REGULATORY APPROACHES TO THE INTEGRATION OF RENEWABLE AND STORAGE RESOURCES INTO ELECTRICITY MARKETS

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REGULATORY APPROACHES TO THE INTEGRATION OF RENEWABLE AND STORAGE RESOURCES INTO ELECTRICITY MARKETS

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This dissertation describes regulatory approaches that encourage the efficient integration and participation of storage and distributed energy resources (DERs) in electricity markets. In particular, it aims to mitigate barriers to the entry and realization of the full value of these technologies with two approaches.

A first approach comprises a mechanism for the participation of storage resources in the wholesale market. The mechanism delineates a regulatory framework aimed (*i*) to diversify the alternatives to monetize the value of storage resources through wholesale markets and (*ii*) to enlarge storage owners opportunities to monetize the value of their assets regardless of their merchant or regulated nature. Essential to this participation mechanism —an open access approach to the integration of storage— is the centralized operation of the participating assets and the use of tradable electricity derivatives, referred to as financial storage rights (FSRs), to remunerate the energy arbitrage service provided by the assets. This remuneration scheme ensures the revenue adequacy of the independent system operator —by means of a generalized simultaneous feasibility test— and brings additional value to market participants. In particular, FSRs allow market participants to hedge intertemporal price risk (*i.e.*, profile risk) and to monetize intertemporal flexibility capabilities for improving the intraday load profile.

The second approach addresses the design of retail electricity tariffs for distribution systems with distributed energy resources (DERs) such as renewable

distributed generation and energy storage. This analysis aims to shed lights on the impact of tariff structure —particularly dynamic pricing and connection charges— upon social welfare and the integration of DERs. In particular, this analysis presents a framework to optimize ex-ante two-part tariffs for a regulated monopolistic retailer who faces stochastic wholesale prices and fixed costs on the one hand and a stochastic demand on the other. Within this framework, the exogenous integration of DERs is addressed by characterizing their endogenous effect on optimal tariffs and on the induced welfare effects. Two DER integration models are considered: a decentralized model involving behind-the-meter DERs integrated by customers in a net metering setting, and a centralized model with retailer-integrated DERs.

This analysis shows, one the one hand, that net metering tariffs relying on price markups to maintain revenue adequacy —which provide strong incentives for DER integration— entail cross-subsidies and significant consumption inefficiencies that can outweigh the social value of DERs. On the other hand, it demonstrates that net metering tariffs can achieve revenue adequacy without compromising social welfare through marginal cost pricing and higher connection charges, but these undermine the incentives to integrate distributed generation. Numerical simulations based on empirical data are presented to illustrate and validate the analysis.

BIOGRAPHICAL SKETCH

Daniel Muñoz Álvarez graduated magna cum laude from Universidad de los Andes (Colombia) in 2010 with Bachelor's degrees in Electrical Engineering and in Electronics Engineering. He then pursued graduate studies at the same university and was awarded a cum laude Master's degree in Electrical Engineering in 2011. During the latter studies he conducted research under the supervision of his advisor Prof. Ángela I. Cadena and also Prof. Francisco D. Galiana at McGill University (Canada).

After his master's studies, Muñoz Álvarez continued his graduate studies joining Cornell University in 2011 to pursue a doctoral degree in the School of Electrical and Computer Engineering. Therein, he had Prof. Lang Tong as his advisor and Prof. Eilyan Bitar and his co-advisor. He obtained his Ph.D. degree in 2017 with a major in Electrical Engineering and a minor in Applied Economics, field in which Muñoz Álvarez was mentored by Prof. Tim Mount.

Throughout his graduate studies Muñoz Álvarez conducted research in the intersection of electricity markets, economics, and optimization focusing on the restructuring of markets for the integration of renewable energy, energy storage technologies, and distributed energy resources.

Para Mandito, Ceci, Sebas, Aya, y sobretodo, Cris

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Daniel Muñoz Álvarez
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CHAPTER 1

INTRODUCTION

At the verge of a transformation driven by technological innovations, the electric power industry has a unique opportunity to evolve towards a decentralized and decarbonized paradigm by favoring more inclusive market rules. These innovations involve cost reductions in modular technologies such as photovoltaic (PV) solar panels, electric batteries, and smart meters, making them more competitive. In fact, due to these innovations, distributed energy resources (DER) and demand response (DR) programs are starting to compete with more traditional generation, transmission, and distribution expansion alternatives. However, to make the widespread adoption of these technologies possible, many entry barriers still need to be mitigated. Many of these barriers are regulatory choices embedded in market rules historically biased towards traditional —more centralized— expansion alternatives. And, as such, they need to be transformed into more inclusive rules that are, for instance, technology-neutral and open to alternative —more decentralized— ownership structures that improve customers' choices regarding their electricity needs.

Consider, for example, the case of energy storage technologies. Many studies and reports argue that storage resources face significant market, regulatory and policy barriers [5, 82, 126, 129, 135, 136, 139]. In response, FERC has acknowledged these barriers and has issued several rulemakings intended to alleviate some of them starting with FERC Order No. 890 [139][1]. In particular, the literature seems to agree that the following are three crucial barriers hampering the deployment of storage. First, the incomplete valuation of the benefits brought by storage is

[1]See [53, footnote 15] for a detailed list of FERC Orders.

one of the most cited barriers [126]. Second, the restrictive regulatory treatment of storage which typically limits the value streams that can be exploited by a particular asset. An example is the inability of storage assets to provide both regulated and market-based services [53,126,129]. Lastly, revenue risk also appears to be a significant barrier, especially for merchant storage developers who —unlike regulated utilities— are exposed to the risk of revenue insufficiency [126]. While storage assets could also be rate based, *e.g.*, as an asset providing transmission services, revenue risk "can add to the difficulty of demonstrating the prudence of a storage project" [126]. To some extent, these barriers are valid for all storage projects regardless their intended location on the electrical system and ownership structure.

Broadly, this thesis addresses certain barriers to the deployment of storage and DERs with two separate proposals. On the one hand, the first proposal in Chapter 2 addresses the participation of storage resources in the wholesale market. This proposal is indifferent to the resources' location within the electric power network, to its capacity and physical model, and it suits both co-located storage resources and aggregated fleets of storage resources. However, it is naturally more appropriate for resources located within a single (wholesale) pricing zone and with a collective capacity large enough for the wholesale market. In particular, the proposal delineates a regulatory framework that allows storage resources to derive revenue primarily from their temporal arbitrage capabilities regardless of whether the resource is classified as a regulated or merchant asset. For regulated storage assets, this framework enables the provision of a market service not allowed by the current regulatory treatment of storage. For merchant storage assets and even DER aggregators, the value of the framework is that it embodies a structured, flexible and centralized market mechanism to hedge the net revenue derived from temporal arbitrage. The framework appears as an alternative to participating in the day-ahead energy market, which has been demonstrated to expose storage resources to significant revenue uncertainty [126][2]. The proposed framework brings additional value by proving market participants with a centralized market for financial instruments that are dedicated to hedge intraday temporal price differences in a manner complementary to the hedge provided by financial transmission rights (FTRs) against nodal price differences. This framework is compatible with the notice of proposed rulemaking recently issued by FERC [53] which intends to "establish a participation model consisting of market rules that, recognizing the physical and operational characteristics of electric storage resources, accommodates their participation in the organized wholesale electric markets". Moreover, it seeks to "define distributed energy resource aggregators as a type of market participant that can participate in the organized wholesale electric markets under the participation model that best accommodates the physical and operational characteristics of its distributed energy resource aggregation" [54].

On the other hand, the second proposal in this dissertation addresses the participation of storage resources—and more generally of distributed energy resources (DERs)—in the retail electricity market. The proposal —developed in Chapters 4 and 5— is intended exclusively for DERs located within the distribution network or on-site at the end-customers' side of the meter. As such, it is more appropriate for DERs with an individual or aggregate capacity suitable for distribution networks or end-customer circuits. In particular, the proposal addresses the impact of DER integration in the highly regulated retail electricity tariff design process. It studies the vicious cycle that current tariff design practices—based on marked-up retail prices and net metering arrangements—can create as end-customers start

[2]For example, [45, 123, 127] show that arbitrage revenues can vary by a factor of up to five from year to year.

adopting DERs, such as solar photo-voltaic (PV) systems and electric batteries, more widely. More specifically, it studies some of the negative effects of the vicious cycle—namely, the economic inefficiencies caused by price markups and the cross-subsidies given to DER-owning customers—and examines how optimally designed dynamic prices and connection charges can mitigate such effects. In a broad sense, this study argues that current tariff design practices stimulate DER integration in an unsustainable manner that increasingly compromises short-run economic efficiency and equity, and suggests a reasonable alternative. This proposal is aligned in many ways with several recent studies intended to guide public utility commissions—the entities regulating electricity utilities in the U.S.—but explores specific theoretical and empirical questions that have been overlooked.

CHAPTER 2

FINANCIAL STORAGE RIGHTS IN ELECTRIC POWER NETWORKS[1]

Daniel Muñoz-Álvarez and Eilyan Bitar[2]

The decreasing cost of energy storage technologies coupled with their potential to bring significant benefits to electric power networks have kindled research efforts to design both market and regulatory frameworks to facilitate the efficient construction and operation of such technologies. In this paper, we examine an *open access* approach to the integration of storage, which enables the complete decoupling of a storage facility's ownership structure from its physical operation. In particular, we analyze a nodal spot pricing system built on a model of economic dispatch in which storage is centrally dispatched by the independent system operator (ISO) to maximize social welfare. Concomitant with such an approach is the ISO's collection of a merchandising surplus reflecting congestion in storage. We introduce a class of tradable electricity derivatives – referred to as *financial storage rights* (FSRs) – to enable the redistribution of such rents in the form of financial property rights to storage capacity; and establish a generalized *simultaneous feasibility test* to ensure the ISO's revenue adequacy when allocating such financial property rights to market participants. Several advantages of such an approach to open access storage are discussed. In particular, we illustrate with a stylized example the role of FSRs in synthesizing fully hedged, fixed-price bilateral contracts

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for energy, when the seller and buyer exhibit differing intertemporal supply and demand characteristics, respectively.

2.1 Introduction

The increased penetration of supply derived from variable renewable energy resources, coupled with the recent decline in the cost of electric energy storage technologies, has brought about an opportunity to significantly reduce the cost of managing the electric power system through careful planning, deployment, and operation of storage resources [60]. Broadly, the short-run value of energy storage derives from its ability to arbitrage energy forward in time, enabling both the absorption of power imbalances on short time scales and the more substantial reshaping of supply and demand profiles over longer periods of time. The extent to which the deployment of a collection of energy storage devices might benefit the power system depends critically, however, on the collective *sizing*, *placement*, and *operation* of said devices [16]. The challenge resides in the design and implementation of electricity markets and instruments that induce strategic expansion and operation of storage in a manner that is consistent with the maximization of social welfare over both the long and short run, respectively.

The coordinated optimal dispatch of a collection of distributed energy storage resources clearly offers the possibility of a sizable reduction in the cost of servicing demand by reshaping it in such a manner as to alleviate both transmission congestion and the reliance on peak power generation [108]. Of interest then is the characterization of mechanisms for the integration of storage, which encourage its efficient operation. And of critical importance to this effort is the resolution of the question: *who commands the storage?* Among the variety of possible answers to this question, there are two extremes – differing in terms of the degree of government intervention – which we naturally refer to as *competitive* and *regulated*. Each implies a distinct mechanism for both the operation of the physical storage facilities and the remuneration of the services provided.

Broadly, the *competitive* or *market-based operation of storage* entails a decentralized operating paradigm in which storage owners pursue their own rational (profit maximizing) interests in the spot energy market. A shortcoming of such approach to storage integration derives from the uncertainty in revenue that storage owner-operators might obtain from the spot market. Energy storage is a capital intensive technology. And several recent studies [44, 113, 126, 136] have indicated that the risk of incomplete capital cost recovery due to such revenue uncertainty may serve to inhibit investment in storage facilities. Sioshansi [124] also goes on to show that a complete reliance on the spot energy market to guide the integration of storage may lead to its substantial underutilization relative to the social optimum, as strategic owner-operators of storage will naturally endeavor to preserve intertemporal price differences for purposes of arbitrage.

The *regulated operation of storage*, on the other hand, calls for a centralized operating paradigm in which storage is treated as a communal asset that is centrally dispatched by the Independent System Operator (ISO) to maximize social welfare subject to its physical constraints.[1] The socially optimal dispatch of storage, in concert with conventional generation and transmission, naturally improves upon the welfare of the system in the short run. Accordingly, such an approach to the operation of storage necessitates the creation of a mechanism capable of extracting

[1]The PJM Interconnection has explored a similar regulatory framework in which energy storage would be operated and compensated traditionally like a transmission asset [108].

and redistributing the value added by storage back to the owners of the responsible storage facilities. Towards this end, we propose a market mechanism founded on the definition of tradable financial instruments, which monetize property rights to storage capacity made available to the ISO for centralized operation. Such an approach resembles the regulation and operation of transmission in the majority of US electricity markets, which entails the centrally optimized operation of the transmission network subject to the locational marginal pricing of energy, and the allocation of financial transmission rights that monetize property rights to said transmission capacity [2, 62, 64, 100, 101].

2.1.1 Open Access Energy Storage

There has been recent activity in both academia and industry to identify alternative paradigms to support the efficient integration of storage into power system operations [108, 126]. One stream of literature centers on an *open access* approach to the integration of storage; or more simply, *open access storage* (OAS) [59, 126, 134]. Loosely, we refer to OAS as a regulatory framework in which energy storage facilities are treated as communal assets accessible by all participants in the wholesale energy market.

To the best of our knowledge, only two concrete approaches to OAS have been proposed. He et al. [59] proposes a market framework where storage owners sell *physically binding rights* to their storage capacity through sequential auctions coordinated by the ISO. The collection of physical rights, which are defined as a sequence of nodal power injections within a specified time horizon, determine the actual operation of the storage. As such, the physical rights associated with a particular storage facility must be collectively feasible with respect to the corresponding physical device constraints. While such physical rights might be used by market participants to execute price arbitrage or mitigate the cost of honoring existing contractual energy commitments, there are several important limitations. First, the ability of a market participant to leverage on a physical storage right depends on her location within the network relative to the storage facilities. Such restriction could serve to limit market access. Second, the eventual physical dispatch of storage is determined by a sequence of auctions – the outcome of which is likely to substantially deviate from the socially optimal dispatch, because of strategic interactions between parties bidding for physical storage rights.

Closer to our proposal, Taylor [134] suggests an approach to OAS that centers on a paradigm in which storage owners sell *financially binding rights* to their storage capacity through an auction coordinated by the ISO. The ISO is charged with the task of operating storage in a socially efficient manner – not unlike its non-discriminatory operation of the transmission network. As financial rights, they do not interfere with the optimal operation of storage, but rather, they represent entitlements to portions of the merchandising surplus collected by the ISO. A central component of the proposal in [134] is the definition of the financial rights in terms of the shadow prices associated with the physical constraints on the storage facilities. This is analogous to the definition of flowgate rights (FGRs) [26–28] in the context of open access transmission. And, as a result, such a definition of financial storage rights is naturally endowed with advantages and disadvantages comparable to those of FGRs in the context of transmission. We refer the reader to Section 2.3.4 and [65, 104] for a more detailed discussion on such issues.

2.1.2 Contribution

We propose a regulatory framework to enable open access storage, which centers largely on the concept of *financial storage rights* (FSRs). Broadly speaking, FSRs can be interpreted as financial property rights to storage capacity; or, more accurately, as financial entitlements to portions of the storage congestion rent collected by the ISO under the socially optimal dispatch of storage capacity. Being defined as such, FSRs enable the complete decoupling of a storage facility's ownership from its physical operation. Moreover, the specific form of FSRs that we propose – viz. a sequence of nodal power injections and withdrawals that yield its holder a payment according to the corresponding sequence of nodal spot prices – provides market participants the ability to perfectly hedge physical or financial energy positions against intertemporal price risk in the spot market.[2] Such hedging capabilities represent a natural complement to financial transmission rights (FTRs) and their ability to hedge spatial price risk across the network. What distinguishes such financial instruments from standard forward energy contracts is the fact that they are issued under the physical cover of transmission and storage capacity, and are settled against the merchandising surplus collected by the ISO. Accordingly, in Section 2.3.5, we establish a generalized *simultaneous feasibility test* (SFT), which constrains the joint allocation of financial transmission and storage rights in such a manner as to guarantee the ISO's revenue adequacy. Namely, any simultaneously feasible collection of transmission and storage rights are guaranteed to yield a rent that does not exceed the merchandising surplus collected by the ISO. A positive attribute of the proposed SFT is that it enables the allocation (auction) of FSRs at nodes without physical storage capacity – a feature which genuinely democratizes

[2]Such a definition of FSRs represents a financial analog to the physical storage rights proposed by He et al. [59], and is in contrast to the constraint-based financial rights proposed in [134].

access to storage by all market participants.

2.1.3 Organization

The remainder of paper is organized as follows. In Section 2.2, we formulate the multi-period economic dispatch problem with storage, and delineate its optimality conditions. In Section 2.3, we formally introduce the concept of financial storage rights, and establish a general test for simultaneous feasibility, which restricts the allocation of both financial transmission and storage rights in such a manner as to ensure the ISO's revenue adequacy. In Section 2.4, we illustrate with a stylized example the role of FSRs in synthesizing flexible, fully hedged, fixed-price bilateral contracts for energy. We close with a discussion on directions for future research in Section 2.5. All mathematical proofs are included in the Appendix to the paper.

2.2 Models and Formulation

2.2.1 Notation

Let $\mathbb{R}$ denote the set of real numbers and $\mathbb{R}_+$ the non-negative real numbers. Denote the transpose of a vector $\mathbf{x} \in \mathbb{R}^n$ by $\mathbf{x}^\top$. Let x_i denote the i^{th} entry of a vector $\mathbf{x} \in \mathbb{R}^n$. We define by $\mathbf{1}$ a column vector of all ones and by $\mathbf{e}_i$ the i^{th} standard basis vector of dimension appropriate to the context. For two matrices $A, B \in \mathbb{R}^{m \times n}$ of equivalent dimension, we denote their Hadamard product by $A \circ B$. Given a matrix $A \in \mathbb{R}^{m \times n}$, we write $A = 0$ to denote entrywise equivalence to zero.

2.2.2 Network Model

Consider a transmission network defined on a set of n nodes (buses) connected by m edges (transmission lines). The associated graph of the network is assumed connected. The nodes are indexed by $i = 1, 2, \ldots, n$. We operate under the assumption of a linear model of steady state power flow defined by the so called DC power flow approximation, where the vector of nodal power injections is linearly mapped to a vector of (directional) power flows along the m transmission lines through the mapping $H \in \mathbb{R}^{2m \times n}$, commonly referred to as the *shift-factor matrix.* Let $\mathbf{c} \in \mathbb{R}_+^{2m}$ denote the corresponding vector of transmission line capacities. It follows that the set of feasible power injections is described by the polytope $\mathcal{P}(\mathbf{c}) \subset \mathbb{R}^n$,

$$\mathcal{P}(\mathbf{c}) \;=\; \left\{\mathbf{v} \in \mathbb{R}^n \;\middle|\; H\mathbf{v} \leq \mathbf{c}, \quad \mathbf{1}^\top \mathbf{v} = 0 \right\}. \tag{2.1}$$

One can readily verify the compactness of $\mathcal{P}(\mathbf{c})$, as $\operatorname{rank}(H) = n - 1$ and $\mathbf{1}^\top$ is linearly independent from the rows of H.

2.2.3 Cost Model

At the core of the formulation considered in this paper is the problem of multi-period economic dispatch over N discrete time periods, which we index by $k = 0, \ldots, N-1$. We measure the cost and benefit of the net injection vector $\mathbf{v}(k) \in \mathbb{R}^n$ at time k according to

$$C(\mathbf{v}(k), k) = \sum_{i=1}^{n} C_i(v_i(k), k),$$

Each component function $C_i(v, k)$ is assumed to be increasing, convex, and differentiable in v over $\mathbb{R}$. Moreover, each function is assumed to satisfy $C_i(0, k) = 0$,

$C_i(v,k) > 0$ for $v > 0$, and $C_i(v,k) < 0$ for $v < 0$. This implies that $C_i(v,k)$ represents the *convex cost of generation* for $v > 0$ at node i and time k. Conversely, $-C_i(v,k)$ represents the *concave benefit of consumption* for $v < 0$ at node i and time k. Finally, the component functions $\{C_i(\cdot,k)\}$ to allowed to vary with time in order to capture the potential variation in the nodal demand preferences over time. We refer the reader to Wu et al. [142] for a more detailed explanation of this model.

2.2.4 Energy Storage Model

We consider an arbitrary collection of n perfectly efficient energy storage devices connected to the transmission network, where we associate with each node i a storage device with energy capacity $b_i \in \mathbb{R}_+$. We denote by $\mathbf{b} = \begin{bmatrix} b_1, \ldots, b_n \end{bmatrix}^\top$ the vector of nodal energy storage capacities. The collective storage dynamics are naturally modeled as a linear difference equation

$$\mathbf{z}(k+1) = \mathbf{z}(k) - \mathbf{u}(k) \tag{2.2}$$

for $k = 0, 1, \ldots, N-1$, where the vector $\mathbf{z}(k) \in \mathbb{R}^n_+$ denotes the vector of energy storage states just preceding time period k, and the input $\mathbf{u}(k) \in \mathbb{R}^n$ denotes the vector of net energy storage extractions during period k. The notational convention is such that $u_i(k) > 0$ (resp. $u_i(k) < 0$) represents a net energy extraction from (resp. injection into) the storage device at node i during time period k. Without loss of generality, we assume an initial condition of $\mathbf{z}(0) = 0$ for the remainder of the paper. The limited capacities of the energy storage devices require that $0 \le \mathbf{z}(k) \le \mathbf{b}$ for all k. Iterating the linear difference equation (2.2) back to its initial condition, one can express the storage capacity constraint as

$$0 \leq \; -\sum_{\ell=0}^{k-1} \mathbf{u}(\ell) \; \leq \mathbf{b} \tag{2.3}$$

for $k = 1, \ldots, N$. As a matter of notational convenience, we consider an *equivalent* characterization of the energy storage capacity constraints (2.3), which enables a decomposition of the constraints across nodes. More specifically, letting $\mathbf{u}_i = \begin{bmatrix} u_i(0), \ldots, u_i(N-1) \end{bmatrix}^\top$ denote the entire sequence of injections and extractions from the storage device at node i, one can recast the constraints defined by (2.3) as

$$\mathbf{u}_i \; \in \; \mathcal{U}(\mathbf{b}_i) \; = \; \left\{ \mathbf{u} \in \mathbb{R}^N \; \middle| \; 0 \leq L\mathbf{u} \leq \mathbf{b}_i \right\} \tag{2.4}$$

for $i = 1, \ldots, n$. Here, $L \in \mathbb{R}^{N \times N}$ denotes a lower triangular matrix with entries $[L]_{k\ell} = -1$ for all $k \geq \ell$, and zero otherwise. We also define $\mathbf{b}_i = \begin{bmatrix} b_i, \ldots, b_i \end{bmatrix}^\top \in \mathbb{R}^n$. It is immediate to see that $\mathcal{U}(\mathbf{b}_i)$ is a compact polytope containing the origin for each $i = 1, \ldots, n$.

Remark 2.2.1 *While the model of storage considered is stylized in nature, much of the ensuing analysis and conclusions derived can be easily extended to accommodate nonidealities in storage, such as constraints on allowable rates of charging and discharging, roundtrip inefficiencies, and dissipative losses.*

2.2.5 Multi-Period Economic Dispatch

Working within the idealized setting considered, we now formulate the problem of multi-period economic dispatch with storage. Broadly, the objective of the ISO is to select a vector of nodal prices for energy that sustains a competitive equilibrium between supply and demand at a feasible system operating point that maximizes social welfare – a so-called *economic dispatch*. Formally, the *multi-period economic dispatch* problem is stated as:

$$\text{minimize} \quad \sum_{k=0}^{N-1} C(\mathbf{v}(k), k) \tag{2.5}$$

$$\text{subject to} \quad \mathbf{v}(k) + \mathbf{u}(k) \in \mathcal{P}(\mathbf{c}), \qquad k = 0, \ldots, N-1 \tag{2.6}$$

$$\mathbf{u}_i \in \mathcal{U}(\mathbf{b}_i), \quad i = 1, \ldots, n \tag{2.7}$$

where the minimization is taken with respect to the variables $\mathbf{v}(k) \in \mathbb{R}^n$ and $\mathbf{u}(k) \in \mathbb{R}^n$ for $k = 0, \ldots, N-1$. We will occasionally denote the decision variables more compactly by the pair (V, U), where $V = \Big[\mathbf{v}(0), \ldots, \mathbf{v}(N-1)\Big]$ and $U = \Big[\mathbf{u}(0), \ldots, \mathbf{u}(N-1)\Big]$.

2.2.6 Optimality Conditions

Definition 2.2.2 *A pair* (V, U) *is a* feasible dispatch *if it satisfies constraints* (2.6)-(2.7)*. A pair* (V, U) *is an (optimal)* economic dispatch *if it solves problem (2.5)-(2.7).*

The multi-period economic dispatch problem (2.5) - (2.7) is a convex optimization problem with linear constraints. As such, an economic dispatch (V, U) is characterized by the existence of Lagrange multipliers such that the Karush-Kuhn-Tucker (KKT) conditions (2.6) - (2.13) hold. More specifically, we associate Lagrange multipliers $\gamma(k) \in \mathbb{R}$ and $\boldsymbol{\mu}(k) \in \mathbb{R}_+^{2m}$ with the power balance and line flow capacity constraints (2.6) at time k, respectively. Similarly, we define $\underline{\boldsymbol{\nu}}_i \in \mathbb{R}_+^N$ and $\overline{\boldsymbol{\nu}}_i \in \mathbb{R}_+^N$ as the Lagrange multipliers associated with the energy capacity constraints (2.7) of the storage device at node i. In specifying the KKT conditions, it will be convenient to define as $\boldsymbol{\lambda}(k) \in \mathbb{R}^n$ a particular linear combination of Lagrange multipliers given by:

$$\boldsymbol{\lambda}(k) = \gamma(k)\mathbf{1} - H^\top \boldsymbol{\mu}(k) \tag{2.8}$$

for each time $k = 0, \ldots, N-1$. The *stationarity condition* is given by:

$$\nabla C(\mathbf{v}(k), k) = \boldsymbol{\lambda}(k), \qquad k = 0, \ldots, N-1 \tag{2.9}$$

$$L^\top(\overline{\boldsymbol{\nu}}_i - \underline{\boldsymbol{\nu}}_i) = \boldsymbol{\lambda}_i, \qquad i = 1, \ldots, n \tag{2.10}$$

where we have defined $\boldsymbol{\lambda}_i = \begin{bmatrix} \lambda_i(0), \ldots, \lambda_i(N-1) \end{bmatrix}^\top$. The *complementary slackness condition* is given by:

$$\boldsymbol{\mu}(k) \circ (H(\mathbf{v}(k) + \mathbf{u}(k)) - \mathbf{c}) = 0, \qquad k = 0, \ldots, N-1 \tag{2.11}$$

$$\underline{\boldsymbol{\nu}}_i \circ L\mathbf{u}_i = 0, \qquad i = 1, \ldots, n \tag{2.12}$$

$$\overline{\boldsymbol{\nu}}_i \circ (\mathbf{b}_i - L\mathbf{u}_i) = 0, \qquad i = 1, \ldots, n. \tag{2.13}$$

It will occasionally prove convenient to work with alternative arrangements of the Lagrange multipliers defined above. Accordingly, we define the vector $\boldsymbol{\mu}_\ell = \begin{bmatrix} \mu_\ell(0), \ldots, \mu_\ell(N-1) \end{bmatrix}^\top$ as the sequence of Lagrange multipliers associated with each transmission line constraint $\ell = 1, \ldots, 2m$. In addition, the vectors $\underline{\boldsymbol{\nu}}(k) = \begin{bmatrix} \underline{\nu}_1(k), \ldots, \underline{\nu}_n(k) \end{bmatrix}^\top$ and $\overline{\boldsymbol{\nu}}(k) = \begin{bmatrix} \overline{\nu}_1(k), \ldots, \overline{\nu}_n(k) \end{bmatrix}^\top$ denote the collection of Lagrange multipliers associated with the lower and upper bounds on storage capacity, respectively, for each time $k = 0, \ldots, N-1$.

2.3 Financial Storage Rights

In this section, we outline the concept of *financial storage rights* (FSRs), and develop their basic properties within the context of a nodal spot market for energy.

Broadly, FSRs amount to financial instruments, which enable the decoupling of the ownership of storage capacity from its physical operation. This is accomplished through the allocation of financial property rights to storage in the form of entitlements to the merchandising surplus generated by the centralized dispatch of the storage assets. Specifically, a FSR is defined as a sequence of hourly injections/withdrawals at a specific node in the power network, which yields the holder a payoff according to the corresponding sequence of nodal spot prices. Being defined as such, FSRs provide energy market participants the ability to hedge their intertemporal exposure to hourly price variability at specific nodes in the power network. And while FSRs are essentially strips of forward energy contracts, what makes this class of financial instruments unique is the fact that FSRs are issued under the physical cover of storage capacity and are funded by the surplus (i.e., the intertemporal arbitrage value) that centrally operated storage generates in the spot market.

In what follows, we investigate the *revenue adequacy* of such instruments in the context of electricity markets employing locational marginal pricing. In particular, we establish conditions under which the allocation of both financial storage and transmission rights is guaranteed to be revenue adequate, *i.e.*, the merchandising surplus collected by the ISO is sufficient to cover the net settlement to all holders of financial storage and transmission rights. We begin with a definition of locational marginal prices under multi-period economic dispatch with energy storage, in the following section.

2.3.1 Locational Marginal Pricing

We refer to $\boldsymbol{\lambda}(k) \in \mathbb{R}^n$ as the vector of nodal prices at time k. More specifically, the i^{th} element, $\lambda_i(k)$, denotes the price at which energy is transacted at node i and time k. We denote by $\Lambda = \Big[\boldsymbol{\lambda}(0), \ldots, \boldsymbol{\lambda}(N-1)\Big]$ the corresponding sequence of nodal prices from time $k = 0$ to $N - 1$. We have the following standard definitions of *market equilibrium* and *efficiency.*

Definition 2.3.1 *The triple* (V, U, Λ) *constitutes a* market equilibrium *if it satisfies* (2.6)*,* (2.7) *and* (2.9)*. The triple* (V, U, Λ) *is said to be an* efficient market equilibrium *if* (V, U) *is also an economic dispatch.*

The requirement that (V, U) satisfy (2.6) and (2.7) in Definition 2.3.1 can be interpreted as *market clearing* and *feasibility conditions*, respectively, as they require that supply equal demand at each time period, while ensuring that the line flow and storage capacity constraints are met. Condition (2.9) is tantamount to requiring *consumer and supplier equilibrium* at every node and time period. In other words, relation (2.9) requires that the marginal cost of supply (benefit of demand) equal the nodal price $\lambda_i(k)$ for all nodes i and time periods k. Consequently, at equilibrium, there is no opportunity for the profitable trading of energy across nodes or time.

It is important to note that there may exist multiple market equilibria – some of which may not be efficient. In other words, the system operating point at a market equilibrium may not maximize social welfare. One can, however, implement an economic dispatch (V, U) at a market equilibrium (V, U, Λ), if the nodal prices Λ are set according to (2.8) – the Lagrange multipliers derived at the corresponding economic dispatch. Such approach to spot pricing is generally referred to as *locational marginal pricing* (LMP) [121].

2.3.2 Merchandising Surplus

In selecting and implementing a market equilibrium (V, U, Λ), the ISO collects payment from the consumers and remunerates the suppliers according to their respective operating points and nodal prices. In doing so, the ISO may collect a nonzero surplus. We refer to this excess as the *merchandising surplus* (MS). Indeed, it is a straightforward generalization of [142] to show that the MS can be either positive or negative at an arbitrary market equilibrium. The latter outcome is undesirable, as it may require the ISO to incur a fiscal deficit in clearing the market. In what follows, we briefly discuss the effects of dispatch efficiency and congestion, in both transmission and storage, on the MS. First, we have a definition.

Definition 2.3.2 *The* merchandising surplus *(MS) at a market equilibrium* (V, U, Λ) *is defined as*

$$\mathrm{MS} = -\sum_{k=0}^{N-1}\sum_{i=1}^{n} \lambda_i(k) v_i(k), \tag{2.14}$$

or, equivalently, as $\mathrm{MS} = -\mathit{trace}(\Lambda^\top V)$.

One can massage the expression for the MS in (2.3.2) to reveal the specific impact that both transmission and storage congestion have on its value. In order to do so, we must first specify the line flows induced by the net injection profile for each time period. More formally, let (V, U) be an arbitrary feasible dispatch. And denote by $p_{ij}(k)$ the resulting power flow over the line from node i to node j at time k.[3] We adopt a sign convention such that $p_{ij}(k) = -p_{ji}(k) > 0$, if power flows from node i to j. It follows from Kirchhoff's Current Law that $v_i(k) + u_i(k) = \sum_{j=1}^{n} p_{ij}(k)$ for all nodes $i = 1, \ldots, n$. Using this relation, one can decompose the merchandising surplus as

$$\text{MS} \;=\; \text{TCS} \;+\; \text{SCS}. \tag{2.15}$$

The first term in the decomposition is commonly referred to as the *transmission congestion surplus* (TCS). The second term, we refer to as the *storage congestion surplus* (SCS). Each term satisfies:

$$\text{TCS} \;=\; \frac{1}{2}\sum_{k=0}^{N-1}\sum_{i,j=1}^{n} \left(\lambda_j(k) - \lambda_i(k)\right) p_{ij}(k), \tag{2.16}$$

$$\text{SCS} \;=\; \sum_{k=0}^{N-1}\sum_{i=1}^{n} \lambda_i(k) u_i(k). \tag{2.17}$$

Lemma 2.3.3 *The* MS*,* TCS*, and* SCS *derived at an efficient market equilibrium* (V, U, Λ) *are nonnegative quantities.*

Lemma 2.3.3 reveals an important property. Namely, at an efficient market equilibrium, the collective transactions between supply and demand are guaranteed to be *revenue adequate* (*i.e.,* MS ≥ 0). Moreover, the reformulation of the MS in (2.15) reveals a decomposition of the effects due to congestion in transmission and storage on the rent collected by the ISO.

Assumption 1 *For the remainder of the paper, we let* (V, U, Λ) *denote an* efficient market equilibrium*, unless otherwise specified.*

[3] According to the formulation of DC power flow considered in Section 2.2.2, the line flow $p_{ij}(k)$ corresponds to a single entry of the vector $H(\mathbf{v}(k) + \mathbf{u}(k))$. And if there is no line connecting nodes i and j, then $p_{ij}(k) = -p_{ji}(k) = 0$ necessarily.

2.3.3 Financial Transmission Rights

In the event that there is transmission congestion at an economic dispatch and the ISO does indeed collect a positive merchandising surplus, it is common practice in US electricity markets to reallocate the MS in the form of *financial transmission rights* [101]. Essentially, a financial transmission right entitles its holder to receive a fraction of the transmission congestion surplus (TCS) collected by the ISO in clearing the spot market [64]. Financial transmission rights can be specified in variety of ways, with the two most predominant types being defined as *point-to-point* and *flow-based* rights.

A *point-to-point financial transmission right* (FTR) is specified in terms of a quantity of power, a point of injection, and a point of withdrawal. It yields the holder the entitlement to receive, or obligation to pay, the difference in nodal spot prices between the chosen point of withdrawal and the point of delivery, times the nominated quantity of power. Accordingly, an FTR may amount to a credit or liability. We have the following definition.

Definition 2.3.4 *A point-to-point financial transmission right (FTR) is any triple* $(i, j, \mathbf{t}_{ij})$, *where* i *denotes an injection node,* j *a withdrawal node, and* $\mathbf{t}_{ij} \in \mathbb{R}_+^N$ *an hourly power profile spanning* N *time periods. The FTR yields the holder a rent (or liability) equal to* $(\boldsymbol{\lambda}_j - \boldsymbol{\lambda}_i)^\top \mathbf{t}_{ij}$. *We refer to the FTR more compactly as* $\mathbf{t}_{ij}$.

Remark 2.3.5 *We have implicitly required injection/extraction symmetry in our definition of FTRs, as we have considered a lossless model of power flow. We refer the reader to [107] for a more general characterization of FTRs that accommodates lossy transmission networks.*

FTRs have become an important component of LMP-based electricity markets, in part, because of their ability to provide market participants with an effective hedge against transmission congestion costs for long-term energy transactions involving known injection and withdrawal points within the transmission network.[4] *Flow-based* or *flowgate rights* (FGRs) have also been proposed as a viable alternative or complement to FTRs [26, 28, 130]. Specifically, a FGR is a link-based transmission right, specified in terms of directed transmission link, and quantity of power flow along that link. It yields the holder the entitlement to receive a payment equal to the Lagrange multiplier (*i.e.*, shadow price) associated with the chosen link's capacity constraint multiplied the nominated quantity of power flow. Note that the rent due to a FGR is guaranteed to be nonnegative, as the corresponding shadow prices on transmission constraints are necessarily nonnegative. We have the following definition of FGRs according to the model considered in this paper.

Definition 2.3.6 *A flowgate right (FGR) is any double* $(\ell, \mathbf{f}_\ell)$*, where the index* $\ell \in \{1, \ldots, 2m\}$ *denotes a directed transmission link, and* $\mathbf{f}_\ell \in \mathbb{R}^N_+$ *a hourly power profile spanning* N *time periods. The FGR yields the holder a rent of* $\boldsymbol{\mu}_\ell^\top \mathbf{f}_\ell$*. We refer to the FGR more compactly as* $\mathbf{f}_\ell$*.*

Although FGRs are not currently offered in the majority of transmission rights auctions that are in operation today, the theoretical literature on the subject has converged on the viewpoint that both FTRs and FGRs could and should coexist, thereby allowing market participants the ability to decide as to what mix of rights is best [28,100,101]. We adopt this perspective, and develop our mathematical results in a framework that is general enough to accommodate both types of financial

[4] We refer the reader to [116] for a recent survey on financial transmission rights.

rights. Accordingly, we denote an arbitrary *collection of FTRs and FGRs* by the pair $(\mathcal{T}, \mathcal{F})$, where

$$\mathcal{T} = \{\mathbf{t}_{ij} \mid i, j = 1, \dots, n\} \quad \text{and} \quad \mathcal{F} = \{\mathbf{f}_\ell \mid \ell = 1, \dots, 2m\}.$$

Here, $\mathbf{t}_{ij}$ is the sum of all FTRs of the same type (i, j), and $\mathbf{f}_\ell$ is the sum of all FGRs of the same type ℓ.

In what follows, we investigate the revenue adequacy of transmission rights in nodal spot markets based on multi-period economic dispatch with storage. In particular, we establish conditions on the joint allocation of FTRs and FGRs, under which the merchandising surplus collected by the ISO is sufficient to cover their net settlement.

Definition 2.3.7 *The* rent due to a collection of transmission rights $(\mathcal{T}, \mathcal{F})$ *is defined as*

$$\Phi(\mathcal{T}, \mathcal{F}) = \sum_{i,j=1}^{n} (\boldsymbol{\lambda}_j - \boldsymbol{\lambda}_i)^\top \mathbf{t}_{ij} \; + \; \sum_{\ell=1}^{2m} \boldsymbol{\mu}_\ell^\top \mathbf{f}_\ell.$$

In general, the merchandising surplus collected by the ISO will not equal the rent due to a collection of transmission rights. Their allocation must, therefore, be restricted in such a manner as to guarantee that the ISO does not incur a financial shortfall. A well known requirement is the *simultaneous feasibility test* (SFT) [64, 107, 142]. We now extend this notion to the multi-period setting to accommodate the enlargement of the set of feasible power injections due to the presence of storage capacity.

We first require additional notation. For each time period $k = 0, \dots, N-1$, denote by $\mathbf{t}(k) \in \mathbb{R}^n$ the net injection vector induced by a collection of FTRs in $\mathcal{T}$, and by $\mathbf{f}(k) \in \mathbb{R}^{2m}$ the vector of direction-specific flowgates induced by a collection of FGRs in $\mathcal{F}$.[5]

Definition 2.3.8 *A collection of transmission rights* $(\mathcal{T}, \mathcal{F})$ *are said to be* simultaneously feasible *if there exists a sequence of storage injections* $Q \in \mathbb{R}^{n \times N}$*, which is feasible according to*

$$\begin{aligned} \mathbf{t}(k) + \mathbf{q}(k) \in &\ \mathcal{P}(\mathbf{c} - \mathbf{f}(k)), \qquad && k = 0, \ldots, N-1 \\ \mathbf{q}_i \in &\ \mathcal{U}(\mathbf{b}_i), && i = 1, \ldots, n. \end{aligned}$$

In other words, a collection of transmission rights $(\mathcal{T}, \mathcal{F})$ are simultaneously feasible if the sequence of nodal injections induced by the FTRs in $\mathcal{T}$ can be reshaped by a feasible sequence of storage injections so that the resulting nodal injections induce power flows that respect the transmission capacity limits, derated according to the FGRs in $\mathcal{F}$. We have the following result, which establishes revenue adequacy for any simultaneously feasible collection of transmission rights.

Lemma 2.3.9 *If* $(\mathcal{T}, \mathcal{F})$ *are a simultaneously feasible collection of transmission rights, then their corresponding rent satisfies*

$$\Phi(\mathcal{T}, \mathcal{F}) \ \leq \ \text{TCS}. \tag{2.18}$$

This inequality is tight*, in the sense that there exists a simultaneously feasible collection of transmission rights with a corresponding rent equal to the* TCS.

Lemma 2.3.9 reveals that a simultaneously feasible collection of transmission rights cannot yield a rent, which exceeds the transmission congestion surplus

[5] Accordingly, the ith element of the net injection vector $\mathbf{t}(k)$ is given by $t_i(k) = \sum_{j=1}^{n}(t_{ij}(k) - t_{ji}(k))$, and the ℓth element of the flowgate vector $\mathbf{f}(k)$ is given by the kth element of the FGR $\mathbf{f}_\ell$.

(TCS). While this ensures the revenue adequacy of the ISO, it also points to the fact that transmission rights, alone, are incapable of capturing the entire merchandising surplus (MS) collected by the ISO, in general. We thus define *financial storage rights* – a new class of financial instruments, which, in combination with transmission rights, enable the full recovery of the MS, among other benefits to market participants.

2.3.4 Financial Storage Rights

We begin with a definition of *financial storage rights.*

Definition 2.3.10 *A financial storage right (FSR) is any double* $(i, \mathbf{s}_i)$*, where* i *denotes a withdrawal node, and* $\mathbf{s}_i \in \mathbb{R}^N$ *a hourly power profile spanning* N *time periods. The FSR yields the holder a rent (or liability) equal to* $\boldsymbol{\lambda}_i^\top \mathbf{s}_i$*. We refer to the FSR more compactly as* $\mathbf{s}_i$*.*

Before embarking upon a formal analysis of FSRs and their properties, we provide a brief qualitative discussion surrounding their structure and potential use. First, FSRs can be thought as financial property rights to storage capacity; or, more accurately, as entitlements to the intertemporal arbitrage gains that storage generates under its socially optimal operation, *i.e.*, the storage congestion surplus (SCS). Being defined as such, FSRs enable the complete decoupling between the actual operation of storage facilities and the settlement of storage congestion charges. Second, as tradable property rights, FSRs can be sold in forward auctions coordinated by the ISO; and the revenue generated by such auctions could serve to incentivize merchant investment in storage – not unlike the role of FTRs in partially supporting the remuneration of merchant transmission investments [63, 75].

Third, from the perspective of its holder, a FSR is equivalent to a strip of forward energy contracts. Accordingly, FSRs yield market participants the ability to perfectly hedge physical or financial positions in the spot market against intertemporal price risk. Such hedging capabilities represent a natural complement to FTRs and their ability to hedge spatial price risk across the network. Finally, an important factor distinguishing FSRs from standard forward energy contracts, is the crucial fact that FSRs are issued under the physical cover of storage capacity and settled against the SCS collected by the ISO, as opposed to the revenue generated from contract sales.

Different forms of financial entitlements to the storage infrastructure can be envisioned. For instance, Taylor [134] proposes an alternative form of financial storage rights, which are defined in terms of specific storage facilities, and entitle their holder to receive the shadow price on a storage facility's energy capacity constraint times the nominated quantity of energy. We refer to this alternative form of financial rights as *energy capacity rights* (ECRs). Working within the confines of our idealized storage model, ECRs can be formally defined as follows.

Definition 2.3.11 *An energy capacity right (ECR) is any double* $(i, \mathbf{e}_i)$*, where the index* i *denotes a storage asset, and* $\mathbf{e}_i \in \mathbb{R}_+^N$ *a hourly energy profile spanning* N *time periods. The ECR yields the holder a rent of* $\overline{\boldsymbol{\nu}}_i^\top \mathbf{e}_i$*. We refer to the ECR more compactly as* $\mathbf{e}_i$*.*

Remark 2.3.12 *In the presence of additional constraints, which limit the rate at which a storage facility can be charged or discharged, one can expand the definition of ECRs to include another class of financial rights that entitle their holder to receive the shadow price on the storage facility's power capacity constraint times* *the nominated quantity of power. Taylor [134] refers to such instruments as* power capacity rights *(PCRs).*

Definition 2.3.11 is in contrast to our *profile-based* definition of FSRs (cf. Definition 2.3.10). Intuitively, the relationship between FSRs and ECRs is analogous to the relationship between FTRs and FGRs. And, to a large extent, the advantages and disadvantages of FSRs versus ECRs mirror those of FTRs as compared to FGRs.[6] For example, while FTRs (FSRs) are convenient instruments for hedging spatial (intertemporal) price risk, FGRs (ECRs) are instruments better suited for remunerating property rights to specific transmission lines (storage facilities).

In Section 2.3.5, we present conditions on the joint offering of transmission and storage rights under which the ISO is guaranteed to be revenue adequate. To that end, we first define the rent due to a collection of FSRs and ECRs. We denote an arbitrary *collection of FSRs and ECRs* by the pair $(\mathcal{S}, \mathcal{E})$, where

$$\mathcal{S} = \{\mathbf{s}_i \mid i = 1, \ldots, n\} \quad \text{and} \quad \mathcal{E} = \{\mathbf{e}_i \mid i = 1, \ldots, n\}.$$

Here, $\mathbf{s}_i$ is the sum of all FSRs of the same type i, and $\mathbf{e}_i$ is the sum of all ECRs of the same type i.

Definition 2.3.13 *The* rent due to a collection of storage rights $(\mathcal{S}, \mathcal{E})$ *is defined as*

$$\Sigma(\mathcal{S}, \mathcal{E}) = \sum_{i=1}^{n} \boldsymbol{\lambda}_i^\top \mathbf{s}_i \;+\; \overline{\boldsymbol{\nu}}_i^\top \mathbf{e}_i.$$

[6] We refer the reader to [28,100–102,117] for detailed discussions surrounding such comparisons in the context of transmission rights.

2.3.5 A Generalized Simultaneous Feasibility Test

We now extend our definition of multi-period simultaneous feasibility to accommodate a combination of both transmission and storage rights.

Definition 2.3.14 *A collection of transmission and storage rights* $(\mathcal{T}, \mathcal{F}, \mathcal{S}, \mathcal{E})$ *are said to be* simultaneously feasible *if there exists a sequence of storage injections* $Q \in \mathbb{R}^{n \times N}$*, which is feasible according to*

$$\mathbf{t}(k) - \mathbf{s}(k) + \mathbf{q}(k) \in \mathcal{P}(\mathbf{c} - \mathbf{f}(k)), \qquad k = 0, \ldots, N-1 \tag{2.19}$$

$$\mathbf{q}_i \in \mathcal{U}(\mathbf{b}_i - \mathbf{e}_i), \qquad i = 1, \ldots, n. \tag{2.20}$$

Remark 2.3.15 (Accommodating Inefficiencies in Storage) *While we have thus far operated under the assumption of perfectly efficient storage facilities, it is straightforward to extend the definition of simultaneous feasibility in Definition 2.3.14 to accommodate dissipative losses and conversion inefficiencies in storage by simply refining the underlying storage constraints on which it is based.*

Essentially, a collection of transmission and storage rights are simultaneously feasible if the nodal injections induced by the FTRs in $\mathcal{T}$ and FSRs in $\mathcal{S}$ can be reshaped by a sequence of storage injections, which both respect the storage capacity constraints (derated according to the ECRs in $\mathcal{E}$), and result in power flows that do not violate the transmission capacity constraints (derated according to the FGRs in $\mathcal{F}$). Notice that, in the absence of storage rights, this generalized definition of simultaneously feasibility reduces to Definition 2.3.8. The following result characterizes the maximum rent achievable by any simultaneously feasible collection of transmission and storage rights.

Theorem 2.3.16 *If $(\mathcal{T}, \mathcal{F}, \mathcal{S}, \mathcal{E})$ are a simultaneously feasible collection of transmission and storage rights, then their corresponding rent satisfies*

$$\Phi(\mathcal{T}, \mathcal{F}) \ + \ \Sigma(\mathcal{S}, \mathcal{E}) \ \leq \ \text{MS}. \tag{2.21}$$

Moreover, this inequality is tight, in the sense that there exists a simultaneously feasible collection of rights $(\mathcal{T}, \mathcal{F}, \mathcal{S}, \mathcal{E})$ with an associated rent equal to MS*.*

Theorem 2.3.16 is reassuring, as it guarantees revenue adequacy on behalf of the ISO when jointly issuing transmission and storage rights in a manner that is simultaneously feasible. More precisely, given a *fixed* configuration of transmission and storage facilities, the MS collected by the ISO in the spot market suffices to cover the rents of all outstanding transmission and storage rights. Revenue adequacy is not, however, guaranteed in the event of unplanned contingencies, as the configuration of transmission and/or storage facilities may deviate from what was assumed in the simultaneous feasibility test. The ISO must, therefore, specify a mechanism to compensate potential revenue shortfalls that might arise in the event that such contingencies occur.[7]

[7] We refer the reader to [102, Sec. 3.6], which examines several mechanisms to cover revenue shortfalls that might occur when settling payments to FTR holders in the event of transmission line contingencies. For example, PJM handles revenue inadequacy in settling FTR payments by prorating the revenue shortfall among the FTR holders; whereas, in NYISO-run markets, transmission line owners are held responsible for the shortfall [101]. A mechanism of the former type generally transfers the risk of shortfall to the FTR holders, undermines the ability of FTRs to provide perfect price hedges, and is vulnerable to gaming due to the socialization of the shortfalls. Conversely, a mechanism of the latter type fully funds the outstanding rights, thereby transferring the risk of shortfall to the transmission line owners themselves. An argument in favor of such a mechanism is that it provides an incentive to transmission line owners to effectively maintain their assets, and avoids the socialization of revenue shortfalls among the FTR holders [101, 102].

2.4 An Illustration of the Use of FSRs

The natural variation of nodal spot prices over both location and time exposes market participants to price risk. Extreme price volatility is particularly problematic for load serving entities (LSEs) that sell electricity to end-use customers at a fixed and predetermined price, as they face the risk that the spot price at which they pay for energy may considerably exceed the fixed price at which they are remunerated during certain hours of the day. Accordingly, LSEs and, more generally, those market participants seeking price stability in their transactions, may wish to hedge their exposure to such price risk. In the following discussion, we explain how FSRs, in combination with contracts for differences (CFDs) and FTRs, can be employed to fully hedge a long-term bilateral contract for energy, when the seller and buyer may exhibit differing intertemporal supply and demand characteristics, respectively. As a special case, the framework considered accommodates the setting in which the seller is physically constrained to deliver the contracted amount of energy through a constant power profile over a predetermined interval of time, while the buyer is compelled to consume that amount of energy according a power profile that (predictably) fluctuates over that same interval of time, due in part to the inelastic nature of its demand.

We consider the setting in which a demander at node j would like to buy an amount of energy q_c (MWh) from a supplier at node i to be delivered over N time periods at a fixed price λ_c (\$/MWh). The supplier is assumed to deliver this quantity of energy according to the production profile $\mathbf{q}_i \in \mathbb{R}^N$, while the demander is assumed to consume that same amount of energy according to the consumption profile $\mathbf{q}_j \in \mathbb{R}^N$. While the production and consumption profiles need not agree at any given time period, they must balance over time, *i.e.*, $\mathbf{1}^\top \mathbf{q}_i = \mathbf{1}^\top \mathbf{q}_j = q_c$.

In addition, it is assumed that both the demander and supplier are required to trade with the ISO according to their respective nodal spot prices. Accordingly, the demander pays $\boldsymbol{\lambda}_j^\top \mathbf{q}_j$, and supplier is paid $\boldsymbol{\lambda}_i^\top \mathbf{q}_i$ in the spot market. Because nodal spot prices will naturally vary over both time and location, and will therefore differ from the contract price λ_c, a hedge is required in order to execute the fixed price contract between the supplier and demander. In what follows, we explain how a combination of a CFD, FTR, and FSR can be employed to perfectly hedge such price differences.

In general, the supplier will lose an amount $\lambda_c q_c - \boldsymbol{\lambda}_i^\top \mathbf{q}_i$ and the demander will gain an amount $\lambda_c q_c - \boldsymbol{\lambda}_j^\top \mathbf{q}_j$, as a result of their respective spot market transactions.[8] In the event that nodal spot prices are constant over both location and time, it is straightforward to see that the amount lost by the supplier is equal to the amount gained by the demander. Thus, a simple money transfer between the two parties in that amount is sufficient to perfectly hedge the fixed price contract. Such transfer can be accomplished with a CFD, which requires that the demander pay the supplier the amount $\lambda_c q_c - \boldsymbol{\lambda}_i^\top \mathbf{q}_i$, as is recorded in the second line of Table 2.1.

More generally, the CFD specified above leaves the demander exposed to a *transmission congestion charge* when nodal spot prices vary over location, and a *storage congestion charge* when nodal spot prices vary over time.[9] The specific form these congestion charges is made explicit in the following expression (2.22), which disentangles the individual effects that locational and temporal price differences have on the demander's market exposure after having settled the CFD with the

[8]Clearly, each of these amounts is as equally likely to be negative as positive, depending on the specific values of the contract price and nodal spot prices.

[9]Of course, this is but one of several natural ways in which the CFD might be specified. Alternative specifications that entail risk sharing between the supplier and demander can also be envisaged.

supplier.

$$\underbrace{\boldsymbol{\lambda}_j^\top \mathbf{q}_j}_{\substack{\text{spot market}\\ \text{charge}}} + \underbrace{(\lambda_c q_c - \boldsymbol{\lambda}_i^\top \mathbf{q}_i)}_{\text{CFD charge}} = \lambda_c q_c + \underbrace{(\boldsymbol{\lambda}_j - \boldsymbol{\lambda}_i)^\top \mathbf{q}_i}_{\substack{\text{transmission congestion}\\ \text{charge}}} + \underbrace{\boldsymbol{\lambda}_j^\top (\mathbf{q}_j - \mathbf{q}_i)}_{\substack{\text{storage congestion}\\ \text{charge}}} \tag{2.22}$$

It is straightforward to see that the transmission (storage) congestion charge vanishes when the nodal spot prices are constant across location (time). In the event that nodal spot prices vary over location, the resulting transmission congestion charge can be perfectly hedged with a FTR from node i to node j given by $\mathbf{t}_{ij} := \mathbf{q}_i$. Similarly, a FSR at node j given by $\mathbf{s}_j := \mathbf{q}_j - \mathbf{q}_i$ yields a perfect hedge against the storage congestion charge, in the event that nodal spot prices vary across time.[10] Essentially, this FSR yields the demander a hedge, which is identical to that which could have been produced using a physical storage facility to purchase the profile $\mathbf{q}_i - \mathbf{q}_j$ in the spot market at node j.

In combination with the CFD, the procurement of a FTR and a FSR by the demander yields a perfectly hedged, fixed price contract between the supplier and demander – provided that both parties deliver and consume power according to the profiles specified by the contract. However, as is argued in [21], such price risk cannot be costlessly eliminated, as FTRs and FSRs will, in general, have nonzero value in expectation. We refer the reader to Table 2.1 for a detailed accounting of the transactions described in the preceding discussion.

[10]It is worth mentioning that, should the two parties enter into a bilateral contract specifying common production and consumption profiles, *i.e.*, $\mathbf{q}_i = \mathbf{q}_j$, the storage congestion charge would vanish – thereby eliminating the need for the procurement of a FSR in the pursuit of a perfectly hedged, fixed price contract.

	Contract or Market	Supplier at node i		Demander at node j	
		Quantity	Payment	Quantity	Payment
1	Spot market	$\mathbf{q}_i$	$\boldsymbol{\lambda}_i^\top \mathbf{q}_i$	$-\mathbf{q}_j$	$-\boldsymbol{\lambda}_j^\top \mathbf{q}_j$
2	CFD	$\mathbf{q}_i$	$\lambda_c q_c - \boldsymbol{\lambda}_i^\top \mathbf{q}_i$	$-\mathbf{q}_i$	$-(\lambda_c q_c - \boldsymbol{\lambda}_i^\top \mathbf{q}_i)$
3	FTR	–	–	$\mathbf{t}_{ij} := \mathbf{q}_i$	$(\boldsymbol{\lambda}_j - \boldsymbol{\lambda}_i)^\top \mathbf{t}_{ij}$
4	FSR	–	–	$\mathbf{s}_j := \mathbf{q}_j - \mathbf{q}_i$	$\boldsymbol{\lambda}_j^\top \mathbf{s}_j$
5	Total	–	$\lambda_c q_c$	–	$-\lambda_c q_c$

Table 2.1: Using CFDs, FTRs, and FSRs to synthesize bilateral contracts.

2.5 Conclusion and Future Work

In this paper, we have proposed a general regulatory and market framework to enable the *open access* integration of storage, in which storage is treated as a communal asset accessible by all market participants. Such an approach represents a substantial departure from the more standard storage integration paradigm in which a storage owner-operator pursues her individual profit maximizing interests within the confines of her local spot market. Central to our proposal is the concept of *financial storage rights* (FSRs), which are defined as a sequence of nodal power injections and withdrawals that yield the holder a payment according to the corresponding sequence of nodal prices. Qualitatively, FSRs represent financial property rights to the capacity of centrally operated storage facilities. This is in sharp contrast to the physical rights proposed in [59]. An essential advantage of FSRs and the modus operandi they entail is that their allocation does not interfere with the socially optimal operation of storage or the independence of the ISO, regardless of the ownership structure of the storage facilities. Most importantly, FSRs enable the synthesis of fully hedged, fixed-price bilateral contracts for energy, when the seller and buyer exhibit differing intertemporal supply and demand characteristics, respectively.

More broadly, we envision storage owners trading such FSRs with other market participants through (short and long term) forward auctions and secondary markets centrally coordinated by the ISO; not unlike markets for FTRs today. And, by selling financial rights to their energy storage capacity in various forward auctions (*e.g.*, yearly, quarterly, etc.), storage owners can more finely manage their exposure to spot price volatility. In addition, the auction revenue derived from the forward sale of FSRs may serve as a transparent long-term market signal to partially guide merchant investment in storage.

The study of financial storage rights presented in this paper represents an initial point of analysis. Many interesting questions remain. First, how should the ISO structure an auction mechanism to jointly allocate both financial transmission and storage rights? For instance, the simultaneous feasibility test (SFT) that we propose would require coordination in clearing both the transmission and storage right auctions. This might be too cumbersome to be practical. Accordingly, it would be of interest to explore the design of alternative conditions for simultaneous feasibility that would enable the decoupling of transmission and storage right auctions. Second, the potential value that energy storage offers to the power system goes well beyond the application of intertemporal energy arbitrage considered in this paper [126]. For example, certain storage technologies posses the capability of providing voltage support or frequency regulation services. A natural question then, is how might one expand the concept of FSRs to incorporate these value streams as well? Third, it would be of interest to generalize the market framework considered to accommodate a broader family of technologies capable of shifting energy in time (*e.g.*, flexible demand-side resources).

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CHAPTER 3

A CONTEXTUAL DISCUSSION OF FSRS

3.1 Introduction

This chapter clarifies the scope of the approach to Open Access Storage (OAS) described in Chapter 2. It aims to clarify how the proposed mechanism fits within the current architecture of U.S. wholesale electricity markets. To that end, it also elaborates on possible generalizations that enable the monetization of multiple services that storage resources can provide beyond energy arbitrage.

The proposed approach to OAS is a dedicated mechanism for storage resources to participate in wholesale markets. Part of its motivation is a concern from academia and the industry that storage resources may be facing avoidable barriers impeding their participation in wholesale markets (e.g., see [5, 53, 82, 126, 135, 136, 139]). This participation mechanism is not mandatory nor comprehensive. Rather, it is optional and dedicated to coordinate specifically the provision of a single service, namely, inter-hour energy arbitrage. In other words, the mechanism should be thought as an optional path for storage owner-operators to monetize the inter-hour energy arbitrage capabilities of their storage resources in ISO markets. As such, it is an alternative to the existing bid-based mechanisms to participate in the day-ahead market (DAM) and the concomitant LMP-based compensation.

As suggested in Section 2.1, the proposed mechanism consists of two parts: (i) an operational arrangement, and (ii) a compensation scheme. We discuss relevant aspects of each of them.

3.2 Centralized operational arrangement

Broadly, the first part is an agreement —between the ISO and storage owner-operators— to dispatch the participating storage resources in a *centralized* manner. That is, the agreement entitles the ISO to dispatch storage resources in the DAM based on their operational constraints and parameters rather than on economic bids (e.g., price-quantity pairs). Such arrangement is virtually equivalent to that used by the ISO to utilize transmission assets. The multi-period economic dispatch formulation that represents the DAM auction in Section 2.2 illustrates the arrangement. Therein, the ISO relies on a storage model embodied by a set of constraints —such as (2.4)— and no bids or offers to produce an efficient market equilibrium, which specifies day-ahead hourly dispatch signals for the storage resources. In other words, the proposed mechanism explicitly internalizes the operational constraints of storage resources into the DAM auction rendering unnecessary[1] the use of hourly bids and offers to internalize them.

We elaborate on three points that clarify how the proposed mechanism fits the current architecture of U.S. wholesale markets. First, rather than economic bids, storage owner-operators would need to report to the ISO the parameters of a predetermined storage model. The storage parameters and model need to match those used in the FSR auctions in order to guarantee the ISOs revenue adequacy[2]. Hence, the storage parameters need to be reported ahead of delivery time before the FTR auctions take place. This type of consistency between models is also required in the context of the transmission network and FTRs to guarantee the ISOs revenue adequacy [64].

[1]Except perhaps daily boundary parameters necessary to value the initial and terminal state of charge in the storage resources.

[2]This may represent a challenge for daily boundary conditions that are inherent part of the model, such as the initial and terminal state of charge, which are likely to vary on a daily basis.

Second, the day-ahead dispatch signals of the participating storage resources would be financially binding as in current two settlement markets. In other words, the day-ahead market clearing quantities would not dictate the actual operation of storage. Rather, real-time deviations would be allowed, and they could be settled in existing real-time markets. In an energy-only two-settlement system, for example, real-time deviations from day-ahead quantities are settled at the real-time energy prices [131, Chap. 3-2]. Hence, the proposed mechanism does not impede the simultaneous participation of storage resources in the real-time market, which can be a relevant source of revenue. Indeed, while the proposed mechanism monetizes the inter-hour energy arbitrage capabilities (through FSRs), the real-time market monetizes the intra-hour energy arbitrage capabilities.

Third and last, the simplified multi-period economic dispatch formulation used in Chapter 2.2 —to represent the DAM auction— does not consider the procurement of ancillary services such as frequency regulation and reserves. These are services that storage resources can provide and on which they are likely to depend on to demonstrate financial viability [114, 126, 129]. Hence, a natural question emerges; how can the proposed operational arrangement accommodate the simultaneous provision of both energy and ancillary services in the DAM? We envision and briefly describe two alternatives.

The first alternative to accommodate ancillary services is a natural generalization of the described operational arrangement. It consists in allowing the ISO to use storage resources to provide *both* energy and ancillary services based solely on their physical models. This method allocates endogenously the capacity attributes of the storage resources among the various services they can provide. Under this generalization, the revenue adequacy of the ISO would still be guaranteed provided that the ancillary services are appropriately settled using Lagrange multipliers as prices. In this case, the surplus generated by the participating storage resources attributable to the provision of ancillary services would be collected by the ISO as part of the merchandising surplus.

The second alternative to accommodate ancillary services is a variation of the first one. It differs in that it allows storage owner-operators to submit offers to provide ancillary services and collect the associated payments. Settling these payments, however, leave the ISO at risk of revenue inadequacy. A way to recover revenue adequacy is to make the storage owner-operators liable for any shortfalls the ISO may encounter. Different methods to allocate shortfalls among the storage owner-operators can be envisioned, e.g., based on the number of rights underwritten or on the payments received for ancillary services.

3.3 FSR-based compensation scheme

The second part of the proposed mechanism specifies a compensation scheme. As described in Chapter 2, FSRs embody the compensation system. Intuitively, they are an indirect payment mechanism that is in contrast to the direct payments that take place in a typical DAM. More specifically, rather than receiving a stream of daily payments in the DAM, storage owner-operators are given tradable entitlements to said future payments (in the form of financial derivatives). These derivatives can be sold in forward markets to other market participants. These forward sales amount to exchanging of a stream of uncertain future daily payments for a single certain payment. Hence, selling FSRs is a way to mitigate the revenue risk and volatility that storage resources derive from energy arbitrage. The

FSR based compensation thus gives storage owner-operators the option to either monetize their energy arbitrage capabilities in forward markets or the DAM (by holding on to their FSR and the associated rents).

It is worth emphasizing that centralized operational arrangements —as the proposed one— are not uncommon to the power industry. Indeed, in [139], the authors claim that some ISOs have started to respond to FERC's Order No. 890[3] by creating a dedicated classification for storage resources that internalizes some of their operational constraints into the DAM auction. More recently, FERC further issued a notice of proposed rulemaking (NOPR) that would mandate all ISOs to incorporate a standard storage participation model that internalizes some of their intertemporal dynamics and constraints [53]. However, the proposed FSR-based compensation mechanism effectively offers a different approach to the integration of storage resources into wholesale markets. It replaces a mechanism based on day-ahead arbitrage gains with a mechanism to rent storage capacity to the ISO in exchange of tradable financial entitlements. These entitlements or rights can be traded —at the storage owner-operators convenience— anytime between the initial FSR allocation and the day before delivery.

A final point of examination is whether a market for FSRs —or functionally equivalent financial products, for that matter— can be recognized as an ancillary benefit of the proposed mechanism. In theory, an FSR market can be implemented without centrally operated storage resources. However, these storage resources serve to increase the FSR market liquidity; without them, liquidity would be highly limited due to the need to guarantee the ISO's revenue adequacy. This link between the use of centrally operated assets and liquidity is explained by [41]

[3]As described in [139], the FERC Order requires wholesale markets to consider non-generation resources for their grid service. See [51] for a summary of the Final Order [52].

in the context of transmission lines and FTR markets. Therein, the authors argue that the revenue adequacy condition imposed by the auction on the FTRs imposes specific liquidity constraints on the ISO. And, according to (2.20), increasing the storage capacity available to the ISO constitutes a relaxation of the simultaneous feasibility test (SFT) and thus of the revenue adequacy condition. The converse is also true, namely, decreasing the centrally available storage capacity constitutes a restriction of the revenue adequacy condition. The implication is clear. The larger availability of storage resources for the ISO, the more liquid the market for FSRs should be.

CHAPTER 4

ON THE EFFICIENCY OF CONNECTION CHARGES—PART I: A STOCHASTIC FRAMEWORK[4]

Daniel Muñoz-Álvarez and Lang Tong[5]

This two-part paper addresses the design of retail electricity tariffs for distribution systems with distributed energy resources such as solar power and storage. In particular, the optimal design of dynamic two-part tariffs for a regulated monopolistic retailer is considered, where the retailer faces exogenous wholesale electricity prices and fixed costs on the one hand and stochastic demands with inter-temporal price dependencies on the other. Part I presents a general framework and analysis for revenue adequate retail tariffs with advanced notification, dynamic prices and uniform connection charges. It is shown that the optimal two-part tariff consists of a dynamic price that may not match the expected wholesale price and a connection charge that distributes uniformly among all customers the retailer's fixed costs and a price-volume risk premium. A sufficient condition for the optimality of the derived two-part tariff among the class of arbitrary ex-ante tariffs is obtained. Numerical simulations quantify the substantial welfare gains that the optimal two-part tariff may bring compared to the optimal linear tariff (without connection charge). Part II focuses on the impact of two-part tariffs on the integration of distributed energy resources.

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4.1 Introduction

The electric power industry is experiencing an important transformation driven by disruptive innovation in distributed renewable generation and energy storage systems [57]. A concern of this transformation is the impact of the inclining adoption of said distributed energy resources (DERs) on the financial viability of regulated distribution grid operators [114]. In particular, under the restriction to volumetric and net-metering tariffs, the gradual decline in energy sales could compromise the ability of grid operators to recover their predominantly fixed operational and capital expenditures. This could result in the need to increase retail prices further above wholesale electricity prices, thereby amplifying the entailed economic inefficiencies, inter-customer cross-subsidies, and incentives for DER adoption in a vicious circle.

This two-part paper aims to shed lights on the effectiveness of connection charges as a means to mitigate the negative impacts of the sustained adoption of DERs. To this end, Part I (Chapter 4) [87] develops a framework to analyze the efficiency of retail electricity tariffs set for a regulated retailer who serves a heterogeneous population of residential customers under demand and wholesale price uncertainties.

In particular, we are interested in two practical and fairly general ex-ante retail pricing models: a volumetric linear tariff and a two-part tariff consisting of a volumetric linear charge and a connection charge. Our goal in Part I is to gain insights into the structure of the optimal revenue adequate linear and two-part tariffs that allow us to analyze, in Part II (Chapter 5) [88], the effects of integrating customer and retailer-owned DERs.

4.1.1 Related Work

There is a vast literature on efficient retail pricing of electricity, the economic foundations of which reside in the classical theory of public utility pricing and peak-load pricing [19]—known more recently as dynamic pricing [72]. According to [34, 72], the basic theory of peak-load pricing dates back to [22, 23], and its direct application to retail electricity pricing has been around for more than 60 years (*e.g.*, [9, 128]). Several works have surveyed this theory (*e.g.*, [19, 34, 140]). More recent reviews of the subject, along with a brief history of its slow and partial adoption by regulators and electric utilities, can be found in [17, 141].

In this context, the inability to fully recover the predominantly fixed costs of utilities through marginal cost pricing is typically approached by imposing a breakeven constraint (or revenue adequacy constraint) [34]. The resulting constrained price optimization is closely related to the Ramsey-Boiteux pricing strategy, which derives its name from Ramsey's classical contribution to the theory of optimal taxation [110] and Boiteux's application to natural monopolies [10].

As an alternative to the optimal linear tariffs characterized in the theory of peak-load pricing as optimal deviations from marginal cost pricing, two-part tariffs (*e.g.*, [3, 50, 99, 103]) and other nonlinear tariffs were used as a means to raise additional revenue to recover the utilities' predominantly fixed costs [19,34,140]. In the U.S., mild connection charges are prevalent with exceptions such as California, where the large investor-owned utilities have used default volumetric residential tariffs with virtually no connection charges[1] [12].

[1]PG&E and SDG&E have no connection charge whereas SCE's charges $0.99/month. While these utilities have a minimum bill of $10/month or less, it is binding on extremely few customers, and thus practically irrelevant [12].

In the last two decades, while the adoption of time-varying prices has been particularly slow in the U.S. [72], the advent of cheaper smart meters, small-scale renewable energy installations, battery storage technologies and home energy management tools has stimulated research in *dynamic pricing* (see [42, 137] and references therein) as sophisticated technologies can enable customers to react to price signals [49, 118]. Of particular interest is real-time pricing (RTP), a form of dynamic pricing widely known to be a critical feature of efficient electricity markets [14]. An overview of dynamic pricing and a recent analysis of its limited adoption in the U.S. are available in [14] and [72], respectively.

Economic approaches to dynamic pricing often rely on functional demand models to characterize competitive equilibrium prices when smart meters become available to customers [11, 13, 71].The most relevant analysis is [71] where the socially optimal linear and two-part retail tariffs subject to a retailer revenue sufficiency constraint are derived. Unlike our work, however, this analysis does not accommodate inter-temporal demand dependencies nor the integration of DERs.

Most engineering approaches, on the other hand, focus on analyzing demand response models in smart grids [42, 118, 137]. These approaches often involve modeling customer behavior [83, 84], sometimes down to the appliance level [40, 78, 80, 122], by characterizing customers' response to certain pricing scheme. Appliances modeled include thermostatically controlled loads (TCL) [78, 80], electric vehicles [122], and batteries [40, 143]. Other works focus on designing said pricing schemes to induce a desired behavior anticipating customers' response [6,29,43,55,66,69,76,77,81,89,119,132,133,144]. For example, the work in [29] considers utility-maximizing consumers and a social-welfare-maximizing supplier that procures electricity in two steps (day-ahead and in real-time). In a multiperiod and deterministic setting, the authors derive the socially optimal retail prices: a time-differentiated linear tariff. In a similar setting where only the real-time market and a stylized TCL model are considered, the work in [69] derives optimal day-ahead retail prices while accommodating cost and demand uncertainty and an implicit retailer revenue requirement[2].

4.1.2 Summary of Results and Contributions

The main contribution of Part I is the explicit characterization of the optimal revenue adequate ex-ante two-part tariff for a stochastic demand with inter-temporal dependencies. The results in Part I lay the foundation for analyzing the welfare impacts of integrating DERs such as solar power and energy storage under different retail tariffs, which we address in Part II. Here we apply the classical Ramsey pricing theory with extensions to accommodate the uncertainty and inter-temporal dependencies of demand that arise with the integration of behind-the-meter renewables and storage. While economic literature has disregarded said extensions, engineering approaches to dynamic pricing and demand response have ignored the revenue adequacy objective of retail tariff design, which our work addresses explicitly. In this context, there are no existing comparable studies in the open literature with the exception of a preliminary work in [85]. To a large extent, our results are an examination of emerging issues in smart distribution systems through the lens of classical economic results on the fundamental efficiency of two-part tariffs in stylized economic models [19].

The main results of this paper are as follows. We consider the design of ex-

[2]The revenue requirement is incorporated indirectly into the formulation through a weighted social welfare objective.

ante retail tariffs from the perspective of a regulated retailer subject to a revenue sufficiency constraint. The ex-ante tariffs considered here include traditional tariffs with long lag times as well as some of the more sophisticated tariffs that are being considered for smart distribution systems. Examples include time-of-use tariffs, critical peak pricing, variable peak pricing, and real-time pricing [49]. The retailer considered in this paper is a regulated monopoly which, on one hand, serves heterogeneous residential customers with elastic demands. The demand model considered here is stochastic and captures inter-temporal price dependencies. On the other hand, the retailer interfaces with an exogenous wholesale market with stochastic real-time prices. We describe the models in our formulation in Section 4.2.

Within this general setting, we characterize the structure of optimal linear and two-part tariffs in the presence of demand and wholesale price uncertainty in Section 4.3. In particular, we show that the optimal ex-ante two-part tariff consists of a time-varying retail price that not always matches the expected wholesale price and a connection charge that allocates uniformly among all customers the retailer's fixed costs and risk-related costs caused by the ex-ante determination of the tariff. We further show that the optimal volumetric tariff, referred hereafter as linear tariff, is characterized by a time-varying price markup—relative to the optimal two-part tariff's price—that depends on the retailer's fixed costs and the price elasticity of demand.

We further compare the efficiency of the linear and two-part tariff in Section 4.3.3. Specifically, we present a parametric characterization of the *social welfare* (SW) or total surplus and the *consumer surplus* (CS) as a function of the retailer's fixed costs. We show that the two-part tariff achieves the same SW regardless of the retailer's fixed costs. For the linear tariff, in contrast, the SW decreases as the fixed costs increase, thus characterizing a trade-off between fixed costs and efficiency. We also provide a sufficiency condition under which the two-part tariff is optimal among all ex-ante nonlinear tariffs.

We demonstrate the performance of the derived tariffs numerically using publicly available data from NYISO and the largest utility company in New York City in Section 4.4. Contingent on the deployment of enabling technologies and smart meters, our results estimate that the optimal day-ahead linear tariff could bring loses (4.8% of the utility's revenue) relative to the utility's suboptimal two-part flat tariff due to the lack of a connection charge. The optimal day-ahead two-part tariff, on the other hand, could bring significant gains (8.1% of the utility's revenue). From a societal perspective, these loses and gains manifest themselves as reductions and increments in electricity consumption, respectively. These estimates assume a realistic own-price elasticity of demand and a stylized model for TCL. Some concluding remarks and proofs are included in Section 4.5 and the Appendix, respectively.

4.1.3 Notations

We use $\overline{x} = \mathbb{E}[x]$ to denote the expectation of a random vector $x \in \mathbb{R}^n$ and $\Sigma_{x,y} = \mathbb{C}\text{ov}(x, y) \in \mathbb{R}^{n\times m}$ to denote the cross-covariance matrix of two random vectors $x \in \mathbb{R}^n$, $y \in \mathbb{R}^m$. Let also x_k denote the k^{th} entry of a vector $x \in \mathbb{R}^n$ and $x^\top$ its transpose.

4.2 Model

Given our focus on the retail electricity market, we assume the state of the wholesale market is represented by an exogenous discrete-time random process $\lambda_k \in \mathbb{R}_+$, which represents the wholesale RTP of electricity at time k in a single location of interest. We assume that the time periods $k = 1, \ldots, N$ partition a billing cycle, which is the time horizon relevant for our formulation. Moreover, we assume the wholesale RTP accurately reflects the *social* marginal cost of electricity [12].

4.2.1 A Retail Tariff Model

In this paper, we consider time-differentiated retail electricity tariffs that are set and announced in advance (*i.e.*, ex-ante) by a regulated retailer with a fixed lag time. These tariffs (*i*) are fixed before the beginning of a billing period of certain length (*e.g.*, a month or a day) with a fixed lag time (*e.g.*, several days or hours), (*ii*) specify a pricing rule that depends on the temporal consumption profile within the billing period rather than on the accumulated consumption, and (*iii*) are allowed to vary dynamically from one billing period to the next. In the context of retail tariffs, the tariff lag time induces a tradeoff between advanced price notification and price signal accuracy [14]. The tariff model considered here captures both the traditional long term flat tariff that has months or years of lag time as well as more sophisticated dynamic tariffs such as those with days or hours of advanced notification, but it generally excludes *ex-post* tariffs such as those indexed to the wholesale RTP.

Formally, some time before the billing cycle starts, the retailer announces a tariff $T : \mathbb{R}^N \to \mathbb{R}$ that maps the metered consumption power profile $q \in \mathbb{R}^N$ of each customer to a scalar charge $T(q) \in \mathbb{R}$. While the k^{th} entry of q is a single customer's metered consumption in period k of the billing period, the amount $T(q)$ (in dollars) represents the total bill. Note that this form of tariff captures the intertemporal dependencies of pricing and consumption within each billing cycle (but not between several billing cycles).

Given a tariff T, customers rationally choose in real-time how much electricity to purchase from the retailer during each consumption period of the current billing cycle. The retailer then pays for the aggregate demand at the wholesale RTP.

Although in practice retailers buy certain portions of the aggregate demand in forward markets (including the day-ahead market), we can neglect such purchases in our formulation without loss of generality for the following reason. In perfectly competitive and well-functioning two-settlement markets, forward transactions are essentially used to hedge against the volatility of the RTP. Here, we consider risk-neutral decision markers that deal with uncertainty by taking expectations. Thus, in our setting, forward markets would bring no significant advantages to any stakeholder. This justifies the reliance of the retailer in the RTP to purchase electricity, which is an assumption that simplifies our exposition considerably.

4.2.2 Consumer Model

We consider M customers (indexed by i) who obtain a monetary benefit (*i.e.*, gross surplus) $S^i(q^i, \omega^i) \in \mathbb{R}$ from consuming a power profile $q^i \in \mathbb{R}^N$ throughout the billing cycle. This benefit is contingent on $\omega^i = (\omega^i_1, \dots, \omega^i_N) \in \mathbb{R}^N$, where $\{\omega^i_k\}_{k=1}^N$ is an exogenous random process that represents customer i's local state. We assume that S^i is continuously differentiable in (q^i, ω^i).

Accordingly, customer i exhibits a consumption profile $q^i = q^i(T, \omega^i)$ when facing a tariff T and a sequence of local states $\{\omega_k^i\}_{k=1}^N$. Customers are rational in that sense that the sequence of consumptions $\{q_k^i(T, (\omega_1, \ldots, \omega_k))\}_{k=1}^N$ solves the multistage stochastic program

$$\overline{\mathsf{cs}}^i(T) = \max_{q^i(\cdot)} \ \mathbb{E}[S^i(q^i(\omega^i), \omega^i) - T(q^i(\omega^i))], \tag{4.1}$$

where the expectation is taken over ω^i, and $\overline{\mathsf{cs}}^i(T)$ represents customer i's expected surplus. Correspondingly, a tariff T yields an (aggregate) expected consumer surplus

$$\overline{\mathsf{cs}}(T) \ = \ \mathbb{E}\left[\textstyle\sum_{i=1}^M S^i(q^i(T, \omega^i), \omega^i) - T(q^i(T, \omega^i))\right], \tag{4.2}$$

where the expectation is taken over $\omega = (\omega^1, \ldots, \omega^M)$.

Of particular interest is the demand response to tariffs T with constant gradient $\nabla T = \pi \in \mathbb{R}^N$, where $\pi \in \mathbb{R}^N$ is a time-varying per-unit price, such as the tariff with the affine form $T(q^i) = A + \pi^\top q^i$. For such tariffs T we use the notation

$$D^i(\pi, \omega^i) = q^i(T, \omega^i) \tag{4.3}$$

for customer i's demand profile, thus implicitly assuming that it depends on T only through π. Hence, D^i is a standard demand function which we assume to be nonnegative and continuously differentiable in π, and its Jacobian $\nabla_\pi D^i \in \mathbb{R}^{N\times N}$, with (k, t) entry $\partial D_k^i / \partial \pi_t$, negative definite. Under the regularity assumptions made on S^i and D^i, one can show that $\overline{\mathsf{cs}}^i(T)$ is decreasing and convex in π (see Prop. 5 in Appendix). We further define the aggregate demand function as $D(\pi, \omega) := \sum_{i=1}^M D^i(\pi, \omega^i)$. A consumer model similar to the one decribed in this section for $N = 1$ is proposed and discussed with more detail in [71].

For example, for a linear tariff $T(q^i) = \pi^\top q^i$, the consumption of a TCL may be modeled with a linear demand function $D^i(\pi, \omega^i) = \omega^i - G^i\pi$, with deterministic and positive definite $G^i \in \mathbb{R}^{N\times N}$. Such demand function can be derived from an additive and temporally-separable quadratic benefit function S^i via stochastic dynamic programming [69].

4.2.3 Retailer Model

We consider the case of a retail monopoly and refer to the single entity as the retailer, utility, or load-serving entity (LSE). In procuring an aggregate demand profile $q = \sum_{i=1}^{M} q^i \in \mathbb{R}^N$, we assume that the retailer incurs a variable cost $\lambda^\top q$, where $\lambda = (\lambda_1, \ldots, \lambda_N)^\top \in \mathbb{R}^N$ is the wholesale RTP[3] Hence, a tariff T yields the expected retailer surplus

$$\overline{\mathsf{rs}}(T) \;=\; \mathbb{E}\left[\textstyle\sum_{i=1}^{M} T(q^i(T,\omega^i)) \;-\lambda^\top q^i(T,\omega^i)\right], \tag{4.4}$$

where the expectation is taken over the global state $\xi = (\lambda, \omega)$. For notational convenience, we define the RS collected from the volumetric charge π of an affine tariff $T(q) = A + \pi^\top q$ as $\phi(\pi) = (\pi - \lambda)^\top D(\pi, \omega)$ so that $\overline{\mathsf{rs}}(T) = \overline{\phi}(\pi) + MA$ and

$$\overline{\phi}(\pi) = (\pi - \overline{\lambda})^\top \mathbb{E}[D(\pi, \omega)] - \mathrm{Tr}(\mathbb{C}\mathrm{ov}(\lambda, D(\pi, \omega))). \tag{4.5}$$

4.3 Retail Tariff Design

In our retail tariff design framework, we assume that the regulator mandates the retailer to choose a tariff T that maximizes the expected consumer surplus. Moreover, in order to recover the upstream fixed costs incurred to deliver electricity,

[3]While in practice the time granularity of the wholesale RTP is finer than that of retail rates, we assume they are equal to simplify our exposition.

the tariff should satisfy the revenue adequacy constraint $\overline{\mathsf{rs}}(T) = F$, where F is a target approved by the regulator.

Formally, the regulator's problem can be stated as

$$\max_{T(\cdot)} \overline{\mathsf{cs}}(T) \quad \text{s.t.} \quad \overline{\mathsf{rs}}(T) = F. \tag{4.6}$$

Broadly, this problem falls in the category of *Ramsey-Boiteux pricing* and *peak-load pricing* in economics [34], which are main components of the theory of public utility pricing [19, Sec. 4.5]. See [141] for a recent overview of this problem in the context of electricity pricing.

In this section, we study linear and two-part tariffs—two of the most widely used tariffs in electricity industry. The restriction to two-part tariff can in fact be made without loss of generality under certain conditions (Theorem 4.3.6). We begin by making the following assumption that guarantees the existence and uniqueness of solutions to problem (4.6).

Assumption 2 $g(\pi) = \mathbb{E}[\nabla_\pi D(\pi,\omega)(\pi - \lambda)]$ *is such that the Jacobian matrix* $\nabla g(\pi)$ *is negative definite (nd).*

This assumption—made mainly for analytical convenience—is common is economics [71] and essentially imposes a limitation on the curvature of the demand function[4]. Intuitively, the demand can be generally linear, concave, or convex in π; however, when convex, restrictions on the "amount" of convexity are required for Assumption 2 to hold.

[4]In particular, for a linear demand $D(\pi,\omega) = b(\omega) - G(\omega)\pi$, $\nabla g(\pi) = \mathbb{E}[\nabla_\pi D(\pi,\omega)]$ is nd since $\nabla_\pi D(\pi,\omega)$ is nd. Moreover, for a demand with additive disturbances $D(\pi,\omega) = b(\omega) + D(\pi)$, A2 holds for $\pi \geq \overline{\lambda}$ if each $D_k(\pi)$ is concave in π since $\nabla g(\pi) = \nabla D(\pi) + \sum_{k=1}^{N}(\pi_k - \overline{\lambda}_k)\nabla^2 D_k(\pi)$. Concave demand functions are common in economic models since they guarantee profit and welfare maximization problems to be well defined [1]. See, for example, Prop. 6 in the Appendix.

4.3.1 Structure of Optimal Two-Part Tariff

By restricting the regulator's problem to two-part tariffs of the form $T(q) = A + \pi^\top q$, problem (4.6) can be reformulated as a convex program under Assumption 2. We emphasize here that our analysis implicitly assumes that no customer chooses to avoid the connection charge by not consuming electricity at all[5]. The following result characterizes the optimal solution.

Theorem 4.3.1 *(Optimal two-part tariff) The two-part tariff T^* that solves problem* (4.6) *is characterized by*

$$\pi^* = \overline{\lambda} + \mathbb{E}[\nabla_\pi D(\pi^*, \omega)]^{-1}\mathbb{E}[\nabla_\pi D(\pi^*, \omega)(\lambda - \overline{\lambda})], \tag{4.7}$$

$$A^* = \tfrac{1}{M}\left(F - \overline{\phi}(\pi^*)\right). \tag{4.8}$$

Theorem 4.3.1 implies that the optimal price π^* is characterized by a *period-specific* price markup relative to the expected RTP, $\overline{\lambda}$. Examination of (4.7) reveals that this markup is essentially determined by the cross-covariance between the price sensitivity of demand and the RTP[6] To gain intuition into (4.7), consider a demand independent across time[7], case in which

$$\pi_k^* = \overline{\lambda}_k + \overline{\varepsilon}_{kk}(\pi^*)^{-1}\,\mathbb{C}\text{ov}\left(\varepsilon_{kk}(\pi^*), \lambda_k\right), \tag{4.9}$$

for each $k = 1, \ldots, N$, where we use

$$\varepsilon_{kt}(\pi) = \frac{\partial D_k(\pi, \omega)/\partial \pi_t}{\mathbb{E}[D_k(\pi, \omega)]/\pi_t} \tag{4.10}$$

[5]This assumption is widely accepted for services such as electricity and water since "it is extremely unlikely that a customer will drop out of the market, however high the tariff" [19, Sec. 4.5]. Studies suggest, however, that more cost-effective DERs might challenge this assumption in future years [114].

[6]In expression (4.7), the second expectation is a second-order expectation that can be thought as the cross-covariance between a matrix and a vector.

[7]That is, a demand with $D_k(\pi, \omega)$ independent of π_t for all $t \neq k$

to represent the (own or cross-time) price elasticity of demand at time k with respect to the price at time t. The latter result resembles the (second-best optimal) ex-ante two-part tariff derived in [71, Sec. 3] for the single period case ($N = 1$)[8].

The expression (4.8) for the optimal connection charge A^* also has an intuitive interpretation. The first term corresponds to a *uniform contribution* towards the retailer's target F. And, the second term corresponds to a *uniform preallocation* of the surplus that the retailer expects to collect from the volumetric charge π^*, $\overline{\phi}(\pi^*)$, which—as noticeable from (4.5)—may be positive or negative in general.

To gain additional insights into these results, we have the following corollary.

Corollary 4.3.2 *If $\nabla_\pi D(\pi, \omega)$ and λ are uncorrelated, then $\pi^* = \overline{\lambda}$ and $A^* = \frac{1}{M}\left(F + \mathrm{Tr}(\mathbb{C}\mathrm{ov}(\lambda, D(\overline{\lambda}, \omega)))\right)$.*

Corollary 4.3.2 indicates that T^* has a very simple and appealing structure that resembles the result for the *deterministic* case where $\pi^* = \lambda$ and $A^* = F/M$. Note that the assumption made in Corollary 4.3.2 is valid for many situations. It is certainly true for demands that are not much affected by consumers' local randomness[9], such as the charging of electric vehicles and typical household appliances. Even for loads from smart HVAC systems that are affected by random temperature fluctuations, the assumption in Corollary 4.3.2 holds because the demand function takes the form $D(\pi, \omega) = \omega + D(\pi)$ [69].

As for the simpler structure of T^*, it may not be surprising since the efficiency of marginal cost pricing (*i.e.*, $\pi^* = \overline{\lambda}$) is a classical result for the deterministic case [19,

[8]Which also applies to the continuous time case where $k \in [0, 1]$, the demand and prices are deterministic, and demand is independent across time.

[9]More precisely, this assumption is satisfied by demands whose *sensitivity* to prices depends on the customers' set of appliances and idiosyncratic preferences rather than on random exogenous factors affecting the wholesale prices, such as random temperature fluctuations.

Sec. 4.5] [71]. Intuitively, marginal cost pricing is efficient because it induces customers to increase consumption until the derived marginal benefit matches the marginal cost of procuring electricity.

The expression for A^* in Corollary 4.3.2 also has an intuitive interpretation. While the first term remains unchanged from (4.8), the second term becomes a risk premium associated to the cross-correlation that the demand and the RTP may exhibit. When such cross-correlation is positive (as in practice [20]), the retailer is likely to face additional variable costs since the expected variable cost $\mathbb{E}[\lambda^\top D(\overline{\lambda},\omega)]$ is larger than the variable revenue $\overline{\lambda}^\top \mathbb{E}[D(\overline{\lambda},\omega)]$. Intuitively, this fee represents a *uniform risk premium* that customers pay to face a deterministic price rather than the volatile RTP. Presumably, the inter-customer cross-subsidies arising from the uniform allocation of this risk premium are negligible compared to the differences. However, the integration of behind-the-meter renewables could make these cross-subsidies worth adjusting, for example, through the use of discriminatory connection charges consistent with the cost-causation principle described in [106]. A discussion on cross-subsidies is held in Part II.

4.3.2 Structure of the Optimal Linear Tariff

A tariff of the form $T(q^i) = \pi^\top q^i$—a linear tariff—is an ex-ante two-part tariff with no connection charge. While such purely volumetric tariff may be simpler, it has two fundamental disadvantages. First, a closed form expression of the optimal linear tariff is not available under general assumptions. Second, such restriction introduces a fundamental trade-off between the retailer surplus target and the attainable social welfare. These drawbacks are noticeable in Theorem 4.3.3 and Corollary 4.3.5, respectively.

When restricted to linear tariffs, a unique solution to problem (4.6) can be obtained due to Assumption 2. We characterize the optimal solution in the following result.

Theorem 4.3.3 *(Optimal linear tariff) Consider the regime where F is large, i.e., $F \geq \overline{\phi}(\pi^*)$. If feasible, the linear tariff $T^\dagger$ that solves problem* (4.6) *is characterized by*

$$\pi^\dagger = \pi^* - \tfrac{\gamma-1}{\gamma}\mathbb{E}[\nabla_\pi D(\pi^\dagger,\omega)]^{-1}\mathbb{E}[D(\pi^\dagger,\omega)], \tag{4.11}$$

or, equivalently, by

$$\sum_{t=1}^{N} -\overline{\varepsilon}_{kt}(\pi^\dagger)\left(\frac{\pi_t^\dagger - \pi_t^*}{\pi_t^\dagger}\right) = \tfrac{\gamma-1}{\gamma}, \quad \forall\ k = 1,\ldots,N, \tag{4.12}$$

where γ, the Lagrange multiplier of (4.6)*, satisfies $\frac{\gamma-1}{\gamma} \in [0,1]$ and is such that $\overline{\mathsf{rs}}(T^\dagger) = F$. In this regime of F, the problem is feasible if and only if $F \leq \overline{\phi}(\pi^{\mathrm{M}})$, where π^{M} is the price that maximizes $\overline{\mathsf{rs}}(T)$ over π, which matches $\pi^\dagger$ as $\gamma \to \infty$.*

In Theorem 4.3.3, expression (4.11) reveals that the structure of the optimal linear tariff is characterized by a *period-specific* price markup relative to the price of the optimal two-part tariff π^*. The scalar $\frac{\gamma-1}{\gamma} \in [0,1]$, often called the Ramsey number, adjusts markups in all periods *uniformly* to the point where the expected retailer surplus matches the target F. A closer examination of (4.11), which can be rewritten as (4.12), shows that the own and cross price elasticities of demand determine altogether the markup for each period within the billing cycle.

To understand (4.12), it is informative to consider the case where the demand is independent across time, namely, $\varepsilon_{kt}(\cdot) = 0$ for $t \neq k$. In this case, the product of the markup $(\pi_k^\dagger - \pi_k^*)/\pi_k^\dagger$ and the own-price elasticity $-\varepsilon_{kk}(\pi^*)$ remains constant in time and equal to the Ramsey number. This means that periods with inelastic demands get high markups and periods with elastic demands get low markups. For this reason, this pricing rule is known in economics as the *inverse elasticity rule* [19, Sec. 3.3].

Even simpler is the single period case, also derived in [71, Sec. 3]. Notably, when $N = 1$, the scalar price $\pi^\dagger$ can be obtained directly from the constraint $\overline{\mathsf{rs}}(T^\dagger) = F$, and it must be set so that it pays for the average total cost of the procured electricity, *i.e.*, $\pi^\dagger = (\mathbb{E}[\lambda \cdot D(\pi^\dagger, \omega)] + F)/\mathbb{E}[D(\pi^\dagger, \omega)]$.

A specialized application of this result was developed in [69], where a model for TCLs under a day-ahead hourly pricing scheme was considered. In this case, the demand function for each consumer is linear and the surplus function is quadratic [69]. The aggregated demand is therefore also linear. The consumers as a collective have a quadratic aggregated surplus [69]. Specifically,

$$D^i(\pi, \omega^i) = \omega^i - G^i \pi, \tag{4.13}$$

$$S^i(D^i(\pi, \omega^i), \omega^i) = \delta^i(\omega^i) - \tfrac{1}{2}\pi^\top G^i \pi. \tag{4.14}$$

where $G^i \in \mathbb{R}^{24\times 24}$ is deterministic, positive definite (and symmetric). Letting $G = \sum_{i=1}^M G^i$ and $\Omega = \sum_{i=1}^M \omega^i$ and applying Theorem 4.3.3 readily yields

$$\pi^\dagger = \overline{\lambda} + \tfrac{\rho}{1+\rho}(\pi^o - \overline{\lambda}), \tag{4.15}$$

where $\pi^o = G^{-1}\overline{\Omega}$ induces $\mathbb{E}[D(\pi^o, \Omega)] = 0$ and $\rho = \frac{\gamma-1}{\gamma}$ is the Ramsey number, which is set so that $\overline{\mathsf{rs}}(T^\dagger) = F$. Intuitively, ρ varies within $[0, 1]$ inducing prices that vary between $\overline{\lambda}$ and the profit-maximizing price $\pi^{\mathrm{M}} = \frac{1}{2}(\pi^o + \overline{\lambda})$ as F varies between $\overline{\phi}(\overline{\lambda})$ and the maximum profit $\overline{\phi}(\pi^{\mathrm{M}})$.

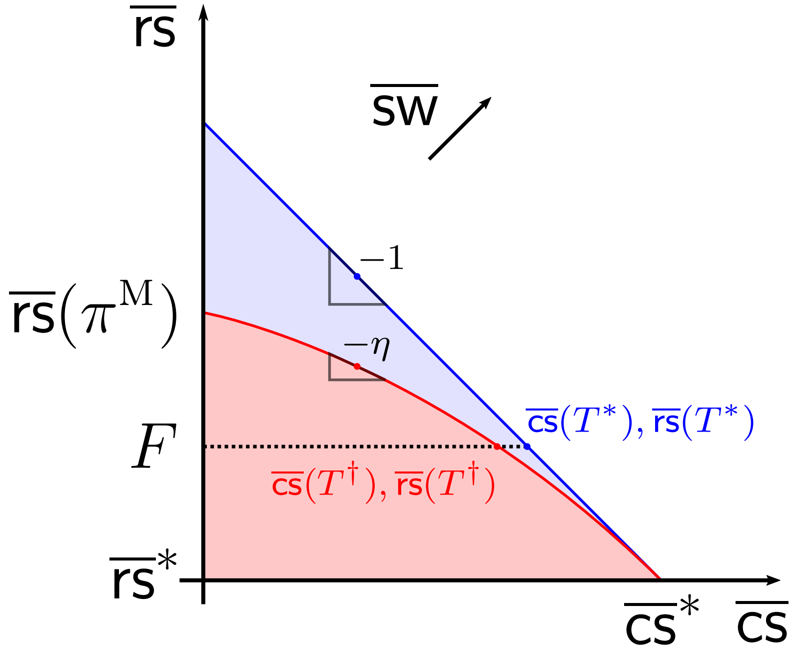


Figure 4.1: Pareto fronts induced by optimal linear and two-part tariffs. The slope $\partial\overline{\mathsf{rs}}(F)/\partial\overline{\mathsf{cs}}(F) = -\eta$ relates to $\gamma \geq 1$ in (4.11) through $\eta = \frac{2}{1+\gamma}$.

4.3.3 Tariff Performance Comparison

We now discuss the performance of the derived tariffs in terms of social welfare (expected total surplus) leveraging the graphical representation provided in Fig. 4.1. Therein, a Pareto front for each tariff illustrates the expected CS and SW induced by the tariff for different RS targets $F \in [\overline{\phi}(\pi^*), \overline{\phi}(\pi^{\mathrm{M}})]$. On one hand, Theorem 4.3.1 has the following implication.

Corollary 4.3.4 *As a tariff parametrized by F, the two-part tariff T^* induces an expected total surplus $\overline{\mathsf{sw}}^*$ that is independent of F and $\overline{\mathsf{cs}}(T^*) = \overline{\mathsf{sw}}^* - F$.*

In Corollary 4.3.4, $\overline{\mathsf{sw}}^*$ denotes the constant SW attained by the price π^*, where $\overline{\mathsf{sw}}^* = \overline{\mathsf{sw}}(T^*) = \overline{\mathsf{cs}}(T^*) + \overline{\mathsf{rs}}(T^*)$. Implicit in this result is that for any affine tariff one can check that

$$\overline{\mathsf{sw}}(T) = \sum_{i=1}^{M} \mathbb{E}\left[S^i(D^i(\pi, \omega^i), \omega^i) - \lambda^\top D^i(\pi, \omega^i)\right] \tag{4.16}$$

depends on π but not on A. Corollary 4.3.4 thus implies that under the tariff T^*, collecting additional revenue from customers to cover larger fixed costs embedded in F reduces consumer welfare but does not compromise social welfare. This "iso-efficient" trade-off between retailer and consumer surplus is illustrated in Fig. 4.1 with a *linear* Pareto front with negative and unitary slope in the $\overline{\mathsf{cs}}$-$\overline{\mathsf{rs}}$ plane. Intuitively, suboptimal two-part tariffs[10] can achieve any point in the $\overline{\mathsf{cs}}$-$\overline{\mathsf{rs}}$ plane in the shaded area below the linear Pareto front in Fig. 4.1, but no ex-ante two-part tariff can achieve points above this front.

Theorem 4.3.3, on the other hand, has a analogous implication.

Corollary 4.3.5 *The quantities $\overline{\mathsf{sw}}(T^\dagger)$ and $\overline{\mathsf{cs}}(T^\dagger)$ induced by $T^\dagger$ as a tariff parametrized by F are decreasing and concave in $F \in [\overline{\phi}(\pi^*), \overline{\phi}(\pi^{\mathrm{M}})]$ with $\overline{\mathsf{sw}}(T^\dagger) = \overline{\mathsf{sw}}^*$ and $\overline{\mathsf{cs}}(T^\dagger) = \overline{\mathsf{sw}}^* - F$ for $F = \overline{\phi}(\pi^*)$.*

Corollary 4.3.5 reveals that, unlike the tariff T^*, the optimal linear tariff $T^\dagger$ compromises not only consumer welfare but also social welfare when collecting additional revenue from customers is required to cover larger fixed costs embedded in F. This trade-off is depicted in Fig. 4.1 with a *decreasing and concave* Pareto front in the $\overline{\mathsf{cs}}$-$\overline{\mathsf{rs}}$ plane that bends away from the efficiency level $\overline{\mathsf{sw}}^*$ attained by the tariff T^* as F increases from $\overline{\phi}(\pi^*)$ until it reaches $\overline{\phi}(\pi^{\mathrm{M}})$. As before, suboptimal linear tariffs can achieve any point in the shaded area below the curved Pareto front in Fig. 4.1, but no ex-ante linear tariff can achieve points above this front.

[10] As the ones currently used by most utilities in the U.S., due in part to additional bill stability and alleged equity concerns imposed by regulators.

From the previous analysis, it is clear that two-part tariffs dominate linear tariffs in terms of expected consumer surplus in the regime of practical relevance where $F \geq \overline{\phi}(\pi^*)$. A natural question to ask is whether two-part tariffs can be dominated by more complex nonlinear ex-ante tariffs. We now argue that, under certain sufficient condition, the two-part tariff T^* is indeed optimal for the regulator's problem (4.6) among all ex-ante arbitrary tariffs. To establish such result it suffices to show that T^* induces the same expected consumer surplus that would be achieved by a social planner who makes consumption decisions on behalf of customers with the unconstrained objective of maximizing the expected total surplus. This is because the social planner's problem provides a trivial upper bound to the regulator's problem.

Because we are interested in comparing ex-ante tariffs only, the social planner's problem should incorporate such implicit restriction. The restriction to ex-ante tariffs translates into a restriction for the social planner to use only the information observable by each customer i when choosing their consumption, namely their local state ω^i. Hence, the social planner's problem can be stated as

$$\max_{\{q^i(\omega^i)\}_{i=1}^M} \overline{\mathsf{sw}} = \mathbb{E}\left[\sum_{i=1}^M S^i(q^i(\omega^i), \omega^i) - \lambda^\top q^i(\omega^i)\right], \tag{4.17}$$

where the expectation is taken with respect to $\xi = (\lambda, \omega)$, and $q^i(\omega^i)$ is causally contingent on (*i.e.*, adapted to) the local state ω^i. Finally, under the assumption that each ω^i and λ are independent, we show that the optimal solution to (4.17) is $q^i(\omega^i) = D^i(\pi^*, \omega^i)$, which matches the demand induced by the optimal two-part tariff. This result and the implied optimality of T^* are summarized in the following Theorem.

Theorem 4.3.6 *If* (A2) *the wholesale RTP λ and the local state ω^i of each customer $i = 1, \ldots, M$ are statistically independent, then the two-part tariff T^* is* *an optimal solution of* (4.6) *among all arbitrary tariffs with the same lag time.*

Theorem 4.3.6 indicates that the restriction to two-part tariffs may imply no loss of generality. This applies—less generally than Corollary 4.3.2—for demands that are not affected by consumers' local randomness[11], such as washers and dryers, computers, and the charging of electric vehicles. For all the other cases, where the sufficient condition (A2) does not hold, Theorem 4.3.6 sheds lights on the performance of the optimal ex-ante two-part tariff T^*. While it is clear that the ex-ante restriction entails some efficiency loss when (A2) is not satisfied[12], it is not clear whether the restriction to two-part tariffs does entail efficiency losses. In other words, is there a necessary condition for T^* to be an optimal solution of (4.6)?

4.4 Numerical Example

We now estimate the performance of the optimal linear and two-part day-ahead tariffs in a practical setting. Using publicly available data from ConEdison (New York City's largest utility) and NYISO for the 2015 Summer season, we estimate the average daily gains in consumer surplus that both tariffs would have brought relative to the utility's default two-part tariff with flat rate. Here we assume a linear demand model (4.13)-(4.14) and day-ahead linear and two-part tariffs.

The utility's monthly residential energy sales[13] and an estimated residential

[11] In other words, demands that, given a retail price vector π, are independent from random exogenous factors affecting the wholesale prices λ.

[12] This is because relaxing the ex-ante restriction enables the use of the ex-post two-part tariff $T(q^i) = F/M + \lambda^\top q^i$ which trivially achieves the maximum social welfare a social planner could achieve (first-best).

[13] For June through August 2015, which can be found in the EIA-826 database at `www.eia.gov/electricity/data/eia826/`.

hourly load profile[14] were used to obtain $2,208$ (92 days $\times$ 24 hr) aggregate hourly consumption data points. We used these points as iid realizations $\{\mathbf{x}_j\}_{j=1}^{92}$ of the random vector $D(\mathbf{1}\pi^{\text{CE}},\omega) = \omega - G\mathbf{1}\pi^{\text{CE}} \in \mathbb{R}^{24}$, where π^{CE} is ConEdison's flat rate[15], to fit G and then to estimate $\overline{\omega}$. Due to the its low-dimensional structure, fitting G can be reduced to determining a scaling parameter after assuming certain own-price elasticity of demand at π^{CE}[16]

$$\overline{\varepsilon}(\pi^{\text{CE}}) = \frac{\partial \mathbb{E}\left[D(\mathbf{1}\pi^{\text{CE}},\omega)^\top \mathbf{1}\right]/\partial \pi^{\text{CE}}}{\mathbb{E}\left[D(\mathbf{1}\pi^{\text{CE}},\omega)^\top \mathbf{1}\right]/\pi^{\text{CE}}} = \frac{\mathbf{1}^\top G \mathbf{1}}{\hat{\mathbf{x}}^\top \mathbf{1}/\pi^{\text{CE}}},$$

where $\hat{\mathbf{x}}$ denotes the sample mean of $\{\mathbf{x}_j\}$. While here we assume a value of $\overline{\varepsilon}(\pi^{\text{CE}}) = -0.3$, which is a reasonable estimate of the short-term own-price elasticity of electricity demand [47], a sensitivity analysis over $\overline{\varepsilon}(\pi^{\text{CE}})$ is presented in Section 5.3.4. We further assumed a total of $M = 2.2$ million of residential customers and used ConEdison's default residential connection charge, which amounts to $A^{\text{CE}} = 0.52$ \$/day, to roughly estimate the utility's average daily revenue from residential customers as $\overline{\mathsf{rev}}(T^{\text{CE}}) = \mathbb{E}[D(\mathbf{1}\pi^{\text{CE}},\omega)]^\top \mathbf{1}\pi^{\text{CE}} + MA^{\text{CE}}$ or \$7.19 million USD. As for the prices λ, we used the day-ahead prices for NYC as iid realizations to estimate $\overline{\lambda}$ and $\Sigma_{\lambda,\omega}$ with sample mean and covariance estimators.

We plot in Fig. 4.2a the Pareto fronts

$$\left\{ (\Delta\overline{\mathsf{cs}}(F), \Delta\overline{\mathsf{rs}}(F)) \,\middle|\, F \in [\overline{\phi}(\overline{\lambda}), \overline{\phi}(\pi^{\text{M}})] \right\} \tag{4.18}$$

induced by the optimal linear and two-part tariffs and three other relevant tariffs that satisfy the revenue sufficiency constraint: an optimized linear *flat* tariff with

[14]For a residential building in NYC, available in the NREL OpenEI building load database `http://en.openei.org/datasets/files/961/pub/`. The location/model with ID 725033-TMY3-BASE was used.

[15]NYC's residential default flat rate during Jun-Aug 2015 was $\pi^{\text{CE}} = 17.2$ cents/kWh (47.7% of which correspond to supply charges and 53.3 to delivery charges). Available at `www.coned.com/rates/supply_charges.asp` and `www.coned.com/documents/elecPSC10/SCs.pdf`.

[16]This is facilitated by assuming a homogeneous thermal parameter α^i across customers, which implies some loss of customer heterogeneity. See [69] for details of the model, where $\alpha^i = 0.2$ is used in a case study.

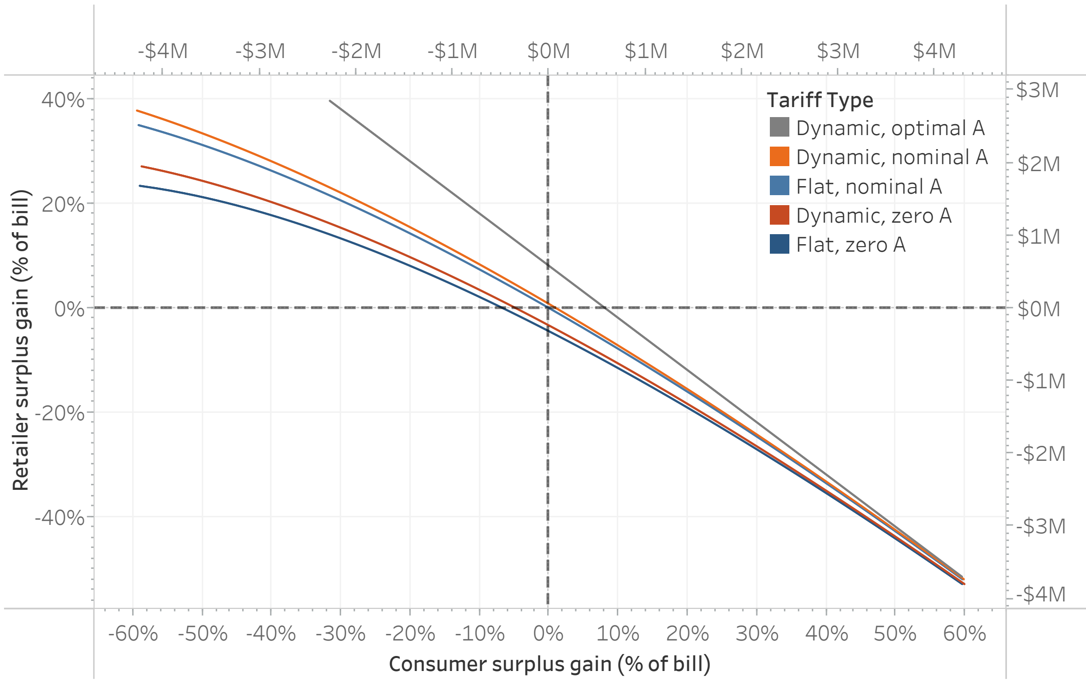
rate $\pi^{\mathrm{F}}(F)$, an optimized two-part tariff with *fixed* connection charge A^{CE} and rate $\pi^{\dagger}(F - A^{\mathrm{CE}}M)$, and an optimized two-part *flat* tariff with *fixed* connection charge A^{CE} and rate $\pi^{\mathrm{CE}} + \Delta(F)$. The latter can be thought as ConEdison's *adjusted* tariff. In (4.18), $\Delta\overline{\mathsf{cs}}(F)$ and $\Delta\overline{\mathsf{rs}}(F)$ denote the surplus gains (losses if negative) relative to the corresponding surplus achieved by T^{CE}. For instance, for the optimal two-part tariff $\Delta\overline{\mathsf{cs}}(F) = \overline{\mathsf{cs}}(T^{*}) - \overline{\mathsf{cs}}(T^{\mathrm{CE}})$.

Fig. 4.2a compares the tariffs' performances in consumer surplus gains for different retail surplus targets. At ConEdison's estimated net revenue level $F = \overline{\mathsf{rs}}(T^{\mathrm{CE}})$, which corresponds to $\Delta\overline{\mathsf{rs}}(F) = 0$, significant performance differences can be observed among the computed tariffs. These differences are more evident in Fig. 4.2b, which magnifies Fig. 4.2a around the origin. Due to its nonzero connection charge, ConEdison's tariff clearly outperforms the tariffs without connection charges, but is outperformed by the other tariffs with connection charges, which are further optimized. It is particularly interesting that switching to the optimal linear tariff would bring loses in CS (-4.8% or $-\$345$k USD/day). Namely, by virtue of a connection charge, even a simple flat tariff can outperform a fairly sophisticated day-ahead hourly volumetric tariff. Moreover, fully optimizing ConEdison's rate (but not its connection charge) brings rather limited CS gains (1% or \$72k USD/day). However, switching to the optimal two-part tariff would bring significant gains in CS (8.1% or \$582k USD/day). This corroborates how effective connection charges can be at increasing the retailer surplus without sacrificing economic efficiency. This optimal two-part tariff, which features a connection charge of $A^{*} = 2.65$ \$/day or nearly 80 \$/month, induces bill reductions for customers 6.62% larger than the average customer and bill increments for all other customers. Clearly, such charges may be politically unacceptable for low-income customers and may require cross-subsidized reduced tariffs, which have been an industry standard [19, Sec. 7.4].

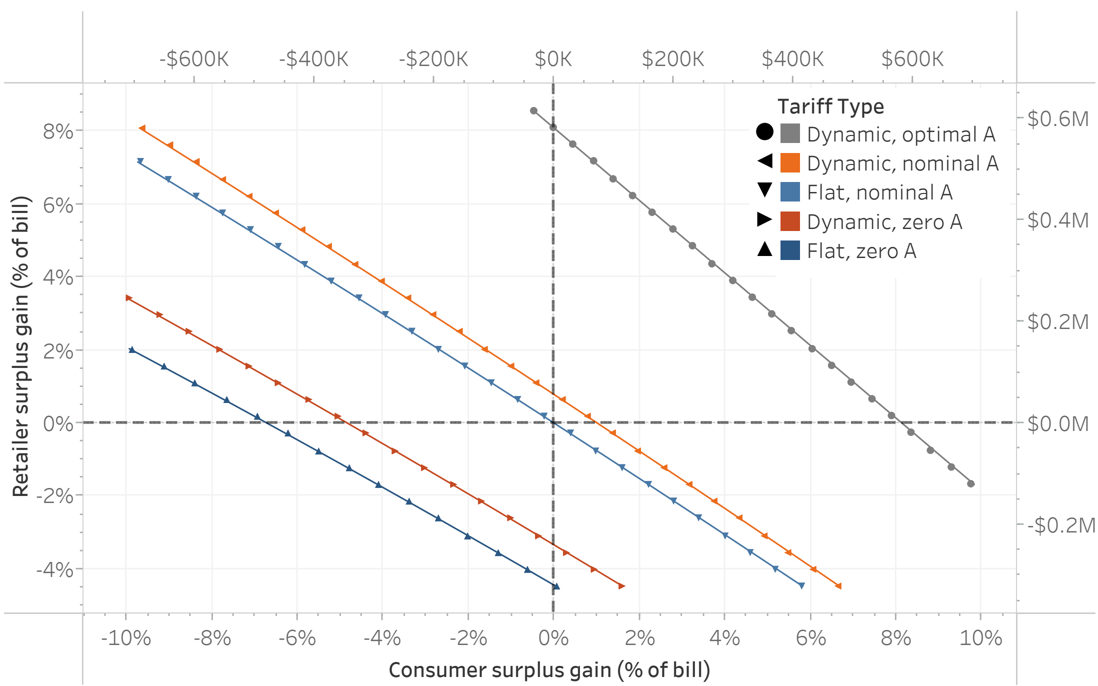
4.5 Conclusions

In this first part, we derive consumer-welfare-maximizing, revenue adequate, and ex-ante linear and two-part dynamic tariffs from the perspective of a regulated retailer. This initial analysis is for the case without renewables or storage in the distribution system. Our results generalize previous works by deriving said tariffs for a stochastic and multi-period demand model with intertemporal dependencies and a predetermined lag time between the announcement of the tariff and the beginning of the billing period. We established that if the wholesale prices and each customer's consumption are statistically independent, then the optimal two-part tariff is optimal among the class of arbitrary tariffs with the same lag time.

While the optimal two-part tariff mitigates inefficiencies induced by the optimal linear tariff, inequity concerns inconsistent with cost causation arise from the structure of the connection charge. These concerns may become significant with the sparse adoption of behind-the-meter renewables. While tariff design criteria beyond efficiency and revenue adequacy are out of the scope of our work, it is worth mentioning that allowing discriminatory connection charges can give flexibility to the regulator to achieve different objectives (such as inter-customer cost-causation equity) and provide effective long-term signals (*e.g.*, location within the distribution network and investment in on-site generation) [106].



(a) Pareto front for wide range of F including $\overline{\mathsf{rs}}(T^{\text{CE}})$.



(b) Zoom into neighborhood of $(\overline{\mathsf{cs}}(T^{\text{CE}}), \overline{\mathsf{rs}}(T^{\text{CE}}))$.

Figure 4.2: Consumer surplus and retailer surplus gains induced by various tariffs parametrized by the fixed cost parameter F assuming an intermediate own-price elasticity of $\bar{\varepsilon}(\pi^{\text{CE}}) = -0.3$.

CHAPTER 5

ON THE EFFICIENCY OF CONNECTION CHARGES—PART II: INTEGRATION OF DISTRIBUTED ENERGY RESOURCES[4]

Daniel Muñoz-Álvarez and Lang Tong[5]

This two-part paper addresses the design of retail electricity tariffs for distribution systems with distributed energy resources (DERs). Part I presents a framework to optimize an ex-ante two-part tariff for a regulated monopolistic retailer who faces stochastic wholesale prices on the one hand and stochastic demand on the other. In Part II, the integration of DERs is addressed by analyzing their endogenous effect on the optimal two-part tariff and the induced welfare gains. Two DER integration models are considered: (i) a decentralized model involving behind-the-meter DERs in a net metering setting, and (ii) a centralized model involving DERs integrated by the retailer in the distribution network.

It is shown that DERs integrated under either model can achieve the same social welfare and the net-metering tariff structure is optimal. The retail prices under both integration models are equal and reflect the expected wholesale prices. The connection charges differ and are affected by the retailer's fixed costs as well as the statistical dependencies between wholesale prices and behind-the-meter DERs. In particular, the connection charge of the decentralized model is generally higher than that of the centralized model.

An empirical analysis is presented to estimate the impact of DER on welfare

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distribution and inter-class cross-subsidies using real price and demand data and simulations. The analysis shows that, with the prevailing retail pricing and net-metering, consumer welfare decreases with the level of DER integration. Issues of cross-subsidy and practical drawbacks of decentralized integration are also discussed.

5.1 Introduction

This two-part paper studies the design of dynamic retail electricity tariffs for distribution systems with distributed renewable and storage resources. We consider a regulated monopolistic retailer who, on the one hand, serves residential customers with stochastic demands, and on the other hand, interfaces with an exogenous wholesale market with stochastic prices. In this framework, we analyze both customer-integrated and retailer-integrated distributed energy resources (DERs). Our goal is to shed lights on the widely adopted net metering compensation mechanism and the efficiency loss implied by some of the prevailing retail tariffs when an increasing amount of DERs are integrated into the distribution system.

While Part I (Chapter 4) [87] establishes a framework to analyze the efficiency of revenue adequate tariffs with connection charges, this Chapter (Part II) [88] extends it to address the integration of DERs.

The main contribution of Part II is twofold. First, we characterize analytically the optimal revenue adequate ex-ante two-part tariff for a distribution system with renewables and storage integrated by customers or the retailer. We characterize the consumer (and social) welfare achieved by the optimal two-part tariff under both integration models. This analysis is an application of the classical Ramsey pricing theory [19] with extensions to accommodate the multi-period integration of stochastic DERs. Second, we analyze a numerical case study based on empirical data that estimates the increasingly larger inefficiencies and interclass cross-subsidies caused by DERs when net metering tariffs with price markups are used to maintain revenue adequacy. In this context, the derived optimal two-part tariffs and a centralized DER integration model offer two alternatives to mitigate these undesirable effects.

The main results of Part II are as follows. We leverage the retail tariff design framework established in Part I (Chapter 4) to accommodate the integration of DERs by customers (in a net-metering setting) and by the retailer in Section 5.2. The extended framework considers heterogeneous customers with arbitrary behind-the-meter renewables and storage. Therein, we derive the optimal ex-ante two-part tariff under both DER integration models and the combined effect of this tariff and DERs on consumer and social welfare.

We find that under the optimal two-part tariff, DERs integrated under either model bring the same gains in social and consumer welfare. This is in contrast to prevailing volumetric tariffs under which the integration of DERs can increase or decrease social and consumer welfare depending critically on the integration model and the retailer's fixed costs. Indeed, we demonstrate that the two-part tariff structure is optimal in the sense that no other tariff structure —however complex— can achieve a strictly higher social welfare. This means that the two-part *net metering* tariff of the decentralized model is optimal as a DER compensation mechanism.

These welfare effects are explained by the structure of the optimal ex-ante two-part tariff. We show that under both integration models the derived tariff consists of an identical time-varying price and a distinct connection charge. In particular, the time-varying price reflects the wholesale prices and their statistical correlation with the elasticity of the random demand. The optimal connection charge allocates uniformly among customers the retailer's fixed costs and additional costs and savings caused by risks and the integrated DERs. Indeed, while savings from retailer-integrated DERs reduce the connection charge, customer-integrated DERs induce slight increments or reductions caused by risks introduced by renewables.

The theoretical analysis of DER integration is complemented in Section 5.3 with an empirical study based on publicly available data from NYISO and the largest utility company in New York City. The performance of the optimal ex-ante two-part tariffs is compared with several other ex-ante tariffs for different levels of DER penetration, under both integration models. Tariffs used as benchmarks include the optimal linear tariff and two-part flat tariffs used extensively in practice by utilities. In particular, relative to a base case with a nominal two-part flat tariff and no DERs, we estimate the efficiency gains or losses brought by tariff changes in Section 5.3.1. Subsequently, in Section 5.3.2, we estimate the efficiency gains or loses brought by the integration of DERs under both integration models and the various ex-ante considered tariffs. Most notably, our results estimate that the efficiency gains brought by switching from flat to hourly pricing, which are below 1% (of the utility's gross revenue) for most relevant cases, can be more than tripled by a $10 increase in the monthly connection charge. Moreover, for the case with customer-integrated DERs, we estimate in Section 5.3.3 the indirect cross-subsidies that customers without DERs give to DER-owning customers due to net metering tariffs with marked-up retail prices. All our estimations in this case study assume a stylized model for thermostatically controlled loads.

Concluding remarks and proofs of the main results are included in Section 5.4

and Appendix C, respectively.

5.1.1 Related Work

The literature on retail electricity tariff design is extensive, and there is an increasing interest in addressing the integration of DERs. We briefly discuss works that are relevant to our paper. Based on their main focus, we group these works into two categories: (*i*) tariff design for fixed cost recovery with DERs, and (*ii*) optimal demand response with DERs.

Tariff design for fixed cost recovery with DERs

The general principles used in retail tariff design are briefly reviewed in [111, 115] and more extensively in [17, 141], and the additional challenges brought by DERs are discussed in [32]. In the light of such challenges, current tariff design practices and broader regulatory issues are being revised in comprehensive studies to address the adoption of DERs [7, 8, 61, 90, 93, 120, 141], to estimate the impact of different tariff structures on the bills of residential customers with solar PV [8], and to investigate pricing issues related to the interaction between distribution utilities and the owners of DERs [61]. .

Research efforts to study more specific issues of DER integration such as [36–39, 46, 68, 125] have also emerged. For instance, in [68], the trade-off between multiple tariff design criteria is studied in a multi-objective optimization framework. An analytical approach leverages a generation capacity investment model in [125] to characterize sufficient conditions for RTP and flat tariffs to be revenue adequate. More empirical approaches are conducted in [46], where interclass cross-subsidies and revenue shortfalls caused by net metering tariffs are estimated, and in [39], which estimates the impact of tariff structure and net metering on the deployment of distributed solar PV.

Finally, there is an increasing volume of literature studying the "death spiral" of DER adoption [4, 24, 30, 33, 74, 112, 114], which is presented as a threat on the financial viability of utilities. This threat refers to a self-reinforcing feedback loop of DER adoption involving a decline in energy sales and the persistent attempt to recover utilities' fixed costs by increasing volumetric charges. The empirical analysis in [24], for example, models the effect that price feedback loops may have on the adoption of solar PV and concludes that it may not be significant within the next decade. In [4], an extensive list of factors that affect the system dynamics of DER adoption is presented. It concludes that while the feedback loop is possible, it is not predetermined and can be avoided. A stylized demand model is used in [33] to argue that a minimum of price elasticity is required for the threat to be an actual problem. The work in [114] provides an estimate of the evolution of the lowest-cost configuration (namely grid only, grid+solar, or grid+solar+battery) for residential and commercial customers to satisfy their load in the long-term for a few U.S. cities.

There are still important gaps in this subject. For example, none of the works above studies the efficiency loss and, with the exception of [46], the interclass cross-subsidies entailed by the adoption of DERs under net metering tariffs. This is precisely a focus of our work.

Optimal demand response with DERs

Many works focus on deriving optimal retail pricing schemes to induce desired electricity consumption behavior on customers with DERs such as [29, 58, 70, 132]. For example, in [70], the authors consider customer and retailer integrated renewables and storage separately in a setting similar to ours. They derive dynamic linear tariffs that maximize an objective that balances the retailer profit and customers' welfare. Unlike our work, however, none of these works consider explicitly a revenue adequacy constraint nor the use of connection charges.

5.2 Retail Tariff Design with DERs

5.2.1 Multi-period Ramsey Pricing under Uncertainty

Consider a regulator who sets a retail electricity tariff T in advance (ex-ante) to maximize the welfare of M customers over a billing cycle of N time periods, subject to a net revenue sufficiency constraint for the monopolistic retailer serving the load. Expectations are used to deal with the uncertainties that naturally arise when fixing a tariff in advance of actual usage.

To quantify the customers' welfare we use the notion of consumers' surplus, which measures the difference between the gross benefit derived from consumption and what the customer pays for it. Formally, we assume that given a tariff T, customer i consumes a profile $q^i(T, \omega^i) \in \mathbb{R}^N$ within the N-period billing cycle contingent on the random evolution of the local state $\omega^i = (\omega^i_1, \ldots, \omega^i_N) \in \mathbb{R}^N$, provided that q^i is purchased from the retailer. Accordingly, customer i derives an expected surplus

$$\overline{\mathsf{cs}}^i(T) = \mathbb{E}\big[S^i(q^i(T,\omega^i),\omega^i) - T(q^i(T,\omega^i))\big], \tag{5.1}$$

where $T : \mathbb{R}^N \to \mathbb{R}$ and $S^i(q^i(T,\omega^i),\omega^i)$ is the derived gross benefit. Collectively, customers derive an expected consumer surplus $\overline{\mathsf{cs}}(T) = \mathbb{E}[\sum_{i=1}^M \mathsf{cs}^i(T)]$, where the expectation is taken with respect to the M-tuple $\omega = (\omega^1, \ldots, \omega^M)$.

Similarly, the expected retailer surplus or net revenue is

$$\overline{\mathsf{rs}}(T) = \mathbb{E}\big[\textstyle\sum_{i=1}^M T(q^i(T,\omega^i)) - \lambda^\top q(T,\omega)\big], \tag{5.2}$$

where $\lambda \in \mathbb{R}^N$ is the profile of random real-time wholesale prices, $q(T,\omega)$ is the aggregated demand profile, $\lambda^\top q(T,\omega)$ is the energy cost faced by the retailer, and the expectation is over the uncertain evolution of the global state $\xi = (\lambda, \omega)$.

Adding the consumer and retailer surplus together yields the (expected) social surplus $\overline{\mathsf{sw}}(T) = \overline{\mathsf{cs}}(T) + \overline{\mathsf{rs}}(T)$ which quantifies the social welfare induced by a tariff T.

We can now formulate the regulator's tariff design problem as the optimization problem

$$\max_{T(\cdot)} \overline{\mathsf{cs}}(T) \quad \text{s.t.} \quad \overline{\mathsf{rs}}(T) = F, \tag{5.3}$$

where F is a constant representing the non-energy costs faced by the retailer that need to be passed on to its customers[1]. As such, (5.3) is a version of the Ramsey pricing problem[2]. In particular, we consider ex-ante two-part tariffs[3] $T(q) = A +$

[1] F may include delivery, metering, and customer service costs, and it may also recognize that a regulated firm should be allowed to earn some profit.

[2] Ramsey pricing is pricing efficiently subject to a breakeven constraint [19]. With (5.3), we seek to apply Ramsey pricing to a single service with time-varying, random marginal costs and temporally dependent stochastic demands.

[3] This restriction may involve no loss of generality (see Thm. 5.2.3 below).

$\pi^\top q$ with connection charge $A \in \mathbb{R}$ and time-varying price $\pi \in \mathbb{R}^N$. These tariffs induce an individual consumption profile $q^i(T, \omega^i) = D^i(\pi, \omega^i)$, where $D^i(\cdot, \omega^i)$ is a demand function assumed to be nonnegative, continuously differentiable in π, and with a negative definite Jacobian $\nabla_\pi D^i(\pi, \omega^i) \in \mathbb{R}^{N\times N}$ that satisfies the following assumption[4].

Assumption 3 $g(\pi) = \mathbb{E}[\nabla_\pi D(\pi,\omega)(\pi - \lambda)]$ *is such that the Jacobian matrix* $\nabla g(\pi)$ *is negative definite (nd).*

In the following sections we accommodate the integration of DERs into the tariff design framework above. To that end, we assume that either customers or the retailer have access to distributed renewable and storage resources. We model an agent's access to renewables as the ability to use a state-contingent energy profile $r \in \mathbb{R}^N_+$ at no cost. Similarly, we model access to a storage with capacity $\theta \in \mathbb{R}_+$ as the ability to offset energy *needs* with any vector of storage discharges $s \in \mathbb{R}^N$ in the operation constraint set[5]

$$\mathcal{U}(\theta) = \left\{ s \in \mathbb{R}^N \;\middle|\; 0 \le -\textstyle\sum_{t=1}^k s_t \le \theta,\ k = 1, \dots, N \right\}.$$

We define the (arbitrage) *value* of the storage given a deterministic price vector $\pi \in \mathbb{R}^N$ as

$$V^{\mathrm{s}}(\pi, \theta) = \max_{s\in\mathbb{R}^N} \left\{ \pi^\top s \;\middle|\; s \in \mathcal{U}(\theta) \right\}, \tag{5.4}$$

and let $s^*(\pi, \theta)$ denote an optimal solution of (5.4).

[4] A detailed discussion on the implications of this assumption and special cases when it is satisfied can be found in Part I [87].

[5] The lossless storage model defined by $\mathcal{U}(\theta)$, which assumes no initial charge nor charging/discharging rate limits, involves no loss of generality since more complex storage models can be accommodated redefining $\mathcal{U}(\theta)$.

In what follows, we focus on characterizing solutions to problem (5.3) considering DERs integrated either behind the meter by customers in a net-metering setting or by the retailer.

5.2.2 Decentralized (behind-the-meter) DER Integration

Suppose that customers install renewables and a battery behind the meter. Let $r^i(\omega^i) \in \mathbb{R}^N$ and $s^i \in \mathbb{R}^N$ denote the energy customer i obtains from renewable resources in state ω^i and from the battery, respectively, and let $\theta^i \in \mathbb{R}_+$ represent its storage capacity. We operate in a net-metering setting where tariffs depend only on $d^i = q^i - r^i - s^i$, which we use to represent customer i's net-metered demand. Hence, given a tariff $T(d) = A + \pi^\top d$, customer i chooses consumption q^i_k and storage operation s^i_k at each time k contingent on $\omega^i_1, \ldots, \omega^i_k$ to solve the multistage stochastic program

$$\overline{\mathsf{cs}}^i(T) = \max_{q^i(\cdot), s^i(\cdot)} \mathbb{E}[S^i(q^i(\omega^i), \omega^i) - T(d^i(\omega^i))], \tag{5.5a}$$

$$\text{s.t} \quad s^i(\omega^i) \in \mathcal{U}(\theta^i). \tag{5.5b}$$

A key observation is that the linearity of two-part tariffs implies that customer i's problem (5.5) can be separated into two sub-problems: choosing $q^i(\cdot)$ to maximize $\mathbb{E}[S^i(q^i(\omega^i), \omega^i) - \pi^\top q^i(\omega^i)] - A$ and choosing $s^i(\cdot)$ to maximize $\mathbb{E}[\pi^\top s^i(\omega^i)]$ subject to (5.5b). The former problem is equivalent to that of customers without DERs analyzed in [87], whose solution characterizes the demand function $D^i(\pi, \omega^i)$. As for the second sub-problem, it is clear from (5.4) that $s^*(\pi, \theta^i)$ is an optimal solution. These solutions constitute an optimal solution to (5.5) and thus a net demand function

$$d^i(\pi, \omega^i) = D^i(\pi, \omega^i) - r^i(\omega^i) - s^*(\pi, \theta^i). \tag{5.6}$$

This fundamental separation of the customer's problem yields the following result, where we use $r(\omega) = \sum_{i=1}^{M} r^i(\omega^i)$ and $s = \sum_{i=1}^{M} s^i$ for notational convenience.

Theorem 5.2.1 *Suppose that customers have access to renewables and storage as characterized in* (5.5) *and* (5.6)*. If* $\nabla_\pi D(\pi, \omega)$ *and* λ *are uncorrelated*[6]*, then the two-part tariff* T^*_{DEC} *that solves problem* (5.3) *is given by* $\pi^*_{\text{DEC}} = \overline{\lambda}$ *and*

$$A^*_{\text{DEC}} = A^* - \tfrac{1}{M} \operatorname{Tr}\left(\mathbb{C}\text{ov}\left(\lambda, r(\omega)\right)\right), \tag{5.7}$$

where A^**, the connection charge in the absence of DER, would be given by* $A^* = \frac{1}{M}\left(F + \operatorname{Tr}(\mathbb{C}\text{ov}(\lambda, D(\overline{\lambda}, \omega)))\right)$.

Before discussing some implications of Theorem 5.2.1, we examine the condition that $\nabla_\pi D(\pi, \omega)$ and λ are uncorrelated. This condition holds in many situations. In particular, it holds for demands that are not much affected by consumers' local randomness, such as the charging of electric vehicles and typical household appliances. It even holds for smart HVAC loads that are affected by random temperature fluctuations since their demand takes the form $D(\pi, \omega) = D(\pi) + b(\omega)$, *i.e.*, a demand with additive disturbances [69].

The tariff T^*_{DEC} in Thm. 5.2.1 reveals the following. Letting retail prices reflect an unbiased estimate of the marginal costs of electricity (λ) maximizes social and consumer welfare. Under net metering, this implies that the retailer should buy customers' energy surplus (from DERs) at the same price that he buys energy at the wholesale market (in expectation).

The expression for A^*_{DEC} in (5.7) has an intuitive interpretation. It indicates that the integration of behind-the-meter DERs would require adjustments to the

[6]The absence of decentralized storage makes this condition unnecessary.

connection charge. These adjustments could be positive if the integrated renewables tend to cause wholesale prices to drop (*i.e.*, negative correlation), but they could be negative otherwise. Consequently, these adjustments can increase or decrease the consumer surplus of customers without DERs because the former are perceived by *all* customers as changes in their electricity bills.

The welfare gains brought by decentralized DERs depend critically on retail tariffs. To assess the performance of two-part tariffs in this regard we first need a point of comparison. In the absence of DERs, T^*_{DEC} reduces to the optimal ex-ante two-part tariff $T^*(q) = A^* + \pi^{*\top} q$ derived in [87], where $\pi^* = \overline{\lambda}$ under the assumption in Theorem 5.2.1. As a point of comparison, consider that in the absence of DERs and under tariff T^*, customers derive an expected surplus $\overline{\mathsf{cs}}_0(T^*) = \overline{\mathsf{sw}}^*_0 - F$, the retailer derives $\overline{\mathsf{rs}}_0(T^*) = F$, and social welfare is

$$\overline{\mathsf{sw}}^*_0 = \sum_{i=1}^{M} \mathbb{E}\big[S^i(D^i(\pi^*, \omega^i), \omega^i) - \lambda^\top D^i(\pi^*, \omega^i)\big]. \tag{5.8}$$

Corollary 5.2.2 *Under the tariff T^*_{DEC}, customer-integrated DERs induce an expected total surplus $\overline{\mathsf{sw}}(T^*_{\text{DEC}}) = \overline{\mathsf{sw}}^*_0 + \sum_{i=1}^M V^{\text{s}}(\overline{\lambda}, \theta^i) + \mathbb{E}[\lambda^\top r^i(\omega^i)]$ that is independent of F and $\overline{\mathsf{cs}}(T^*_{\text{DEC}}) = \overline{\mathsf{cs}}_0(T^*) + \sum_{i=1}^M V^{\text{s}}(\overline{\lambda}, \theta^i) + \mathbb{E}[\lambda^\top r^i(\omega^i)]$.*

The expressions $\overline{\mathsf{cs}}_0(T^*)$ and $\overline{\mathsf{cs}}(T^*_{\text{DEC}})$ above characterize the tradeoff between the retailer's surplus target F and consumers' surplus $\overline{\mathsf{cs}}$ induced by the tariffs T^* and T^*_{DEC}, respectively. Indeed, noting the linear dependence of A^* in F, it becomes clear that in both cases the $\overline{\mathsf{rs}}$-$\overline{\mathsf{cs}}$ tradeoff is linear, as illustrated in Fig. 5.1. Moreover, the fact that the social welfare achieved in both cases ($\overline{\mathsf{sw}}^*_0$ and $\overline{\mathsf{sw}}(T^*_{\text{DEC}})$) does not depend on F implies that said tradeoff is not only linear but one-to-one (*i.e.*, the Pareto fronts in Fig. 5.1 have slope -1). This means that while an increased net revenue target $F + \Delta F$ decreases consumer surplus in expectation, it

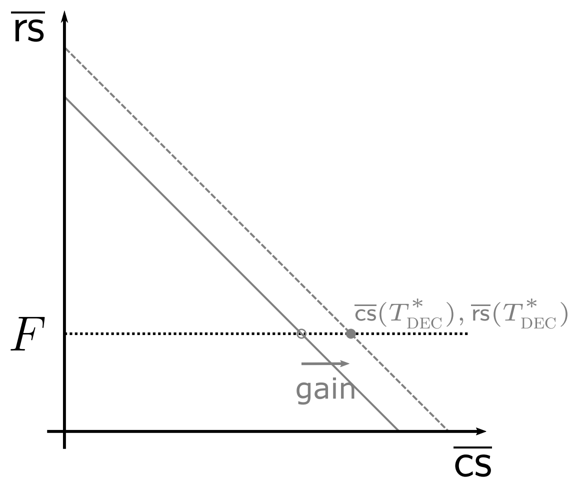


Figure 5.1: Efficient Pareto fronts or $\overline{\mathsf{rs}}$-$\overline{\mathsf{cs}}$ tradeoff induced by optimal ex-ante two-part tariffs T^*_{DEC} (solid line) and T^* (dashed line) with and without DERs.

does not decrease social surplus. Conversely, the integration of DERs behind-the-meter increases both social and consumer surplus by $\sum_{i=1}^{M} V^{\text{s}}(\overline{\lambda}, \theta^i) + \mathbb{E}[\lambda^\top r^i(\omega^i)]$ in expectation regardless of the retailer's net revenue target F.

Another implication of the optimal two-part tariff T^*_{DEC} is the likely impact it would have on the rapid adoption of behind-the-meter DERs. Prevailing tariffs that rely on retail markups to achieve revenue adequacy provide an strong incentive for customers to integrate Distributed Generation (DG). This is because, under net-metering, the higher the retail prices, the more savings DG represents. By eliminating retail markups and imposing virtually unavoidable connection charges, T^*_{DEC} generally reduces such savings. Hence, T^*_{DEC} is likely to decelerate the adoption of decentralized DERs compared to the prevailing less efficient retail tariffs. This suggests that there is a tradeoff between efficiency and the rapid adoption of behind-the-meter DERs.

Optimality of Net Metering

We have restricted the regulator to offer net-metering two-part tariffs. There are, however, alternative mechanisms to compensate DERs that do not rely on net metering (*e.g.*, feed-in tariffs). We argue that the regulator cannot improve upon the efficiency attained by T^*_{DEC} with more complex ex-ante tariffs under certain condition[7]. This holds true because T^*_{DEC} induces the same efficiency attained by the social planner, which provides an upper bound to the regulator's problem (5.3)[8].

Theorem 5.2.3 *Suppose that customers have access to renewables and storage. If wholesale prices λ and customers' states ω are statistically independent (i.e., $\lambda \perp \omega$), then T^*_{DEC} is an optimal solution of* (5.3) *among the class of ex-ante tariffs.*

Namely, the restriction to two-part net metering tariffs, which are simple and thus practical tariffs, imply no loss of efficiency if $\lambda \perp \omega$. The latter condition, however, makes the result somewhat restrictive as it applies to loads not affected by customers' local randomness such as washers and dryers, computers, batteries and EV charging *but* not to HVAC loads or behind-the-meter solar and wind DG. Nonetheless, said condition suggests that if the net load and λ are poorly correlated (or either exhibits little uncertainty at the time the tariff is fixed) then T^*_{DEC} may have a good performance.

[7]The optimality argument in [87, Sec. III.C] without DERs applies to the case with retailer-integrated DERs presented in the following section since both problems are equivalent except for a difference in the parameter F.

[8]Due to the restriction to ex-ante tariffs, we restrict the social planner's decisions to be contingent on each customer's local state ω^i. This is because ex-ante tariffs cannot carry updated information of the global state $\xi = (\lambda, \omega)$, unlike real-time or ex-post tariffs.

5.2.3 Centralized (retailer-based) DER Integration

As an alternative to behind-the-meter DERs, we now consider the case where the retailer installs DERs within the distribution network. To that end, suppose that the retailer has access to a renewable supply $r^o(\xi) \in \mathbb{R}_+^N$ and a storage capacity $\theta^o \in \mathbb{R}_+$. Without loss of generality, we assume that the retailer determines the operation of storage before the billing cycle starts (*i.e.*, ex-ante)[9]. Assuming that the retailer operates storage to maximize his net revenue, the resulting surplus induced by a tariff T can be written as

$$\begin{aligned} \overline{\mathsf{rs}}(T) &= \max_{s \in \mathcal{U}(\theta^o)} \mathbb{E}\left[\sum_{i=1}^{M} T(q^i(T, \omega^i)) \; - \lambda^\top (q(T, \omega) - r^o(\omega) - s)\right] \\ &= \overline{\mathsf{rs}}_0(T) - \mathbb{E}[\lambda^\top r^o(\xi)] - V^{\mathrm{S}}(\overline{\lambda}, \theta^o), \end{aligned} \tag{5.9}$$

The fact that the two last terms in (5.9) do not depend on T facilitates obtaining the following result since both terms simply offset the surplus target F when imposing $\overline{\mathsf{rs}}(T) = F$.

Theorem 5.2.4 *Suppose that the retailer has access to renewables and storage as characterized in* (5.9)*. Then the two-part tariff* T^*_{CEN} *that solves problem* (5.3) *is given by*

$$\pi^*_{\text{CEN}} = \overline{\lambda} + \mathbb{E}[\nabla_\pi D(\pi^*_{\text{CEN}}, \omega)]^{-1} \mathbb{E}[\nabla_\pi D(\pi^*_{\text{CEN}}, \omega)(\lambda - \overline{\lambda})],$$

$$A^*_{\text{CEN}} = A^* - \tfrac{1}{M}\left(V^{\mathrm{S}}(\overline{\lambda}, \theta^o) + \mathbb{E}[\lambda^\top r^o(\xi)]\right) \tag{5.10}$$

where A^**, the connection charge in the absence of DER, would be given by* $A^* = \frac{1}{M}\left(F - \mathbb{E}[(\pi^*_{\text{CEN}} - \lambda)^\top D(\pi^*_{\text{CEN}}, \omega)]\right)$.

[9] Allowing storage operation to be contingent on partial observations of $\lambda \in \mathbb{R}^N$ (say $s^o(\lambda) \in \mathbb{R}^N$) only makes the maximum value of $\mathbb{E}[\lambda^\top s^o(\lambda)]$ over $s^o(\lambda) \in \mathcal{U}(\theta)$ in (5.9) hard to compute under general assumptions.

We first note that, unlike Thm. 5.2.1, Thm. 5.2.4 does not require $\nabla_\pi D(\pi,\omega)$ and λ to be uncorrelated. However, if this condition is satisfied it holds that $\pi^*_{\text{CEN}} = \pi^*_{\text{DEC}} = \overline{\lambda}$. In other words, under optimally set ex-ante two-part tariffs, the integration of DERs by either customers or their retailer do not require updating prices to maintain revenue adequacy. Hence, in both cases, any potential feedback loop of DER integration on retail prices (and thus on consumption) is undermined.

In terms of the connection charge in (5.10), the integration of DERs by the retailer results in reductions relative to A^*. These reductions contrast with the potential increments required by customer-integrated DERs (*cf.*, A^*_{DEC} in (5.7)). The underlying reason for such difference is intuitive, specially considering the identical retail prices $\pi^*_{\text{CEN}} = \pi^*_{\text{DEC}}$. Decentralized DERs represent savings in volumetric charges for customers (with reduced net loads) whereas centralized DERs represent savings in electricity purchases for the retailer. Because the latter savings cannot increase the retailer surplus beyond F, they are allocated uniformly between customers through reductions in the connection charge.

Unlike with decentralized DERs in general, the welfare gains brought by DERs integrated (and operated) by the retailer do not depend on retail tariffs. This is formalized by the following result.

Corollary 5.2.5 *Under the tariff T^*_{CEN}, retailer-integrated DERs induce an expected total surplus $\overline{\mathsf{sw}}(T^*_{\text{CEN}}) = \overline{\mathsf{sw}}^*_0 + V^{\text{s}}(\overline{\lambda},\theta^o) + \mathbb{E}[\lambda^\top r^o(\xi)]$ that is independent of F and $\overline{\mathsf{cs}}(T^*_{\text{CEN}}) = \overline{\mathsf{cs}}_0(T^*) + V^{\text{s}}(\overline{\lambda},\theta^o) + \mathbb{E}[\lambda^\top r^o(\xi)]$.*

In Cor. 5.2.5, $\overline{\mathsf{cs}}(T^*_{\text{CEN}})$ characterizes a linear one-to-one tradeoff between F and $\overline{\mathsf{cs}}$ induced by the T^*_{CEN}. This tradeoff—equivalent to the Pareto front induced by T^*_{DEC} in Fig. 5.1—is characterized by the social welfare achieved by T^*_{CEN}, $\overline{\mathsf{sw}}(T^*_{\text{CEN}})$.

Consequently, similar to behind-the-meter DERs, the integration of centralized DERs increases both social and consumer surplus by $V^{\mathrm{s}}(\overline{\lambda}, \theta^0) + \mathbb{E}[\lambda^\top r^0(\omega)]$ in expectation regardless of the retailer's net revenue target F.

The equivalent *collective* welfare effects of DERs integrated under both models (characterized by Cor. 5.2.2 and 5.2.5) are in contrast to their *individual* welfare effects. As suggested above, welfare gains (or losses) from decentralized DERs are captured individually by DER-integrating customers as reductions in their bills and as bill reductions or increments for all other customers due to the adjustments to the connection charge A^*_{DEC}. This allocation of welfare gains constitutes an inter-class cross-subsidy between customers. Conversely, welfare gains from centralized DERs are uniformly captured by all customers as reductions in the connection charge A^*_{CEN}.

Lastly, an implication of T^*_{CEN} is the likely impact it has on the adoption of DERs. The reduction in the connection charge characterized by A^*_{CEN} relative to A^* is the net benefit perceived by each customer due to the integrated centralized DERs. Hence, customers should be willing to let the retailer integrate DERs even if they entail capital costs that offset a portion of said reductions in the connection charge.

5.3 An Empirical Case Study

In this section, we analyze a case study of a hypothetical distribution utility that faces New York city's wholesale prices and residential demand for an average summer day. We compare the performance of several day-ahead tariffs with hourly prices at different levels of solar and storage capacity. Day-ahead tariffs with hourly prices are a particular form of ex-ante tariffs commonly offered in a voluntary basis for residential customers [72]. Tariff performance is measured both in terms of welfare gains (or losses) and of the cross-subsidies induced between DER owners and non-owners. We close our study with a sensitivity analysis over the price elasticity of demand to demonstrate empirically the critical impact that demand responsiveness has on the magnitude of the consumer surplus gains that more efficient tariff design practices could bring.

Besides the optimal two-part tariff, we study other tariff structures with two pricing alternatives (flat pricing or hourly dynamic pricing) and with daily connection charges fixed at various levels: zero, a nominal value reflecting Con Edison's connection charge, the nominal value plus 0.33 \$/day (10 \$/month), and the nominal value plus 1.66 \$/day (50 \$/month). Similar tariff reforms are being proposed in practice to solve utilities' fixed cost recovery problem [141]. Given a tariff structure, we optimize the non-fixed parameters to maximize the expected consumer surplus subject to revenue adequacy.

This case study uses the same demand model as in Part I [87], which comprises a linear demand function and a quadratic utility function for each customer. We use publicly available energy sales data and rates from Con Edison for the 2015 Summer to fit the demand model. Con Edison's default tariff for its 2.2 million residential customers is essentially a two-part tariff T^{CE} with a *flat* price of $\pi^{\text{CE}} = 17.2$ ¢/kWh and a connection charge of 15.76 \$/month ($A^{\text{CE}} = 0.53$ \$/day). We use day-ahead wholesale prices for NYC from NYISO.

5.3.1 Base case

This is the case without DERs and nominal tariff T^{CE}. Throughout the case study, we assume an average price elasticity of the total daily demand of $\overline{\varepsilon}(\pi^{\text{CE}}) = -0.3$ at π^{CE}, which is a reasonable estimate of the short-term own-price elasticity of electricity demand [11, 47, 79]. Moreover, we consider a total of $M = 2.2$ million residential customers and use the tariff T^{CE} to compute the utility's average daily revenue from the residential segment and the portion that contributes towards fixed costs, which amount respectively to $\overline{\mathsf{rev}}(T^{\text{CE}}) = \$7.19$ million (M) dollars and

$$F^{\text{CE}} := \overline{\mathsf{rs}}_0(T^{\text{CE}}) = \overline{\mathsf{rev}}(T^{\text{CE}}) - \mathbb{E}\left[\lambda^\top D(\mathbf{1}\pi^{\text{CE}}, \omega)\right] = \$5.83\text{M}.$$

For the sake of brevity, the details of these computations already described in Part I [87] are not reproduced here.

We illustrate in Fig. 5.2a the expected retailer surplus ($\overline{\mathsf{rs}}$) and expected consumer surplus ($\overline{\mathsf{cs}}$) induced by the revenue adequate tariff that maximizes the expected consumer surplus within each tariff structure for different values of F. For each tariff structure, the resulting parametric curve is a Pareto front that quantifies the compromise between $\overline{\mathsf{cs}}$ and the $\overline{\mathsf{rs}}$ target, F. We plot these curves as (possibly negative) surplus *gains* relative to the values induced by T^{CE}, $\overline{\mathsf{rs}}_0(T^{\text{CE}})$ and $\overline{\mathsf{cs}}_0(T^{\text{CE}}) = \$9.54\text{M}$, normalized by $\overline{\mathsf{rev}}(T^{\text{CE}})$.

We make some observations from Fig. 5.2a. First, the -1 slope of the Pareto front associated to the optimal two-part tariff T^* corroborates that the induced efficiency $\overline{\mathsf{sw}}(T^*)$ does not depend on F. Conversely, the larger the F, the more inefficient the suboptimal two-part tariffs considered become. This can be seen from the non-unitary slopes exhibited by all tariffs except T^*. Second, at the nominal $\overline{\mathsf{rs}}$ target F^{CE} (*i.e.*, the horizontal axis), significant differences in the induced

$\overline{\mathsf{cs}}$ gains are observed among the tariffs. In particular, moving from flat prices to hourly prices improves $\overline{\mathsf{cs}}$ by approximately 1% ($72k/day). A more significant $\overline{\mathsf{cs}}$ gain (8.1%) is brought by also increasing the connection charge to the optimal level (which amounts to $A^* = 2.65$ \$/day or 79.5 \$/month). Conversely, decreasing the connection charge to zero reduces $\overline{\mathsf{cs}}$ by 4.8%. These empirical computations suggest that additional fixed costs can be recovered more efficiently by increasing connection charges than by pricing more dynamically.

5.3.2 Tariff structure and net benefits of DERs

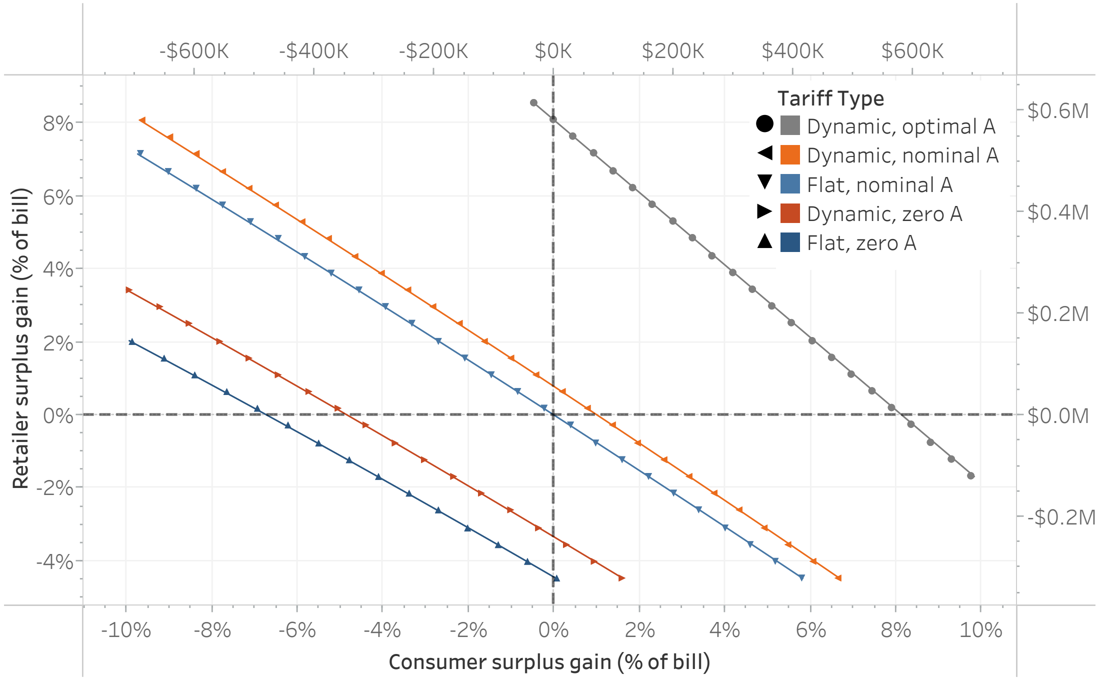
We now analyze the combined impact of tariff structure and DER integration on consumers' surplus. We measure changes in $\overline{\mathsf{cs}}$ relative to $\overline{\mathsf{cs}}_0(T^{\text{CE}})$ and normalized by $\overline{\mathsf{rev}}(T^{\text{CE}})$.

Customer-integrated DERs

We start by estimating changes in $\overline{\mathsf{cs}}$ as a function of the solar and battery storage aggregate capacity integrated by customers. The tariffs here considered are applied to the hourly net metered demand, so they differ from existing net metering tariffs with rolling credit. Moreover, we model the integration of renewable resources using hourly solar PV generation data from a simulated 5kW-DC-capacity rooftop system located in NYC[10]. Similarly, we consider the basic specifications of a 6.4 kWh Tesla Powerwall battery[11]. We integrate as many of these systems as necessary to reach the specified level of capacity.

[10] "Typical year" solar power data for the same months as temperature is taken from NREL's PVWatts Calculator available in `http://pvwatts.nrel.gov`.

[11] More precisely, a 3.3 kW charging/discharging rate and a 96% charging/discharging efficiency are used.



(a) Zoom into neighborhood of $(\overline{\mathsf{cs}}(T^{\mathrm{CE}}), \overline{\mathsf{rs}}(T^{\mathrm{CE}}))$.

Figure 5.2: Normalized retailer surplus target *v.s.* induced consumer surplus gain (Pareto front) for various tariffs in base case (*i.e.*, no DERs).

In Fig. 5.3a we plot the Pareto fronts associated to three types of tariffs and three decentralized solar PV integration levels. This figure is a zoomed-out version of Fig. 5.2a computed for three DER integration levels. As such, it gives a rough intuition of how decentralized DERs transform the Pareto fronts of different tariff structures and, in turn, affect $\overline{\mathsf{cs}}$. In general, horizontal differences between the Pareto fronts represent changes in $\overline{\mathsf{cs}}$ due to tariff structure and/or to different levels of decentralized DER integration, for certain F. Evidently, for any F, decentralized DERs bring $\overline{\mathsf{cs}}$ gains if the flat tariff structure is replaced by the optimal two-part tariff T^*_{DEC}. Conversely, $\overline{\mathsf{cs}}$ losses are brought by the DERs for $F = F^{\mathrm{CE}}$ if the adjusted flat tariff structure is kept, or if it is replaced by the "dynamic, nominal A" structure. We quantify these changes in $\overline{\mathsf{cs}}$ for $F = F^{\mathrm{CE}}$ explicitly with the following parametric analysis over the decentralized DER integration level.

In Fig. 5.4a, for several tariff structures, we plot the normalized $\overline{\mathsf{cs}}$ gains (or, equivalently, the $\overline{\mathsf{sw}}$ gains) caused by increments in the PV capacity integrated by customers and the corresponding updates to the tariff required to maintain revenue adequacy, *i.e.*, $\overline{\mathsf{rs}}(T) = F^{\text{CE}}$. This case assumes that the storage capacity integrated is half the PV capacity.

In particular, Fig. 5.4a shows how integrating decentralized DERs can trigger both efficiency gains and losses depending on the tariff structure. For example, the curve for the adjusted flat tariff T^{CE} suggests that maintaining revenue adequacy with flat rate increments would cause DERs to bring no significant net gains or losses in $\overline{\mathsf{cs}}$ and $\overline{\mathsf{sw}}$ for small levels of integration. However, DER integration levels beyond 500 MW would bring increasingly larger losses in $\overline{\mathsf{cs}}$ and $\overline{\mathsf{sw}}$ of 1.3% at 1.1 GW and 15% at 2 GW. A similar performance is shown by the optimal linear tariff (dynamic pricing) with nominal connection charge A^{CE}. The gain of 1% it exhibits with no DERs vanishes to 0% at 1.1 GW of PV, becoming net efficiency losses for higher levels of DER. The optimal linear tariffs with higher connection charges — 10 and 50 \$/month larger than the nominal—, which bring initial efficiency gains of 2.8% and 7.7%, respectively. While the gains of the former increase to then decrease after reaching a maximum of 3.5%, the gains of the latter monotonically increase reaching 13.6% at the maximum PV capacity considered, 2.2 GW. Other example is the flat tariff with no connection charge, which starts with efficiency losses of 6.8% that increase sharply up to 20.4% at 1.1 GW. Lastly, the optimal two-part tariff starts with an efficiency gain of 8.2%, and it lets customer-integrated DERs to generate their full value, which amounts to an additional 6.6% of efficiency at 2.2 GW or 3% per GW. In other terms, the efficiency gains foregone by using the adjusted flat tariff T^{CE} rather than the optimal two-part tariff T^* increase linearly with the level of DER integration and reach 29.3% (or \$2.11 M/day) at 2 GW.

In summary, connection charges embody a method for fixed cost recovery that seems to be even more effective than dynamic pricing in the sense that it can harness at least 90% of the efficiency gains attained by the optimal two-part tariff for all the integration levels considered, whereas dynamic pricing alone can harnesses at most 12.5% and it generates efficiency losses for higher integration levels. A word of caution on tariffs with high connection charges and lower flat prices, however, is that they induce customers to consume more on peak, thus precipitating the need for network upgrades that increase the retailer's fixed costs in a way not captured by our model. This problem can be tackled using dynamic prices and high connection charges to recover fixed costs, such as the optimal two-part tariff, and more forcefully by considering endogenous fixed costs dependent of the coincident peak net-load.

Retailer-integrated DERs

We now estimate changes in surplus as a function of the solar and battery storage capacity integrated by the retailer. For the sake of a fair comparison, DERs with the same characteristics as before are used.

In Fig. 5.4b, for several tariff structures, we plot the normalized gains in $\overline{\mathsf{cs}}$ and $\overline{\mathsf{sw}}$ caused by increments in the PV and storage capacity integrated (in a 2:1 ratio) by the retailer and the corresponding tariff updates required to maintain revenue adequacy. The figure reveals that the DERs bring monotonic surplus gains under all the tariffs considered. This is because the benefits brought by centralized DERs are not offset by the consumption inefficiencies induced by decentralized DERs. In fact, the inefficiencies induced by suboptimal tariffs without DERs are slightly mitigated by centralized DERs because these DERs help the retailer recover a small portion of F.

Hence, Fig. 5.4b suggests that the changes in $\overline{\mathsf{cs}}$ and $\overline{\mathsf{sw}}$ brought by retailer-integrated DERs are virtually unbiased by tariff structure. This is unlike customer-integrated DERs whose effect on $\overline{\mathsf{cs}}$ and $\overline{\mathsf{sw}}$ is significantly biased by tariff structure changes, and specially, by the reliance on retail price markups for fixed cost recovery, as it is evident in Fig. 5.4a. In other words, under tariffs with significant retail markups, while centralized DERs generally bring surplus gains, decentralized DERs tend to mitigate surplus gains or bring surplus losses. It also clear from Fig. 5.4 that dynamic pricing and higher connection charges help consistently (*i.e.*, regardless the level of DER integration) to mitigate existing inefficiencies. Notably, connection charges seem to offer a much more effective measure to mitigate such inefficiencies than dynamic pricing.

5.3.3 Cross-subsidies induced by net metering

Considering the inequity concerns raised by using net metering as a mechanism to compensate DERs [15, 46] [120, Sec. 9.5], it is instructive to quantify the cross-subsidies induced by the tariffs in the previous section. To that end, we compute the cross-subsidies between PV owners and non-PV owners for different levels of customer-integrated solar PV capacity.

For a given tariff structure and level of (decentralized) solar integration, the cross-subsidy is computed by first obtaining the contribution that PV owners make towards the fixed costs F. Similarly, the contribution that PV owners would make under a version of the given tariff that settles consumption and generation separately is also computed. This version, which is also optimized subject to revenue adequacy, settles all consumption at the rates π and all generation at the prices $\overline{\lambda}$[12]. Clearly, PV owners contribute less towards F under the net metering tariff than its counterpart if the associated prices are marked up as a means to recover the fixed costs F. We compute said cross-subsidy as the difference between these two values, normalized by F. Intuitively, cross-subsidies are the difference between the costs that each group *should* pay for and those they *actually* pay for, due to net metering.

The computation of cross-subsidies requires specifying individual demand functions and the distribution of solar capacity between customers. We consider a simple illustrative case. Customers have identical demand functions except for a scaling parameter σ_i satisfying $\sigma_i = i \cdot \sigma$ for some $\sigma > 0$. The 5-kW solar installations are allocated to the largest consumers, who have the greatest incentive to invest in solar generation. The resulting inter-class cross-subsidies are depicted in Fig. 5.5. Evidently, all tariffs induce non-trivial cross-subsidies except for the optimal two-part tariff which yields virtually no cross-subsidy (in spite of the discussion in Sec. 5.2.2). This is not entirely surprising since pricing according to $\pi^*_{\text{DEC}} = \overline{\lambda}$ is efficient and consistent with cost causality. Hence, cross-subsidies with such tariff happen only through the second term in (5.7) which is rather small compared to A^*. The cross-subsidies of all the other tariffs increase with PV capacity, and they do it at an increasingly faster rate for flat tariffs.

[12]Customer-integrated storage is not considered in this analysis because nonlinear tariffs make customers' problem fundamentally more complicated.

5.3.4 Sensitivity of results to price elasticity of demand

We close this numerical study with a sensitivity analysis over the price elasticity of demand to demonstrates the significant impact of demand responsiveness on the potential benefits brought by more efficient retail pricing. To that end, we compute new parameters for the linear demand model assuming different values for the price elasticity of demand $\overline{\varepsilon}(\pi^{\text{CE}})$. Details on similar calculations can be found in Section 4.4. We analyze three different cases: $\overline{\varepsilon}(\pi^{\text{CE}}) \in \{-0.2, -0.3, -0.6\}$. These values reflect the estimates of short-term own-price elasticity of residential demand surveyed in a recent report [91], where the low and high values (in magnitude) indicate the range of reported values and the intermediate value—our base case—is a central tendency proposed in the report.

In Fig. 5.6 we plot the Pareto fronts of three types of tariffs for each of the cases considered. Similar to Figs. 5.3a and 5.3b, Fig. 5.6 depicts the way the own-price elasticity transforms the Pareto fronts of three types of tariff. These transformations reveal the fundamental impact that the own-price elasticity has on the welfare effects of price changes, namely, the more elastic the demand is, the more significant the welfare effects become. This can be seen in Fig. 5.6 from the way the Pareto fronts of the different tariffs get farther apart from each other more rapidly when the demand is more elastic. For example, for $F = F^{\text{CE}}$, the higher elasticity (-0.6) changes the potential gains in consumer surplus and efficiency of switching to T^* from 8.2% to 16.2% and to 5.4% for the lower elasticity (-0.2). With this in mind, one can revisit Figs. 5.3a and 5.3b to understand the impact of elasticity on the welfare effects induced by DER integration. Broadly, the effects of DER integration on the relative efficiency of the tariffs would be either weakened or amplified for more inelastic or elastic demands, respectively. More importantly, the relative inefficiencies introduced by customer-integrated DERs under tariffs that rely on price markups for fixed cost recovery could grow alarmingly—*i.e.*, more than in Fig. 5.4—if the aggregate residential demand becomes particularly responsive to short-time price variations, *e.g.*, with the adoption of enabling technologies such as home energy management systems.

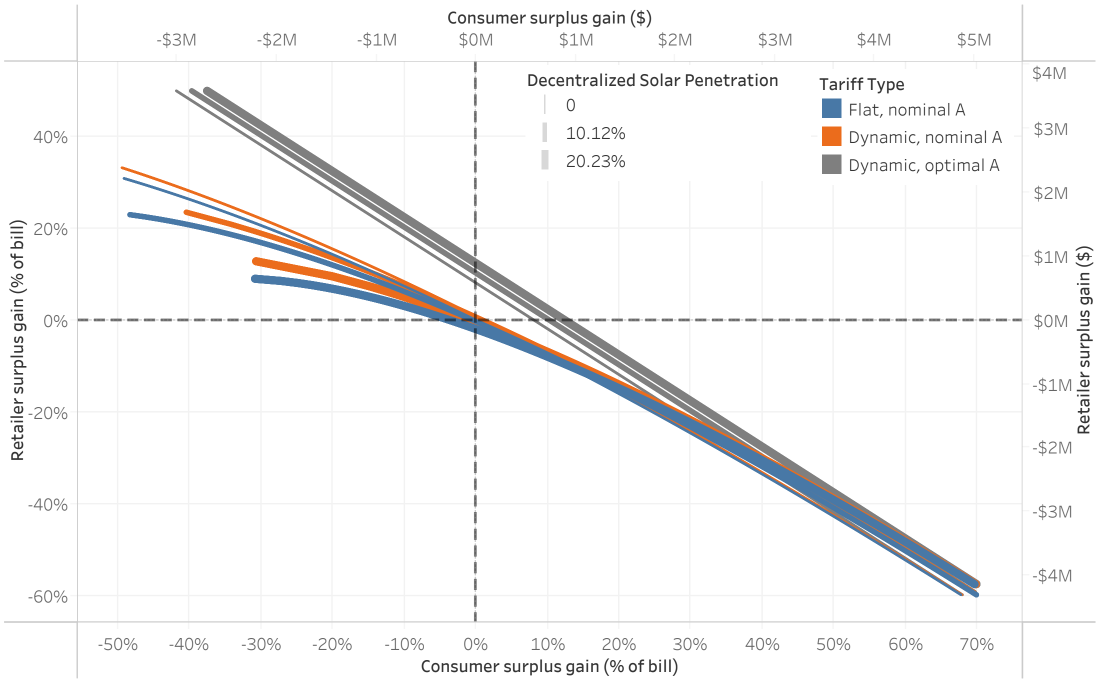
5.4 Conclusions

We leverage the analytical framework developed in [87] to study how retail electricity tariff structure can distort the net benefits brought by DERs integrated by customers and their retailer. This work is an application of Ramsey pricing with extensions to accommodate the integration of DERs.

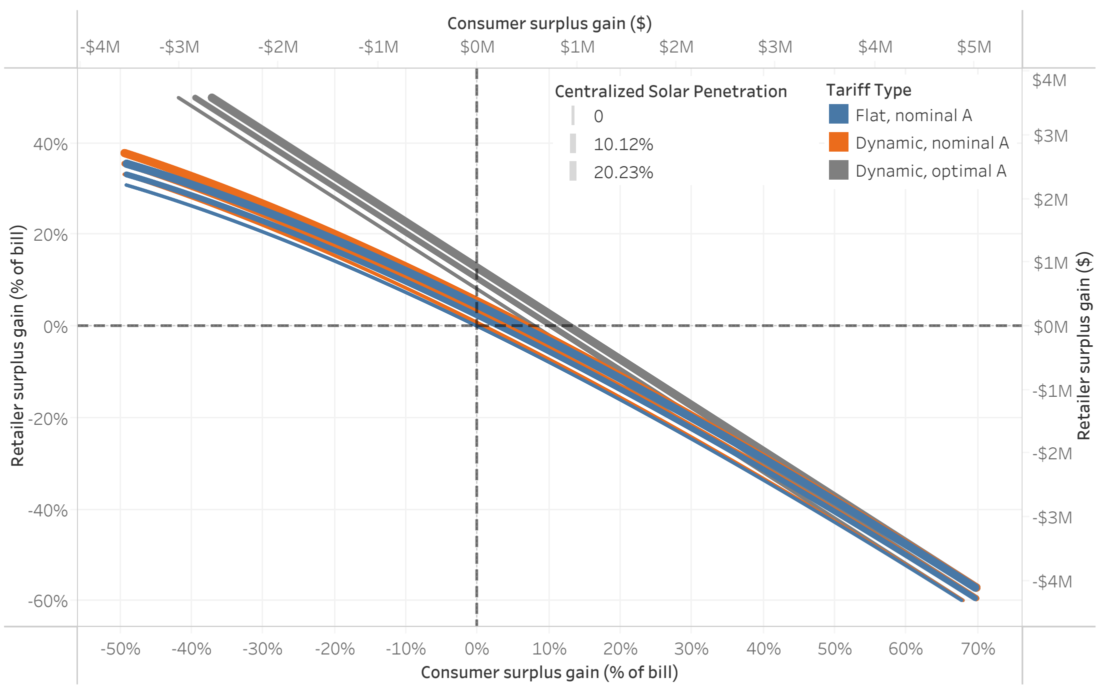
Our analysis offers several conclusions. First, while net metering tariffs that rely on flat and higher prices to maintain revenue adequacy provide increasingly stronger incentives for customers to integrate renewables, they induce increasingly larger cross-subsidies and consumption inefficiencies that can outweigh renewables' benefits. These significant inefficiencies have draw little attention in the literature compared to the cross-subsidies. Second, net metering tariffs can achieve revenue adequacy without compromising efficiency by using marginal-cost-based dynamic prices and higher connection charges. These tariffs, however, provide little incentive to integrate renewables. Third, retailer-integrated DERs bring customers net benefits that are less dependent on tariff structure, and they cause no tariff feedback loops. As such, this alternative to behind-the-meter DERs seems worth exploring.

This study represents an initial point of analysis, for it has various limitations.

First, policy objectives beyond efficiency and revenue sufficiency —often considered in practice— are here ignored. Practical criteria such as bill stability make "desirable" tariffs hard to be ever attained. Second, customer disconnections are assumed to be not plausible as a customer choice. This assumption becomes increasingly less realistic with the decline of DER costs. Lastly, retailer non-energy costs are assumed to be fixed and independent of the coincident (net) peak load. Relaxing this assumption leads to peak-load pricing formulations [34]. We discuss one such relaxation in Section 6.2.1, where capacity costs are recovered with a *demand charge* applied to the net demand coincident with the peak period.

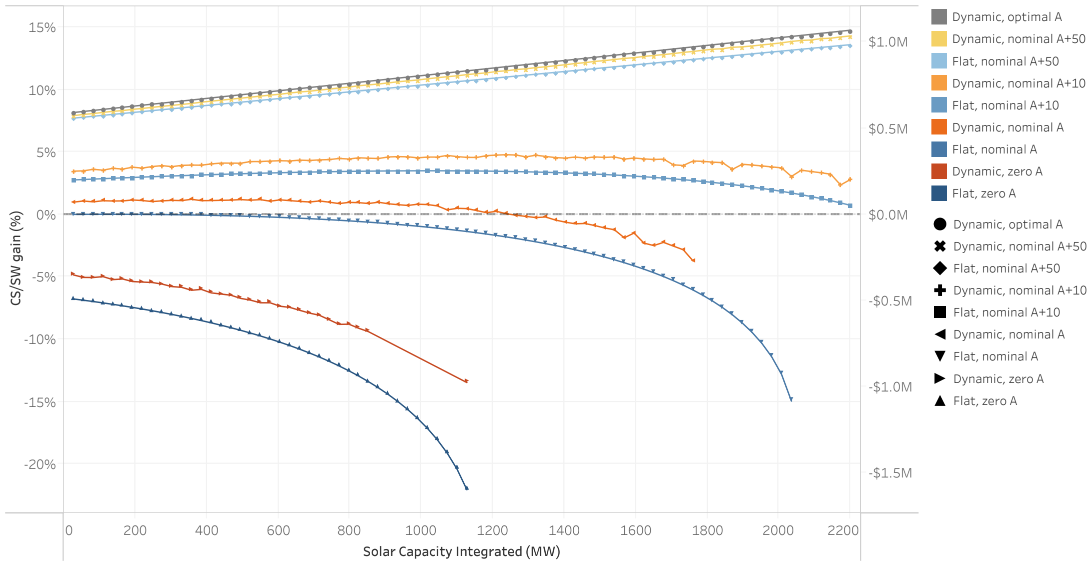


(a) Pareto fronts with decentralized DERs.

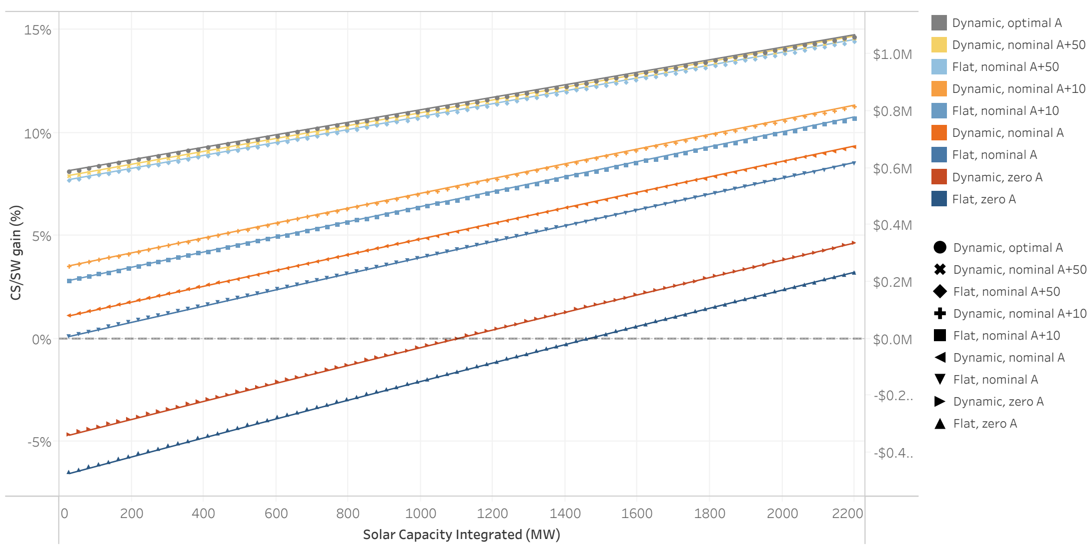


(b) Pareto fronts with centralized DERs.

Figure 5.3: (a) Normalized retailer surplus target *v.s.* induced consumer surplus gain (Pareto front) for various tariffs in base case (*i.e.*, no DERs) and two cases with different DER integration levels (10.12% and 20.23%) are compared.



(a) Decentralized DER integration.



(b) Centralized DER integration.

Figure 5.4: Expected gains in consumer and social surplus induced by (a) behind-the-meter solar-plus-battery capacity and (b) retailer-integrated solar-plus-battery capacity under different types of tariffs. Gains are measured relative to base case with tariff T^{CE} and no DERs.

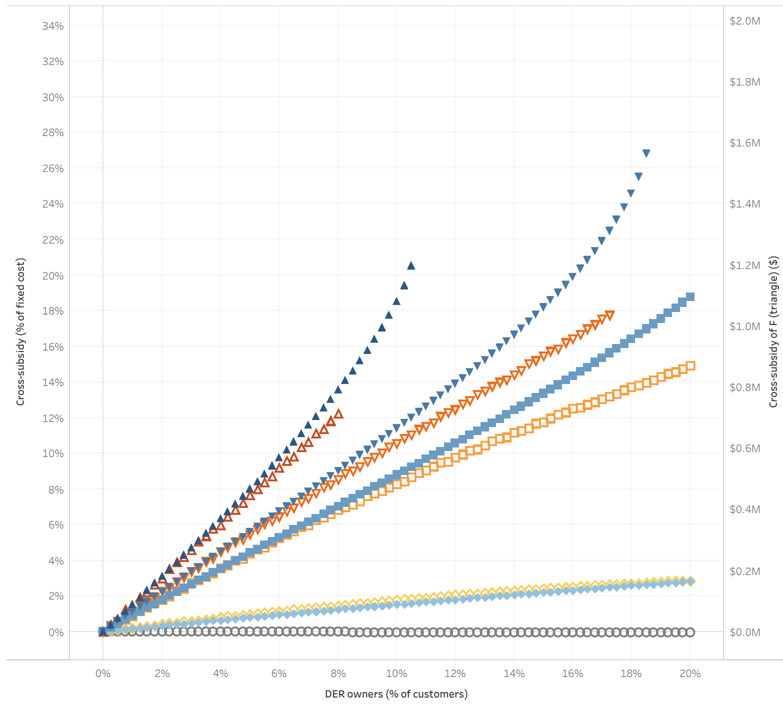


Figure 5.5: Cross-subsidy from customers without solar to customers with solar *v.s.* level of behind-the-meter solar integration.

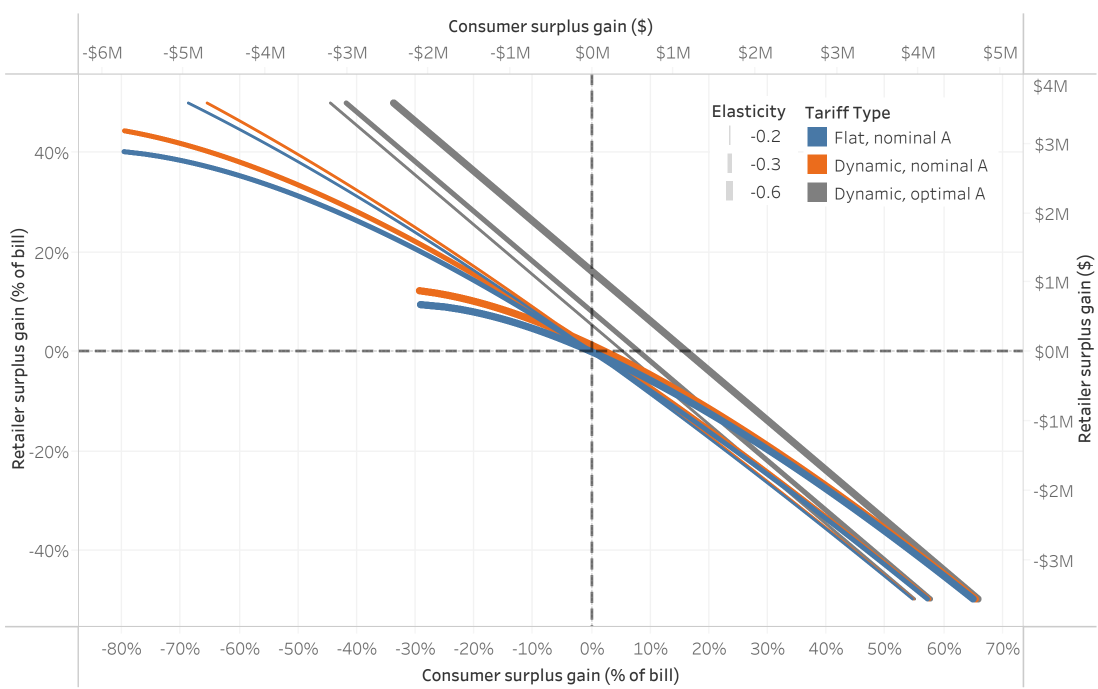


Figure 5.6: Pareto fronts (parametrized by F) induced by several tariff types and computed for daily demand models with different price elasticities, $\bar{\varepsilon}(\pi^{\text{CE}})$, including a low value of -0.2 (left), an intermediate value of -0.3 (center), and a high value of -0.6 (right).

CHAPTER 6

A CONTEXTUAL DISCUSSION OF RETAIL TARIFF DESIGN WITH DISTRIBUTED ENERGY RESOURCES

6.1 New York's REV Initiative

In 2014, New York State's Public Service Commission (PSC or the "Commission")[1] launched a comprehensive initiative aimed to "align electric utility practices and [their] regulatory paradigm with technological advances in information management and power generation and distribution" [95]. These developments "promise improvements in system efficiency, greater customer choice, and greater penetration of clean generation and energy efficiency technologies, but only if barriers to adoption are eliminated and proper regulatory incentives are established."

This initiative, called *Reforming the Energy Vision* or REV, is proceeding on two tracks that intend to address explicitly the following questions:

(Q1) What should be the role of the distribution utilities in enabling system wide efficiency and market-based deployment of DERs and load management?

(Q2) What changes can and should be made in the current regulatory, tariff, and market design and incentive structures in New York to better align utility interests with achieving the PSC's energy policy objectives?

While the research conducted in this thesis relates to both questions, it responds directly to the latter. Accordingly, this section provides a brief description of the main components of REV that relate to the first question and a more detailed

[1]This is the governing body that regulates electricity and gas utilities in NY State.

examination of those related to the second question and to the issues examined in this thesis.

The questions above were initially posed and addressed in a preliminary REV proposal [92] elaborated by New York State's Department of Public Service (DPS) building on the Commission's guidance. Therein, the policy objectives the Commission is to pursue with the REV initiative are explicitly stated [95]:

1. Enhanced customer knowledge and tools that will support effective management of their total energy bill,
2. Market animation and leverage of ratepayer contributions,
3. System wide efficiency,
4. Fuel and resource diversity,
5. System reliability and resiliency; and
6. Reduction of carbon emissions.

Building upon the initial REV proposal, a stakeholder process started and, since then, several rulings and orders describing more concrete solutions to both questions have been produced. Among the most relevant documents that the stakeholder process has produced so far since the initiation of this proceeding in April 2014 marked by the publication of the initial proposal [92] seem to be [93, 94, 96]. I now summarize and highlight some of the most relevant elements articulated in these documents, in chronological order.

In February 2015, the Commission first issued an order adopting a regulatory policy framework and an implementation plan (the "Framework Order") [96]. The Framework Order, which responds to Q1 (Track One), articulates a vision for the future of the electric industry in New York that leverages DERs to enrich customers alternatives to satisfy their electricity needs. Perhaps the single most important component of this vision is that it requires electric utilities in NY to provide distributed system platform (DSP) services that enable third-party providers of DERs to create value for both customers and the system.

Broadly, facilitated by the utilities or DSP Providers, "products, rules, and entrants will develop in the market over time, and markets will value the attributes and capabilities of all types of technologies. As [DSP] capabilities evolve, procurement of DER attributes will develop as well, from a near-term approach based on requests for proposals (RFPs) and load modifying tariffs, towards a more sophisticated auction approach." In particular, the services transacted in or by the DSP will be of two types:

- "Distribution grid services that will enable the DSP to optimize the distribution system, including through offsetting or deferring both immediate and long-term costs"; and
- "Aggregated energy resources and ancillary services that can be sold to the [NYISO] or through NYISO markets to optimize the generation and transmission system."

Subsequently, in July 2015, the DPS issued a staff white paper on ratemaking and utility business models [93] (the "White Paper") containing proposals for comment and discussion. The discussion led the Commission to issue an order adopting a ratemaking and utility revenue model policy framework [97] (the "Ratemaking Order") later in May 2016. The objectives of the White Paper, which responds to Q2 (Track Two), were to (i) describe the limitations embedded in current tariff design practices in the context of REV, (*ii*) describe the direction of comprehensive tariff design and business model reforms, and (*iii*) make recommendations for near-term reforms where possible.

Following REV principles, the White Paper and Ratemaking Order discuss three categories of reforms:

- Market-oriented utility business models,
- Incremental reforms to traditional utility revenue models, and
- Rate design changes to provide accurate value signals while meeting public policy objectives.

Within the last category, which comprises reforms closely related to this thesis, the documents suggest that future tariff design should consider the different types of customers, namely,

- *Traditional consumers*, who do not choose to actively manage their energy usage, or for whom it is difficult to do so;
- *Active consumers*, who integrate DERs that allow them to actively modulate their usage in response to rate signals with the purpose of reducing their bills; and
- *Prosumers*, who integrate DERs including generation or other technologies that allow them to provide services to the grid.

The documents further suggest that tariff granularity should be developed along the following dimensions:

- *Temporal*, by time-differentiating prices reflecting marginal price variations;

- *Locational*, by "reflecting congestion or capacity constraints in pricing; for example, locational marginal pricing or distribution locational marginal pricing";
- *Attribute*, by "unbundling rates to reflect the individual attributes embedded in electricity service; for example, energy, capacity, ancillary services, environmental impacts, or others".

To guide tariff reforms under REV, the following tariff design principles are therein adopted [97, Appendix A]: cost causation, encourage outcomes, policy transparency, decision-making, fair value, customer-orientation, stability, access, gradualism, and economic sustainability.

These tariff design principles reveal that under REV, while economic efficiency is not listed explicitly as design principle by utility regulators, it is indeed pondered (at the very least) through the cost causation principle. The cost causation principle embodies efficiency since the latter dictates that prices should reflect marginal costs and connection charges should reflect costs independent of consumption. As stated in [97, Appendix A], cost causation means that "[r]ates should reflect cost causation, including embedded costs as well as long-run marginal and future costs. Fixed charges should only be used to recover costs that do not vary with demand or energy usage.".

Moreover, the long list of tariff design principles mentioned above is clear evidence that many criteria —not only cost causation and economic sustainability— are balanced when setting retail tariffs. This is perhaps the most important difference between the analytical framework for tariff design analyzed in this dissertation, which considers only efficiency and revenue adequacy[2], and current ratemak-

[2]Utilities' revenue adequacy is a form of economic sustainability for the distribution business.

ing practices. Hence, our framework can be seen either as an analysis of ideal tariffs (or better, minimally constrained "second best" tariffs) or as an additional step towards more rigorous tariffs design practices.

Among the many proposals adopted in the Ratemaking Order, the following are particularly relevant to this thesis [97, pg. 27]:

- "*Opt-in rate design.* Voluntary participation in advanced rate design will be encouraged in two ways:
  - *Opt-in time of use rates.* Each utility will examine its existing TOU rates with reference to rates in other jurisdictions that have higher participation; each utility will also develop improved promotion and education tools.
  - *Smart Home rates.* Utilities will collaborate with NYSERDA and third parties to develop Smart Home Rate pilots.
- *Large customer demand charges.* "[Future] rate cases will examine the existing demand charges applicable to commercial and industrial customers to determine if they can be made more time-sensitive."

Of critical relevance to the integration of DERs is the Smart Home Rate (SHR) proposed in the White Paper. While in the Ratemaking Order the SHR is only discussed in the context of demonstration projects and early adoption, it is considered "the model for a rate design that should become the widely adopted norm as markets mature". As such, the Commission initiated a separate proceeding[3] to establish a methodology to value DERs a path to replace Net Energy Metering (NEM), the current DER compensation mechanism. The SHR will combine

[3] Case 15-E-0751, In the Matter of the Value of Distributed Energy Resources.

time-varying prices with a full value DER compensation mechanism, which will be based on a formula of LMP+D (location-based marginal prices plus distribution value) that represents the full value of DER on a time and location-specific basis. The detailed specification of this DER compensation mechanism leads us to the last REV document here discussed.

In October 2016, the DPS released a staff report and recommendations on the value of DERs for public comment and discussion [94].[4] Broadly, this report aims to set the methodology to value DERs, design tariffs for DERs that compensate their value, and replace NEM[5]. Among the many recommendations, the following are particularly relevant to tariff design and DER compensation analysis in this thesis:

1. *Value of DER (VDER) compensation tariff.*[6] This tariff should compensate only exported generation from DER projects at a time and location specific rate that accounts for the following streams of value [94, pg. 32]:

    - *Energy value* in a per kWh compensation based in the day-ahead NYISO hourly LMPs.
    - *Installed capacity value* in a "per kWh compensation based on the capacity portion of the utility's full service market supply charges" for intermittent technologies[7], and in a monthly lump sum equal to the

[4]As of December 2016, the Commission has not issued an order acting on the recommendations within [94] and the comments filed.

[5]The current NEM compensation methodology in NY is as follows. Customers' "kWh usage and generation is netted each [monthly] billing cycle; if their usage exceeds generation, they pay only for the excess usage; and if their generation exceeds their usage, their excess generation becomes kWh credits that offset their usage in the next billing cycle."

[6]Or "Phase One tariff" as it is also referred to in [94] given that it is an "interim methodology" to be replaced by a more definitive "Phase Two tariff" by December 2018.

[7]As commented in [94, pg. 33], this compensation recognizes that the otherwise more appropriate compensation suggested below for dispatchable technologies "would result in substantial variability for intermittent technologies, which could present issues for project financing."

"MW performance [of the project] during the peak hour in the previous year multiplied by the actual monthly generation capacity spot prices from NYISO's ICAP [Installed Capacity] market that month" for dispatchable DERs.

- *Environmental value* in a per kWh compensation reflecting the higher of the applicable Tier 1 Renewable Energy Certificates (RECs) NY market price or the Social Cost of Carbon as calculated by the U.S. Environmental Protection Agency.
- *Demand reduction value* in a monthly lump sum based on the project's kW performance during the ten highest usage hours in the previous year within the utility's territory multiplied by a time and location specific marginal cost of service (MCOS) that reflects the value to the distribution system of reducing demand during distribution peaks.
- *Locational system relief value* in a compensation similar to the previous but applied only to projects in certain "high value areas" and for a limited number of MWs.

2. *Transition from NEM to interim VDER.* This transition should differ across DER project segments[8] and be generally gradual and interim in the sense that a more definitive and refined Second Phase tariff should replace VDER in the next few years.

    - *Legacy projects.* Existing DER projects should continue to be compensated based on NEM for 20 years from the date of installation.
    - *On-site mass market projects.* New projects should continue to be compensated based on NEM until 2020 or a specified MW cap is reached

[8]DER project segments are on-site mass market projects, community DG projects, remote NEM projects, and on-site large projects.

and face the Second Phase tariff thereafter.

- *Community distributed generation projects.* New projects should either be compensated based on NEM (up to certain cap) or based on VDER with an additional market transition credit (MTC) to be stepped down in three batches over time.

- *Remote net metering projects and On-Site large projects.* New projects not eligible for continuation of NEM[9] should be compensated based on VDER.

- *Opt-In Availability.* All DER projects that are entitled to continue to receive NEM may elect to opt-in for compensation based in VDER instead, but only until the Phase Two tariff becomes the default DER compensation mechanism.

- *Metering Requirements.* In order to be eligible for VDER, all DER projects except those in the on-site mass market segment must be equipped with metering with hourly recording capabilities.

We conclude this section with two remarks. First, while stylized, the framework for tariff design and DER compensation developed in this dissertation sets a theoretical basis that could be extended in different ways to capture more nuanced models that could corroborate (or disapprove) REV tariff reforms and guide further reforms. Clearly, a focus of REV is to move towards dynamic pricing which is a premise in the proposed framework. A main challenge with the framework, however, will be to deal analytically with tariffs that are applied to the net metered demand and that are nonlinear in such quantity. The VDER tariff proposed in

[9]Some of these projects may qualify for NEM through previous Commission's orders such as the Remote Net Metering Transition Plan Order which may allow Remote Net Metering projects to grandfather a remote net metering compensation methodology.

REV is an example of a nonlinear tariff since the rate applied to the net consumption generally differs from that applied to the net generation.

Second, the proposed framework can be made more compelling as richer structures of both the non-energy costs of utilities and the non-energy streams of value of DERs are incorporated into the model. This should naturally lead to optimal two-part tariffs with embedded charges explicitly associated to the different utility cost and DER value attributes. This is precisely one of the objectives of REV, namely, to increase tariff granularity not only along the time and location dimensions, but also along the attributes embedded in the electricity service (*e.g.*, capacity, ancillary services, environmental impacts, etc.).

6.2 Limitations of the tariff design framework

In this section, two discussions related to the limitations of the analytical framework developed in Chapter 4 and extended in Chapter 5 are held.

In the first part, we provide a discussion on the implications of relaxing the assumption that the fixed costs to recover through retail tariffs are exogenous. Therein, beyond a qualitative analysis of the possible implications, a simple extension to the mathematical tariff design framework that embodies such relaxation is presented along with its likely implications on the structure of the optimal two-part tariff.

In the second part, we discuss the nuanced trade-off that the exists between ex-ante and ex-post tariffs (or tariff attributes, for that matter). Therein, we briefly describe some of the practical arguments that favor price certainty over price accuracy.

6.2.1 Endogenous distribution costs

Clearly, it is unrealistic to assume that the delivery costs[10] faced by distribution utilities to serve electricity demand are generally fixed. This is because distribution networks need to be expanded or adapted to cope with peak (net) loads and flow patterns that change gradually in the long run.

In economics, the notion of fixed costs refers broadly to expenses that do not depend on the level of good or services provided. To be meaningful, however, this notion must be associated to a time horizon since there exist virtually no costs that are truly fixed in the the long run. Hence, while it may be reasonable to assume that distribution utilities' delivery costs are fixed in the short run (*e.g.*, the next day), it is certainly not realistic to do so in the long run (*e.g.*, the next month, season, or year). A concrete example of these costs are the charges for installed generation capacity (ICAP) imposed by ISOs to distribution utilities[11]. For example, the "NYISO requires utilities to purchase capacity [on a monthly basis] based on the MW usage on their system during the statewide peak hour of the previous year." [94].

In the industry, the notion of fixed costs permeates retail tariff design practices in a way that is illustrated by the following text: "there is little controversy over the principle that fixed charges should recover only costs that are invariable with usage; but parties disagree strongly as to which types of delivery system costs fall into the invariable category." [97, pg. 122] Indeed, on the one hand, many distribution

[10] As opposed to supply or energy costs.

[11] or Load Serving Entities (LSEs), to be more accurate.

utilities in the U.S. have been proposing increases in fixed or connection charges for all residential customers[12] as a practical means to resolve the potential fixed cost recovery problem and financial threat embodied by DERs articulated in [74]. On the other hand, DER developers and consumer advocate against the use of connection charges for fixed cost recovery based arguing, among other things, that they provide no useful incentives, are a short-term practical solution for a long-run problem that has not yet been materialized in practice, have disproportionate impacts on low-income customers, and may unfold peak-load increments [73, 138]. Other perspectives on fixed costs (and other tariff attributes/structures) as a means to resolve the fixed cost recovery problem can be found in [141].

In general, DERs have the potential to rapidly change usage patterns of the distribution network. In particular, they have the potential to not only shift the magnitude and time of system-wide and circuit-specific *load* peaks but also to induce circuit-specific *generation* or *export* peaks in the opposite flow direction. Research shows that the system-wide and circuit-specific changes in usage patterns can entail additional capital expenditures (see *e.g.*, [120]). Indeed, studies argue that to realize their full value, DERs must be included in distribution planning and operation, just as central generation resources are included in transmission planning and operation [48].

As an alternative or complement to DER integration based on centralized distribution planning and operation, DER investment may be guided by more precise and granular tariffs or other market mechanisms that better compensate the value streams DERs offer. This is precisely the alternative currently pursued by the NY REV initiative [94].

[12] "In 2015, 61 utilities in 30 states proposed increasing monthly fixed charges on all residential customers by at least 10%. The median increase requested in these cases was 62%." [67]

In particular, the DER benefits and costs depend critically on their operation, sizing, and spatial distribution within the network. On one the hand, the real-time operation of DERs, if controllable to any extent, involves short run decisions that can be shaped through price signals that better reflect the marginal short run costs avoided by each particular DER to the system as a whole, thereby increasing their short run value and the ability of customers to monetize it. As argued above, this can be done by increasing the granularity of the *prices* faced by DER operators. On the other hand, the size and spatial distribution of DERs is the result of long run investment decisions that can be shaped through tariffs structures that better reflect the marginal long run system costs avoided by DERs. Such tariffs can thus increase the long run value of DERs and customers' ability to monetize it. This can be done, for instance, by unbundling volumetric charges faced by DER operators into tariffs with multiple attributes that reflect transparently the location-specific costs of energy, capacity, and ancillary services.

To give an idea of how refining or unbundling the structure of the delivery costs faced by distribution utilities[13] can have an impact on retail tariffs we present the following analysis. The tariff design framework developed in Chapters 4 and 5 models delivery costs with an exogenous parameter $F \in \mathbb{R}$ that assumes such costs are entirely fixed (*i.e.*, not dependent on net load). Here, we refine the structure of delivery costs by adding a linear capacity cost β (in $\$/MW$). We assume that the retailer has to pay for the maximum capacity (measured in MW) used collectively by its customers during the billing period, namely, their customers' noncoincident peak demand. This is different from the retailer's customers' coincident peak demand, which refers to their aggregated (net) load during the time of peak demand

[13]Or, more generally, the structure of the total costs faced by retailers, which may also incorporate generation ICAP costs as those mentioned above.

across the entire system (*e.g.*, NYISO's service territory)[14]. While the latter charge (based on coincident demand) is closer to the current practice in U.S. wholesale markets, the former (based in noncoincident demand) allows for a notationally cleaner mathematical formulation.

One way to incorporate such capacity costs into the regulator's problem (4.6) is to use an auxiliary decision variable $K(\omega) \in \mathbb{R}$ to represent the maximum capacity used by customers during the billing cycle contingent on the state ω. One can then subtract the expected capacity cost

$$\mathbb{E}[\beta K(\omega)] \tag{6.1}$$

to the left hand side of the budget constraint of problem (4.6) (*i.e.*, to the retailer's surplus $\overline{\mathsf{rs}}(T)$) and add the capacity constraints

$$d_k(\omega) \leq K(\omega), \qquad k = 1, \ldots, N, \tag{6.2}$$

where $d_k(\omega) = \sum_{i=1}^{M} d_k^i(\omega^i)$ represents the aggregate net demand at time k.

This type of capacity costs have been addressed in the literature of retail tariff design but only in settings without DERs. Indeed, this problem is generally known in economics as the peak-load pricing problem[15], and it has been widely studied with many different variations not including the integration of DERs. Several models of such classical problem are studied and generalized in [109] in the absence of demand uncertainties. Demand uncertainty complicates the analysis considerably when accompanied with an *ex-ante* capacity constraint[16] due to the need to model (the cost of) rationing inelastic demand. According to the survey of

[14]We further assume that a retailer's customers' maximum usage of the system's capacity is due to their net consumption and not to their net generation, which seems rather unlikely in current systems.

[15]Broadly, this problem can be thought as an specialization of the Ramsey pricing problem to a single good that is supplied over multiple time periods.

[16]This is in contrast to the *ex-post* capacity constraint in (6.2).

the peak-load pricing problem in [34], while the original Boiteux work [9] modeled a stochastic demand, most of the contributions in the treatment of stochastic demand came later after the seminal work by Brown and Johnson [18]. For example, the subsequent work [35] extended the stochastic model to incorporate multiple supply technologies and time periods whereas [25] further incorporates supply-side uncertainties. Works that may have more relevance to the integration of DERs are the extensions to deal with centralized storage discussed in [56, 98] and with stochastic demands with price interdependencies across a continuous time horizon in [105].

We now analyze the more general formulation of (4.6) with (6.1) and (6.1) by conveying a basic intuition of the resulting optimal two-part tariff that is valid for the case with deterministic demand and prices. The idea is to leverage the existing literature on peak-load pricing to build such intuition. To that end, we first make the analysis without DERs, and then we accommodate customer and retailer-integrated DERs leveraging the linearity of the two-part net metering tariff.

The intuition is as follows. The analysis in [109] suggests that in the absence of uncertainties and DERs, when both the revenue adequacy and capacity constraints are considered modeled, the optimal linear tariff $T^{\dagger}(q) = \pi^{\dagger\top} q$ should depend on the wholesale prices λ, the marginal cost of capacity β, the fixed costs F, and the own and cross price elasticities of demand at $\pi^{\dagger}$. Moreover, in deriving the optimal two-part tariff $T^{*}(q) = A^{*} + \pi^{*\top} q$, the additional degree of flexibility given by the uniform connection charge A^{*} essentially allows one to drop the revenue adequacy constraint. This is because A^{*} can be set arbitrarily to make T^{*} revenue adequate. This implies that the price π^{*} of the optimal two-part tariff T^{*} should depend on λ, β, and possibly on the price elasticities of demand at π^{*}, but not on F. We argue below that π^* reflects both λ and β in a way equivalent to a tariff with a volumetric charge reflecting λ and a demand charge applied to the demand at the retailer's coincident peak period that reflects β.

Before giving a more detailed explanation of this intuitive result, we summarize the previous discussion as follows. Incorporating capacity costs into the structure of the delivery costs faced by the retailer yields an optimal two-part tariff that resembles a three-part tariff with

- volumetric charges reflecting marginal energy costs λ,
- a connection charge reflecting fixed costs F, and
- a demand charge reflecting the marginal capacity cost β.

We now give a more detailed explanation of this result. In [109], it is shown that in the absence of the revenue adequacy constraint, the optimal price is set according to marginal-cost pricing principles. This means that the net-metered demand at the peak period $\text{P} = \arg\max_k\{d_k(T)\}$ is charged for both the marginal cost of energy λ_{P} and the marginal cost of capacity β whereas off-peak demand is charged only for the marginal cost of energy, *i.e.*, for each $k = 1, \ldots, N$,

$$\pi_k^* = \begin{cases} \lambda_k + \beta, & k = \text{P}, \\ \lambda_k, & k \neq \text{P}. \end{cases} \tag{6.3}$$

This expression assumes the simpler case where the peak net load is attained at a single time period. If the peak net load is attained at two or more periods then the marginal cost of capacity would be split somehow between the peak periods. In theory, this is likely to occur if β is large enough (relative to λ) and the demand elastic enough. In such case, the problem really becomes determining endogenously which are the peak periods, which renders difficult the computation of π^*.

With an expression for π^*, the optimal connection charge A^* can be then computed appropriately by solving for A the (now deterministic) revenue adequacy constraint $\mathsf{rs}(T) = F + \beta K$ or

$$\sum_{i=1}^{M} \pi^{*\top} D^i(\pi^*) + A - \lambda^\top D^i(\pi^*) = F + \beta D_{\text{P}}(\pi^*)$$

which ultimately yields

$$A^* = F/M. \tag{6.4}$$

This result could be extended to the case with customer and retailer-integrated DERs with arguments similar to Theorems 5.2.1 and 5.2.4. It should be the case that the optimal price π^* is not affected by the integration of DERs regardless of who integrates them, *i.e.*,

$$\pi^*_{\text{DEC}} = \pi^* \qquad \text{and} \qquad \pi^*_{\text{DEC}} = \pi^*.$$

Consequently, leveraging on the expressions for A^*_{DEC} in (5.7) and A^*_{CEN} in Theorem 5.2.4, the optimal connection charges under both integration models and without uncertainty would be given by

$$A^*_{\text{DEC}} = A^* \tag{6.5}$$

$$A^*_{\text{CEN}} = A^* - \tfrac{1}{M}\big(V^{\text{S}}(\pi^*, \theta^o) + \lambda^\top r^o\big). \tag{6.6}$$

Notably, this relies on the expression (6.3) for π^* which conveniently assumes that the peak load occurs at a single time period.

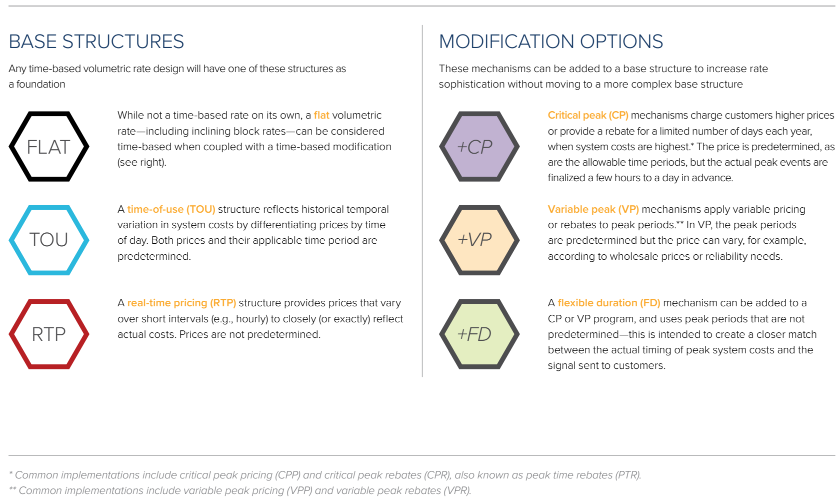
6.2.2 Ex-ante *vs.* ex-post retail tariffs

In general, retail tariffs can be fixed in advance of the beginning of each billing cycle, at the beginning of each cycle, during each billing cycle, or even after the billing cycle. More generally, the attributes that constitute a tariff can be fixed separately (*i.e.*, not a the same time) before, at, or even after the beginning of the time interval (within the billing cycle) for which they are valid.

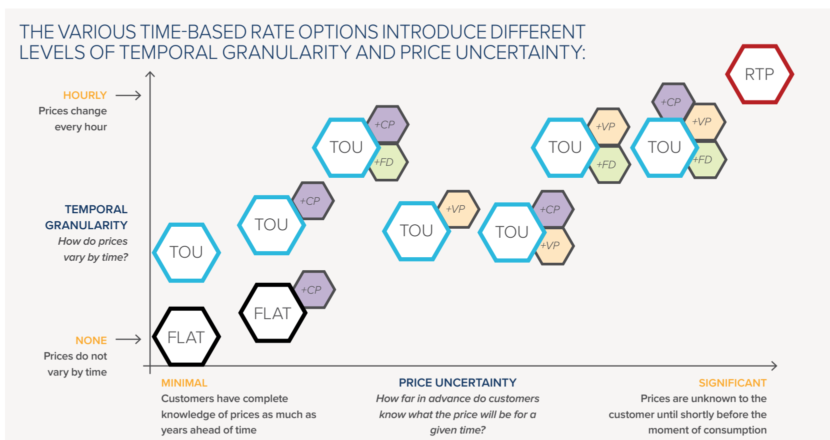
Consider for example the traditional ratemaking process followed in the U.S. by which electric utilities set the tariffs or "rates" they will charge customers of different classes. The main structure and most of the attributes of all tariffs are fixed through rate case proceedings several months in advance of the beginning of the period for which they remain valid, which often comprises several years[17]. These tariffs are typically applied or settled in monthly billing cycles, and, depending on the capabilities of the installed meter (*e.g.*, cumulative, time-of-day, real-time), they can specify time-varying prices for more granular time intervals. Moreover, the attributes of these tariffs that reflect delivery costs (*e.g.*, network costs) tend to remain unchanged over until the next rate case proceeding. In contrast, the tariff attributes that reflect supply or energy charges tend to be updated more frequently. An example of these rates are the "energy delivery charges" and the "market supply charges" embedded in Con Edison's default flat tariff for residential customers in NYC, which are respectively updated on rate cases every few years and every month.

In a sense, the trade-off between ex-ante and ex-post tariffs is between greater advanced price notification and more accurate prices. There is a relevant discussion on this trade-off in [14, Sec. I.C.1] in the context of real-time pricing (RTP) and time-of-use (TOU) tariffs. The authors argue that, on the one hand, "a longer lag time between the price announcement and the price implementation will result in prices that less accurately reflect the actual real-time supply/demand situation in the market." Moreover, "the longer lag time means that the prices will be less

[17]Typically, annual updates are also conducted to incorporate updated forecasts.



(a)



(b)

Figure 6.1: (a) Time-based rates used in practice and (b) comparison in temporal granularity *vs.* price uncertainty (Source: Rocky Mountain Institute [31])

volatile than, for instance, the real-time wholesale electricity price." This suggests that setting prices ex-ante implies at least:

1. More certainty and time for customers to optimize consumption;
2. A shift of the risk of facing the RTP to retailers;
3. A limitation to reflect accurately the variation of wholesale prices.

In Fig. 6.1, taken from [31], several time-based tariffs are compared in two dimensions: temporal granularity *vs.* price uncertainty. In other words, ex-ante prices facilitate customers' decision making but limit the effectiveness of prices to carry updated centralized information to coordinate decentralized decisions in real-time. According to [14], "the cost of this loss of information will depend very much on how customers would react if they were given the finer information." The example the authors give is instructive [14, pg. 14]:

> "For instance, if a factory can react to price changes only by making long-term adjustments, such as changing worker shift schedules that can be made only semi-annually, then the information in TOU prices may be all that the factory can use. In that case, no price-responsiveness is being sacrificed in using TOU prices instead of RTP. On the other hand, if the customer can make such adjustments more frequently, such as weekly or monthly, or can adjust quickly to idiosyncratic supply/demand information, such as by adjusting air conditioning settings and lighting when the system is strained, TOU rates fail to send the information that the customer needs to make these adjustments."

The authors make a final point emphasizing the fundamental impact of technology on this trade-off: "technology changes have also enhanced, and continue to enhance, the customer's ability to respond to real-time price changes." Indeed, the communication between smart meters and energy managements systems reduce the need of human intervention. This, in turn, reduces the transaction costs involved in monitoring price profile updates and in optimizing consumption[18], and increases price-responsiveness.

[18]See [71, Sec. 3] for a discussion on these transaction costs.

There is another case in which certainty may not compromise efficiency significantly by losing accuracy. This is the case of the "Value of DER" tariff proposed to compensate DER under NY's REV initiative. There is an attribute of this tariff that compensates for the generation capacity that DERs provide to the system. The following segment of the report [94] makes a clear argument:

> "The [Value of DER] tariff could base compensation for installed capacity on this value by compensating eligible generation facilities each month with a lump sum equal to their *MW performance during the peak hour in the previous year* multiplied by the actual monthly generation capacity spot prices from NYISO's ICAP market that month. However, this would result in substantial variability for intermittent technologies, which could present issues for project financing."

Recognizing this challenge, the report recommends a compensation methodology based on a "typical" technology-specific generation profile that mitigates entirely the excessive uncertainty entailed by a mechanism under which the 12 monthly payments for capacity of any year would depend on entirely on the generation exported during a single hour of the previous year.

In conclusion, when designing tariffs, there is a trade-off between longer lag times and price accuracy. This trade-off is difficult to capture in part because it involves two aspects of consumer behavior that are challenging to model or measure. These aspects are customers' risk preferences and the trade-off they face between the transaction costs involved in reacting to dynamic prices[19] and the potential bill savings they may achieve by doing so.

[19] Customers may face significant transaction costs to act timely upon complex and ex-post tariffs. Alternatively, they face the costs of technologies such as energy management systems that can mitigate such transactions costs.

APPENDIX A

APPENDIX TO CHAPTER 2

Proof of Lemma 2.3.3

Let (V, U, Λ) denote an efficient market equilibrium throughout. And, let $(\boldsymbol{\lambda}(k), \gamma(k), \boldsymbol{\mu}(k), \overline{\boldsymbol{\nu}}_i, \underline{\boldsymbol{\nu}}_i)$ denote the corresponding Lagrange multipliers satisfying the KKT conditions (2.6)-(2.13) for all k and i. We prove the desired result by establishing nonnegativity of both the TCS and SCS. ■

Proposition 1 $\text{TCS} = \sum_{k=0}^{N-1} \boldsymbol{\mu}(k)^\top \mathbf{c} \geq 0$.

Proof. We have that $\text{TCS} = -\sum_{k=0}^{N-1} \boldsymbol{\lambda}(k)^\top (\mathbf{v}(k) + \mathbf{u}(k))$ based on its definition in (2.16). Substituting for $\boldsymbol{\lambda}(k)$ according to Equation (2.8), and using the fact that $\mathbf{1}^\top (\mathbf{v}(k) + \mathbf{u}(k)) = 0$ for all k, we have that

$$\text{TCS} = \sum_{k=0}^{N-1} \boldsymbol{\mu}(k)^\top H(\mathbf{v}(k) + \mathbf{u}(k)).$$

The complementary slackness condition (2.11) yields $\text{TCS} = \sum_{k=0}^{N-1} \boldsymbol{\mu}(k)^\top \mathbf{c}$, which is clearly nonnegative. ■

Proposition 2 $\text{SCS} = \sum_{i=1}^{n} \overline{\boldsymbol{\nu}}_i^\top \mathbf{b}_i \geq 0$.

Proof. We have that $\text{SCS} = \sum_{i=1}^{n} \boldsymbol{\lambda}_i^\top \mathbf{u}_i$ based on its definition in (2.17). A direct substitution of the stationarity condition (2.10) and complementary slackness conditions (2.12)-(2.13) yields

$$\text{SCS} = \sum_{i=1}^{n} \overline{\boldsymbol{\nu}}_i^\top L\mathbf{u}_i - \underline{\boldsymbol{\nu}}_i^\top L\mathbf{u}_i = \sum_{i=1}^{n} \overline{\boldsymbol{\nu}}_i^\top \mathbf{b}_i,$$

which is clearly nonnegative. ■

The desired result follows from Propositions 1 and 2, as MS = TCS + SCS.

Proof of Lemma 2.3.9

Let (V, U, Λ) denote an efficient market equilibrium throughout. Clearly, the maximum rent achievable by any *simultaneously feasible* collection of transmission rights is given by the optimal value of

$$\begin{aligned} &\text{maximize} && \Phi(\mathcal{T}, \mathcal{F}) && && \text{(A.1)} \\ &\text{subject to} && \mathbf{t}(k) + \mathbf{q}(k) \in \mathcal{P}(\mathbf{c} - \mathbf{f}(k)), && k = 0, \ldots, N-1 && \text{(A.2)} \\ & && \mathbf{q}_i \in \mathcal{U}(\mathbf{b}_i), && i = 1, \ldots, n. && \text{(A.3)} \end{aligned}$$

This is a convex optimization problem with linear constraints in the decision variables $\mathbf{t}(k)$, $\mathbf{f}(k)$, and $\mathbf{q}(k)$ ($k = 0, \ldots, N-1$). Upon comparing the KKT conditions of the above problem with those of the multi-period economic dispatch problem (2.5)-(2.7), it is straightforward to verify that a (non-unique) optimal solution to problem (A.1)-(A.3) is given by

$$\mathbf{t}(k) = \mathbf{v}(k) + \mathbf{u}(k), \quad \mathbf{f}(k) = \mathbf{0}, \quad \text{and} \quad \mathbf{q}(k) = \mathbf{0}$$

for all k. This optimal solution yields a collection of transmission rights with an associated rent of $\Phi(\mathcal{T}, \mathcal{F}) = -\sum_{k=0}^{N-1} \boldsymbol{\lambda}(k)^\top (\mathbf{v}(k) + \mathbf{u}(k))$. This equals the TCS at the efficient market equilibrium, thus completing the proof. ■

Proof of Theorem 2.3.16

Let (V, U, Λ) denote an efficient market equilibrium throughout. Clearly, the maximum rent achievable by any *simultaneously feasible* collection of transmission and storage rights is given by the optimal value of

$$\begin{aligned} \text{maximize} \quad & \Phi(\mathcal{T}, \mathcal{F}) + \Sigma(\mathcal{S}, \mathcal{E}) && && \text{(A.4)} \\ \text{subject to} \quad & \mathbf{t}(k) - \mathbf{s}(k) + \mathbf{q}(k) \in \mathcal{P}(\mathbf{c} - \mathbf{f}(k)), && k = 0, \ldots, N-1 && \text{(A.5)} \\ & \mathbf{q}_i \in \mathcal{U}(\mathbf{b}_i - \mathbf{e}_i), && i = 1, \ldots, n. && \text{(A.6)} \end{aligned}$$

This is a convex optimization problem with linear constraints in the decision variables $\mathbf{t}(k)$, $\mathbf{f}(k)$, $\mathbf{q}(k)$, $\mathbf{s}(k)$ $(k = 0, \ldots, N-1)$, and $\mathbf{e}_i$ $(i = 1, \ldots, n)$. Upon comparing the KKT conditions of the above problem with those of the multi-period economic dispatch problem (2.5)-(2.7), it is straightforward to verify that a (non-unique) optimal solution to problem (A.4)-(A.6) is given by

$$\mathbf{t}(k) = \mathbf{v}(k) + \mathbf{u}(k), \quad \mathbf{f}(k) = \mathbf{0}, \quad \mathbf{q}(k) = \mathbf{u}(k), \quad \mathbf{s}(k) = \mathbf{u}(k), \quad \text{and} \quad \mathbf{e}_i = \mathbf{0}$$

for all k and i. This optimal solution yields a collection of transmission and storage rights with an associated rent of $\Phi(\mathcal{T}, \mathcal{F}) + \Sigma(\mathcal{S}, \mathcal{E}) = -\sum_{k=0}^{N-1} \boldsymbol{\lambda}(k)^\top \mathbf{v}(k)$. This equals the MS at the efficient market equilibrium, thus completing the proof. ■

APPENDIX B

APPENDIX TO CHAPTER 4

Proof of Theorem 4.3.1

Solving $\overline{\mathsf{rs}}(T) = F$ in (4.6) for A and substituting in the objective $\overline{\mathsf{cs}}(T)$ yields the expression

$$\overline{\mathsf{sw}}(T) \;=\; \sum_{i=1}^{M} \mathbb{E}\left[S^i(D^i(\pi,\omega^i),\omega^i) - \lambda^\top D^i(\pi,\omega^i)\right].$$

Differentiating the objective $\overline{\mathsf{sw}}(T)$ over π yields

$$\nabla_\pi \overline{\mathsf{sw}}(T) = \sum_{i=1}^{M} \mathbb{E}\left[\nabla_\pi D^i(\pi,\omega^i)\left(\nabla_q S^i(D^i(\pi,\omega^i),\omega^i) - \lambda\right)\right]$$

$$= \mathbb{E}\left[\nabla_\pi D(\pi,\omega)(\pi - \lambda)\right] \tag{B.1}$$

where the second equality follows from Prop. 4 below. Now, the assumption that each $\nabla_\pi D^i(\pi,\omega^i)$ is negative definite implies that $\mathbb{E}[\nabla_\pi D(\pi,\omega)]$ is invertible. Hence, one can rewrite the necessary first-order condition (FOC), which is obtained from equating $\nabla_\pi \overline{\mathsf{sw}}(T) = 0$, as (4.7). Given the expression (4.7) for π^*, (4.8) can be obtained by solving the equality constraint $\overline{\mathsf{rs}}(T^*) = F$ for A^*. Lastly, these FOC are sufficient for the optimality of (A^*,π^*) since $\overline{\mathsf{sw}}(T) = \overline{\mathsf{cs}}(T) + \overline{\mathsf{rs}}(T)$ is strictly concave in π according to Prop. 6. ■

Proposition 3 *For each $k = 1,\ldots,N$, $D^i(\cdot,\cdot)$ satisfies*

$$\mathbb{E}\left[\partial S^i(D^i(\pi,\omega^i),\omega^i)/\partial q^i_k \middle|\; \omega^i_1,\ldots,\omega^i_k\right] = \pi_k \tag{B.2}$$

where the conditional expectation is taken over ω^i conditioned on $\omega^i_1,\ldots,\omega^i_k$.

Proof. (B.2) are FOCs of customer i's multi-stage decision problem (4.1) of sequentially choosing $q^i_1,\ldots,q^i_k,\ldots,q^i_N$ contingent on the so-far observed local states

$\omega_1^i, \ldots, \omega_k^i$ to maximize his expected net utility or surplus, *i.e.*,

$$\max_{q^i(\cdot)} \mathbb{E}_{\omega^i} \left[S^i \left(q^i(\omega^i), \omega^i \right) - T \left(q^i(\omega^i) \right) \right] \tag{B.3}$$

given a tariff $T(q^i) = A + \pi^\top q^i$ known in advance (ex-ante). Hence, the optimal solution $q^i(\cdot) = D^i(\pi, \cdot)$ of (B.3) must satisfy these necessary optimality conditions.

Each of these stationarity (KKT) FOCs is obtained by differentiating the objective in (B.3) with respect to q_k^i and equating the result to zero. To see that, note that for each time $k = 1, \ldots, N$ one can use the law of total expectation to rewrite the objective in terms of an expectation conditioned on the information observed up to k, *i.e.*,

$$\mathbb{E}_{\omega_1^i, \ldots, \omega_k^i} \left[\mathbb{E} \left[S^i \left(q^i(\omega^i), \omega^i \right) - T \left(q^i(\omega^i) \right) \middle| \, \omega_1^i, \ldots, \omega_k^i \right] \right].$$

The FOC in (B.2) follows since $\partial T(q^i(\omega^i))/\partial q_k^i = \pi_k$. ■

Proposition 4 *$D^i(\cdot, \cdot)$ satisfies the equation*

$$\partial \mathbb{E}[S^i(D^i(\pi, \omega^i), \omega^i)]/\partial \pi = \mathbb{E} \left[\nabla_\pi D^i(\pi, \omega^i) \right] \pi \tag{B.4}$$

where the expectations are taken over ω^i.

Proof. We establish this vectorial identity proving each component separately. Assuming the differentiation and expectation operators can be exchanged, we apply the chain rule to the k-th component of the left-hand-side of (B.4) yielding the following sequence of equalities

$$\begin{aligned} \frac{\partial \mathbb{E}[S^i(D^i(\pi, \omega^i), \omega^i)]}{\partial \pi_k} &= \mathbb{E} \left[\sum_{t=1}^{N} \frac{\partial S^i}{\partial q_t^i} \cdot \frac{\partial D_t^i}{\partial \pi_k} \right] \\ &= \sum_{t=1}^{N} \mathbb{E} \left[\mathbb{E} \left[\frac{\partial S^i}{\partial q_t^i} \cdot \frac{\partial D_t^i}{\partial \pi_k} \middle| \, \omega_1^i, \ldots, \omega_t^i \right] \right] \end{aligned}$$

$$= \sum_{t=1}^{N} \mathbb{E}\left[\mathbb{E}\left[\frac{\partial S^i}{\partial q_t^i}\middle|\omega_1^i,\ldots,\omega_t^i\right]\frac{\partial D_t^i}{\partial \pi_k}\right]$$
$$= \pi^\top \mathbb{E}\left[\frac{\partial D^i}{\partial \pi_k}\right],$$

where the second equality follows from the law of total expectation, the third equality is due to the causality of $D^i(\pi, \omega^i)$, and the last equality is due to Prop. 3. The identity (B.4) readily follows.

Proposition 5 *For any affine tariff $T(q) = A + \pi^\top q$, $\overline{\mathsf{cs}}(T)$ is strictly convex and (componentwise) decreasing in π.*

Proof. Differentiating $\overline{\mathsf{cs}}(T)$ with respect to π (using the chain rule) and leveraging on the expression (B.4) from Prop. 4 one readily obtains $\nabla_\pi \overline{\mathsf{cs}}(T) = -\mathbb{E}[D(\pi, \omega)]$. Because $D^i(\pi, \omega^i)$ is nonnegative, the expression above implies that $\overline{\mathsf{cs}}(T)$ is componentwise decreasing π. Moreover, we have that

$$\nabla_\pi^2 \overline{\mathsf{cs}}(T) = -\mathbb{E}[\nabla_\pi D(\pi, \omega)]. \tag{B.5}$$

Recall that a function is strictly convex (over a convex domain) if its Hessian is positive definite (over said domain). Hence, the strict convexity of $\overline{\mathsf{cs}}(T)$ in π readily follows from the assumed negative definiteness of each matrix $\nabla_\pi D^i(\pi, \omega)$. ■

Proposition 6 *Consider an affine tariff $T(q) = A + \pi^\top q$. If Assumption 2 holds then $\overline{\mathsf{rs}}(T)$ and the weighted surplus $\overline{\mathsf{cs}}(T) + \gamma \overline{\mathsf{rs}}(T)$ are strictly concave in π for any $\gamma \geq 1$.*

Proof. First, we differentiate twice $\overline{\mathsf{rs}}(T)$ with respect to π. Using Prop. 4 and some algebra one obtains the Hessian

$$\nabla_\pi^2 \overline{\mathsf{rs}}(T) = \mathbb{E}[\nabla_\pi D(\pi, \omega)] + \nabla g(\pi). \tag{B.6}$$

Recall that a function is strictly concave (over a convex domain) if its Hessian is negative definite (over said domain). Hence, the assumed negative definiteness of $\nabla_\pi D^i(\pi, \omega)$ and of $\nabla g(\pi)$ (Assumption 2) readily imply the negative definiteness of $\nabla_\pi^2 \overline{\mathsf{rs}}(T)$ and thus the strict concavity of $\overline{\mathsf{rs}}(T)$ in π.

It remains to show that $\nabla_\pi^2(\overline{\mathsf{cs}}(T) + \gamma\overline{\mathsf{rs}}(T))$ is negative definite for $\gamma \geq 1$. From (B.5) and (B.6) we have that

$$\nabla_\pi^2(\overline{\mathsf{cs}}(T) + \gamma\overline{\mathsf{rs}}(T)) = (\gamma - 1)\mathbb{E}[\nabla_\pi D(\pi, \omega)] + \gamma \nabla g(\pi).$$

Similar arguments yield the desired result since both terms on the right hand side are negative definite for $\gamma \geq 1$. ■

Proof of Corollary 4.3.2

If $\nabla_\pi D(\pi, \omega)$ and λ are uncorrelated, then clearly $\mathbb{E}[\nabla_\pi D(\pi, \omega)\lambda] = \mathbb{E}[\nabla_\pi D(\pi, \omega)]\overline{\lambda}$. It follows that the expression for π^* in (4.7) reduces to $\pi^* = \overline{\lambda}$. In turn, the expression for $\overline{\phi}(\pi^*)$ in (4.8) reduces to $\overline{\phi}(\pi^*) = \overline{\phi}(\overline{\lambda}) = -\operatorname{Tr}(\mathbb{C}\text{ov}(\lambda, D(\overline{\lambda}, \omega)))$, thus readily simplifying (4.8) to

$$A^* = \tfrac{1}{M}\left(F + \operatorname{Tr}\left(\mathbb{C}\text{ov}\left(\lambda, D\left(\overline{\lambda}, \omega\right)\right)\right)\right). \qquad ■$$

Proof of Corollary 4.3.4

Leveraging on (4.2) and (4.4), the expected total surplus induced by the tariff T^* characterized in Thm. 4.3.1 can be written as

$$\begin{aligned}\overline{\mathsf{sw}}^* &= \overline{\mathsf{sw}}(T^*)\\ &= \overline{\mathsf{cs}}(T^*) + \overline{\mathsf{rs}}(T^*)\\ &= \sum_{i=1}^{M} \mathbb{E}\left[S^i(D^i(\pi^*, \omega^i), \omega^i) - \lambda^\top D^i(\pi^*, \omega^i)\right].\end{aligned}$$

Clearly, $\overline{\mathsf{sw}}(T)$ is a function of π but not of F or A. It remains to show that π^* does not depend on F. But the FOC characterizing π^* is obtained by differentiating $\overline{\mathsf{sw}}(T)$ with respect to π and equating it to zero. It follows that $\overline{\mathsf{sw}}^*$ does not on F. Moreover, since $\overline{\mathsf{rs}}(T^*) = F$ must hold at optimality, it readily follows that

$$\overline{\mathsf{cs}}(T^*) = \overline{\mathsf{sw}}(T^*) - \overline{\mathsf{rs}}(T^*) = \overline{\mathsf{sw}}^* - F. \qquad \blacksquare$$

Proof of Theorem 4.3.3

Consider the Lagrangian of problem (4.6)

$$\mathcal{L}(\pi, \gamma) = \overline{\mathsf{cs}}(T) + \gamma(\overline{\mathsf{rs}}(T) - F), \tag{B.7}$$

where $\gamma \in \mathbb{R}$ is the multiplier of the equality constraint. Differentiating $\mathcal{L}(\pi, \gamma)$ over π yields

$$\begin{aligned}\nabla_\pi \mathcal{L} &= \nabla_\pi \overline{\mathsf{cs}}(T) + \gamma \nabla_\pi \overline{\mathsf{rs}}(T)\\ &= \mathbb{E}[\gamma \nabla_\pi D(\pi, \omega)(\pi - \lambda) + (\gamma - 1) D(\pi, \omega)],\end{aligned} \tag{B.8}$$

where we use Prop. 4 to obtain the second equality. The necessary FOC in (4.11) follows from equating (B.8) to zero after some algebra. These operations use the negative definiteness and thus invertibility of the matrix $\mathbb{E}[\nabla_\pi D(\pi,\omega)]$ and the expression for π^* in (4.7) (Thm. 4.3.1).

The expressions in (4.12) characterizing $\pi^\dagger$ componentwise can be obtained from (4.11) after some algebraic manipulations using the definition of price elasticity in (4.10). In particular, subtracting π^* from both sides of (4.11) and left-multiplying by $\mathbb{E}[\nabla_\pi D(\pi^\dagger,\omega)]$ one obtains

$$\mathbb{E}[\nabla_\pi D(\pi^\dagger,\omega)](\pi^\dagger - \pi^*) = -\tfrac{\gamma-1}{\gamma}\mathbb{E}[D(\pi^\dagger,\omega)].$$

Componentwise, for each $k = 1,\ldots,N$, we have

$$\begin{aligned}
\mathbb{E}[\nabla_\pi D_k(\pi^\dagger,\omega)]^\top(\pi^\dagger - \pi^*) &= -\tfrac{\gamma-1}{\gamma}\mathbb{E}[D_k(\pi^\dagger,\omega)] \\
\frac{\sum_{t=1}^N \mathbb{E}[\partial D_k(\pi^\dagger,\omega)/\partial \pi_t](\pi_t^\dagger - \pi_t^*)}{\mathbb{E}[D_k(\pi^\dagger,\omega)]} &= -\frac{\gamma-1}{\gamma} \\
\sum_{t=1}^N -\overline{\varepsilon}_{kt}(\pi^\dagger)\left(\frac{\pi_t^\dagger - \pi_t^*}{\pi_t^\dagger}\right) &= \frac{\gamma-1}{\gamma}.
\end{aligned}$$

As for the last statement of the theorem, consider that maximizing $\overline{\mathsf{rs}}(T)$ (or equivalently $\overline{\phi}(\pi)$) over π yields the related stationarity FOC

$$\pi^{\mathrm{M}} = \pi^* - \mathbb{E}[\nabla_\pi D(\pi^{\mathrm{M}},\omega)]^{-1}\mathbb{E}[D(\pi^{\mathrm{M}},\omega)]. \tag{B.9}$$

This condition, which is similar to (4.11), characterizes the unregulated monopoly price π^{M}. Indeed, (B.9) can be obtained from (4.11) by replacing $\frac{\gamma-1}{\gamma}$ by 1, or equivalently, by letting $\gamma \to \infty$ on both sides of (4.11).

Now, because π^{M} maximizes $\overline{\phi}(\pi)$ and $\overline{\mathsf{rs}}(T)$ over $\pi \geq 0$, there does not exist $\pi \geq 0$ such that $\overline{\mathsf{rs}}(T) > \overline{\phi}(\pi^{\mathrm{M}})$. Hence, when restricted to linear tariffs, problem (4.6) is infeasible for all $F > \overline{\phi}(\pi^{\mathrm{M}})$. For all the other values of F within the considered regime, *i.e.*, $F \in [\overline{\phi}(\pi^*), \overline{\phi}(\pi^{\mathrm{M}})]$, the fact that π^* and π^{M} achieve $\overline{\phi}(\pi^*)$ and $\overline{\phi}(\pi^{\mathrm{M}})$, respectively, and the concavity of $\overline{\mathsf{rs}}(T)$ (Prop. 6) imply the feasibility of problem (4.6) over said interval of F. Concluding, in the regime $F \geq \overline{\phi}(\pi^*)$, problem (4.6) over linear tariffs is feasible if $F \leq \overline{\phi}(\pi^{\mathrm{M}})$ and unfeasible otherwise.

Proof of Corollary 4.3.5

At optimality, we have that $\overline{\mathsf{rs}}(T^\dagger) = F$ and thus $d\overline{\mathsf{rs}}(T^\dagger)/dF = 1$. The envelope theorem further implies that the derivative of the value function $\overline{\mathsf{cs}}(T^\dagger)$ of problem (4.6) with respect to the parameter F can be computed as $d\overline{\mathsf{cs}}(T^\dagger)/dF = \partial\mathcal{L}(\pi^\dagger,\gamma)/\partial F = -\gamma$. The total derivative of the expected total surplus with respect to F is then $d\overline{\mathsf{sw}}(T^\dagger)/dF = 1-\gamma$. Hence, to show that $\overline{\mathsf{cs}}(T^\dagger)$ and $\overline{\mathsf{sw}}(T^\dagger)$ are decreasing and concave functions of F over $F \in [\overline{\phi}(\pi^*), \overline{\phi}(\pi^{\mathrm{M}})]$, it suffices to show that γ, as a function of F, satisfies $\gamma \geq 1$ and $d\gamma/dF \geq 0$ over $F \in [\overline{\phi}(\pi^*), \overline{\phi}(\pi^{\mathrm{M}})]$.

Moreover, it is clear from the Lagreangian $\mathcal{L}(\pi,\gamma)$ in (B.7) that $\overline{\mathsf{rs}}(T^\dagger)$ must be a decreasing function of the parameter γ. Conversely, the constraint $\overline{\mathsf{rs}}(T) = F$ implies that $\overline{\mathsf{rs}}(T^\dagger)$ is a strictly increasing function of F. Hence, we have that γ increases as F increases, and thus $d\gamma/dF \geq 0$.

Finally, note that $\gamma = 1$ and $\pi^\dagger = \pi^*$ are optimal for $F = \overline{\phi}(\pi^*)$ since they satisfy the FOC (4.11) and the constraint $\overline{\mathsf{rs}}(T^\dagger) = F$. Recall also from Thm. 4.3.3 that the problem at hand remains feasible if $F \leq \overline{\phi}(\pi^{\mathrm{M}})$. Because $d\gamma/dF \geq 0$, we can conclude that $\gamma \geq 1$ for $F \in [\overline{\phi}(\pi^*), \overline{\phi}(\pi^{\mathrm{M}})]$, thus completing the proof.

Proof of Theorem 4.3.6

We prove this result by showing that the optimal two-part tariff T^* characterized by Theorem 4.3.1 attains an upper bound for the performance of all *ex-ante* tariffs. This upper bound is the performance achieved by a social planner who directly makes all decisions on behalf of consumers. The social planner is unlike the regulator who is limited to coordinate such decisions indirectly through a tariff. To obtain a tight upper bound for ex-ante tariffs only (rather than a looser bound for all possibly ex-post tariffs), the social planner makes customers' decisions relying only on the information observable by each of them (*i.e.*, ω^i) as opposed to based on global information (*e.g.*, $\xi = (\lambda, \omega^1, \ldots, \omega^M)$).

Consider the social planner's problem in (4.17), which corresponds to the regulator's problem (4.6) in the absence of any DERs. Therein, the notation $q^i(\omega^i)$ indicates the restriction of the social planner to make (causal) decisions *contingent only* on the local state of each customer ω^i. Recall from (4.1) that the expected consumer surplus for a given ex-ante tariff is given by $\overline{\mathsf{cs}}(T) = \sum_{i=1}^{M} \overline{\mathsf{cs}}^i(T)$, where

$$\begin{aligned}\overline{\mathsf{cs}}^i(T) &= \max_{q^i(\cdot)} \mathbb{E}\left[S^i\left(q^i(\omega^i), \omega^i\right) - T\left(q^i(\omega^i)\right)\right] \\ &= \mathbb{E}\left[S^i(q^i(T, \omega^i), \omega^i) - T\left(q^i(T, \omega^i)\right)\right],\end{aligned}$$

and the corresponding expected retailer surplus is given by

$$\overline{\mathsf{rs}}(T) = \mathbb{E}\left[\sum_{i=1}^{M} T\left(q^i(T, \omega^i)\right) - \lambda^\top q^i(T, \omega^i)\right],$$

and the expected total surplus by

$$\begin{aligned}\overline{\mathsf{sw}}(T) &= \overline{\mathsf{cs}}(T) + \overline{\mathsf{rs}}(T) \\ &= \mathbb{E}\left[\sum_{i=1}^{M} S^i\left(q^i(T, \omega^i), \omega^i\right) - \lambda^\top q^i(T, \omega^i)\right].\end{aligned}$$

The following sequence of equalities/inequalities shows that problem (4.17) provides an upper bound to problem (4.6).

$$\begin{aligned}
&\max_{T(\cdot)}\{\overline{\mathsf{cs}}(T) \mid \overline{\mathsf{rs}}(T) = F\} + F \\
&\quad = \max_{T(\cdot)}\{\overline{\mathsf{cs}}(T) + F \mid \overline{\mathsf{rs}}(T) = F\} \\
&\quad = \max_{T(\cdot)}\{\overline{\mathsf{cs}}(T) + \overline{\mathsf{rs}}(T) \mid \overline{\mathsf{rs}}(T) = F\} \\
&\quad = \max_{T(\cdot)}\{\overline{\mathsf{sw}}(T) \mid \overline{\mathsf{rs}}(T) = F\} \\
&\quad \le \max_{T(\cdot)}\ \overline{\mathsf{sw}}(T) && \text{(B.10)} \\
&\quad \le \max_{\{q^i(\cdot)\}_{i=1}^M} \mathbb{E}\left[\sum_{i=1}^M S^i(q^i(\omega^i), \omega^i) - \lambda^\top q^i(\omega^i)\right] && \text{(B.11)} \\
&\quad = \max_{\{q^i(\cdot)\}_{i=1}^M}\ \overline{\mathsf{sw}}. && \text{(B.12)}
\end{aligned}$$

In particular, the inequality in (B.11) holds because $\overline{\mathsf{sw}}(T)$ depends on T only through $q^i(T, \omega^i)$. This implies that maximizing $\overline{\mathsf{sw}}(T)$ directly over $\{q^i(\cdot)\}_{i=1}^M$ rather than indirectly over $T(\cdot)$ is a relaxation of the optimization in (B.10). Clearly, the problem in (B.11) corresponds to the social planner's problem in (B.12) and (4.17).

It suffices to show now that T^* attains the upper bound in (B.12). To that end, we use the independence sufficient condition $\omega \perp \lambda$. We show that, under said condition, the expected total surplus $\overline{\mathsf{sw}}(T^*)$ matches the upper bound. First note that the condition $\omega \perp \lambda$ allows to rewrite the upper bound in (B.11) and

(B.12) as follows.

$$
\begin{aligned}
&\max_{\{q^i(\cdot)\}_{i=1}^M} \mathbb{E}_\xi \left[\mathsf{sw}\right] \\
&\qquad = \sum_{i=1}^{M} \max_{q^i(\cdot)} \ \mathbb{E}_{\omega^i} \left[S^i(q^i(\omega^i), \omega^i) - \mathbb{E}\left[\lambda^\top | \omega^i\right] q^i(\omega^i)\right] \\
&\qquad = \sum_{i=1}^{M} \max_{q^i(\cdot)} \ \mathbb{E}_{\omega^i} \left[S^i(q^i(\omega^i), \omega^i) - \overline{\lambda}^\top q^i(\omega^i)\right] \\
&\qquad = \sum_{i=1}^{M} \mathbb{E}_{\omega^i} \left[S^i(D^i(\overline{\lambda}, \omega^i), \omega^i) - \overline{\lambda}^\top D^i(\overline{\lambda}, \omega^i)\right].
\end{aligned}
$$

The last equality follows from the definition of the demand function $D^i(\pi, \omega^i)$ in (4.3) as the optimal response of customers to deterministic prices.

The result follows since the tariff T^* induces the same expected total surplus if $\omega \perp \lambda$, *i.e.*,

$$
\begin{aligned}
\overline{\mathsf{sw}}(T^*) &= \mathbb{E}_\xi \left[\sum_{i=1}^{M} S^i(D^i(\pi^*, \omega^i), \omega^i) - \lambda^\top D^i(\pi^*, \omega^i)\right] \\
&= \sum_{i=1}^{M} \mathbb{E}_{\omega^i} \left[S^i(D^i(\overline{\lambda}, \omega^i), \omega^i) - \overline{\lambda}^\top D^i(\overline{\lambda}, \omega^i)\right]. \qquad \blacksquare
\end{aligned}
$$

APPENDIX C

APPENDIX TO CHAPTER 5

Proof of Theorem 5.2.1

To solve the optimization problem (5.3) over affine tariffs of the form $T(d) = A + \pi^\top d$, we obtain expressions for $\overline{\mathsf{cs}}(T)$ and $\overline{\mathsf{rs}}(T)$ in terms of the parameters π and A, considering the customer-integrated DERs.

On one hand, from the separability implications of the linearity of T on the customers' problem established in Sec. 5.2.2, we have that customers with DERs obtain an expected surplus

$$\begin{aligned}\overline{\mathsf{cs}}^i(T) &= \mathbb{E}[S^i(D^i(\pi,\omega^i)) - T(d^i(\pi,\omega^i))]\\ &= \overline{\mathsf{cs}}^i_0(T) + \mathbb{E}[\pi^\top(s^*(\pi,\theta^i) + r^i(\omega^i))],\end{aligned}$$

where $\overline{\mathsf{cs}}^i_0(T)$, the expected consumer surplus without DERs, is computed according to (5.1), *i.e.*,

$$\overline{\mathsf{cs}}^i_0(T) = \mathbb{E}\big[S^i(D^i(\pi,\omega^i),\omega^i) - \pi^\top D^i(\pi,\omega^i)\big] - A. \tag{C.1}$$

On the other hand, since this case does not consider retailer-integrated DERs, the retailer derives an expected surplus

$$\begin{aligned}\overline{\mathsf{rs}}(T) &= \sum_{i=1}^{M} \mathbb{E}[T(d^i(\pi,\omega^i)) - \lambda^\top d^i(\pi,\omega^i)]\\ &= \overline{\mathsf{rs}}_0(T) - \sum_{i=1}^{M} \mathbb{E}[(\pi-\lambda)^\top(s^*(\pi,\theta^i) + r^i(\omega^i))]\end{aligned}$$

where $\overline{\mathsf{rs}}_0(T)$, the expected retailer surplus without DERs, is computed according to (5.2), *i.e.*,

$$\overline{\mathsf{rs}}_0(T) = A\cdot M + \sum_{i=1}^{M} \mathbb{E}\left[(\pi-\lambda)^\top D^i(\pi,\omega^i)\right].$$

We can now solve the constraint $\overline{\mathsf{rs}}(T) = F$ for A,

$$A = \frac{1}{M}\left(F - \mathbb{E}\left[\sum_{i=1}^{M}(\pi - \lambda)^\top d^i(\pi, \omega^i)\right]\right) \tag{C.2}$$

and replace it in the objective function of problem (5.3), $\overline{\mathsf{cs}}(T)$, which yields

$$\overline{\mathsf{cs}}(T) = \overline{\mathsf{sw}}_0(T) - F + \sum_{i=1}^{M} \mathbb{E}[\lambda^\top (s^*(\pi, \theta^i) + r^i(\omega^i))] \tag{C.3}$$

where $\overline{\mathsf{sw}}_0(T) = \overline{\mathsf{cs}}_0(T) + \overline{\mathsf{rs}}_0(T)$, the expected total surplus that T would induce in the absence of DERs, is given by

$$\overline{\mathsf{sw}}_0(T) = \sum_{i=1}^{M} \mathbb{E}\left[S^i(D^i(\pi, \omega^i), \omega^i) - \lambda^\top D^i(\pi, \omega^i)\right]. \tag{C.4}$$

One can then show that $\overline{\mathsf{sw}}_0(T)$ is maximized over π at $\pi_{\text{DEC}} = \overline{\lambda}$ (see proof of Theorem 1 in [87]), when $\nabla_\pi D(\pi, \omega)$ and λ are uncorrelated (see Cor. 1 in [87]). Moreover, each term $\mathbb{E}[\lambda^\top s^*(\pi, \theta^i)]$ is also maximized over π at $\pi_{\text{DEC}} = \overline{\lambda}$ since

$$\mathbb{E}[\lambda^\top s^*(\pi, \theta^i)] = \overline{\lambda}^\top s^*(\pi, \theta^i) \leq \overline{\lambda}^\top s^*(\overline{\lambda}, \theta^i) = V(\overline{\lambda}, \theta^i)$$

for all $\pi \in \mathbb{R}^N$. Consequently, the expression $\overline{\mathsf{cs}}(T)$ in (C.3) is maximized over π at $\pi^*_{\text{DEC}} = \overline{\lambda}$. The strict concavity of $\overline{\mathsf{sw}}_0(T)$ in π (Prop. 4 in [87]) guarantees the uniqueness and optimality of π^*_{DEC} and A^*_{DEC}. Replacing π and $d^i(\pi, \omega^i)$ in (C.2) for $\overline{\lambda}$ and $d^i(\overline{\lambda}, \omega^i)$ according to (5.6), respectively, yields the expression for A^*_{DEC} in (5.7), where

$$A^* = \frac{1}{M}\left(F + \text{Tr}\left(\mathbb{C}\text{ov}\left(\lambda, D\left(\overline{\lambda}, \omega\right)\right)\right)\right)$$

is the optimal connection charge without DERs for uncorrelated $\nabla_\pi D(\pi, \omega)$ and λ (Corollary 1 in [87]). ■

Proof of Corollary 5.2.2

Theorem 5.2.1 implies that if $\nabla_\pi D(\pi, \omega)$ and λ are uncorrelated then $\pi^*_{\text{DEC}} = \overline{\lambda}$, which does not depend on the parameter F. Hence, it is clear from (C.4) that

$\overline{\mathsf{sw}}_0^* \equiv \overline{\mathsf{sw}}_0(T^*)$, where $T^*(q) = A^* + \pi^{*\top} q$, is also independent from the parameter F. It follows from (C.3) that

$$\overline{\mathsf{cs}}(T^*_{\text{DEC}}) = \overline{\mathsf{sw}}_0^* - F + \textstyle\sum_{i=1}^M V(\overline{\lambda}, \theta^i) + \mathbb{E}[\lambda^\top r^i(\omega^i)]$$

and, since $\overline{\mathsf{rs}}(T^*_{\text{DEC}}) = F$ at optimality,

$$\overline{\mathsf{sw}}(T^*_{\text{DEC}}) = \overline{\mathsf{sw}}_0^* + \textstyle\sum_{i=1}^M V(\overline{\lambda}, \theta^i) + \mathbb{E}[\lambda^\top r^i(\omega^i)].$$

Thus, $\overline{\mathsf{sw}}(T^*_{\text{DEC}})$ is also independent of the parameter F. ■

Proof of Theorem 5.2.3

We show this result using arguments analogous to those in the proof of Theorem 3 in [87]. That is, we show that the optimal two-part tariff T^*_{DEC} attains an upper bound for the performance of all *ex-ante* tariffs derived from the social planner's problem. To obtain a tight upper bound for ex-ante tariffs only (rather than a looser bound for all possibly ex-post tariffs), the social planner makes customers' decisions relying only on the information observable by each of them (*i.e.*, ω^i) as opposed to based on global information (*e.g.*, $\xi = (\lambda, \omega^1, \ldots, \omega^M)$).

Consider the social planner's problem

$$\max_{\{q^i(\cdot), s^i(\cdot)\}_{i=1}^M} \quad \overline{\mathsf{sw}} \tag{C.5a}$$

$$\text{s.t} \quad s^i(\omega^i) \in \mathcal{U}(\theta^i), \qquad i = 1, \ldots, M. \tag{C.5b}$$

with

$$\overline{\mathsf{sw}} = \mathbb{E}_\xi \left[\sum_{i=1}^M S^i(q^i(\omega^i), \omega^i) - \lambda^\top d^i(\omega^i) \right]$$

which is related to the regulator's problem (5.3) with customer-integrated DERs. The notations $q^i(\omega^i)$, $s^i(\omega^i)$, and $d^i(\omega^i)$ indicate the restriction of the social planner to make (causal) decisions *contingent only* on the local state of each customer ω^i. Recall from (5.5) that the expected consumer surplus for a given ex-ante tariff is given by $\overline{\mathsf{cs}}(T) = \sum_{i=1}^{M} \overline{\mathsf{cs}}^i(T)$, where $\overline{\mathsf{cs}}^i(T)$ can be written as

$$\begin{aligned}\overline{\mathsf{cs}}^i(T) &= \max_{q^i(\cdot), s^i(\cdot)} \left\{ \mathbb{E}\left[S^i(q^i(\omega^i), \omega^i) - T\Big(q^i(\omega^i) - r^i(\omega^i) - s^i(\omega^i)\Big)\right] \Big| s^i(\omega^i) \in \mathcal{U}(\theta^i) \right\} \\ &= \mathbb{E}\Bigg[S^i(q^{i*}(T, \omega^i), \omega^i) - T\Big(\underbrace{q^{i*}(T, \omega^i) - r^i(\omega^i) - s^{i*}(T, \omega^i)}_{d^{i*}(T,\omega^i)} \Big)\Bigg], \end{aligned} \tag{C.6}$$

and note that the corresponding expected retailer surplus is given by

$$\overline{\mathsf{rs}}(T) = \mathbb{E}\left[\sum_{i=1}^{M} T(d^{i*}(T, \omega^i)) - \lambda^\top d^{i*}(T, \omega^i) \right],$$

and the expected total surplus by

$$\begin{aligned}\overline{\mathsf{sw}}(T) &= \mathbb{E}\Bigg[\sum_{i=1}^{M} S^i(q^{i*}(T, \omega^i), \omega^i) - \lambda^\top d^{i*}(T, \omega^i) \Bigg] \\ &= \mathbb{E}\Bigg[\sum_{i=1}^{M} S^i(q^{i*}(T, \omega^i), \omega^i) - \lambda^\top q^{i*}(T, \omega^i) \Bigg] \\ &\qquad + \mathbb{E}\Bigg[\sum_{i=1}^{M} \lambda^\top (r^i(\omega^i) + s^{i*}(T, \omega^i)) \Bigg]. \end{aligned}$$

The following sequence of equalities/inequalities shows that problem (C.5) provides an upper bound to problem (5.3).

$$\begin{aligned} &\max_{T(\cdot)} \{\overline{\mathsf{cs}}(T) \mid \overline{\mathsf{rs}}(T) = F\} + F \\ &= \max_{T(\cdot)} \{\overline{\mathsf{cs}}(T) + \overline{\mathsf{rs}}(T) \mid \overline{\mathsf{rs}}(T) = F\} \\ &= \max_{T(\cdot)} \{\overline{\mathsf{sw}}(T) \mid \overline{\mathsf{rs}}(T) = F\} \\ &\le \max_{T(\cdot)} \ \overline{\mathsf{sw}}(T) && \text{(C.7)} \\ &\le \max_{\{q^i(\cdot)\}_{i=1}^M} \mathbb{E}\left[\sum_{i=1}^{M} S^i(q^i(\omega^i), \omega^i) - \lambda^\top q^i(\omega^i) \right] \\ &\quad + \sum_{i=1}^{M} \max_{s^i(\cdot)} \Big\{ \mathbb{E}\left[\lambda^\top (r^i(\omega^i) + s^i(\omega^i))\right] \ \Big| \ s^i(\omega^i) \in \mathcal{U}(\theta^i) \Big\} && \text{(C.8)} \\ &= \max_{\{q^i(\cdot), s^i(\cdot)\}_{i=1}^M} \ \Big\{ \ \overline{\mathsf{sw}} \ \Big| \ s^i(\omega^i) \in \mathcal{U}(\theta^i), \ i = 1, \ldots, M \Big\}. && \text{(C.9)} \end{aligned}$$

In particular, the inequality in (C.8) holds because $\overline{\mathsf{sw}}(T)$ depends on T only through $q^{i*}(T, \omega^i)$ and $s^{i*}(T, \omega^i)$. This implies that maximizing $\overline{\mathsf{sw}}(T)$ directly over $\{q^i(\cdot), s^i(\cdot)\}_{i=1}^M$ rather than indirectly over $T(\cdot)$ is a relaxation of the optimization in (C.7). Clearly, the problem in (C.8) corresponds to the social planner's problem in (C.9) and (C.5).

It suffices to show now that T^*_{DEC} attains the upper bound in (C.9). To that end, we use the independence sufficient condition $\omega \perp \lambda$. We show that, under said condition, the expected total surplus $\overline{\mathsf{sw}}(T^*_{\text{DEC}})$ matches the upper bound. First note that the condition $\omega \perp \lambda$ allows to rewrite the upper bound in (C.8) and (C.9) as follows.

$$
\begin{aligned}
&\max_{\{q^i(\cdot), s^i(\cdot)\}_{i=1}^M} \left\{ \overline{\mathsf{sw}} \;\middle|\; s^i(\omega^i) \in \mathcal{U}(\theta^i),\; i = 1, \ldots, M \right\} \\
&= \sum_{i=1}^M \max_{q^i(\cdot)} \; \mathbb{E}_{\omega^i} \left[S^i(q^i(\omega^i), \omega^i) - \mathbb{E}_{\lambda|\omega^i} \left[\lambda | \omega^i \right]^\top q^i(\omega^i) \right] \\
&\qquad\qquad + \mathbb{E}_\xi \left[\lambda^\top r^i(\omega^i) \right] \\
&\qquad\qquad + \max_{s^i(\cdot)} \left\{ \mathbb{E}_\xi \left[\lambda^\top s^i(\omega^i) \right] \;\middle|\; s^i(\omega^i) \in \mathcal{U}(\theta^i) \right\} \\
&= \sum_{i=1}^M \max_{q^i(\cdot)} \; \mathbb{E}_{\omega^i} \left[S^i(q^i(\omega^i), \omega^i) - \overline{\lambda}^\top q^i(\omega^i) \right] \quad + \quad \overline{\lambda}^\top \overline{r}^i \\
&\qquad\qquad + \max_{s^i(\cdot)} \left\{ \overline{\lambda}^\top \overline{s}^i \;\middle|\; s^i(\omega^i) \in \mathcal{U}(\theta^i) \right\} \\
&= \sum_{i=1}^M \mathbb{E}_{\omega^i} \left[S^i(D^i(\overline{\lambda}, \omega^i), \omega^i) - \overline{\lambda}^\top D^i(\overline{\lambda}, \omega^i) \right] \\
&\qquad\qquad + \overline{\lambda}^\top \overline{r}^i \quad + \quad \overline{\lambda}^\top s^*(\overline{\lambda}, \theta^i),
\end{aligned}
$$

where the last equality follows from the definition of the demand function $D^i(\pi, \omega^i)$ and the simplification of storage operation policy under deterministic prices.

The result follows since the tariff T^*_{DEC} induces the same expected total surplus if $\omega \perp \lambda$, *i.e.*,

$$\begin{aligned}\overline{\mathsf{sw}}(T^*_{\text{DEC}}) &= \mathbb{E}_\xi\Bigg[\sum_{i=1}^{M} S^i(D^i(\pi^*_{\text{DEC}},\omega^i),\omega^i) - \lambda^\top D^i(\pi^*_{\text{DEC}},\omega^i)\Bigg] \\ &\qquad + \mathbb{E}\Bigg[\sum_{i=1}^{M} \lambda^\top (r^i(\omega^i) + s^*(\pi^*_{\text{DEC}},\theta^i))\Bigg] \\ &= \sum_{i=1}^{M} \mathbb{E}_{\omega^i}\Big[S^i(D^i(\overline{\lambda},\omega^i),\omega^i) - \overline{\lambda}^\top D^i(\overline{\lambda},\omega^i)\Big] \\ &\qquad + \overline{\lambda}^\top (\overline{r}^i + s^*(\overline{\lambda},\theta^i)). \qquad \blacksquare\end{aligned}$$

Proof of Theorem 5.2.4

To solve problem (5.3) over affine tariffs of the form $T(d) = A + \pi^\top d$, we first need expressions for $\overline{\mathsf{cs}}(T)$ and $\overline{\mathsf{rs}}(T)$ in terms of (π, A), considering the retailer-integrated DERs.

On the one hand, since this case does not consider customer-integrated DERs, the customers derive an expected surplus that remains unchanged, *i.e.*, $\overline{\mathsf{cs}}^i(T) = \overline{\mathsf{cs}}^i_0(T)$. On the other hand, (5.9) characterizes the expected retailer surplus induced by T considering the retailer-integrated DERs.

According to (5.9), $\overline{\mathsf{rs}}(T)$ depends on the decision variables (π, A) only through $\overline{\mathsf{rs}}_0(T)$. Hence, the regulator's problem (5.3) at hand, with parameter F, is equivalent to that of the regulator without any DERs and parameter $\tilde{F} := F - V(\overline{\lambda},\theta^o) - \mathbb{E}[\lambda^\top r^o(\xi)]$, *i.e.*,

$$\max_{T(\cdot)} \ \overline{\mathsf{cs}}_0(T) \quad \text{s.t.} \quad \overline{\mathsf{rs}}_0(T) = \tilde{F}. \tag{C.10}$$

Theorem 1 in [87] for the case without DERs characterizes the optimal two-part tariff for problem (C.10). Applying this result to problem (C.10) yields the desired result, *i.e.*,

$$\pi^*_{\text{CEN}} = \overline{\lambda} + \mathbb{E}[\nabla_\pi D(\pi^*_{\text{CEN}}, \omega)]^{-1}\mathbb{E}[\nabla_\pi D(\pi^*_{\text{CEN}}, \omega)(\lambda - \overline{\lambda})]$$

and

$$\begin{aligned} A^*_{\text{CEN}} &= \tfrac{1}{M}\left(\tilde{F} - \mathbb{E}\left[(\pi^*_{\text{CEN}} - \lambda)^\top D(\pi^*_{\text{CEN}}, \omega)\right]\right) \\ &= \tfrac{1}{M}\left(F - \mathbb{E}\left[(\pi^*_{\text{CEN}} - \lambda)^\top D(\pi^*_{\text{CEN}}, \omega)\right]\right) \\ &\qquad\qquad - \tfrac{1}{M}\left(V(\overline{\lambda}, \theta^o) - \mathbb{E}[\lambda^\top r^o(\xi)]\right) \\ &= A^* - \tfrac{1}{M}\left(V(\overline{\lambda}, \theta^o) - \mathbb{E}[\lambda^\top r^o(\xi)]\right). \end{aligned} \qquad \blacksquare$$

Proof of Corollary 5.2.5

Applying Cor. 2 in [87] to problem (C.10) implies that

$$\begin{aligned} \overline{\mathsf{cs}}(T^*_{\text{CEN}}) &= \overline{\mathsf{sw}}^*_0 - \tilde{F} \\ &= \overline{\mathsf{sw}}^*_0 - F + V(\overline{\lambda}, \theta^o) + \mathbb{E}[\lambda^\top r^o(\xi)] \end{aligned}$$

where, according to (5.8), $\overline{\mathsf{sw}}^*_0 \equiv \overline{\mathsf{sw}}_0(T^*)$ does not depend on F. The result follows since $\overline{\mathsf{rs}}(T^*_{\text{CEN}}) = F$ further implies that

$$\begin{aligned} \overline{\mathsf{sw}}(T^*_{\text{CEN}}) &= \overline{\mathsf{cs}}(T^*_{\text{CEN}}) + \overline{\mathsf{rs}}(T^*_{\text{CEN}}) \\ &= \overline{\mathsf{sw}}^*_0 + V(\overline{\lambda}, \theta^o) + \mathbb{E}[\lambda^\top r^o(\xi)]. \end{aligned} \qquad \blacksquare$$

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