal potential power management issues for the utility operating the grid (see Section 3.5 for further details on these issues).

[51] I.e., in excess of power consumption

[52] Equal to the energy charge of the tariff alone.

[53] See the flat tariff and NEM "Off" case in Figure 9.

[54] Without the flat component including network and policy costs.

[55] I.e., under NEM "On" regime and under the NEM "Off" regime and RTP-Efficient tariff.

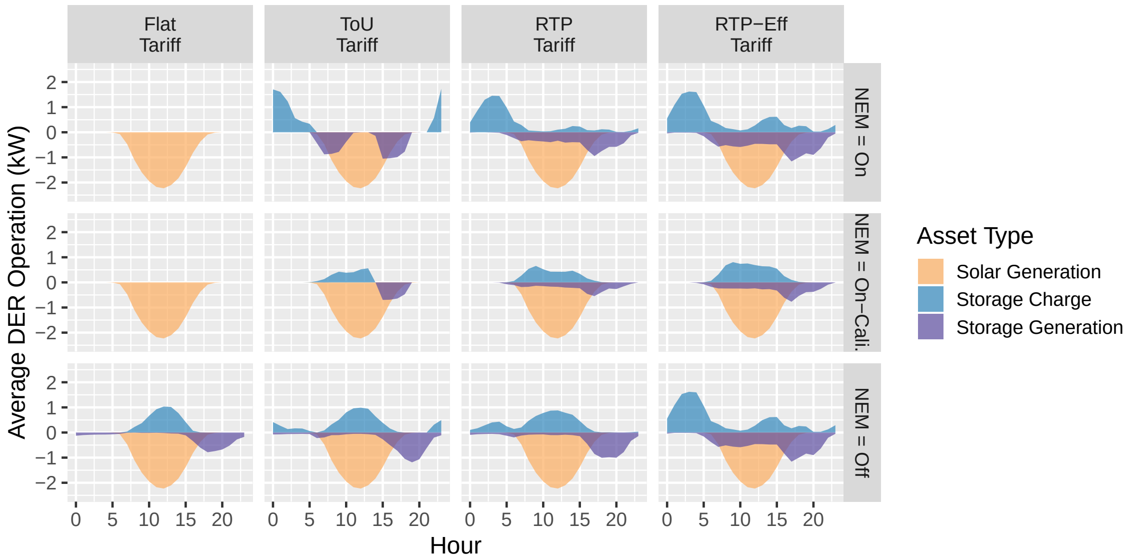


Figure 8: Hourly average of DER operation for a particular customer.

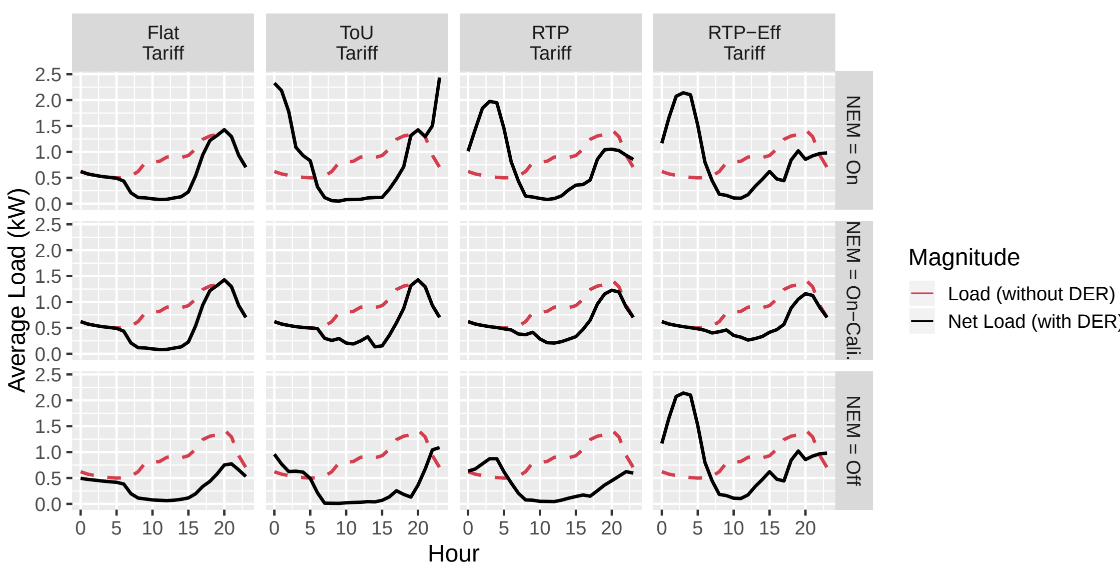


Figure 9: Hourly average of load and net load for a particular customer (same customer as Figure 8).

3.2 NEM policies benefit adopter customers while shifting costs onto non-adopters, rising equity concerns

Firstly we focus on DER adoption impacts on owners of these assets. Figure 10 shows the mean change of bills for adopter customers considering solar alone, under different penetration scenarios and ToU tariffs. Here we see the effects of DER adoption, through which customers are able to decrease their yearly bill considerably (up to 68% reduction on average in the best case). The upward trend we find on average bill impacts with respect to adoption levels is a consequence of increasing flat volumetric charges due to residual cost recovery.

It is important to note in the same Figure that removing NEM schemes reduces benefits from adopting DER considerably. In the three adoption scenarios shown, bill reductions decrease around 27 percentage points on average when NEM schemes are removed.

When considering solar plus storage adoption and ToU tariffs, as shown in Figure 11, trends are similar but quantities change to some extent. Bill reductions with solar plus storage and NEM schemes reach 71% on average in the best case. Whereas when NEM schemes are removed, bill reductions decrease around 17 percentage points on average. Once NEM schemes are removed, batteries allow the customer to avoid power exports to the grid and reduce bills further, compared to the pure solar case. Consequently, without NEM schemes bills tend to be lower in the solar plus storage case. This interplay between the value of storage, NEM schemes and tariff designs will be studied in detail in Section 3.4.

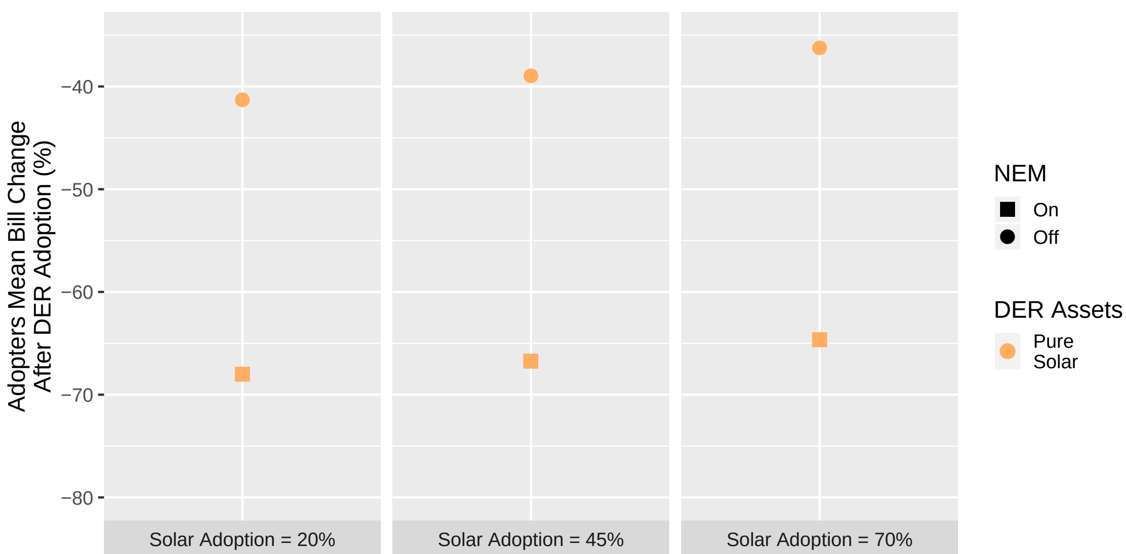


Figure 10: Mean bill change for DER adopters under different adoption levels (compared to the no adoption scenario), considering solar adoption alone and time-of-use tariffs.

In contrast to previous graphs, Figure 12 shows the impact of solar adoption on non-adopter clients under ToU tariffs, which suffer bill increases as rooftop solar penetration rises. This is so, given that residual costs that have failed to be collected from adopter customers are re-distributed

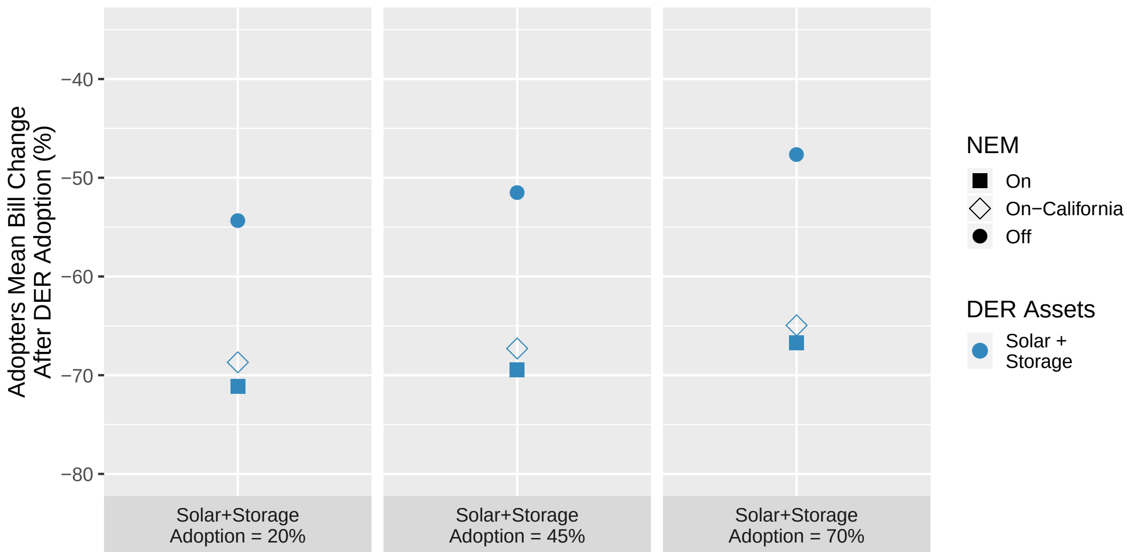


Figure 11: Mean bill change for DER adopters under different adoption levels (compared to the no adoption scenario), considering solar plus storage adoption alone and time-of-use tariffs.

through volumetric charges, increasing non-adopter bills.

As DER penetration increases, more costs are shifted from DER adopters onto non-adopters. In effect, when penetration of DER is relatively low (i.e., 20%), bill increases for non-adopters under time-of-use tariffs and NEM, seem to be relatively low (close to 7% on average). However, when penetration reaches higher levels, this effect can be as high as 19% and 38% on average for 45% and 70% DER penetrations respectively. However, when the NEM scheme is removed, cost-shifting onto non-adopters is reduced significantly. In this case, bill increases reach only 10% on average under very high DER penetration levels (70%).

Both trends mentioned above, i.e., cost-shifting effects increasing with DER adoption levels and the fact that the removal of NEM schemes alleviate cost-shifting effects, are also true for the solar plus storage case. Figure 13 shows bill impacts for non-adopters when solar plus storage is considered (in addition to ToU tariffs and all 3 NEM regimes). Here we see that under NEM schemes, the pure solar case and solar plus storage give similar results. As in the case of solar, considering solar plus storage adoption leads to bill increases close to 6.5% for 20% penetration, 18% for 45% penetration and up to 37% for the 70% adoption scenario.

In contrast, the case without NEM schemes for solar plus storage differs when compared to the pure solar case. In the former, non-adopter bills may increase up to 21% (for the 70% penetration case) compared to the 10% caused by solar adoption alone. The latter is evidence that in absence of NEM schemes, storage still provides considerable flexibility to adopter customers to avoid residual costs. The latter is shown more clearly in Figure 14, where we can see the difference in bill increases when considering solar adoption alone and solar plus storage.

Other lever to consider when the objective is to reduce cost-shifting effects is changing the tariff design. Figure 15 shows average impact on non-adopters under 45% adoption, different tariff

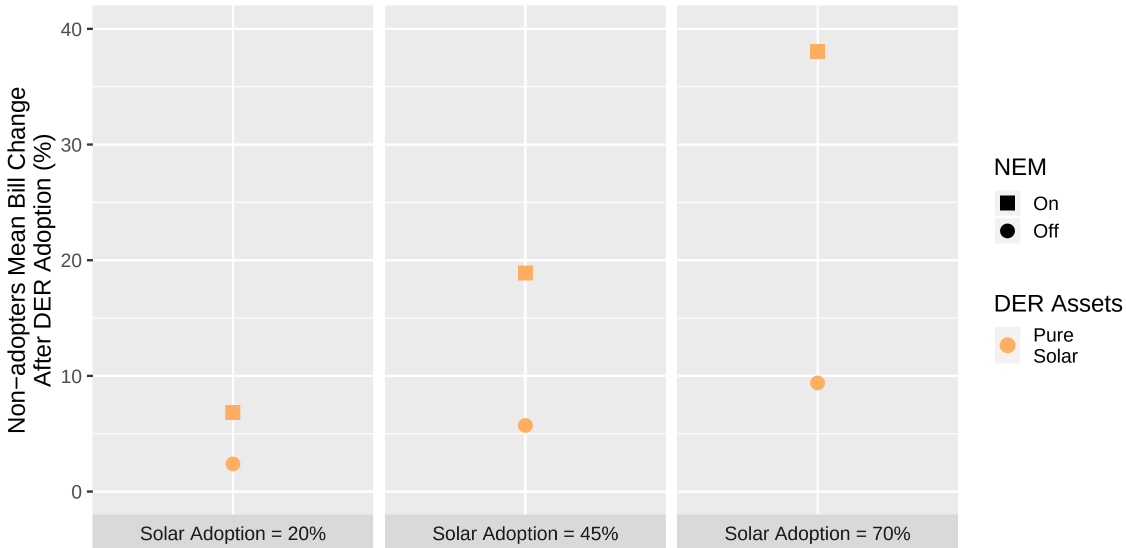


Figure 12: Mean bill change for non-adopters under different adoption levels (compared to the no adoption scenario), considering solar adoption alone and time-of-use tariffs.

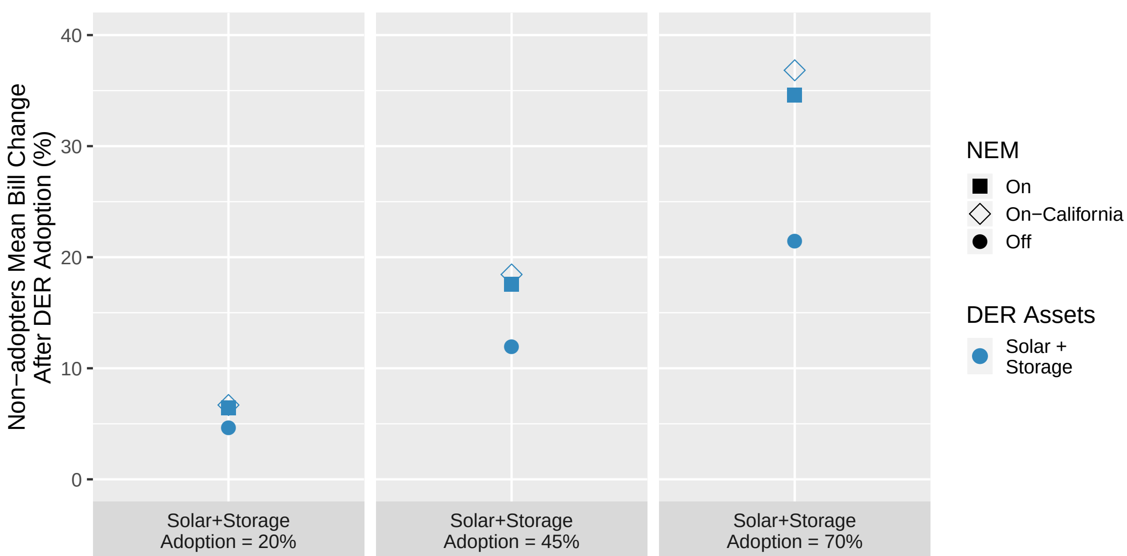


Figure 13: Mean bill change for non-adopters under different adoption levels (compared to the no adoption scenario), considering solar plus storage adoption alone and time-of-use tariffs.

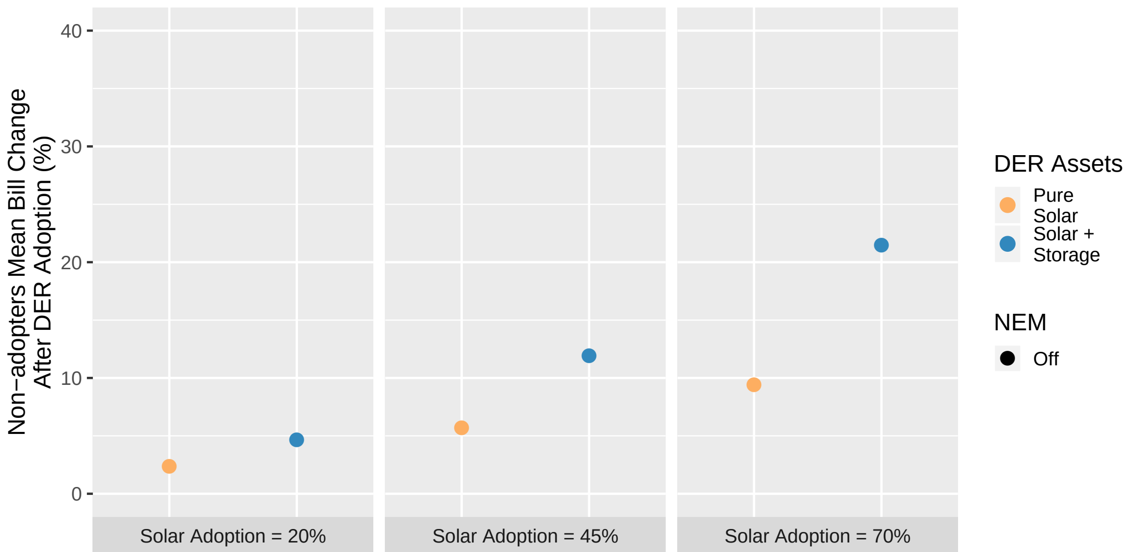


Figure 14: Mean bill change for non-adopters under different tariff designs (compared to the no adoption scenario), considering solar plus storage adoption alone and 45% penetration.

designs and NEM regimes. We see in this Figure that all tariffs that allocate residual costs through volumetric charges present similar cost-shifting effects. However, our RTP-Efficient tariff, which allocates all network costs through fixed charges, reduces cost shifting effects to zero.

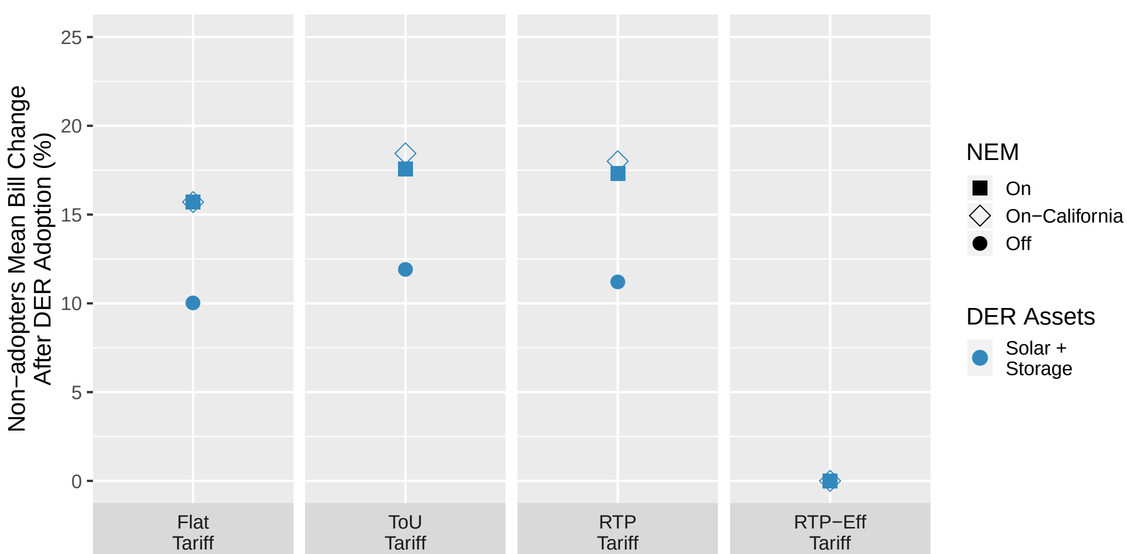


Figure 15: Mean bill change for non-adopters under different tariff designs (compared to the no adoption scenario), considering solar plus storage adoption alone and 45% penetration.

Also notable is how similar a pure NEM scheme behaves to the NEM scheme currently in force in California or Massachusetts. In terms of cost-shifting from adopters to non-adopters, both policies seem to deliver very similar results under different DER penetration levels and tariff designs.

For results obtained with all combinations of tariff designs, NEM schemes and DER adoption levels please refer to Section A.1 in the appendix.

Furthermore, the magnitude of cost-shifting effects shown is highly dependent on sizing of solar and storage assets for each customers. For instance, if customers install relatively low amounts of solar capacity, the cost shifting effects of solar and/or solar plus storage adoption would be lower. Appendix B provides a sensibility analysis on how results would change if customers decide to offset less or more energy consumption with solar energy. The base case considers 90% of solar offset, while the low and high case consider and increase/decrease of 20 percentage points relative to the base case.

In earlier chapters of this work, we defined equity as the ability of price designs to allocate costs on the basis of marginal cost-drivers and avoid that one agent's decisions would shift costs onto others. Results showed above clearly show that recovering residual costs through volumetric charges and NEM schemes reduce the equity of electricity prices that customers pay, given that these aspects contribute to the cost-shifting of residual costs from adopters of DER to non-adopters.

3.3 Removing NEM regimes improves fairness of tariff designs

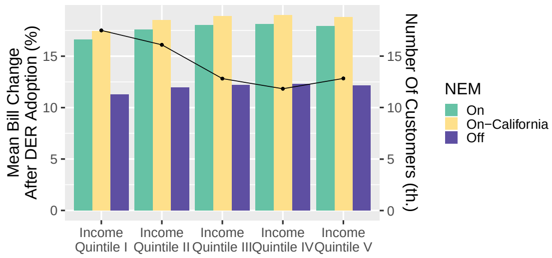
In Figure 16(a), we show the mean bill change for non-adopters in each income quintile under a 45% adoption of solar plus storage systems. On the average, all income quintiles seem to be impacted proportionally similar. Under both NEM regimes considered in this study, non-adopters from all quintiles, on average, see an increase in their electricity bills of around 16-19%, whereas in the absence of NEM schemes, bill increases across quintiles are closer to the 11-12% range.

Despite the fact that all income quintiles seem to be proportionally affected similarly, if a major part of adopter customers continue to be among the three higher income quintiles, as has been assumed here[56], we should expect that a larger portion of wealth that is transferred from non-adopters to adopters, is taken from low-income quintiles. The latter is depicted in Figure 16(b), where we show the total amount of wealth that is collected from the different income groups and allocated onto adopter customers. The graph is enlightening given that it shows how under all NEM regimes, wealth transfers from the two lower income quintiles are slightly higher or equal than wealth transfers from each of the higher income quintiles. Moreover, under NEM regimes total wealth transfer from the two lowest income quintiles sums up close to 3.5 million dollars. In contrast, without the application of NEM schemes this number is reduced to 2.2 million dollars.

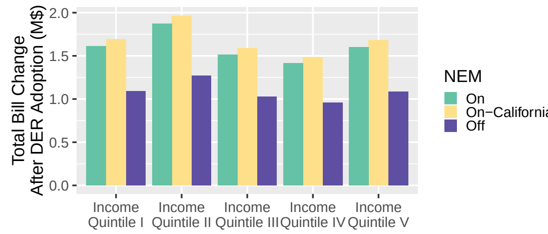
Under equity considerations (as defined in this work), we would aim for a minimization of cost-shifting from adopters to non-adopters. If the latter is not possible, it seems reasonable to aim for a fair outcome where customers affected by bill increases are wealthier, and thus the relative impact to their welbeing is proportionally lower to the impact on lower income consumers.

Previous results highlight the fact that under NEM policies not only non-adopters suffer higher bill increases in general, in contrast to the no NEM case, but also that low income customers suffer the highest relative damage due to the similarity of effects across quintiles and their lower overall

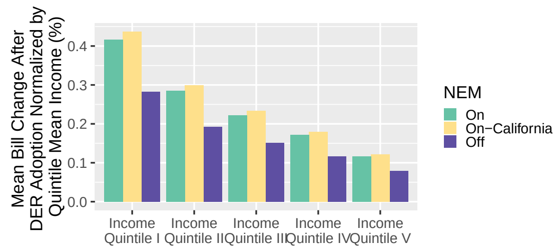
[56] Based on historic adoption of rooftop solar in the U.S. (Barbose et al., 2018).



(a) Mean bill change and no. of customers.

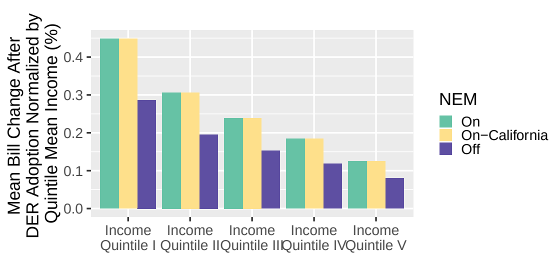


(b) Total wealth transfer from each quintile.

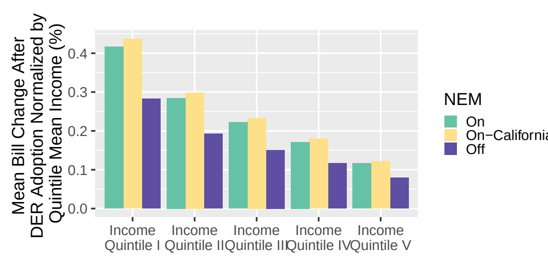


(c) Mean bill increase normalized by quintile mean income.

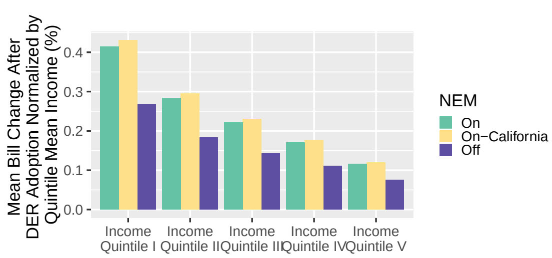
Figure 16: Bill impacts of DER adoption on non-adopters by income quintile and NEM regime, calculated using the Time-of-use tariff and 45% of solar plus storage adoption.



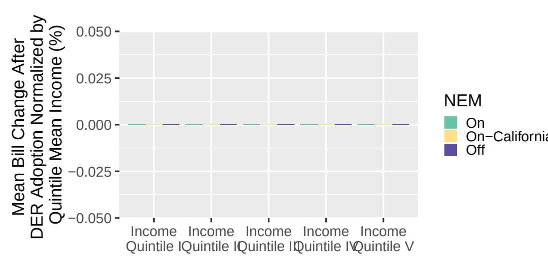
(a) Flat tariff.



(b) ToU tariff.



(c) RTP tariff.



(d) RTP-Efficient tariff.

Figure 17: Mean bill increase for non-adopters, normalized by quintile mean income assuming a 45% adoption level of solar plus storage.

income level. The latter is reinforced by Figure 16(c), where we normalize mean bill impacts by the mean income of each quintile. The graph helps us visualize how DER adoption may damage low income customers more, in contrast to relative effects on higher income quintiles.

Figure 17 shows that in all tariff designs the trend is similar, lower income customers are affected relatively more by cost shifts stemming from DER adoption, with the exception of the case where the RTP-Efficient tariff is considered. As underscored in the previous Section, this tariff eliminates the risk that DER adopters avoid expenses on residual costs, reducing wealth transfers from non-adopters from all income quintiles to zero.

In summary, results show that applying NEM schemes and recovering residual costs through volumetric charges may trigger unfair effects, given that wealth transfers from low income customers onto DER adopters are relatively larger than wealth transfers extracted from higher income customers.

3.4 Removing NEM regimes improves economic value of storage for adopters

Figure 18 shows the marginal value that solar adopters obtain when adding storage to their DER portfolio. To calculate this value, we substracted resulting bills for solar adopters with bills for the case when these customers are assigned solar plus storage, under the same tariff design. This way, we obtain the economic value of storage that these customers accrue over a year.

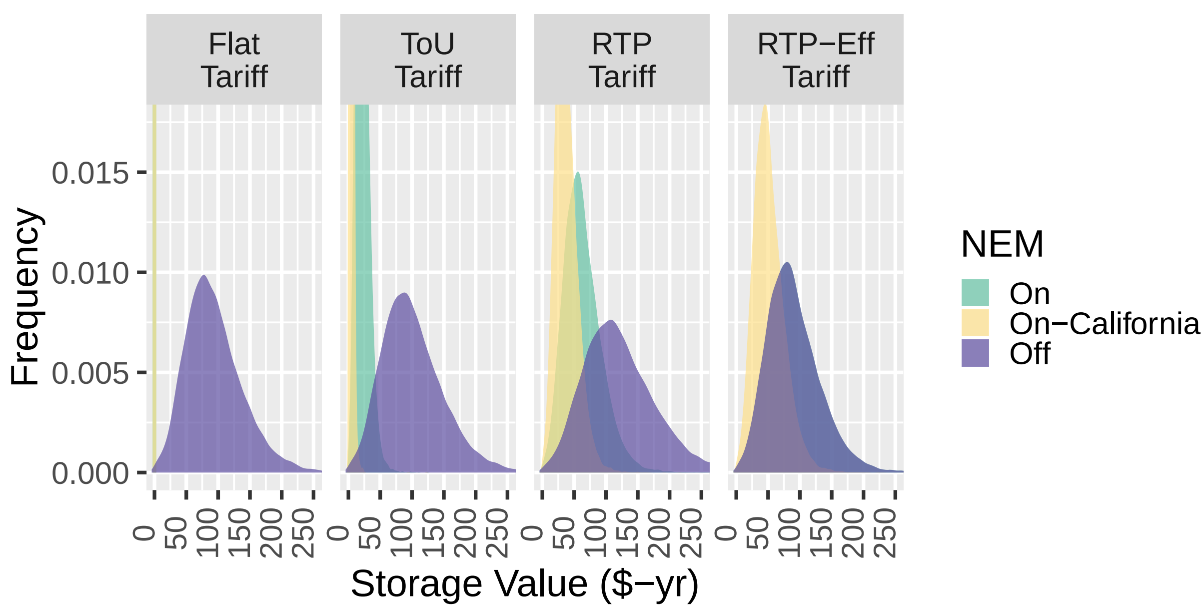


Figure 18: Marginal revenues (i.e., economic value) for solar adopters, triggered by installing storage under different tariff designs.

Under our flat tariff and considering NEM schemes, storage has zero economic value and does not operate, as explained in Section 3.1.

Under ToU and RTP tariffs and NEM schemes, storage provides some value to customers, given that they are able to perform energy arbitrage between low and high price hours[57]. In the case of the NEM "On" regime, storage is completely free to arbitrage between low and high price hours, whereas in the NEM "On-California" case, storage is restricted to charge during hours with solar availability. It is due to this constraint that storage value is lower for the latter.

On the other hand, without any NEM regime in force, storage value ends up being higher for each customer than in the other two cases.[58] In the absence of NEM schemes, storage systems allow customers to avoid selling solar power to the grid at a price equal to the energy charge of the tariff at low price times, store it in the storage system and sell it[59] at high price hours at the full retail price. The latter implies that customers are allowed to arbitrage between prices with larger differences than in the NEM cases.

Lastly, in the RTP-Efficient case, the NEM "On" and NEM "Off" regimes provide the same storage value, since they both cause that storage systems arbitrage between low and high energy charge periods (all other charges are paid on a $/customer basis). The case of NEM "On-California" is different, since the storage system operation is constrained to charge only through the solar system and not from the grid. Consequently, storage value in this case tends to be lower.

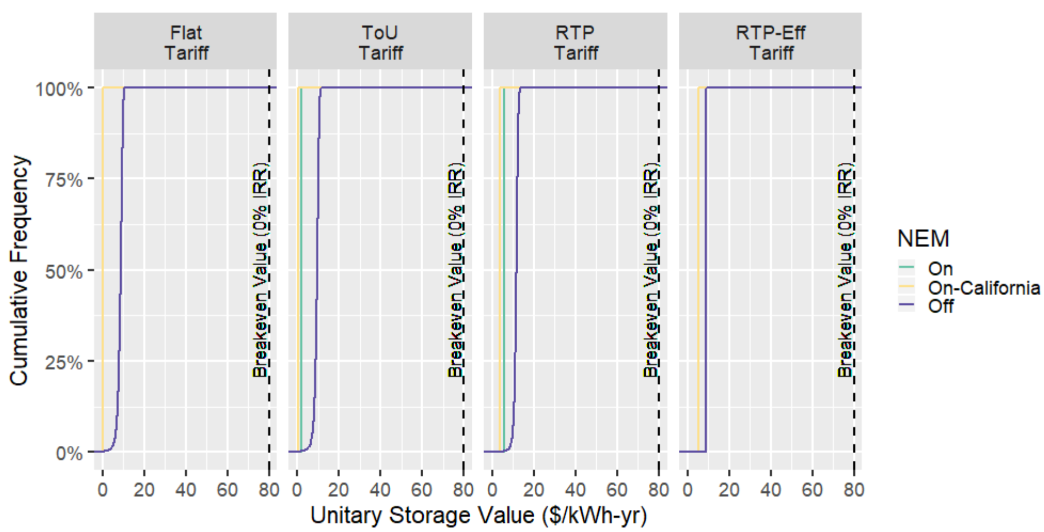


Figure 19: Cumulative frequency of the per-kWh economic value of storage.

In order to compare these values to storage technology costs, we normalize them by the installed storage capacity for each customer and then calculate the breakeven normalized value necessary to obtain a 0% IRR for the investment.[60]

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[57]I.e., charging in low price hours and generating at high price hours.

[58]Although the PDFs in 18 shows some customers for which storage value is lower than in the cases with NEM schemes, it should be noted that for each customer, storage value is higher without NEM regimes in force. The overlap between distributions of values accrued by customers is misleading because it captures the comparison of storage value between different customers.

[59]I.e., strictly speaking, reduce their consumption.

[60]We assume the storage value remains constant for 20 years, which is the approximate lifetime of a lithium-ion battery under a BTM application (Lazard, 2019). Then, we take a reference investment cost for lithium-ion batteries from (Lazard, 2019) equal to 1,597 $/kWh[61] and calculate the necessary storage value to obtain the 0% IRR.

Figure 19 shows the results. In these graphs we see that in every case, the value of storage is far from the value necessary to make investment profitable. However, it is important to note that in this simplistic calculation we have not considered Investment Tax Credits (ITC) currently in force in the U.S., other value streams that storage systems may provide[62] and other costs such as maintenance costs, taxes, etc.

Finally, Figure 20 shows how storage value changes with respect to tariff designs, keeping the NEM regime constant. For both NEM regimes (i.e., the On and On-California cases), the more cost-reflective[63] the price signal, the higher the storage value. This trend arises in the flat, ToU and RTP tariffs since the more granular the energy price signal becomes (i.e., varies with more dynamism with time), the higher the ability of storage to arbitrage between low and high energy price periods. The difference between RTP and RTP-Efficient tariffs is explained because, for the battery, the main difference between both tariffs under NEM is a constant offset[64], which reduces benefits of storage in the RTP tariff case, to some extent.

The NEM Off case is slightly different, since the most cost-reflective tariff design (i.e., RTP-Efficient)[65] does not present the highest storage value. In the NEM Off case, when residual costs are recovered through volumetric charges, installing storage allows customers to arbitrage between the pure energy charge and the full retail tariff, by storing power excess in the battery. Since in the RTP-Efficient tariff we recover residual costs through fixed charges, storage loses value to some extent.

3.5 Depending on the tariff design, presence/absence of NEM regimes changes grid usage considerably under high DER penetrations

In our models we did not consider the distribution network to which customers are connected. However, we set out to investigate potential different effects on network utilization for each of the tariff designs and NEM regimes, using proxy variables for the operation of the network.

In figures 21 and 22, we show an approximation of the way load flows throughout the distribution grid could potentially change in contrast to the case without DER adoption[66], under different NEM regimes, adoption levels and a flat or ToU tariff, respectively. To build these graphs, we summed up the net load[67] for all clients, under each NEM regime, adoption levels and tariff design individually. We then substracted the original load of each customer to its corresponding half-hourly net load, summed up the results for all customers and then plotted the hourly average values for 24 hours of the day. Through this process, we could identify periods where net load exceeds the original

[62]E.g., peak shaving and distribution network investment deferrals.

[63]We use the term cost-reflectivity here as a synonym for economically efficient. A tariff design that is able to convey costs closer to their short-term marginal driver, is considered a more cost-reflective or economically efficient tariff.

[64]I.e., the total flat volumetric charge.

[65]Our RTP-Efficient tariff is the most cost-reflective since it allocates energy costs in a real-time-pricing fashion and allocates network costs, which are fixed, through fixed charges.

[66]I.e., we assume that the pre-adoption scenario is a proxy to the design condition of the grid.

[67]I.e., half-hourly household consumption minus DER operation.

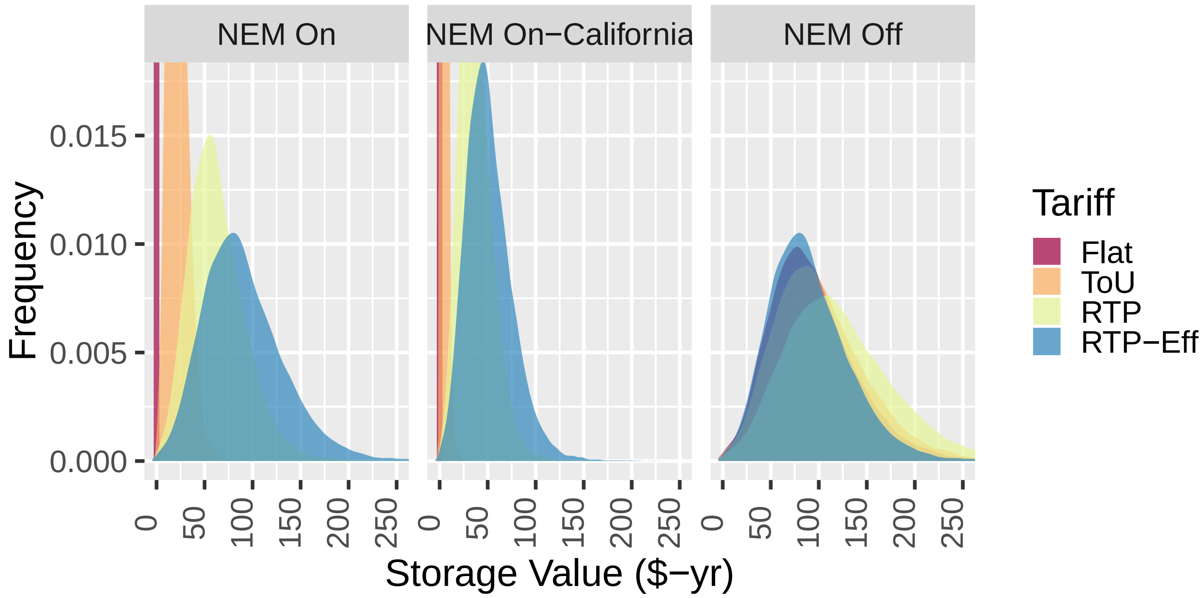


Figure 20: Marginal revenues (i.e., economic value) for solar adopters, triggered by installing storage under different NEM regimes and tariff designs.

load due to the adoption of DER, which could be an indicator for the need for network investments (these values are shown in red in figures below). On the other hand, negative values (shown in blue in the graphs) represent hours where DER adopters are injecting more power than what they are consuming, causing power flows coming to their households to change direction, which typically represents an abnormal condition in distribution networks.

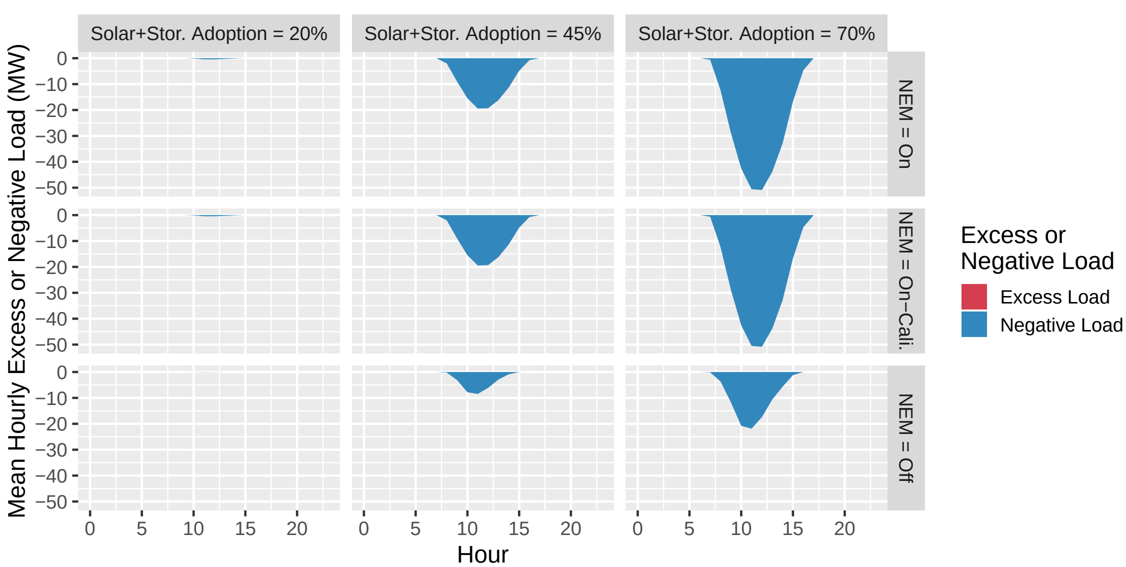


Figure 21: Excess load compared to original total load and negative load (or exports to the grid from customers) for all NEM regimes, different solar plus storage adoption levels and flat tariff.

In the flat tariff case (Figure 21), we see that there are no hours with excess load. Regarding NEM cases, this is so since, as described in the previous Section, storage systems do not operate under flat tariffs and thus, changes to the original load patterns are caused only by solar generation. On the other hand, in the no-NEM case, storage is mainly used to shift solar from excess power hours and reduce consumption on hours where there is less solar power available, thus storage is never charged in the absence of solar, maintaining excess load at zero at all times.

In all cases we see that as DER adoption increases, there is increasingly more power that is sold back to the grid from solar generation. Interestingly, in the case without any NEM regime in force, power exports to the grid tend to be lower due to the usage of storage to store excess solar power.

In the time-of-use and real-time pricing tariff cases on the other hand (figures 22 and 23), we see that storage is effectively charged from the grid, causing hours with excess load compared to the original load of each customer. Although not a direct indicator, it is at these hours where we would expect that network investment needs would trigger, given the increase of power flowing through the grid compared to the pre-adoption of DER condition.

Again, for ToU and RTP tariffs and for all NEM cases, as DER adoption levels increase, excess load and negative load increases as well. However, under these tariffs effects among different NEM regimes differ considerably. In the NEM "On" case, the grid suffers the most stress, given that all customers use their storage system during off-peak hours to charge and then they sell back the power stored during peak hours. Storage operation seems to reduce negative load caused by solar[68] but there is still considerable negative load when DER penetration is at 70%. In the NEM "On-California" case, grid stress is considerably lower, given that storage is charged only at solar hours, which keeps excess load at zero and exports of power at low levels. In the NEM "Off" case, the grid suffers the least, given that the economically optimal operation of storage implies reducing solar exports as much as possible, in order to maximize its value. The latter depends on solar availability but also on each customers load profile, adding diversity to storage operation of each customer and thus, reducing the aggregated effect on the grid. Under this regime we also see some effects of arbitraging during time of low prices and that is why we see some excess load hours at night.

So far, we have seen that under flat, ToU and RTP tariffs, NEM schemes could potentially cause greater stress on the grid in comparison to the no-NEM case, given that they incentivize customers to adopt load patterns that could be very different to their original loads. We see next, that in the case of our RTP-Efficient tariff, the NEM "Off" case does not provide any advantages regarding grid usage, in comparison to the NEM "On" case.

Figure 24 shows excess and negative load times under the RTP-Efficient tariff. Since in this case, network and policy costs are all recovered through fixed charges, the NEM "On" regime provides the same incentives for storage operation as the NEM "Off" regime. In both cases, storage of all consumers arbitrage between low and high energy charge periods, independently of solar generation. The latter causes all consumers to charge and generate power with their batteries at

[68] In contrast to the flat tariff case.

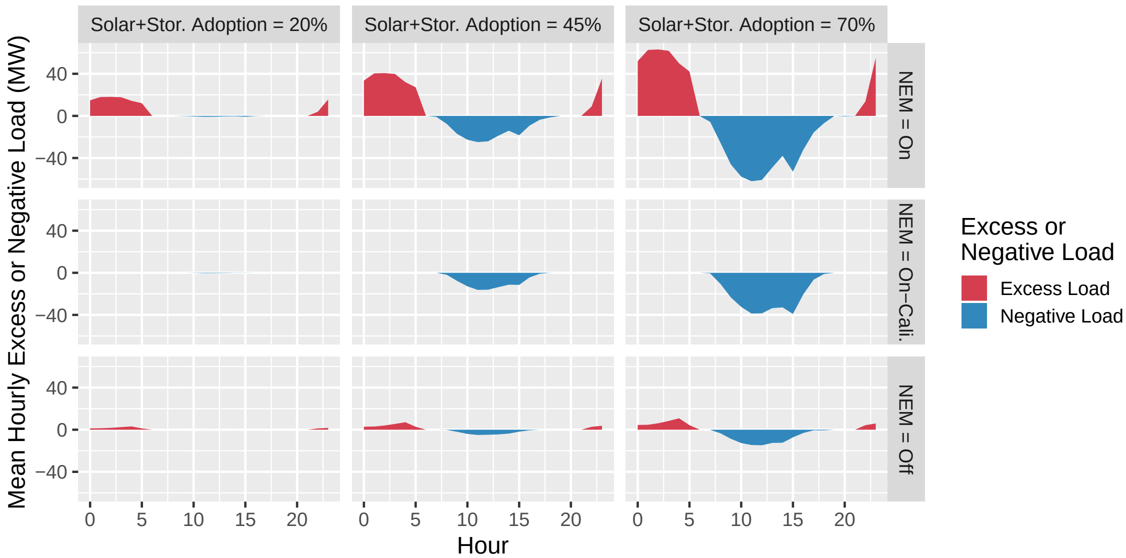


Figure 22: Excess load compared to original total load and negative load (or exports to the grid from customers) for all NEM regimes, different solar plus storage adoption levels and ToU tariff.

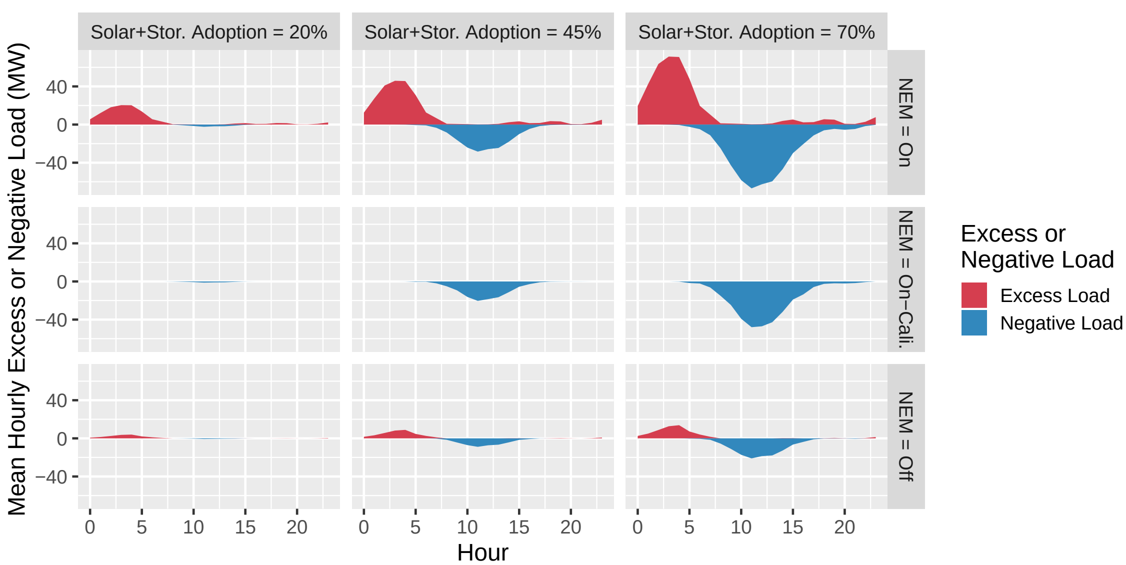


Figure 23: Excess load compared to original total load and negative load (or exports to the grid from customers) for all NEM regimes, different solar plus storage adoption levels and RTP tariff.

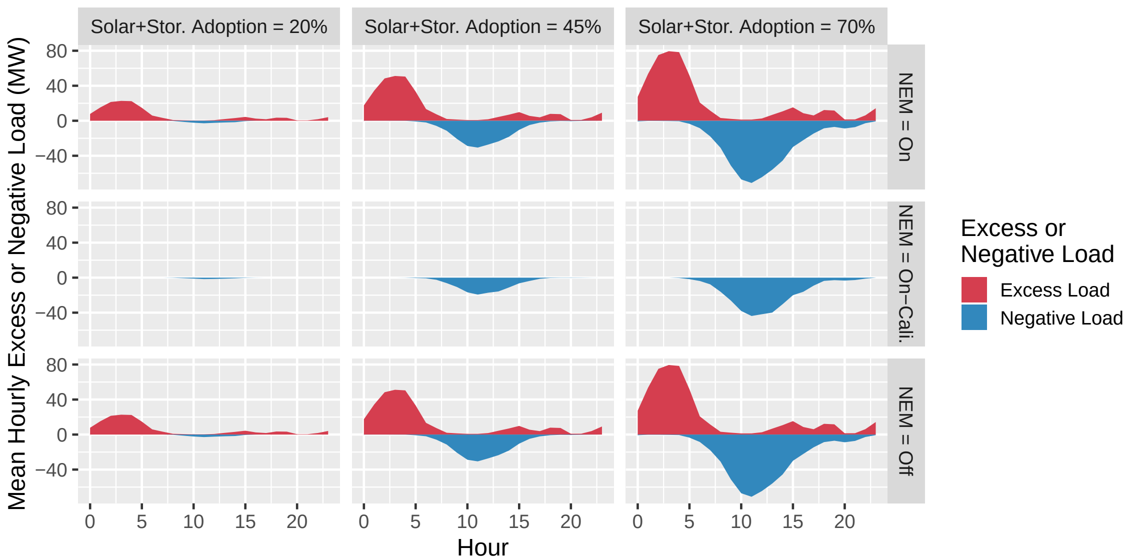


Figure 24: Excess load compared to original total load and negative load (or exports to the grid from customers) for all NEM regimes, different solar plus storage adoption levels and RTP-Efficient tariff.

the same tame, potentially causing greater grid stress.

In summary, results shown here indicate that DER adoption levels could potentially be less complex for distribution grids in the absence of NEM schemes when considering flat, ToU or RTP tariffs and recovering residual costs through volumetric charges, given that the operation of DER would change customers loads less than in the presence of NEM policies. However, when residual charges are recovered through fixed charges, all customers are incentivized to respond to the same energy charges and thus, grid stress could potentially be high independently of NEM policies.

We acknowledge however, that these results should be interpreted with care. Firstly, we have modeled tariffs that expose all customers in the sample to the same time-varying energy charges, without adding a component that varies according to the connection node of each customer. If sufficiently location-specific charges are implemented, we argue that negative effects of NEM policies on grid power management could improve considerably, given that customers would be able to respond to different price signals, adding diversity to the load in each node and reducing grid stress. Secondly, further work involving network modeling is necessary to achieve more accurate results. For now, we consider results in the present Section to be useful to motivate further research on network impacts of NEM schemes under high DER penetrations, at most.

4 Conclusion

Possibly due to the increasing penetration of DER in electricity markets around the world, the potential benefits and hazards of policies supporting these technologies have gained attention both in the academic and policy arenas. Since DER adopters in the U.S. have been wealthier on average than non-adopters to date, several authors argue that some DER supporting policies, such as net metering schemes, could be regressive, given the possibility that DER adopters shift certain costs onto non-adopters (i.e., more economically vulnerable customers).

The present work aims at providing insights on these potentially relevant distributional effects of NEM schemes, in the presence of different levels of DER adoption (i.e., solar PV and behind-the-meter storage) and different electricity tariff designs. By using a dataset containing close to 100,000 customers' half-hourly load and income quintiles, we simulate the operation of these assets under 20%, 45% and 70% of adoption levels and calculate both resulting bills as well as cost shifts arising from the allocation of residual costs through volumetric charges.

Overall, results show that the combination of NEM schemes and recovery of residual costs through volumetric charges may cause important cost shifting effects from adopter onto non-adopter customers, rising equity and fairness concerns. Firstly, under NEM schemes, we calculate that adopter customers may, on average, obtain bill reductions of 71% when installing solar plus storage, whereas non-adopters can see their bills increased around 18% in high DER penetration scenarios (i.e., 45% penetration). Moreover, under the same NEM schemes, 45% adoption and considering solar plus storage adoption alone, we calculate that customers from the two lowest income quintiles may suffer bill increases in the 16-19% range on average, while removing NEM schemes reduces these increases to the 11-12% range.

We also set out to investigate potential effects on power management for grid operators. Although we did not model grid operation, we calculated the aggregated change on load patterns after DER operation and used the pre-DER adoption condition as a proxy for the design condition of the grid. Overall we see that in 3 out of 4 tariff designs considered, NEM schemes provide incentives to use the grid more intensively, which could be a cause for concern by grid operators, due to potential higher network investment costs.

While the analysis performed here used data from Chicago, Illinois in the U.S., fundamental causes for the cost-shifting effects of DER adoption and inadequate tariff designs can be tested using our methods in any other jurisdictions where similar tariff and billing practices are present (e.g., other states in the U.S., Chile, Australia, U.K., etc.).

Finally, it is important to note that in this study we have focused our efforts on identifying and quantifying specific potential effects of NEM schemes without intending to perform a comprehensive analysis of the benefits and costs of these policies. As pointed out in Section 1.2, many aspects not considered in this study matter when performing such an assessment, such as benefits on reduced environmental footprint of the energy supply, job creation and potential incentives for grid-defection. Consequently, results here should be considered in combination with an assessment of these other effects in order to provide quality recommendations on the societal desirability of NEM schemes.

A Appendix: Additional results for 90% (base case) of solar energy offset assumption

A.1 Bill impacts on adopters and non-adopters under all tariff designs and DER penetration levels

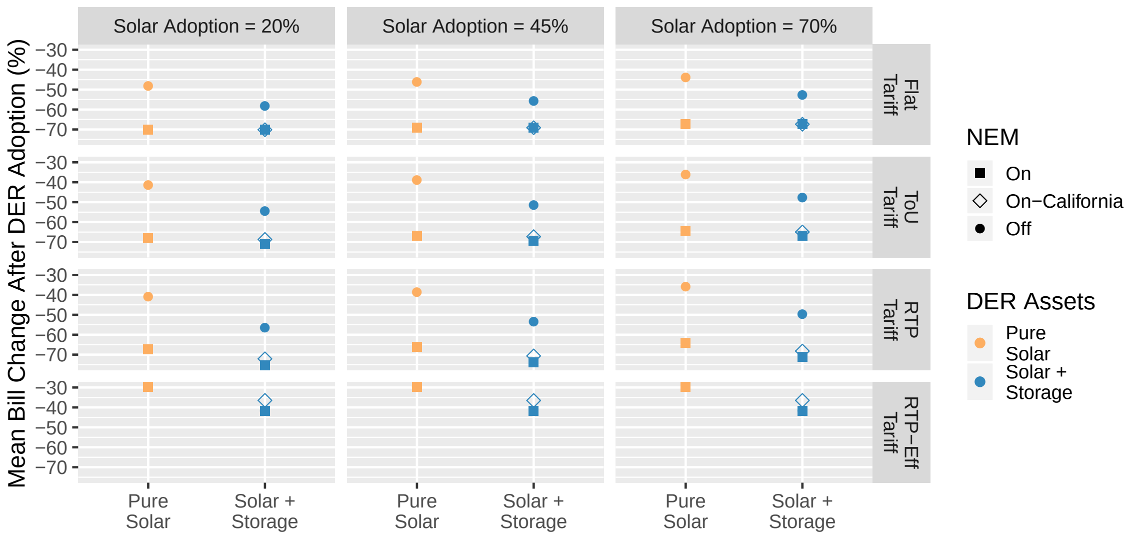


Figure 25: Mean bill change for DER adopters under different adoption levels (compared to the no adoption scenario) and tariff designs.

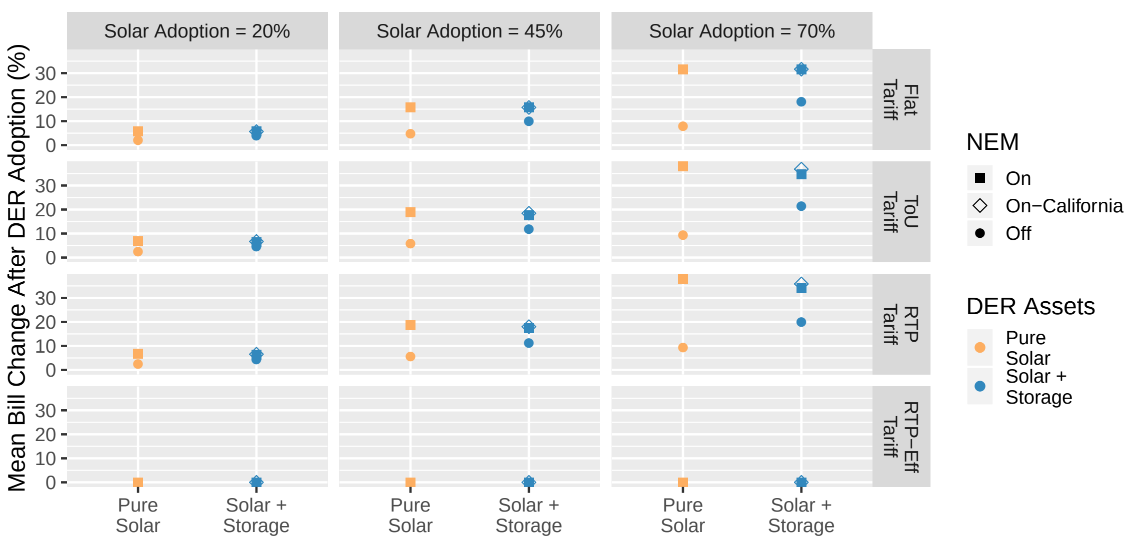
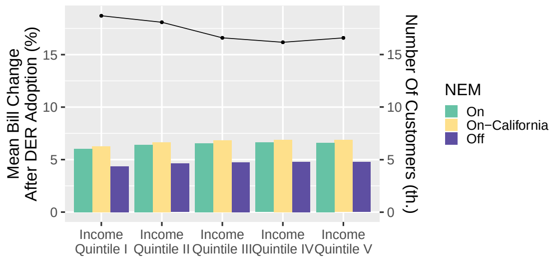
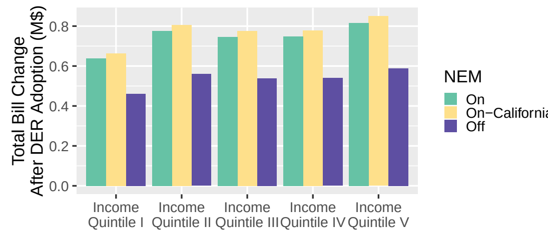


Figure 26: Mean bill change for non-adopters under different adoption levels (compared to the no adoption scenario) and tariff designs.

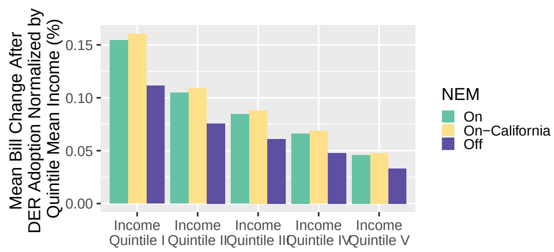
A.2 Bill impacts on non-adopters under ToU tariff and 20% and 70% adoption levels by income quintile



(a) Mean bill change and no. of customers.

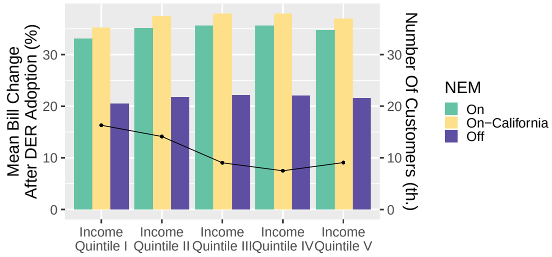


(b) Total wealth transfer from each quintile.

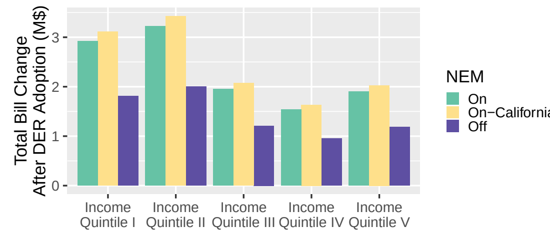


(c) Mean bill increase normalized by quintile mean income.

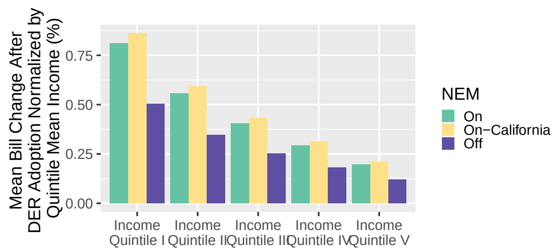
Figure 27: Bill impacts of DER adoption on non-adopters by income quintile and NEM regime, calculated using the Time-of-use tariff and 20% of solar plus storage adoption.



(a) Mean bill change and no. of customers.



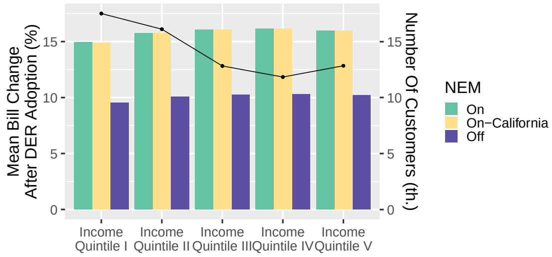
(b) Total wealth transfer from each quintile.



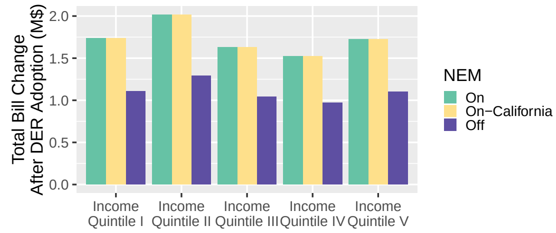
(c) Mean bill increase normalized by quintile mean income.

Figure 28: Bill impacts of DER adoption on non-adopters by income quintile and NEM regime, calculated using the Time-of-use tariff and 70% of solar plus storage adoption.

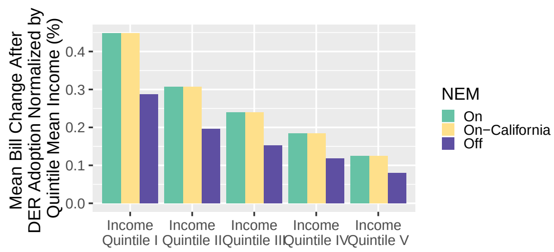
A.3 Bill impacts on non-adopters under flat, RTP and RTP-Efficient tariffs and 45% adoption level



(a) Mean bill change and no. of customers.

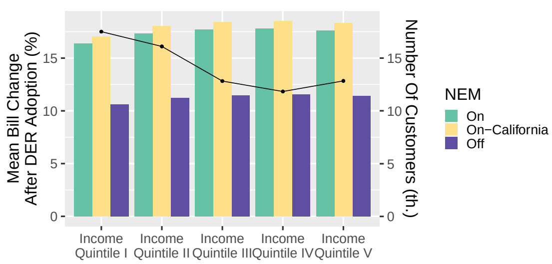


(b) Total wealth transfer from each quintile.

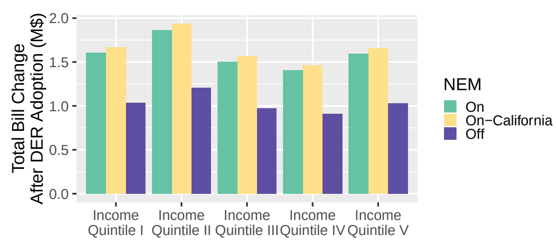


(c) Mean bill increase normalized by quintile mean income.

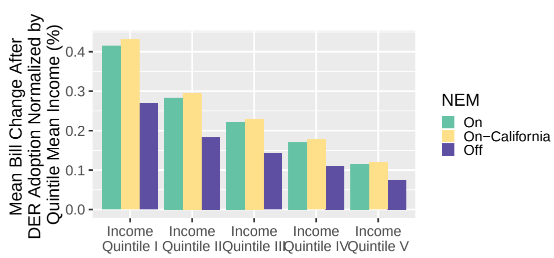
Figure 29: Bill impacts of DER adoption on non-adopters by income quintile and NEM regime, calculated using the flat tariff and 45% of solar plus storage adoption.



(a) Mean bill change and no. of customers.

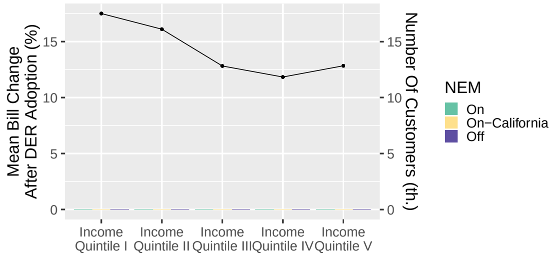


(b) Total wealth transfer from each quintile.

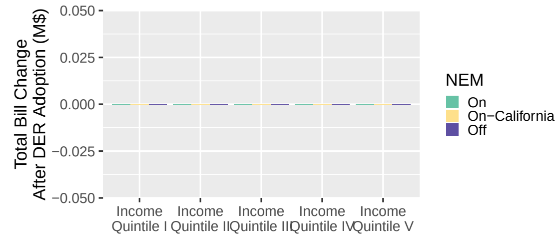


(c) Mean bill increase normalized by quintile mean income.

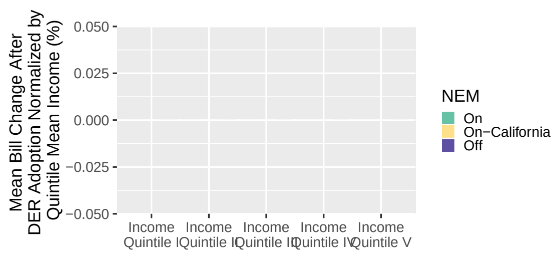
Figure 30: Bill impacts of DER adoption on non-adopters by income quintile and NEM regime, calculated using the RTP tariff and 45% of solar plus storage adoption.



(a) Mean bill change and no. of customers.



(b) Total wealth transfer from each quintile.



(c) Mean bill increase normalized by quintile mean income.

Figure 31: Bill impacts of DER adoption on non-adopters by income quintile and NEM regime, calculated using the RTP-Efficient tariff and 45% of solar plus storage adoption.

B Appendix: Bill impacts on non-adopters for 70%, 90% (base case) and 110% of solar energy offset assumption

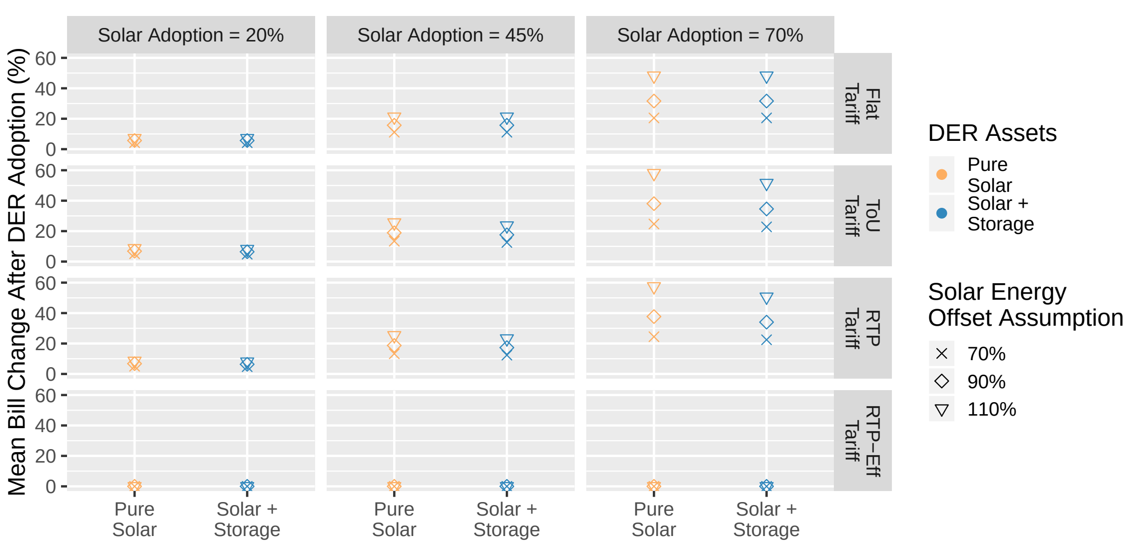


Figure 32: Mean bill change for non-adopters (compared to the no adoption scenario) under different adoption levels, tariff designs and solar energy offset assumption for the **NEM On case.**

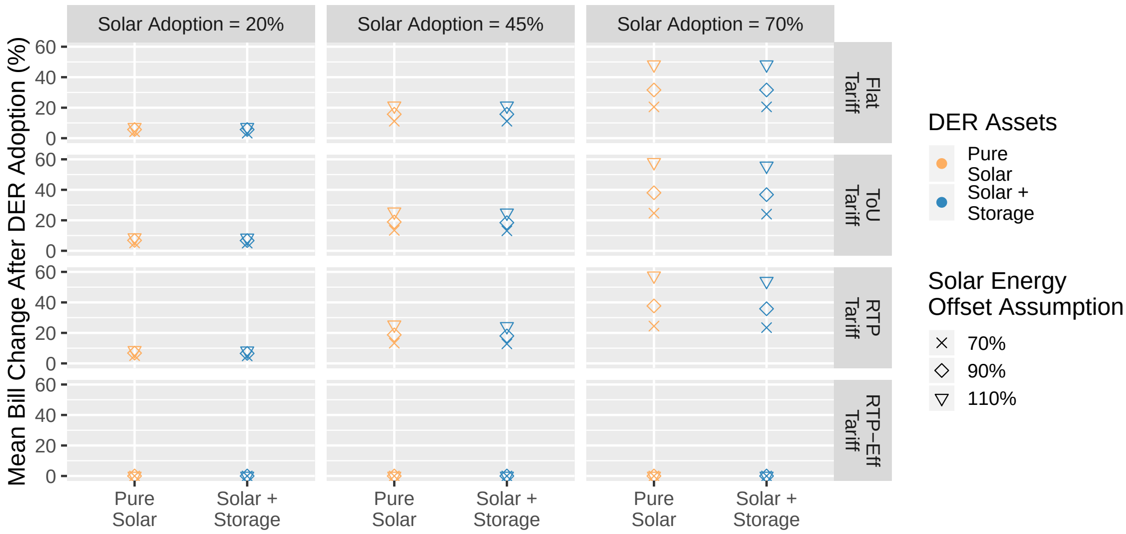


Figure 33: Mean bill change for non-adopters (compared to the no adoption scenario) under different adoption levels, tariff designs and solar energy offset assumption for the **NEM On-California case.**

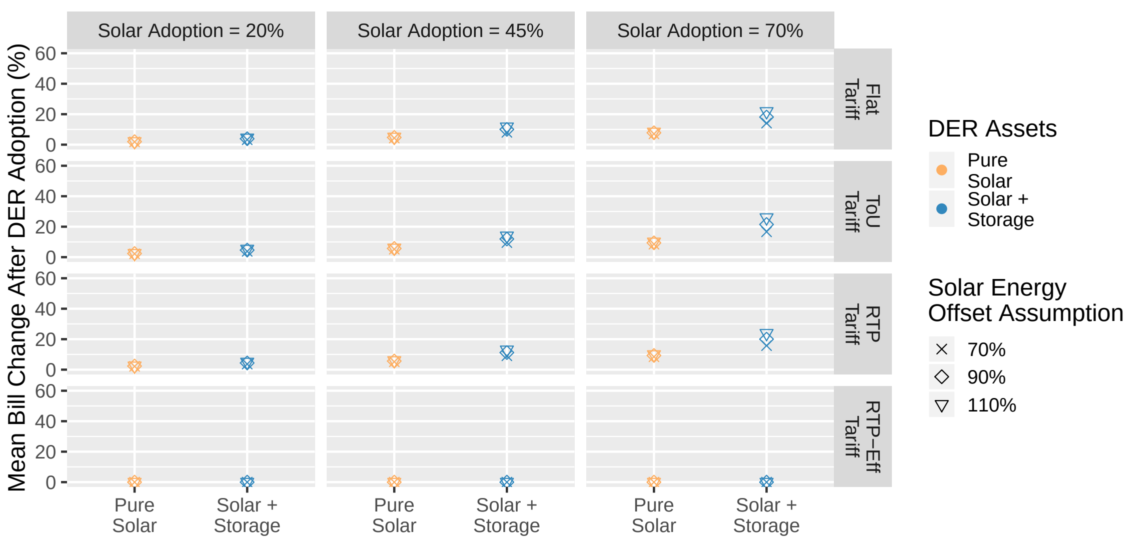


Figure 34: Mean bill change for non-adopters (compared to the no adoption scenario) under different adoption levels, tariff designs and solar energy offset assumption for the **NEM Off case.**

C Appendix: Tariff and solar generation profile datasets

Additional data for tariff designs and solar generation profile have been made available at the URL: https://bit.ly/2yDA6O9

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