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Fair, Equitable, and Efficient Tariffs in the Presence of Distributed Energy Resources

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Fair, equitable, and efficient tariffs in the presence of distributed energy resources

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Distributed energy resources (DERs) hold the potential to deliver substantial benefits to the power system. However, under traditional tariff schemes, DERs may increase inequities already present in the power system. This chapter explores key equity considerations with respect to rate design and outlines distinct methods for improving economic efficiency without sacrificing equity. This chapter demonstrates that economically efficient tariffs always improve certain concepts of equity relative to temporally and geographically invariant ("flat"), volumetric tariffs. However, without intervention, efficient tariffs may violate certain definitions of social justice or fairness. This chapter highlights how well designed interventions can improve distributional equity without sacrificing economic efficiency. In addition, this chapter outlines mechanisms to mitigate the customer bill impacts of transitioning from today's tariffs to more efficient designs without unduly harming equity and efficiency.

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1. Introduction

Utilities, regulators, and academics no longer debate whether or not distributed energy resources (DERs) will reshape the power sector; they now debate what form this transformation will take and when it will take place. At the center of the new vision for the power sector is the consumer. As highlighted in the introduction to this book, DERs give consumers new options for how to source and manage their electricity and offer utilities and service providers new means to provide better services to their customers. This trend can potentially deliver significant benefits to electricity consumers by lowering costs, increasing reliability, lowering emissions, and enhancing customer choice. However, if integrated poorly, DERs can substantially increase power system costs and emissions (Fares & Webber 2017; Pérez-Arriaga et al. 2016; Schmalensee et al. 2015).

Regulators, policy makers, consumer advocates, and utilities are searching for solutions to ensure that DER integration increases - rather than decreases - the social net benefits of the power system. While many regulatory and market changes will be required to efficiently integrate DERs, changes to tariff design are one of the primary tools for increasing the benefits of customer engagement and DER adoption (Pérez-Arriaga et al. 2016, chap.4). The New York Department of Public Service concluded that value-driven DER adoption requires "more precise price signals for these new products and services that will, over time, convey increasingly granular system value further enabling increasingly

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accurate compensation and driving informed and therefore effective investment decisions" (NYDPS 2016). New York is not alone. In 2017, regulators in 45 of 50 U.S. states and the District of Columbia opened dockets related to tariff design or made changes to tariff design to better enable socially beneficial DER integration (North Carolina Clean Energy Technology Center 2018). Similarly, in November 2016, the European Commission issued a sweeping set of rulings designed to put consumers at the center of the European power system, and tariff design was central to the new rulings (European Commission 2016).

Of course, economics is not the only consideration in tariff design. In order for regulators to adopt more efficient tariff designs, these tariffs must be socially and politically acceptable. The perception of the fairness and equity of a tariff are critical aspects of whether or not the tariff will be accepted, and fairness considerations have historically been critical components of regulatory decision making (Jones & Mann 2001). For example, both the Massachusetts Department of Public Utilities (DPU) and the New York Department of Public Service list fairness as a core principle for tariff design, and the Massachusetts DPU recently cited fairness in a recent ruling denying a utility's petition for an increase in fixed charges (Massachusetts DPU 2016; New York DPS 2016). Similarly, the Nevada Public Utilities Commission recently overturned a previously approved increase in fixed charges, citing, fairness considerations (Nevada PUC 2017). These anecdotes are supported by the fact that equity is central to commonly cited tariff design principles (Bonbright 1961; Pérez-Arriaga et al. 2013, chap.8).

This chapter builds on existing literature to examine the issue of whether or not efficient tariffs are fair and equitable.[1] While many scholars have considered the economic and emissions implications of efficient tariffs and their relationship to DER adoption, comparatively few have examined fairness and equity considerations. This chapter aims to fill this gap, with a special focus on the equity and fairness of efficient and inefficient tariffs in the presence of DERs.

This chapter provides a clear definition of several key equity and fairness considerations in the context of electricity rate design and proposes distinct mechanisms for improving each consideration. Different groups and individuals often have different views of what is fair and equitable, and these views are sometimes grouped together or blurred in discussion regarding fairness and equity. The clear boundaries around the considerations we describe enable a better understanding of how efficient tariffs will impact equity and fairness. This chapter uses illustrative examples to highlight how properly designed, efficient tariffs can improve equity and fairness along many dimensions in the presence of DER adoption. Moving to more efficient tariff designs is critical to ensuring that customer choice and the resulting customer stratification benefit society as a whole, rather than a single customer or set of customers at the expense of others. As this chapter highlights, in many cases, tariffs can be made more efficient without compromising equity and fairness.

The chapter is organized into eight sections:

- Section 2 summarizes the existing literature on the equity and fairness of electricity tariffs.
- Section 3 provides a brief overview of the economic theory of efficient tariff design.

[1] Pérez-Arriaga et al. (2013, p.402) defines equity as meaning that "equal power consumption should be charged equally, regardless of the nature of the user or the use to which the energy is put." Section 4 highlights a number of aspects of the debate on fairness and expands upon how fairness and equity are used in this chapter.

- Section 4 outlines three key aspects of equity and fairness in the power system context. While the three considerations outlined are not novel, they provide clear boundaries between commonly discussed ideas of equity and fairness in the context of tariff design.
- Section 5 highlights how one particular aspect of equity – what we term "allocative equity" – is always improved by improving economic efficiency.
- Section 6 discusses how efficient tariffs often improve distributional equity with respect to key vulnerable customer groups. Section 6 highlights the fact that, while efficient tariffs may have "unfair" impacts on some vulnerable customers, there are many mechanisms for alleviating these distributional concerns that are superior to today's tariffs.
- Section 7 discusses the fairness and equity challenges that must be overcome in transitioning from one tariff structure to another.
- Section 8 concludes.

2. Literature Review

The existing literature on the fairness and equity of tariffs has focused on three primary issues. First, some stakeholders have argued that more efficient tariff designs are inequitable or unfair. Second, an alternative set of scholars – primarily academics and economists – have taken an opposing stance, generally arguing that efficient tariffs are indeed more equitable and fair. Finally, in response to the rapidly increasing penetration of rooftop solar photovoltaics (PV), some scholars have examined the extent to which policy support for rooftop solar PV is fair or equitable. This has also been a primary focus of regulatory proceedings in recent years.

Some power sector stakeholders – primarily select consumer advocates and trade groups – have advocated for maintaining today's largely time invariant and volumetric[2] tariffs. These stakeholders argue that efficient prices will be fundamentally unfair and/ or inequitable, arguing that efficient tariffs will have undesirable bill impacts for certain classes of consumers (e.g. low-income, fixed-income, or rural customers) (AARP et al. 2010; Southern Environmental Law Center et al. 2015; Solar Energy Industries Association et al. 2017; Alexander 2010). These stakeholders argue that today's temporal and locationally invariant tariffs protect vulnerable customer groups. Moreover, they argue that at-risk customer groups will not be able to respond to efficient prices and would face higher and more volatile bills as a result (Alexander 2010). Others take a more precautionary approach, noting that, because real time pricing may harm some vulnerable customers, real time pricing should be offered with caution and only to certain groups (Horowitz & Lave 2014).

Focusing primarily on time varying versus flat[3] rates, many scholars have noted that today's flat tariffs are inequitable, as they imbed cross subsidies between customers that consume more power during high price hours and those that consume less (Simshauser & Downer 2016; Faruqui 2012; Hogan 2010; Faruqui et al. 2010). In the short term, these "expensive" customers pay less than their cost of service, while other customers pay more. In the long term, customers that tend to consume at times of high system demand drive greater need for investment in system infrastructure, which drives up costs for all

[2] Volumetric refers to charges that are based on the volume of energy consumed. That is, the charges are primarily in a dollar-per-kilowatt-hour form.
[3] Flat rates refer to time and locationally invariant tariffs.

users. Further, they argue that concerns over the distributional impacts of efficient tariffs are exaggerated, as, depending on the local circumstances, vulnerable customers will not be harmed on average by time varying rates (Simshauser & Downer 2016; Faruqui 2012). For example, Hledik and Greenstein (2016) highlight how demand charges do not systematically harm low income customers in the dataset they examined. Similarly, Borenstein (2012) and (2016) shows that volume of electricity consumption is imperfectly correlated with income, and argues that, as a result, increasing fixed charges[4] won't necessarily increase bills for low-income customers. Borenstein (2013) discusses an opt-in time varying tariff design, showing how the introduction of this option is unlikely to significantly impact those that do not opt-in. Pérez-Arriaga et al. (2016) and Convery et al. (2017), among others, argue that economic efficiency should be the guiding principle for tariff design in the face of distributed resources, as efficient tariffs are likely to minimize cross subsidies between customers with and without distributed resources. Neuteleers et al. (2017) take a broader view, outlining different theoretical definitions of fairness and different consumer perceptions of fairness. Neuteleers et al. (2017) present a strong overview of different concepts of fairness and conclude that dynamic tariffs may be perceived as more or less fair than flat tariffs and other tariff designs, depending on the context and implementation.

The increasing penetration of rooftop solar PV has led many researchers to examine the distributional impacts of this adoption. Nelson et al. (2011) and Nelson et al. (2012) argue that the mechanism for supporting rooftop solar PV in Australia is regressive, benefitting high income customers at the expense of low income customers. Also focusing on Australia, Simpson and Clifton (2016) use surveys to explore sentiments of Western Australians surrounding the "justice" of rooftop solar support policies; they show that many Western Australians support rooftop solar despite concerns about the inequity of these policies. In the U.S., utilities have repeatedly argued that current subsidy policies for rooftop solar are unfair and inequitable (Rule 2015). This stems from a host of economic analyses highlighting the potential for cost shifts from solar owners to non-solar owners (Kassakian et al. 2011; Schmalensee et al. 2015; Borenstein 2017).

This chapter expands upon this body of literature on equity considerations of electricity tariffs in two ways. First, this chapter clearly articulate three component parts (allocative, distributional, and transitional equity) of the equity and fairness discussion. By breaking down the discussion into these three parts, this chapter is able to propose more targeted solutions to the identified challenges. Second, this chapter extends the discussion of previous authors to account for the impact of DERs beyond solar PV and pricing structures beyond time varying pricing. Specifically, this chapter expands the conversation by explaining how three key features of more efficient rates – time and location varying, and higher fixed charges – impact equity and fairness.

3. A Review of Economically Efficient Electricity Tariffs

Tariffs recover four broad classes of costs from customers: energy, capacity and ancillary services, networks, and policy and regulatory costs. Energy costs vary over time and space due to the changing marginal cost of power generation, the physical laws that govern the flow of power over transmission and distribution networks, and the need to keep electricity supply and demand balanced at all times and

[4] That is, a charge on a customer's bill that does not scale with quantity of energy consumed or peak demand.

locations (Schweppe et al. 1988). At any given point in time and location in the power system, the efficient energy price is the short run marginal cost of delivering power to that point, adjusted for losses, congestions, and the potential for scarcity (Rivier & Pérez-Arriaga 1993; Hogan 2013).[5]

Capacity and ancillary services[6] costs stem from various forms of forward commitments to enhance the reliability of energy supply. Generation capacity costs are driven by the desired margin of available generation capacity over power demand required over a period of time.[7] Under certain conditions, short run marginal energy prices can cover the full operating and investment costs of the generating plants in a given power system. However, these conditions are rarely met in practice for a variety of reasons (Read et al. 1999; Vázquez et al. 2002; Joskow 2008). As a result, in many locations throughout the world, regulators have implemented some form of capacity remuneration mechanism. These mechanisms pay generators to maintain a desired margin of available capacity above demand. These capacity mechanisms have the effect of suppressing short run marginal energy prices below the level necessary to support the level of installed firm capacity in the system. Where capacity remuneration mechanisms are in place, an efficient tariff would include a charge that reflects the impacts that a customer's consumption or production decisions during times of generation scarcity have on future capacity procurement costs (Joskow & Tirole 2007; Pérez-Arriaga et al. 2016; Mays & Klabjan 2017). This charge would resemble a peak-coincident demand charge.

While network costs are driven in the long run by the need to develop network infrastructure to meet peak injections and/ or withdrawals, the costs of existing network infrastructure largely do not change in the short term with the amount of energy consumed or produced (Borenstein 2016; Pérez-Arriaga et al. 2016). Differences in energy prices at different locations in the network can recover only a small fraction of network costs due to the significant impact of a variety of non-convex costs and constraints, including:

- regulatory, political, engineering, and environmental constraints on network investment decisions;
- the discrete nature of network investments; and
- economies of scale (Pérez-Arriaga et al. 1995).

In areas of growing demand, peak-coincident demand-based charges, that is, charges as a function of a network user's demand during times of peak network utilization, can improve economic efficiency by signaling a network user's contribution to future network costs (Pérez-Arriaga et al. 2016). It is critical to distinguish these forward-looking charges from more generic demand-based charges. Many argue that, because networks are developed to meet peak demand, demand-based charges are "cost-reflective"

[5] The nature of the efficient short-run energy price is clear, but questions remain regard default notification strategies for time-varying prices (Schneider & Sunstein 2017). Transaction costs and behavioral biases impact the optimal type and frequency of price notifications.
[6] The costs of ancillary services, that is, short-term operating reserves and other services required for system security, typically make up less than 1% of a consumer's bill. This chapter therefore focuses primarily on capacity, and largely ignores cost allocation for ancillary services.
[7] In most thermal generation-dominated system, capacity requirements have historically been driven by peak demand. As variable renewable resources and energy constrained resources gain market share in power systems globally, firm capacity requirements will increasingly be driven by the desired margin of generation capacity during periods of minimum available generation capacity margin over demand. Due to the variability of many renewable resources, these periods will not necessarily align with the periods of peak demand.

and efficient. This is a common misconception. Residual costs do not change with respect to peak demand; if peak demand is not growing or driving new network investments, peak demand-based charges do not improve efficiency. In locations in which forward-looking, peak-coincident charges are in place, these charges will recover some, but not all, network costs.

All network costs that are not recovered through differences in energy charges and through forward-looking peak-coincident network charges are referred to as "residual" costs. Designing efficiency maximizing charges for residual network cost recovery is extremely challenging. Depending on the adopted assumptions made, different methods for residual cost allocation vary.[8] Some of the key assumptions are:

1. the benefits that customers receive from connecting to the system;
2. the wealth elasticity of electricity demand for different customers;
3. the ability of customers to avoid paying for residual costs by self-generating or defecting from the grid; and
4. the information available to the regulator regarding assumptions 1, 2, and 3.

For a wide range of reasonable assumptions, fixed charges are the most efficient mechanism of residual cost recovery. This chapter assumes that the utility must serve all customers in its service territory that desire service and that customers can't avoid paying for residual network costs by defecting from the grid.[9] The latter assumption is generally true in practice today, as the costs of grid defection are prohibitively large for the vast majority of customers (Khalilpour & Vassallo 2015; Hittinger & Siddiqui 2017); for a wide range of fixed charges, the benefits of connection are still greater than the costs for essentially all customers. Under these assumptions, the welfare maximizing method of residual cost allocation is through "Ramsey-like"[10] fixed charges, in which residual costs are allocated in inverse proportion to elasticity of demand.

Any residual cost allocation method that has no effect on marginal consumption or production decisions can be considered equally economically efficient (Borenstein 2016). Critically, however, wealth effects mean that fixed charges for some customers may impact marginal consumption decisions; that is, an efficient allocation would account for the fact that higher fixed charges may reduce total electricity consumption and welfare more for poor customers than for wealthy ones. In practice, wealth and/ or income effects can be substantial. For example, the European Commission estimates that at least 50 million Europeans struggle to pay their energy bills or heat their homes (Csiba et al. 2016). However, these effects are also very challenging to measure in practice.

Finally, policy and regulatory costs are any taxes or charges designed to recover costs associated with programs like energy efficiency, renewables support, or general taxation. While some policy costs scale directly with the amount of energy consumed or produced,[11] the majority of policy costs are independent of the energy that a customer consumes or produces. Any essentially fixed policy costs are

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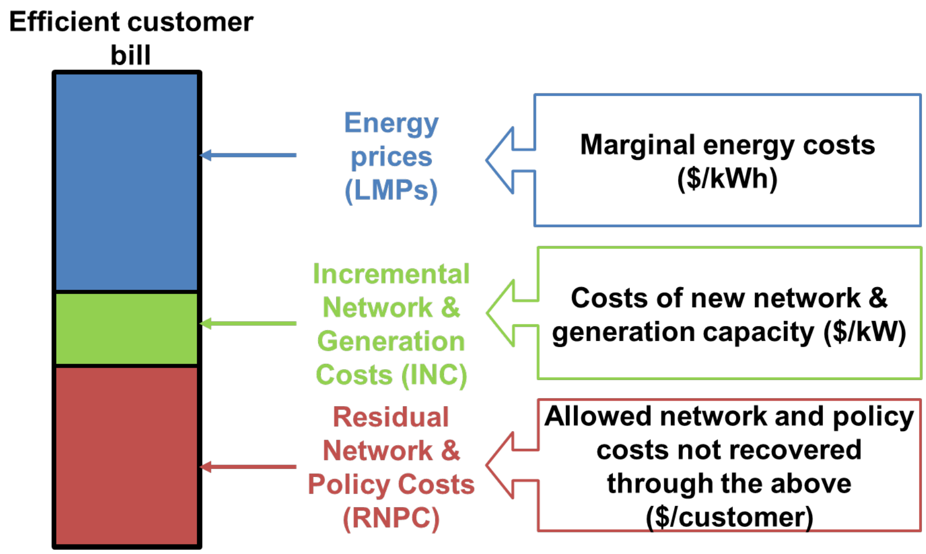
[8] See (Joskow 2007) for a discussion of the impacts of several of these assumptions.
[9] This could be the case, for instance, if residual costs are recovered through taxation. It could also occur if utilities use disconnection fees to recover residual costs.
[10] Following from Frank Ramsey's seminal work on taxation (Ramsey 1927).
[11] For example, the costs of renewable portfolio standards.

also best recovered through a non-distortive, fixed, per-customer charge following "Ramsey-like" principles.

In sum, an economically efficient customer bill would look approximately like the bill in Figure 1.

Figure 1: The composition of an allocatively efficient customer bill



The possibility of self-generation and grid defection (or "prosuming," "prosumaging," or "nonsuming") challenge much of the existing economic literature on efficient tariff design. The ability for customers to defect from the grid gives electricity provision many characteristics of "club goods" in economic literature. However, there are limits to drawing upon club goods literature, and the presence of DERs creates many interesting challenges that must be explored in future work.

While the exact details of an efficient tariff will vary across systems, certain recommendations are robust to all systems. These are:

1. Volumetric prices should closely mirror marginal energy prices, and should vary throughout time and across locations.
2. Fixed charges should be utilized to recover network and policy costs that are not recovered through efficient, cost-reflective short run charges (that is, residual costs).

This chapter takes these recommendations – that efficient tariffs should feature time- and location-varying volumetric prices and non-negligible fixed charges – as a starting point. It then examines certain equity considerations associated with their implementation.

In order to explore the fairness and equity of efficient tariffs and DER adoption, we must first define these concepts in the context of this paper. Drawing from economic theory and the existing literature on equity and fairness, we define certain aspects of these concepts in the context of electricity tariff design in Section 4.

4. Allocative Equity, Distributional Equity, and Transitional Equity

Different stakeholders in the power sector may have dramatically different views of what is fair or equitable (Harvey & Braun 1996). Indeed, there are a multitude of ways to define fairness and equity with respect to tariffs (Neuteleers et al. 2017). In general, regulators must attempt to balance these varying views to achieve an acceptable design at least economic cost.

For example, some may consider that a tariff in which all customers within a service territory pay the same per-kilowatt-hour (kWh) charge – regardless of when or where they consume – to be equitable. Many scholars have noted that tariffs of this nature benefit some customers at the expense of others (that is, some customer pay less than the costs that they drive, while others pay more) and, relatedly, that meeting this definition of equity comes at a significant societal cost.[12] Of course, others may consider tariffs of this nature to be inequitable for these reasons and others. Making informed tariff design decisions requires understanding these various tradeoffs.

The purpose of this chapter is not to definitively define equity and fairness. Rather, this chapter examines the potential tradeoffs between economically efficient tariffs and certain key aspects of equity and fairness. This chapter explores three equity considerations with respect to electricity tariff designs: allocative equity, distributional equity, and transitional equity.

In this chapter, we define an **allocatively equitable** tariff as a tariff that treats identical customers equally. Our definition of allocative equity therefore aligns with common definitions of equality (Isaac et al. 1991) and, in particular, those of Bonbright (1961) and Pérez-Arriaga et al. (2013, chap.8). 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.

Because customers located in different areas of a given network or consuming at different times are not electrically identical, this definition does not mean that all customers pay the same rate for electricity. This implies that two customers connected at the same location and consuming at the same times would pay the same marginal rates for electricity, and that no cross-subsidies of marginal costs between customers exist.[13] Many previous scholars have assessed how time invariant tariffs create cross-subsidies between customers and thus violate this concept of equity (see, for example, Faruqui et al. 2010).

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[12] See the many citations in the Literature Review section.
[13] That is, if one customer drives a cost, no other customer pays for that cost. This eliminates, for example, cross-subsidies between peaky and non-peaky customers.

Of course, as noted in Section 3, marginal cost-based charging does not recover residual costs. By definition, residual costs aren't caused by the actions of any one customer and therefore can't be charged to those who cause them. Identical customers would, according to this definition, have an identical allocation of residual costs; this meets definitions of distributive justice or equality based on equal starting points (Rawls 2001; Dworkin 2000). If a tariff allows a customer to alter their contribution to residual cost recovery by changing their consumption or production, the tariff would not be charging or paying according to marginal costs or values. Therefore, the second implication follows from the first. Tariffs that allow customers to alter their contribution to residual costs based on consumption or production decisions allow customers to deviate from the equal starting point allocation based on factors other than cost or value.

This definition of equity provides regulators leeway to define which customers are identical. For instance, regulators could use wealth or other customer characteristics to determine residual cost allocations. Section 5 delves into this issue in more detail, and highlights how improving economic efficiency always improves allocative equity.

This chapter defines a tariff structure as **distributionally equitable or fair** if it meets locally defined standards of social justice[14] with respect to the distribution of goods between vulnerable and non-vulnerable customers.[15] Of course, as noted, other definitions of fairness exist; nonetheless, here we focus on the issue of whether or not vulnerable customer groups pay an acceptable amount for electricity service, as this is a critical consideration for many regulators.

As Hogan (2010) and Neuteleers et al. (2017) describe, society's preferences for equitable distribution do not necessarily imply specific goals or preferences for how to distribute individual goods; for example, how to price electricity (Young 1995). Practically, however, regulators and policy makers in many power systems explicitly or implicitly price electricity in such a way as to meet social justice outcomes. Indeed, scholars have long recognized that one of the key regulatory functions in electric power is to distribute benefits among members of society - a function typically associated with the government (Posner 1971; D. Newbery 2018). For example, the state of New York funds programs to ensure that low-income customers spend less than six percent of their total income on electricity (New York State 2017), and the state of California offers discounts on electricity and gas prices to low income customers (CPUC 2018).

To the extent that a certain tariff scheme meets local and regional goals designed to achieve social justice, this chapter considers this scheme to be distributionally equitable or fair. Efficiency maximizing tariffs would, in theory, incorporate wealth effects into residual cost allocation, achieving some socially desirable and welfare enhancing redistribution. However, this does not imply that efficient, allocatively equitable tariffs will always meet local targets for a fair distribution of goods.

[14] Throughout this paper, fairness, social justice, and distributional equity are used interchangeably.
[15] Vulnerable customers in this context refers broadly to any customer group that has been defined as needing electricity price and/ or bill protections in a given location. Low-income, fixed-income, and rural customers are the most common types of vulnerable customers.

Finally, this chapter notes that in a transition from one tariff structure to another, there are also likely to be **transitional equity challenges**, as some consumers experience higher costs and others lower costs. In the context of electricity tariffs, the Pareto criterion[16] for a transition states that a transition should be made only if at least one customer will experience lower electricity bills while no customers experience higher bills. On the other extreme is the Kaldor-Hicks criterion,[17] which states that a transition should be made if it is net welfare improving, regardless of whether certain customers are worse off. In practice, tariff structure transitions will not satisfy the Pareto criterion. Tariff design changes may negatively impact the value of assets, and, in some cases, create stranded assets.[18] This may violate certain concepts of fairness to legitimate expectation and holds the potential to create political economy opposition to new tariff designs. To the extent that regulators or policy makers wish to address these transitional impacts, they should be addressed separately from allocative and distributional equity considerations.

Of course, these three equity considerations are not intended to cover the entire scope of possible definitions of equity. However, they are commonly discussed concepts, and thus deserve special attention.

Sections 5, 6, and 7 provide more in depth discussion of allocative equity, distributional equity, and transitional equity, respectively, in the context of electricity tariff reform.

5. The Allocative Equity of Electricity Tariffs

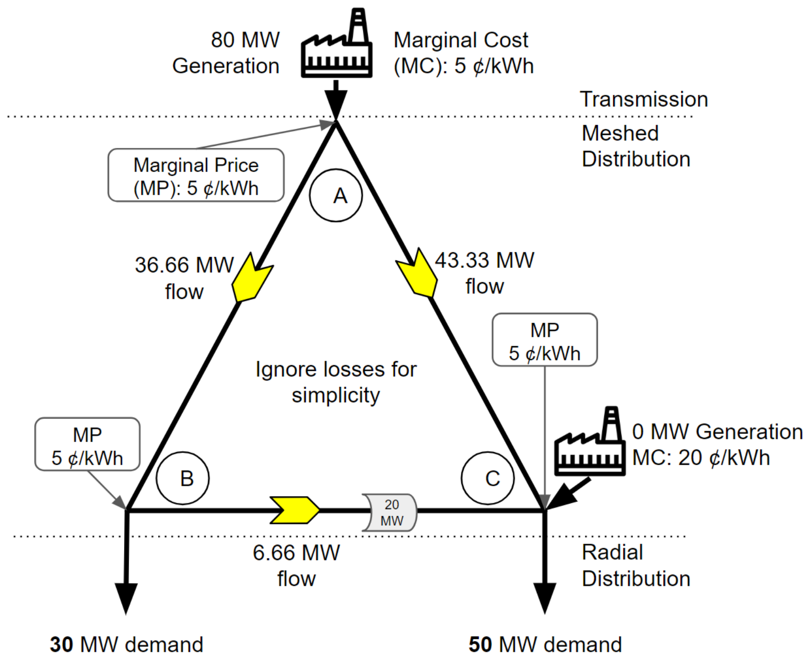
The following subsections explore three examples to better understand the allocative equity of different tariff designs. In order to maintain consistency and provide more clarity, many examples draw on a common, hypothetical power system. For simplicity and without loss of generality, this paper assumes that the system is run by a vertically integrated utility, called Investor Owned Utility, or IOU for short. The concepts described in this paper hold for all utility types (for example, municipal utilities or co-operative utilities), and are not specific to investor owned utilities.

IOU's system is depicted in Figure 2. IOU's system has three meshed nodes (nodes A, B, and C) in its distribution system and two radial distribution feeders (one connected to node A and one to node B). During both day and night, demand at node B is 30 megawatts (MW) and demand at node C is 50 MW. All customers within IOU's system are identical. For simplicity, IOU's meshed distribution power lines are lossless, and each line (i.e. line A-B, B-C, and A-C) has equal impedance. Line B-C has a 20 MW transfer capacity - that is, the line will become congested at 20 MW. The other lines each have 60 MW transfer capacities. The power flows are shown in Figure 2. The marginal cost of generation coming from the transmission grid is 5 cents per kilowatt-hour (kWh). Because this transmission-connected generator serves all of IOU's customers day and night and because there are no losses or congestions, the marginal prices at nodes B and C are 5 ¢/kWh. There is an additional generator connected to node C with a high marginal cost of 20 ¢/kWh. Because of its high marginal cost, this generator is not currently producing any power.

[16] See (Hochman & Rodgers 1969).
[17] See (Hicks 1940; Kaldor 1939).
[18] For example, the value of a home may decrease due to an increase in energy bills. Similarly, tariff design changes may render an investment in solar photovoltaics (PV) unprofitable, stranding the asset.

In this example and those that follow in Section 5, all power flows and marginal costs are calculated using a simple direct current, lossless, linearized optimal power flow model. The formulation of this model is outside of the scope of this chapter.

Figure 2: Investor Owned Utility's (IOUs) system and power flows with no distributed generation

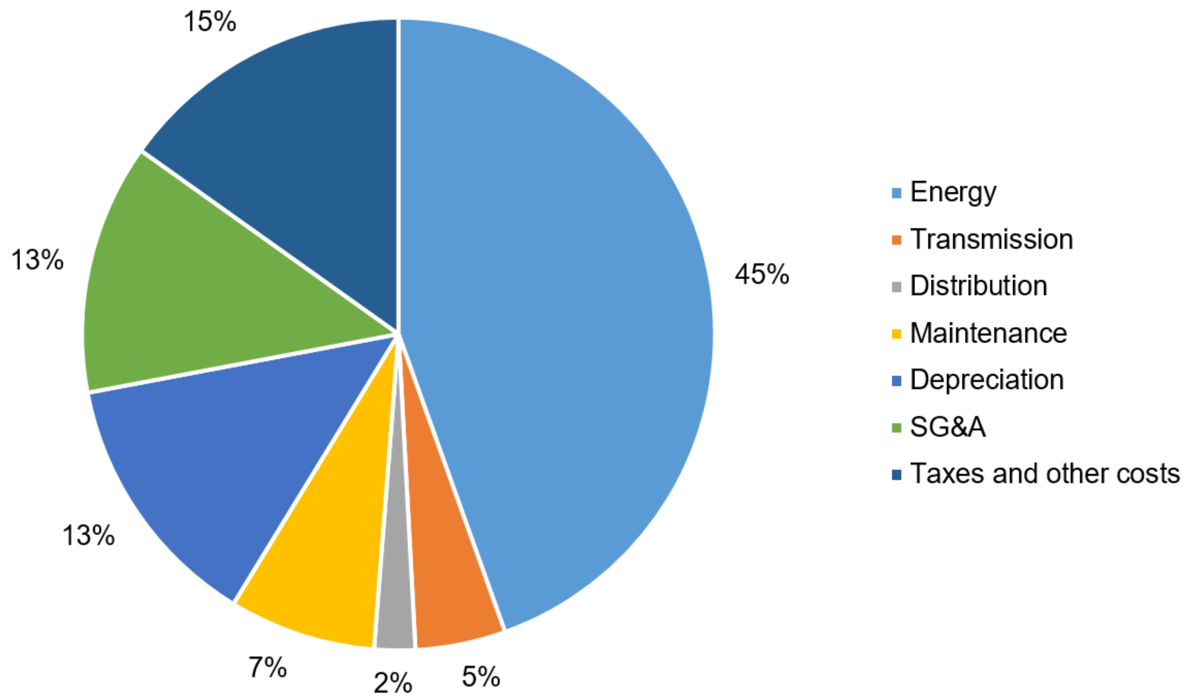


It is assumed that IOU's cost structure is identical to the average investor owned utility in the U.S., as depicted in Figure 3.[19] 45% of IOU's costs are related to the production and procurement of energy; 27% are related to network asset investment, maintenance, and depreciation; 13% are related to sales, general, and administrative (SG&A) costs; finally, 15% are taxes and other policy and regulatory costs. For the sake of simplicity, this chapter assumes that all network and depreciation costs, SG&A costs, and taxes and other costs are essentially fixed in the short term.[20] Thus, 45% of costs vary in the short term with the quantity of energy consumed, while 55% do not.

[19] Average investor owned utility cost from (FERC 2017).

[20] This is a reasonable assumption, although some costs are likely not entirely fixed. For example, certain taxes and maintenance costs may vary with the volume of energy consumption. Network and depreciation costs vary in the long term according to peak demand, but are invariant in the short term. Similarly, SG&A costs, taxes, and policy costs are related to the total size of the utility, and thus may vary in the long term but are not likely to vary in the short term.

Figure 3: Cost structure of IOU



Data source: (FERC 2017)

The following sections explore the equity and fairness of efficient and inefficient tariffs in the presence of DERs.

To analyze the typical tariff structure today, Section 5.1.1 first examines a situation in which IOU's tariffs are volumetric. The energy price for IOU's customers is 5 ¢/kWh and the charge for all the remaining costs is 6 ¢/kWh.[21] IOU therefore recovers $96,000 in energy costs and $115,200 of residual costs per day, which will be assumed to be its regulated revenue requirement.[22] For the sake of simplicity, with the exception of one example, we assume that demand in IOU's system is not growing. This chapter thus ignores the forward-looking, peak-coincident charges for network and generation capacity expansion in most examples.

This type of volumetric tariff is very common. Despite broad agreement on the benefits of efficient tariffs and widespread deployment of the infrastructure needed to calculate and communicate these tariffs,[23] less than 0.5% of residential customers and less than 5% of commercial customers in the United States even have the option of being exposed to real time prices today (EIA 2017). Instead, the vast majority of electricity consumers are on time and locationally invariant ("flat") electricity prices that recover residual policy and network costs via volumetric (that is dollar per kilowatt-hour) charges.

[21] 5 ¢/kWh covers 45% of IOU's costs, thus the remaining 55% of the costs are recovered through a 6 ¢/kWh charge.

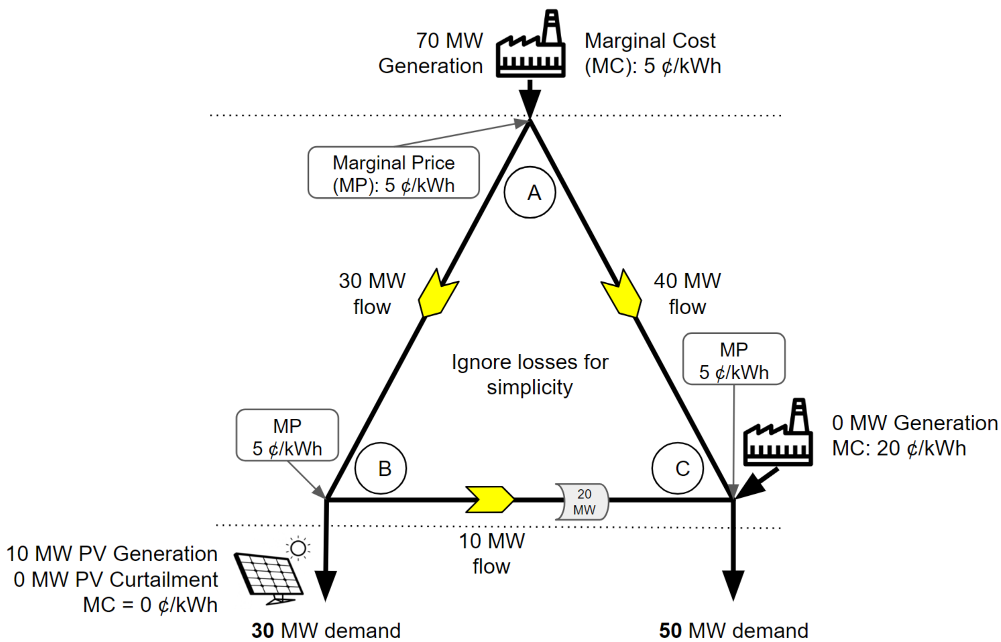
[22] 5 ¢/kWh for 80 MW during 24 hours for energy costs, and 6 ¢/kWh for 80 MW during 24 hours for residual costs.

[23] 47% of American households and 45% of American commercial properties have advanced metering infrastructure (EIA 2017)

5.1 Allocatively equitable tariffs minimize network cost shifts

Let us consider a situation in which customers at node B adopt solar. Figure 4 depicts the flows and marginal prices at each node when customers at node B have adopted a moderate amount of solar (10 MW). For simplicity, the solar system produces an average of 10 MW for all 12 daylight hours. All solar produced at node B is consumed locally, and any additional power demand must be produced at node A. Thus, the marginal prices at nodes B and C are still 5 ¢/kWh.

Figure 4: Moderate solar adoption at node B



An allocatively equitable tariff design would allocate IOU's residual costs through fixed, per customer charges. If these charges also accounted for each customer's wealth elasticity of demand, they would be economically efficient. In this example, this fixed charge would cover 55% of each customer's bill. Under an allocatively equitable tariff design, as customers increased solar production, they would be paid the marginal value of that production: 5 ¢/kWh.

Solar customers that reduce the need for future network investments should benefit from doing so. These benefits could come in the form of lower forward-looking charges in advance of a network investment and lower fixed charges in the future associated with lower levels of residual costs. Where distribution wires are constrained, this may also come in the form of payments for reducing demand during constrained network periods (Pérez-Arriaga et al. 2016). If these payments fixed for any period of time, they are essentially residual and should be recovered as such.

With flat, volumetric tariffs, customers at node B are in effect paid 11 ¢/kWh for every kWh generated since their consumption is reduced by the amount of solar generated.[24] Customers at node B are offsetting 120 megawatt-hours (MWh)[25] of 5 ¢/kWh generation, thus reducing the system's costs by $6,000 during the day time period. Solar customers at node B also avoid paying $7,200 in residual network and policy charges (per day).

Solar at node B does not change the total amount of residual costs associated with existing infrastructure that must be recovered (Schmalensee et al. 2015; Borenstein 2016). Some argue that distributed solar systems decrease future distribution system costs. Both modeling-based and empirical research efforts demonstrate that distributed solar rarely reduces and often increases future distribution system costs (Cohen et al. 2016; Schmalensee et al. 2015; Wolak 2018). Where distributed solar does reduce future network costs, the costs of any remuneration mechanisms for providing this value should be recovered as a residual cost (as no near-term action can change the need to pay for this remuneration mechanism).[26]

In this example, under flat, volumetric tariffs, IOU does not fully recover its residual costs. IOU has two options: raise tariffs to recover these costs or write these costs off.

First, IOU can raise tariffs. This would require IOU to increase tariffs for all customers by 0.4 ¢/kWh, or a 3.6% increase; this impact is especially significant for non-solar owners, because solar owners have low consumption of grid power. Citing the Faulhaber principle for cross-subsidization,[27] Wolak (2018) argues that this does not, in fact, create a cross-subsidy between customers, as solar owners are likely paying more than their incremental cost of service. Some stakeholders have used similar arguments to justify volumetric tariffs that enable customers with self-generation to contribute less to residual cost recovery. However, this idea violates both economic efficiency principles and the allocative equity principles outlined above (as solar customers' marginal actions impact the residual cost payments for non-solar customers).

Second, IOU may write these assets off as stranded, and pass these losses on to IOU's shareholders. There is legal precedent for such action (Hempling 2015). However, in most cases, regulators and utilities are hesitant to write off assets if regulators have approved cost recovery for these assets. In addition, writing off assets runs the risk of increasing IOU's cost of capital, as IOU's investments are now more risky. An increased cost of capital will have one of two effects. First, IOU may require a higher regulated rate of return, which will ultimately increase costs for all consumers. Second, IOU may slow investment in its network if the cost of capital increases closer to the allowed rate of return. This has the risk of causing deteriorating service for all network users (Baumol & Sidak 1995).

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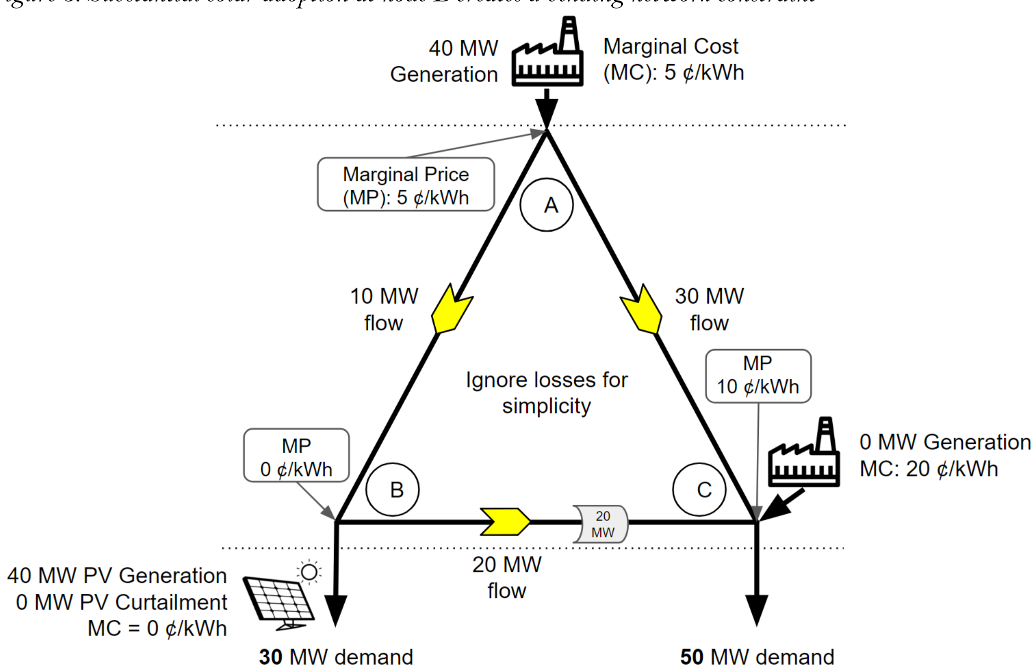
[24] This example does not require that customers are net-metered; indeed, under most tariff designs, consuming energy produced on site reduces net consumption and thus total residual cost payments.
[25] 10 MWh per hour for 12 hours.
[26] Distributed solar also provides emissions mitigation benefits (that is, avoided CO_2 and other pollutants). In some cases, the magnitude of these benefits exceed the magnitude of residual network costs on a per-kWh basis (Borenstein & Bushnell 2018). These benefits should be remunerated. However, remunerating these benefits via decreased residual cost payments simply results in a cost shift as described herein (as there is a revenue adequacy constraint on total residual cost payments). These benefits should ideally be remunerated through mechanisms independent of residual cost recovery (e.g. a carbon tax).
[27] The Faulhaber principle states that there are no cross-subsidies between customers if all customers are paying more than their incremental cost of service and less than their stand-alone cost of service. See (Faulhaber 1975).

This example demonstrates how tariffs that allocate sunk costs through volumetric charges are not allocatively equitable in the presence of rooftop solar. This example also highlights how allocatively equitable tariffs would eliminate this inefficient cost shift. The following example builds on this example and previous research, demonstrating how the inequities present in time and locationally invariant tariffs can be exacerbated by the presence of DERs like rooftop solar.

5.2 Allocatively equitable tariffs minimize energy cost shifts

Let us now consider another example in which solar at node B grows significantly. This section ignores residual cost allocation, as the previous section covered this topic. Figure 5 depicts the flows and marginal prices at each node when customers at node B have adopted a large amount of solar. In this case, solar at node B meets all of the load at node B and 10 MW of the load at node C during the daylight period. Because of the line constraint between nodes B and C and because of the need for power to flow according to Kirchhoff's laws, any production greater than 40 MW must be curtailed. The marginal price at node B is 0 ¢/kWh, as any additional demand will be met locally by zero marginal cost solar. The marginal price at node C, on the other hand, is 10 ¢/kWh, as, in order to meet an increment of 1 megawatt-hour (MWh) of demand at node C, the generator at node A must increase production by 2 MWh and the solar system at node B must curtail production by 1 MWh.

Figure 5: Substantial solar adoption at node B creates a binding network constraint



If flat, locationally invariant prices are used, the energy price seen by customers at nodes B and C will be 5.625 ¢/kWh: the average energy price. This is inefficient and problematic for several reasons.

First, customers at node B cross-subsidize customers at node C substantially during the day. Customers at node C pay less for energy than the marginal cost of service during the day, and customers at nodes B and C pay more than the marginal cost of production at night. Similarly, customers at node B pay more for energy during the day than necessary, underutilizing the zero marginal cost resource.

Second, if customers at node B are paid the average energy price for solar production, this sends a signal that power at this node is still valuable, despite the fact that any new solar production will simply be curtailed. This could drive further solar adoption at node B, exacerbating cost shifting problems. This also masks the value of power at node C.

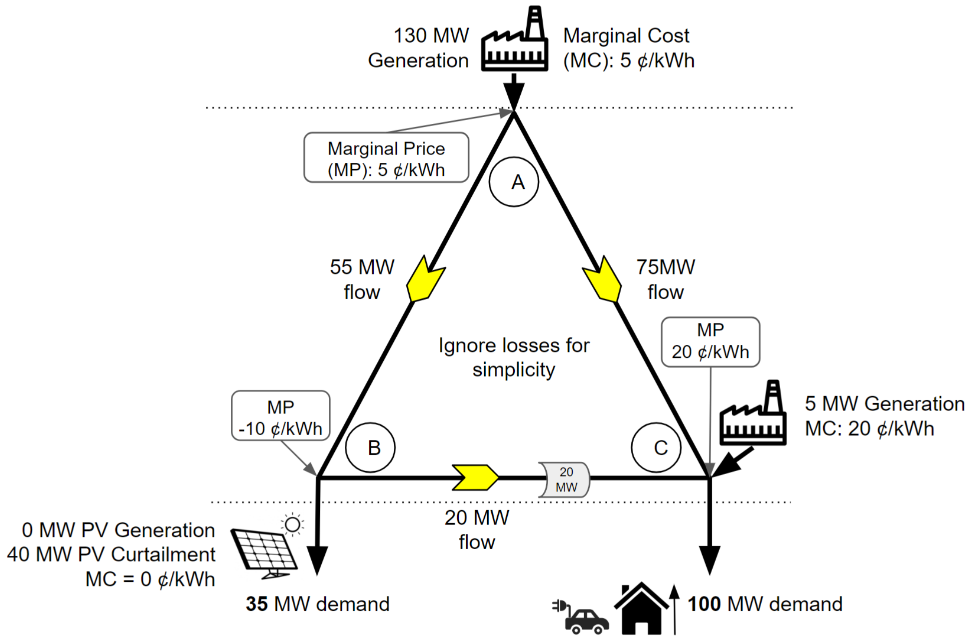
Allocatively equitable tariffs would charge each customer the marginal cost of energy at each time and location (that is, the marginal price at each node). Hence, allocatively equitable tariffs would enhance social welfare by eliminating inefficient under- and over-consumption, and by providing better investment signals.

5.3 Allocatively equitable tariffs improve incentives for efficient network utilization

The final example in this section highlights how forward-looking network charges can improve allocative equity over today's socialized, volumetric network charges. In this example, substantial load growth at node C creates a binding constraint on the B-C line. Some load growth occurs at node B, but this load growth is not nearly as large. Due to the load growth at node C, the high marginal cost generator at node C must be dispatched to meet additional demand at node C. This drives the marginal price at node C to 20 ¢/kWh. In this case, consuming more at node B would actually lower the total system cost, as it would enable more demand at node C to be met by the generator at node A. This is reflected in the marginal energy price at node B, which is -10 ¢/kWh.[28] This scenario is depicted in Figure 6.

[28] That is, consumers would get paid for increasing consumption, and producers would pay for increasing production.

Figure 6: Substantial load growth at node C leads to dramatically different nodal energy prices



In this example, if energy prices are averaged, customers at node B may pay significantly more than their cost of service, while customers at node C will pay significantly less than their cost of service.

Imagine that IOU found it welfare improving to expand the capacity of the B-C line by 5 MW. In this case, the beneficiaries of this investment are the generator(s) connected to node A, the generators connected to node B, and the consumers connected to node C. Generators at node A and B benefit by selling more power. Customers at node C benefit substantially, as the marginal price of energy falls 75% from 20 ¢/kWh to 5 ¢/kWh. Consumers at node B pay higher prices, as the marginal cost of service increases to 0 ¢/kWh during daylight hours and 5 ¢/kWh during night hours.

An allocatively efficient tariff design would charge customers at node C for their impact on future network costs, signaling the impact of customers at node C's behavior on future network costs and enabling IOU to recover the costs of the B-C line. Consumers at node B would not face such charges, as their behavior is not driving the investment. If the costs of this upgrade were socialized to all customers at nodes B and C, consumers at node B would pay substantially more than their benefits would justify, while customers at node C would pay substantially less. This is clearly not an allocatively equitable outcome.

Cost socialization could be considered allocatively equitable if all customers had similar benefits from electricity consumption and production and similar load and production profiles. However, as customers begin to stratify through DER investments and other services, the assumption of customer homogeneity will be increasingly problematic.

6. Distributional Equity

The above section demonstrated that efficient tariffs improve allocative equity (that is, minimize the amount that one customer's actions negatively impact other customers). Efficient tariffs internalize the costs (or value) of consumers' (or producers') decisions, eliminating cost shifts from one customer to another. However, policy makers and regulators often use tariffs as a means to achieve distributional outcomes (Posner 1971). Some power sector stakeholders insist that efficient tariffs will have undesirable distributional outcomes for some vulnerable customers, particularly customers with low- and fixed-income. Nevertheless, today's tariffs are allocatively inequitable and inefficient. Thus, this argument begs three key questions, further explored in this section:

1. Will efficient tariffs create undesirable distributional outcomes?
2. How do DERs affect the distributional impacts of today's tariffs?
3. Are there ways to achieve desired distributional outcomes without sacrificing allocative equity and efficiency?

The nature of residual cost recovery under efficient tariffs provides initial insight into the distributional impacts of efficient tariffs. Ramsey cost allocation allocates costs in inverse proportion to the demand elasticity of the customer. Given that residual costs under an efficient tariff are recovered through fixed charges, customers will only respond if, due to wealth effects, higher fixed charges lead to a reduction in total consumption. Thus, in short, efficient tariffs would allocate a higher proportion of residual costs to high income customers relative to low income customers.

6.1 Efficient tariffs likely improve distributional equity on average

The distributional outcomes of efficient tariffs will depend on the locational context, the demand patterns of vulnerable customers in the region, and the exact structure of the implemented tariffs. However, the bulk of the existing literature on efficient tariffs indicates that efficient prices neither harm low income or other vulnerable customers on average nor disproportionately harm these groups relative to high income customers (Allcott 2011; Faruqui et al. 2010). On the contrary, by driving demand reductions and DER generation during high cost hours, efficient tariffs will reduce power system costs for all customers, including vulnerable groups. While efficient tariffs likely won't increase prices on average for vulnerable customers, efficient tariffs may increase costs for *some* vulnerable customers. Vulnerable customers whose demand is correlated with local and system-wide high price periods or who are located in high cost areas will likely see higher bills.

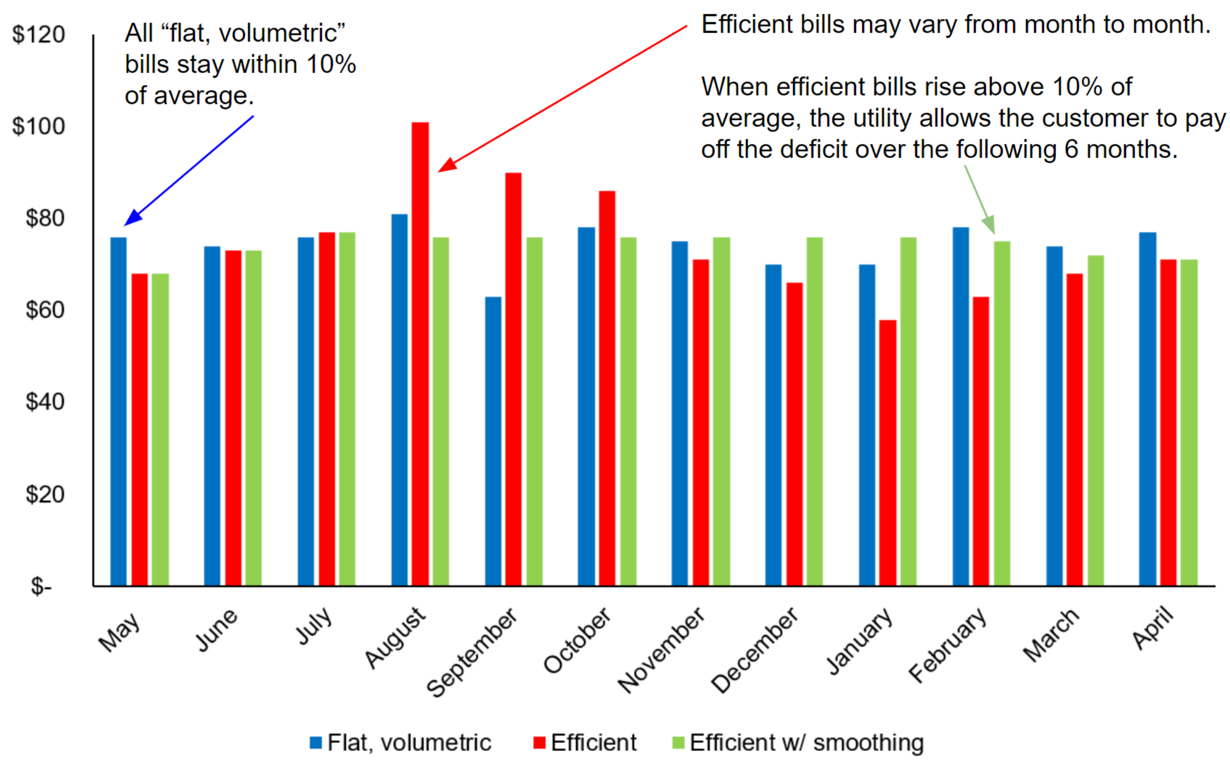
However, the fact that some vulnerable customers may be worse off under efficient tariffs – absent any intervention – should not dissuade regulators, policy makers, and consumer advocates from pursuing efficient tariffs for at least two reasons:

1. Today's tariffs are imperfect tools for socially desirable redistribution, and are therefore not inherently distributionally equitable compared to other tariff designs under consideration.
2. There are superior ways to support vulnerable customers than through flat, volumetric tariffs.

The argument that flat, volumetric tariffs aren't distributionally equitable follows directly from the fact that efficient tariffs do not harm vulnerable customers on average. That is, as demonstrated by Allcott (2011) and Faruqui et al. (2010), moving from flat to dynamic prices benefits low-income customers on average. Some research has indicated that certain volumetric tariff structures do benefit low income customers on average (Borenstein 2012). However, this research highlights that income and electricity consumption are imperfectly correlated, and that there are alternative mechanisms for improving distributional equity and efficiency simultaneously (Borenstein 2012). Section 6.3 dives deeper into the argument that there are more efficient mechanisms for improving distributional outcomes in the following subsection.

While average bills for vulnerable customers may not increase under efficient tariffs, efficient tariffs may increase month-to-month bill volatility. Increased bill volatility can be a concern for all customers, but the challenge presented by bill volatility may be especially acute for low- and fixed-income customers. Borenstein (2006) examines the extent of that volatility and shows that simple hedging and payment plan options can mitigate the bulk of bill volatility. For example, utilities can automatically provide a payment plan that allows customers to pay off bills over many months when bills rise to a certain percent above average. This concept is demonstrated in Figure 7. In each of the cases in Figure 7 (that is, in flat, volumetric, efficient, and efficient w/ smoothing cases), the average bill is $74 per month. In the "efficient w/ smoothing" case, in any given month, if the customer's bill increases above 10% of his or her average bill, he or she automatically pays off the remainder of the bill over time.

Figure 7: Illustration of customer bills under a simple volatility-smoothing payment plan (with synthetic data)



6.2 DERs create distributional inequity with flat, volumetric tariffs

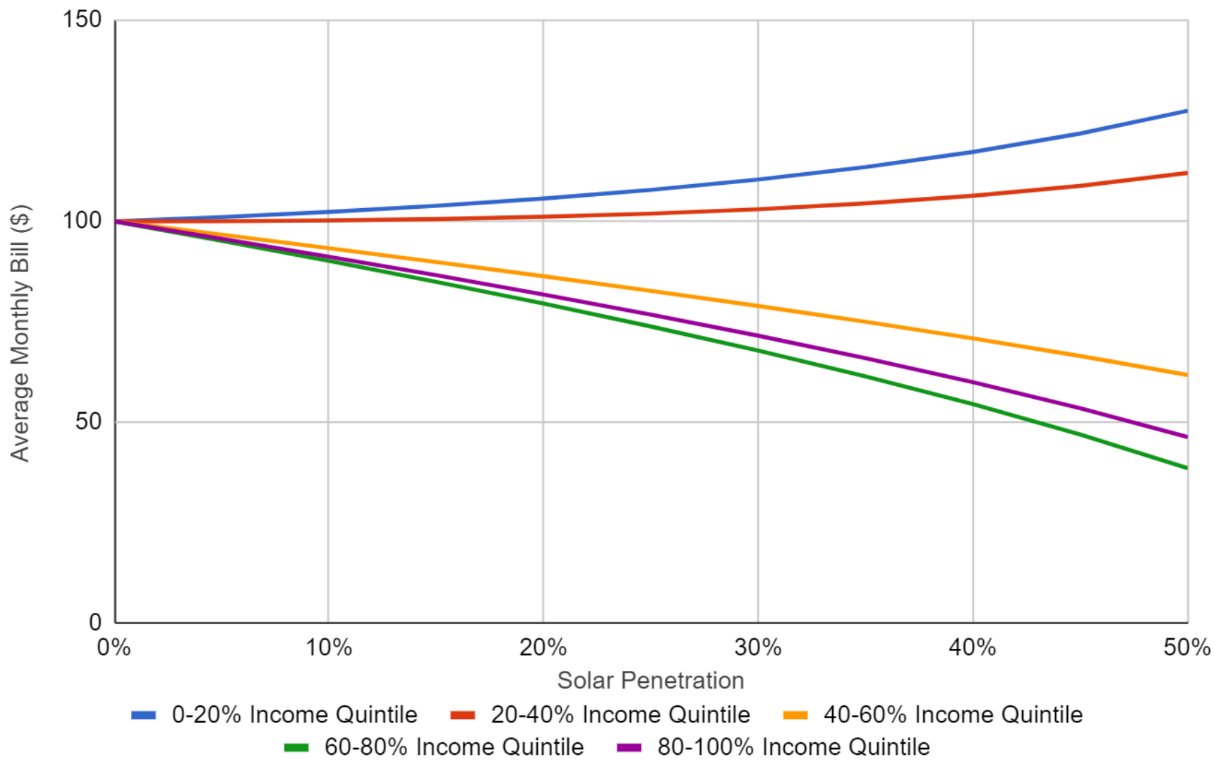
Under today's tariff designs, DER adoption and customer stratification is likely to drive greater distributional inequity. This stems from the fact that, under inefficient tariffs, DERs drive significant cost shifts as described in Section 5. The average DER adopter tends to be significantly higher income than non-DER adopters, so low-income customers are likely to pay higher bills as a result of these cost shifts.

In the largest review of solar owner income to date in the United States, the Lawrence Berkeley National Laboratory found that median income of solar adopting households is over 50% higher than the U.S. median (Barbose et al. 2018). This finding is consistent with other findings regarding the income of solar PV owners (Borenstein 2017). EV owners also tend to be substantially wealthier than non-EV owners (Tal & Nicholas 2014); in fact, as of 2015, the top income quintile had received 90% of electric vehicle tax credits in the U.S. (Borenstein & Davis 2016). EV adoption is ultimately expected to drive significant investments in network infrastructure, especially if charging is poorly coordinated (Muratori 2018; Fernandez et al. 2011). If the cost of this infrastructure is socialized (rather than paid for by the individuals driving the investments in this infrastructure), low-income customers will likely pay for network costs incurred for the benefit of high-income customers.

The distributional impacts of flat, volumetric tariffs[29] in the presence of rooftop solar are demonstrated in Figure 8. The figure shows the changes in customer bills by income quintile as the penetration of rooftop solar increases. This analysis assumes that solar adoption in each income quintile remains at the average adoption by quintile in the U.S. as of 2016, as described in (Barbose et al. 2018). That is, the 0% to 20% income quintile accounts for 7% of rooftop solar adoption; 20% to 40% accounts for 11%; 40% to 60% for 24%; 60% to 80% for 30%; and the top income quintile for 28%. This example also assumes that IOU's fixed costs remain the same under all solar PV penetration levels.[30] As solar PV penetration grows, all income quintiles offset some energy expenditures. However, given that solar PV adoption rates are highest among high-income quintiles, the average bill for the bottom two income quintiles ultimately increases, as these customers pay for the majority of residual costs. This stems from the fact that low income customers now have higher average net consumption (household consumption minus PV production) versus customers in the higher income quintiles.

[29] The tariff structure in this example is initially identical to the tariff used in Section 5.1.1: 5 ¢/kWh for energy and 6 ¢/kWh for all residual network and policy costs. As solar penetration decreases net consumption, the utility must raise the rate for network and policy costs to fully recover residual costs.
[30] This is a generous assumption, as the bulk of existing research suggests that distributed solar PV more often increases rather than decreases distribution network costs (Wolak 2018; Schmalensee et al. 2015; Vaishnav et al. 2017).

Figure 8: Changes in customer bills by income quintile as rooftop solar PV grows under flat, volumetric tariffs



By charging all residual costs to customers in the form of a fixed charge, efficient tariffs would eliminate cost shifts from wealthy to low-income customers, improving distributional outcomes. Similarly, tariff designs that charge future network investments to the beneficiaries of those investments improve distributional outcomes, as highlighted in Section 5.3.

6.3 Achieving distributional and allocative equity

Sections 6.2 and 6.3 have demonstrated that efficient tariffs likely improve distributional outcomes on average and that today's tariffs are not distributionally equitable to begin with. However, Section 6.1 showed that moving from today's tariffs to more efficient designs may result in higher bills for *some* vulnerable customers. It is possible to support these vulnerable customers without sacrificing efficient marginal signals. As aforementioned, an efficient tariff structure would ideally allocate residual costs in such a way as to have the minimal impact on the utility of low income customers. However, in practice, it is extremely challenging to measure the impacts of fixed charges on a customer's utility, and other measures may be necessary.

The optimal method would be to create means-tested bill rebates for vulnerable customers. In means-tested programs, the parameter of interest (e.g. income level) is directly measured and used to determine the level of bill support.[31] These types of program should be financed through fixed charges levied on non-vulnerable customer bills. This mechanism would maintain allocatively efficient marginal price

[31] One could conceive of a state-sponsored program whereby, when creating a utility account, customers are required to provide information that enables the utility to verify income levels without violating privacy.

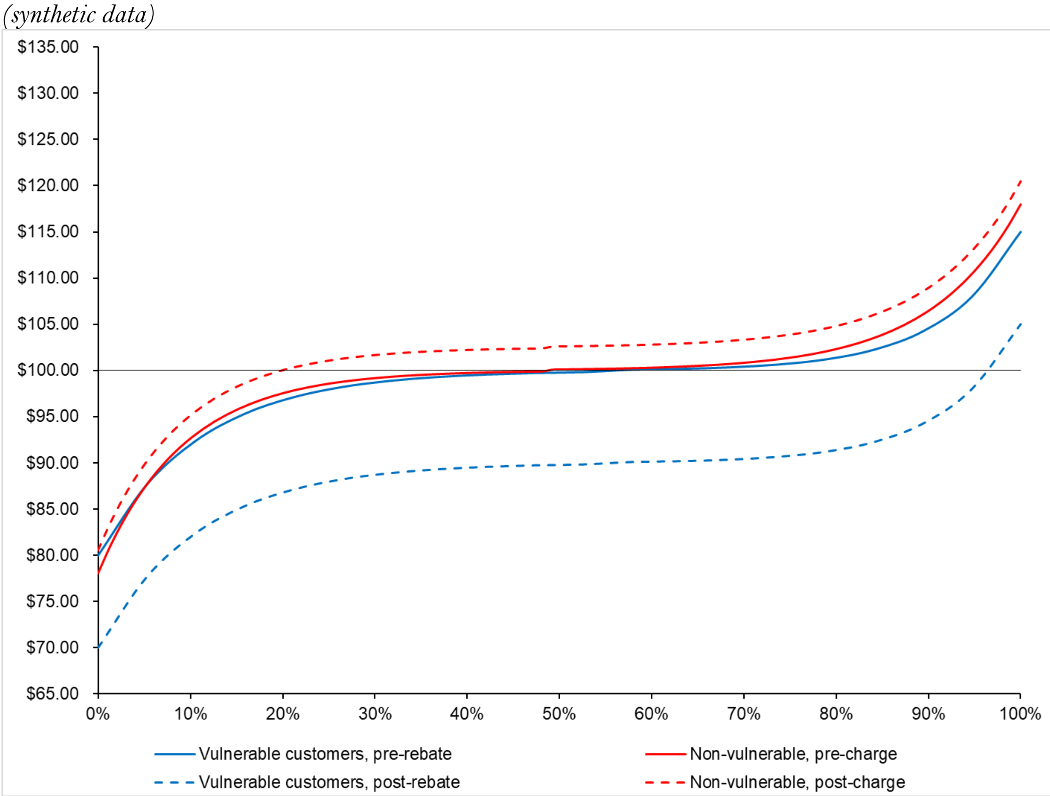
signals while achieving desired distributional outcomes. If regulators or consumer advocates are concerned with the feasibility of implementing means-tested programs, rebates provided to customers in predominately low-income geographies or alternative mechanisms are possible.

As the majority of customers are likely not vulnerable, small charges to the majority of customers could finance substantial bill reductions for the small set of vulnerable customers. Figure 9 demonstrates this concept using synthetic data. In this hypothetical example, small fixed charges ($2.50 per customer) slightly increase the bill of the 80% of customers who do not qualify as vulnerable. Because vulnerable customers represent a minority (20% of customers), these customers' bills are reduced substantially (by $10 per month). These charges and rebates enable nearly all low income customers to benefit from the transition to more efficient tariffs. So long as the increased fixed charges on non-vulnerable customers do not:

1) drive costs above customers' incremental cost of service; and
2) cause customers to consume below what their marginal value would dictate,

There is no loss of economic efficiency.

Figure 9: Average Bill Following Transition From Flat to Efficient Tariffs, Before and After Vulnerable Customer Support (synthetic data)



Some stakeholders have advocated for creating DER deployment mechanisms targeted at low-income customers. While such programs may lower bills for participating low-income customers, they solve none of the fundamental allocative or distributional equity problems described herein. A better mechanism would be to improve the allocative efficiency of tariffs, support low-income customers through means-tested rebates, *and* support targeted DER deployments for vulnerable customers if desired.

This section has demonstrated that flat, volumetric tariffs are distributionally inequitable, and that these inequities are likely going to be exacerbated as DER penetration grows. This section introduced mechanisms for managing the transition from today's tariff regime to more efficient tariffs for vulnerable customer groups. The next section introduces mechanisms for supporting all customers in the transition from today's tariff regimes to more efficient tariffs.

7. Transitional Equity

A tariff design change that is net welfare improving will reduce average bills while potentially increasing bills for certain customers or customer groups (this meets the Kaldor-Hicks criteria for a beneficial transition, as introduced in Section 4). As prices become more temporally and spatially granular, customers who consume more than average in high price hours and areas will see higher bills. An increase in fixed charges to recover residual costs will mean a commensurate decrease in volumetric charges. This may raise bills for customers with relatively low net consumption (either due to low gross consumption or due to ownership of distributed generation). These bill increases may materially affect the value of long-lived assets with substantial fixed costs, like homes and solar PV plants.

Regulators and policy makers may wish to address these concerns, as, in general customers cannot reasonably be expected to account for the potential for future tariff design changes in their investment decision-making processes. This is generally referred to in the natural justice literature as fairness to legitimate expectation (Rawls 2001, p.72). Customers may feel they have a right to compensation following the change, given their legitimate expectation of the continuation of a previously implemented tariff design. Such views also have grounds in behavioral economics; because customers often evaluate fairness based on changes relative to a baseline, tariff design changes that make some worse off may be viewed as unfair (Kahneman et al. 1986). These transitional impacts are simply the result of prices becoming more aligned with costs or value. Nonetheless, they are often conflated with allocative equity or distributional fairness considerations.

While regulators and policy makers may wish to address these transitional challenges, these challenges are distinct from the allocative and distributional equity issues discussed above. Distinct problems call for distinct solutions. In many ways, the issues regulators will face in transitioning towards more efficient tariffs will mirror those faced in the transition from vertically integrated to restructured markets; however, in this case, customers, rather than utilities will own the sunk assets.

One of the key methods to alleviate transitional equity challenges is implementing changes gradually (this is commonly referred to as gradualism). Regulators may wish to educate customers (for example, through shadow billing) in the months or years preceding a tariff design change. Similarly, regulators could implement a tariff design change and fully hedge customers against the impact of that change. Over time, regulators could reduce and eventually eliminate the hedge. This hedge would effectively act as a transfer from customers who benefit from the change to those who lose under the change. These transfers would ideally take the form of lump-sum bill rebates, financed through non-distortive taxes or charges, as introduced in Section 6.3. Regulators may also wish to grandfather certain assets into existing programs (for example, solar PV systems into net metering programs). Finally, regulators may wish to maintain opt-out options. For example, if regulators changed default prices from flat, volumetric tariffs to a more efficient design, regulators could maintain the option to opt into the old design. This option would not guarantee that the magnitude of the flat, volumetric tariff would remain unchanged; it could be combined with the hedging option described above in order to reduce the rate of change.

In the long run, consumers can internalize the impacts of tariffs on their investment decisions. While this concept may seem far-fetched in the context of electric power, there is precedent for this type of cost internalization. Similarly, consumers buy cars and home appliances understanding the impact of fuel and electrical efficiency. Armed with appropriate information, consumers could make similar decisions regarding investments in a greater array of electricity consuming or producing goods. If companies design products that schedule energy usage to reduce energy costs, more efficient tariffs will help concentrate the benefits of the product in certain areas; companies can more effectively advertise to customers with high value of adoption, reducing acquisition costs. After a transition period, and with appropriate technological enablement and education, efficient tariffs could simply be another part of a consumer's investment decision-making process.

Beyond the considerations of fairness with respect to legitimate expectation, regulators may seek to blunt transitional impacts in order to mitigate political economy issues that limit the viability of more equitable prices. People who would experience higher bills under a new tariff design might lobby to keep the current design in place, even when the current design is inefficient for society as a whole. Higher bills or other negative outcomes (for example, lower valuations for distributed solar) are likely to be concentrated, while the benefits of more efficient tariffs will likely be diffuse (assuming a net beneficial transition with relatively evenly distributed costs and benefits). The converse of this is that customers may not clamor for more efficient tariffs, as the benefits are often diffuse and opaque.

8. Conclusions

With improved tariff design, the transition to a more distributed power system holds great potential to produce a more equitable, reliable, low carbon, and cost effective power system. However, flawed tariff designs such as those in place today will enable customer stratification based on regulatory arbitrage. This outcome is neither equitable, sustainable, nor desirable.

This chapter demonstrates that the tariffs necessary to enable socially beneficial customer stratification are more equitable across many dimensions than today's flat, volumetric tariffs. By reducing cross subsidies of marginal costs and cost shifts of residual costs between customers, efficient tariffs are more "allocatively" equitable. In addition, this chapter highlights that, within a set of reasonable assumptions, it is possible to improve the efficiency of electricity tariffs without sacrificing allocative equity. Should regulators or policy makers wish to mitigate all potential distributional impacts, means-tested, minimally-distortionary rebate programs can protect vulnerable customers without sacrificing efficient signals for the remaining mass market customers. In other words, supporting vulnerable customers is not synonymous with creating rate designs that lead to inefficient and distortionary customer stratification and DER deployment. Finally, this chapter also demonstrated how tariff designs that improve equity may create negative outcomes for certain customers in the short term. These transitional concerns are distinct from distributional and allocative equity issues and deserve tailored solutions.

Contrary to commonly held beliefs, today's flat, volumetric tariffs are not inherently more equitable than efficient tariffs across many dimensions. The emergence of DERs will only exacerbate the allocative inequities present in today's tariffs. Transitioning from today's designs to more efficient and equitable tariffs will not be seamless. The benefits of efficient tariffs are diffuse, while the costs are often concentrated to certain companies, service providers, and customer groups.

However, as highlighted in the introduction to this book, the trend of customer stratification is likely to accelerate in the coming years. Technologies like solar PV panels, energy storage systems, and smart home devices might look more like consumer electronics than traditional power system infrastructure. Nonetheless, their aggregate impact on the grid could be massive. These technologies have the potential for major positive changes, creating a more efficient, low carbon, and equitable system for all consumers. However, without bold regulatory action, this impact could be destructive, creating a power system that works for certain customer strata at the expense of others. Which future is realized depends on the ability of regulators and policy makers to align the benefits and costs of increased customer stratification and DER adoption. Fortunately, such actions will create a more equitable system for all customers.

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